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2016

World Oil Outlook

Organization of the Petroleum Exporting Countries

2016

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Organization of the Petroleum Exporting Countries

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Foreword

This year's World Oil Outlook (WOO) is the tenth edition of the publication, a significant milestone for OPEC's flagship publication. The WOO 2016 once again provides OPEC's analysis and views of the medium- and long-term outlook, and marks the conclusion of a challenging twelve months.

Since the publication last December of the WOO 2015, oil producers, consumers and investors have faced an oil market that has continued to readjust to the changing industry landscape – something that started in mid-2014. During 2016, the market has shown signs that fundamentals are gradually rebalancing. However, despite non-OPEC supply contracting considerably, global demand remaining robust and the pace of the stock build decelerating, it is clear that instability and volatility remain.

In January of this year, the OPEC Reference Basket (ORB) price fell to $22.48/barrel. It means that between June 2014 and January 2016 the ORB price fell by 80%. This is the largest percentage drop in the five episodes of sharp price declines that the market has experienced over the past three decades. Since then, however, prices mostly saw an upward trend until May, with the ORB price then settling above $40/b in the third quarter of this year.

Meanwhile, stock levels have recently levelled out, but remain well-above their five-year average. And while global spending on exploration and production by oil and gas producers is expected to fall slightly less this year, the combined amount over the two years still equates to a loss of more than $300 billion. This will impact not only new projects coming onstream, but new discoveries too.

The WOO 2016 takes these various shifting dynamics on board in its analysis and considers developments in the global economy, in oil supply and demand, both in the upstream and downstream, as well as various other drivers, challenges and uncertainties. These include policies, technology, the changing energy mix and sustainable development concerns, all of which contribute to the future outlook. The consideration of these factors helps to provide a detailed analysis that includes a breakdown by region, sector and timeframe.

In regards to the global economy, last year's WOO anticipated that medium-term global economic growth would average 3.6% per annum (p.a.) in the period 2014–2020. This year it has been revised down slightly to 3.4% p.a. for the timeframe of 2015–2021. This revised growth rate reflects the fact that there have been some marginal downward revisions in the medium-term growth outlook for some regions this year, particularly China and Latin America. However, the outlook remains optimistic concerning long-term global economic growth rates, which are the same as those in the WOO 2015, averaging 3.5% p.a. in the period to 2040.

On the demand side, it is important to highlight that the medium-term outlook to 2021 is 99.2 million barrels a day (mb/d), which is 1 mb/d higher than that assumed in last year's outlook. This is the result of a lower medium-term oil price assumption, which is expected to have a stronger influence than assumptions of lower medium-term economic growth and expanded energy efficiency policies. In the long-term, however, additional energy efficiency measures and the potential for new technological developments – such as alternative fuel vehicles – have led to oil demand in 2040 dropping slightly to 109.4 mb/d, a downward revision of 0.4 mb/d compared to last year.

In terms of supply, the lower oil price environment is expected to see overall non-OPEC supply decline in the period 2016–2017, before slowly rising again to 2021. It is expected to rise from 56.9 mb/d in 2015 to 58.6 mb/d in 2021, an increase of 1.7 mb/d. In the long-term, non-OPEC supply again rises steadily, but it is expected to peak at 61.4 mb/d in 2027, before dropping to 58.9 mb/d in 2040. However, uncertainties remain, and these are explored in the outlook through downside and upside non-OPEC supply scenarios.

It all means that OPEC will be required to meet most of the additional long-term oil demand. In terms of crude, it is expected that OPEC will have to supply an additional 8.9 mb/d between 2015 and 2040. For all OPEC liquids, the figure is 12.6 mb/d. The share of OPEC crude in the global liquids supply is also expected to increase from around 34% today to around 37% by 2040.

In the downstream sector, lower oil prices have also impacted the medium-term outlook. A number of investors have deferred refining projects from the 2016–2018 timeframe to 2019–2021. The latter period is now the one that is expected to see an excess of refining capacity emerging, hence increased competition, which could lead to reduced margins and, potentially, closures.

Further downstream capacity rationalization is expected in the longer term to 2040, particularly if refining regions are to maintain utilization rates of at least 80%, with closures in Europe leading the way. Moreover, slowing global demand growth and rising non-crude supplies see the pace of required refinery capacity additions decelerating in the long-term, although regions with growing demand will still see strong growth. Additions are led by the Asia-Pacific and the Middle East regions which, when combined, are expected to see almost 13 mb/d of the total 19.5 mb/d of global capacity additions needed by 2040.

Given the demand and supply outlook, there is a need for significant investments across the entire industry. Overall, the outlook sees oil-related investment requirements of around $10 trillion over the period to 2040. In this regard, it is important to remember that the short-, medium- and long-term timeframes are all linked.

One question that needs to be asked is whether the recent lower oil price environment is putting this future outlook at risk, particularly given the drop-off in investments seen over the past two years. While the recent oil market environment has been one of oversupply, it is vital that the industry ensures that a lack of investments today does not lead to a shortage of supply in the future.

Let me stress that OPEC Member Countries remain committed to investing in new capacity and necessary infrastructure as they have always done as reliable suppliers of crude oil and products. But it is essential to ensure that investment projects have the right enabling environment, with a focus on sustainable market stability. If the right signals are not forthcoming, there is the possibility that innovation will dry up, that technological breakthroughs will not materialize, and that not enough new capacity and infrastructure will be in place in time to meet future demand levels.

Market stability, balanced fundamentals and ensuring that the necessary future investments are made were central to the recent decision taken at the 170th (Extraordinary) Meeting of the OPEC Conference in Algiers, when the Conference opted for an OPEC-14 production target ranging between 32.5 and 33 mb/d, in order to accelerate the ongoing drawdown of the stock overhang and bring the rebalancing further forward.

The WOO 2016 also explores a number of other issues that are likely to have an impact on how the future oil market and energy mix evolve. One example is future energy policies, with a major focus on last year's COP21 Paris Agreement, which aims to stabilize the increase in global average temperature and limit greenhouse gas emissions. OPEC welcomes this agreement, its Member Countries played a role in drafting it, and they will also play a role in helping to implement it.

The impact of the increased focus on climate change mitigation measures can already be seen in this year's Reference Case energy mix. In the power generation sector, for example, there is a shift to renewables and away from coal, in particular, and gas to a lesser extent. While gas does see a drop in expected demand by 2040 compared to last year's outlook, it should be noted that it still sees the largest growth by far in absolute terms. And oil and gas are still anticipated to meet 53% of the world's energy needs by 2040. In percentage terms, other renewables, mainly wind, solar and geothermal, see the largest average annual growth at 6.6% p.a. However, given their low initial base, the overall share in the energy mix is anticipated to be only 4.7% by 2040.

The Paris Agreement also provides a context in which the objectives of achieving sustainable development and eradicating poverty can be pursued. It is essential to appreciate, however, that sustainable development and its three dimensions or 'pillars' – economic, environmental and social – mean different things to different people. In addition, the energy dimension in this is sometimes overlooked. It is thus important to recall that one of the United Nation's Sustainable Development Goals focuses specifically on energy and calls for nations to ensure universal access to affordable, reliable and modern energy services. Today there are around 2.7 billion people worldwide who still rely on biomass for their basic needs, and 1.3 billion who have no access to electricity. It is critical that this energy poverty be addressed.

The outlook also considers the possible impact of technology in areas such as renewable energies, alternative fuel vehicles, and clean or low-carbon energy processes, such as carbon capture and storage, and many others. At OPEC, we recognize the importance of continually looking to advance the environmental credentials of oil, both in production and use.

As always, the aim of the WOO is to serve as an important and informative reference tool, with the hope that it contributes to a better and more enhanced understanding of the global oil and energy markets. It aims to share the Organization's views on the global oil market – specifically, in the medium- and long-term – and to provide an overall assessment of the future prospects for the entire global energy mix.

I should also like to take this opportunity to praise the hard work of the dedicated team of experts and staff at the OPEC Secretariat that put together this publication. Their commitment to research, comprehensive analysis, data transparency and to providing a detailed breakdown of the key issues needs to be recognized. Their work is also an expression of the broader, ongoing commitment of the Organization to further discussions on energy outlooks and widen engagement with other energy stakeholders. Such a steadfast commitment supports and reinforces one of the main tenets of our organizational mission: to foster dialogue and encourage cooperation in order to help ensure market stability in the short-, medium- and long-term.

Mohammad Sanusi Barkindo
Secretary General

Executive Summary

2016: a turning point towards a more balanced market

Since the previous World Oil Outlook (WOO) was launched last December, the oil market has shown signs that it is heading towards a more balanced situation, despite continuing volatility and challenges remaining on several fronts. In January 2016, the OPEC Reference Basket (ORB) reached its lowest level ($22.48/barrel) since the price decline that started in the second half of 2014. It has since shown a general upward trend and over the past couple of months it has fluctuated in the range of $40–45/b. On the supply side, non-OPEC production has contracted this year, while demand remains relatively heathy at around 1.2 million barrels per day (mb/d).

Contributing to this more optimistic, albeit cautious, sentiment is the behaviour of oil stocks. Despite the current exceptionally high level of stocks, the pace of the build-up has clearly decelerated in 2016. In addition, the sharp decline in oil upstream capital expenditure (CAPEX) investment experienced in 2015 has slightly decelerated in 2016. Moreover, in some specific areas, investment is even coming back in a watchful fashion compared to last year. Overall, it can be said that, despite its fragile state, the oil market is in the process of readjusting.

Population growth increasingly coming from Developing countries, but growth decelerating and populace ageing

Global population is projected to increase by almost 1.8 billion people from 2015–2040 and surpass 9 billion people. The majority of the population increase will take place in Developing countries. By 2040, 81% of the global population will be in Developing countries, *versus* 78% in 2015.

Population growth rates have been steadily trending downward since the 1970s and this trend will continue in the future. Moreover, the overall age structure of the world is expected to shift towards an older population. Currently, 8% of the global population is over 65 and this is expected to increase to 14% by 2040, while the working age population comprised of individuals aged between 15–64 is estimated to decrease from 66% to 64%.

Population by region

millions

	Levels				Growth
	2015	2020	2030	2040	2015–2040
OECD	1,288	1,320	1,371	1,404	117
Developing countries	5,675	6,043	6,724	7,339	1,664
Eurasia	343	345	342	334	–8
World	**7,305**	**7,708**	**8,437**	**9,078**	**1,772**

GDP growth gradually recovers to average 3.4% p.a. in the medium-term and then 3.5% p.a. in the long-term

Global Gross Domestic Product (GDP) growth in the Reference Case is assumed to gradually recover and accelerate in the medium-term to average 3.4% per annum (p.a.). Within the medium-term, average GDP growth in the OECD region is expected

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

	2015–2021	2021–2030	2030–2040	2015–2040
OECD	2.0	2.1	2.0	2.0
Developing countries	4.8	4.7	4.2	4.6
Eurasia	1.7	2.5	2.3	2.2
World	**3.4**	**3.6**	**3.4**	**3.5**

to improve from the current level of just below 2% and stabilize at around 2.2% p.a. Growth in Developing countries is also expected to improve over the medium-term, from 4.4% in 2016 to around 4.9% p.a. during 2018–2021. In Eurasia, medium-term growth is anticipated to accelerate as a result of geopolitical improvements and less instability. Long-term global economic growth for the period 2015–2040 is assumed at 3.5% p.a. Growth is mainly driven by Developing countries, which has an estimated average growth rate of 4.6% p.a. over the forecast period. Within Developing countries, GDP growth in India and China is especially noteworthy, with rates estimated at 6.9% p.a. and 4.9% p.a., respectively, over the forecast period.

China and India increase their GDP share of the world economy, as the OECD region grows at a slower pace

The size of the world economy in 2040 is anticipated to be 234% that of 2015. The overall GDP increase is estimated at almost $141 trillion (2011 Purchasing Power Parity (PPP)). Most of the growth will come from Developing countries, which will account for three-quarters of the total increase.

In fact, there will be significant changes in the distribution of the global economic pie. By 2020, China will overtake OECD America in terms of real GDP and, by 2040, China's real GDP will be more than 1.5 times that of OECD America. India will surpass OECD Europe around 2034 and, by 2040, India's real GDP will be about the same size as OECD America. The global share of real GDP in the OECD region is expected to decrease from 45% in 2015 to 32% in 2040. Separately, India and China will see an increase in their combined global share of real GDP from 24% in 2015 to 40% in 2040.

Energy policies continue to focus on emission reductions

The Reference Case takes into account numerous energy policies that are already in place. Additionally, the Outlook accepts the fact that the policy process will evolve over time. Therefore, new policies are assumed to be a reasonable extension of past trends and a reflection of the current debate on policy issues. These focus primarily on measures to achieve emission reductions.

Oil price assumption echoes expected gradual improvements in market conditions

The average ORB price for 2016 is expected to be around $40/b. In the medium-term, the price recovery is assumed to continue with $5/b increments in the period up to 2021. With this, the ORB price reaches a level of $65/b by 2021 in nominal terms, slightly above $60/b in real 2015 prices. This assumption reflects expected gradual improvements in market conditions. In the long-term, prices are assumed to reach a level of $92/b by 2040 in real ($2015) prices, which is equivalent to $155/b in nominal terms. It should be stressed that these are neither price forecasts nor a desired price path for OPEC crude, but working assumptions that help guide the development of the Reference Case.

Total primary energy demand is forecast to increase by 40% in the period to 2040, with the bulk of the increase from Developing countries

On a global level, total primary energy demand is forecast to increase by 40% in the period to 2040 to reach 382 million barrels of oil equivalent per day (mboe/d). On a regional basis, energy demand in Developing countries is expected to grow at an average rate of 2.1% p.a. over the forecast period 2014–2040. This is in sharp contrast with the average 0.1% p.a. growth projected for OECD regions and the 0.6% for Eurasia. This variation is a reflection of the relatively higher economic growth forecast for Developing countries combined with higher population growth rates and increased urbanization.

Total primary energy demand by region

	Levels *mboe/d*				Growth *% p.a.*
	2014	2020	2030	2040	2014–2040
OECD America	55.7	57.9	58.6	58.0	0.2
OECD Europe	36.5	36.7	36.4	36.1	0.0
OECD Asia Oceania	18.4	19.3	19.8	19.8	0.3
OECD	**110.6**	**113.9**	**114.8**	**113.9**	**0.1**
China	60.2	68.8	80.9	88.1	1.5
India	16.0	20.3	30.2	41.2	3.7
OPEC	23.8	27.4	34.9	41.3	2.1
Other DCs	39.7	45.5	56.5	69.9	2.2
Developing countries	**139.8**	**162.0**	**202.5**	**240.5**	**2.1**
Russia	14.9	14.8	15.8	16.5	0.4
Other Eurasia	8.6	9.2	10.4	11.3	1.1
Eurasia	**23.5**	**24.0**	**26.3**	**27.8**	**0.6**
Total world	**273.9**	**299.9**	**343.6**	**382.1**	**1.3**

Energy mix continues to see fast growth for renewables, but 53% of the world's energy needs will still be satisfied by oil and gas in 2040

Currently, fossil fuels – namely, oil, gas and coal – account for 81% of the global energy mix. By 2040, fossil fuels will maintain their importance in the global energy mix, although with a lower share of 77% of total energy demand. Combined, oil and gas are forecast to satisfy 53% of the energy needs in 2040, similar to current

World primary energy demand by fuel type

mboe/d

	Levels *mboe/d*				Growth *% p.a.*
	2014	2020	2030	2040	2014–2040
Oil	85.1	90.7	96.7	99.8	0.6
Coal	77.7	82.7	88.9	91.5	0.6
Gas	59.6	66.9	84.0	101.7	2.1
Nuclear	13.2	15.5	19.5	23.4	2.2
Hydro	6.6	7.6	8.9	9.9	1.5
Biomass	28.2	30.7	34.6	38.1	1.2
Other renewables	3.4	5.7	11.0	17.9	6.6
Total world	**273.9**	**299.9**	**343.6**	**382.1**	**1.3**

levels. With regard to non-fossil fuels, the largest gains in terms of the share in the total energy mix are expected in 'Other renewables' (+3.4 percentage points) and nuclear (+1.3 percentage points).

The shift away from coal towards gas and renewables in power generation is not surprising as policymakers are increasingly engaged in climate change mitigation initiatives. In absolute terms, the majority of the demand growth will come from gas (+42.3 mboe/d) followed by oil (+14.7 mboe/d), other renewables (+14.5 mboe/d), coal (+13.8 mboe/d) and nuclear (+10.2 mboe/d).

Medium-term oil demand revised upwards by 1 mb/d in 2021…

The medium-term oil demand outlook shows an increase of 6.2 mb/d from 93 mb/d in 2015 to 99.2 mb/d in 2021. This corresponds to an average annual increase of around 1 mb/d. Compared to last year's WOO, oil demand in 2021 has been revised upwards by 1 mb/d. The net revision to oil demand in Developing countries is 0.6 mb/d. Within Developing countries, major revisions were made for India which accounted for an increase of 0.5 mb/d, while downward revisions were made to Latin America (–0.2 mb/d) and China (–0.1 mb/d) on the back of a gloomier economic outlook. Demand in OECD Europe (+0.2 mb/d), OECD America (+0.2 mb/d) have been revised upwards by 2021.

Medium-term oil demand in the Reference Case

mb/d

	2015	2016	2017	2018	2019	2020	2021
OECD	46.2	46.4	46.5	46.4	46.2	45.9	45.7
Developing countries	41.5	42.4	43.4	44.5	45.7	46.8	47.9
Eurasia	5.3	5.4	5.4	5.5	5.5	5.6	5.6
World	**93.0**	**94.2**	**95.3**	**96.4**	**97.4**	**98.3**	**99.2**

During the medium-term, demand in the OECD region is expected to decrease by 0.5 mb/d. Contrary to this, oil demand in Developing countries is expected to grow by 6.4 mb/d. In Eurasia, the medium-term oil demand outlook shows marginal growth of 0.3 mb/d. In terms of refined products, strong demand growth is expected for both light products and middle distillates, particularly in transportation fuels and petrochemicals feedstock.

…but long-term oil demand is revised downwards by 0.4 mb/d in 2040

The Reference Case sees oil demand reaching 109.4 mb/d by 2040. This corresponds to a marginal downward revision of 0.4 mb/d with respect to the WOO 2015. This downward revision is on the back of a further tightening of energy policies and additional technology developments that foster the penetration of alternative fuel vehicles.

Developing countries will continue to lead demand growth, increasing by close to 25 mb/d over the period, to reach 66.1 mb/d by 2040. Eurasia also expands to 6 mb/d by 2040. Demand in the OECD region, however, is expected to fall to 37.3 mb/d by the end of the forecast period, a drop of almost 9 mb/d.

Long-term oil demand in the Reference Case

mb/d

	2015	2020	2025	2030	2035	2040
OECD	46.2	45.9	44.3	42.1	39.7	37.3
Developing countries	41.5	46.8	52.2	57.4	62.0	66.1
Eurasia	5.3	5.6	5.8	6.0	6.1	6.0
World	**93.0**	**98.3**	**102.3**	**105.5**	**107.8**	**109.4**

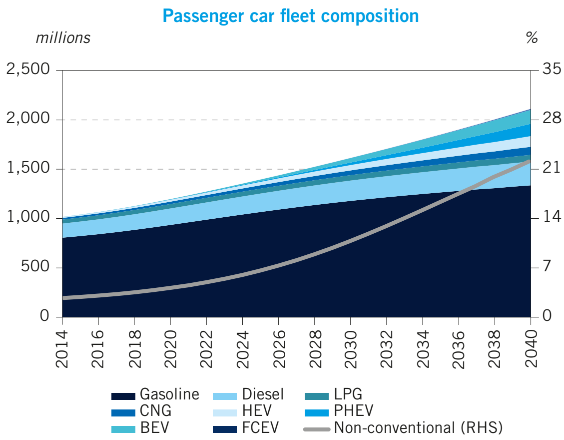
Demand growth comes mainly from the road transportation, petrochemicals and aviation sectors

Over one-third of the total demand increase between 2015 and 2040 comes from the road transportation sector (6.2 mb/d). Strong growth is also foreseen in the petrochemicals sector (3.4 mb/d) with OPEC, Other Asia, China and India accounting for most of the growth, as well as the aviation sector with an addition of 2.8 mb/d by 2040. Aviation demand growth is expected in every region, particularly in China and India, as the growing middle class push demand for aviation services. The only sector where declining oil demand is expected is the electricity generation sector, with 1.3 mb/d of demand anticipated to be removed from this sector between 2015 and 2040.

Future car fleet: increasing, particularly in Developing countries, and more non-conventional

By 2040, the total number of passenger cars is expected to double, increasing from around 1 billion in 2015 to 2.1 billion in 2040. Most of the increase comes from Developing countries.

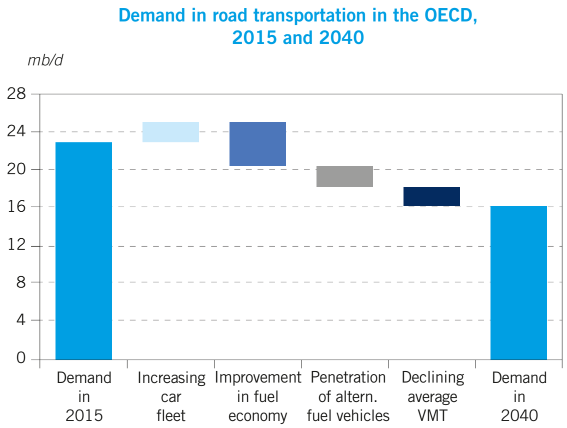
The car fleet composition is also expected to change significantly in the years ahead. While conventional powertrains (comprising gasoline, liquefied petroleum gas (LPG) and diesel vehicles) are expected to continue to account for most



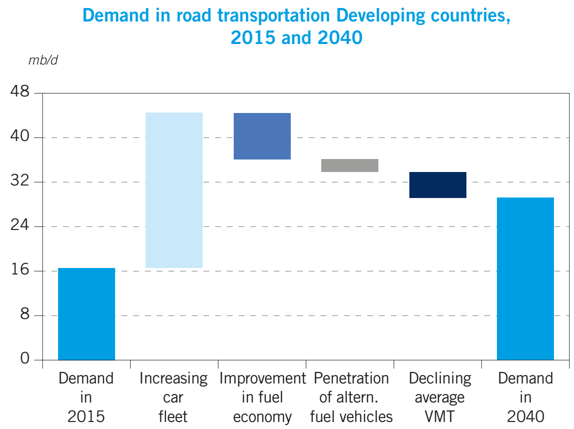
of the passenger cars on the roads, non-conventional powertrains such as natural gas vehicles (NGVs), hybrid electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs) and fuel cell vehicles (FCVs) are starting to play an increasing role, although they are currently at a very low level.

Overall, non-conventional powertrain passenger vehicles will represent 22% of the passenger car fleet by 2040, up from only 3% in 2014. Most of the growth in non-conventional powertrain passenger vehicles will come from BEVs. By 2040, they are anticipated to account for 6.7% of the car fleet, or a total of 141 million cars.

Driving forces in the road transportation sector: increasing car fleet in Developing countries and declining oil use per vehicle in the OECD region



Demand in the road transportation sector is set to grow by 6.2 mb/d over the forecast period. However, growth is unequally distributed. In the OECD, demand in this sector is expected to drop by 6.7 mb/d between 2015 and 2040 as a strong decline in oil use per vehicle (OPV) – the result of car fleet efficiency improvements, the penetration of alternative fuel vehicles and the declining average vehicle miles travelled (VMT) – far outbalances the moderate increase in the passenger car and commercial vehicle fleet. In Developing countries, however, demand is anticipated to increase by



12.6 mb/d between 2015 and 2040. Contrary to what is foreseen in the OECD, the expected decline in OPV in Developing countries is not enough to compensate for the significant increase in the vehicle fleet.

A slow road to recovery for medium-term non-OPEC supply

Total non-OPEC liquids supply is expected to shrink from 56.9 mb/d in 2015 to 55.9 mb/d in 2017 – a decline of 1 mb/d – in response to reduced spending in the lower oil price environment. A slow recovery in output is then projected for the rest of the medium-term, in line with the gradual rise in the Outlook's price assumption over the period. By 2021, supply is seen reaching 58.6 mb/d, with most of the growth coming from Latin America and the US & Canada.

Medium-term liquids supply outlook in the Reference Case

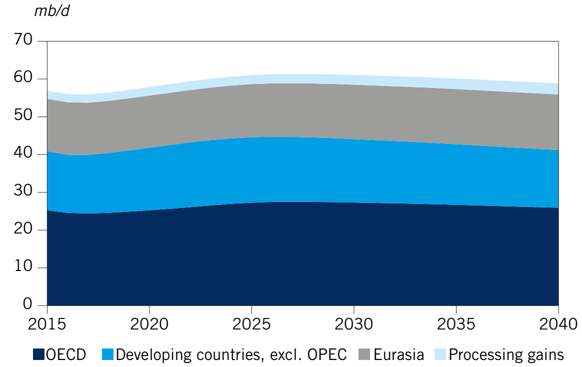
mb/d

	2015	2016	2017	2018	2019	2020	2021
US & Canada	18.4	17.9	17.9	18.2	18.5	18.9	19.4
of which: tight crude	*4.9*	*4.2*	*4.1*	*4.2*	*4.3*	*4.5*	*4.8*
OECD	**25.2**	**24.6**	**24.4**	**24.6**	**24.9**	**25.2**	**25.6**
DCs, excl. OPEC	**15.7**	**15.4**	**15.5**	**15.9**	**16.2**	**16.6**	**16.9**
Eurasia	**13.8**	**13.9**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**
Non-OPEC	**56.9**	**56.0**	**55.9**	**56.4**	**57.1**	**57.9**	**58.6**
Crude	*42.5*	*41.5*	*41.4*	*41.6*	*42.0*	*42.5*	*42.9*
NGLs	*7.1*	*7.1*	*7.1*	*7.1*	*7.2*	*7.4*	*7.5*
of which: unconv. NGLs	*2.1*	*2.2*	*2.2*	*2.3*	*2.4*	*2.5*	*2.7*
Other liquids	*7.2*	*7.4*	*7.5*	*7.7*	*7.9*	*8.1*	*8.3*
Total OPEC supply	**38.2**	**38.9**	**39.4**	**40.0**	**40.4**	**40.6**	**40.7**
OPEC crude	*32.0*	*32.7*	*33.0*	*33.4*	*33.7*	*33.7*	*33.7*
Stock change	**2.1**	**0.8**	**0.0**	**0.0**	**0.2**	**0.2**	**0.2**
World supply	**95.1**	**95.0**	**95.3**	**96.4**	**97.6**	**98.5**	**99.4**

Non-OPEC supply fairly flat over long-term, but declines post-2030

Non-OPEC liquids output is seen rising to a high of 61.4 mb/d in 2027 and then slowly dropping to 58.9 mb/d in 2040. The OECD reaches a maximum of 27.5 mb/d in 2027 (mainly from the US & Canada), while Developing countries (particularly Latin America) reach a high of 17.3 mb/d in 2024. Only Eurasia continues to grow over the long-term, reaching 14.7 mb/d in 2040.

Long-term non-OPEC liquids supply in the Reference Case



Until 2030, a major source of growth is US tight crude. Around this time, tight crude begins to contract, while sources like oil sands and biofuels become more important non-OPEC supply growth drivers.

Tight oil makes a comeback, then gradually declines

On the back of lower oil prices and investment cuts, the production of tight oil (tight crude and unconventional natural gas liquids (NGLs)) is seen falling in both 2016 and 2017. It is then expected to return to a positive growth pattern. Global tight crude plus unconventional NGLs production reaches a high of approximately 10 mb/d in 2029 and then remains relatively level for a few years thereafter, before declining to below 9 mb/d in 2040. At that stage, around 8 mb/d of this production is anticipated to come from the US & Canada. Some long-term tight oil production is also anticipated from Argentina and Russia. The higher projections in this year's outlook are due to reduced costs and the sector's productivity improvements, some of which are anticipated to have lasting effects.

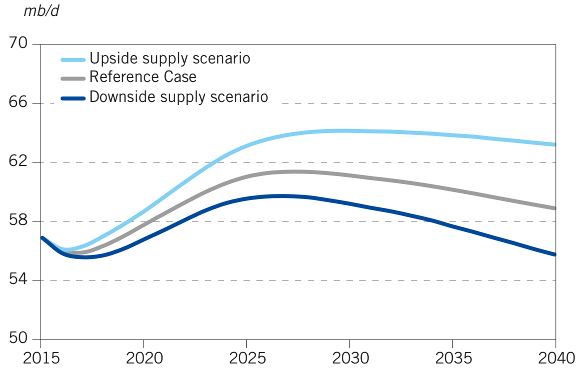
OPEC crude relatively flat from 2019–2025, but rises steadily post-2025

The demand for OPEC crude rises from 32 mb/d in 2015 to 33.4 mb/d in 2018. It then stays approximately constant for several years – hovering in the range of 33.6–33.8 mb/d between 2019 and 2025. From that point forward, OPEC crude exhibits steady growth until the end of the projection period when it is anticipated to reach 41 mb/d. Moreover, the estimated share of OPEC crude in the total world liquids supply in 2040 is 37%, which is 3 percentage points higher than the 2015 level.

Non-OPEC supply outlook still marked by uncertainty

To reflect supply uncertainties that result from various factors including costs, technologies, geology, policies and geopolitical developments, upside and downside scenarios have been developed for non-OPEC supply sources including tight oil, crude, NGLs, biofuels and other liquids. By 2040, non-OPEC output reaches 63.2 mb/d in the upside scenario and 55.8 mb/d in the downside scenario – compared with 58.9 mb/d in the Reference Case. It should be noted that these scenarios also lead to a range of requirements for OPEC crude over the long-term. In the Reference Case, demand for OPEC crude amounts to 41 mb/d in 2040. In the downside non-OPEC supply scenario OPEC crude increases to 44.1 mb/d and in the upside non-OPEC supply scenario it drops to 36.6 mb/d in 2040.

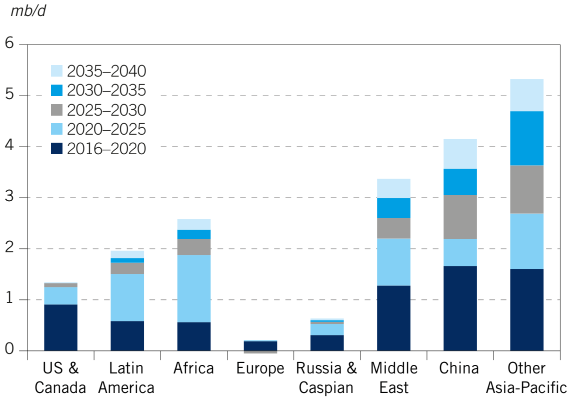
Non-OPEC supply in the Reference Case, the upside and downside supply scenarios



New refining capacity continues to follow demand growth to developing regions, led by the Asia-Pacific

The trend for new refinery distillation capacity to be located in developing regions continues in this Outlook. The fundamental driver is the shift in demand growth to those areas and away from industrialized regions. Assessed project additions to 2021 total 7.3 mb/d, with further capacity requirements of 12.2 mb/d by 2040, for a total of 19.5 mb/d of new capacity projected as needed by the end of the timeframe. Of this, only just over 2 mb/d is in the US & Canada, Europe, and the Russia & Caspian combined. In contrast, 9.5 mb/d is projected for the Asia-Pacific region, 3.4 mb/d for the Middle East and the remaining 4.6 mb/d is split between Africa and Latin America.

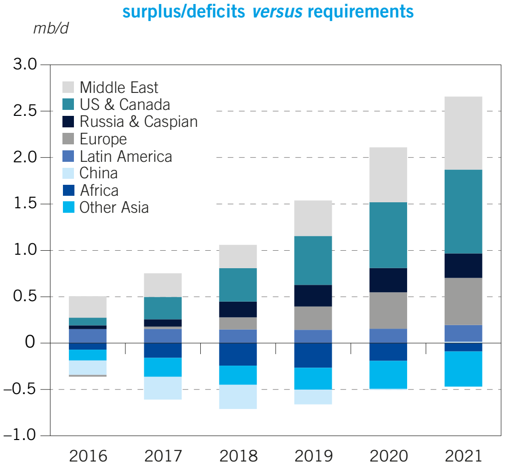
Crude distillation capacity additions in the Reference Case



The crude oil price drop has led to significant project deferrals yet excess medium-term capacity remains an issue

The recent crude oil price drop has had the effect of deferring some projects and related investments from the 2016–2018 period to the 2019–2021 timeframe. Nevertheless, assuming that the projects will materialize as assessed, allowing for some minor capacity 'creep' and for realistic maximum utilizations, total incremental potential refinery output by 2021 is 7.4 mb/d. This compares to an expected net incremental demand for refined products of 5.2 mb/d. Thus, the 2019–2021 period looks to be the one where an excess of refining capacity emerges, with implications for increased competition for product markets and, hence, for refinery margins and potential closures. By 2021, China looks to be in balance on incremental projects *versus* refinery demand, while Africa and Other Asia are in deficit, and all other regions are in surplus.

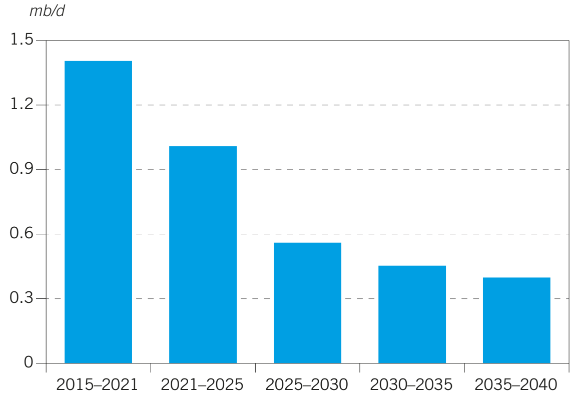
Net cumulative regional refining potential surplus/deficits *versus* requirements



Slowing demand growth and rising non-crude supplies see the pace of required refinery capacity additions dropping inexorably in the long-term

The progressive reduction in demand growth rates over the long-term, together with increases in the supply of non-crude streams, steadily reduces the level of required refinery additions. Current assessed projects of 7.3 mb/d expected to be online by 2021 comprise nearly 40% of the total additions projected as needed to 2040. From a current pace of around 1.4 mb/d p.a. based on projects and creep, required additions drop to around 0.6 mb/d p.a. post-2025, and to 0.4 p.a. mb/d post-2035. Given the need for continuing closures, the long-term prospects are for an era in which there could be no net increase in global refining capacity, and even the possibility of a net shrinkage.

Rate of distillation capacity additions in the Reference Case



Capacity rationalization is a long-term requirement

Some 2.5 mb/d of net refinery closures are expected by 2020 and an estimated 4 mb/d by 2025. Added to this, further closures to 2040 of around 5 mb/d are indicated as needed if refining regions are to maintain utilization rates of at least 80%, a level considered as a minimum for viable operations. The implied annual closure rate for 2016–2040 of 0.3–0.4 mb/d is well below the 1 mb/d rate that applied from 2012–2015.

Europe is expected to see continuing closures as the region's demand progressively declines and even as net product exports moderately increase. A long-term decline in domestic demand, after peaking around 2018, also makes US refineries vulnerable. However, model projections indicate that US refineries will remain sufficiently competitive over the longer term to be able to raise product exports as domestic demand drops, thereby mitigating – but not eliminating – reductions in crude runs and needed closures. For Japan and Australasia, substantial recent and announced closures are indicated as sufficient to avert the need for additional closures in the long-term provided refiners there can also moderately reduce imports and raise product exports.

In the developing regions, apart from selected closures planned for Middle East refineries prior to 2020, the main areas where long-term rationalization is indicated as needed are in Latin America and Africa.

Secondary processing projects are running at significant levels relative to distillation, but even higher proportions are needed longer term

Current firm secondary unit projects to 2021 are significant, with conversion at 41% of new distillation capacity, desulphurization at 70% and octane units at

18.3%. These ratios are remarkably similar to those for the 2016 global base capacity. Over the long-term, however, higher proportions of secondary processing are needed; from 2016–2040, conversion additions are close to 60% of distillation additions, desulphurization are over 100% and octane units are at 25%. These are the result of the need to deal with the long-term decline in residual fuel demand, complete the shift to ultra-low sulphur (ULS) standards for gasoline and diesel worldwide, and meet a gradual increase in octane levels driven by fuel efficiency standards.

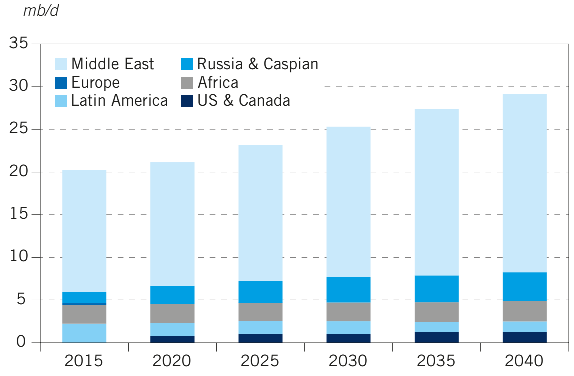
Lifting the US crude oil export ban and logistics developments bring changes to crude flows

The lifting of the US crude oil export ban allows for a new cross-trade to develop wherein light and super light crudes – not well-fitted to US refinery configurations – are exported, which leaves room for heavier, sour crudes to be imported. Canadian exports may become hampered by a lack of sufficient pipeline (plus rail) capacity unless new projects are built in the next few years. Of four major pipeline projects, two may go ahead, one to the west and one to the east. These would impact crude flows. From less than 0.1 mb/d in 2015 and 0.5–0.6 mb/d by mid-2016, crude oil exports from the US & Canada are projected to exceed 1 mb/d by 2020 and 2 mb/d by 2035, based on the outlooks for crude and condensate supply in each country.

The primary trend in long-term oil trade is growing crude imports into the Asia-Pacific from the Middle East

As product demand and crude runs decline in the industrialized regions, so too do their crude oil imports. Combined crude oil imports into the US & Canada, Europe, Japan and Australasia drop by 3 mb/d between 2015 and 2040. In marked contrast, imports into the Asia-Pacific region grow by nearly 9 mb/d during the same period as this region remains the primary focus of demand growth. Of this increase, over 6.5 mb/d comprises growth in exports from the Middle East. Increased flows, mainly via the ESPO pipeline, will progressively raise imports from the Russia & Caspian region, but the Middle East to the Asia-Pacific dominates crude trade growth going forward.

Crude oil imports to the Asia-Pacific by origin, 2015–2040



In the period to 2040, required global investment in the oil sector is estimated at $10 trillion

The expected oil upstream investment requirements over the period 2016–2040 are $7.4 trillion (in 2015 dollars). On an annual basis, the average upstream investment requirement is estimated at almost $300 billion with non-OPEC accounting for more than three-quarters. While OPEC average annual investment requirements total $65 billion, in non-OPEC countries it adds up to around $230 billion. Within non-OPEC countries, the bulk of the investment needs are anticipated in the OECD, with an average annual requirement of more than $160 billion as a result of higher exploration costs and steeper decline rates.

In the downstream sector, refinery investment requirements are estimated at somewhat over $1.5 trillion for the forecast period. Of this, $265 billion is needed for investments in known projects, around $385 billion for additions beyond firm projects and just under $900 billion for capacity maintenance and replacement. Finally, investment requirements in the midstream sector are estimated at $1.1 trillion.

Intended Nationally Determined Contributions (INDCs) and the Paris Agreement provide guidance for future energy policies

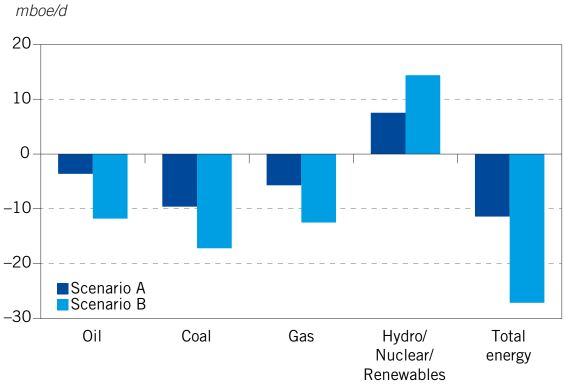
The Paris Agreement calls for the stabilization of the rise in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to enhance the temperature target further to 1.5°C. The Agreement also draws a powerful context within which its objectives should be pursued, namely, achieving sustainable development and eradicating poverty. Within these contexts, the Agreement considers the differences among the countries and calls on the Parties to reflect on 'equity' and the 'principle of common but differentiated responsibilities and respective capabilities, in the light of different national circumstances', when they take actions.

INDC submissions to the United Nations Framework Convention on Climate Change (UNFCCC) cover nearly all Parties and provide important guidance on how future energy policies might evolve. At the same time, the broad-based nature of INDCs introduces uncertainties in terms of how their aggregate effect might contribute to the objectives of the Convention and the Paris Agreement. However, such broad-based contributions also provide an extensive opportunity for the Parties to cooperate by better matching the needs of developing countries with the means of implementation to be provided under the Paris Agreement.

The implementation of INDCs will likely lead to reduced energy demand and a further shift in the energy mix towards renewable energy

Modelling results demonstrate a progressive decline in total energy demand when moving towards more carbon-restricted scenarios. This is on the basis that measures targeting improved energy efficiency, as well as changes in consumer behaviour, will increasingly be adopted across countries, though the rate of implementation of such measures will differ among countries.

Change in global primary demand for major fuels relative to the Reference Case by scenario in 2040



In respect to major energy sources, the

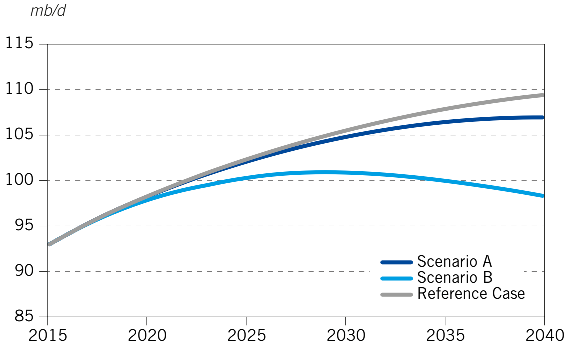
achievement of INDC targets will have significant effects on the future energy mix. Broadly, demand for all fossil fuels at the global level in alternative scenarios is projected to decline relative to the Reference Case. In addition to the demand decline for fossil fuels, the share of renewable energy sources, as well as nuclear energy, will increase, thereby partially compensating/substituting for the energy demand loss from fossil fuels. The nature of these fuel substitutions is a key factor in shaping the energy mix. As most of the substituting fuels generate electricity, they tend to substitute coal and gas in electricity generation. This means that in the alternative scenarios there is more demand reduction in coal and gas compared to oil.

Policies geared to accelerate fuel efficiency improvements and a faster penetration of alternative fuel vehicles have the potential to significantly reduce oil demand

In Scenario A, oil demand in 2040 will reach 106.9 mb/d, which is 2.5 mb/d less than in the Reference Case. Furthermore, between 2030 and 2040, demand growth decelerates significantly so that demand actually plateaus at the end of the forecast period. In Scenario B, oil demand peaks in 2029 at 100.9 mb/d and then declines to 98.3 by 2040. This is 11.1 mb/d lower than in the Reference Case.

In Scenario A, the oil demand reduction compared to the Reference Case is mainly a result of efficiency improvements in all sectors of consumption. In Scenario B, the introduction of policies that support achieving the INDC targets is combined with the assumption of an accelerated technology development and its transfer across countries. Similar to Scenario A, this would have implications for oil demand in each sector of consumption with the road transportation in the frontline. In this sector, demand is expected to drop by 6.2 mb/d by 2040 as a result of the higher fuel efficiency improvements and a much faster penetration of alternative fuel vehicles than assumed in both the Reference Case and Scenario A.

Oil demand in the Reference Case and alternative scenarios

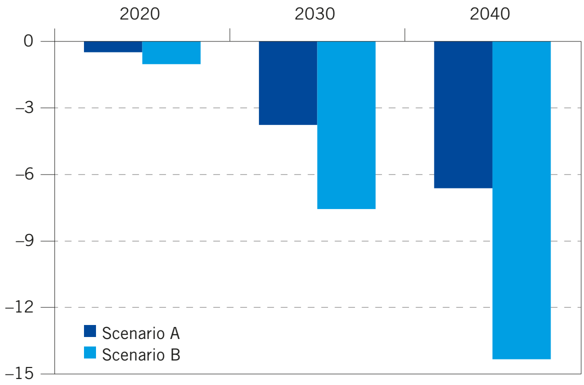


Compared to the Reference Case, the reduction in total energy-related CO_2 emissions in Scenario B could reach the level of about 14% by 2040

In the Reference Case, annual energy-related CO_2 emissions are likely to reach the level of almost 40 Gigatonnes (Gt) CO_2 in 2030 and surpass 42 Gt CO_2 in 2040. Considering the contributions included in the INDCs, as broadly measured by Scenario B, total energy-related CO_2 emissions are projected to increase until at least 2030. By then, the current commitments by the Parties are expected to lead to CO_2 emission reductions from energy use, compared to the Reference Case. The reduction could reach the level of about 14% by 2040.

In addition, it should be noted that while per capita emissions in Annex I Parties reduce gradually over the period 2015–2040, even by 2040, under Scenario B, per capita emissions from Annex I Parties are projected to be still about one-and-a-half times that of Non-Annex I Parties.

Percentage change in total CO_2 emissions compared to the Reference Case



Uncertainties loom large

There continue to be many hurdles for the oil and energy industries to overcome. There is the lower oil price environment and market instability, which creates economic hardship and uncertainty for oil producing countries in their efforts to make appropriate and timely investments. This, in turn, could have a potential knock-on effect for consuming countries. In terms of economic growth, there are numerous uncertainties that could lead to varying outcomes for the global economy. As always, the uncertainties associated with energy and environmental policies at national and international levels cloud the long-term outlook for energy demand and supply.

Another major determinant with the potential to significantly alter the oil and energy landscape is technological progress, both on the demand and supply side. In the downstream sector, the response of refiners to the need for capacity rationalization, changes in the future crude slate quality, regulations concerning product quality specifications and the development of additional routes for oil movements, among others, will significantly affect the industry.

In spite of the challenges and uncertainties, the energy industry's history of resilience and its innovative nature can help to weather future storms and deliver the energy required for the improvement of the world at large.

Producer-consumer dialogue remains paramount

OPEC continues to be focused on the strengthening of current partnerships and the development of future opportunities for cooperation. Several dialogues have been held over the past year, the result of the Organization's determination for engagement. These include with organizations like the International Energy Agency, the International Energy Forum, the Joint Organisations Data Initiative programme, the Vienna Energy Club and the G20. Dialogues were also held with China, India, the European Union and Russia. Moreover, cooperation between producers and consumers is appreciated for its ensuing benefits to all parties involved and for its contribution to achieving market stability.

Section One

Oil supply and demand outlook to 2040

Assumptions for the Reference Case

Key takeaways

- Global population is projected to increase by 1,772 million to reach 9,078 million in 2040. The majority of the increase will take place in Developing countries, particularly in the Middle East & Africa and India.
- Population growth rates have been steadily trending downward since the 1970s and this trend will continue in the future. At the global level, the population average annual growth rate is expected to fall to 0.7% in the 2030s decade.
- The overall global age structure is expected to shift towards an older population. Currently, 8% of the global population is over 65 and this is anticipated increase to 14% by 2040.
- Global Gross Domestic Product (GDP) medium-term growth is assumed to gradually recover from current levels and accelerate to 3.7% per annum (p.a.) in 2021. In the long-term, global economic growth for the period 2015–2040 is assumed at 3.5% p.a.
- Compared to last year's estimates, the long-term GDP growth in China is revised downwards. However, India and Eurasia have been revised upwards.
- India is also expected to see dramatic increases in its real GDP over the next 25 years. It will surpass OECD Europe in 2034 and, by 2040, India's real GDP will be about the same size as OECD America.
- Total world GDP is estimated at over $245 trillion (2011 Purchasing Power Parity (PPP)) by 2040. This implies that the size of the world economy in 2040 will be 234% that of 2015. Most of the growth will come from Developing countries, which will account for three-quarters of the total increase.
- The Reference Case takes into account policies that are already in place, but it also assumes an extension of those policies beyond their current stage. Recent policy developments have continued to focus on emission reduction and increasing efficiency.
- For the Reference Case, an evolutionary development of existing technologies is assumed. The cost of renewables is expected to continue decreasing while the efficiency of internal combustion engines will continue improving. Technology development will also incentivize further powertrain electrification in the road transportation sector.
- The average OPEC Reference Basket (ORB) price for 2016 is assumed at $40/barrel and then price recovery is assumed to continue with $5/b increments up to 2021. In the long-term, prices are assumed to reach $92/b by 2040 in real ($2015) prices, equivalent to $155/b in nominal terms.

Introduction

Since the previous World Oil Outlook (WOO) was launched last December, the oil market has shown signs that it is heading towards a more balanced situation. Some have suggested that 2016 may mark a turning point for the oil industry, although it is evident that volatility has remained part of the market this year and challenges remain on several fronts.,

In January this year, the oil price reached its lowest level since the price decline that started in the second half of 2014. On 20 January, the ORB price dropped to $22.5/b. Since then, however, the price has recovered significantly, reaching $48/b on 8 June, and generally staying above $40/b.

At the same time, the sharp investment decline in upstream oil capital expenditure seen in 2015, when it declined by more than $130 billion compared to 2014, has decelerated slightly in 2016. For 2016, it is expected that global investment will decline by less than $80 billion. It should be noted that in some specific areas investment is actually coming back, albeit in a cautious fashion. Contributing to this more optimistic, but watchful sentiment is the behaviour of stocks. Despite the current exceptionally high level of stocks, the pace of the build-up has clearly decelerated in 2016. Overall, it can be said that, despite its fragile state, the oil market is in the process of realigning.

The past year has also enabled the industry stakeholders to have more time to observe market developments and the adjustments taking place after the price drop that began in mid-2014. In that sense, 2016 has challenged the industry's common views on the impact of lower oil prices on the economy, demand and supply. While analysts initially anticipated that lower oil prices would have a positive impact on global economic growth, the reality is that the overall impact has been neutral. The gloomier outlook for oil producing countries has not been out-balanced by a more optimistic picture in oil consuming countries. Scars from the economic crisis such as high household debt levels, fiscal imbalances and high unemployment, combined with industry investment cuts, have limited the propensity to consume.

Similarly, while lower oil prices were expected to significantly boost oil demand, the real impact has been far less evident than in past industry cycles. The drop in prices for final consumers has been somewhat constrained as a result of tax 'buffers' in several countries, subsidy removals and the depreciation of domestic currencies against the US dollar. Finally, the resilience of supply in the lower oil price environment caught the industry by surprise, particularly tight oil in North America. Productivity gains and cost reductions have helped producers maintain output at higher levels than expected and thus delay the slowdown. In addition, the role of financial markets, in particular that of hedging has proven to be an efficient cushioning mechanism.

It should be emphasized that the oil market uncertainties are no less pronounced than a year ago. From the economic perspective, the continuous deceleration in the Chinese economy and its possible spillover effects is a major source of uncertainty that needs to be closely monitored. Likewise, there is still a high degree of uncertainty on how the United Kingdom's (UK) decision to leave the European Union (EU), the so-called Brexit, will unfold and how it will affect the economic prospects of the two regions. The economic situation in commodities-driven economies, following the sharp declines experienced in the last couple of years, is another element that needs to be closely scrutinized.

Uncertainties can also be viewed when analyzing technology developments. For example, during the past year there have been some important developments in the commercialization of battery electric vehicles (BEVs). Several car manufacturers have introduced new electric models, including Hyundai's Ioniq, GM's Bolt EV and the Tesla Model 3. Other large car manufacturers are also investing in this area. However, there remains a significant degree of uncertainty surrounding how BEVs will overcome limitations related to price, range and ease of charging. Moreover, with Toyota's new Mirai fuel cell vehicle (FCVs) also introduced in 2016, the competition for future transportation technologies is entering a new stage.

The COP21 meeting in Paris in December 2015 has added another element of uncertainty on the policy front. OPEC has welcomed the agreement, and all of its Member Countries were part of it. However, there remains many questions concerning the possible implementation path of such an agreement, and on how countries will make sure that their Intended Nationally Determined Contribution (INDC) targets become reality.

Similarly, the new global Sustainable Development Goals (SDGs) adopted in September 2015, and which for the first time tackle energy is as an important element of human development, offers up ambitious goals, but it remains to be seen how energy policies will evolve towards achieving these targets. SDG 7 calls for ensuring universal access to energy, increasing the share of renewable energy in the global energy mix and promoting further energy efficiency gains by 2030

Finally, political developments should not be overlooked. For example, the upcoming US presidential election constitutes a significant source of uncertainty. As a prime actor in the global energy landscape, the outcome of the elections could have important ramifications for the market. And of course, geopolitics remains another element that further clouds the oil outlook.

The Secretariat continues to closely monitor all these developments and, with this outlook, sheds light on a plausible outlook, alongside scenario analysis, for the medium- and long-term oil market.

On a technical note, it should be mentioned that the Outlook reflects the current membership status of OPEC. Since the WOO 2015 was published last year, the Organization has added two new Member Countries: Indonesia and Gabon. Therefore, throughout the Outlook, when OPEC is referred to, it includes the current 14 Member Countries.

The WOO 2016 also marks an important landmark for OPEC – the tenth edition of the publication. This is an impressive achievement for the Secretariat. In the first edition of the WOO in 2007 it was emphasized that the Outlook was meant to contribute to OPEC's commitment to support market stability and to provide a platform from which to review, analyze and evaluate scenarios as to how the oil scene may develop. This guiding principle has remained valid over the past decade. We hope the Outlook has helped create space for discussion and debate, stimulate ideas and further analysis, and help foster further dialogue and cooperation amongst all industry stakeholders.

At the OPEC Secretariat we are committed to delivering credible, unbiased and robust analysis of the energy and oil market so that research experts, policymakers, students, journalists and the energy community continue to find the WOO a useful reference.

Demographic trends

Population growth has important implications for economic growth potential. Simplistically, higher population growth goes hand-in-hand with higher economic growth potential, all things being equal. However, population growth needs to be further dissected as trends in urbanization, age structure, migration and fertility are also part of the dynamics.

Based on the United Nations (UN) Population Division's *2015 Revision of World Population Prospects*, Table 1.1 presents the assumed population levels and growth used in the Reference Case. Population growth rates have been steadily trending downward since the 1970s and this trend will continue in the future (Figure 1.1). At the global level, the population growth rate is expected to fall by more than 58%, from an average annual growth of 1.8% in the 1980s to 0.7% in the 2030s.

This decrease will be more prevalent in Organisation for Economic Co-operation and Development (OECD) regions where annual population growth is anticipated to fall to 0.2% in 2040. Eurasia experienced population growth declines from the early 1990s until around 2005, following the dissolution of the former Soviet Union. During this period, Russia had low birth rates and abnormally high death rates. However, the region's population has expanded slightly since, but from 2024 onward, Eurasia will see negative population growth again. Although population

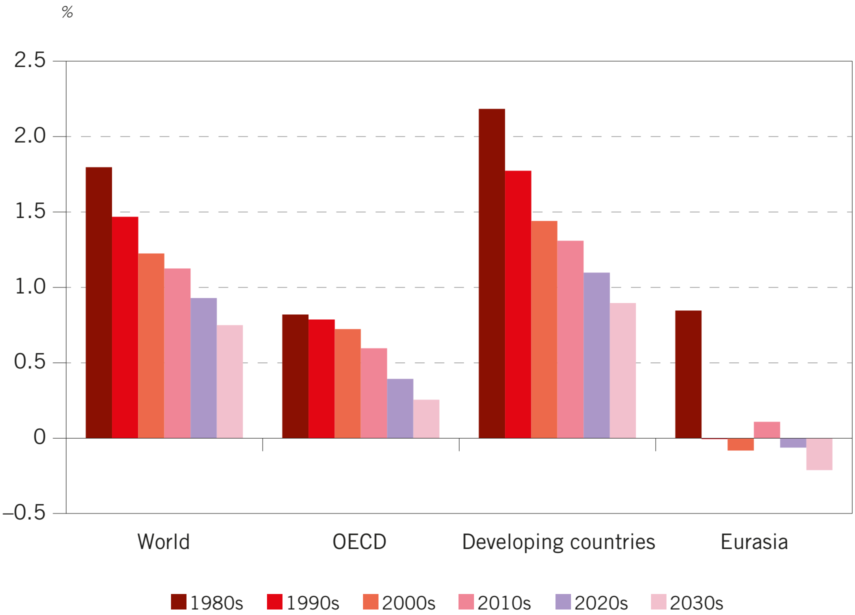
Table 1.1
Population by region

millions

	Levels				Growth
	2015	2020	2030	2040	2015–2040
OECD America	509	531	571	602	93
OECD Europe	564	572	582	588	23
OECD Asia Oceania	214	216	217	215	0
OECD	**1,288**	**1,320**	**1,371**	**1,404**	**117**
Latin America	436	456	490	514	78
Middle East & Africa	952	1,074	1,343	1,642	690
India	1,286	1,362	1,499	1,603	317
China	1,403	1,431	1,444	1,423	19
Other Asia	877	936	1,039	1,122	244
OPEC	720	785	910	1,036	316
Developing countries	**5,675**	**6,043**	**6,724**	**7,339**	**1,664**
Russia	143	142	138	132	–11
Other Eurasia	200	203	204	202	2
Eurasia	**343**	**345**	**342**	**334**	**–8**
World	**7,305**	**7,708**	**8,437**	**9,078**	**1,772**

Sources: United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.

Figure 1.1
Average annual growth rate of population per decade



Sources: *United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.*

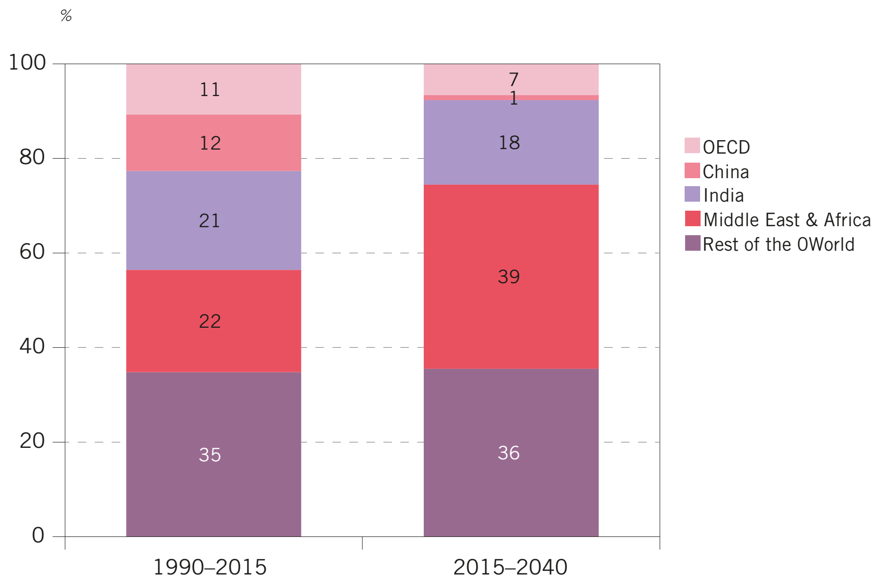
growth in Developing countries is projected to fall from 1.3% in 2015 to 0.8% in 2040, it will remain above the world average of 0.7%.

In terms of absolute levels, the global population is projected to increase by 1,772 million between 2015 and 2040 to reach 9,078 million by then. The majority of the population increase will take place in the Middle East & Africa region as the population is expected grow by 690 million. India is projected to see its population grow by 317 million, OPEC's population is forecast to expand by 316 million and Other Asia will see an increase of 244 million. OECD America will be the main growth region for the OECD, increasing by an expected 93 million between 2015 and 2040. Russia's population is forecast to decrease by 11 million over this period, while very limited growth will be seen in OECD Asia Oceania.

By 2040, 81% of the global population will be in Developing countries *versus* 78% in 2015, while the share of people in the OECD will decline from 18% to 15%. However, it should be noted that in looking at the last decade of the forecast period (2030–2040), population will actually decline in OECD Asia Oceania, China, Russia, and Other Eurasia.

In the past 25 years, the largest share of additions to global population came from India and the Middle East & Africa (Figure 1.2). This trend will continue for the next 25 years with 39% of the new population growth expected to come from the Middle East & Africa. The most significant change will be that China's contribution to global population growth will fall from a cumulative 12% over the last 25 years, to a mere 1% over the next 25 years.

Figure 1.2
Share of global population growth by region – historical trend and forecast



Sources: United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.

Box 1.1

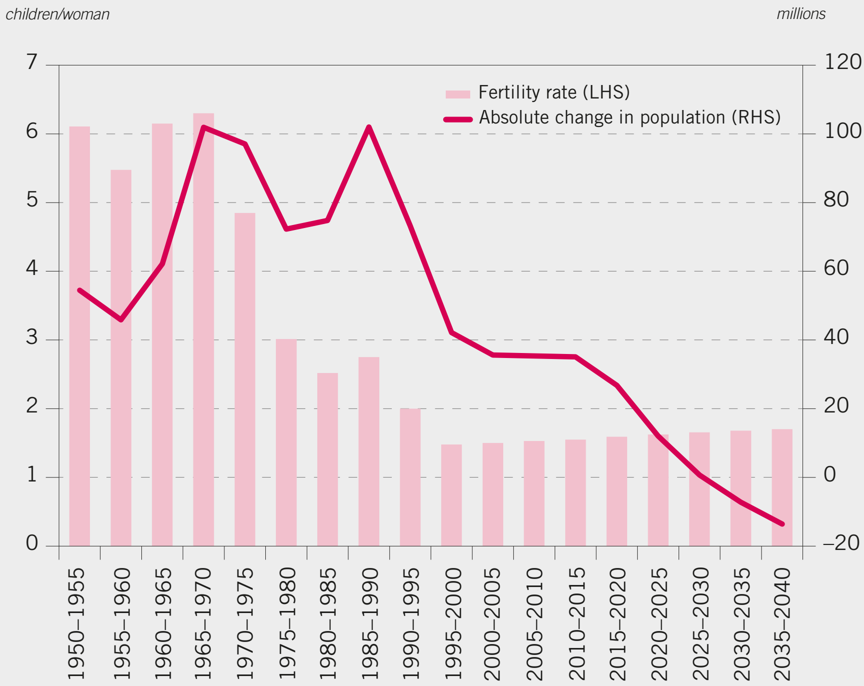
The end of China's one-child policy

On 1 January 2016, the Chinese Government finally abolished its one-child policy that had been in place since 1979. The policy change was driven by an evolving trend in the country's demographics, specifically a shrinking of the working age population, combined with an extension in life expectancy with a growing number of people over 60 years. It begs the question: will this policy change have an impact on China's future demographics?

Historically, rural populations tended to have more children. In the period 1950–1960, 88% of China's population lived in rural areas, compared with the global average of 70% and population growth was actively encouraged by the government during this period as increased manpower was viewed as a driving force for economic development. In terms of fertility rates, the country had a fertility rate of 5.8 births per woman, compared to the global average of 4.9 (Figure 1).

It meant that China's population increased by over 100 million, from 544 million in 1950 to 644 million in 1960. And over the next two decades, this trend accelerated with the country's population increasing by another 333 million to reach

Figure 1
China total population change and fertility rate



Sources: United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.

977 million in 1980. This translates into a population increase of around 80% over a relatively short 30-year period.

It is this backdrop that led China to introduce a one-child policy in 1979 under the 'Family Planning Policy'. The focus was on controlling population growth as a means to limit the demand on resources and to prevent unfavourable economic and social development in the country.

In the 35 years that followed, China's population increased by 398 million, an increase of about 40%, and the fertility rate decreased from 4.9 in 1975 to 1.6 in 2015. Moreover, there were also important structural transformations in the Chinese economy as the percentage of people living in rural areas fell from 81% in 1980 to 44% in 2015, slightly below the global average of 46%. In terms of economic advancement, China's GDP per capita increased 17-fold from 1980–2015. This compares with an increase of 4.6 and 1.8 times for India and the US over the same period, respectively. The period also coincides with China's market-economy reforms and the country's rise as an engine of world economic growth.

It is also important to note that the one-child policy also affected the make-up of the nation's demographics. Comparable with the global pattern, the age structure of China's population has changed significantly since 1980, when just 7% of its population was above the age of 60. This share now stands at 15% and it is expected to increase to 31% by 2040. This is considerably higher than the anticipated 2040 global average of 19%.

This denotes that there will be a need for greater public healthcare expenditure in the years ahead, as the traditional burden of caring for the elderly will likely not be a financially sustainable option for those children born to parents of the one-child policy. This is often referred to as the '4-2-1' problem, where each single child has two parents and four grandparents to care for in their old age.

Furthermore, looking at the gender ratio of China's youth, there is a clear trend of there being more males than females. The ratio reached 116 men to every 100 women in 2015. It is largely believed that this gender skewness arises from the one-child policy, combined with China's traditional preference for boys. Although this ratio is forecast to decrease by 2040, it will remain well above the global average. This disparity poses some future sociological concerns.

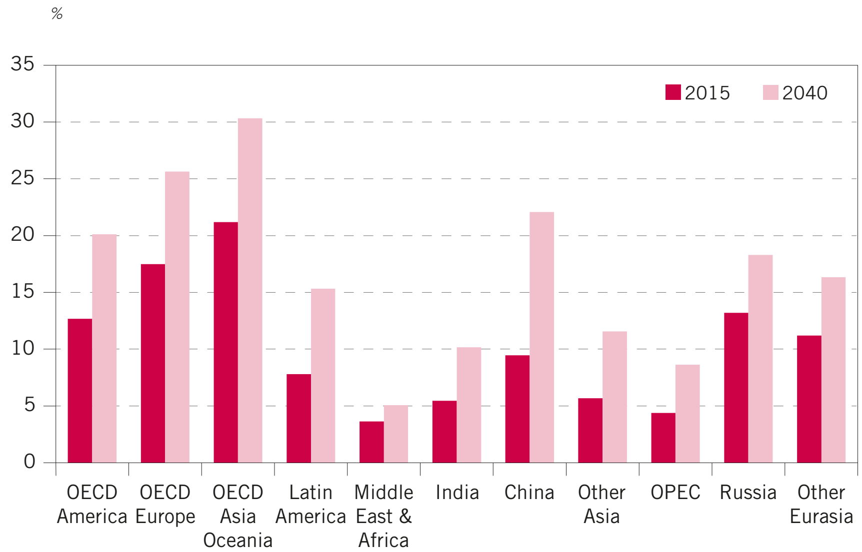
China's policymakers, aware of a shrinking working age population, combined with an ageing population that adds financial strains to the state's funds, decided in November 2013 to further relax the one-child policy[1] across most provinces whereby families could have two children if one of the parents was an only child. This policy applied to about 11 million couples living mostly in urban areas, of which only around one million had an additional child, contrary to the expectation of two million. Subsequently, the Chinese Government abolished one-child policy effective on 1 January 2016, allowing all couples to have a second child.

There is an expectation that more Chinese couples will now have two children and reverse the dwindling fertility rate of the nation. However, as the results of the initial relaxation of the one-child policy in 2013 showed, the policy change may in fact have only a minimal impact on the population as many couples may decide – for various reasons such as rising housing and education costs – to stick to having one child. This expectation is reflected in the projected average annual population growth of 0.07% from 2015–2040, with China's population anticipated to peak in 2028, and actually fall thereafter. In a broad sense, this follows trends in fertility rates in many developed countries. Furthermore, even if there is a sudden increase in fertility from 2016 onward, its effect on the economy will not much be seen for at least one generation – that is, not until these second-born-children enter the workforce.

Overall the age structure of the world is expected to shift towards an older population. Currently, 8% of the global population is over 65, but this will increase to 14% by 2040. On the other hand, the working age population percentage, comprising individuals aged between 15 and 64 is expected to decrease from 66% to 64%. When looking at the details across the various world regions, it is easy to observe this trend in the OECD regions, as well as in China.

In China, the number of people over 65 years old will account for 13% of the population in 2040, *versus* the current 9%. And the OECD regions, which already have a significant ageing population relative to the global average, will see a further

Figure 1.3
Share of population over the age of 65 by region



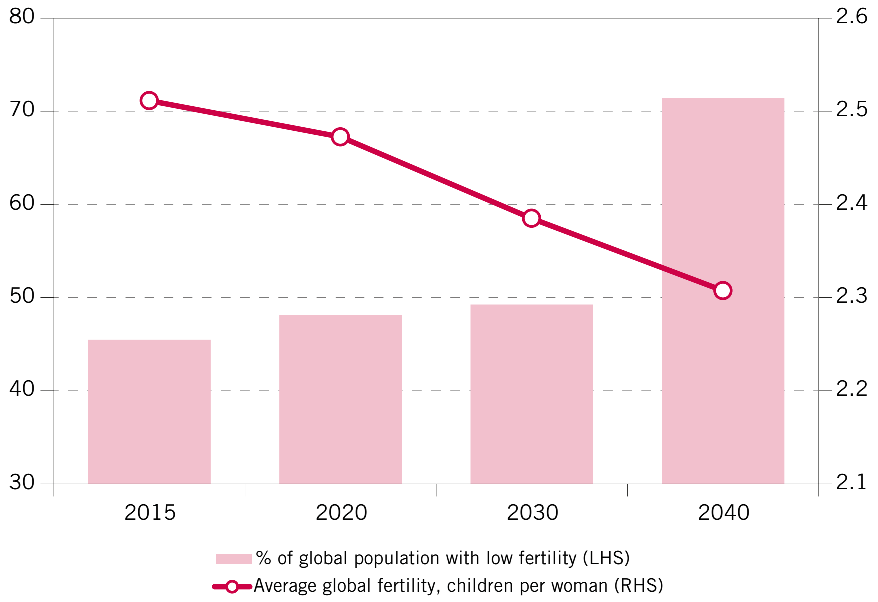
Sources: *United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.*

increase. For example, 30% of the population in OECD Asia Oceania will be over 65 years old in 2040. This compares with 5% in the Middle East & Africa, 9% in OPEC and 10% in India (Figure 1.3). Furthermore, as the share of people under the age of 15 is also projected to decrease across all regions of the world by 2040, there will be fewer individuals entering the workforce beyond the 2040 forecast period. By 2040, 22% of the global population will be under 15 years of age, compared to the current 26%.

The decline in the size of the working age population is not surprising. Global fertility has been falling since the 1960s, from 5.0 children per woman to 2.5 in 2015. Although the rate of this decrease is forecast to ease, global fertility is still expected to fall to 2.3 by 2040.

There are, of course, significant regional variations in global fertility trends. The UN 2015 Revision of World Population Prospects report states that a fertility rate of 2.1 corresponds to the level required for a full replacement of the population. That is, fertility rates below this level are referred to as ‘low fertility’. Most of the countries in the OECD already have fertility rates below 2.0 and these are projected to stay below this level by 2040. Conversely, the majority of countries in the Middle East & Africa will have fertility rates above 3.0 by 2040. These relatively high fertility rates will not be seen in other regions, with the exception of a handful of countries. That is, 71% of the global population will have low fertility rates by 2040, *versus* 46% in 2015 (Figure 1.4). This is not surprising as India, which accounts for almost one-fifth of the global population, will become a low fertility

Figure 1.4
Share of global population with low fertility



Sources: *United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.*

nation from 2030 onward. Lower fertility rates are an expected outcome of increasing numbers of people shifting to urban areas from rural ones. Notably, the global urban population will increase to 63% in 2040, from 54% in 2015 and 43% in 1990. Lower fertility rates are also an outcome of the increased participation of women in the labour force, combined with increased educational levels of women, which in turn corresponds to women marrying and starting families at a later age. Finally, a reduction in mortality rates of children under five, which is an indicator of the overall improvement in the health of young children, is an important factor to consider when examining falling fertility rates.

Another important factor in demographics analysis is international migration. Recalling that fertility rates are below 2.0 in most OECD countries, migration enables countries to enhance their shrinking working age population and can also help secure the financing of social security schemes in the OECD. The UN also produces a ‘zero-migration variant’ that differs from its ‘medium variant’ base case. Under the medium variant assumption, the future path of international migration is based on past internal migration estimates and also takes into account the policy stance of each country with respect to future international migration flows. The zero-migration variant, on the other hand, allows for an assessment of the effect that zero net migration has on the total population of a country.

By comparing the population projections under the medium and zero-migration variants, Table 1.2 shows the impact that international migration has on regional population expressed as a share of the total population. Not surprisingly, OECD regional population projections reflect positive net migration, while net migration is negative in Developing countries and Eurasia. Given the relatively low fertility rates in the OECD, migration allows for an influx of working-aged people who add to the productive output of the economy. Net migration is expected to account for over 11 million people in the OECD in 2020, increasing to over 36 million by 2030 and over 67 million by 2040.

Table 1.2
Net migration by region as a share of total population in the medium variant

%

	2020	2030	2040
OECD America	1.1	3.4	5.8
OECD Europe	0.7	2.1	4.1
OECD Asia Oceania	0.7	2.2	4.0
OECD	**0.9**	**2.7**	**4.8**
Latin America	–0.3	–0.9	–1.4
Middle East & Africa	–0.2	–0.4	–0.8
India	–0.1	–0.5	–0.7
China	–0.1	–0.4	–0.7
Other Asia	–0.4	–1.2	–2.0
OPEC	–0.1	–0.2	–0.3
Developing countries	**–0.2**	**–0.5**	**–0.9**
Russia	–0.5	–1.6	–2.8
Other Eurasia	0.6	1.5	2.6
Eurasia	**–0.1**	**–0.3**	**–0.6**

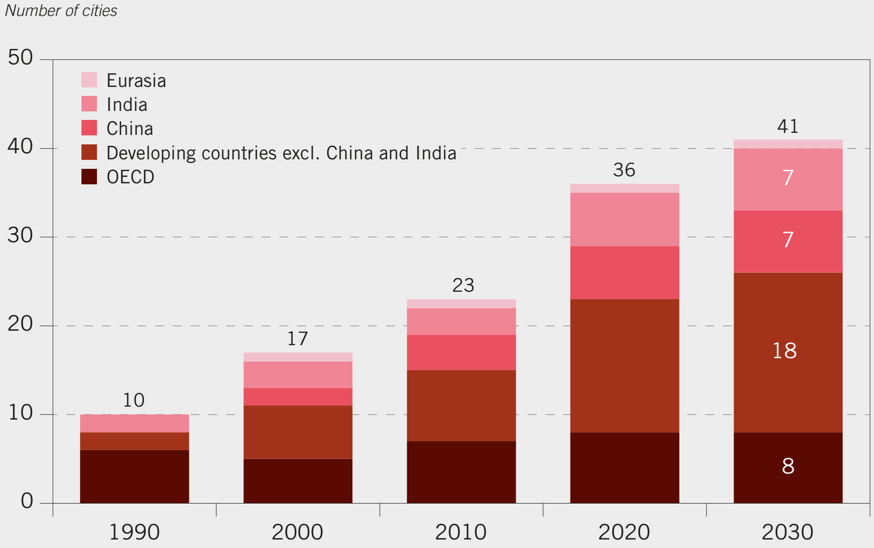
Sources: *United Nations, Department of Economic and Social Affairs, Population Division (2015). World Population Prospects: The 2015 Revision, DVD Edition, OPEC Secretariat estimates.*

Box 1.2

Megacities: the transportation challenge

Metropolitan areas with total population exceeding 10 million people are referred to as megacities. In 1990, the global population was about 5.3 billion people and there were 10 megacities. Between 1990 and 2015, the world's population grew by 2 billion to reach 7.3 billion people. However, the number of megacities almost tripled to 29 over the same period. Looking forward to 2030, global

Figure 1
Number of megacities per decade by major regions



population is expected to reach 8.5 billion and it is estimated there will be 41 megacities.

What this trend highlights is that human population is increasingly moving to urban areas and these are becoming larger in size. By 2030, it is anticipated that 60% of the world's population will be living in urban centres *versus* 43% in 1990 and 54% in 2015. There are evidently various economic, social, and environmental implications of this continued population shift, and of course, it will no doubt have implications for future energy demand.

The current decade is expected to see the greatest growth in megacities, with the addition of 13, bringing the total to 36 by 2020 (Figure 1). Eight of these new megacities are anticipated to be located in Asia, two in Africa, two in Latin America and one in Europe. Given this, by 2020, half of the world's megacities will be located in Asia. Moving to 2030, Asia is expected to add another three megacities and Africa will add two.

Given the role of Asia in these projections, it is important to take a closer look at the region and assess the implications of the growth of its megacities.

In terms of analyzing future energy needs, it is important to consider a number of issues: the population density, transportation planning, and the motorization of population. The density of the population in Asian cities varies greatly from that of European and North American cities. North American cities generally span over large areas and, as such, public transportation is often cost ineffective. Dense cities, such as those in Asia, conversely have lower energy demand for the transport sector as public transportation offers a viable alternative to automobiles. However, in the absence of an integrated pubic transport system, Asian cities will see a rise in motor traffic, despite them being densely populated.

Transportation challenges will play a vital role in shaping the energy needs of Asia's growing megacities. Car ownership is often a symbol of social status across developing countries and there is a direct positive link between rising incomes and rising car ownership. This trend of increased motorization in densely populated megacities will inevitably lead to greater traffic and congestion levels. Currently, this decade's new megacities have low levels of motorization, but also an underdeveloped public transport infrastructure. It remains to be seen whether public transport infrastructure planning and building can outpace rising private motorization. It is noteworthy to examine the experience of Tokyo, a megacity with a well-connected public transport system not seen elsewhere in Asia.

In many respects, the 'Tokyo Model' of megacity transportation represents an (almost) ideal system for densely populated megacities. However, it is important to recognize that Tokyo's urban rail infrastructure was set up well before its road infrastructure and before the rapid growth in automobiles. It means that, due to Tokyo's public rail transit system, the city saw relatively less road congestion, compared to today's newer megacities. In fact, as early as 1962, Tokyo reigned in car use in the city through restricting car ownership to those with a dedicated parking space.

The trend for today's growing megacities is reversed, with much larger investments being made in road construction compared to rail. In Bangkok, which is expected to hit megacity status in 2020, congestion had already reached alarming levels in the 1980s and early 1990s as vehicle ownership increased sharply and became the primary mode of transport in the absence of a public rail transit system. Beijing has suffered a similar fate. On the other hand, another Chinese megacity, Shanghai, has fared slightly better since road construction was much slower in Shanghai than in Beijing – that is, Beijing's earlier road network construction fortified a car-use habit among citizens. In addition, Shanghai was a relatively early-adopter of limiting car registrations with policies having been in place since 1994, which was well before the surge in motorization levels. Beijing only implemented a vehicle quota system in 2011 as a reactionary response to traffic congestion.

Higher traffic congestion means that, especially during peak traffic hours, vehicles are travelling at much lower speeds. It means that there is higher average energy consumption per vehicle due to road congestion. Studies have shown that in Bangkok in the late 1980s and early 1990s, massive traffic congestion meant that cars were travelling an average of 7 km/h with below-average fuel economy. Inefficient automobile energy consumption due to traffic congestion may be a reality in newly emerging megacities and this will need to be carefully monitored when assessing future energy demand in the transportation sector.

Today, there is greater public and governmental awareness of the implications of traffic congestion and certain measures are being put in place in various megacities to provide some relief. For example, car ownership control policies to restrict the number of registered automobiles have been implemented in three Chinese megacities – as already mentioned, Shanghai, but in Beijing and Guangzhou too. Beijing has also initiated other means of restricting road traffic such as banning non-local vehicles from entering the 5th ring of the road network during peak hours. Moreover, Beijing's construction of the Bus Rapid Transit system combined with subsidies on transit fares has provided incentives for individuals to increasingly favour public transport over private car use. Nevertheless, demand for car ownership rights continues to increase rapidly.

Looking forward, it is increasingly evident that the new emerging megacities will not be able to replicate the 'Tokyo Model' as the pre-planning stage for investment in a well-connected rail infrastructure has long passed. These cities are now faced with the challenge of dealing with increased traffic congestion and instilling incentive schemes and quota systems to limit car use and encourage public transport. Public transportation aside, the current situation is further worsened as the building of roads cannot keep pace with increased car ownership in many megacities.

The experiences of Beijing and Shanghai may provide a blueprint on how to move forward, although it is now a game of playing catch-up and reacting to the realities of increased car ownership and congestion as opposed to a pre-emptive approach that Tokyo was able to develop.

Medium- and long-term economic growth assumptions

It is widely accepted that economic growth is a key determinant of energy and oil demand. Despite the fact that energy and oil intensity have been exhibiting a declining trend, economic growth and development continue to be strongly linked to oil demand growth. Faster GDP growth means, in general, that households have more disposable income for use on cars, holidays, home appliances, food, personal products, etc. This, in turn, has the effect of increasing demand in such areas as mobility services and product manufacturing, which then leads to higher oil demand.

To arrive at credible and robust GDP growth assumptions at both the global and regional level, the forecast methodology adopted in the analysis differs depending on the time horizon. For medium-term estimates, information drawn from OPEC's *Monthly Oil Market Report* (MOMR) is used together with internal research findings. In particular, the Outlook incorporates July's MOMR GDP growth estimates for 2015, 2016 and 2017. However, for the long-term, the methodology is quite different, with estimates based on demographic and productivity trends under the assumption that the economic theory of 'conditional convergence' holds in the very long-run.

Table 1.3 shows the Reference Case medium-term economic growth assumptions. Global GDP growth is assumed to gradually recover from the current lower levels and accelerate to 3.7% p.a. in 2021. Overall, for the medium-term period, world GDP increases on average by 3.4% p.a. It can be observed that average GDP growth in the OECD region is expected to stabilize at around 2.2% p.a. This is higher than the growth of around 1.8% expected in the short-term (2015–2017). Within the OECD region, growth is driven by OECD America, which is expected to reach a rate of around 2.8% p.a in 2021. OECD Europe growth in 2017 and 2018 is lowered from last year's projections due to the potential impact that 'Brexit' could have on the economy. Despite the fact that there is still a high degree of uncertainty on the specific material impact of the UK's decision, it is foreseen that European growth potential will be affected. Nevertheless, growth reaches 1.9% p.a. at the end of the medium-term. OECD Asia Oceania stabilizes at around 1.5% p.a. in 2021.

Table 1.3
Medium-term annual real GDP growth rates in the Reference Case *% p.a.*

	2015	2016	2017	2018	2019	2020	2021	2015–2021
OECD America	2.3	2.0	2.1	2.4	2.6	2.7	2.8	2.4
OECD Europe	2.0	1.7	1.3	1.6	1.8	1.9	1.9	1.7
OECD Asia Oceania	1.3	1.4	1.5	1.5	1.6	1.6	1.5	1.5
OECD	**2.0**	**1.8**	**1.7**	**2.0**	**2.1**	**2.2**	**2.2**	**2.0**
Latin America	–0.5	–0.6	1.6	2.0	2.6	2.8	3.1	1.9
Middle East & Africa	2.5	2.9	3.1	3.2	3.4	3.4	3.5	3.2
India	7.3	7.5	7.2	7.2	7.3	7.4	7.4	7.3
China	6.9	6.5	6.1	6.0	5.9	5.8	5.7	6.0
Other Asia	3.8	3.8	3.9	4.0	4.1	4.2	4.2	4.0
OPEC	2.4	2.3	2.8	3.1	3.1	3.2	3.4	3.0
Developing countries	**4.5**	**4.4**	**4.7**	**4.8**	**4.9**	**4.9**	**5.0**	**4.8**
Russia	–3.7	–1.0	0.7	1.4	1.7	2.0	2.2	1.2
Other Eurasia	0.5	1.6	2.0	2.4	2.6	2.7	2.8	2.4
Eurasia	**–2.0**	**0.1**	**1.3**	**1.8**	**2.1**	**2.3**	**2.5**	**1.7**
World	**3.0**	**3.0**	**3.1**	**3.4**	**3.5**	**3.6**	**3.7**	**3.4**

Growth in Developing countries is also expected to improve in the short-term. And in the medium-term it is anticipated to stabilize around 4.9% p.a. It is assumed that Latin America will overcome the current distressed situation and start growing again at healthy rates. China is expected to continue decelerating, though at a faster pace than previously expected. India's growth, in contrast, is assumed to reach 7.4% at the end of the medium-term period. Growth in OPEC Member Countries is anticipated to accelerate in line with the Reference Case oil price assumption. The assumed growth rates for Middle East & Africa and Other Asia are all expected to be influenced by Chinese economic expansion, as well as a recovery in the US economy (particularly in the case of Other Asia).

In Eurasia, growth is expected to accelerate as a result of improvements in the geopolitical situation and greater stability. Russian growth is forecast to recover to higher levels in the medium-term, while also lifting the region of Other Eurasia, which is also forecast to benefit from an economic recovery in Ukraine.

Compared to the medium-term GDP growth estimates from last year's WOO, a marginal downward revision is generally applied to global growth rates, particularly for the short-term. This is particularly noticeable in China and Latin America. In the former, the economy is seen to be decelerating faster than previously expected. And in the case of Latin America, the current recession in Brazil is seen as more profound than that foreseen at the time of last year's publication. In contrast, Russian growth has been revised upwards.

1

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

	2015–2021	2021–2030	2030–2040	2015–2040
OECD America	2.4	2.6	2.4	2.5
OECD Europe	1.7	1.8	1.7	1.7
OECD Asia Oceania	1.5	1.4	1.3	1.4
OECD	**2.0**	**2.1**	**2.0**	**2.0**
Latin America	1.9	3.2	2.8	2.7
Middle East & Africa	3.2	3.3	3.2	3.2
India	7.3	7.1	6.4	6.9
China	6.0	5.1	4.1	4.9
Other Asia	4.0	3.9	3.5	3.8
OPEC	3.0	3.3	3.1	3.1
Developing countries	**4.8**	**4.7**	**4.2**	**4.6**
Russia	1.2	2.3	2.1	1.9
Other Eurasia	2.4	2.8	2.6	2.6
Eurasia	**1.7**	**2.5**	**2.3**	**2.2**
World	**3.4**	**3.6**	**3.4**	**3.5**

Long-term estimates are shown in Table 1.4. Global economic growth for the period 2015–2040 is assumed at 3.5% p.a. GDP growth decelerates from an average of 3.6% p.a. for the period 2021–2030, to 3.4% p.a. for 2030–3040 – and even 3.2% p.a. for the last couple of years of the forecast period. This is a common feature across all regions. It is the result of an expected deceleration in population growth due to declining fertility rates, together with the assumed convergence in productivity levels across regions.

It can also be observed that global growth is mainly driven by Developing countries, with the average growth rate for this grouping estimated at 4.6% p.a. for the entire forecast period. In the OECD region, growth averages 2% p.a. and 2.2% p.a. in Eurasia. Within the OECD region, OECD America stands out due to its higher growth rates compared to other OECD sub-regions. Higher population growth rates, partly as a result of increasing migration to the US, have had an important impact on GDP growth estimates. In fact, according to estimates from the UN,[2] for the forecast period, the US is by far the most important destination for immigrants. The country is expected to receive around 25 million immigrants between 2015 and 2040. Within Developing countries, GDP growth in India and China is especially noteworthy, with rates estimated at 6.9% p.a. and 4.9% p.a., respectively, over the forecast period.

As already mentioned, global growth for the period 2015–2040 is assumed at 3.5% p.a., which is a marginal downward revision compared to the WOO 2015, mainly as a result of medium-term changes. It is not surprising that this year, long-term

Figure 1.5
Growth in real GDP between 2015 and 2040 in the Reference Case

GDP growth estimates are generally similar to those in last year's WOO, since the determinants, and trends in population growth and productivity, have not changed significantly. However, some differences at the regional level are worth mentioning.

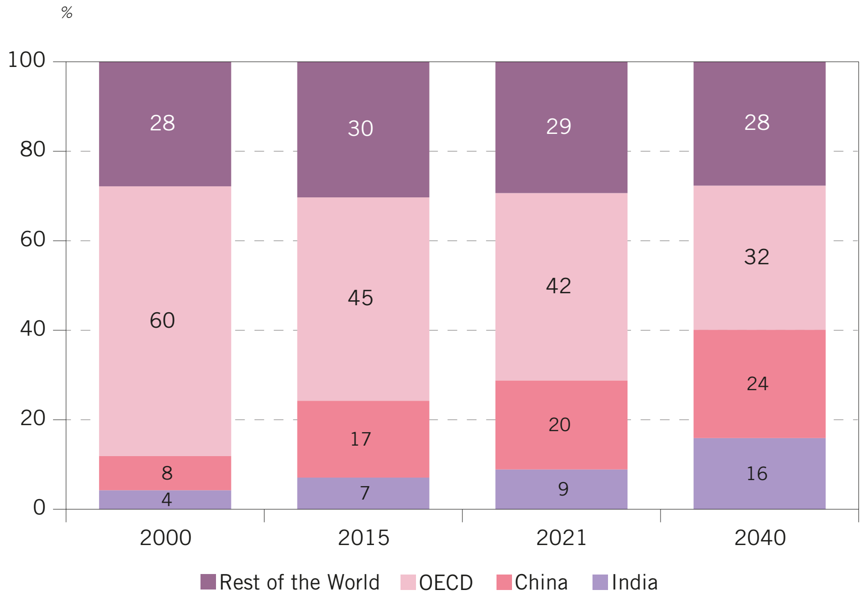
The growth picture for China is significantly less optimistic this year. In particular, for the whole forecast period, this year's average GDP growth is 0.4% p.a. lower than last year, as medium-term expectations point to less of a soft landing than assumed in the WOO 2015. On the positive side, the Indian, Russian and Other Eurasia outlook is more optimistic. In the case of India, the upside potential for the economy materializes as structural deficiencies, such as a lack of infrastructure, are overcome. For Russia and Other Eurasia, an improving geopolitical situation is expected to have a significant impact so the expected long-term growth rates have been revised upwards.

Based on these growth assumptions, total world GDP is estimated at over $245 trillion (2011 PPP) by 2040 (Figure 1.5). This implies that the size of the global economy in 2040 will be 234% that of 2015. The overall GDP increase is estimated at almost $141 trillion (2011 PPP). Most of the growth will come from Developing countries, which will account for three-quarters of the total increase. In particular, China ($41.3 trillion) and India ($31.6 trillion) will together contribute more than half of the total global economic growth between 2015 and 2040.

Ranking in GDP and GDP per capita

From 2015–2040, there will be significant changes in the distribution of global economic wealth. In 2015, OECD America represents the largest global region with a share of 20% of real GDP. It is followed by OECD Europe and China with shares of 18% and 17%, respectively. However, as mentioned earlier, China and India will

Figure 1.6
Real GDP shares from 2000–2040

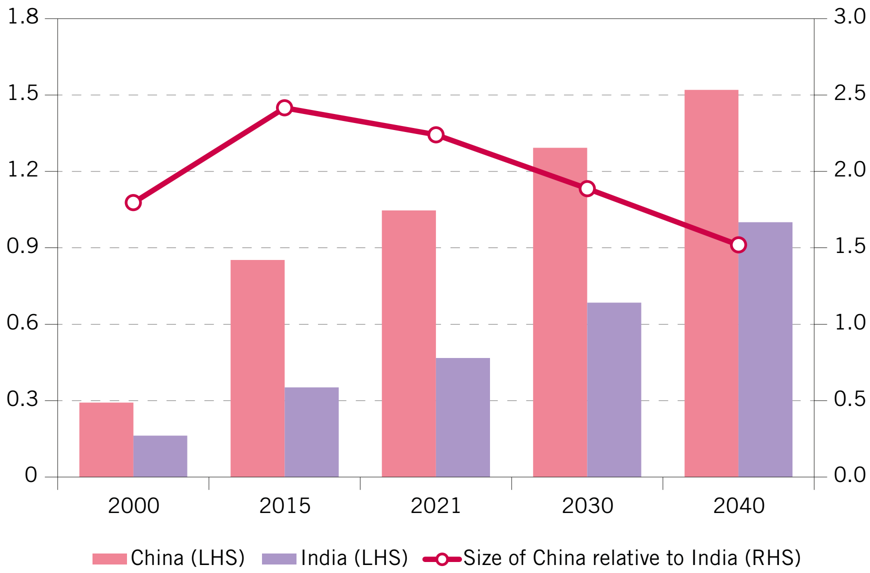


be the largest contributors to the growth in global real GDP from 2015–2040. In fact, by 2020, China is expected to overtake OECD America in terms of real GDP and by 2040, China's real GDP will be more than 1.5 times that of OECD America. India will also see dramatic increases in its real GDP over the next 25 years. It is anticipated to surpass OECD Europe in 2034 and, by 2040, India's real GDP is estimated to be about the same size as OECD America. After India and China, the other regions expected to see the largest increase in the size of their economies are Other Asia and Middle East & Africa, which are expected to be 2.5 and 2.2 times larger, respectively, in 2040, *versus* 2015.

Figure 1.6 shows that the global share of real GDP in the OECD region will decrease from 45% in 2015 to 32% in 2040. Separately, India and China will see an increase in their joint global share of real GDP from 24% in 2015 to 40% in 2040. Figure 1.7 shows that, the economies of China and India will be about the same size as OECD America by 2021 and 2040, respectively. The figure also shows that the economy of China is currently 2.4 times as large as India. However, given that India's expected growth of 6.9% p.a. over the forecast period will outpace China's 4.9% p.a. estimated growth, the economy of China will only be 1.5 times as large as India's by 2040. Together, India, China and the OECD will account for 72% of the global economy in 2040. By 2030, China will rank first as the largest economy among the 11 regions, pushing OECD America into second place. And by 2040, OECD America will move further down to third place as India takes over second position.

In terms of the global ranking of the economy sizes of other regions, there are some changes worth noting. OECD Asia Oceania went from the third largest region in 2000 to the fifth largest in 2015. It is forecast to move further down the ranking to be the eighth largest region in 2040. The region's economy is expected to

Figure 1.7
Size of the economies of China and India relative to OECD America



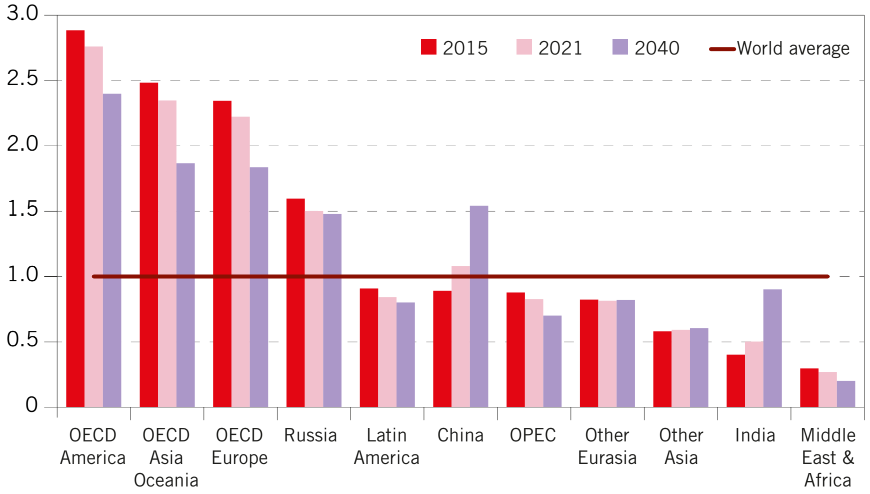
grow to only 1.4 times of its current size by 2040, in comparison to the global economy which is expected to grow 2.3 times over the same period. The economy of Russia is also at the lower end of the growth scale, with expectations that it will expand by 1.6 times from 2015–2040. The economies of OPEC Member Countries are anticipated to increase by 2.2 times their current size over the entire forecast period, similar to the Middle East & Africa region. The Middle East & Africa, Russia and Other Eurasia regions ranking remains unchanged over the 2015–2040 period as these three regions maintain their ninth, tenth and eleventh place ranks, respectively.

GDP per capita

While the world economy will be 2.3 times larger in 2040 compared to 2015, this needs to be set against global population increases. As such, it is important to examine how GDP per capita will develop across regions. Global GDP per capita in PPP terms is anticipated to increase 88% over this 25-year period, increasing to $27,015, from $14,335 in 2015. However, there are significant regional variations over the forecast period.

India and China are estimated to see huge increases of 322% and 226%, respectively. This is followed by an increase of 97% in Other Asia, 88% in Other Eurasia and 75% in OPEC. OECD Asia Oceania and OECD Europe are anticipated to experience a relatively low GDP per capita growth of 42% and 48%, respectively, which is about less than half the world average. OECD America, Latin America and Russia are also projected to see below-world average increases in per capita GDP (57%, 66% and 75%, respectively). The smallest increase in GDP per capita is

Figure 1.8
Per capita real GDP relative to the world average



expected to occur in the Middle East & Africa (29%). This is also the poorest region with the lowest per capita GDP of $4,245 in 2015.

Figure 1.8 shows the development of GDP per capita across regions relative to the global average. By 2030, China will already have surpassed the global average and, by 2040, China's GDP per capita will be 1.5 times greater than the global average. India, on the other hand, will still have a GDP per capita below the world average in 2040. The figure also shows that there will be a decreasing gap in GDP per capita across regions, as GDP per capita in OECD regions shifts down towards the world average, while China and India post significantly larger gains.

This observation is confirmed with the calculation of the Gini coefficient,[3] which decreases from 0.36 in 2015 to 0.35 in 2021 and to 0.30 in 2040. This suggests that there will be less income inequality among the regions over the next 25 years. However, it is worth noting that when comparing the wealthiest region (OECD America) to the poorest region (Middle East & Africa), the projections show that in 2015 OECD America's GDP per capita is 9.7 times greater than that of the Middle East & Africa. By 2021, this ratio will increase to 10.2 and by 2040 it will reach 11.9. In other words, an increasing disparity is foreseen between these two regions. Hence, although there may be less income inequality as a whole across regions of the world as China and India begin to converge closer to the OECD, there remain significant disparities that cannot be ignored.

Policy assumptions

The Reference Case takes into account numerous policies that are already in place. Every year the Outlook also reviews and considers new policies that have been adopted in the preceding year, as well as conducts a reassessment of the already implemented policies to estimate the potential impact of these policies beyond their current stage.

Naturally, every long-term analysis of energy trends faces a dilemma in dealing with energy policies. 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. In the former, it is likely that long-term oil demand would be overestimated as efficiency improvements would be driven only by technology development. In the latter, new policies are assumed to be 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. What follows is a review of some specific policies, particularly those that have been implemented since the publication of last year's WOO.

In the US, the Environmental Protection Agency (EPA) published a final rule under the Renewable Fuel Standards (RFS) programme for calendar years 2014, 2015 and 2016, on 14 December 2015. This comprises volume requirements and associated percentage standards, covering cellulosic biofuels, biomass-based diesel, advanced biofuels and total renewable fuels. It also finalized the volume requirement for biomass-based diesel for 2017. This final rule is effective as of 12 February 2016. In general, as part of its blending percentage considerations, the rule recommends a level of 10.1% for renewable fuels in the country's final fuel consumption in 2016. It does not seem to consider any significant increase in this percentage during the following years.

In Canada, a draft of the Federal Sustainable Development Strategy (2016–2019) was presented for public comments in February 2016. The Strategy aims to reduce Canada's total greenhouse gas (GHG) emissions by 17% by 2020 and 30% by 2030, based on 2005 emission levels. It is expected to be approved during the second half of the year. The targets are linked to the country's INDC, which includes more stringent GHG emissions standards for heavy-duty vehicles (2014–2018 models), and for passenger cars and light trucks (2011–2025 models). The Strategy also requires that gasoline contains 5% and diesel contains 2% of biofuels.

In Europe, on the decarbonization policy side, the European Commission has made significant advances with the restructuring of the EU Emissions Trading System (ETS). The Market Stability Reserve, which will be in place from 2019, is expected to help the ETS control the surplus of allowances, in order to increase carbon prices. The reform was adopted by the European Council in September 2015, with the aim of reducing the two billion emission allowances surplus, which has pushed prices down. In March 2015, the EU submitted its INDCs to the United Nations Framework Convention on Climate Change (UNFCCC), formally putting forward a binding, economy-wide target of at least a 40% domestic GHG emissions reduction below 1990 levels, by 2030.

The European Commission is also preparing a proposal to apply the World-Harmonized Light Duty Vehicle Test Procedure (WLTP) in the EU, which it aims to bring into force in 2017. Because it reflects driving conditions in the real world, rather than just a test environment, the WLTP is expected to encourage car producers to further improve their vehicle fleet's efficiency. The WLTP is the result of a UN-led initiative that aims to produce a test procedure that reflects actual driving conditions in the real world.

The EU's new Renewable Energy Directive and its bioenergy sustainability policy for 2030 is expected to be finalized before the end of 2016. These will provide a framework to achieve the binding EU-level target of producing at least 27% from renewable energy by 2030. Additionally, the European Commission foresees the passing of legislative proposals to align the Energy Efficiency Directive to the EU's 2030 target of at least 27% of renewable energy. This is expected to be reviewed by 2020, with the view to have an eventual level of 30%.

As part of the strategy of meeting Europe's energy market targets, a second list of Projects of Common Interest (PCIs) has been adopted by the EU. The main target of the PCIs is a fully integrated European energy market and enhanced EU energy security. By November 2015, 195 projects had already been approved. Until 2020, these projects will count on the financial support of the Connecting Europe Facility (CEF). On the electricity side, the Commission foresees that it will need to issue a 'communication' on the necessary measures to reach a 15% electricity interconnection by 2030.

In the transport sector, the evolution of electric cars has resulted in an incentives agreement between the German Government and some automobile producers (Volkswagen, BMW and Daimler) in order to kick-start Germany's electric car market. The agreement, which was issued at the end of April 2016, states that anyone who purchases a new electric car will be eligible to receive a rebate of €4,000 for a BEV or €3,000 for a plug-in hybrid electric vehicle (PHEVs). However, the incentive is limited by the available fund of €1.2 billion, which is shared equally by the government and car manufacturers.

In Asia, China's 13th Five-Year-Plan (FYP) was approved on 5 March 2016 (see *Focus* on page 52). The main goal of the FYP is to keep energy consumption within five billion tonnes of standard coal equivalent by 2020, which was estimated under the assumption of 6.5% GDP growth during the period 2016–2020. The FYP also aims to bring China's energy intensity (energy consumption per GDP) down by 15%, while carbon dioxide (CO_2) emissions per GDP (carbon intensity) are targeted to be cut by 18% compared to 2015. It should be noted that most of the details of the FYP have not yet been revealed. It is expected that specific targets will be set by the relevant authorities during 2017.

Since October 2015, the Chinese Government has also halved the 10% purchase tax on passenger cars with small engines (1.6 litres or smaller) and has been providing supportive monetary incentives. These initiatives showed immediate results in terms of an increase in passenger car sales. However, the policy is expected to be phased out at the end of 2016, which is likely to result in a reduction in passenger car sales.

In June 2016 China's National Energy Administration (NEA) released a draft version of the 'China Six' quality standards for motor gasoline and diesel. The standards stipulate that sulphur content of China 6 diesel should not be higher than 10 parts per million (ppm) – the same as China 5, but with a specified total pollutant content of less than 24 ppm. China 6 gasoline should also have a sulphur content of less than 10 ppm and a lead content of under 5 ppm. The China 6 diesel and gasoline standards should come into force on 1 January 2019, according to the draft. China 5 standards are to be compulsory nationwide from 1 January 2017.

In India, two sets of Corporate Average Fuel Consumption (CAFC) standards for cars have been announced, with one coming into force in the 2016–2017 fiscal year and the second expected in 2021–2022. Under the new standards, the fuel efficiency of cars is expected to improve by 10% and 15% in 2016–2017 and 2021–2022, respectively, compared to the period 2009–2010 as the base. After they come into force, new vehicles should have an average fuel efficiency of 18.2 km/litre (km/l) by 2016–2017 and 21 km/l by 2021–2022.

India also launched the Faster Adoption and Manufacturing of Hybrid & Electric Vehicles in India (FAME India) on 9 April 2015, a scheme formulated as part of the National Electric Mobility Mission Plan 2020 (NEMMP) to promote the use of hybrid and electric vehicles. Under FAME India, buyers of battery-operated scooters and motorcycles will be eligible, depending on what technology they utilize, to receive incentives ranging between Rupees (Rs) 1,800 and Rs 29,000 ($26–$431). Similarly for three-wheelers, the incentives range from Rs 3,300 to Rs 61,000 ($50–$909). For four-wheelers, the incentives range from Rs 13,000 to Rs 1.38 lakh[4] ($194–$2,057), while light commercial vehicles will receive financial support from Rs 17,000 to Rs 1.87 lakh ($253–$2,787) and buses from Rs 34 lakh to Rs 66 lakh ($5,068–$9,840).

In addition to the vehicle efficiency efforts highlighted, India will also continue to improve fuel quality with new standards under its existing Vehicle Fuel Efficiency Programme, which the government implemented in 2014. According to the programme's schedule, the new standards took effect in April 2016. On 6 April 2016, the Indian government approved a policy under which state-run refiners will have the freedom to independently plan and import their crude oil requirements. This will give them the flexibility to ship in more cargoes from the spot market and to take advantage of market fluctuations.

In Japan, the 'Energy Mix Plan 2030' adopted in July 2015 set energy targets in order to complement the 'Energy Plan 2014'. The most debated target was the increase in the country's share of nuclear power in its electricity supply to 20–22% by 2030, from zero in 2014. The zero level was the result of the shutting down of nuclear power plants following the Fukushima disaster. This led to an increase in the share for fossil fuels that approached almost 87% in 2013, but the Plan sees fossil fuels decreasing to 56% by 2030. Natural gas is expected to contribute 27% of the total power generation, coal 26%, while oil use could be as low as 3% by 2030.

In Latin America, before the Mexican Energy Reform was enacted, only the National Oil Company (NOC) Pemex could import fuels. This situation changed with the enactment of a law governing retail opening which stipulated that private companies would be able to import fuels (gasoline and diesel) from January 2017. In fact, Mexico's President Peña Nieto decided to accelerate the retail opening process and this began in April 2016. The reform process is expected to conclude in 2018, when gasoline and diesel prices will no longer be set by Mexico's Finance Ministry.

Argentina is experiencing significant changes under the new President, Mauricio Macri. Currently, residential consumers pay only 30% of their total energy bill, but the new government plans to cut existing electricity subsidies. The new government has also confirmed the continuation of the previous 'Nuclear Plan'. Additionally, Argentina has continued with Law 27191 that introduced incentives to attract private investment, diversify the energy matrix and produce 8% of electricity from renewables by 2017. Although the Law is currently being reviewed by the new government, no significant changes seem likely.

It is also worth noting the initiative of the International Air Transport Association (IATA) that aims to achieve carbon-neutral growth by 2020 and then to reduce CO_2 emissions to half of 2005 levels by 2050. In the short-term, the IATA continues to rely on technological developments to bring the industry to a carbon-neutral stage by 2020. It expects 1.5% efficiency improvements per year through to 2020.

The recent low oil price environment has also made it possible for some governments, especially those in oil producing countries, to eliminate fossil fuel subsidies. In addition, some OPEC Member Countries have gone through pricing restructuring too. For example, the UAE started linking gasoline and diesel to global prices in August 2015. In January this year Saudi Arabia applied a price reform to almost every fuel, while in Qatar, the first modifications were made to its gasoline and diesel prices since 2011. In February 2016, in what turned out to be a historic move, Venezuela also raised fuel prices for the first time in 20 years. Other OPEC Member Countries – such as Ecuador, Indonesia, Kuwait and Nigeria – have experienced some price modifications, or are considering modifying their fuel pricing system.

In the OECD region too, subsidies are being removed. The OECD has agreed to restrict subsidies used to export technology for coal-fired power plants with effect from 1 January 2017. A review is planned for 2019. It is expected that this would force countries like Japan and South Korea to limit the construction of new coal-based power plants. The EU also plans to end domestic coal subsidies by 2018.

Further to the negotiations under the Ad Hoc Working Group on the Durban Platform for Enhanced Action (ADP), the COP, by its decision during the COP19, held in Warsaw from 11–23 November 2013, invited all Parties to initiate or intensify domestic preparations for their INDCs in the context of adopting a protocol, another legal instrument or an agreed outcome with legal force under the Convention applicable to all Parties.

In December 2015, the COP21 meeting adopted the Paris Agreement with the intention of "holding the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels". However, this Agreement noted that the INDCs submitted by the Parties to the UNFCCC are not enough to hold the increase in the global average temperature to below 2°C. Further details and scenario analysis on the INDCs are provided in Chapter 8.

On the oil supply side, one of the most relevant policy events occurred on 18 December 2015, when the US Congress passed a bill that ended the country's 40-year-old ban on crude oil exports. The liberalization of exports may increase investments, and some increase in production could be expected in the medium-term. However, the recent lower oil price circumstances have softened the effects of this measure.

In Russia, current conditions (low oil prices and sanctions) have forced the country to shift its preferences concerning its energy strategy. The recent focus has been on such issues as reduced state controls, greater consolidation and the expanded presence of Asian investors. Additionally, fiscal pressure has prevented the government from continuing with its intention to bring down export duties. At the same time, there has been a tax hike on gasoline and middle distillates.

Among OPEC Member Countries, Saudi Arabia has taken a significant leap with its 'Vision 2030 Strategy'. On 6 June 2016, the Saudi Government approved the first of seven executive programmes to implement the 'Vision 2030 Strategy'.

This first 'executive programme', the National Transformation Plan (NTP), sets the conditions to boost the country's non-oil revenues more than three-fold by 2020, compared to 2015 levels, as well as to cut public expenses. In the energy section of the NTP, the aim is to keep oil production capacity at 12.5 mb/d until 2020, as well as to increase natural gas production to 185 billion cubic metres per year (bcm/y) by 2020 and 238 bcm/y by 2030. The development of renewables has also been adjusted to a more realistic number than the one suggested in 2010, with 3.45 gigawatts (GW) of power generation now expected to come from renewables by 2020. For the implementation of the 'Vision 2030 Strategy', six other executive programmes are to be implemented by the country. They are: the Programme for the Strategic Transformation of Aramco; the Restructuring of the Public Investment Fund; the Kingdom's Human Capital Programme; Strategic Partnership; Privatizations; and, the Programme for Strengthening Public Sector Governance.

In Latin America, the Brazilian Senate passed a bill in February this year that ends the current requirement for state-owned Petrobras to operate all of the country's new pre-salt oil and gas projects, and hold a minimum 30% stake in such projects. Under this decision, Petrobras will have a 30-day option to take a 30% operational stake in any newly-offered pre-salt exploration blocks. If Petrobras chooses not to exercise this option, the blocks would be offered to other companies in a competitive auction.

Petrobras' financial situation has also been reflected in its '2015–2019 Business and Management Plan'. According to this Plan, the company will spend $130 billion in the period 2015–2019, which represents a cut of 37% compared to the previous plan. There have also been cuts in production targets. The company now plans to reach a total oil and gas production of 3.7 mboe/d in 2020, by which time the pre-salt area will account for 66% of Brazil's total oil production. Previously, the level was 5.3 mboe/d in 2020.

In Argentina, the new government confirmed in January 2016 that it will keep the domestic price of oil higher than the international price in order to support the industry's investment environment. At the end of 2015, a barrel of oil in Argentina was $77/b and, according to the new announcement, the price will be $63.5/b for Medanito crude oil and $54.90/b for Escalante crude oil, higher than international prices. Given this measure, international oil companies operating in Argentina have confirmed that their investment levels will continue in the country.

In Argentina, however, it should be recalled that in July 2015 the country's 'Oil-Plus Programme' was eliminated. The Programme offered tax credits to companies in order to spur investments that might lead to the discovery of new reserves and boost oil production. Moreover, the $3/b stimulus that some producers received as a further incentive was also eliminated in January 2016.

In Mexico, the bidding process to liberalize the oil and gas market as part of the Energy Reform has recently shown more successful results after the disappointing 2014 experience. Phase Two of the reform allocated three out of five contracts offered in September last year. The big winners were Eni, and the consortia of Pan American Energy with E&P Hidrocarburos y Servicios, and Fieldwood Energy with Petrobal. But the real surprise occurred on 15 December 2015, during Phase Three of Round One, when all 25 available bids were granted either to one company or a consortium, and all blocks available were awarded under conditions that were even better than those requested during the bidding process. Large international oil companies, such as BP and Shell, have already expressed an interest in Phase Four of Round One. The first phase of the second round, which includes 30 production sharing contracts in 15 exploration and production blocks, was launched in July 2016. The registration deadline was set as 15 December 2016, with proposals to be released on 22 March 2017.

Additionally, since 1 April 2016, the Mexican Government has opened the market to gasoline imports. However, as of June 2016, no international investment had been seen in this area. According to the Mexican Association of Gasoline Entrepreneurs (Amegas), the reason international investment has not been possible is because of the onerous taxes that reduce profits almost to zero. Transport fees from international markets will also make the base cost of the product more expensive, reducing profits even further.

In Africa, a new president of the African Development Bank, Nigeria's Akinwumi Adesina, was elected in May 2015. Among his first priorities was the launching in September 2015 of the 'New Deal for Energy in Africa', which will focus on Africa's huge energy deficit and on finding ways to end energy poverty by 2025. Additionally, Africa continues with its efforts to improve governance through the African Governance Initiative and to increase transparency through its Extractive Industries Transparency Initiative (EITI).

Focus

China's 13th Five-Year Plan for Economic and Social Development, 2016–2020

China's 13th FYP for Economic and Social Development was adopted during the annual 'two sessions' of the National People's Congress (NPC) and Chinese People's Political Consultative Conference (CPPCC). These were convened this year on 3 March and 5 March, respectively, in Beijing.

The latest FYP presents several unique characteristics. First, the FYP was designed under the leadership of Xi Jinping, who became President of China after ten years of Hu Jintao governance, and thus reflects his emphasis on internal developments. And second, the FYP marks a transition of the economy from an investment and export-driven system to a more sustainable and consumption-oriented model with high-income conditions.

Additionally, since the 100th anniversary of the Communist Party of China will be celebrated in 2021, 'Two Centennial Goals' and 'Four-Pronged Comprehensive Strategies' have been used as the basis for the 13th FYP. According to these, in the lead-up to 2021, the Chinese leadership plans to comprehensively build a society characterized by moderate prosperity. This goal was discussed at the 16th National Congress of the Communist Party of China and is expected to be implemented as the foundation for the 'Second Centennial Goal', which is to develop the People's Republic into a modern socialist country – one that is prosperous, strong, culturally advanced and harmonious – by the 100th anniversary. Given these goals, the 13th FYP includes a real GDP growth target of 6.5%.

The FYP also reflects a new environmental trend with 10 out of 25 numerical targets related to the environment. By 2020, these include capping energy consumption at 5 billion tonnes of coal equivalent, decreasing energy intensity by 15%, reducing carbon intensity by 15% and increasing the share of non-fossil fuels in the energy mix to 18%, compared to 2015 levels. The government targets are supported by provincial governments, which have all committed to reduce air pollution. Imposing tougher penalties for polluters and setting goals to evaluate officials according to environmental criteria have also been recommended. The 13th FYP also reiterates President Xi Jinping's pledge to launch a national carbon emission trading scheme, though it does not mention the 2017 timeframe that has been mooted before the latest FYP.

A more detailed 13th FYP for oil and gas, with an emphasis on the ways and means to meet the stated targets, has yet to be published. While rising income levels and an increasing number of car sales are seen as driving the growth of oil and gas demand during the 13th FYP, it is expected that a focus on energy efficiency, reducing carbon intensity and technological innovations may dampen overall demand.

However, it is expected that it will be coal that is impacted most by the focus on efficiencies and reduction in carbon intensities. In fact, the coal industry is already being restricted by a number of obstructive actions. During 2016–2019, the NEA will not approve coal production projects. It aims to shut down 60 million tonnes of coal production during 2016 and 500 million tonnes by 2020. It also means that parts of the country's heavy industry, which uses a significant amount of coal, will be shut down. The country's steel production capacity is expected to be cut by 100–150 million tonnes over the next five years.

As part of the energy industry efficiency plan, Beijing has also downsized its public housing programme. During the 13th FYP, China aims to complete 20 million units of public housing, around half the number of houses built during the 12th FYP. The programme puts an emphasis on renovating old homes and increasing their efficiency.

The FYP also considers special actions to compensate for the job losses resulting from the reduction in heavy industry. For that, it will provide strong support to the 'Made in China 2025' programme, which has a special focus on the development of New Energy Vehicles (NEVs), including plug-in hybrid, electric and gas-fired vehicles.

The 13th FYP for the automotive sector is also yet to be announced. However, the Chinese Association of Automobile Manufacturers (CAAM) has suggested that the FYP may include targets for a production capacity of 30 million vehicles per year by 2020, as well as annual production of two million plug-in hybrid electric vehicles (PHEVs) and pure electric vehicles.

As already mentioned, support for the NEVs in the 13th FYP is provided under the 'Made in China 2025' programme. NEVs have counted on government support since 2012. Passenger car subsidies for NEVs vary from RMB 30,000 to RMB 60,000 ($4,550–$9,050) while NEVs subsidies for commercial vehicles go from RMB 500,000 to RMB 600,000 ($75,250–$90,250). Additionally, electric vehicles are excluded from licence lotteries or auctions in many provinces that have used this system to control the number of car sales in their region. Electric vehicles are also excluded from driving restrictions on work days in many provinces. As a further complementary measure, in September 2014, the Chinese Government cut the sales tax on domestically produced NEVs.

Moreover, an investment campaign is underway to spur the technological development of electric batteries, as well as to support the implementation of charging infrastructure. In December 2015, China issued a plan to add 1,200 charging stations and 4.8 million distributed charging poles by 2020. This is in line with the target to have five million electric vehicles on the road by 2020. The country also has a production capacity of two million electric vehicles by the same year. Regarding natural gas vehicles (NGVs), China aims to achieve 10.5 million units by 2020.

The 13th FYP has also recommended that price controls in power, oil and natural gas be lifted, and at the same time a pricing mechanism for refined products needs to be improved by 2020. For that, a new 'open market' mechanism, which as yet has not been defined, is required. The 13th FYP recognizes that without private sector investment, it will be very difficult to improve the efficiency of public companies. Better efficiencies are vital for them if they want to compete at the global level.

In general, the 13th FYP focuses on a shift from the export-driven system to a more consumption-oriented model. In terms of energy, the focus is on improving efficiencies, reducing carbon intensity, possible tougher penalties for polluters, and an increasing share of non-fossil fuels in the energy mix. Overall, it is anticipated that energy consumption will decelerate. Despite the fact that many details are still not available, it is clear that this FYP will shape the Chinese economic and energy landscape and will have global implications for years to come.

Technology trends for the Reference Case

Technological development has always been important for the energy industry. Innovations have created and expanded the market since the advent of the industrial revolution. The steam engine required for the first time large quantities of fossil energy, that is, coal. Other resources such as hydropower, for example, appeared on a large scale with the development of the electricity sector. Today, vehicles fuelled by gasoline and diesel have replaced coal-fired steam locomotives, and large thermal or nuclear power plants provide the predominant share of electricity. Both developments became possible through innovative technologies.

There is no good reason why the ongoing advance of technology will not continue to change the future energy panorama, and some potential changes can be seen already with the discussion around renewable energies and attempts to introduce BEVs as a replacement for current Internal Combustion Engine (ICE) vehicles. Any energy outlook must, therefore, consider current and possible future technological developments – especially in view of their impact on energy provision and energy efficiency. For the Reference Case, an evolutionary development of existing technologies is assumed, that is, a continuous advance of engineering capabilities. What follows is a brief overview of the main technology assumptions used in the Reference

Case, from Enhanced Oil Recovery (EOR) to transport as the main consumer of oil, as well technology options for other energies, including renewables.

The use of CO_2 pumped into the wells of mature oil fields as an EOR technique does not only ensure further yield, it also prevents the escape of this GHG into the atmosphere during oil production. Thus it helps to reduce the carbon footprint of the petroleum industry as a whole. However, incorporating renewable energy to provide steam and power for exploitation and transport will play an increasing role, although it will start from a considerably low level. The ever-increasing computing power of modern IT equipment – together with ongoing data collection about the geological and geophysical characteristics of a large part of the earth's crust – increases the ability to supervise existing and potential oil reserves, and make the search for future production wells more efficient. Innovative imaging methods such as multi-dimensional seismic methods, for example, largely benefit from such increasing computing power. As a consequence, the provision of primary energy from fossil fuels becomes more efficient and results in more abundant supply, which will likely put an additional pressure on alternative sources.

Technology will continue playing a very important role in the road transportation sector, the single-most important source of oil consumption. Since the beginning of road transportation, piston engines have remained the most important power unit. Recently Exhaust Gas Recirculation (EGR) and down-sizing have significantly pushed gasoline engine technology towards a new de-throttled generation. While diesel remains the most efficient combustion engine for now, gasoline engines will become equally fuel-saving within the next few years. On the other hand, diesel engines still require a far more sophisticated – and, consequently, more expensive – exhaust gas after-treatment. The diesel share in the vehicle fleet can be expected, therefore, not to grow in the future.

In addition, powertrain electrification is already a reality for passenger cars. It encompasses hybrid electric vehicles (HEVs) and PHEVs, as well as BEVs. While HEVs use the ICE as the only power source, PHEVs can also consume electricity in replacement of at least a part of conventional fuel, awarding them at least a partial zero-emissions status in urbanized areas. The Reference Case assumes that battery costs will decrease somewhat faster than expected a few years ago. In addition, power electronics will become cheaper, more efficient and more reliable. Consequently, future PHEVs, as well as BEVs, will benefit from declining costs.

The ability to incorporate larger batteries in PHEVs at moderate prices may provide a solution to the most important limitation of BEVs: their enormous upfront battery costs and their limited range. However, it is expected that BEVs will continue to be limited by the upfront battery investments, even if battery costs reach $150/kWh, which is expected now in the early 2020s, as the real cost of electric mobility surpasses the cost of electric power.

The cost of recharging also remains a substantial issue. Peak power for quick recharging represents the most serious drawback of such technology if consumers insist on maintaining their long-accustomed refuelling habits. The Reference Case also considers such peripheral aspects. Solving these issues requires substantial grid investments, again increasing the financial burden for electric mobility.

To overcome such electric power storage and refuelling issues, fuel cell vehicles (FCVs) have been proposed. It must be noted that hydrogen is commonly foreseen as a fuel for FCVs, but it has a low distribution efficiency when considering the whole chain from hydrogen production to the vehicle's wheel. While today nearly all hydrogen is produced from natural gas by steam reforming, future hydrogen will be produced from renewable energy, mainly wind and solar. The low storage temperature required for liquefied hydrogen and the high pressure needed for compressed hydrogen makes distribution and temporary storage of hydrogen technically difficult, inefficient and expensive. A substantial amount of the initial energy is lost in this process, especially when considering distribution on a regional or global level. The Reference Case, therefore, assumes that FCVs will not significantly penetrate the market.

It is evident that ICE powered vehicles will remain the cheapest kind of vehicles. In view of this, the Reference Case assumes that conventional powertrain technologies will continue to dominate the fleet. Moreover, it must not be ignored that ICEs will also improve over the next 10–20 years and will thus keep putting pressure on BEVs.

Vehicles themselves bear other important possibilities to reduce power consumption, mainly by reducing the vehicle's weight. New car generations are becoming lighter than their predecessors. On the other hand, bad road infrastructure results in an increase in fuel consumption (and reduces vehicle life) and counteracts improvements in the fuel efficiency of the vehicles. Additionally, the rapid increase of traffic congestion in fast developing countries causes further unnecessary fuel consumption and partially cancels out the vehicle efficiency improvements.

The Reference Case assumes a limited efficiency improvement potential for large commercial vehicles. This is because heavy-duty diesel engines, the main mover in this segment, have already reached a fuel-to-power conversion efficiency of 45% and more in some cases. This is significantly above the efficiency of passenger cars and small commercial vehicles (30% to 40%, on average). Waste heat recovery (WHR) is an option for large trucks but will hardly reduce fuel consumption by more than 5%. The most promising alternative remains LNG, although the required fuelling infrastructure represents a large financial burden. In the context of ongoing discussions about GHG emissions, CNG and LNG have been promoted as a fuel source with substantially reduced CO_2. But the unwanted emission of unburned natural gas – the so-called 'methane slip' – can reduce and even revert this advantage of natural gas.

The size of ships and merchant vessels requires large and powerful engines. Marine engines take advantage of the accompanying scaling effects (usually efficiency increases with engine size) so that the large two-stroke diesel engines of merchant vessels hold the current ICE record efficiency of around 52%. The potential for future ICE improvements is, therefore, substantially limited in the marine sector. Further improvements to the hull and other innovative technologies – such as, for example, air lubrication – are more promising and may contribute several percentage points more to fuel savings in the future.

From the perspective of air transportation, commercial airplanes are today solely equipped with flight gas turbines running on jet fuel. These have become much more efficient than their predecessors in recent decades and now provide a far better thrust-to-fuel ratio. The other improvement strategy refers to the airplane itself. Apart from introducing innovative wing designs, the use of new materials – such as, for example, carbon fibre reinforced composites – has reduced the hull and wing weight substantially. Boeing's Dreamliner 787 and Airbus' widebody A350 are the first representatives of a new generation of large commercial airplanes. Attempts are also underway to make air traffic control and navigation more efficient by integrating GPS into direct point-to-point connections. This can reduce flight distance by avoiding unnecessary detours via beacons and reduce flight time through improved scheduling. The Reference Case assumes ongoing technical advances in turbines, as well as airplane structure, in addition to overall improved flight management.

Power generation has always played an important role in relation to primary energy consumption. In the past four decades, a significant shift towards coal has caused oil to lose most of its market share in power generation. The major reason has been the low price of coal together with its large reserves. With the introduction of high-pressure supercritical plants of the latest generation, the electric efficiency of state-of-the-art coal-fired power plants has risen to 45%, compared to less than 35% in the mid-1970s. It must be noted, however, that a fairly significant segment of coal-fired power plants in operation today do not even surpass 30%. The typical lifetime of a coal-fired power plant of 30–40 years delays the advantageous effect of new and highly efficient plants in terms of overall GHG emissions.

In the Reference Case, technology development also applies to natural gas as an important energy source for power generation with gas turbines remaining the first choice. Large units are running as Combined Cycle Power Plants (CCPP), which can reach a net efficiency beyond 60%. Together with the lower carbon content of natural gas, such plants are by far the least CO_2-emitting fossil fuel power plants.

In the beginning of the civil nuclear power era, nuclear power had been regarded as a sustained solution to mankind's power needs: cheap and clean. In the Reference Case, technology trends also include technical advances in nuclear power.

It should be noted, however, that installed nuclear capacity has largely stagnated after the Chernobyl accident in 1986, and its future role was further questioned after the Fukushima disaster in 2011. As a consequence, the nuclear industry has developed several models for a new generation of nuclear reactors with passive security characteristics. Thus, in the event of a serious failure, these reactors no longer rely on the active intervention of dedicated components – such as, for example, mechanically introduced neutron absorbers. Rather, the reactor is kept under control based on physical laws, such as those of gravity and nuclear reactions. Emergency cooling, for example, is largely achieved by the gravity-driven circulation of cooling fluids. More importantly, the criticality of the reactor will drop in order to bring a nuclear reaction to a halt as soon as an unwanted high temperature is reached. However, while earlier nuclear accidents may have been avoided by such a reactor design, this kind of new, secure and reliable reactor has become very costly. For example, construction of the recently announced 3.2 GW Hinkley Point C plant in the UK is expected to cost at least £18 billion.

The Reference Case considers wind and solar as the two renewable energies with the highest potential by far for the global energy supply. Onshore wind is already competitive in some areas when compared to fossil power production, and it is expected that costs will decrease at a rate of around 1% p.a. for onshore, and around 2% p.a. for offshore wind parks. Technology has improved and modern wind turbines can now use low wind speed in far better ways.

Important efforts have also been made to use solar radiation for power production. The fact that only around 0.018% of the sun's radiation that hits the earth's surface is currently consumed by mankind demonstrates the long-term potential of solar energy. Some of the latest large solar power plants have already been announced at prices competitive to conventional power production. Earlier, concentrated solar power (CSP) had been the most auspicious technology because employing mirrors to focus sunlight onto an absorber to produce heat basically replaces the furnace of a conventional – and, therefore, technologically mature – steam power plant. As a consequence, such CSPs could be developed quickly. Today, however, photovoltaics (PV) seem to be more promising because costs are coming down quickly and have dropped below $1/W of power. Beyond 2030, new PV cells that are able to increase conversion efficiency are expected to enter the mass market at prices competitive with today's technology.

Nevertheless, it must be noted that although wind and PV are approaching grid parity, there is an additional cost for holding back-up plants (gas, CCPP, etc.) during periods when wind and PV plants cannot produce power. Petroleum products may also play an important role in covering fluctuating renewables because a liquid can be stored easily, cheaply and safely for later consumption. The corresponding expenses must be added to renewable power generation costs, because only when they are used in combination with back-up plants can reliable power generation be ensured.

However, in order to eventually replace fossil fuel back-up plants, cheap and efficient power storage is required, making their development by far the most important technology in ensuring the success of renewable power production. Large battery storage will become cheaper with declining battery prices. Although they are today mainly deployed to stabilize the grid, they may provide some storage capacity in the future.

Further improvements are expected to emerge through smart grids, a concept which offers a better integration of different generation technologies (notably intermittent power) with storage technologies and demand side management. The key element of this integration is the application of information technology (i.e. real-time data provided by smart metering), which helps to balance out the supply and demand side of the power market. This occurs not only through the adjustment of the supply side, but also through demand side management, where consumers actively react to supply patterns. In order to ensure the sufficient willingness of consumers to adjust their behaviour, smart grids are accompanied by system automation (i.e. smart appliances) and appropriate market design (e.g. monetary incentives). Smart grids also offer the possibility to integrate electric vehicles into the overall power system. While still in the early stages of development, the smart grids concept is expected to increase overall system efficiency and enable the integration of intermittent renewable power generation in the long-term.

The main objective of renewables is to reduce the emission of GHGs, mainly CO_2, in order to limit global warming. In this regard, it is also important to recognize that coal and natural gas, and with successful EOR technologies, oil too, could also play a major role. The use of Carbon Capture and Storage (CCS), as well as Carbon Capture and Utilization (CCU), on a large scale have been proposed to resolve the CO_2 issue of fossil fuels. CCS is already a proven technology on a large scale when used to increase the yield of mature oil and gas fields. The concept of capturing CO_2 can be applied to the exhaust of power plants burning fossil fuel and other large CO_2 emitters (such as, for example, cement and steel plants), making them all CO_2-free. However, the efficiency of coal-fired power plants decreases substantially by up to one-fourth. The proposed Oxyfuel method, which uses nearly pure oxygen for combustion, promises to almost maintain the energetic efficiency. The higher CO_2 content in the exhaust gas makes carbon capture easier and, therefore, more efficient. However, the current high costs remain the main impediment to its broader deployment, but these may decrease in the future.

In the Reference Case, the production of chemicals, and especially plastics, still relies on oil. Several attempts have been made in the past to replace polyolefins with starch, celluloses and milk protein polymers. However, they remain too expensive for most mainstream applications. They could gain some market share, however, especially in the medical industry and as packing material for organic foods. Up to now, most bioplastic products struggle to meet the quality standards of conventional petrochemical products, particularly in regards to temperature and humidity resistance.

Oil price assumption

Looking back to 2015, crude oil prices showed something of a recovery in the second quarter of the year, from previous lower levels, and then stabilized in the range of \$50–60/b. However, oil prices then declined again in the second half of 2015, reaching a level of around \$30/b by the end of the year. During this period, global oil markets and prices continued to suffer from persistent oversupply, increasing signs of a slowdown in the Chinese economy, and a significant price decline in global equity and commodity markets.

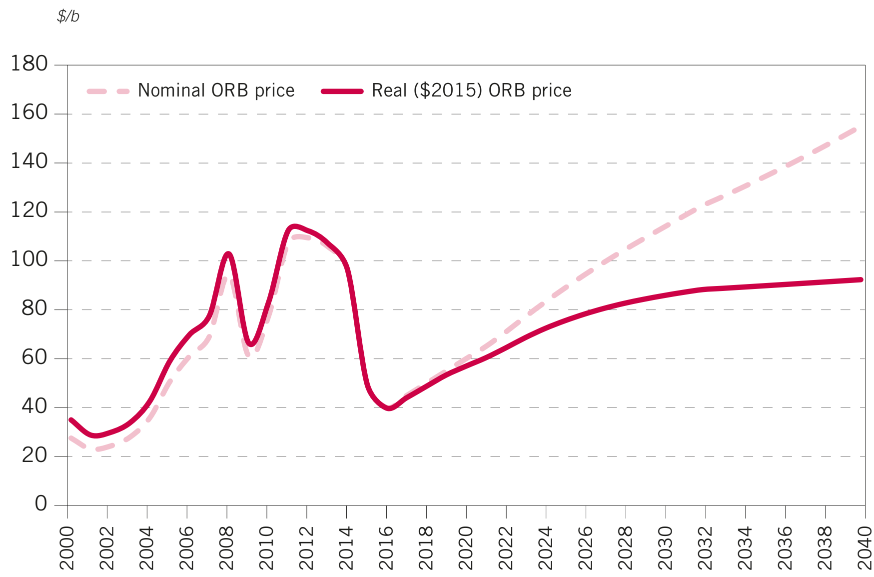
This year crude oil prices have also experienced another period of rather wide swings. After tumbling to a 12-year low at the beginning of 2016, with the ORB reaching levels around \$22/b in January 2016, crude oil prices began to see some recovery at the end of the first quarter with ORB levels around \$35–40/b. Fundamental factors were the main drivers behind the lower oil price at the start of the year, including continued excess supply, higher oil inventories, the slower pace of growth in the Chinese economy, and warmer-than-usual winter weather in the Northern Hemisphere. The overwhelmingly bearish sentiment of investors in the financial oil markets also contributed to the downward momentum.

The market sentiment started to shift, however, towards the end of the first quarter, as further hints of declining non-OPEC supply emerged and efforts to alleviate the persistent supply glut intensified. As a result, prospects for more balanced markets towards the end of 2016 led to a further strengthening of crude prices to the range of \$40–50/b during the second and third quarters of 2016.

Turning to the future price assumption, a distinct set of drivers will determine future prices in the medium- and long-term. Short- to medium-term prices are primarily driven by expected supply and demand balances – best measured by global implied stock changes – but they are also affected by other factors such as geopolitics, speculative activities and market sentiment. While these latter factors are almost impossible to quantify, a simulation of global implied stock change behaviour is possible, although subject to a number of assumptions, such as a build-up of strategic reserves, an expansion in refining capacity and the construction of new pipelines.

Contrary to this, future long-term oil prices are believed to be primarily driven by the cost factors of producing the marginal barrels. This is because the longer-term horizon provides sufficient time for markets to find a new equilibrium for stabilizing stock levels, resolving geopolitical issues and achieving neutral market sentiment. In

Figure 1.9
OPEC Reference Basket price assumption in the Reference Case



this case, a rising marginal barrel cost is expected as a result of increasingly complex supply developments, such as the need to expand oil sands projects, tight oil plays in more complex geological structures, deep-water and potentially Arctic fields. On the other hand, the drive for more efficiencies and innovative technology will partially limit the rise in exploration and production (E&P) costs.

Bearing this in mind, it is assumed that the average ORB price for 2016 will be around $40/b and the price recovery will continue with $5/b increments during the medium-term horizon up to 2021. With this, the ORB price reaches the level of $65/b by 2021 in nominal terms, slightly above $60/b in real 2015 prices. This is presented in Figure 1.9. This assumption reflects expected gradual improvements in market conditions as growing demand, declining non-OPEC supply in the period 2016–2017, and lower levels of non-OPEC supply growth than previously expected beyond this period, will result in the gradual elimination of the oversupply and some depletion of commercial stocks from the very high levels accumulated during the period 2014–2016. This, in turn, will provide some support to prices. Although the contracting non-OPEC supply is expected to reverse direction and start expanding again in 2018, the significant drop in upstream spending will dent its growth below that of global oil demand.

Towards the end of, and after the medium-term, a moderate price recovery is assumed to continue as long-term factors start to prevail and many upstream projects deferred during the low price period gradually come back to meet growing demand, thus providing upward support to oil prices. In real-terms, however, price increases will decelerate gradually and are assumed to reach the level of around $92/b by 2040 in real ($2015) prices, equivalent to $155/b in nominal terms. This is marginally lower than the long-term price assumed a year ago. This reflects the lasting effect of a slower medium-term price recovery and the greater pressures for cost-cutting measures in the upstream industry.

It is important to note, however, that the price outlined in Figure 1.9 represents neither the Secretariat's price forecast, nor a desired price path for OPEC crude. These prices should only be considered as a working assumption needed to develop a Reference Case scenario. This is also emphasized by the fact that the ORB price is assumed to increase in regular $5/b increments every year until 2021, thus not taking into account any likely price fluctuations during the period.

Energy demand: the Reference Case

Key takeaways

- Total global primary energy demand is forecast to increase by 108.2 mboe/d (or 40%) from 273.9 mboe/d in 2014 to 382.1 mboe/d by 2040.
- Developing countries' energy demand will increase by more than 100 mboe/d from 2014–2040 compared to energy demand growth of 3.3 mboe/d in the OECD regions and 4.3 mboe/d in Eurasia. By 2040, almost 63% of global energy demand will stem from Developing countries, compared to the current share of 51%.
- Oil is expected to remain the fuel with the largest share for most of the forecast period, but it is anticipated that it will be overtaken by gas at some point close to 2040. Oil is also estimated to be the second largest contributor to additional energy needs between 2014 and 2040.
- Although overall coal consumption is forecast to increase in the long-term, its share in the total global energy mix is expected to decline by 4.4 percentage points.
- Global gas demand is forecast to increase on average by 2.1% p.a., from around 60 mboe/d in 2014 to almost 102 mboe/d in 2040. This represents the largest increase among all energy sources.
- Nuclear power is expected to increase significantly over the forecast period, driven by energy security and the need to limit CO_2 emissions.
- Other renewables – which include mainly wind, PV, solar thermal and geothermal – is expected to increase from over 3 mboe/d in 2014 to 18 mboe/d in 2040 bringing its share in the global energy mix to almost 5%.
- Globally, energy intensity, measured as the amount of energy required to produce one unit of GDP, is falling and this trend is expected to continue over the long-term.
- Energy consumption per capita in OECD regions peaked around 2005 and is now on a steady downward trend. This reflects a service-oriented economy and technology-induced energy efficiency gains.
- In emerging and developing economies, energy consumption per capita is increasing, reflecting greater electrification, urbanization, expansion of the middle class, overall economic development and strong economic growth. Despite this positive trend, energy poverty and access to affordable, reliable and modern energy for all will remain a major challenge in developing countries.

Total primary energy demand

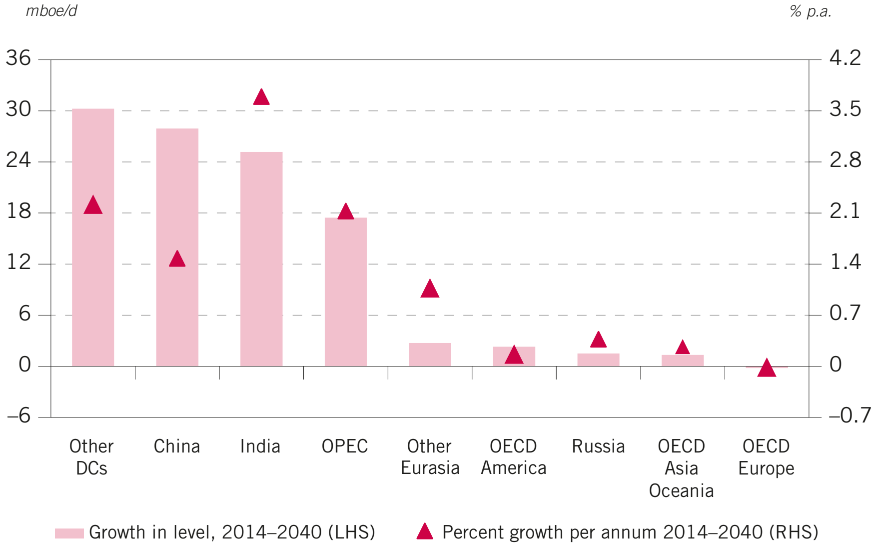
Throughout history, economic growth and development gone hand in hand with energy use. Although the strength of this link changes over time and with the level of economic development, it is much stronger when countries are in the intermediate stages of development since the manufacturing sector, which is a high energy intensity sector, expands rapidly during this phase. As economies develop further, other factors – such as technology, energy efficiency, structural shifts in the economy towards the service sector and demographics – enter into the equation.

Reflecting the interactions of these factors, on a global level, total primary energy demand has increased 1.6 times since 1970, from 104.5 mboe/d in 1970 to 273.9 mboe/d in 2014. It is forecast to increase by another 40% by 2040 to reach 382.1 mboe/d (Table 2.1). On a regional basis, energy demand in Developing countries is expected to grow at an average rate of 2.1% p.a. over the forecast period 2014–2040. This is in sharp contrast with an average 0.1% p.a. growth projected for OECD regions and 0.6% for Eurasia (Figure 2.1). This variation is a reflection of the relatively higher economic growth forecast for Developing countries, since economic growth is a major driver of energy demand growth. Developing countries are forecast to post real GDP growth at PPP of 4.6% p.a. over the 2014–2040 period, compared with an average 2% p.a. growth in the OECD regions. Moreover, higher population growth and increased urbanization in Developing countries are also driving future energy demand growth. In contrast to this, OECD regions are at a more mature and saturated stage of development with a lower potential for strong energy demand growth.

Table 2.1
Total primary energy demand by region

	Levels *mboe/d*				Growth *% p.a.*	Share of global energy demand *%*			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
OECD America	55.7	57.9	58.6	58.0	0.2	20.3	19.3	17.0	15.2
OECD Europe	36.5	36.7	36.4	36.1	0.0	13.3	12.2	10.6	9.5
OECD Asia Oceania	18.4	19.3	19.8	19.8	0.3	6.7	6.4	5.8	5.2
OECD	**110.6**	**113.9**	**114.8**	**113.9**	**0.1**	**40.4**	**38.0**	**33.4**	**29.8**
China	60.2	68.8	80.9	88.1	1.5	22.0	22.9	23.5	23.0
India	16.0	20.3	30.2	41.2	3.7	5.9	6.8	8.8	10.8
OPEC	23.8	27.4	34.9	41.3	2.1	8.7	9.1	10.2	10.8
Other DCs	39.7	45.5	56.5	69.9	2.2	14.5	15.2	16.4	18.3
DCs	**139.8**	**162.0**	**202.5**	**240.5**	**2.1**	**51.0**	**54.0**	**58.9**	**62.9**
Russia	14.9	14.8	15.8	16.5	0.4	5.4	4.9	4.6	4.3
Other Eurasia	8.6	9.2	10.4	11.3	1.1	3.1	3.1	3.0	3.0
Eurasia	**23.5**	**24.0**	**26.3**	**27.8**	**0.6**	**8.6**	**8.0**	**7.6**	**7.3**
Total world	**273.9**	**299.9**	**343.6**	**382.1**	**1.3**	**100.0**	**100.0**	**100.0**	**100.0**

Figure 2.1
Growth in primary energy demand by region, 2014–2040



In terms of the actual quantity of energy demand, Developing countries' energy demand will increase by more than 100 mboe/d from 2014–2040 compared to energy demand growth of 3.3 mboe/d in the OECD regions and 4.3 mboe/d in Eurasia. As a result, almost 63% of global energy demand will stem from Developing countries by 2040, compared to the current share of 51%. On a global level, India's share of energy demand will increase from around 6% in 2014 to almost 11% in 2040. China is already consuming more energy than OECD America and this gap will continue to widen as China's future energy demand growth of 1.5% p.a. is far greater than the 0.2% p.a. growth projected in OECD America. Energy demand in OPEC and 'Developing countries excluding China, India and OPEC' will grow at rates close to the overall pace of all Developing countries, around 2.1% p.a.

For the OECD group, its share of total world energy demand is forecast to decrease from about 40% in 2014 to 30% in 2040 while Eurasia's share is expected to decrease from 9% in 2014 to 7% by 2040. These projections are driven by the future outlook for demographics, economic growth, changes in the structure of national economies, and policy developments.

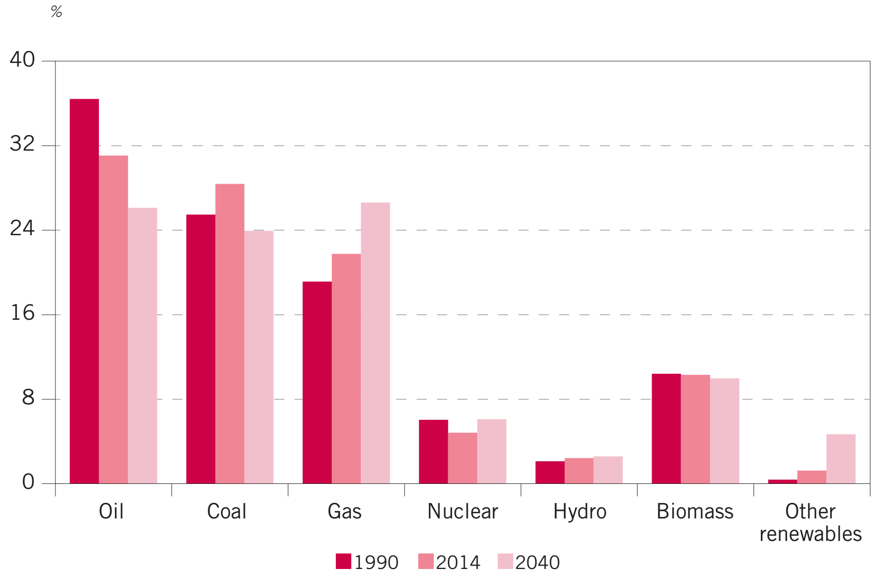
Most of the world's energy needs traditionally have been supplied by fossil fuels – namely, oil, gas and coal. In 1970, fossil fuels accounted for 87% of the global energy mix and the fuel mix was dominated by oil (44%). Fossil fuels continue to dominate current global primary energy demand with a share of 81% of total energy demand recorded in 2014. Oil's share has decreased to 31% and the share of gas has increased from 16% to 22% over the same period. Biomass had a share of 10.3% in 2014 followed by nuclear with 4.8%, hydro with 2.4% and other renewables with 1.3%.

By 2040, fossil fuels will maintain their importance in the global energy mix, although with a lower share of 77% of total energy demand (Table 2.2). By 2040,

Table 2.2
World primary energy demand by fuel type

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	85.1	90.7	96.7	99.8	0.6	31.1	30.3	28.2	26.1
Coal	77.7	82.7	88.9	91.5	0.6	28.4	27.6	25.9	23.9
Gas	59.6	66.9	84.0	101.7	2.1	21.8	22.3	24.4	26.6
Nuclear	13.2	15.5	19.5	23.4	2.2	4.8	5.2	5.7	6.1
Hydro	6.6	7.6	8.9	9.9	1.5	2.4	2.5	2.6	2.6
Biomass	28.2	30.7	34.6	38.1	1.2	10.3	10.2	10.1	10.0
Other renewables	3.4	5.7	11.0	17.9	6.6	1.3	1.9	3.2	4.7
Total	**273.9**	**299.9**	**343.6**	**382.1**	**1.3**	**100.0**	**100.0**	**100.0**	**100.0**

Figure 2.2
Change in fuel shares in the total energy mix, 1990–2040



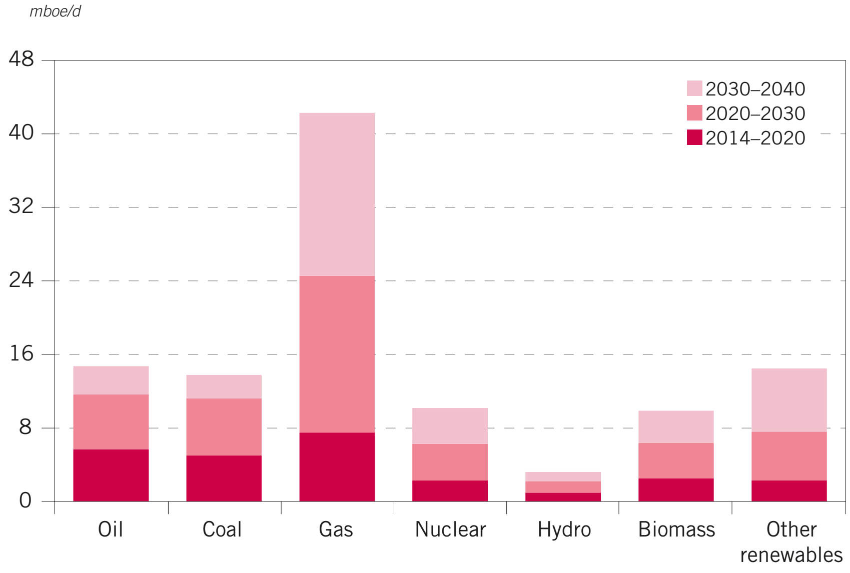
the share of oil in the energy mix is projected to decline by 5 percentage points while the share of gas is expected to increase by 4.9 percentage points (Figure 2.2). The share of coal is forecast to decline by 4.4 percentage points.

With regard to non-fossil fuels, the largest gains in terms of shares in the total energy mix are expected in other renewables (+3.4 percentage points) and nuclear (+1.3 percentage points). Compared to the previous 25 years, the notable difference is that the share of coal is projected to decrease over the forecast period whereas the share of coal increased between 1990 and 2014. Also, the shares of gas and other renewables will increase by greater amounts when compared with the last 25 years.

In absolute terms, as mentioned earlier, total primary energy demand is forecast to increase by 40% by 2040 to reach 382.1 mboe/d, or an average increase of 1.3% p.a. Figure 2.3 (which represents this increase by fuel type) shows that the majority of this growth will come from gas (+42.1 mboe/d) followed by oil (+14.7 mboe/d), other renewables (+14.5 mboe/d), coal (+13.8 mboe/d) and nuclear (+10.2 mboe/d).

This progressive shift away from oil and coal and towards gas and renewables is not surprising given that policymakers are increasingly engaged in climate change mitigation initiatives. A declining share for oil in the energy mix is mainly the result of tightening fuel efficiency standards across most countries of the world. Examples of such measures include the Corporate Average Fuel Economy (CAFE) and CAFC standards in the US and India, respectively, the Energy Efficiency Directive in the EU and the Federal Sustainable Development Strategy in Canada, among others. Moreover, a gradual increase in the penetration of alternative vehicles (as discussed in more detail in Chapter 3) also plays a role. In the case of coal, the loss of its share in the total energy mix has mainly been driven by its substitution for natural gas and renewables in the electricity sector, which are more environmentally acceptable alternatives. This change has been supported by the Clean Power Plan in the US, decarbonization policies in the EU (such as Renewable Energy Directive) and recent policy changes in China, among others.

Figure 2.3
Growth in energy demand by fuel type, 2014–2040



Regional primary energy demand

The composition of the energy mix in any given place is influenced by many factors. These include the stage of development of an economy, the structure of an economy, natural resource endowments, geographical proximity to available resources, population demographics, and the distribution of wealth and income in a country. Moreover, at the country or regional level, the energy mix is greatly influenced by rural *versus* urban dwelling and even physical geography and climate.

Tables 2.3–2.5 show the primary energy demand by fuel type for the three main regions: OECD, Developing countries and Eurasia. When looking at 2014 data, there are noticeable differences across the three main fossil fuel types and their importance across the various regions: oil has the largest share of the energy mix in OECD regions (38%), followed by gas (25%). Coal is the most prominent fuel

Table 2.3
OECD primary energy demand by fuel type

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	41.9	41.7	37.8	33.1	–0.9	37.9	36.6	32.9	29.0
Coal	20.3	19.5	17.6	15.5	–1.0	18.4	17.1	15.4	13.6
Gas	27.8	29.4	31.7	33.3	0.7	25.1	25.8	27.6	29.2
Nuclear	10.4	11.1	12.1	12.9	0.8	9.4	9.7	10.5	11.3
Hydro	2.4	2.6	2.7	2.8	0.6	2.2	2.3	2.4	2.5
Biomass	6.0	6.7	7.8	8.9	1.5	5.5	5.9	6.8	7.8
Other renewables	1.8	2.9	5.0	7.4	5.6	1.6	2.5	4.4	6.5
Total	**110.6**	**113.9**	**114.8**	**113.9**	**0.1**	**100.0**	**100.0**	**100.0**	**100.0**

Table 2.4
Developing countries primary energy demand by fuel type

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	38.2	43.7	53.2	61.1	1.8	27.3	27.0	26.3	25.4
Coal	52.9	58.7	66.6	71.3	1.2	37.8	36.2	32.9	29.6
Gas	20.3	26.1	39.9	55.4	3.9	14.5	16.1	19.7	23.0
Nuclear	1.3	2.7	5.3	8.0	7.1	1.0	1.7	2.6	3.3
Hydro	3.7	4.5	5.5	6.3	2.1	2.6	2.8	2.7	2.6
Biomass	21.7	23.5	26.2	28.5	1.0	15.6	14.5	12.9	11.9
Other renewables	1.6	2.8	5.8	10.0	7.3	1.1	1.7	2.9	4.1
Total	**139.8**	**162.0**	**202.5**	**240.5**	**2.1**	**100.0**	**100.0**	**100.0**	**100.0**

Table 2.5
Eurasia primary energy demand by fuel type

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	5.0	5.3	5.7	5.6	0.4	21.3	22.0	21.5	20.3
Coal	4.5	4.5	4.7	4.7	0.1	19.2	18.9	18.0	16.7
Gas	11.5	11.3	12.4	13.1	0.5	48.8	47.3	47.2	47.0
Nuclear	1.5	1.7	2.1	2.5	1.9	6.5	7.2	7.9	9.0
Hydro	0.5	0.6	0.6	0.7	0.9	2.3	2.4	2.4	2.5
Biomass	0.4	0.5	0.6	0.7	2.0	1.8	2.0	2.2	2.5
Other renewables	0.0	0.1	0.2	0.5	11.8	0.1	0.3	0.7	2.0
Total	**23.5**	**24.0**	**26.3**	**27.8**	**0.6**	**100.0**	**100.0**	**100.0**	**100.0**

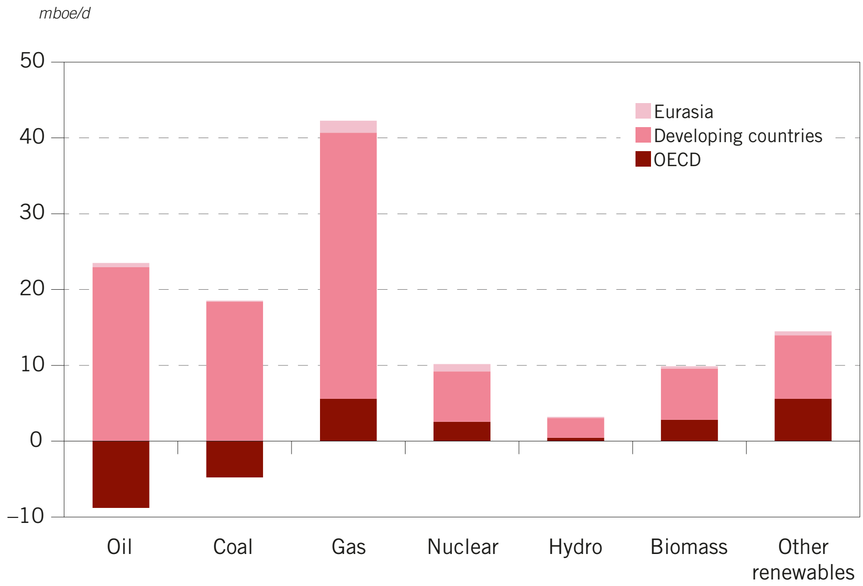
in Developing countries (38%), followed by oil (27%); in Eurasia gas accounts for 49% of the energy mix, followed by oil (21%). This is largely an indication of the availability of each of the fossil fuels across the three regions, besides the role of transport that changes the share of oil in some regions. China, for example, accounts for almost 50% of global coal production, while Russia has a 20% share of global gas production.

There are, however, also regional differences across non-fossil fuels. For example, in many developing countries, the primary source of energy for individuals living in rural areas is biomass (fuelwood, charcoal, agricultural waste), which is used largely for cooking and often accounts for over 90% of the household's energy consumption. Tables 2.3 and 2.4 show that biomass has a 15.6% share in the energy mix in Developing countries *versus* 5.5% in OECD regions. Conversely, nuclear energy is most prominent in the OECD regions with a 9% share of the energy mix compared to only 1% in Developing countries.

Turning to the projections, given that economic and demographic changes will not be uniform across all regions for the next 25 years, changes in energy demand by fuel will also vary across regions. These variations are presented in Figure 2.4, which shows total energy demand growth by fuel type for each of the three regions.

In the OECD, the greatest shifts in the energy mix will arise from a lower reliance on oil (–8.8 percentage points) and coal (–4.7 percentage points) in favour of a shift towards other renewables (+4.8 percentage points) and gas (+4.1 percentage points). Notably, gas and other renewable energy demand are forecast to increase by 5.5 mboe/d and 5.6 mboe/d by 2040, respectively. At the same time, demand for coal and oil together will fall by 13.6 mboe/d. This shift is primarily a reflection of growing environmental concerns and related policy measures aimed at reducing global emissions and local pollution. These policies not only provide direct support to the expansion of renewable energy (such as wind, solar, geothermal, etc.), but also provide incentives for fostering technology developments that result in better energy efficiency (thus, energy savings) and accelerating fuels substitution towards less emitting fuels.

Figure 2.4
Growth in energy demand by fuel type and region, 2014–2040

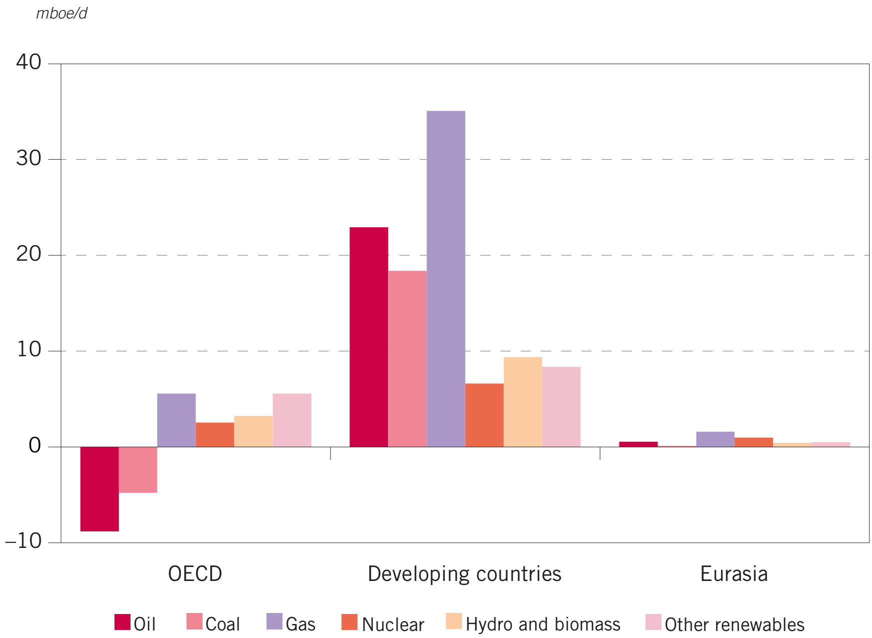


Overall, OECD energy demand is forecast to grow by 0.1% p.a. from 2014–2040 with the greatest growth rate of 5.6% p.a. forecast for other renewables. On the other hand, demand for coal and oil will fall 1.0% and 0.9% p.a. on average, respectively.

Energy demand trends in Developing countries in the next few decades will be marked by the search for a delicate balance between future energy needs and environmental concerns. Also, as stipulated by the United Nation's SDGs, ending extreme poverty (Goal 1) and ensuring access to affordable, reliable and modern energy for all (Goal 7) will need to be considered within the global frameworks aimed at limiting future emissions levels. This will certainly have an impact on the future energy mix of developing countries. To meet the energy needs of rapidly growing populations in developing countries, all types of energy will have to grow. However, it is expected that the shares of both (traditional) biomass and coal will decrease in the overall energy mix in Developing countries. Recent projections indicate that the share of coal will fall by 8.2 percentage points and biomass' share will fall by 3.7 percentage points. On the flip side, the share of gas in the energy mix of Developing counties will increase by 8.5 percentage points and other renewables' share will increase by 3 percentage points.

It was already shown in Table 2.1 that 93% of future energy demand growth from 2014–2040 will come from Developing countries. Figure 2.5 shows that this also holds true across all fuel types. From 2014–2040 gas demand is expected to grow by 35 mboe/d followed by oil and coal with 22.9 mboe/d and 18.4 mboe/d, respectively. Overall, Developing countries' energy demand will grow by 2.1% p.a. on average from 2014–2040 with the greatest growth rate forecast for other

Figure 2.5
Energy demand growth by region, 2014–2040



renewables (7.3% p.a.) and nuclear (7.1%). On the low end, biomass energy demand will grow 1% p.a. over the forecast period.

In Eurasia, the shifts in the energy mix from 2014–2040 are less pronounced though still revealing. There will be an overall decrease in the share of fossil fuels with coal seeing the largest drop of 2.5 percentage points (falling to a 16.7% share of the energy mix by 2040 from the current 19.2% share). Gains in the energy mix shares will be seen in nuclear (+2.5 percentage points) and other renewables (+1.8 percentage points). The total energy demand increase of 4.3 mboe/d from 2014–2040 is expected to come mostly from gas (1.6 mboe/d), nuclear (1 mboe/d), oil (0.6 mboe/d) and other renewables (0.5 mboe/d). Overall, Eurasian energy demand will grow 0.6% p.a. from 2014–2040 with the greatest average growth rate of 11.8% p.a. forecast for other renewables and 1.9% for nuclear. On the low end, coal demand is anticipated to grow just 0.1% p.a. on average over the forecast period.

It is also worthwhile to take a more granular look at the energy demand mix among Developing countries, particularly in China and India. Given China's abundance of coal natural resources, its primary energy demand is currently dominated by coal with a share of over 65% of the total energy mix (Table 2.6). Coal is expected to continue to be the major source of energy for China through to 2040, although the share of coal is projected to fall to 52%. At the same time, it should be noted that future demand for coal in China depends on the extent of further structural changes to its economy and on the path policymakers will adopt to reduce the country's emissions. Coal offers China many cost-effective options to achieve

Table 2.6
China primary energy demand by fuel type

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2014	2020	2030	2040	2014–2040	2014	2020	2030	2040
Oil	10.0	11.6	14.0	16.0	1.8	16.6	16.9	17.3	18.1
Coal	39.7	42.9	46.3	46.2	0.6	65.9	62.4	57.2	52.5
Gas	3.0	4.4	6.9	8.9	4.2	5.1	6.4	8.6	10.1
Nuclear	0.7	1.8	3.8	5.4	8.3	1.1	2.6	4.7	6.1
Hydro	1.6	2.1	2.6	2.8	2.1	2.7	3.1	3.2	3.2
Biomass	4.3	4.5	4.9	5.1	0.6	7.2	6.6	6.0	5.8
Other renewables	0.8	1.4	2.5	3.7	5.9	1.4	2.1	3.1	4.1
Total	**60.2**	**68.8**	**80.9**	**88.1**	**1.5**	**100.0**	**100.0**	**100.0**	**100.0**

such a goal. If coal becomes a primary target of new environmental policies, a further reduction in its share of the country's energy mix, as well as lower energy consumption, are very likely. The shift away from coal would be primarily absorbed by gas and nuclear energy, which are projected to grow on average by 4.2% and 8.3% p.a., respectively. Other renewables will also post strong growth of 5.9% p.a. from 2014–2040.

Similar to China, India's energy mix is also dominated by coal with a 45% share of the energy mix followed by oil with a share of 23% (Table 2.7). Unlike China, all fossil fuels in India are projected to grow above 4% p.a. on average over the forecast period with the share of coal reaching almost 50% by 2040. Demand for nuclear

Table 2.7
India primary energy demand by fuel type

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2014	2020	2030	2040	2014–2040	2014	2020	2030	2040
Oil	3.7	5.0	7.5	10.1	4.0	23.0	24.7	24.8	24.5
Coal	7.2	9.2	14.7	20.5	4.1	44.6	45.3	48.6	49.7
Gas	0.9	1.2	2.0	3.1	4.8	5.8	6.0	6.6	7.6
Nuclear	0.2	0.4	0.7	1.2	7.4	1.2	1.7	2.4	3.0
Hydro	0.3	0.3	0.4	0.4	2.2	1.6	1.5	1.2	1.1
Biomass	3.8	4.0	4.4	4.7	0.9	23.4	19.9	14.6	11.4
Other renewables	0.1	0.2	0.5	1.1	10.5	0.5	0.9	1.8	2.7
Total	**16.0**	**20.3**	**30.2**	**41.2**	**3.7**	**100.0**	**100.0**	**100.0**	**100.0**

energy and other renewables are projected to increase 7.4% and 10.5% p.a. on average, respectively.

Biomass demand growth will be subdued, registering 0.9% p.a., while the share of biomass is forecast falling from 23% in 2014 to 11% in 2040. This would be likely a result of a combination of factors such as a limited resource base for biomass, the intentions of Indian policymakers to contribute to emissions abatement by increasing forestation and shifting away from traditional biomass (used primarily in rural areas for cooking) towards other fuel sources (such as LPG and kerosene).

Global primary energy demand by fuel type

Oil

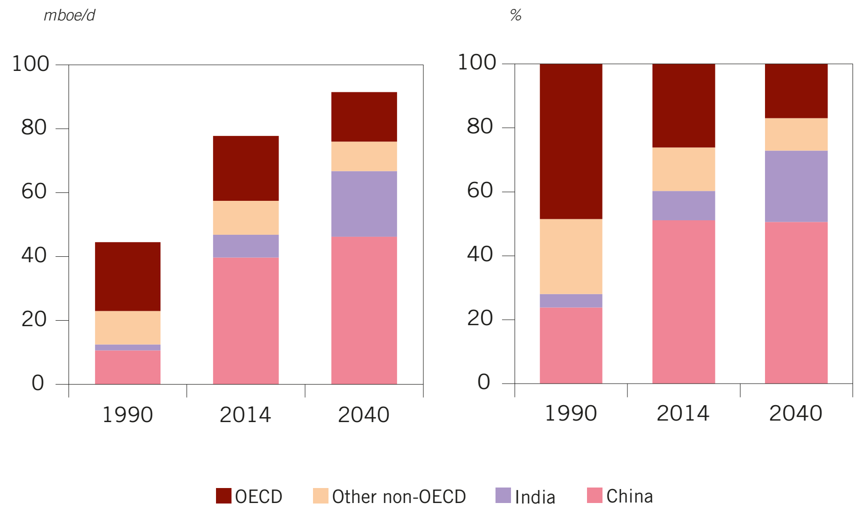
As already discussed in the previous sections of this Chapter, oil is set to remain an important part of the global energy mix for the foreseeable future, despite the fact that its share in the global energy mix is projected to decline by 5 percentage points between 2014 and 2040, from around 31% in 2014 to some 26% in 2040. Nevertheless, oil will still remain the fuel with the second largest energy share by 2040, as well as the second largest contributor to additional energy needs over the forecast period – with an overall demand increase of almost 15 mboe/d between 2014 and 2040, reaching the level of close to 100 mboe/d by 2040. Because oil is the core focus of this report, a detailed analysis of the drivers for this change is included in Chapter 3. Similarly, Chapter 4 provides details of the supply side of the oil industry.

It should be noted, however, that oil demand figures included in this Chapter are expressed in terms of energy content (that is, in mboe/d), while in Chapters 3 and 4 they are all on a more common volumetric bases (that is, in mb/d). Therefore, absolute numbers may look different. Moreover, when dealing with the comparison of various energy sources, the definition of major categories is also slightly different. Chapter 2 compares the 'origin of energy' such that specific fuels are associated with their source of energy. Thus, biofuels are part of biomass, coal-to-liquids (CTLs) is part of coal and gas-to-liquids (GTLs) is part of gas. Chapters 3 and 4 include these fuels as part of liquids demand and supply. Thus, overall figures in these chapters are higher than in Chapter 2.

Coal

Following a long period of strong growth, global coal demand dropped in 2015 according to initial estimates as coal faced challenges in many world regions including the OECD, but also in developing countries such as China. Climate policy measures – including the expansion of renewables and energy efficiency measures – combined with concerns about pollution, the weakening competitiveness of coal against other fossil fuels and changes in economic structure all remain hurdles for long-term coal demand. On the other hand, economic growth and population development still outweigh negative trends. The net effects result in a significant slowdown of global coal annual demand growth, with average growth of 0.6% in the period 2014–2040. Although overall coal consumption is forecast to increase in the long-term, the share of coal demand in the total global energy mix is expected to

Figure 2.6
Global coal demand and shares by region



decline by some 4.4 percentage points to around 24% in 2040, from levels above 28% in 2014.

Looking at the details on a regional basis (Figure 2.6), the coal demand outlook shows differentiated pictures. While coal use in non-OECD countries is expected to rise, driven by economic and population growth, the OECD region is estimated to show a strong decline in coal demand as the fuel is phased out due to regulatory pressures and is substituted by cleaner alternatives such as natural gas and renewable, in the electricity sector.

Non-OECD countries, which already contribute to the bulk of global coal demand, are expected to expand their share even further in the long-term. This expansion, however, is dominated by two countries: China and India. While aggregate coal consumption in the two countries only made up around 28% of global coal demand in 1990, this share climbed to 60% in 2014 and is forecast to rise to levels just below 75% in 2040. In absolute figures, coal demand in the two countries is estimated to increase from 46.9 mboe/d in 2014 to 66.7 mboe/d in 2040 (Figure 2.6). This illustrates the relevance and importance of the two countries for the global coal demand outlook.

In China, after a decade of remarkable growth rates, with an average rate of around 8% p.a. between 2000 and 2013, coal demand showed its first signs of weakness, dropping by 2.9% in 2014 and 3.7% in 2015 as reported by China's National Bureau of Statistics (NBS).[5] The reason for the slowdown in China was a combination of slower economic growth and a shift away from energy-intensive industries (that is, declining energy intensity), but also environmental policies aiming at air pollution and CO_2 emissions. Moreover, public opinion in China is increasingly turning against coal-fired power plants, thus creating additional hurdles for coal use in the country.

Despite current weaknesses, China's coal demand is expected to continue growing in the medium- and long-term following further economic growth, although at a much lower average rate compared to the recent past. Furthermore, the replacement of old coal-fired power generation units with highly efficient coal power plants will also contribute to less coal demand per unit of power produced. As a result, average growth between 2014 and 2030 is estimated at around 1% p.a., with demand peaking at 46 mboe/d around 2030 and remaining fairly stable thereafter.

Putting things into perspective, while the share of coal in the Chinese energy mix will decline, it is expected to continue dominating the long-term primary energy supply of China. The share of coal in the energy mix is seen at around 52% in 2040, down from over 65% in 2014.

At the same time, India is increasingly becoming an important player for global coal demand. It became the world's second largest coal consumer in 2015,[6] surpassing the US after a long period of strong growth rates, which had averaged around 6% p.a. since 2000. The fast growing population – a large share of which still do not have access to electricity – and strong economic growth are estimated to be the main drivers of future coal demand.

Nevertheless, there are several constraints to this growth. These include a lack of domestic coal supplies and a growing reliance on imported coal, limited water supplies for coal-fired power plants and rising environmental concerns. Consequently, India's coal use is seen growing by an average of around 4% p.a. in the forecast period until 2040. In absolute terms, demand projections show a rise from 7.2 mboe/d in 2014 to 20.5 mboe/d in 2040. As a result, the share of coal in India's energy mix increases from around 45% in 2014 to almost 50% in 2040.

Overall, other non-OECD regions show a moderate decline over the forecast period. Growing economies such as Thailand and Vietnam show strong demand growth over the outlook period. This is, however, offset by declines in several other non-OECD countries. In the Eurasia region including Russia, coal demand is estimated to be broadly stable at levels around 4.5 mboe/d throughout the forecast period. Nevertheless, the share of coal in the total energy mix is expected to gradually decline to below 17% in 2040, down from more than 19% in 2014. This is due to the expansion of other fuels such as nuclear and renewables.

In OECD countries, the picture for coal is gloomy with countries set to reduce coal use in both the power generation and industrial sectors. This is driven not only by regulation (including a push for greater renewables use), which has squeezed coal out of the energy mix, but also by increasing energy efficiency and growing competition from cleaner alternative fuels such as natural gas. Population growth and changes in the structure of the economy have contributed to this trend. In absolute terms, coal demand is expected to decline from 20.3 mboe/d in 2014 to 15.5 mboe/d in 2040. Consequently, its share of the energy mix is anticipated to decline by 4.8 percentage points to reach 13.6% in 2040 (Figure 2.6).

The penetration of heavily subsidized renewables, combined with declining power demand in OECD Europe in the recent past, has led to reduced requirements for coal-fired power generation and consequently lower coal demand. Although coal temporarily profited from high gas prices in some countries and low carbon prices in the EU ETS in 2013, this trend was reversed in 2014/15 when lower gas prices and regulatory pressure increased carbon prices in some countries (for example, the UK with the carbon floor price).

Looking to the future, the demand for coal in OECD Europe should continue to decline under pressure from alternatives, such as renewables and gas, as well as regulatory initiatives (such as the Large Combustion Plant Directive and Industrial Emissions Directive), which seek the limitation of operations and the decommissioning of old coal power plants. As a result, the use of coal in OECD Europe declines on average by 2% p.a. in the forecast period, from 6 mboe/d in 2014 to 3.6 mboe/d in 2040. Despite efforts to phase out coal use in Europe, the share of coal in OECD Europe's primary energy demand in 2040 is still around 10% (from around 16% in 2014), which is due to the opposition of some countries in OECD Europe, that are heavily reliant on coal use, such as Poland.

In the US, coal consumption declined in 2014 and 2015 mainly due to strong competition from gas in the power sector. While gas- and coal-fired power generation were almost at parity in 2015, gas-fired generation is set to surpass coal-fired power production in 2016 on an annual basis.

This is an important milestone, as coal has traditionally been the most important fuel source by far for power generation in the US. In addition, policymakers are putting even more pressure through the Mercury and Air Toxic Standard, as well as the Carbon Pollution Standard for New Power Plants issued by the US EPA. Moreover, the implementation of the Clean Power Plan released in August 2015 (currently on hold due to judicial review by the Supreme Court) aims for a reduction of carbon emissions by 32% by 2030 relative to 2005. This would inevitably lead to the closure of a large number (mostly old and inefficient) of coal-fired power units and obstruct the construction of new coal-fired plants, which would necessarily reduce US coal demand. Despite some uncertainties surrounding the implementation of the plan, the declining trend in coal consumption in OECD America (dominated by the US) is seen continuing, from around 9 mboe/d in 2014 to 7 mboe/d by 2040. This is an average decline of some 1% p.a. over the outlook period.

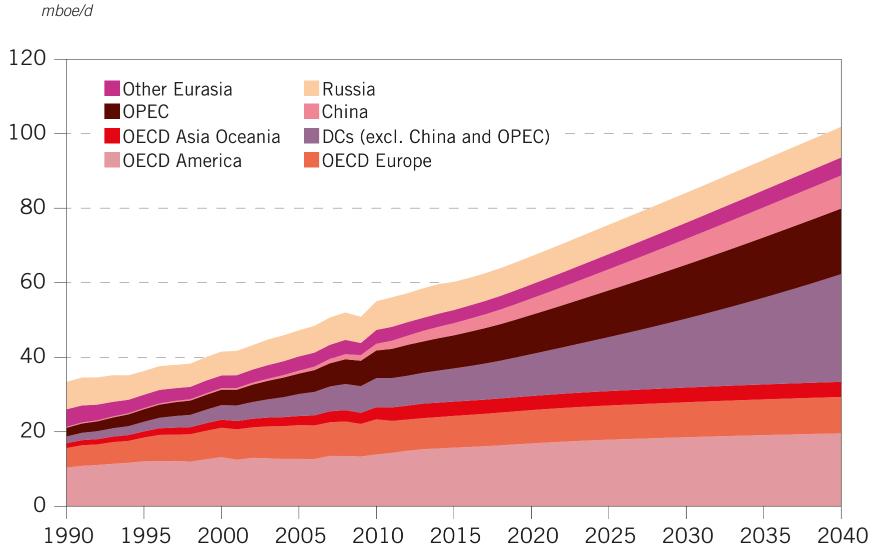
In the OECD Asia Oceania region, coal use is forecast to increase in the medium-term mainly due to the continued use of coal in Japan and an expansion of the power sector in South Korea. However, consumption in the long-term is set for a gradual decline, driven by the increasing penetration of alternatives (such as renewables and gas) in the power generation sector. In addition, the return of nuclear power in Japan following the Fukushima disaster, is expected to weigh on the region's coal demand. As a result, coal demand is expected to increase from 5.1 mboe/d in 2014 to 5.4 mboe/d in 2020 and then decrease to just below 5 mboe/d by the end of the outlook period.

In summary, global coal demand is expected to increase gradually from 78 mboe/d in 2014 to 91 mboe/d in 2040. This is an average rate of 0.6% p.a. However, numerous uncertainties, especially in large developing countries such as China and India, surrounding economic development, environmental issues and renewables penetration, as well as potential technological breakthroughs, remain, and will continue to affect the development of coal demand in the medium- and long-term.

Natural gas

Figure 2.7 shows the rise of natural gas demand from 1990 until the present, and a projection to the year 2040. The Reference Case gives a relatively optimistic view of gas consumption over the long-term. Vast recoverable resources and rapidly expanding gas trade support this view. Climate policies will also play an important role, since gas use offers environmental advantages. For example, natural gas emits

Figure 2.7
Natural gas demand by region, 1990–2040

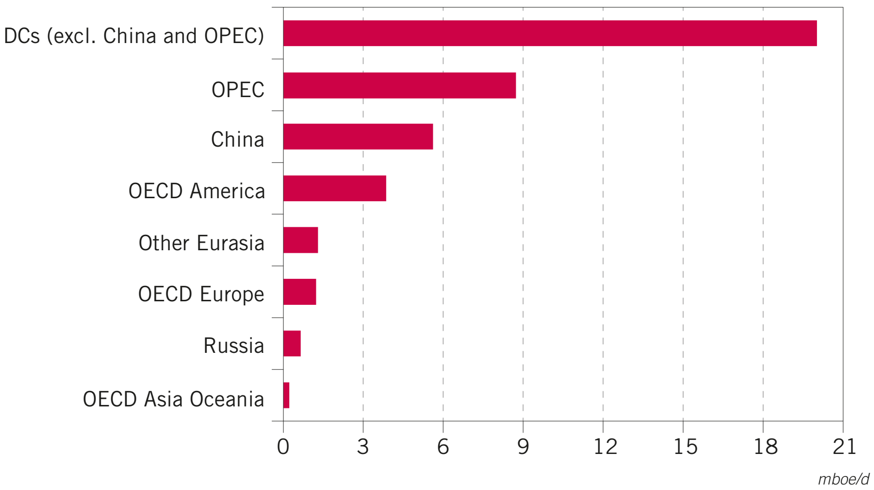


about one-half to one-third of the emissions of coal when burned, making it easier for policymakers to meet emissions targets. Though most of the world's gas demand is expected in the electricity sector, some opportunities will also arise in the residential sector, the industry sector, including petrochemicals, and the transportation sector. For all these reasons, several energy companies have signalled their intention to shift their portfolios more towards natural gas.

After having accounted for the majority of historical gas demand, the OECD, led by the US and Europe, is expected to reach 33.3 mboe/d – out of a world total of nearly 102 mboe/d – in 2040. The non-OECD represents more than two-thirds of gas demand, about 68.4 mboe/d, in 2040. The growing importance of gas is mainly driven by rising energy needs in these countries and by fuel switching from coal to gas in Asia's power generation sector. So far, economic growth in the region has mostly been fuelled by coal and to a lesser extent oil. The shift to gas is supported by the aims of emerging nations in the region to reduce emissions. In addition to rising long-term consumption in traditionally important gas and liquefied natural gas (LNG) consumers, such as China, Japan and South Korea, demand is expected to rise sharply in nations like India, Indonesia, Malaysia, Singapore, Thailand and Vietnam.

Gas demand growth in selected regions, spanning the years 2015–2040, is shown in Figure 2.8. The figure reveals a substantial difference in gas demand growth between Developing countries and elsewhere. China, still heavily reliant on coal, sees its gas use increase by 5.6 mboe/d, from 3.3 mboe/d in 2015 to 8.9 mboe/d in 2040. OPEC Member Countries experience a steady rise of 8.6 mboe/d, from 8.9 mboe/d in 2015 to 17.5 mboe/d by the end of the forecast period. Other developing countries, which include India, experience the fastest growth in gas demand. In 2015, these countries were consuming 8.9 mboe/d. The figure is estimated to rise to an impressive 28.9 mboe/d by 2040.

Figure 2.8
Natural gas demand growth by region, 2015–2040



The OECD sees only marginal growth from present levels until 2040. In OECD America, however, gas use rises from 15.7 mboe/d in 2015 to 19.5 mboe/d in 2040 – an increase of 3.8 mboe/d. The growth is partly fuelled by the unconventional US gas boom, which continues to demonstrate resilience in the face of low natural gas prices. The result has been increased consumption of gas for power generation and as a feedstock for the petrochemical sector, a trend that is expected to continue. Gas use in the rest of the OECD remains relatively flat.

Eurasia, with its high current gas consumption of 11.1 mboe/d, sees slight additional demand over the period: a rise of 0.7 mboe/d for Russia and 1.3 mboe/d for Other Eurasia.

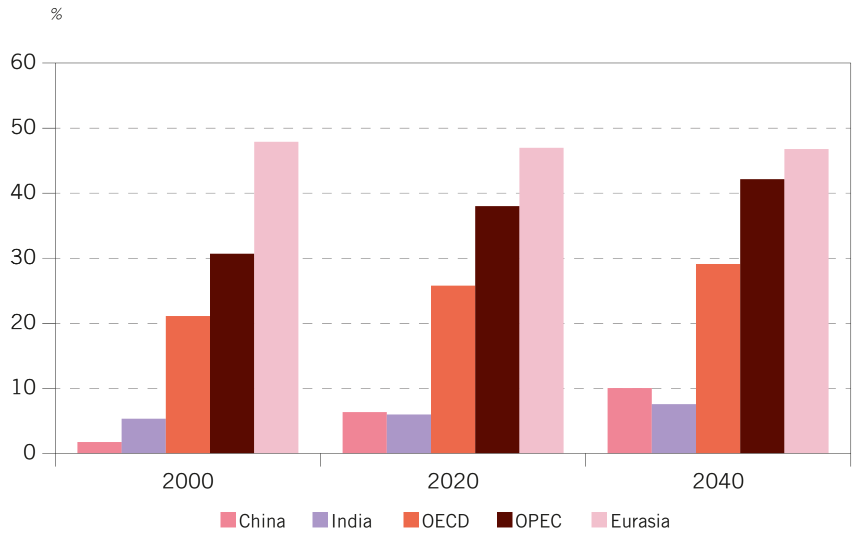
Despite the high levels of gas use projected for the non-OECD, it is noteworthy that prominent consumers like China and India have relatively small shares of natural gas in their primary energy mixes (Figure 2.9). China sees its share of gas consumption rise from 2% in the year 2000, to 6% in 2020, and then 10% in 2040. In the case of India, gas accounts for 5% of the mix in 2000, 6% in 2020 and 8% in 2040.

The OECD has a modest, but growing share over time, reaching 29% in 2040, from 21% in 2000. Eurasia and OPEC Member Countries have the highest overall shares of gas in their energy markets by 2040, with 42% and 47%.

An important determinant of the energy demand mix in the Reference Case is the competition between natural gas, coal and renewables in the power sector, where relative prices play a role. Gas and coal prices are presently very low, while supportive policies for renewables continue.

The natural gas price divergence observed from 2011–2014 has narrowed significantly. Converging prices can generally be explained by the growing supply overhang of natural gas and LNG, lacklustre gas demand over the past few years, and the oil price drop for the case of European and Asian prices. The oil

Figure 2.9
Share of natural gas in primary energy mix by region



indexation mechanism is still widely used in the latter two markets to price natural gas supply.

It is noteworthy that even though gas prices have fallen, coal prices are even lower in Europe and Asia, making it difficult for gas to compete economically at present. In the long-term, however, the introduction of environmental policies should favour gas development *versus* coal. For instance, a tax on carbon increases the relative price of coal, given its higher carbon intensity, while promoting investment in gas extraction and use – thus inducing substitution from coal towards gas. Such policies will also result in higher growth rates for renewables, albeit from a low base, and may at times make some renewables competitive with gas as well.

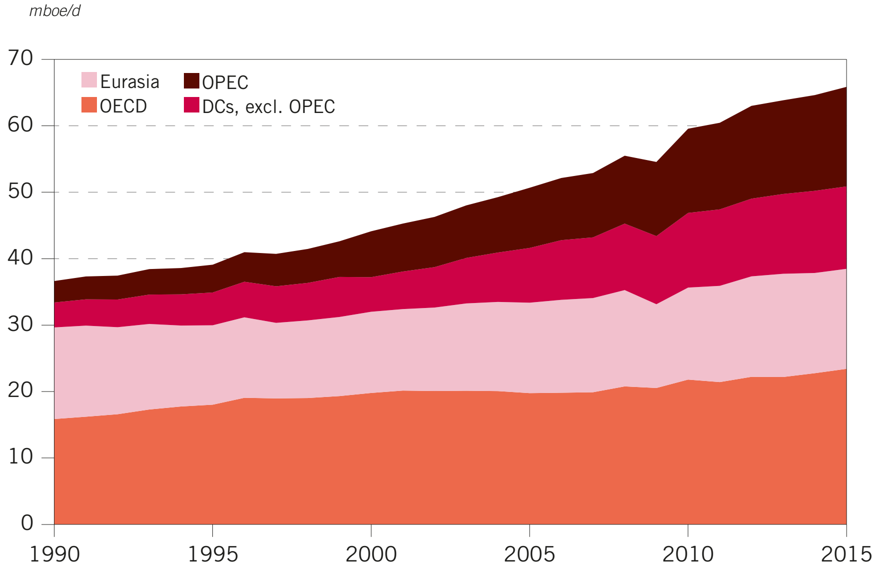
A glimpse of the coal to gas transition is provided by the US experience in recent years, with a narrowing gas and coal price differential in energy terms since 2008. Gas use in electrical power generation has risen as a consequence, while coal use has decreased.

Another factor underpinning the gas outlook is the abundance of natural gas around the world. According to OPEC's *Annual Statistical Bulletin*, proven natural gas reserves in 2015 were approximately 202 trillion cubic metres (1.3 trillion barrels of oil equivalent (boe)). Of the large reserve holders, the Middle East accounts for 39% of the total, and Russia for 25%.

Unconventional gas resources are also large and widely distributed. Shale gas technically recoverable resources alone have been estimated at 1.3 trillion boe – equal to existing proven conventional gas reserves. Despite some of the technical challenges and environmental sensitivities associated with hydraulic fracturing, supply is expected to rise and play an increasingly important role in meeting global demand requirements.

Figure 2.10 shows historical gas supply from 1990 until 2015. The largest producing region in 2015 was the OECD at 23.4 mboe/d, with much of the

Figure 2.10
Natural gas supply by region (marketed production on annual basis), 1990–2015



Source: *OPEC Annual Statistical Bulletin, 2016.*

output coming from the US. Supply from Eurasia, mostly from Russia, stood at 15.1 mboe/d in 2015, followed by OPEC at 15 mboe/d and Other developing countries at 12.4 mboe/d.

The rise of gas demand in the Reference Case, particularly in the non-OECD, is partially explained by the significant number of new LNG projects coming onstream. Most of the new capacity is coming from North America and Australia, with much of the LNG intended for delivery to Asia. Despite current low prices and oversupply, demand is expected to be attractive over the long-term, especially in Asia.

In Australia, the past decade saw investment in LNG projects of around $200 billion. In North America, although the US currently plays a small role in the global LNG markets, numerous projects have been approved for exports by the US authorities. The first project to materialize was Sabine Pass, which made its first shipment from Louisiana to Brazil in February 2016. Substantial LNG projects are under development, with many targeting major markets in Asia. Investment of about $50 billion has taken place. Investing companies expect that the supply overhang will be alleviated over the long-term as demand picks up and supply growth slows due to the ongoing cancellations and deferrals of projects in the low price environment.

In the context of current market circumstances, it should be stressed that there is uncertainty associated with the LNG outlook. The major companies that invested heavily are entering a significantly weaker international gas market than first anticipated. This raises questions regarding how much LNG will actually be exported, and how much of an impact it will have on international trade and prices. For instance, the effect on oil-indexed gas markets is still uncertain, due to the different market structures in each region and the high costs associated with liquefaction, shipping and regasification. Against the background of low prices, LNG sellers are striving to bring project costs down.

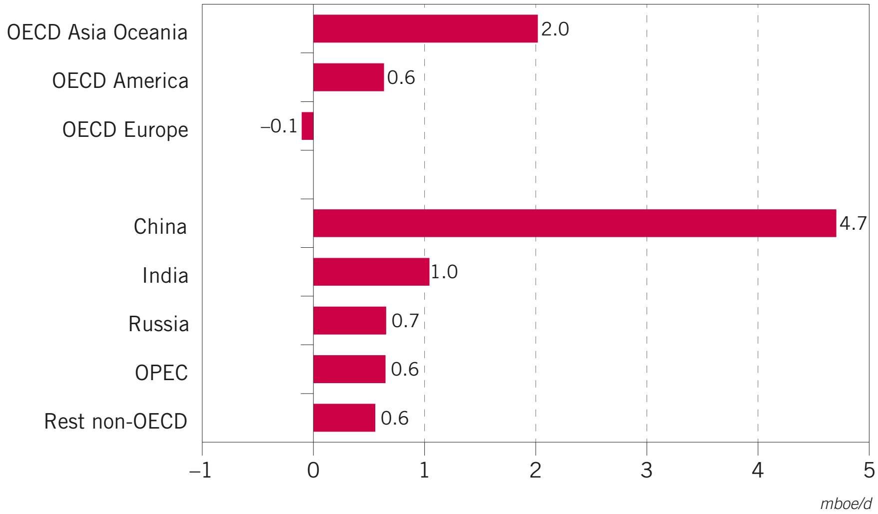
Nuclear

The current installed nuclear generation capacity is estimated at around 380 GW, and comprises almost 450 reactors. In 2015, nuclear supplied more than 13 mboe/d. The majority of the installed capacity is currently located in OECD countries and the Former Soviet Union (FSU), where approximately 90% of the global nuclear energy is supplied. As with other fuels, however, developing countries are set to gradually expand their nuclear capacities in the medium- and long-term.

While nuclear capacity provides required energy, contributes to energy security and simultaneously limits CO_2 emissions, it also brings the significant risks of potential nuclear accidents, heavy capital spending requirements, as well as the waste issue. These advantages and risks are assessed differently by various countries resulting in diverse policies and regulations.

For example, several OECD countries are partly stepping back from nuclear energy (especially Germany and to some extent France) and strong public opposition has been seen in some other countries. This trend is supported by the push for alternatives such as renewable energies, as well as expanding energy efficiency measures and a shift within economies towards the service sector, which limits total energy demand growth. At the same time, developing countries (led by China and India) are becoming global leaders in the expansion of nuclear energy, driven by the energy requirements of their growing economies and expanding populations (Figure 2.11).

Figure 2.11
Nuclear energy additions, 2014–2040



More specifically, the OECD region shows three different trends: a strong rise in OECD Asia Oceania, a gradual increase in OECD America and a slight decline in OECD Europe.

In OECD Asia Oceania, Japan has historically been the dominant nuclear player, although generation from nuclear units was phased out after the Fukushima disaster in 2011. Consequently, nuclear power generation in the OECD Asia Oceania region was seen at around 0.8 mboe/d in 2014, down from a much higher 2.3 mboe/d that was observed in 2010. Japan is, however, expected to restart some of its reactors in the coming years, although reactors will have to comply with the stricter safety standards implemented after Fukushima. The nuclear restart actually began in 2015, with two reactors being put back online. Although this trend is likely to continue in the medium- and long-term, Japan is not expected to reach the level of nuclear energy generation seen prior to 2011. Elsewhere in the region, South Korea will be the main driver for nuclear capacity growth with four 1.4 GW units currently under construction. In total, nuclear energy in OECD Asia Oceania is forecast to increase from 0.8 mboe/d in 2014 to 2.8 mboe/d in 2040.

Nuclear energy in OECD Europe is mainly dominated by Germany and France. The former is continuing to phase out nuclear power plants in the framework of its 'Energiewende' plan and France, which is heavily reliant on nuclear power, decided to cap the level of nuclear power at around 63 GW and at a maximum 50% of total power output (currently around 75%). Apart from Germany and France, several other countries in OECD Europe either already have units under construction or plan to expand the existing nuclear capacity, such as Slovakia, Finland and the UK. In addition, some countries have declared long-term interest to enter the nuclear sector, such as Turkey and Poland. In total, nuclear energy in OECD Europe is estimated to remain broadly stable at around 4.5 mboe/d throughout the forecast period, with new builds offsetting the retirement of existing plants.

OECD America is expected to see modest long-term increases with the US being the main contributor, whereas Canada is likely to decommission some of its capacity in the future. Nuclear energy in the region is forecast to increase by some 0.6 mboe/d until 2040 from around 5 mboe/d in 2014.

It is the non-OECD region that is seen as the major contributor to the growth of nuclear energy in the long-term, with volumes more than tripling from levels of just below 3 mboe/d in 2014 to 10.5 mboe/d in 2040.

Similar to other fuels in the energy mix, growth comes mainly from two countries: China and India. Currently, there are some 26 reactors under construction in these two countries, which comprises 40% of the total number of reactors under construction globally. In the long-term, the combined nuclear energy of the two countries is expected to increase by some 5.7 mboe/d to around 6.5 mboe/d in 2040.

At the same time, other non-OECD countries are also contributing to the growth, though to a lesser extent. This includes Middle Eastern countries, where several units are already under construction in the UAE and interest has been shown by Saudi Arabia, Iran and Kuwait. In addition, countries of the FSU are also expected to expand their capacities, led by Russia and followed by Ukraine and Belarus. And, lastly, there are several other countries which are expected to expand their nuclear capacity, such as Pakistan, Brazil and Argentina.

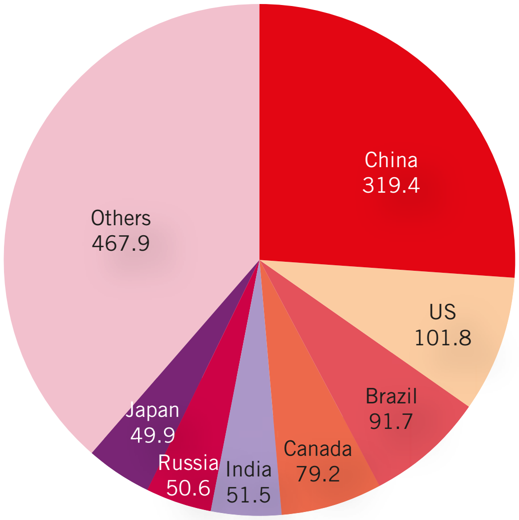
In summary, the attractiveness of nuclear power is expected to support its expansion in the long-term with nuclear energy estimated to increase significantly over the forecast period, from 13.2 mboe/d in 2014 to 23.4 mboe/d in 2040. The risk of public opposition, as well as regulatory interference, costs and technological risks resulting in project delays are the main sources of uncertainties for nuclear in this outlook.

Hydro

Although hydro energy has a relatively small share of the total energy mix compared to other fuels (only 2.4% in 2014), it is of great importance for the power systems in countries and regions with relatively significant installed capacity. The ability to store energy (conventional storage and pumped-storage plants) helps to stabilize the power system in these countries and regions – that is, to balance out variations in constantly changing power demand and supply. On the negative side, hydro energy itself is subject to weather risks (such as rainfall), which can lead to unstable production volumes and extreme variations in production over years. For example, South America has been suffering from extreme drought during 2016, which has had big impacts on hydro generation.

On a regional basis, distribution of hydro energy is extremely uneven with some countries being dominated by hydropower, such as Norway or Austria, while in some countries the role of hydropower is negligible. In 2015, the global installed capacity of hydropower was estimated at around 1,200 GW of which over 300 GW are located in China. More broadly, the top seven countries in terms of installed hydro capacity – China, the US, Brazil, Canada, India, Russia and Japan – had in total around 740 GW (Figure 2.12) in 2015, which was over 60% of the global total installed capacity. While many developed regions have already reached the

Figure 2.12
Global installed hydro capacity including pumped-storage in 2015[8] *GW*



limit in terms of exploitable resources, there are still a number of countries with untapped hydro potential, where growth can be expected in the medium- and long-term.

In the OECD regions, the growth of hydropower is constrained not only by the lack of available resources but also because of concerns over the environmental impact of potential large hydro projects. While growth in large-scale projects may be limited, some upside potential exists not only from small-scale hydropower (run-of-river), but also from the refurbishment of old hydropower plants through increasing efficiency. Looking at this in more detail, OECD Europe is expected to grow only slightly over the forecast period, reaching 1.15 mboe/d in 2040, up from 1 mboe/d in 2014. Some countries, such as Turkey, are still investing in large-scale hydro projects, while other countries of the region are likely to add mostly smaller units, which are also supported by governmental subsidies for renewable energy. More activity can be seen in OECD America where hydropower is forecast to increase by 0.3 mboe/d from 2014 to 1.5 mboe/d in 2040. This expansion is largely based on undeveloped resources that exist in the US and Canada. In OECD Asia no major changes are expected with hydropower levels remaining stable at around 0.2 mboe/d throughout the forecast period.

The majority of the global growth is expected in non-OECD Asia, led by China. China currently has 320 GW of installed capacity, of which close to 20 GW was installed during 2015 alone.[9] This trend is likely to continue with relatively large untapped resources across the country and in line with the efforts of the government to reduce air pollution and CO_2 emissions. In total, hydropower in China is expected to increase from around 1.6 mboe/d in 2014 to 2.8 mboe/d in 2040.

Similarly, many other countries in non-OECD Asia with untapped hydro potential – such as India, Thailand, Vietnam, Philippines and Indonesia – are also expected to increase hydropower in the long-term. This is in line with growing power demand in these countries as their economies grow and more people have access to electricity. Elsewhere, the potential exists in several Latin American countries, such as Brazil, Venezuela and Peru, as well as in sub-Saharan Africa. As a result, hydropower in Developing countries (excluding China) is projected to increase from 2.1 mboe/d in 2014 to 3.5 mboe/d in 2040.

Finally, for Eurasia, the Reference Case sees only slight growth over the forecast period, increasing by 0.2 mboe/d to reach 0.7 mboe/d in 2040. Hydropower development of hydropower in this region remains subdued despite large potentials (globally, Russia has the largest undeveloped potential[10]) due to a lack of infrastructure, the remoteness of potential projects and the continuing strong focus on fossil fuels in these countries.

In total, the contribution of hydropower to the global energy demand mix is expected to increase from 6.6 mboe/d in 2014 to just below 10 mboe/d in 2040, comprising an annual average growth of 1.5% p.a. over the period. The significance of hydropower will remain as it has a vital role for balancing the power system. In the long-term, this will be even more important as the growing volume of energy from intermittent sources such as wind and solar will need to be balanced from elsewhere. However, concerns over environmental and social impacts could delay or cancel some large-scale projects, which, in combination with the potential change in rainfall patterns in some regions, represent the main challenges for hydropower future development.

Biomass

Biomass consumption, for both commercial and non-commercial purposes, is projected to rise by 1.2% p.a. on average from 2014–2040. Throughout the forecast horizon, biomass is the fourth largest consumed energy source, behind the three fossil fuels. In 2014, world biomass demand stood at 28.2 mboe/d. It is expected to increase by 3.3 mboe/d over the medium-term, reaching 31.5 mboe/d in 2022.

By 2040, biomass use rises to 38.1 mboe/d, representing approximately 10% of the global primary energy mix in that year. This signifies a slight decrease of 0.3 percentage points from 2014–2040, despite the volumetric increases over the period. The figures include biofuels, which are addressed in more detail in Chapter 4.

The OECD's biomass demand rises from 6 mboe/d in 2014 to 8.9 mboe/d in 2040. Much of that increase can be attributed to biofuels, primarily from the US and Europe. The largest increase in biomass demand over the long-term comes from Developing countries. Those countries consumed 21.7 mboe/d in 2014, which accounted for approximately 77% of global biomass consumption. In 2040, demand is expected to rise to 28.5 mboe/d, which will represent 75% of global demand. The overwhelming majority of biomass use in Developing countries is for the agricultural, commercial and residential sectors.

It is significant that despite the growth in absolute biomass use in Developing countries from 2014–2040, there is a decline in the long-term share of biomass within the energy mix. Standing at 15.6% in 2014, the share of biomass in the total energy mix of Developing countries falls to 11.9% in 2040. The drop comes on the back of rising living standards in these countries, as they reduce the consumption of solid biomass, like waste and residues, relative to other energy sources.

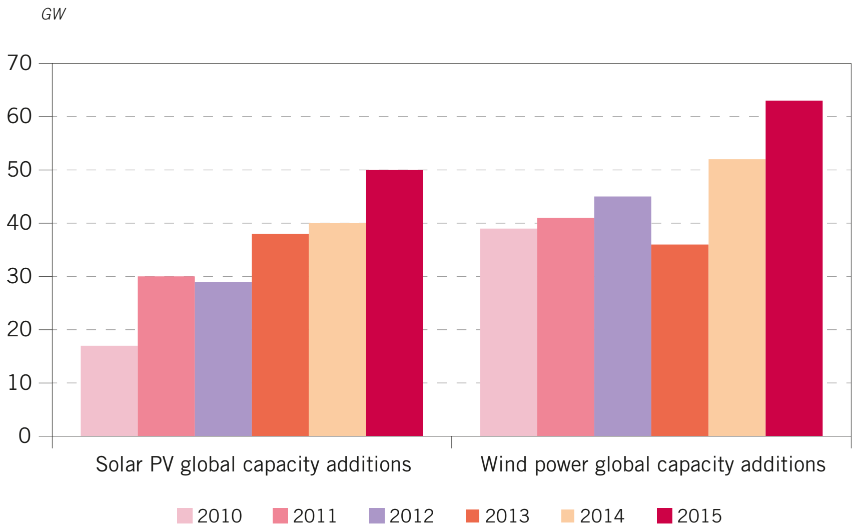
Other renewables

Other renewables – which include mainly wind, PV, solar thermal and geothermal – showed considerable growth in 2015 with some renewable technologies reaching all-time highs in terms of annual additions, such as solar PV and wind. In 2015, solar PV power capacity rose by 50 GW to total 227 GW (Figure 2.13). The majority of additions in 2015 came from China (15 GW), Japan (11 GW) and the US (7 GW). At the same time, wind power (mostly onshore wind) climbed by 63 GW to 433 GW in 2015. Similar to solar PV, wind growth in 2015 was led by China (31 GW), followed by the US (9 GW) and Germany (6 GW).

Meanwhile, other technologies, generally receiving less support from policymakers, also saw increases, although on a smaller scale. The installed capacity of solar-based heating and cooling was estimated at around 435 GW in 2015, up by some 25 GW compared to 2014. Geothermal power capacity was seen at around 13 GW in 2015, a slight increase on the previous year, while moderate increases were also observed from concentrated solar thermal power, climbing to 4.8 GW in 2015.[11] At the regional level, the biggest players were the US, the EU, China and Japan, with new players emerging around the globe including countries in Latin America, Africa, Middle East and the rest of Asia.

Strong and continuous growth of this energy source is the result of ongoing support at a national level through regulation, fiscal incentives and subsidies in

Figure 2.13
Global solar PV and wind power capacity additions per year



Source: *REN21 Renewables 2016 Global Status Report.*

various forms (for example, feed-in-tariffs). This type of support is driven not only by environmental concerns (reduction of GHG emissions), but also by attempts to diversify energy supply, reduce import dependency and create new jobs by strengthening the domestic renewables industry sector. Currently, a vast majority of countries, including major consumers such as the EU, the US and China already have renewable energy policies in place. These policies include specific targets for renewable energy in terms of volume, installed capacity or share of the total energy mix. Regarding the supporting mechanisms, countries use various modalities such as different subsidies, preferential financing conditions, tendering mechanisms and/or tax benefits. On the application side, major support is given to renewables in power generation, while, at the same time, renewables for heat production receive much less backing.

It should be noted, however, that the fast expansion of renewables in the past few years was driven not only by policies, but also by significant reductions in the production costs of all major renewable energies. Economies of scale, learning effects and improving technology combined with growing efficiency, were all major drivers behind this growth. For example, the total costs for utility-scale solar PV systems decreased from close to $5,000/kW in 2009 to around $1,800/kW in 2015, with further potentials for cost reduction in the future.[12] In addition, the higher fossil fuel price levels prior to the decline in late 2014 also provided strong support to the development of renewables.

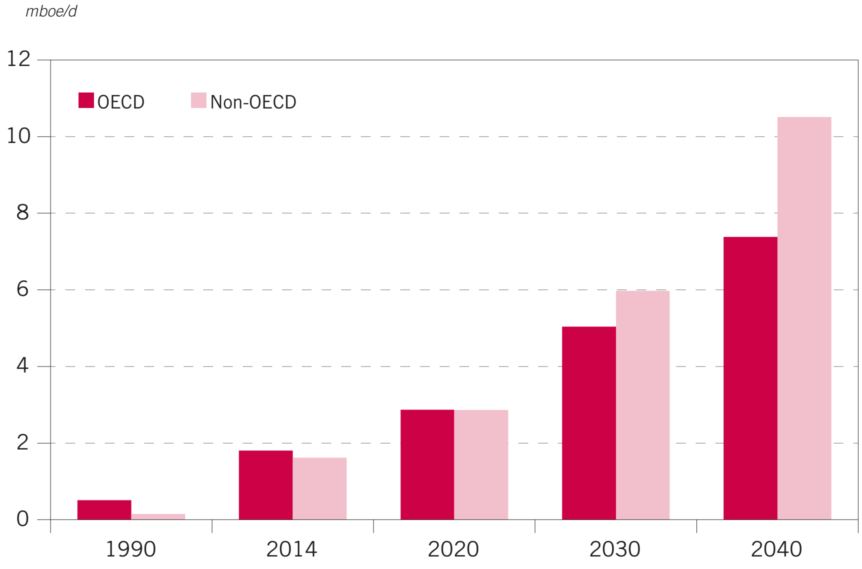
Nevertheless, despite all the positive trends for renewable technologies, ‘other renewables’ currently account for a relatively small share in global energy balances (around 1%). Moreover, there are a number of issues that still need to be addressed if more intensive deployment of this type of energy is to be achieved. This is mainly the integration of renewables (mostly wind and solar PV) into the wider energy system. Large volumes of intermittent sources from solar and wind put great pressure on the existing transmission infrastructure and lead to an increasing need for balancing services. To solve this problem, there are several approaches being developed such as smart grids, smart energy (including demand side management), capacity markets (that is, providing support to maintain extra capacity) and the development of storage facilities, among others.

Assuming that integration problems are gradually solved, the Reference Case sees considerable growth for 'other renewables' in all world regions, although at different rates. While in the past, OECD countries showed somewhat higher volumes of 'other renewables' compared to non-OECD countries, this trend is expected to reverse around 2020 (Figure 2.14).

In the OECD region, strong growth is expected in all countries of the group. OECD Europe is forecast to continue with its efforts to reduce CO_2 emissions through renewables targets and supporting mechanisms. This is confirmed by the EU's new climate and energy framework adopted in late 2014, which includes the target of increasing the share of renewable energy to at least 27% by 2030.[13] Consequently, 'other renewables' are forecast to grow from 0.9 mboe/d in 2014 to 2.9 mboe/d by 2040, which comprises an average growth rate of around 4.5% p.a.

Furthermore, OECD America is anticipated to show even faster growth driven mainly by developments in the US. The US, mainly through its Clean Power Plan (released in August 2015 and currently on hold pending judicial review by the US Supreme Court) in combination with tax benefits for renewables and stricter regulations for new fossil fuel power plants such as coal, has put more pressure on new conventional power plant investments and has favoured the additional deployment

Figure 2.14
Global expansion of other renewables



of renewables such as PV and wind. As a result, the volume of 'other renewables' in OECD America is expected to increase from 0.6 mboe/d in 2014 to 3.2 mboe/d in 2040, representing an average growth rate of almost 6.5% p.a. over the forecast period.

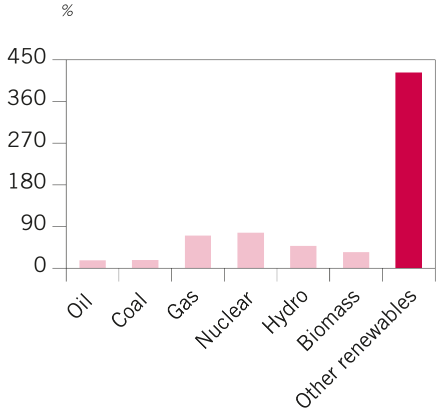
Lastly, OECD Asia, led by Japan, is also expected to expand in the long-term although less than in other OECD regions. The total volume is seen at around 1.3 mboe/d in 2040, rising from 0.2 mboe/d in 2014.

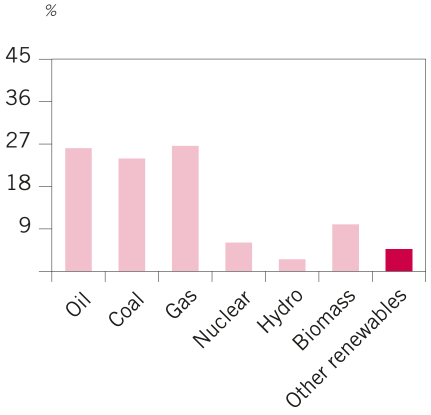
In total, demand for 'other renewables' in the OECD region is expected to increase from 1.8 mboe/d in 2014 to 7.4 mboe/d in 2040. Consequently, the share of 'other renewables' in the total energy mix of OECD countries is forecast at 6.5% by 2040, up from just around 1.5% in 2014.

Non-OECD Asia is actually expected to boost its renewables deployment even more than the OECD in absolute terms. Similar to trends in other fuels, the single largest contribution in terms of growth comes from China, where 'other renewables' which have been estimated at levels of around 0.8 mboe/d in 2014 should rise to some 3.7 mboe/d in 2040. This development is spurred on by environmental policies in the country including the latest FYP of the Chinese Government (see *Focus* in Chapter 1), which aims to reduce air pollution and limit CO_2 emissions. The fact that many wind turbine and solar panel producers, in particular, are located in China provides additional support to the expansion of renewables in the country.

Other non-OECD regions are also forecast to show considerable growth in the long-term. This includes India as the second largest contributor to growth in the non-OECD sector, where energy provided from 'other renewables' is seen increasing from 0.1 mboe/d in 2014 to 1.1 mboe/d in 2040. A strong expansion is also expected in the OPEC region as some Member Countries are increasingly looking into the possibility of renewables deployment. As the power sector in several OPEC Member Countries is heavily dependent on oil, increasing the share of renewables would also help to limit demand growth for oil and oil products in electricity

Figure 2.15
Growth in global energy demand by fuel, 2014–2040 (left), and share in the total energy mix in 2040 (right)





production. In absolute terms, 'other renewables' in OPEC are forecast to increase from 0.3 mboe/d in 2014 to 2.4 mboe/d in 2040. Other developing countries (especially in Southeast Asia, but also in Latin America) are seen joining the trend with the total volume of 'other renewables' in Developing countries climbing to almost 3 mboe/d in 2040, up from 0.3 mboe/d in 2014, which represents an average growth rate of 9% p.a. over the forecast period.

Finally, Eurasia sees only moderate growth despite its large potential. The region is expected to increase from a level close to zero in 2014 to around 0.6 mboe/d in 2040.

On the global level, 'other renewables' are expected to increase from 3.4 mboe/d in 2014 to almost 18 mboe/d in 2040, thus showing by far the highest growth rate compared to other fuels over the forecast period (Figure 2.15). Nevertheless, despite this significant growth, the share of 'other renewables' in the total energy mix is expected to remain relatively low even by 2040.

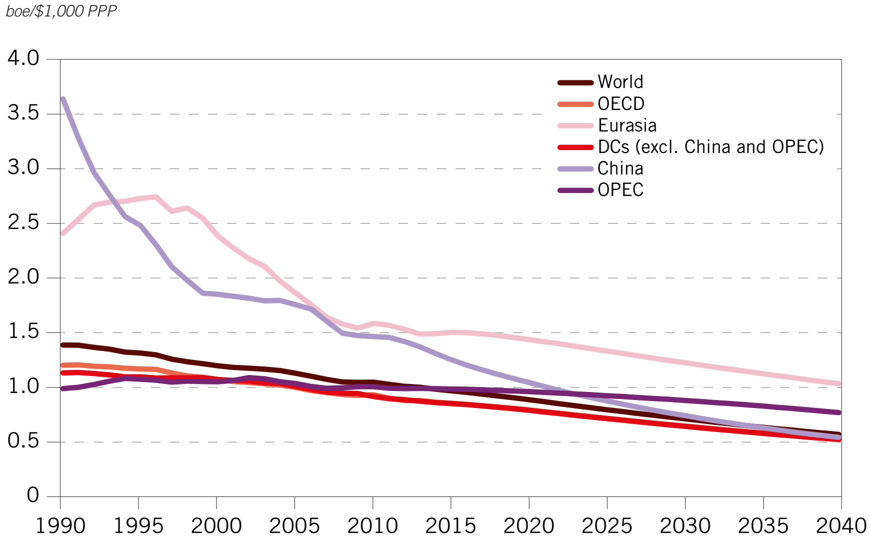
Energy intensity

Energy intensity is measured by the quantity of energy required per unit of output or economic activity. That is, lower energy intensity means that less energy is being used to produce a given quantity of output. Energy intensity can be measured at the microeconomic level of households, at the sectoral level to compare various industries, or at the macroeconomic level to compare intensities across countries. The inverse of energy intensity is energy efficiency, which measures the quantity of output produced with one unit of energy input.

Energy intensity comparisons across countries and regions need to be handled with caution, as often there are many other factors entering into the equation. These include the economic structure of an economy, the level of economic development of a nation, population demographics, the climate of the region and urbanization levels, to name a few. For example, a country whose economy has a large steel industry will inevitably have higher energy intensity compared to a nation where light-weight manufacturing has a greater weight in the economy. This is simply because the steel industry is, by its very nature, one of the most energy-intensive industries. As such, examining trends within a country/region may be more informative as it would not only show changes in energy efficiency, but also the evolution of structural changes in the economy, technology changes and social-demographic factors.

In simpler terms, energy intensity changes may merely reflect economic growth arising from economic development. This is often the case as economies transition from agricultural to more manufacturing and industry-based economies, and finally to largely service-based economies. In the initial shift towards industrialization and away from agriculture, energy intensity will increase as more energy-intensive industries form a greater share of a nation's GDP. In the later stages where the economic structure shifts more towards the service sector, it is likely that energy intensity will fall. This upside U-shape transition may only illustrate the changes in the structure of the economy and not necessarily changes in actual energy efficiency. Furthermore, as GDP per capita increases, individuals' purchases of household consumer goods also increase – that is, consumers buy bigger cars, bigger houses, more household appliances, etc. – and thus the energy intensity of an economy may

Figure 2.16
Primary energy intensities across regions

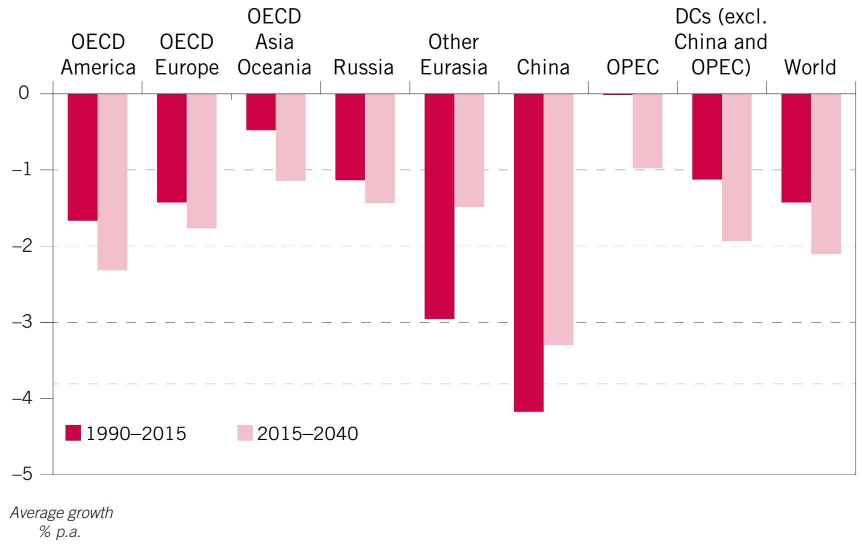


rise due to shifts in the purchasing power and purchasing patterns of individuals. In many developing countries, the rise of a middle class that can now afford to purchase cars will surely impact the energy intensity of various countries. In addition, climate, geography and transportation patterns cannot be ignored, nor can economic recessions or booms. All these factors impact energy intensity at varying levels across regions and countries.

Figure 2.16 shows that, globally, the amount of energy required to produce one unit of GDP is falling. As mentioned earlier, energy intensity peaks when the economic structure of a country is concentrated in heavy industry. For example, in the US, this peak occurred around 1920, whereas China's energy intensity peaked close to 1980. Despite greater deviation in the past, there is a move towards convergence among energy intensities worldwide. The gap between Eurasia and the rest of the world is also narrowing over time.

Figure 2.17 shows a comparison of how the growth of energy intensity has developed in the last 25 years *versus* how it is projected to develop from 2015–2040. Globally, and across most regions, energy intensity is projected to fall at a faster pace in the coming 25 years. The exceptions are China and Other Eurasia where energy intensity will still continue to fall in the next 25 years, although at a slower pace than in the past. In large part, this is due to the fact that China and Other Eurasia had relatively high levels of energy intensity in the pre-1990 period. These have fallen rapidly since and are now in a phase of steady convergence towards the world average. In Other Eurasia, this holds true for the intensity of all fossil fuels, while in China this holds true only for oil intensity driven primarily by the fast growing road transport and petrochemical sectors. After increasing intensity from 1990–2015, gas intensity in China is expected to decline over the next 25 years.

Figure 2.17
Growth rates per annum of energy intensities across regions last 25 years *versus* next 25 years



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With regard to coal intensity in China, the pace of decline is expected to further accelerate during the period from 2015–2040 compared to the declines seen in the 1990–2015 period. This is expected given that the transition away from coal provides the greatest potential for emissions reduction in the country, while the trend of decoupling economic growth from energy use is projected to continue.

Energy consumption per capita

Similar to energy intensity, energy consumption per capita is also a reflection of a variety of factors – the stage of development of a country, the structure of its economy, the climate of the region, per capita income level and urbanization, among others. For example, in the early stages of a country's move towards industrialization, energy per capita consumption surges to reflect structural changes in the economy, greater urbanization of the population and falling fertility rates. At this stage, income growth basically drives energy demand. In advanced economies, on the other hand, energy consumption per capita tends to peak and level out before steadily decreasing to reflect technological changes and improvements in energy efficiency. That is, in the case of advanced countries, energy consumption per capita may be used as an indicator of energy efficiency. Figure 2.18 shows the positive relationship between energy consumption per capita and the United Nations Human Development Index (HDI).[14] A country's improvement in its HDI is reflected in higher energy use per capita and higher GDP per capita.

Figure 2.18 presents the historical trends in energy consumption per capita across various regions. The figure shows that OECD energy consumption per person peaked around 2005 and is on a steady downwards trend, reflecting a service-oriented

Figure 2.18
Primary energy consumption per capita *versus* Human Development Index, 2015

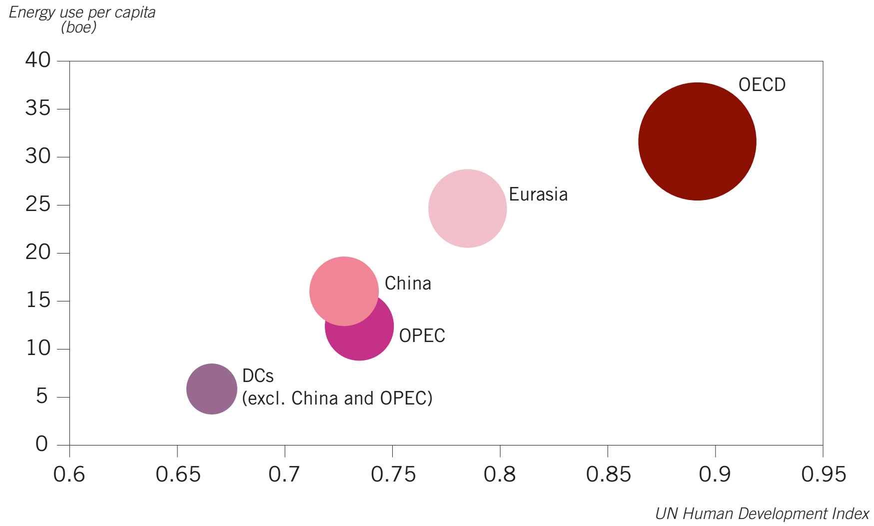


Figure 2.19
Primary energy consumption per capita across regions

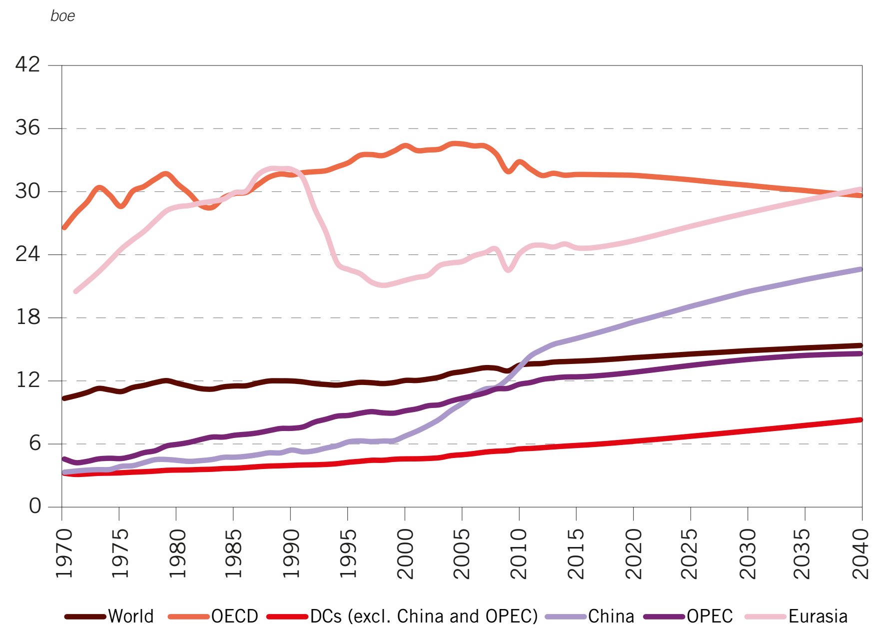
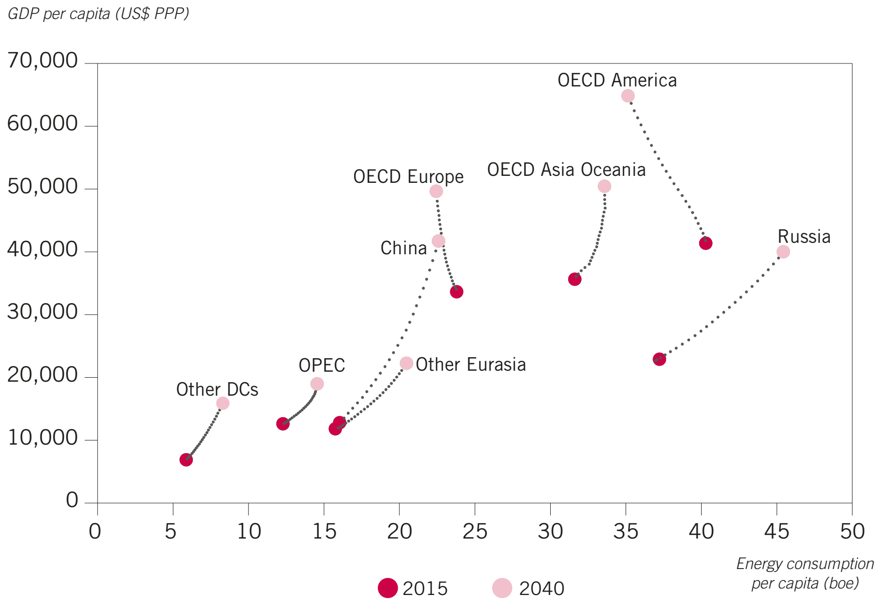


Figure 2.20
Energy consumption per capita *versus* GDP at PPP per capita, 2015–2040



economy and technology-induced energy efficiency gains. In emerging and developing economies, however, energy consumption per capita is increasing, reflecting greater electrification, urbanization, the growth of the middle class, overall economic development and strong economic growth. This phenomenon is particularly apparent in China (Figure 2.19) as energy use per person accelerated rapidly from 2000–2010 and is forecast to grow steadily until 2040. Over time, the advanced economies and developing economies should see a convergence of their levels of energy intensity and energy consumption per capita towards reasonably narrow ranges.

Figure 2.20 shows that absolute differences in energy consumption per capita can largely be accounted for by differences in GDP per capita. However, a country's energy consumption per capita may also be dominated by changes in population. For example, in Eurasia, energy consumption per capita is projected to increase primarily because population growth is projected to fall below zero around 2023. Over the forecast period 2015–2040, energy use in Eurasia is projected to increase by 0.7% p.a. on average while the population is projected to decline by 0.1% p.a. In the OECD regions, however, average population growth of 0.3% p.a. will outpace average energy consumption growth of 0.1% p.a., which explains why energy consumption per capita is projected to steadily decline.

In Developing countries, as expected based on the economic development cycle, energy consumption growth (2.1% p.a.) is expected to outpace population growth (1% p.a.) implying an upward trend in energy consumption per capita in the future. Despite this positive trend in per capita energy consumption over the forecast period, it is obvious that energy poverty and access to affordable, reliable and modern energy for all will remain an issue in Developing countries.

Box 2.1

Energy access for productive use supports poverty alleviation

The adoption of the SDGs by world leaders at the UN Sustainable Development Summit on 25 September 2015, was a major milestone for international cooperation among a large array of stakeholders in sustainable development.

Among the SDGs, goal number seven or SDG 7 focuses on energy and calls for nations to "ensure access to affordable, reliable, sustainable and modern energy for all". It specifically calls for nations to "ensure universal access to affordable, reliable, and modern energy services", "increase substantially the share of renewable energy in the global energy mix", and "double the global rate of improvement in energy efficiency" – all to be achieved by 2030. These are laudable goals, and it is vital that international stakeholders ensure that the right framework is in place to achieve these targets. There is no doubt that the successful implementation of SDG 7 resides heavily on engaged and successful international cooperation and allocating sufficient finance and investment.

OPEC has been a strong advocate of sustainable development and considers inclusion of 'energy' in the international development agenda as highly appropriate, particularly when considering it in the context of poverty. There is a well-established relationship between energy consumption and GDP (Figure 2.20). Today, many developed economies are trying to decouple their economic growth from energy consumption growth and the increase in emissions of GHGs. However, applying SDG 7 to such economies needs to be differentiated from applying SDG 7 to developing countries, particularly the least developed economies that continue to struggle with extreme poverty. The size of the energy poor is staggering, almost 20% of the world's population live without access to energy,[15] and many more have access to energy, but cannot afford to use adequate energy for their development needs. Moreover, addressing 'energy poverty' through the implementation of SDG 7 could have a significant effect in tackling other SDGs related to poverty.

Energy poverty is linked to income poverty, and income poverty is linked to other aspects of poverty. According to the World Development Indicators, in 2012 around 13% of the world population, or some 900 million people, lived on less than $1.90 a day.[16] This level of income poverty is associated with 'health poverty', 'food insecurity', 'inadequate education', and other such dimensions of underdevelopment.

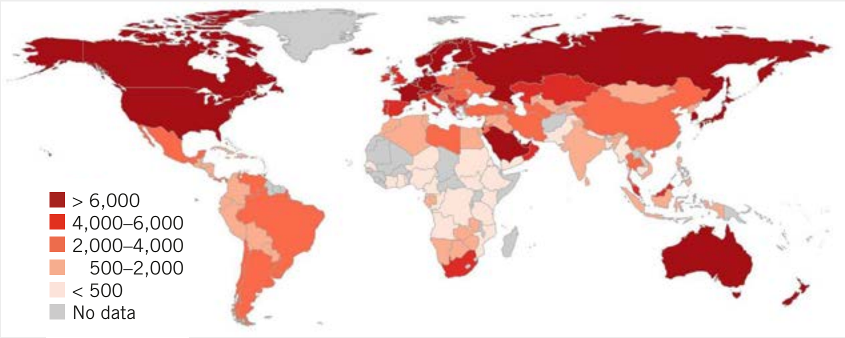
For example, in the period from 2014 into 2016 it is estimated that 795 million people were suffering from chronic hunger, which means they have access to less food than needed to meet their daily minimum dietary energy requirements of about 1,800 calories. Most of these people are concentrated in sub-Saharan Africa and South Asia.[17] In sub-Saharan Africa, about 23% of the population still lack the food they need for an active and healthy life. Approximately 90 million children are underweight, and 57 million do not attend primary school.[18] Of these, about 30 million live in sub-Saharan Africa and almost half of them are expected to never enrol in school.[19] Life expectancy at birth is also low in many developing countries, with an estimated 6 million children dying before reaching the age of 5 years.[20]

Energy poverty is often a common denominator associated with other forms of poverty. Figures 1 and 2 illustrate the level of electric power consumption along with the gross national income (GNI) in 2013, expressed on a per capita basis. The association between electric power consumption and GNI is clearly demonstrated in this figure. Many people in countries in sub-Saharan Africa experience both low per capita electricity consumption of less than 500 kWh per year and low per capita GNI of less than $500 (2011 PPP $) per year.[21]

Addressing energy poverty requires international cooperation on finance and investment. However, the level of such finance and investment depends on the degree or the extent of 'energy access'. For example, in sub-Saharan Africa, estimates from the World Bank indicate an investment need ranging between $1 billion and $37 billion a year for electricity access.[22]

Figure 1
Per capita electric power consumption, 2013

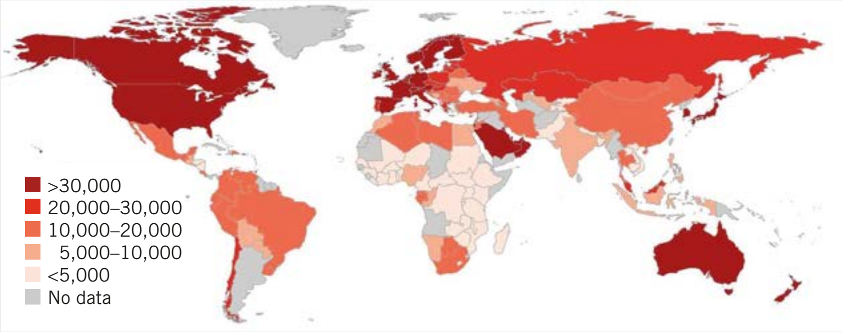
kWh per capita



Source: World Bank, 2016. World Development Indicators 2016.

Figure 2
Per capita GNI, 2013

2011 PPP $ per capita



Source: World Bank, 2016. World Development Indicators 2016.

Estimates by the OPEC Fund for International Development (OFID) indicate that to achieve universal energy access requires on average about $50 billion per year up to 2030. However, there is a funding gap, with data available suggesting that the size of the annual gap was over $40 billion in 2012.[23] Recognizing energy as an 'enabler' of sustainable development, OFID has pledged a revolving amount of $1 billion to finance its 'Energy for the Poor' initiative, supporting energy projects in more than 80 countries to help advance energy access.

Given the challenge related to financial needs, a critical element that requires attention is the importance of enabling the energy poor to generate additional income. This means the provision of such a level of energy access that helps them in not only providing for their basic energy needs but also in creating income generation opportunities. Such income generation opportunities can sustain and complement other poverty alleviation efforts.

Two areas of activities that can provide income generation opportunities to the poor are agriculture and micro-and-small enterprises (MSEs).[24] In sub-Saharan Africa, agriculture and MSEs are the main source of employment. Employment in agriculture is about 60% of the workforce with women being more active than men. MSEs account for approximately 15% of employment in this region.[25]

In agriculture, energy is needed *inter alia* for transport, water lifting and pumping, land preparation, seedbed preparations, weed control, planting, and harvesting. For instance, electricity could power irrigation pumps, tractors and other agricultural machinery could provide power for higher crop production leading to increased farm income. There is evidence that agricultural land with an irrigated system may be more than twice as productive as non-irrigated land, but only about 4% of agricultural land in sub-Saharan Africa is under irrigation.[26] Refrigerators could also reduce the post-harvest waste of agricultural products, which is estimated at the level of 130 million metric tonnes in sub-Saharan Africa alone.[27] In terms of mechanization, the number of tractors per 1,000 hectares is less than 30 in sub-Saharan Africa, compared to more than 240 tractors in other regions.[28]

Electrification also has a high potential for local job generation and increased economic activity for poverty alleviation.[29] Energy poverty is a major constraint to productivity of MSEs. Electricity use can significantly increase productivity per worker. For example, case studies in Kenya and Burkina Faso show that electricity access and reliability can increase productivity per worker by about 100–200% for carpenters and by 50–170% for tailors.[30] Workers are often paid on the basis of their production, therefore, their income increases accordingly. In addition, electricity access and use can help flourishing home-based businesses. It can also help in the empowerment of women – women may be more able to take advantage of electrification for income generation by working at home.

With the bulk of the poor living in dispersed rural settlements, the option for decentralized electricity access may be a cost effective means of access to electricity where other options are unavailable or too expensive. Examples from Senegal, Mali, Tanzania, Kenya and other countries show diesel mini-grids can supply and complement other sources of electricity in times when alternative energy sources are not sufficient or not feasible.[31]

Oil demand

Key takeaways

- Oil demand in the medium-term reaches 99.2 mb/d by 2021. This corresponds to an upward revision with respect to the WOO 2015 of 1.04 mb/d.
- In the long-term, oil demand is expected to increase by 16.4 mb/d between 2015 and 2040 to reach 109.4 mb/d. Developing countries will continue to lead growth with an additional 25 mb/d over the forecast period.
- Global oil demand growth comes mainly from the road transportation sector (+6.2 mb/d), petrochemicals (+3.4 mb/d) and aviation (+2.8 mb/d).
- While in Developing countries and Eurasia growth is foreseen in every sector except electricity generation, in the OECD, growth is expected only in the aviation and petrochemical sectors.
- Driven by strong growth in the road transportation sector and the switch away from residual fuel in the marine bunker sector, demand for gasoil/diesel is estimated to increase 5.7 mb/d.
- The vehicle stock is expected to increase significantly during the forecast period. The number of passenger cars and commercial vehicles is anticipated to more than double. Most of this growth comes from Developing countries.
- The average oil use per vehicle (OPV) is expected to fall in the future as a result of fuel efficiency improvements, the declining average distance driven and the increasing penetration of alternative fuel vehicles.
- Non-conventional powertrain passenger vehicles are expected to represent 22% of the car fleet by 2040, up from only 3% in 2014. Most of the growth will come from passenger BEVs, which are anticipated to increase to 141 million in 2040.
- Oil demand in the road transportation sector in the OECD is expected to fall by 6.7 mb/d. A strong decline in OPV by far outbalances the increase in the vehicle stock.
- In Developing countries, road transportation demand will increase by 12.6 mb/d. The expected decline in OPV is not enough to compensate for the significant increase in the vehicle stock.
- In the marine bunker sector, due to International Maritime Organization (IMO) regulations, the use of gasoil/diesel will increase significantly from 0.6 mb/d in 2015 to 2.5 mb/d in 2040.

This Chapter examines the Reference Case oil demand outlook up to 2040. A detailed analysis is shown from the regional viewpoint, together with a comprehensive analysis of the product demand outlook.

Because the fundamental drivers of demand are different, the aforementioned analysis is done separately for the medium-term (up to 2021) and for the long-term (up to 2040). The Chapter also examines in detail the demand outlook from the sectoral point of view. Given the important weight that the road transportation sector has in total oil demand, special emphasis is placed on the sectoral analysis.

It will be shown that developing countries will account for most of the future demand growth, while overall demand growth is expected to decelerate. Moreover, strong demand growth is anticipated in the middle distillates and light products. It will also be highlighted that most of the oil consumed today and in the future will come from the road transportation sector. However, efficiency improvements in internal combustion engines, declining average miles travelled and the penetration of alternative fuel vehicles will limit growth.

Medium-term demand

The outlook for the medium-term period 2015–2021 shows an increase of 6.2 mb/d from 93 mb/d to 99.2 mb/d, which is shown in Table 3.1. This corresponds to an average annual increase of around 1 mb/d. During this period, demand in the OECD regions is expected to decrease by 0.5 mb/d, going from 46.2 mb/d in 2015 to 45.7 mb/d in 2021. Within the OECD region, OECD America is assumed to increase from 24.4 mb/d to 24.7 mb/d over the period. Demand in OECD Europe is expected to shrink from 13.7 mb/d to 13.4 mb/d and OECD Asia Oceania from 8.1 mb/d to 7.6 mb/d.

Oil demand in Developing countries is expected to grow by 6.4 mb/d in the medium-term. Demand increases from 41.5 mb/d in 2015 to an estimated 47.9 mb/d in 2021. Within Developing countries, demand in Latin America is expected to reach 6.1 mb/d at the end of the medium-term, and 4.3 mb/d in the case of the Middle East & Africa. Demand in India and China by 2021 is estimated to be 5.4 mb/d and 12.5 mb/d, respectively. Following the expansion of OPEC membership, it is estimated that oil demand in Other Asia and OPEC will reach 7.3 mb/d and 12.4 mb/d, respectively.

In Eurasia, the medium-term oil demand outlook shows a marginal growth of 0.3 mb/d, going from 5.3 mb/d to 5.6 mb/d between 2015 and 2021. Most of this marginal growth is concentrated in Other Eurasia, where demand is expected to reach 2.1 mb/d. Demand in Russia is assumed to increase only marginally.

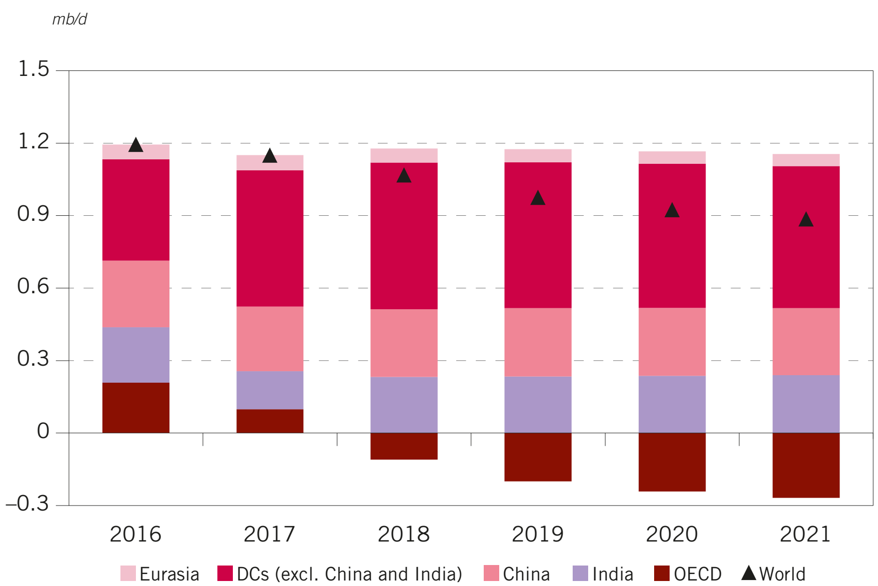
As already mentioned, annual average demand growth for the period up to 2021 is close to 1 mb/d. However, this rate is not constant for the entire medium-term. In Figure 3.1, it can be observed that demand growth is expected to decelerate from 1.2 mb/d in 2016 to less than 0.9 mb/d in 2021. Medium-term oil demand growth is heavily determined by oil prices, economic growth and, to a lesser extent, energy policies. While GDP growth dynamics are expected to improve and accelerate to 3.7% p.a. by 2021, adding strength to demand growth, the oil price is assumed to resume an upward trend, which reduces the scope for further demand increases. In fact, the oil price in 2021 is assumed to be almost double that of 2016.

Table 3.1
Medium-term oil demand in the Reference Case

mb/d

	2015	2016	2017	2018	2019	2020	2021
OECD America	24.4	24.7	24.8	24.9	24.8	24.8	24.7
OECD Europe	13.7	13.7	13.7	13.6	13.6	13.5	13.4
OECD Asia Oceania	8.1	8.0	7.9	7.8	7.8	7.7	7.6
OECD	**46.2**	**46.4**	**46.5**	**46.4**	**46.2**	**45.9**	**45.7**
Latin America	5.6	5.6	5.7	5.8	5.9	6.0	6.1
Middle East & Africa	3.8	3.8	3.9	4.0	4.1	4.2	4.3
India	4.1	4.3	4.4	4.7	4.9	5.1	5.4
China	10.8	11.1	11.4	11.7	11.9	12.2	12.5
Other Asia	6.3	6.4	6.6	6.8	7.0	7.1	7.3
OPEC	10.9	11.2	11.4	11.7	11.9	12.2	12.4
Developing countries	**41.5**	**42.4**	**43.4**	**44.5**	**45.7**	**46.8**	**47.9**
Russia	3.4	3.4	3.4	3.5	3.5	3.5	3.5
Other Eurasia	1.9	1.9	2.0	2.0	2.1	2.1	2.1
Eurasia	**5.3**	**5.4**	**5.4**	**5.5**	**5.5**	**5.6**	**5.6**
World	**93.0**	**94.2**	**95.3**	**96.4**	**97.4**	**98.3**	**99.2**

Figure 3.1
Global annual oil demand growth in the medium-term



Additionally, new energy policies, in particular the removal of fuel subsidies, will further have the effect of limiting demand growth potential.

In the OECD region, growth is expected in 2016 and 2017, mainly in the road transportation sector and the petrochemicals sector. However, moving further forward, demand is expected to decline during the rest of the period. By 2021, OECD demand is set to drop by almost 0.3 mb/d. The picture is rather different in Developing countries where annual growth stabilizes around 1.1 mb/d, driven mainly by China and India. In 2016, however, demand growth is estimated at 0.9 mb/d on the back of a gloomier economic outlook. In Eurasia, it is assumed that improving economic conditions translate into demand growth during the whole medium-term period.

Growth dynamics within the OECD regions are examined in Figure 3.2. In the case of OECD America, increasing demand is expected up to 2018. These dynamics are in line with the anticipated regional demand outlook in the road transportation sector. Due to lower taxes on road transportation fuels, sectoral and, therefore, regional demand is heavily impacted by the assumed oil price. In fact, in last year's WOO a higher oil price was assumed in the medium-term and OECD America demand growth was only foreseen up to 2017.

For OECD Europe, the demand decrease is expected to accelerate in the medium-term. While in 2016 and 2017 demand is set to remain roughly constant, by 2021 it will decline by 0.1 mb/d. In OECD Asia Oceania, the demand decline is more evident in 2016 and 2017 as Japan reopens the door to nuclear and oil is substituted in the electricity generation sector.

Figure 3.2
Annual oil demand growth in the OECD region in the medium-term

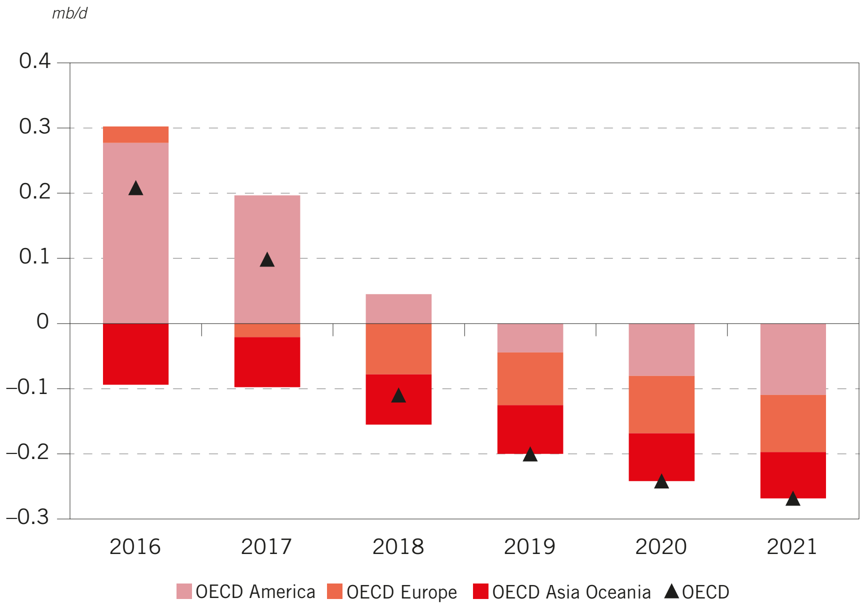


Figure 3.3 shows medium-term demand growth for Developing countries. As mentioned previously, growth in 2016 is lower than in the rest of the medium-term, despite the assumed lower oil price. This is a result of particularly low demand growth in Latin America and, to a lesser extent, in the Middle East & Africa, on the back of a gloomier economic outlook and the removal of subsidies. It is also interesting to observe that China is the main source of the regional demand increase over the period. However, it should be noted that the relative weight of China is estimated to shrink as Chinese GDP growth is anticipated to decelerate. In fact, while in 2016 China accounts for almost a third of demand growth in Developing countries, by 2021 it accounts for just a quarter. Growth in India is also significant and estimated at over 0.2 mb/d each year.

From the product point of view, oil demand is sorted into three categories: light products containing ethane/liquefied petroleum gas (LPG), naphtha and gasoline (including ethanol); middle distillates comprising jet/kerosene (including jet kerosene and domestic kerosene) and gasoil/diesel (including biodiesel); and heavy products containing residual fuel and other products (including bitumen, lubricants, waxes, still gas, coke, sulphur and the direct use of crude oil).

Strong demand growth is expected for both light products and middle distillates, particularly in road transportation fuels and petrochemicals feedstock. Gasoline demand is expected to increase by 2.1 mb/d between 2015 and 2021. Gasoil/diesel is anticipated to grow by 2.4 mb/d on the back of increasing demand in the road transportation sector, but also growth in the petrochemicals sector and the continuous switch away from residual fuel oil in the marine bunkers sector. Increasing

Figure 3.3
Annual oil demand growth in Developing countries in the medium-term

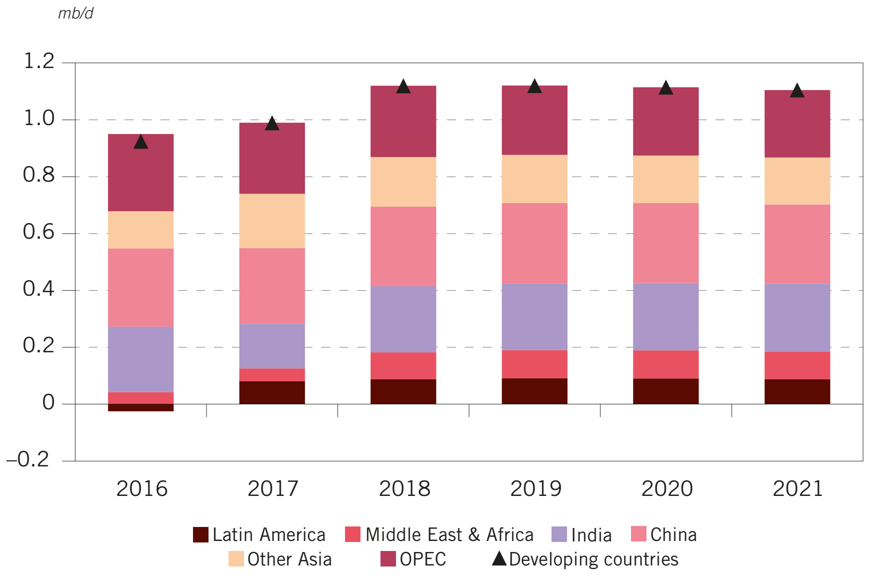
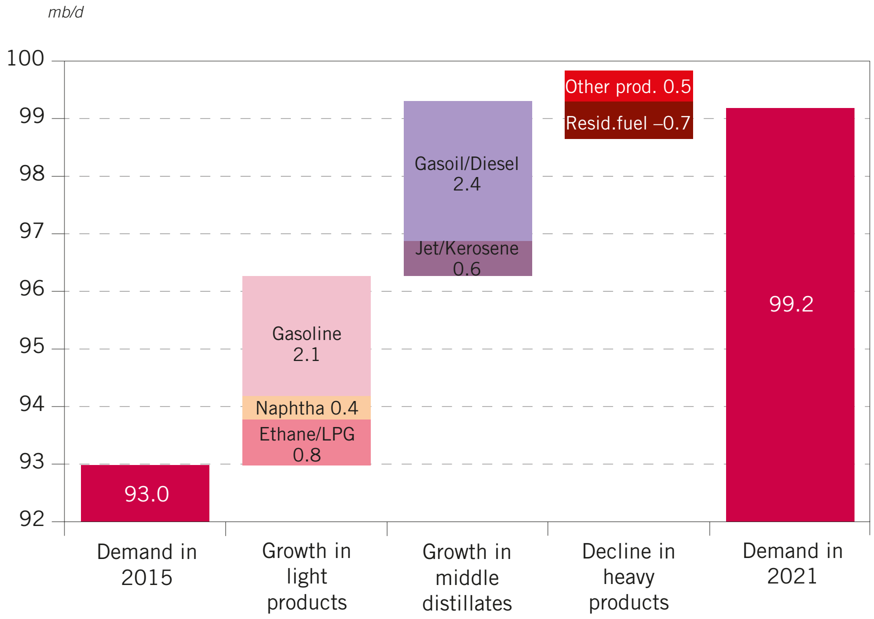


Figure 3.4
Demand growth by product category in the medium-term



demand in the petrochemicals sector also impacts the demand growth of ethane/LPG and naphtha (0.8 mb/d and 0.4 mb/d, respectively). Growth in heavy products is concentrated in 'other products' with an increase of 0.5 mb/d in the medium-term. Demand for residual fuel is expected to decline by 0.7 mb/d due to the IMO regulations expected to be in force in 2020.

From the sectoral point of view, medium-term demand growth will be concentrated in the road transportation sector where demand is more responsive to lower oil prices. Sectoral demand is set to increase by 3.1 mb/d between 2015 and 2021 fostered by economic growth and lower pump prices. Strong growth is also foreseen in petrochemicals (0.8 mb/d), aviation (0.6 mb/d), residential/commercial/agriculture (0.6 mb/d) and the other industry sector (0.6 mb/d). Demand in the electricity generation sector is set to remain virtually flat as declines in the OECD region, particularly in OECD Asia Oceania, offset the increasing demand in OPEC, India and the Middle East & Africa.

When comparing the Reference Case oil demand outlook with that of last year, some important observations should be noted. As already highlighted, the oil price assumption is lower this year compared to last year. Therefore, it is expected that, in general, the first order effect would be to foster demand. At the same time, however, economic growth has been revised marginally downwards compared to last year, particularly for the next couple of years. Furthermore, energy policies continue to push for greater energy efficiency together with a further drive for the removal of subsidies. Therefore, it is expected that, in general, these two aspects have a first order effect to discourage demand. Which of these two forces is more robust depends on the characteristics of each region. However, at the global level, oil demand in 2021 has been revised upwards by 1.04 mb/d compared to last year.

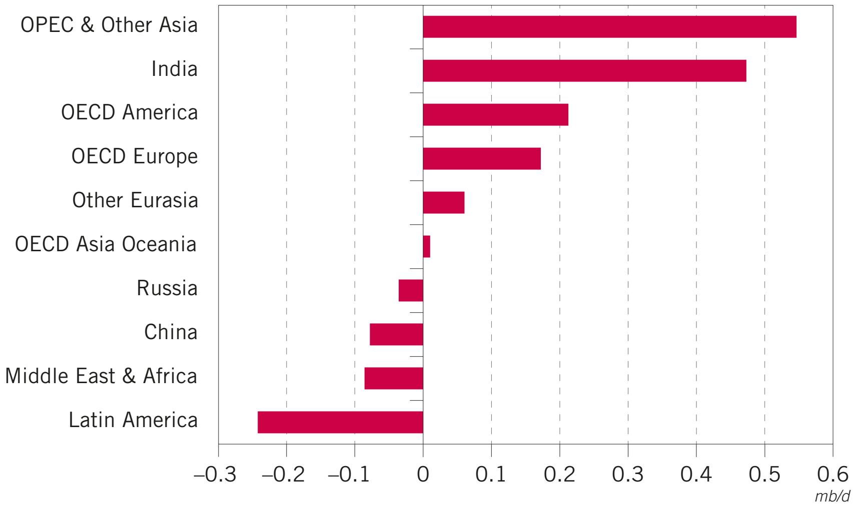
At the same time, as a result of updated historical data, the 2015 baseline demand figures have been revised. For some regions, the revision in 2015 is significant. For example, for India, demand in 2015 has been revised upwards by 0.12 mb/d and in OECD Europe the upward revision is 0.07 mb/d. In addition, both OPEC and Other Asia have seen upwards baseline demand revisions. There have also been notable downward revisions. For OECD America, baseline demand has been reduced by 0.13 mb/d, and the figure is 0.05 mb/d for Latin America.

In terms of 2021 numbers, Latin America has been revised downwards by 0.24 mb/d, compared to last year's WOO, on the back of a gloomier economic picture. The recession in Brazil coupled with lower commodity prices in the region has had a significant impact on the growth expectations in the short- and medium-term. Oil demand in China has also been revised downwards, by 0.08 mb/d in 2021, as a result of the fact that the economy is decelerating faster than previously expected.

On the flip side, demand in OECD Europe has been revised up by 0.17 mb/d in 2021. This medium-term revision is rather limited because GDP growth estimates are not significantly different with respect to last year and, despite the lower oil price, further energy efficiency policies are envisaged. The case of OECD America is interesting. Looking at the medium-term, oil demand is revised upwards by 0.21 mb/d mainly as a result of the lower oil price environment and a more optimistic economic outlook. It is a well-known fact that this region has higher oil price demand elasticity due to lower taxes on oil products.

Oil demand in India is also revised upwards, by 0.47 mb/d in 2021. This is mainly on the back of a more optimistic economic picture, especially towards the

Figure 3.5
Oil demand revision (with respect to WOO 2015) in 2021



end of the medium-term, and the lower oil price assumption compared to last year. It should be highlighted that the updated OPEC Membership is reflected in the figure. In that sense, Indonesia, which was part of 'Other Asia' last year, is now included in OPEC.[32] For comparability reasons, Figure 3.5 shows the demand revision for the sum of both regions. Oil demand for 'Other Asia' and OPEC is revised up by 0.55 mb/d in 2021, mainly as a result of a more optimistic economic picture in OPEC and given the more positive expectations for Iran.

Long-term demand

While medium-term demand is mostly affected by prices and economic growth, in the long-term, policies, technology developments and population dynamics also play an important role in shaping the outlook.

The Reference Case sees oil demand increasing to reach 109.4 mb/d by 2040 (Table 3.2). Developing countries will continue to lead this growth, increasing by close to 25 mb/d over the period, to reach 66.1 mb/d by 2040. Eurasia also expands, from 5.3 mb/d to 6.0 mb/d by 2040. Demand in the OECD region, however, is expected to decrease to 37.3 mb/d by the end of the forecast period.

It is interesting to observe that, while demand in the OECD region in 2015 accounted for 50% of global demand and that of the Developing countries accounted for 45%, by 2040 the situation is anticipated to change significantly. The OECD is forecast to represent just 34% and Developing countries 60% of global demand.

Table 3.2
Long-term oil demand in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040
OECD America	24.4	24.8	24.0	22.8	21.5	20.1
OECD Europe	13.7	13.5	13.0	12.4	11.8	11.1
OECD Asia Oceania	8.1	7.7	7.3	6.9	6.5	6.1
OECD	**46.2**	**45.9**	**44.3**	**42.1**	**39.7**	**37.3**
Latin America	5.6	6.0	6.4	6.7	7.0	7.3
Middle East & Africa	3.8	4.2	4.6	5.1	5.5	6.0
India	4.1	5.1	6.4	7.7	9.0	10.4
China	10.8	12.2	13.6	14.9	16.1	17.1
Other Asia	6.3	7.1	7.9	8.7	9.3	9.8
OPEC	10.9	12.2	13.3	14.3	15.0	15.4
Developing countries	**41.5**	**46.8**	**52.2**	**57.4**	**62.0**	**66.1**
Russia	3.4	3.5	3.6	3.6	3.6	3.5
Other Eurasia	1.9	2.1	2.3	2.4	2.5	2.5
Eurasia	**5.3**	**5.6**	**5.8**	**6.0**	**6.1**	**6.0**
World	**93.0**	**98.3**	**102.3**	**105.5**	**107.8**	**109.4**

Furthermore, demand in India and China together accounted for 16% of the total demand in 2015. This percentage is set to increase to 25% by 2040.

As shown in Table 3.3, gasoil/diesel is the most important product category, accounting for almost 30% of global demand in 2015. Driven by strong growth in the road transportation sector and the switch away from residual fuel in the marine bunker sector, gasoil/diesel demand is expected to increase further and reach 33.2 mb/d in 2040. In addition, demand for gasoline, driven by strong growth in the road transportation sector is anticipated to show healthy growth, increasing from 24.2 mb/d in 2015 to 28 mb/d in 2040. Its share in total global demand is set to remain at around 26%.

Demand for ethane/LPG amounted to 10.4 mb/d in 2015 and is expected to reach 12.7 mb/d in 2040, as a result of increasing demand in the petrochemical and residential/commercial/agriculture sectors. By 2040, this product category will represent 12% of global demand. In the 'other products' category, it is estimated that demand will reach 11.2 mb/d in 2040, up from 10.3 mb/d in 2015, mainly driven by increasing demand in the 'other industry' sector. Residual fuel, the only product category whose demand is expected to decrease in the future, accounted for 7.7 mb/d in 2015. As a result of switching to gasoil/diesel in the marine bunker sector and declining demand in the electricity generation sector, demand in 2040 is estimated at 6.4 mb/d.

Jet/kerosene is anticipated to account for 9.4 mb/d at the end of the forecast period, up from 6.8 mb/d in 2015, as demand for aviation services increases due to growing urbanization and higher income levels, especially in Developing countries. Demand for naphtha, a product used exclusively in the petrochemical sector, totalled 6.2 mb/d in 2015, and it is expected that its demand will increase to 8.5 mb/d in 2040, representing 8% of global demand.

3

Table 3.3
Long-term oil demand by product category in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040
Ethane/LPG	10.4	11.1	11.7	12.1	12.4	12.7
Naphtha	6.2	6.5	6.9	7.4	7.9	8.5
Gasoline	24.2	26.1	26.9	27.4	27.8	28.0
Light products	**40.8**	**43.7**	**45.5**	**46.9**	**48.2**	**49.1**
Jet/kero	6.8	7.3	7.8	8.4	9.0	9.4
Gasoil/diesel	27.5	29.5	31.1	32.0	32.7	33.2
Middle distillates	**34.3**	**36.7**	**38.9**	**40.4**	**41.7**	**42.6**
Residual fuel	7.7	7.2	6.9	6.9	6.7	6.4
Other products	10.3	10.7	11.0	11.3	11.3	11.2
Heavy products	**17.9**	**17.9**	**18.0**	**18.1**	**18.0**	**17.7**
World	**93.0**	**98.3**	**102.3**	**105.5**	**107.8**	**109.4**

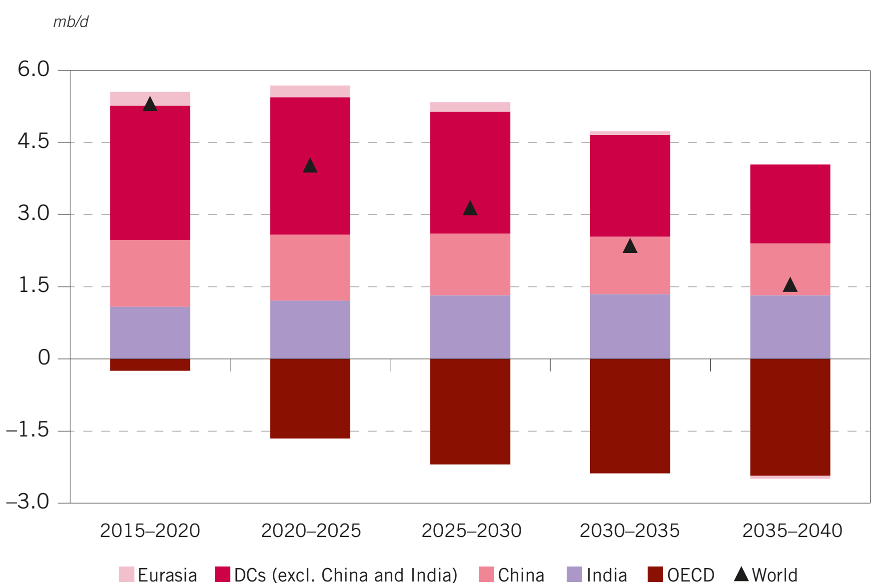
Interestingly, more than half of the expected 16.4 mb/d global oil demand growth between 2015 and 2040 will take place up to 2025. In fact, demand growth is expected to decelerate in the long-run as shown in Figure 3.6. Between 2015 and 2020 demand is anticipated to grow by 5.3 mb/d. Growth is reduced to 4 mb/d between 2020 and 2025, and to 3.2 mb/d in the last five years of that decade. Demand will then increase by 2.4 mb/d between 2030 and 2035, and only 1.6 mb/d between 2035 and 2040.

This expected deceleration in oil demand growth is a result of slowing long-term economic growth, lower population expansion, and a tightening of energy policies focusing on energy efficiency and a lower environmental footprint. Similarly, saturation effects, the penetration of alternative fuel vehicles and competition from other fuel types, among others, contribute to a lower long-term demand growth.

As shown in Figure 3.6, demand in the OECD is expected to exhibit a declining trend throughout the entire forecast period, apart from the period between 2015 and 2017, as mentioned earlier. This is mainly a result of decelerating economic growth and tighter energy policies. The demand decline will be especially significant in the road transportation sector. Eurasia is expected to show a positive trend up to 2035, especially during the first five years of the next decade as a result of improving economic growth conditions. A marginal demand decline is expected during the last five years of the forecast period on the back of decelerating economic growth and declining population.

Demand growth in Developing countries is expected to continue increasing at healthy rates in the next ten years – over 1 mb/d every year – as the middle class expands and population grows at high rates. Towards the end of the forecast

Figure 3.6
Global oil demand growth in the long-term



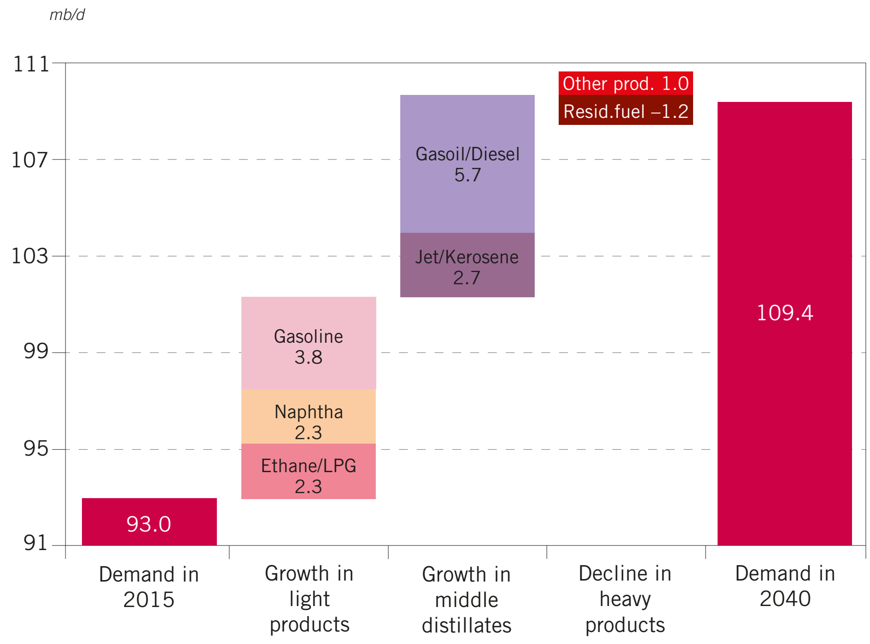
period, demand growth starts to show signs of deceleration as a result of saturation effects and energy efficiency improvements. Interestingly, as shown in Figure 3.6, the growth patterns in India and China are markedly different. This is clearly linked to the expected GDP trends and population dynamics in both countries. While growth decelerates over the whole projection period for China, going from 0.28 mb/d annually between 2015 and 2020 to 0.22 mb/d between 2035 and 2040, the growth in India actually accelerates until 2035, before exhibiting a very marginal deceleration.

There are also important trends from the product point of view that are worth exploring further. For example, growing global demand is expected in every product category except for residual fuel. Regional differences are also significant. While in Developing countries all the product categories are expected to increase, for the OECD region growth will occur only in jet/kerosene and naphtha.

Globally, strong demand growth is expected in the middle distillates category with an additional 8.4 mb/d between 2015 and 2040. From this, 5.7 mb/d is estimated to come from gasoil/diesel, making it the product category with the largest increase. However, significant regional differences are expected. Driven by declining regional demand in the road transportation sector, gasoil/diesel demand from the OECD region is expected to decline by 3.3 mb/d. However, strong road transportation demand in Developing countries will more than offset the declining use in the OECD region. Gasoil/diesel growth is particularly significant in India and China where an additional 2.5 mb/d and 2.3 mb/d, respectively, are expected.

Growth is also significant in the jet/kerosene category with an additional 2.7 mb/d by 2040. This is on the back of increasing sectoral demand for aviation

Figure 3.7
Demand growth by product category in the long-term

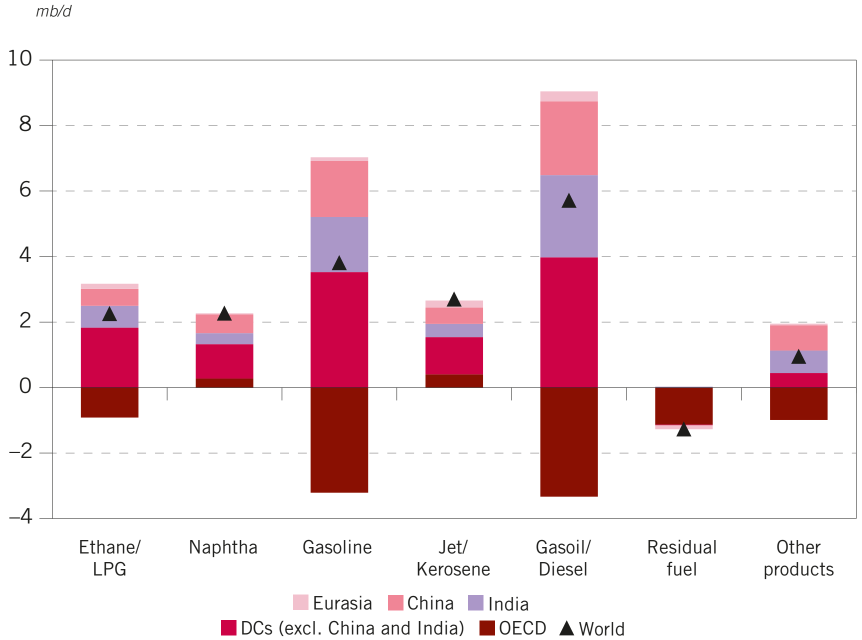


in every region and despite the decline in the demand of domestic kerosene used in the residential/commercial/agriculture sector. Increasing income levels in Developing countries will promote its use, especially in China and India, with an additional 0.5 mb/d and 0.4 mb/d by 2040, respectively.

In the light products category, growth is driven by ethane/LPG with an additional 2.3 mb/d by 2040. This is driven by an increase in demand for petrochemical end-products and as the use of oil in the residential/commercial/agriculture sector in Developing countries surges. It is expected that the OPEC region (1.1 mb/d), India (0.7 mb/d) and China (0.5 mb/d) will drive long-term growth. An additional 2.3 mb/d of naphtha is expected to be consumed during the forecast period driven by growing demand in the petrochemicals sector. Growth will be significant in developing Asia. In the OECD region demand for naphtha increases by 0.3 mb/d during the forecast period, and demand in the Eurasia region is also set to increase marginally.

Sectoral demand dynamics in the road transportation sector are also visible in the gasoline demand outlook. On the one hand, demand in the OECD region is expected to decline by 3.2 mb/d on the back of an increasing penetration of alternative fuel vehicles, declining average miles travelled and fuel efficiency improvements. However, for Developing countries, high population growth rates and strong car ownership growth will have the effect of increasing demand for gasoline by 6.9 mb/d, with China and India adding 1.7 mb/d each. Marginal growth is also expected in Eurasia. In total, gasoline demand is expected to increase by 3.8 mb/d between 2015 and 2040.

Figure 3.8
Oil demand growth by product category and region in the long-term



Heavy products are expected to initially increase from 17.9 mb/d in 2015 to 18.3 mb/d by 2018. Afterwards, however, a clear declining trend is observed up to 2040. Overall, demand will decline by 0.3 mb/d during the forecast period. Within the heavy products category, 'other products' will increase by 1 mb/d between 2015 and 2040. Growth will be particularly important in China and India at 0.8 mb/d and 0.7 mb/d, respectively. This is mainly on the back of increasing road construction. In contrast, demand in the OECD region is expected to decline by 1 mb/d.

Global residual fuel demand will decline by 1.2 mb/d during the forecast period. Marginal growth is only expected in the Middle East & Africa and India, mainly due to increasing demand in the electricity generation sector as energy poverty alleviation policies are incorporated. In the OECD, demand is expected to decline by 1.1 mb/d due to falling marine bunkers demand coupled with a switch to gasoil/ diesel and the shrinking use of oil in the electricity generation sector.

In terms of long-term sectoral demand, global demand growth is expected in every sector except the electricity generation sector. However, there are again significant regional differences. While in Developing countries and Eurasia growth is foreseen in every sector except electricity generation, in the OECD growth is expected only in the aviation and petrochemical sectors.

Overall, most of the demand growth globally is concentrated in the road transportation sector, which is expected to increase by 6.2 mb/d between 2015 and 2040, with growth there concentrated in Developing countries (12.6 mb/d). Growth in other sectors such as the petrochemicals (3.6 mb/d), aviation (2.8 mb/d), marine bunkers (1.8 mb/d) and residential/commercial/agriculture sector (1.7 mb/d) is also significant.

This year's Reference Case oil demand by 2040 corresponds to a marginal downward revision of 0.36 mb/d with respect to the WOO 2015. This is despite the fact that medium-term demand in 2021 has been revised upwards by 1.04 mb/d. This long-term downward revision is despite the lower oil price assumption and is on the back of a further tightening of energy policies, additional technology development fostering the penetration of alternative fuel vehicles and fuel economies, and a marginal downward revision to global economic growth compared to last year's WOO. In particular, tighter energy policies play a key role in the downward demand revision in the OECD region of 0.6 mb/d by 2040. Demand has also been revised down in China by 0.9 mb/d, mainly as a result of the downward revision in its GDP growth up to 2040. In contrast, demand in India has been revised upwards by 0.8 mb/d by 2040, chiefly due to a more positive economic outlook compared to last year's WOO.

Sectoral demand

This section presents a breakdown of sectoral demand in the Reference Case. The analysis includes the different components of the transportation sector: road, aviation, rail and domestic waterways and marine bunkers, together with the petrochemical, 'other industry', electricity generation and the residential/ commercial/ agriculture sectors. As shown in Figure 3.9, between 2015 and 2040 growth is expected in every sector except electricity generation. However, between 2035 and 2040, only moderate growth is expected in the road transportation and 'other industry' sectors.

Figure 3.9
Global oil demand by sector

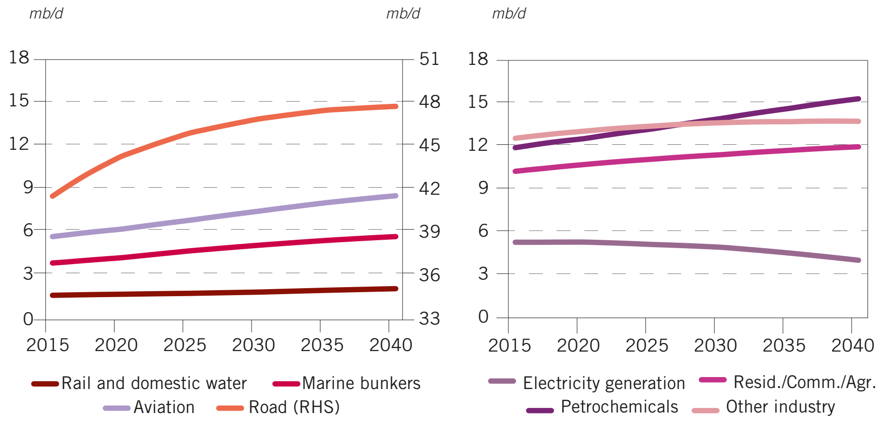


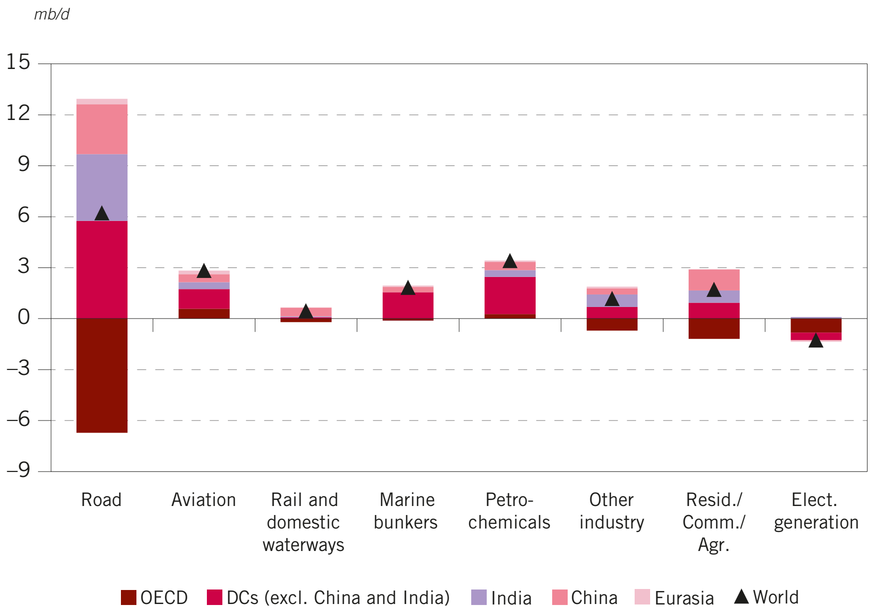
Figure 3.9 shows that most of the oil consumed today and in the future will come from the road transportation sector. In 2015, sectoral demand totalled 41.6 mb/d, which represented 45% of the overall demand. Demand is expected to continue increasing and reach 47.8 mb/d in 2040. The relative weight of the sector in global demand is expected to remain roughly constant in the medium-term, before assuming a slow downward trend. By 2040, the road transportation sector will represent 44% of total demand.

The 'other industry' sector, which primarily includes iron and steel, glass and cement production, construction and mining, is the second biggest contributor to oil demand. In 2015, sectoral demand reached 12.6 mb/d, representing 14% of total demand. As the world moves towards a more service oriented economy, future sectoral demand will grow at a slower pace than overall global demand. In fact, the petrochemicals sector takes over as the second most important source of demand towards the end of the medium-term. In 2015, demand in this sector accounted for 11.9 mb/d and, by 2040, it is expected that it will reach 15.5 mb/d.

The fourth sector in terms of oil demand is the residential/commercial/agriculture sector. In 2015, it accounted for 11% of total demand. In the future it is expected that this share will remain roughly constant. By 2040, sectoral demand will reach 12 mb/d. Demand in the aviation sector, which totalled 5.8 mb/d in 2015, is expected to grow at healthy rates so the share that this sector represents in terms of total demand will increase from 6% to 8%. Demand in the marine bunkers sector and rail and domestic waterways is also expected to increase. In contrast, demand in the electricity generation sector is set to remain approximately constant in the medium-term at around 5.3 mb/d, before declining in the long-term.

As shown in Figure 3.10, over one-third (6.2 mb/d) of the total demand increase of 16.4 mb/d between 2015 and 2040 comes from the road transportation sector. Strong growth is also foreseen in the petrochemicals sector (3.4 mb/d) with OPEC, Other Asia, China and India accounting for most of the growth. Sectoral demand growth for petrochemicals in China and India is also significant.

Figure 3.10
Oil demand growth by sector and region in the long-term



The aviation sector is forecast to add additional barrels of oil demand, with 2.8 mb/d extra by 2040. Growth is expected in every region, in particular in China and India, as the growing middle class push demand for aviation services. Total demand in the marine bunkers sector is anticipated to increase by 1.8 mb/d over the forecast period, despite estimated marginal decline in OECD demand.

In the residential/commercial/agriculture sector, total demand is expected to increase by 1.7 mb/d up to 2040. Growth is concentrated in Developing countries as increasing income levels, coupled with advancing urbanization, implies a switchaway from traditional fuels to commercial fuels. However, sectoral demand in the OECD is expected to fall.

Growth in the 'other industry' sector is led by China and totals 1.2 mb/d between 2015 and 2040. In the case of the rail and domestic waterways sector, growth in the forecast period is estimated at 0.5 mb/d, again led by China. As mentioned earlier, the only sector where declining demand is expected is the electricity generation sector, with 1.3 mb/d of demand anticipated to be removed from this sector between 2015 and 2040. However, growth is foreseen in the Middle East & Africa and India due to increasing efforts to alleviate energy poverty and the infrastructural deficit, which constrains competition from alternative sources.

Road transportation sector

In 2015, a total of 41.6 mb/d were consumed in the road transportation sector. As highlighted previously, this represents 45% of global demand. Sectoral demand in the OECD reached 23 mb/d in 2015 with OECD America being the most important region. In Developing countries, demand in 2015 totalled 16.6 mb/d with China and OPEC accounting for a significant share. In Eurasia, 2 mb/d were consumed in the road transportation sector last year. Gasoline, including ethanol, was the most consumed product in this sector at 23.6 mb/d in 2015. Gasoil/diesel, including biodiesel, follows with 17.1 mb/d. Finally, the use of LPG as fuel in the road transportation sector is rather marginal. In 2015, it represented only 2% of the total sectoral demand.

The future demand outlook for the road transportation sector takes into account two main variables. Evidently, the number of cars on the road is a primary driver of oil demand. Additionally, the average OPV is also relevant to estimate expected oil consumption. It should also be noted that there are important regional trends in these two variables that are explored later. Furthermore, differences are also evident in terms of vehicle types, with the WOO providing a differentiated analysis of passenger cars and commercial vehicles. The analysis shown below is based on a detailed modelling approach benefiting from the OPEC Road Transportation Model (ORTM).

Vehicle stock

The number of vehicles, both passenger and commercial, has increased significantly over the last few decades. In 1980, there were 350 million passenger cars and 58 million commercial vehicles on the road. By far the majority of these vehicles were located in the OECD region. By 2000, the number of passenger cars had increased to 655 million and for commercial vehicles the figure was 145 million, and the share in Developing countries had started to increase. In 2015, it is estimated that there were 1,040 million passenger cars in the world with one in every three in Developing countries. Furthermore, out of the estimated 218 million commercial vehicles in the world in 2015, half were located in Developing countries.

Looking into the future, the number of vehicles is expected to continue growing. However, different trends are anticipated, depending on the region and vehicle type considered. In the case of passenger cars, vehicle ownership is closely linked to income levels, albeit in a non-linear fashion. As more people join the middle class the demand for road mobility increases and disposable income is often spent in buying a car. As income levels continue increasing, however, car ownership growth decelerates on the back of saturation effects and the declining marginal utility of additional cars. Additionally, increasing pollution and policies that promote the use of public transportation will likely further limit car ownership growth.

Historical evidence underlines this trend. In the OECD region, passenger car ownership growth outpaced GDP per capita growth in the 1970s. During the decade of the 1980s and the first part of the 1990s both variables grew roughly at the same rate. However, this century it has been evident that GDP per capita has grown faster than passenger car ownership, highlighting the saturation effect. The picture is significantly different for Developing countries where since 1970 passenger car ownership growth has continued to outpace GDP per capita growth.

By 2040, the total number of passenger cars is expected to double, increasing from 1,040 million in 2015 to 2,111 million. Most of the increase comes from Developing countries with an additional 916 million cars. Growth is particularly strong in China and India as a result of strong economic development, a marked urbanization process

Table 3.4
Projection of number of passenger cars

millions

	2015	2020	2025	2030	2035	2040
OECD America	274	291	311	327	340	351
OECD Europe	253	260	268	275	282	288
OECD Asia Oceania	93	94	95	96	96	97
OECD	**619**	**645**	**674**	**698**	**718**	**736**
Latin America	75	79	89	101	114	128
Middle East & Africa	29	36	44	55	66	78
India	20	33	54	88	141	220
China	123	192	271	350	420	476
Other Asia	40	54	73	99	132	173
OPEC	56	72	94	120	150	185
Developing countries	**343**	**464**	**626**	**813**	**1,023**	**1,259**
Russia	44	50	54	55	57	58
Other Eurasia	34	38	42	47	53	58
Eurasia	**78**	**88**	**96**	**103**	**110**	**117**
World	**1,040**	**1,197**	**1,395**	**1,614**	**1,851**	**2,111**

and a significant increase in the number of people joining the middle class. For the OECD region, already high levels of car ownership prevent a significant increase in the number of cars. Nevertheless, between 2015 and 2040, the number of passenger cars is still estimated to increase by 117 million, with OECD America accounting for most of this. In Eurasia, an additional 38 million are expected in the forecast period.

Compared to WOO 2015 estimates, the new projections for total passenger cars are slightly lower. For instance, the total number of passenger cars in China has been revised down by 48 million in 2040 on the back of the lower long-term GDP growth expectations.

Growth in the number of commercial vehicles is more influenced by economic growth and trade. In 1970, there were 39 million commercial vehicles. As the size of the economy increased by 4.5 times up to 2014 and trade (merchandise exports) went from $0.3 trillion to $19 trillion over the same period, so the number of commercial vehicles increased, reaching 212 million vehicles in 2014. Contrary to the case of passenger cars, saturation effects do not tend to limit further growth of the commercial vehicle fleet.

While the number of passenger cars is anticipated to increase by 103% between 2015 and 2040, the stock of commercial vehicles is estimated to increase by 113%, reaching 463 million vehicles. Most of the growth will also come from Developing countries where, by 2040, there is expected to be 299 million commercial vehicles. By that year, the OECD region is expected to have 149 million and Eurasia 15 million commercial vehicles.

Table 3.5
Projection of number of commercial vehicles *millions*

	2015	2020	2025	2030	2035	2040
OECD America	37	41	45	49	54	58
OECD Europe	39	43	47	52	58	64
OECD Asia Oceania	25	26	26	26	27	27
OECD	**102**	**109**	**118**	**128**	**138**	**149**
Latin America	19	22	26	31	36	42
Middle East & Africa	13	16	20	25	32	39
India	13	18	25	34	46	59
China	23	30	37	45	55	66
Other Asia	16	22	28	34	40	47
OPEC	22	25	29	34	39	46
Developing countries	**106**	**132**	**165**	**204**	**248**	**299**
Russia	6	6	6	6	7	7
Other Eurasia	4	5	6	7	8	9
Eurasia	**10**	**11**	**12**	**13**	**14**	**15**
World	**218**	**253**	**296**	**345**	**400**	**463**

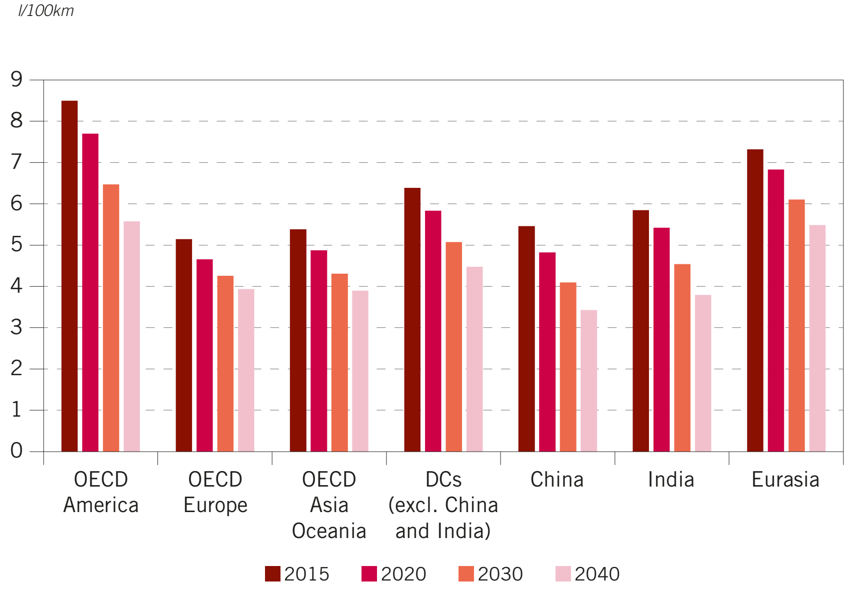
Oil use per vehicle

The second element taken into account to estimate the future road transportation demand outlook is the OPV. This variable is driven by the average car fleet efficiency, the average miles each car is driven and the penetration of alternative fuel vehicles such as natural gas, electric and fuel cell vehicles. In the future, it is expected that OPV will decline as a result of the increasing fuel economy of the fleet – due to efficiency improvements in the conventional ICE vehicles and the further penetration of hybrid vehicles – the declining average distance driven by each car and the increasing penetration of alternative fuel vehicles (see *Focus* on page 119).

Efficiency improvements in ICEs are expected to play a significant role in shaping oil demand in the road transportation sector. In particular, today modern supercharged gasoline engines meet diesel engines at or close to their optimum operating point in view of specific fuel consumption (SFC), which is given as grams of fuel per kWh (g/kWh). However, the difference in partial load can still be substantial. The SFC of gasoline engines has dropped from 265 g/kWh in 1995 to 215 g/kWh in 2015, a reduction of 19%. Gasoline direct injection, variable and fully-variable valve trains, down-sizing and exhaust gas recirculation have substantially broadened both the revolution and load range of minimum SFC.

Typically, HEVs are equipped with a gasoline ICE as single source of power (the battery is charged by the gasoline ICE and by recuperating brake or downhill power). Hence, improving the efficiency of hybrids can be achieved by both improving the ICE and the electric part. In the latter case, reducing the system weight is

Figure 3.11
Gasoline passenger cars fuel consumption

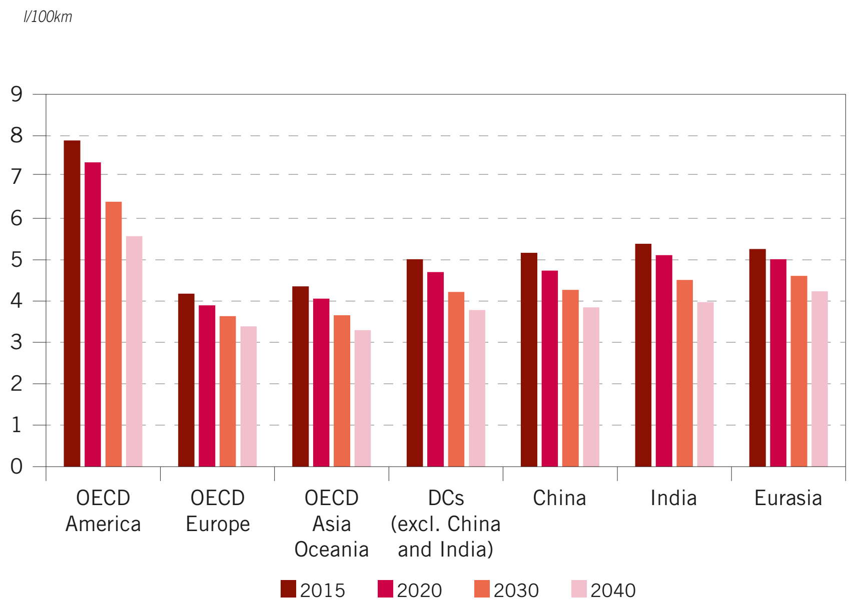


crucial. The e-system efficiency is already very high with, consequently, very limited improvement potential for the future. As hybrids are a newer technology than well-known ICEs, a 1% p.a. improvement of the electric part of the vehicle is expected until 2025, decreasing to 0.5% afterwards. This leads to a combined and, hence, overall efficiency improvement of 1.5–2% p.a. until 2025 and 1–1.5% afterwards. Figure 3.11 shows the expected future development of fuel consumption for gasoline passenger cars until 2040 for specific regions.

Modern diesel cars are still the most fuel-efficient passenger vehicles. The SFC of diesel engines remains stable throughout a much broader load range and has fallen from 240 g/kWh in 1995 down to 205 g/kWh in 2015 (gasoline equivalent). The most important technical advance was the adaption of the direct injection diesel engine formerly employed only in trucks to small and fast running passenger diesel cars. A revolutionary SFC reduction cannot be expected in the short-term, but 190 g/kWh is realistic by 2025. Although the SFC (given as g/kWh of shaft power) of the combustion engine is the most input, many other factors contribute to the fuel consumption of the vehicle (given as litre of fuel per 100 km) as, for example, vehicle weight, air resistance, among others. Figure 3.12 shows the expected decrease in fuel consumed by diesel passenger cars until 2040.

It should be highlighted that, despite the fact that ICEs are becoming increasingly more efficient from the technology point of view, there are other factors limiting the further fuel economy improvements of passenger cars. Higher security and comfort standards, together with the ever-increasing demand for space and engine power, have gradually, but constantly, increased the average weight of passenger vehicles over the years, typically between 1% and 2% over 15–20 years, but sometimes much higher. For example, between 2005 and 2014 India saw a

Figure 3.12
Diesel passenger cars fuel consumption



weight increase of 15%, albeit from a low vehicle weight of below 1,000 kg and over the same period China went from below 1,200 kg to beyond 1,400 kg, a 25% increase. It should be stressed that this refers not only to ICE-powered vehicles, but it is at least equally important for hybrids and particularly BEVs. These suffer from the additional weight of the electric powertrain components. At the same time, however, the weight increase resulting from additional equipment is partly offset by an optimized structure and new materials (e.g. carbon) used in the construction of vehicles. The net effect in some vehicle segments is even a decrease weight for new generation models.

Modern cars and commercial vehicles require power to not only move the vehicle, but also for a broad range of other requirements. An incomplete list includes air conditioning, seat and wheel heating, cargo refrigeration, rear window heating, illumination, the increasing number of electronic devices and telecommunication. Heating the interior of a vehicle is not a major issue as long as ICEs or fuel cells are employed, but becomes a serious issue in the case of BEVs. Specifically for air conditioning (A/C), in hot and humid climates the power requirement of the A/C can play a very important role, in the case of extreme city traffic it may even reach the average power required to move the vehicle.

Efficiency improvements will also become apparent in the commercial vehicle segment, comprising all medium- and heavy-duty vehicles employed for commercial reasons. The focus of engine development over the last 10–15 years has been on reducing pollution, mainly by improving combustion and employing filters and catalysts, so that modern heavy-duty trucks are often cleaner than passenger vehicles, with even lower nitrogen oxide (NO_x) emissions. Because pollution and fuel consumption are counter-running, the engine efficiency of heavy-duty diesel engines has only risen by an average of less than 0.5% p.a. over the same period. Hence, a slightly higher improvement rate of 0.7% p.a. can be expected until 2025.

A further potential for fuel saving is waste heat recovery. The use of improved (better steel quality) and new materials (aluminium, carbon, etc.) will reduce the deadweight of vehicles in the future. Other improvements will be on a continuous basis, mainly stretching today's possibilities a little more towards further increased injection pressure, increased and possible multi-staged super-charging with optimized intercooler, reduced friction, enlarged Miller/Atkinson valve timing, optimized supercharger efficiency, reduced specific engine weight by employing lighter materials and optimized structures.

Additionally, manufacturers of lubrication media and systems will contribute to reduce friction. Some potential lies also in reducing the weight of commercial vehicles, mainly by improving the chassis resistance at decreased weight. Attempts are also underway to decrease the air resistance although this plays a minor role in comparison to passenger vehicles. However, there are several other important parameters that have a serious impact on fuel consumption outside the influence of the vehicle efficiency. This includes road congestion as vehicles then consume fuel (any kind) in an over-proportional manner. Poor road infrastructure also increases fuel consumption (and reduces vehicle life) due to increased brake/accelerate manoeuvres so as to avoid vehicle damage or simply because of traffic congestion. Without the presence of an appropriate road infrastructure attempts to reduce fuel consumption are limited. In total, an overall improvement of around 0.5% p.a. for heavy-duty and 0.8% for medium- and light-duty vehicles can be expected over the next couple of decades.

The car fleet composition is also expected to change significantly in the years ahead. While conventional powertrains (comprising gasoline, LPG and diesel vehicles) are expected to continue accounting for most of the passenger cars in the roads, non-conventional powertrains such as NGVs, HEVs, PHEVs, BEVs and FCVs are starting to play an increasing role – albeit from a very low level.

For passenger cars, the change in composition will become more evident in the years ahead. Even complying with stricter emission and consumption regulations, gasoline engines remain the cheapest engines with costs around $1,200 for small naturally aspirated and $1,800 for supercharged mainstream units. Today more than 80% of passenger cars are equipped with gasoline engines (including gasoline-based hybrids). Europe, Egypt, Turkey and India are exceptions with diesel shares of 50% and more, mainly due to strong government incentives (high gasoline *versus* low diesel taxation). Technology, even in the simpler gasoline engines, has recently advanced quickly and efficiencies have improved significantly in recent years.

The use of LPG for passenger cars relies entirely on government initiatives – granting substantial tax advances as compared to competing fuels (gasoline, diesel). In the past, only in Italy and South Korea could LPG gain an important share of close to 10%. Most of the LPG promoting countries have built a satisfactory infrastructure (Germany: 6,700 LPG stations; Italy: 3,160; Netherlands: 2,100; France: 1,700; UK: 1,400). Nevertheless, a stable share of LPG vehicles is expected.

The introduction of small, but fast running and supercharged diesel engines with common rail technology, as well as substantial improvement in the fuel quality itself during the 1980s created long-lasting success for diesel cars, particularly in Europe. Modern diesel engines are typically 30–50% more expensive than comparable gasoline engines. To encourage the acquisition of diesel cars with the aim of reducing fuel consumption, many governments decided to strongly tax gasoline fuel. As a consequence and as already mentioned, the diesel share of new cars has risen to more than half in the EU and Turkey.

The sustainability of high level of new sales of diesel cars in Europe has, however, been questioned after recent tests detected that in real traffic, gaseous and especially NO_x emissions, may rise even to a multiple of the levels specified by manufacturers and granted by policy makers. The required technology to make diesel cars cleaner is available, but it will increase overall costs substantially. This will help alternative powertrains (mainly electric) to close the cost gap.

This fact was also reflected in recent statements from several car manufacturer executives who question the long-term outlook for diesel. Additionally, published diesel sales numbers for Western Europe – by far the most important market for diesel passenger cars – has shown a small, but constant declining share since 2011. It has fallen by 1% p.a. after the all-time high of 55.7% in 2011. Both facts suggest a constant decrease in diesel's passenger car market share until 2040.

In the commercial vehicle fleet segment, diesel has an overwhelming market share in the heavy trucks, medium trucks and buses segment. There is no good reason why diesel should lose its dominant role in heavy trucks and buses over the next 15 or even 25 years. Development cycles for heavy-duty engines are much longer than those for smaller engined passenger vehicles. Additionally, today's heavy-duty diesel engines are the most efficient ICEs, with efficiency close to 45% for 300 kW engines.

Diesel fuel has received tax preference in most markets in view of its energy content. The most extreme example is Egypt where diesel prices are only around 30% of gasoline when considering nominal costs ($/litre) and 25% when considering energy content ($/Megajoule). Even countries with a balanced tax scheme for diesel and gasoline, for example, the US, China, the UK, Russia, Australia, South Africa and the UAE, grant preferences to diesel fuel when considering energy content.

From the perspective of buses – both local and long-distance buses – these too mainly use diesel due to the unsurpassed fuel economy. An important alternative in some markets has been buses with spark ignited gas engines running on LPG or compressed natural gas (CNG) instead of gasoline, given their lower pollution levels. However, the City of Vienna, for example, in a comprehensive investigation has determined that modern diesel buses have lower pollution than LPG buses and, consequently, has abandoned the long-lasting use of LPG in favour of modern diesel buses. The regular start/stop operation of urban buses makes hybridization a perfect choice, recuperating the brake energy in the case of short distances between two stops. The vast fleet of smaller and mid-sized delivery vehicles will benefit from hybridization in the medium- to long-term. However, market penetration will only increase slowly in comparison to the passenger vehicles.

With some delay, the increasing share of alternative fuel vehicles in terms of overall sales will also change the composition of the vehicle fleet. Figure 3.13 shows the composition of the global passenger car fleet – strongly increasing – in absolute numbers, as well as the changing shares of the respective fuel types. The fleet of gasoline cars will further increase from around 800 million in 2014 to more than 1,300 million units by 2040, although its share declines from 79% to 63%. The diesel passenger car fleet is also expected to increase from around 140 million in 2014 to 240 million in 2040 – albeit a much slower pace than for gasoline. LPG cars are estimated to grow from 40 million to 67 million during the forecast period.

Focus

Penetration of non-conventional powertrains

Non-conventional powertrains encompass a broad range of different concepts, from NGVs, HEVs, where the ICE is still the one and only power source, through to PHEVs and BEVs, which partially, or fully, rely on external electric power to FCVs that convert fuel directly into electric power without any mechanically moving component. The technology for large serial hybrid vehicles is already known and has been in use for a long time, for example, as diesel-electric locomotives and diesel-electric pods for ships. It is important to emphasize that the electrification of the vehicle powertrain is already a reality and undergoing constant improvements in view of efficiency, weight and costs.

Hybrid electric vehicles and plug-in hybrid electric vehicles

While HEVs still use the main ICE as the only source of power – electricity is produced by the ICE through the electric motor, which is then operating as generator, or when recuperating brake power – so-called PHEVs can also use grid power to charge the battery when the ICE is off (usually when the car is parked and connected to the grid by a plug).

The main electrified non-conventional powertrain is the HEV, which does not compromise the driving range expected by consumers using the existing fuel infrastructure. It had more than 1.2 million sales in 2015 globally. Such conventional HEVs allow the main engine – whether gasoline or diesel – to run at, or close to, its optimum efficiency. Additionally, brake power can be recovered and engine-stop periods can be extended – a clear advantage over both pure gasoline- and diesel-powered cars in the stop-and-go traffic of cities. Considering the globally increasing pollution concern in urbanized areas, hybrid cars allow, at least to a limited extent, a zero-emission circulation in densely populated areas.

The major drawback of HEVs is the substantially increased weight – and cost – of the additional powertrain. It is generally known that every 100 kg of weight causes a fuel consumption increase of 0.15–0.25 cubic decimetres (dm^3)/100 km gasoline equivalent. While early HEVs usually had an older gasoline engine with accordingly higher SFC, new models now incorporate much better performing engines, considerably reducing the fuel consumption of hybrids. For mid-sized cars in the US market, it has improved from 8 litres/100 km to around 6 litres/100 km between 2006 and 2016. Nowadays, modern hybrids have comparable fuel consumption to diesel cars of the same size.

PHEVs with an increased battery capacity allow for battery charging with grid power, and driving somewhat longer distances on battery power only (up to 30 km or, in some cases, 50 km). These ideally run in city centres on only electricity. Consequently, PHEVs have larger batteries and stronger e-motors and attempt to combine the ICE and electric powertrain world. The main advantage is the extended zero emission capability in urban areas, while maintaining the long driving range of ICE-powered cars. The predicted further decrease in battery costs in the near future will also make HEVs and PHEVs more competitive by closing the price gap especially to diesel vehicles.

The expected cost reduction in batteries from $300–400/kilowatt hour (kWh) today to around an expected $150/kWh, at some point in the 2020s, will not only benefit BEVs, but also PHEVs. The pure electric range may rise to 100 km at very moderate extra costs of not more than $3,000. This is an attractive scenario that combines zero emission in city centres and the highly appreciated long range and fast refuelling characteristic of the ICE-powered car. PHEVs may be a long-term transition concept, allowing customers to avoid a premature decision in deciding between an ICE or BEV by selecting an intelligent synthesis of both worlds.

Natural gas passenger cars

Gasoline engines can run on natural gas without any major adjustments as the combustion process is very similar. Natural gas is available in abundant quantities at competitive prices and several countries have set-up a nationwide distribution system. In 2015, the leader was China with around 6,500 stations, followed by Pakistan with 3,000 stations. Although fuel taxing in the US is traditionally low and impartial of fuel type, the provision of only a minor tax incentive in favour of natural gas means there are now approximately 2,000 public and private stations in operation. Worldwide the number has risen to 26,600 CNG stations. In the future, however, it is expected that only countries actively promoting natural gas vehicles, for example, China (5% of the total sales in 2040 from 1.5% in 2014), India (7% from 4.5% in 2014) and OECD America (3% from 0.1% in 2014), will see the share of natural gas fuelled passenger cars rise.

The earlier advantage of considerably lower pollution of NGVs, when compared to old gasoline or diesel cars, has been whittled away and will vanish in the near future given the stricter pollution standards independent of vehicle types. Moreover, although CNG and LNG have been promoted in view of the ongoing discussion about GHGs as a fuel source with substantially reduced CO_2 (196 g CO_2/kWh for natural gas *versus* approximately 270 g CO_2/kWh for light to medium petroleum distillates), the so-called methane slip (the unwanted emission of unburned methane), can reduce and even reverse this obvious advantage of natural gas over traditional petroleum fuel.

Battery electric vehicles

BEVs have been talked about for some time, but there remain some major drawbacks that, to a certain extent, will limit the penetration of such vehicles.

To start with, it should be noted that the drastically increased weight of BEVs over conventional ICE-powered cars causes the average power consumed at the wheel to be much higher than for a comparable conventional car. Additionally, even very large batteries (beyond 100 kWh) will not allow the same driving range as conventional ICE-powered cars. Consequently, charging is still an issue, and it is expected to remain one in the future. Average overnight recharging of BEVs can be carried out easily and without major investment in existing grid infrastructure.

An average 100 km drive per day at 21.8 kWh/100 km (Tesla model X) requires 22 kWh of power overnight or less than 3 kW of charging power. The existing grid infrastructure will only need some minor expansion to deliver this power. However, the outlook changes completely if a large percentage of the e-car owners wants to travel over a distance exceeding the battery capacity within a short period of time (e.g. national holidays or vacation periods). The requested charge power will obviously overwhelm any existing grid infrastructure. The required investment needed for a smooth operating system under such extreme conditions is enormous, especially if the infrastructure is only used a few days per year.

Currently, there is no large-scale storage technology available – or even apparent within the next 20 years – that could challenge the 'buffer character' of conventional fuels and allow renewable energy, the primary energy source commonly envisioned for electric mobility, to be stored with an acceptable efficiency for weeks and even months. All systems are either far too small or too inefficient. A BEV or PHEV will require recharging several times per week and perhaps up to several times per day. A conventional ICE-powered car, on the contrary, may need refuelling only once or twice per month. This makes it essential, from the consumer's point of view, to design the recharging infrastructure to be as easy as possible. It is anticipated that it will be a major challenge to provide sufficient public recharging infrastructure.

BEV manufacturers are currently focusing on several issues, with the most important being driving down battery cell costs. This is evolving faster than expected with today's costs of between \$300/kWh and \$400/kWh estimated to be down to an expected \$150/kWh by the early 2020s. However, the electric powertrain comprises other components, mainly power electronics and electric motors, which are not witnessing cost reductions at the same pace. Additionally, these components also show a limited efficiency, so that the overall plug-to-wheel efficiency is somewhere between 80% and 85%.

Moreover, it is a challenge to cool the battery cells efficiently, as well as the power electronics, to avoid overheating, and subsequent cell and component destruction. At low temperatures, precautions must also be taken so that frost does not destroy the cells. This is usually achieved through limited discharging. Consequently, the range of the BEV is reduced. This makes BEVs less attractive, both in hot and cold climates.

This year's announced Tesla Model 3 has drawn public attention mainly due to its 'comfortable' base price of \$35,000 (including essential extras that Tesla expects to cost \$42,000). The main driver behind this is the reduced battery price, achieved by reducing its capacity to 50–60 kWh, as compared to 85 kWh for the model S, and the expected lower per-kWh-price. It must not be forgotten, however, that reducing battery costs not only favours BEVs, but also all other concepts employing a battery, such as HEVs and PHEVs.

Fuel cell vehicles

The development of efficient and cheap fuel cells has been a recurring topic over the past decades. However, to date no large-scale developments have occurred, particularly in terms of fuel cells being able to use fuel other than hydrogen. However, it should be noted that Toyota, one of the world's most important passenger car manufacturers, has announced a push for fuel cell development. At the end of 2015, a total of 214 hydrogen fuelling stations had been installed worldwide, basically all in the US, Western Europe, Japan and South Korea.

The typical efficiency of modern fuel cells is around 60%, with a somewhat lower efficiency at high and prolonged loads. Engineers are optimistic they can reach 65–70% pure cell efficiency in the next few years. The main disadvantages of using hydrogen are that a parallel distribution system must be installed, and the fact that the distribution efficiency of hydrogen – whether compressed at 700 bar or liquefied – is the lowest of all. Compression to 700 bar or liquefying may consume up to 25% of the energy at the beginning of the distribution chain.

Today, 90% of all hydrogen is produced by steam reforming from fossil fuels (mainly natural gas and petroleum). The associated conversion losses mean that fuel cell cars based on hydrogen are not more efficient than conventional ICEs running on natural gas used for hydrogen production. Future hydrogen for vehicle applications must be produced, therefore, this needs to come from renewable power (mainly wind and solar). Considering electrolysis, hydrogen transport and distribution, as well as on-board conversion into power again by the fuel cell, means less than 50% of the power from solar or wind sources will appear at the vehicle wheel. This is far below the efficiency of a battery system and, consequently, the question arises why hydrogen should be used instead of charging batteries directly – whether BEV or PHEV. The often cited advantage that hydrogen solves the storage problem of renewable power is hardly convincing.

Expansion will occur

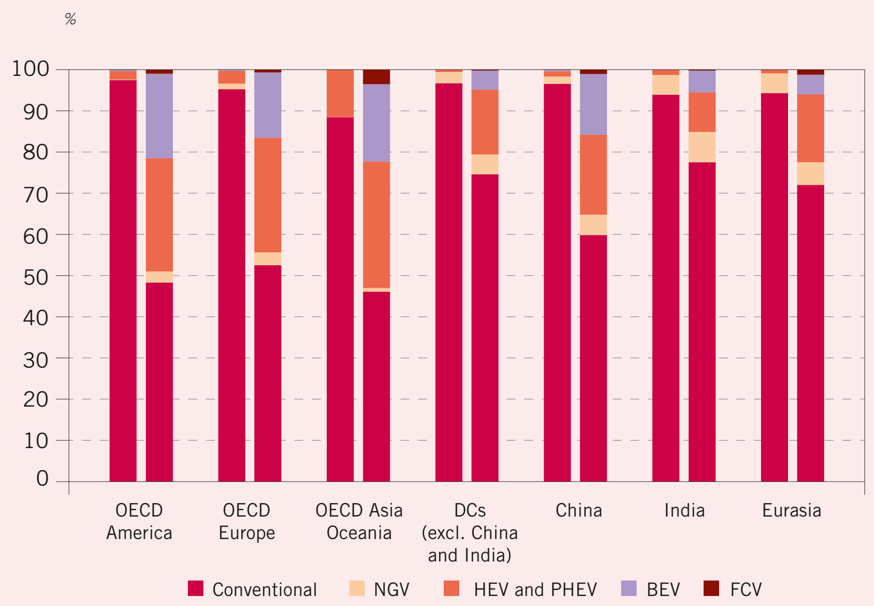
Despite the mentioned setbacks and challenges of non-conventional powertrains, they will play an increasingly important role in the passenger car segment and occupy a larger share of the future market. This will mainly be in the wealthy OECD regions, as well as in China, which has promoted, and will further actively promote, BEVs. Figure 1 shows the composition of new passenger car sales in 2014 and that expected in 2040. It is clear that the share of conventional powertrains will be reduced significantly in every region.

For example, while in 2014 conventional powertrains in OECD America accounted for 99.5% of total passenger car sales; by 2040 they are expected to only account for 48%. By 2040, hybrids (both HEV and PHEV) are anticipated to represent 28% of total sales in OECD Europe, 31% in OECD Asia Oceania and 19% in China. BEVs will likely become popular in OECD America (21% of total sales in 2040) and OECD Asia Oceania (19% of total sales).

The shift towards non-conventional powertrains will be less evident in Eurasia and in Developing countries, apart from China. In the former, sales of conventional powertrains are estimated to still represent over 70% of the total. In India, almost eight out of 10 new cars are expected to still rely on gasoline, diesel or LPG. In Developing countries (excluding China and India) only one out of every four passenger cars sold are projected to be non-conventional.

In the commercial vehicle segment, the penetration of non-conventional powertrains is mainly limited by the refuelling infrastructure and the additional weight

Figure 1
Composition of new sales of passenger cars, 2014 and 2040



required. In the case of medium heavy-duty trucks for local/regional delivery with a short 250 km range, battery electric operation with upcoming technology requires large (volume beyond 200 dm^3 compared to 38 dm^3) and heavy batteries (600 kg *versus* 32 kg of diesel). Considering the fact that this truck type usually has a gross weight of no more than 10 tonnes, it is clear that battery electric operation has substantial disadvantages. For long distance trucks and buses, LNG may be an alternative when competing with diesel. However, for a driving distance of 2,000 km the tank for LNG will be nearly double the size of diesel.

Several countries have already enlarged their LNG distribution system or are planning to do so. The US has a grid of more than 80 public LNG refuelling stations, plus the same amount of privately-owned, mainly along the West-to-East transport routes, as well as the eastern and south-eastern parts of the country. The EU's 'Blue Corridor' project is set to build a distribution network of 181 LNG stations at a maximum distance of 400 km apart. This will range from Sweden to the Iberian Peninsula. The Natural Gas Utilization Policy in several large provinces of China (mainly Shandong, Xinjiang, Hebei and Guangdong) has boosted the number of LNG stations to 2,500 at the end of 2014, making China the global champion in promoting LNG as an alternative fuel.

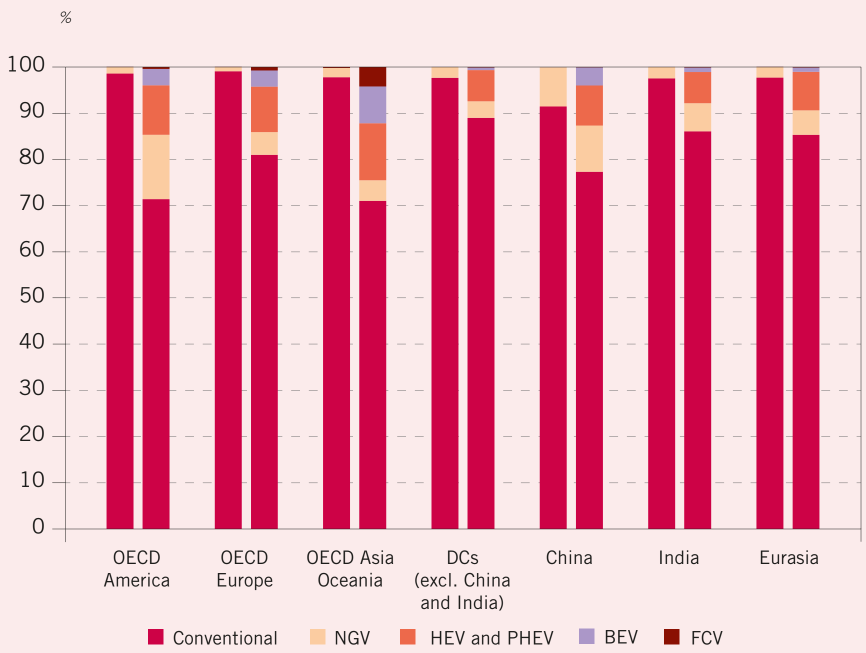
The current attractive diesel price has discouraged several engine manufacturers from progressing with the initially planned aggressive development plan for dual-fuel heavy-duty engines. High-pressure natural gas direct injection technology has been put aside although it promises equal or, in some cases, even better performance and fuel economy than diesel, as it still requires a substantial development path. It can be expected that both market size and technology advances for natural gas engines will recover, as soon as the market witnesses a sustained price differential between diesel and natural gas.

It should also be mentioned that fuel cell trucks running on hydrogen have been presented as a long-term solution. The high energy content of hydrogen per weight (120 Megajoules/kg) reduces the fuel mass as compared to diesel. However, the extremely low density, even for liquid hydrogen (1 dm^3 weighs only 70 g), makes tanks for hydrogen very large.

Pure battery operation, even with upcoming battery technology commercially available in the course of the next decade, is a no-go for heavy-duty trucks. The battery weight of more than 12 tonnes would reduce the payload drastically, lowering the profitability of a long-distance truck to an unacceptable level. The battery volume of around 5 m^3 makes it nearly impossible to incorporate the battery into these vehicles. Recharging only 50% of the battery within a generous four-hour period requires a charge power of 450 kW. Freight forwarders cannot – and will not – wait for longer times as passenger car owners may do, as they want their commercial vehicles to move to pay the bills.

Assuming that several electric trucks are recharged simultaneously at a dedicated site, then the grid load may quickly achieve several megawatts (MW) – a very serious amount comparable to an entire town of several thousand inhabitants.

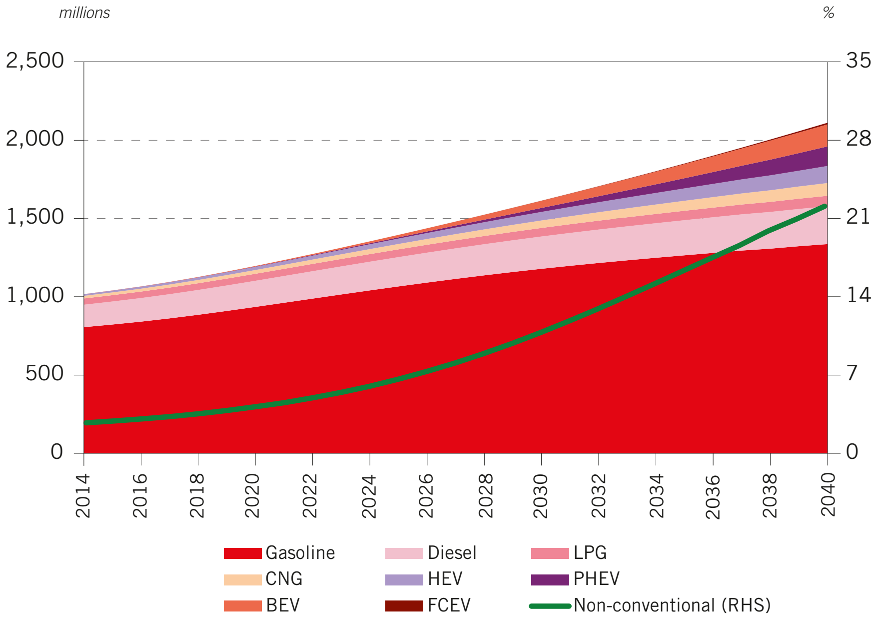
Figure 2
Composition of new sales of commercial vehicles, 2014 and 2040



In contrast to the passenger vehicle sector, the composition of new sales for medium- and heavy-duty vehicles will remain much more uniform due to the long-term primacy of diesel as shown in Figure 2. Only in OECD America, OECD Asia Oceania and China will the share of conventional powertrains in terms of total sales be reduced to less than 80% in 2040. In the case of OECD America and China, this is due to the increasing penetration of NGVs. On the other hand, in OECD Asia Oceania, hybrids and BEVs will play a significant role in new sales. In Developing countries, excluding China and India, by 2040 nine out of every 10 commercial vehicles sold are expected to be conventional powertrains.

Natural gas will gain a substantial share by 2040 in OECD America, reaching 14% of new sales, and in China it is estimated to reach 10%. Hybrids, both HEVs and PHEVs, will tend to replace pure gasoline commercial vehicles in the medium-duty segment in terms of sales. However, they will only account for slightly more than 10% of sales in the OECD regions. BEVs will play a minor role and are largely limited to short-distance urban delivery vehicles, which may benefit from zero emissions and the quiet operation requirements. Only in the OECD Asia Oceania will the share of commercial BEVs and FCVs surpass 8% and 4%, respectively, by 2040.

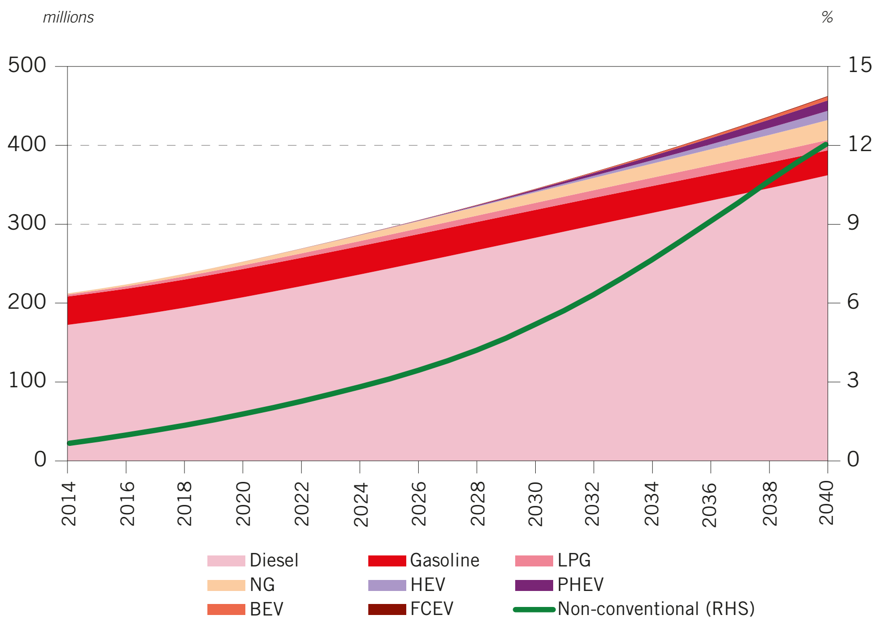
Figure 3.13
Passenger car fleet composition



Non-conventional powertrain passenger vehicles are anticipated to increase at a much faster rate. The number of HEVs will grow 10-fold between 2014 and 2040 while PHEVs will reach 125 million. The relative share of NGVs will increase from 1.7% to almost 4% in 2040. By then, there are expected to be almost 10 million FCVs. However, most of the growth in non-conventional powertrain passenger vehicles will come from BEVs. While in 2014 they represented less than 0.1% of the car fleet, by 2040 they will account for 6.7% of it, totalling 141 million cars. Overall, non-conventional powertrain passenger vehicles are estimated to represent 22% of the passenger car fleet by 2040, up from only 3% in 2014.

As is the case for passenger cars, the slow but steady change of the composition of commercial vehicle sales will also alter the composition of the overall fleet. Figure 3.14 shows the composition of the global commercial vehicle fleet in absolute numbers. The fleet of diesel commercial vehicles will further increase from around 172 million in 2014 to more than 360 million units by 2040. However, its share will decline marginally from 81% to 78%. The gasoline fleet will actually shrink from 36 million in 2014 to 32 million in 2040 as a result of the aforementioned replacement by hybrids. The number of LPG commercial vehicles will increase from over 2 million in 2014 to 13 million in 2040. The growing share of non-conventional powertrains, from less than 1% of the commercial fleet in 2014 to more than 12% in 2040, is largely driven by NGVs. While in 2014 there were over 1 million NGVs, by 2040 it is expected that there will be 25 million. The number of both HEVs and PHEVs will also increase at healthy growth rates. BEVs, as well as FCEVs, will only play a very minor role in the commercial vehicle segment.

Figure 3.14
Commercial vehicle fleet composition



Box 3.1

Autonomous vehicles: where next?

There have been significant recent developments in the autonomous vehicle sector. Multiple companies, including Google, Volvo and Tesla, have been testing self-driving cars on public roads for several years. And in August this year, the world's first self-driving taxis, operated by nuTonomy in Singapore, allowed select members of the public to hail a free ride through their smartphones for the first time. It is leading many to ask the question: where next?

Autonomous vehicles that move independently on the road, without the interaction of a human driver, have been talked about for a number of years. The concept foresees that the user supplies start and destination information and the vehicle travels automatically between these locations. The 'autonomous characteristic' of such vehicles can, therefore, be regarded as an integrated '24/7 driver', making this up-to-now luxury feature available for everybody at a fraction of the cost of today's human driver.

The concept is not limited to passenger cars, and may have a faster and stronger impact, for example, on the delivery of goods. In the case of passenger cars and vans, such autonomous vehicles may complement and even replace public transportation systems, especially in areas that currently lack such systems. The offered door-to-door transport is an important advantage compared to traditional stop-to-stop public systems.

Considering the fact that, in 2014, 53% of the world's population already lived in urbanized areas and that this value will likely rise to 70% in 2050, it becomes clear that autonomous vehicles may play a substantial role in future transportation systems.

It should be noted that the power source for moving autonomous vehicles will likely cover the complete range of engine types – from pure ICE through hybrid to electric and hydrogen. Medium- and long-distance may tend to use the ICE, while short-distance or pure local (urban) autonomous vehicles may have a substantial or even mainly electric power source. The latter requires a solid and powerful electric grid in place, which of course requires large investments.

Autonomous vehicles may also drastically increase the productivity of humans, particularly in the case of vehicles used for deliveries with humans likely only needed for supervision related tasks. In the past, the development of more efficient and cheaper transport infrastructure has always increased transport volumes (as per person km or tonne km) and, consequently, energy consumption. There is no reason to expect any different behaviour with the ramp up in the development of autonomous vehicles. As a consequence, overall energy consumption may well increase and petroleum products will play an important role.

However, the use of autonomous vehicles raises a variety of challenges and uncertainties. Tesla, which has been to the fore in rolling out limited automated steering and similar features, made global headlines this year when one of its cars was involved in a fatal crash. Although it has been acknowledged that the 'autopilot' system was far from fully autonomous, and the crash is still being investigated, it does underscore some of the worries about the transition to self-driving cars.

These worries, related to security, legal and ethical issues, the optimum use of road infrastructure and the timing required for sophisticated control systems, are magnified when talk turns to running a large number of autonomous vehicles on the road.

The penetration of autonomous vehicles in the transportation sector beyond limited field tests is dependent on the resolution of the important challenges and uncertainties highlighted. Moreover, given the expected investments in IT infrastructure and the still to-be-developed artificial intelligence, it is evident that the large-scale introduction of autonomous vehicles a long-term project.

However, if these issues can be overcome then large-scale testing in a few designated areas may take place in the middle of the next decade. And the large-scale commercial introduction of autonomous vehicles in selected local and regional areas can be expected in the 2030s, providing these vehicles with a non-negligible share in around 20 years.

Road transportation demand

The demand increase in the road transportation sector of 6.2 mb/d over the forecast period is due to the fact that, globally, the increase in the car fleet outbalances the decline in OPV resulting from car fleet efficiency improvements, the penetration of alternative fuel vehicles and the declining average vehicle miles travelled (VMT). However, the picture is somewhat different at the regional level.

In the OECD, sectoral demand is expected to decline by 6.7 mb/d between 2015 and 2040 as a strong decline in OPV by far outbalances the increase in the passenger car and commercial vehicle fleet. As mentioned earlier, the number of passenger cars and commercial vehicles will increase moderately in the forecast period. If OPV is assumed to remain constant, this modest increase in the car fleet will only add 2.1 mb/d to sectoral demand in 2040. Efficiency improvements in the car fleet (including the penetration of hybrid vehicles) have a very significant impact as they are expected to reduce sectoral demand by 4.6 mb/d in 2040. The penetration of alternative fuel vehicles such as natural gas, electric and fuel cells further reduces sectoral demand by 2.2 mb/d at the end of the forecast period. Finally, the declining average VMT has a shrinking effect on demand of 2 mb/d. Overall, sectoral demand is reduced to 16.3 mb/d in 2040.

In Developing countries, demand is anticipated to increase by 12.6 mb/d between 2015 and 2040. Contrary to what is foreseen in the OECD, the expected decline in OPV is not enough to compensate for the significant increase in the fleet in Developing countries. As shown in Figure 3.16, the impact that the growth in the passenger cars and commercial vehicle fleet would have on sectoral demand is huge. Sectoral demand would increase by 27.9 mb/d by 2040 to reach 44.4 mb/d, if OPV is assumed to remain constant. However, efficiency improvements will limit demand growth by 8.4 mb/d and the penetration of alternative fuel vehicles by an additional 2.3 mb/d at the end of the forecast period. Finally, declining average VMT will further reduce sectoral demand by 4.6 mb/d so that, by 2040, demand in the road transportation sector in Developing countries will reach 29.2 mb/d.

Figure 3.15
Demand in road transportation in the OECD, 2015–2040

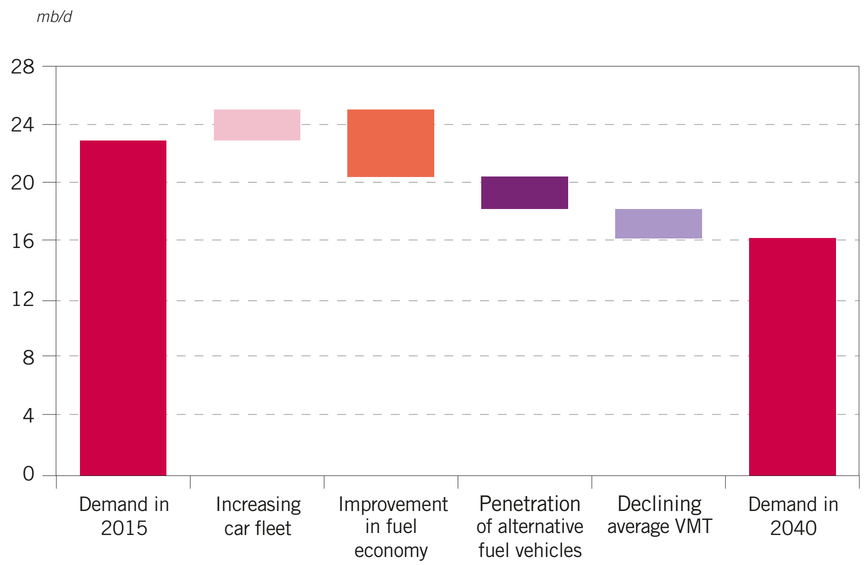


Figure 3.16
Demand in road transportation in Developing countries, 2015–2040

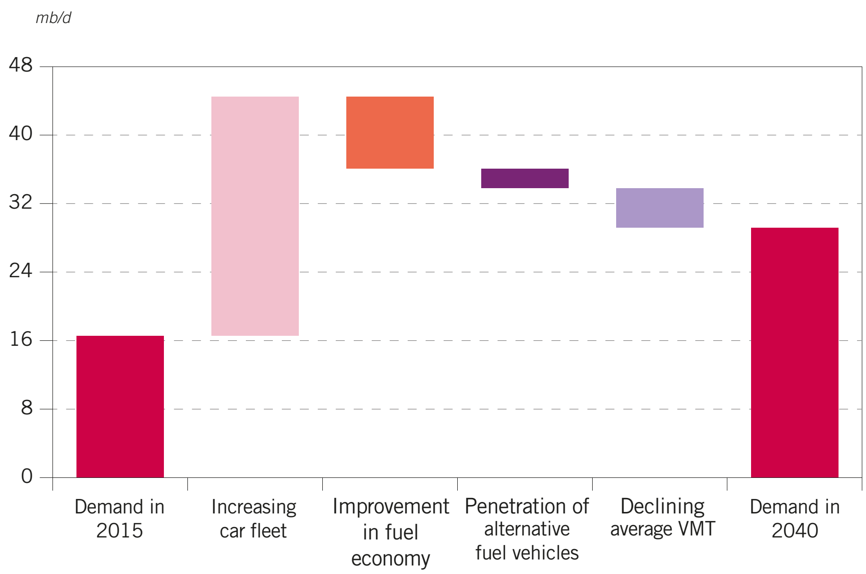


Table 3.6
Oil demand in road transportation in the Reference Case *mb/d*

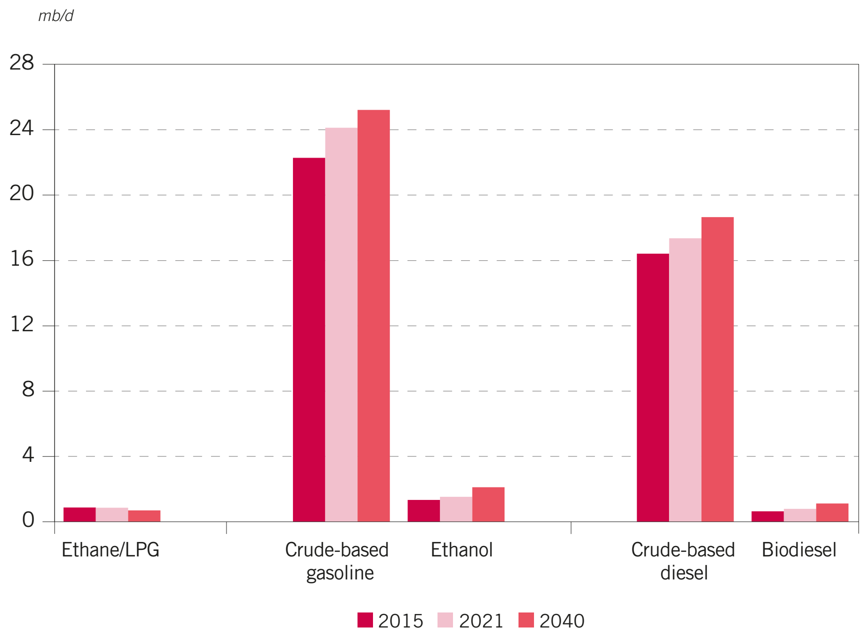
	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	13.9	14.1	13.3	12.3	11.3	10.2	–3.7
OECD Europe	6.4	6.3	6.0	5.6	5.1	4.5	–1.9
OECD Asia Oceania	2.8	2.7	2.5	2.3	2.0	1.6	–1.2
OECD	**23.0**	**23.2**	**21.9**	**20.2**	**18.3**	**16.3**	**–6.7**
Latin America	2.7	2.9	3.1	3.2	3.3	3.3	0.6
Middle East & Africa	1.7	1.8	2.1	2.3	2.6	2.8	1.2
India	1.5	2.0	2.7	3.4	4.4	5.5	3.9
China	4.5	5.3	6.0	6.7	7.1	7.4	2.9
Other Asia	2.0	2.3	2.6	2.9	3.2	3.6	1.6
OPEC	4.2	4.7	5.4	5.9	6.3	6.6	2.4
Developing countries	**16.6**	**19.1**	**21.8**	**24.4**	**26.9**	**29.2**	**12.6**
Russia	1.1	1.1	1.2	1.2	1.1	1.1	0.0
Other Eurasia	0.9	1.0	1.1	1.2	1.2	1.2	0.3
Eurasia	**2.0**	**2.1**	**2.2**	**2.3**	**2.3**	**2.3**	**0.3**
World	**41.6**	**44.3**	**46.0**	**46.9**	**47.5**	**47.8**	**6.2**

From the product point of view, gasoline will continue to be the dominant product. Its demand will reach 27.3 mb/d by 2040, accounting for 57% of the total sectoral demand. Gasoil/diesel will also show a positive trend and will increase by 2.7 mb/d to reach 19.8 mb/d by the end of the forecast period. The use of LPG remains marginal. Total gasoline and gasoil/diesel demand includes the pure crude-based product, but also the biofuels component. As shown in Figure 3.17, crude-based gasoline is expected to increase from 22.3 mb/d in 2015 to 25.2 mb/d in 2040. Ethanol is anticipated to increase by 57%, to total 2.1 mb/d in 2040.

In the last few years, the WOO had estimated that demand growth for pure crude-based gasoline would decelerate strongly and plateau at 24.6 mb/d at the end of the forecast period. In this year's analysis, the penetration of diesel vehicles has been reassessed by virtue of the recent emission scandals and policy measures to limit the use of diesel vehicles in big cities to avoid pollution. Additionally, the strong growth in gasoline vehicles seen in the last year as a result of the lower oil price is expected to have a long-lasting effect.

Turning to the use of diesel in the transport sector, this year's results show that the use of the pure crude-based diesel component will increase by 2.2 mb/d up to 18.7 mb/d, while biodiesel will reach 1.1 mb/d, both by 2040.

Figure 3.17
Product demand in the road transportation sector



Aviation sector

In 2015, oil demand in the aviation sector accounted for 5.8 mb/d, that is, around 6% of total demand. More than half of the sectoral demand was in the OECD region. However, OECD demand is increasingly losing weight as growth is increasingly being driven by Developing countries. In 1999, the OECD accounted for almost three-quarters of total demand. Since then, demand in Developing countries has increased by 113%, while that in the OECD has remained relatively constant. From the product point of view, almost the entire sectoral demand is satisfied by jet/kerosene. The use of gasoline is marginal and it is confined to recreational aviation.

Sectoral demand is determined by total traffic, both passenger and freight, and fleet efficiency. Traffic has being growing at healthy rates in the recent past, despite the drop-off in 2009 as a result of the economic crisis. Data from the International Civil Aviation Organization (ICAO) shows that traffic, measured as revenue passenger kilometres (RPK), increased on average by 5% p.a. from 2005–2014. In the next decades, traffic is expected to continue expanding on the back of rising income levels, especially in Developing countries, the increasing availability of low cost carries (LCC) and further market liberalization.

Technology improvements, load factors and air traffic management are the major factors for increases in aviation sector fuel efficiency. Airlines are trying to maximize revenue and minimize costs through applying different approaches such as more airplane utilization, increasing load factors and air traffic management. Applying these approaches not only increases profit, but also results in fuel

Table 3.7
Oil demand in aviation in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	1.7	1.7	1.7	1.8	1.8	1.8	0.2
OECD Europe	1.1	1.2	1.2	1.3	1.4	1.4	0.3
OECD Asia Oceania	0.5	0.5	0.6	0.6	0.6	0.6	0.1
OECD	**3.3**	**3.4**	**3.6**	**3.7**	**3.8**	**3.9**	**0.6**
Latin America	0.3	0.3	0.4	0.4	0.4	0.5	0.2
Middle East & Africa	0.2	0.2	0.3	0.3	0.3	0.3	0.1
India	0.2	0.2	0.3	0.4	0.5	0.6	0.4
China	0.5	0.6	0.7	0.8	0.9	1.0	0.5
Other Asia	0.6	0.7	0.8	0.9	0.9	1.0	0.4
OPEC	0.4	0.5	0.6	0.7	0.8	0.9	0.5
Developing countries	**2.1**	**2.5**	**2.9**	**3.4**	**3.8**	**4.2**	**2.0**
Russia	0.3	0.3	0.3	0.4	0.4	0.5	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Eurasia	**0.4**	**0.4**	**0.4**	**0.5**	**0.5**	**0.6**	**0.2**
World	**5.8**	**6.3**	**6.9**	**7.5**	**8.1**	**8.6**	**2.8**

saving and environmental benefits. Based on figures from the IATA, the effects of air traffic management could reduce environmental impacts by 10%, and cut costs by 50%.

Load factor is directly linked to the fuel economy of airplanes. An airplane has the highest fuel economy when it is flying at full capacity. Historical passenger load factors showed an upward trend during 2004–2014. This has been a major source of decline in fuel economy. At the same time, new airplanes will obviously replace older, less efficient ones. In 2014, the total world aircraft fleet was 21,600. According to Boeing, in 2034, there will be 43,560 in service.

A significant development in the sector has been the adoption of the first-ever binding energy efficiency and CO_2 reduction targets for the aviation sector. These were adopted in February 2016. CO_2 emission standards will apply to all new commercial and business aircraft delivered after 1 January, 2028, with a transition period for modified aircraft starting in 2023. The standards will on average require a 4% reduction in the cruise fuel consumption of new aircraft starting in 2028, compared to 2015 deliveries.

Looking ahead, sectoral demand is expected to continue growing at healthy rates and reach 6.3 mb/d at the end of this decade, 7.5 mb/d at the end of the next decade and 8.6 mb/d by 2040. However, decelerating GDP growth, energy efficiency standards and infrastructure constraints will slow long-term growth. Between 2015 and 2021, demand is expected to increase at 1.8% p.a. on average while, during the rest of the forecast period, growth decelerates to 1.5% p.a.

Additionally, sectoral demand trends are closely linked to economic growth, population growth and income levels. Therefore, it is not surprising that most future demand growth will come from Developing countries. Demand in China and OPEC is expected to double, while in India demand will expand four-fold between 2015 and 2040. Growth in Latin America and Other Asia is also significant. Additionally, in the medium-term, the assumed lower oil price will further stimulate demand.

Rail and domestic waterways

The rail and domestic waterways sector accounted for 1.7 mb/d of demand in 2015, which represented less than 2% of the global total, with gasoil/diesel being, by far, the main product consumed in the sector. In the rail subsector, several trends will continue to shape future sectoral demand. To start with, the total length of railway lines has remained roughly constant in the last ten years at around 1.7 million km. Investment has mainly concentrated on replacing old uneconomic infrastructure with more efficient ones.

At the same time, investment is increasingly focusing on electrifying the rail network. Currently, around one-third of the global network is electrified while, in 2002, it was only one-quarter. However, significant regional disparities can be observed. While in OECD Europe around 60% of the railway network is electrified, in OECD America this percentage is almost zero. It is also interesting to observe that China is increasingly electrifying its railway network. Currently, over 40% of its network is electrified, up from 20% in 2004.

In the case of India, 60,000 km of its total railway network of 110,000 km uses electricity. However, it is expected that this figure will increase in the near future. In fact, the Indian Government has recently announced plans to electrify nearly 35,000 km of railway line in the next 5–7 years. However, this is expected to be rather challenging as in the last few years electrification has increased at a rate of only 1,350 km per year.

Another important trend in the sector is the continuous growth of high speed train lines worldwide. This type of train is electrified. As of April 2015, there were just under 30,000 km of high speed lines and 3,603 high speed trains in operation. Most of the growth in the last few years has been concentrated in China. While in 2008, the country accounted for less than 1,000 km, in 2014 the high-speed network had grown to 17,186 km. Moreover, according to the International Union of Railways (UIC), by 2020, it is anticipated that the global high-speed railway network will reach around 45,000 km.

Despite increasing electrification and high-speed rail infrastructure development, the use of oil in the sector has continued to increase in the last few years. This is a result of increasing passenger traffic that has grown at a healthy 2.9% p.a. since 2007, going from 2.5 trillion passenger kilometres (pkm) to 3.1 trillion pkm in 2014. Freight traffic, however, has seen less prominent growth. As it is very much linked to economic activity, the economic crisis that began in 2008 has impacted this segment. Nevertheless, freight traffic continues to recover from its lowest level in 2009 when it bottomed out at 8.9 trillion tonne kilometres (tkm). In 2014, it reached a level similar to pre-crisis at 9.7 trillion tkm.

Table 3.8
Oil demand in rail and domestic waterways in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	0.5	0.5	0.5	0.5	0.5	0.4	–0.1
OECD Europe	0.2	0.2	0.1	0.1	0.1	0.1	–0.1
OECD Asia Oceania	0.1	0.1	0.1	0.1	0.1	0.1	0.0
OECD	**0.8**	**0.8**	**0.7**	**0.7**	**0.6**	**0.6**	**–0.2**
Latin America	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
India	0.1	0.1	0.1	0.1	0.1	0.1	0.0
China	0.5	0.6	0.6	0.7	0.9	1.0	0.5
Other Asia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
OPEC	0.0	0.0	0.1	0.1	0.1	0.1	0.0
Developing countries	**0.8**	**0.9**	**1.0**	**1.1**	**1.3**	**1.4**	**0.6**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
World	**1.7**	**1.8**	**1.8**	**1.9**	**2.1**	**2.2**	**0.5**

An important recent development that is negatively affecting the freight segment is the recent decline in US liquids supply and coal consumption. Data from the Association of American Railroads (AAR) shows that the annual traffic of crude petroleum in 2015 was around 40 million tonnes (mt), down from 47.5 mt in 2014. Moreover, 2016 data shows an even less optimistic picture. Petroleum and petroleum products carloads in May 2016 totalled 12,000, down by 20% compared to May 2015. In the case of coal, the picture is gloomier further. Car loads totalled 62,000 in April 2016, while one year previous they were at almost 100,000.

Looking ahead, sectoral growth will be significantly impacted by China's development. As the country moves towards a more service-oriented economy, industrial activity will lose weight. Therefore, it could be expected that traffic in the freight segment will be affected. In fact, preliminary data suggests that freight traffic in China dropped by 10.5% in 2015. However, it should also be highlighted that economic expansion and increasing income levels will likely push demand for passenger traffic. In 2015, it increased by 6.1%.

Demand in the domestic waterways subsector is heavily marked by natural endowment. China is by far the country with the longest inland waterways network. Although the economy's growth has slowed, inland waterways traffic has not been significantly affected. Freight traffic in 2015 remained roughly constant compared to 2014 and passenger traffic increased at healthy growth rates.

Positive news for the subsector also comes from India. The country accounts for 14,000 km of navigable rivers and canals. However, domestic waterways transportation has historically remained undeveloped as only 3.5% of trade uses this mode. In countries such as the US, China and Europe this percentage is much higher. In April this year, the Parliament approved the National Waterways Bill that declares 106 additional inland waterways as national waterways, greatly adding to the five existing national waterways. This initiative will most likely boost passenger and freight traffic and will, according to the Indian Government, reduce transportation costs substantially.

Demand in the rail and domestic waterways sector is expected to show steady future growth. It will reach 1.8 mb/d by 2020 and 2.2 mb/d by 2040. The sectoral product outlook is not likely to change significantly as gasoil/diesel will continue to account for most of the demand. Gasoline and residual fuel will only be used marginally. Demand in the OECD is expected to stagnate in the medium-term and then decline in the long-term as a result of increasing electrification and energy efficiency. On the other hand, demand growth in Developing countries will accelerate in the future due to increasing passenger and freight traffic demand, particularly in the rail subsector. Additionally, increasing urbanization rates will require significant investment in the railway sector in order to facilitate the flow of people. And policy support, such as the National Waterways Bill in India, will likely provide further strength to the sector in the coming years. In Eurasia, demand is expected to remain flat.

Marine bunkers

Marine bunkers oil demand is closely correlated with economic and trade activity. Demand has remained relatively constant in the years since the global financial crisis at around 3.8 mb/d. Furthermore, higher oil prices had the effect of carriers increasingly using slow steaming as a way of improving efficiency. However, the picture changed in 2015. Sectoral oil demand increased to 3.9 mb/d in 2015 on the back of lower fuel prices, economic recovery and increasing traffic. Residual fuel is the most consumed product in this sector. However, as mentioned later, gasoil/diesel is expected to become a widely used product in marine bunkers.

Demand for maritime transport services showed positive signs in 2014. The volume of world seaborne shipments expanded by 3.4% in 2014, reaching 9.8 billion tonnes (bt), up from the 9.5 bt in 2013 that was reported in last year's outlook. While tanker cargo remained roughly constant, main bulks (iron ore, grain, coal, bauxite/alumina and phosphate rock) and other dry cargo (containerized trade, forest products and others) increased notably. Looking ahead, it remains to be seen how the slowdown and the restructuring of the Chinese economy will affect the demand for maritime services in the future.

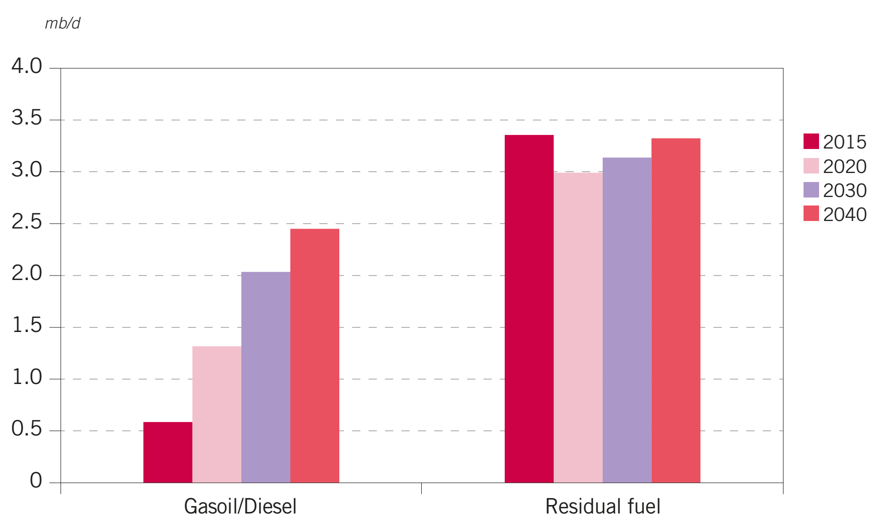
Regional marine bunkers demand is highly concentrated in the most important bunkering ports. Singapore is the largest bunkering port in the world. After three years of stagnant bunker sales, in 2015 a record high figure of 45 mt was achieved. Preliminary data for 2016 confirms this positive trend. In fact, in the first quarter of this year 11.8 mt were sold, 11% higher than in the first quarter of 2015. The same trend has been observed in the other two most important bunkering ports, Fujairah (UAE) and Rotterdam (The Netherlands).

Table 3.9
Oil demand in marine bunkers in the Reference Case

mb/d

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	0.6	0.5	0.6	0.6	0.6	0.6	0.0
OECD Europe	0.8	0.8	0.8	0.8	0.7	0.7	–0.1
OECD Asia Oceania	0.2	0.2	0.2	0.2	0.2	0.2	–0.1
OECD	**1.6**	**1.6**	**1.6**	**1.6**	**1.5**	**1.5**	**–0.1**
Latin America	0.3	0.3	0.4	0.4	0.5	0.5	0.3
Middle East & Africa	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
China	0.2	0.3	0.3	0.4	0.4	0.5	0.3
Other Asia	1.1	1.2	1.4	1.6	1.8	1.9	0.8
OPEC	0.4	0.5	0.6	0.7	0.8	0.8	0.4
Developing countries	**2.2**	**2.5**	**3.0**	**3.4**	**3.7**	**4.0**	**1.9**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.1	0.1	0.2	0.2	0.2	0.2	0.1
Eurasia	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.1**
World	**3.9**	**4.3**	**4.8**	**5.2**	**5.5**	**5.8**	**1.8**

Figure 3.18
Product demand in the marine bunkers sector



From the infrastructural viewpoint, the most important news has been the finalization of the expansion of the Panama Canal. Even though Panama falls behind the top three bunkering ports in terms of sales, its relative size is significant. In 2015, total bunker sales increased to 3.5 mt, up from 2.9 mt in 2014. The project was inaugurated in June 2016 after several delays. It involved the widening and deepening of the existing locks and the building of a third set of locks in a new lane. This will double its capacity and allow traffic for ships with capacity up to 14,000 TEUs (twenty foot equivalent unit). While the impact of the project on traffic flowing through the canal is still uncertain, it will most likely be positive. Furthermore, according to official sources, marine bunker sales are expected to increase by 10% by 2025 as a result of increasing traffic.

However, the main development in the sector continues to be the implementation of the IMO regulations. As from January 2015, sulphur content is limited to 0.1% in Emission Control Areas (ECAs). Looking to the future, there is still a significant degree of uncertainty regarding the implementation of reducing sulphur content in non-ECAs from 3.5% to 0.5%. Initially, it was planned to take place in 2020. However, it could be delayed. In any case, ship owners will have to choose between switching to diesel/gasoil or installing scrubbers to be able to continue using residual fuel oil, which implies additional costs.

Recent data from the main bunkering ports suggest that switching to diesel/gasoil will be the preferred option. According to the Port of Rotterdam Authority, the sales of low sulphur diesel/gasoil increased from 0.7 million m^3 in 2014 to 1.8 million m^3 in 2015. At the same time, fuel oil sales declined from 9.8 million m^3 to 8.7 million m^3 over the same period. Similarly, sales of low sulphur diesel/gasoil in Singapore hit a record high level in March 2016 at 87,500 tonnes.

Marine bunker demand is expected to increase by 1.8 mb/d over the forecast period. However, growth is not equal in terms of timeframes and regions. In the medium-term, sectoral demand is expected to increase at an average rate of 1.9% p.a. as traffic increases. In the long-term, efficiency improvements, together with a marginal penetration of LNG, will impact demand growth. It is expected that growth will decelerate to average 1.5% p.a. between 2021 and 2040. Global demand is estimated to reach 5.8 mb/d in 2040.

Regionally, demand in the OECD region will remain relatively flat in the medium-term, before declining marginally in the long-term. Strong growth is expected in Developing countries, particularly in Other Asia, where most of the sectoral demand is located. Growth in China and OPEC is also significant.

From the product point of view, gasoil/diesel is expected to increase significantly from 0.6 mb/d in 2015 to 2.5 mb/d in 2040. Its share in the sectoral demand is also set to jump from 16% to 42%. In contrast, the outlook for residual fuel use is gloomier. IMO regulations will imply that demand for this product will decline from 3.3 mb/d in 2015 to less than 3 mb/d in 2020, before resuming growth to reach 3.3 mb/d by 2040.

Petrochemicals

The demand for petrochemicals products across regions has exhibited patterns reflecting market maturity and size. Mature markets are often characterized by saturation as they have limited potential for further growth. This is clearly depicted for the

OECD region where demand, in established mature markets like Japan, Europe and North America, is growing at a very low rate (substantially lower than GDP). Major players in these regions are also looking more globally and seeking opportunities in dynamic markets elsewhere.

One of the important elements of naphtha and liquids cracking, in general, is the large portfolio of derivatives that create opportunities for synergies among downstream products in order to optimize cost advantages. A key trend for petrochemicals, and an important element for its success, has been the continuing emergence of industrial clusters. Clustering activity has been in place for a while in Europe, the US and China, and more recently in the Middle East. Clusters provide the opportunity to harmoniously develop a platform of infrastructures to gather the polymer, plastics and manufacturing industries, as well as related services, to create the best competing conditions for an export-oriented industrial sector or a large domestic consuming market. It should be noted that India and Russia have put clustering on their agenda priority list as they look to further develop their petrochemical industries. It is important to underscore that supportive government actions are often needed to implement and incentivize the clusters and R&D activities.

In view of the harsh competition facing major players today, many have started a migration to low-cost regions in a 'go-to market' approach. This is especially the case for players in mature markets like Europe and the OECD Asia Oceania

Table 3.10
Oil demand in the petrochemical sector in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	2.9	2.9	3.0	3.0	3.0	3.1	0.2
OECD Europe	1.8	1.8	1.7	1.7	1.7	1.7	–0.1
OECD Asia Oceania	2.0	2.0	2.0	2.0	2.0	2.1	0.1
OECD	**6.6**	**6.7**	**6.7**	**6.7**	**6.8**	**6.9**	**0.3**
Latin America	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Middle East & Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.1
India	0.3	0.4	0.5	0.6	0.7	0.7	0.4
China	1.3	1.3	1.4	1.5	1.6	1.7	0.5
Other Asia	1.1	1.2	1.4	1.6	1.7	1.8	0.7
OPEC	1.3	1.6	1.8	2.1	2.4	2.7	1.4
Developing countries	**4.4**	**4.9**	**5.6**	**6.2**	**6.9**	**7.5**	**3.1**
Russia	0.9	0.9	0.9	0.9	0.9	0.9	0.0
Other Eurasia	0.0	0.0	0.0	0.0	0.1	0.1	0.0
Eurasia	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**0.1**
World	**11.9**	**12.5**	**13.2**	**13.9**	**14.6**	**15.3**	**3.4**

that rely on product differentiation capabilities and know-how to help keep their long-standing advantages.

Attracting foreign investment has thus become a crucial element for the developing world to enable this type of clustering approach. The focus is on how best to offer favourable conditions for foreign direct investment (FDI), specifically through the development of a stable legal framework and business climate. From a global perspective, China's petrochemical market, thanks to its size, its recent growth and its potential, is probably the best example to consider for the diversification it has achieved in terms of raw material sourcing, as well as the implications for its end-products.

Looking at the current market situation, it is evident that oil demand for petrochemicals may benefit from a prolonged lower crude oil price, with the subsequent emergence of lower feedstock costs that trigger added value opportunities along the polymers/plastics value chain. For example, the low crude oil price environment could make naphtha-based polymers production more competitive, potentially slow China's coal-to-olefins/methanol-to-olefins (CTO/MTO) project developments and even contribute to a repositioning of naphtha in the market.

Being at the crossroads between the oil and gas businesses, the petrochemical industry has also been impacted by the recent natural gas surge from the US shale gas boom. This has provided an extra boost for the traditional petrochemical industry, and is probably the main challenge and opportunity in the upcoming years. It clearly has the potential to be a game changer for the petrochemical sector. The availability of cheap ethane has put a lot of pressure on the US naphtha crackers market and its derivatives, and the phenomenon is now diffusing into Europe. It may also take on a global dimension if ethane becomes a large traded commodity. Around the world, China is planning to construct its first ethane-based cracker. The cracker will use mainly cheap ethane and propane supplied from North America. India, South Korea and Japan, whose crackers already rely on naphtha, are also looking to improve the flexibility of their crackers. Nevertheless, the global spread of shale gas remains subject to environmental performance improvements in hydraulic fracking, with the environmental debate ongoing both in, and outside, the US.

From an environmental standpoint, petrochemical applications still face the problems of biodegradability, as well as the need to adapt to any new climate change rules. For decades, petrochemical plants have been implementing energy efficiency measures and cogeneration solutions as best practices to improve their environmental footprint. Today, it is evident that there is also a need to consider other CO_2 mitigation options, such as the integration of CCS into their portfolio.

Total oil consumed in the petrochemical sector is expected to increase from 11.9 mb/d in 2015 to 15.5 mb/d in 2040. While oil demand growth in the OECD is expected to increase marginally, mainly in OECD America, strong growth is expected in Developing countries with an additional 3.3 mb/d by 2040. Naphtha will continue to be the dominant product in the sector. However, strong growth is also foreseen for ethane/LPG.

'Other industry'

The 'other industry' sector includes the energy-intensive production industries of iron, steel, glass and cement together with construction and mining activities.

In 2015, this sector consumed 12.6 mb/d of oil, with the OECD accounting for 5.1 mb/d. Within the Developing countries grouping in 2015, demand is concentrated in China (2.2 mb/d) and in OPEC (1.6 mb/d). In Eurasia, demand in 2015 totalled 0.9 mb/d. From the product point of view almost two-thirds of the sectoral demand is satisfied with 'other products', particularly those used in road construction. Gasoil/diesel (2.6 mb/d), residual fuel (1.4 mb/d) and ethane/LPG (0.7 mb/d) account for the rest.

The use of oil in the 'other industry' sector is closely linked to economic growth and economic structures. Normally, as a country starts developing the industry sector expands and its share in the economy increases. However, as a country moves further down the development path and income levels increase, the share of the industry sector tends to decline, in favour of the service sector. This is clearly seen in the recent economic history of China. In 1990, the industry sector accounted for 41% of its GDP, and reached a peak of 48% in 2006. Since then, however, China's expansion has become more service-oriented and the share of industry dropped to 43% in 2014. It should be highlighted that the picture is rather different for the other large fast growing economy, India. Its share of industry in GDP stayed roughly constant in the 1990s at around 26%. However, since then industry has continually gained weight in the economy, reaching over 30% in 2014.

Another important element that shapes sectoral demand is road construction and maintenance. In the OECD, the road network is already developed and no

Table 3.11
Oil demand in 'other industry' in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	2.7	2.8	2.8	2.7	2.6	2.6	–0.2
OECD Europe	1.5	1.4	1.3	1.3	1.2	1.2	–0.2
OECD Asia Oceania	0.9	0.8	0.7	0.7	0.6	0.6	–0.3
OECD	**5.1**	**5.0**	**4.9**	**4.7**	**4.5**	**4.4**	–0.7
Latin America	0.9	0.9	0.9	0.9	1.0	1.0	0.2
Middle East & Africa	0.6	0.6	0.6	0.7	0.7	0.7	0.2
India	0.8	1.0	1.2	1.4	1.5	1.6	0.7
China	2.2	2.3	2.4	2.5	2.5	2.6	0.4
Other Asia	0.7	0.7	0.8	0.8	0.8	0.8	0.1
OPEC	1.5	1.6	1.7	1.7	1.8	1.8	0.2
Developing countries	**6.6**	**7.2**	**7.6**	**8.0**	**8.3**	**8.4**	**1.8**
Russia	0.5	0.5	0.4	0.4	0.4	0.4	0.0
Other Eurasia	0.4	0.4	0.5	0.5	0.5	0.5	0.1
Eurasia	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**0.1**
World	**12.6**	**13.1**	**13.4**	**13.6**	**13.7**	**13.7**	**1.2**

significant expansion has been seen in the last few years. Specifically for the US, the country with the largest road network, the total number of kilometres of roads has stayed constant at around 6.5 million km since 2008. Moreover, the percentage of paved roads has not changed significantly. For other OECD countries with large networks, such as Canada, France, Spain and Germany, the same is also true. Therefore, oil is mostly consumed for road maintenance.

Road construction, which is more oil intensive, has exhibited a clear upward trend in the non-OECD region. In India, the country with the second largest road network, the number of kilometres has increased from 4.1 million km in 2008 to 5.2 million km in 2013. Moreover, there has also been an increase in the percentage of paved roads in the overall network, from 50% to 55%. In China, the road network increased from 3.7 million km to 4.3 million km over the same period, with paved roads accounting for 68% in 2013, up from 53% in 2008.

In the future, sectoral demand is expected to increase by 1.2 mb/d to reach 13.7 mb/d by 2040, with 'other products' accounting for 9 mb/d by 2040. However, it is important to mention that growth will decelerate from an average of 0.8% p.a. in the medium-term to 0.3% p.a. in the long-term. In the OECD region, demand is expected to decline as efficiency gains advance, competition from gas increases, and due to the decreasing weight of the industry in the region's economy. In Developing countries, demand will increase significantly, but it will also decelerate. Interestingly, as the Chinese economy slows and moves away from an industry-oriented growth path towards a more service-driven economy, sectoral growth is constrained. On the contrary, in India, in line with the observed increasing weight of the industrial sector in its economy, sectoral oil demand will almost double.

Residential/commercial/agriculture

In 2015, sectoral demand in the residential/commercial/agriculture sector totalled 10.2 mb/d, which represents 11% of overall demand. OECD demand accounted for 4.4 mb/d in 2015, while in Developing countries the figure was 5.2 mb/d. Demand in Eurasia in this sector is marginal. In terms of demand by product, most of the demand is satisfied by two products: ethane/LPG (4.2 mb/d), particularly in the residential subsector as a fuel for cooking, and gasoil/diesel (4.3 mb/d) for heating. Domestic kerosene (0.9 mb/d), other products (0.3 mb/d) and residual fuel (0.2 mb/d) are also consumed in this sector.

Sectoral demand has been impacted, and will continue to be impacted by significant regional trends. In the OECD, oil has historically faced strong competition from gas and, therefore, a clear downward trend has been observed. While in the 1970s sectoral demand averaged 8.4 mb/d, it has only averaged 4.8 mb/d over the last ten years. Although this downward trend will continue, it is anticipated that the decline will decelerate. As there is limited scope for the further substitution of oil with gas in this region, declining oil demand will be mostly driven by efficiency gains, such as better insulation, efficiency certificates and standards.

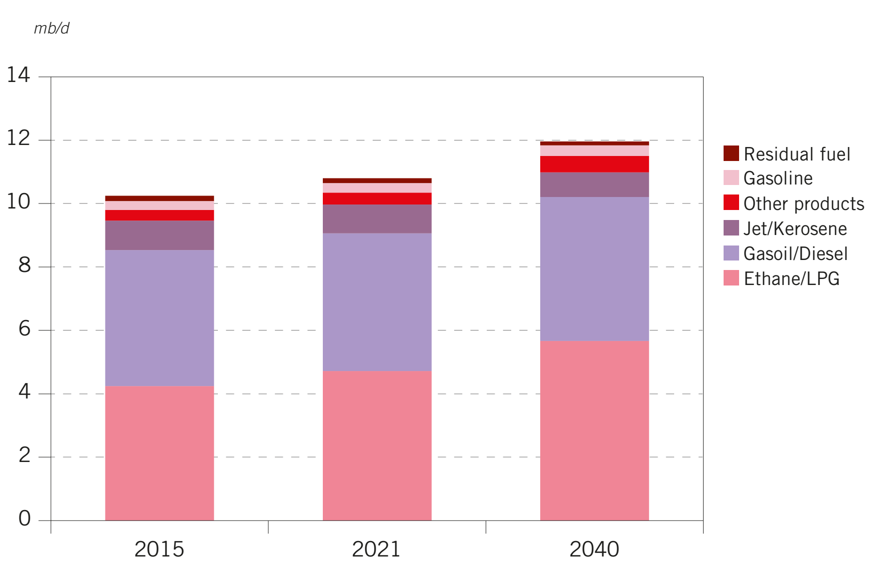
In Developing countries, increasing income levels coupled with rising urbanization levels have enabled a switch away from traditional fuels for cooking and heating such as wood, dung or crop residues to commercial fuels, particularly oil. However, billions still remain without access to commercial fuels. The sectoral use of oil per capita in the OECD region in 2015 was 1.26 barrels, while in Developing countries

Table 3.12
Oil demand in residential/commercial/agriculture in the Reference Case

mb/d

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	1.7	1.7	1.7	1.5	1.4	1.3	–0.4
OECD Europe	1.7	1.6	1.5	1.4	1.4	1.3	–0.4
OECD Asia Oceania	1.0	0.9	0.8	0.8	0.7	0.6	–0.4
OECD	**4.4**	**4.3**	**4.0**	**3.7**	**3.5**	**3.2**	**–1.2**
Latin America	0.7	0.7	0.7	0.8	0.9	1.1	0.4
Middle East & Africa	0.6	0.7	0.7	0.8	0.9	0.9	0.3
India	0.9	1.1	1.3	1.5	1.6	1.7	0.7
China	1.6	1.8	2.0	2.2	2.5	2.8	1.2
Other Asia	0.5	0.5	0.6	0.6	0.6	0.6	0.1
OPEC	0.9	1.0	1.0	1.0	1.0	1.0	0.1
Developing countries	**5.2**	**5.8**	**6.4**	**7.0**	**7.6**	**8.1**	**2.9**
Russia	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Other Eurasia	0.3	0.3	0.4	0.4	0.4	0.4	0.1
Eurasia	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.6**	**0.0**
World	**10.2**	**10.7**	**11.1**	**11.4**	**11.7**	**12.0**	**1.7**

Figure 3.19
Product demand in the residential/commercial/agriculture sector



it was only 0.33 barrels. In the Middle East & Africa it was even lower, at 0.23 barrels. This underscores the extremely important issue of energy poverty. In the future it is expected that this gap will close as policymakers around the globe increasingly tackle the problem of energy poverty and many more millions of people gain access to reliable and affordable energy.

The long-term sectoral demand outlook shows that demand will increase by 1.7 mb/d between 2015 and 2040, reaching 12 mb/d at the end of the period. While in the OECD demand will continue to decline and Eurasia will stay roughly constant, strong growth is foreseen in Developing countries with an additional 2.9 mb/d, with China (1.2 mb/d) and India (0.7 mb/d) the main contributors during the forecast period. From the product viewpoint, it is not surprising that the use of ethane/LPG is expected to account for most of the increase in sectoral demand, reaching 5.7 mb/d by 2040. This fuel category competes directly with traditional fuels for cooking. The use of gasoil/diesel is expected to increase marginally.

Electricity generation

Globally, oil is used only marginally for electricity generation. The sector represents less than 6% of total demand with 5.3 mb/d in 2015. In some regions, oil is a common fuel to produce electricity. Specifically, the main countries with a high reliance on oil for electricity generation are OPEC Member Countries with a total sectoral demand in 2015 of 2.1 mb/d. The high oil consumption in this sector is linked to high year-round regional temperatures in many OPEC countries and energy pricing mechanisms. Global sectoral demand is skewed towards residual fuel with a relative share of 46%.

Increasing competition from coal and gas, but also from renewables, is anticipated to reduce the use of oil for electricity generation. Demand is expected to shrink by 1.3 mb/d by 2040 to reach 4 mb/d. While the use of gasoil/diesel is expected to remain relatively stable at around 1.5 mb/d, most of the decline will be in the use of residual fuel, going from 2.4 mb/d in 2015 to 1.6 mb/d in 2040, and other products from 1.3 mb/d to 1 mb/d.

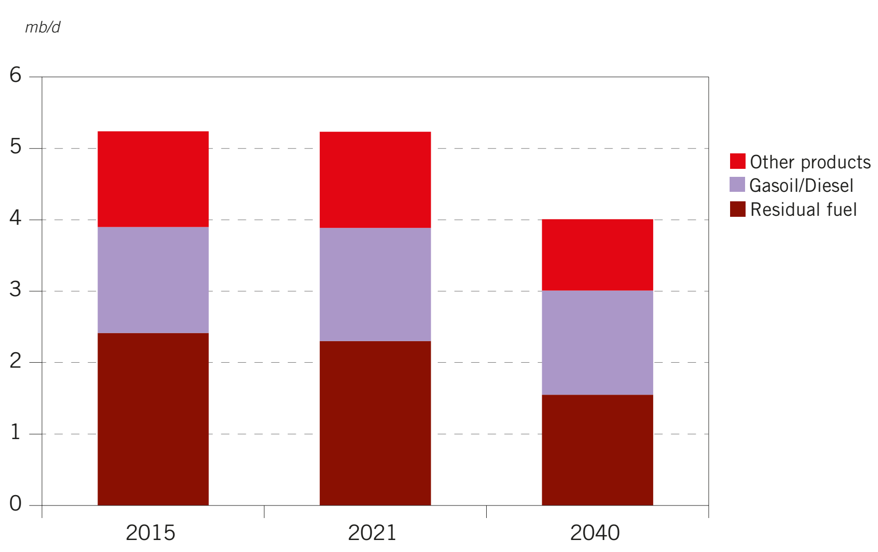
Sectoral oil demand in the OECD is expected to decline by 0.8 mb/d between 2015 and 2040 with a strong reduction in OECD Asia Oceania. This is due to the fact Japan is in the process of restarting its nuclear power plants after they were shutdown following the 2011 Fukushima nuclear disaster. The shutdown had seen an increase in the production of electricity from combustible fossils fuels, but this trend is now in reverse. In Developing countries, oil use is estimated to decline by 0.4 mb/d and the downward trend is common to every region except for India and the Middle East & Africa. In these two regions, the prevalence of energy poverty remains high. As increasing efforts by policymakers to eradicate this problem are taken on board, the use of oil as a fuel to generate electricity is anticipated to increase. Sectoral oil use in OPEC is expected to decline by 0.5 mb/d as increasing efforts to promote renewables and nuclear will limit the role of oil in the electricity generation.

However, the expected declining use of oil in the electricity generation sector might be subject to some uncertainty. Findings from the OPEC Secretariat's recently commissioned study for oil to regain market share in electricity generation foresees the potential for generating electricity inside refineries from low value products,

Table 3.13
Oil demand in electricity generation in the Reference Case *mb/d*

	2015	2020	2025	2030	2035	2040	Growth 2015–2040
OECD America	0.5	0.4	0.4	0.3	0.2	0.2	–0.3
OECD Europe	0.3	0.3	0.2	0.2	0.2	0.2	–0.1
OECD Asia Oceania	0.6	0.5	0.4	0.3	0.2	0.2	–0.4
OECD	**1.3**	**1.1**	**0.9**	**0.8**	**0.6**	**0.5**	**–0.8**
Latin America	0.5	0.5	0.5	0.5	0.5	0.5	0.0
Middle East & Africa	0.5	0.5	0.6	0.7	0.7	0.7	0.2
India	0.2	0.2	0.2	0.2	0.3	0.3	0.1
China	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Asia	0.4	0.3	0.3	0.3	0.3	0.2	–0.2
OPEC	2.1	2.2	2.1	2.1	1.9	1.6	–0.5
Developing countries	**3.7**	**3.9**	**3.9**	**3.9**	**3.7**	**3.3**	**–0.4**
Russia	0.2	0.2	0.2	0.2	0.2	0.2	–0.1
Other Eurasia	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Eurasia	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**–0.1**
World	**5.3**	**5.3**	**5.1**	**4.9**	**4.5**	**4.0**	**–1.3**

Figure 3.20
Product demand in the electricity generation sector



essentially petcoke from refinery conversion units. However, the overall impact at a global level would be limited. The study does not envisage major changes to the share of oil in the projected foreseeable future for oil-linked decentralized power options, such as reciprocating engines, essentially due to the high fuel cost, and for micro-turbines and stationary fuel cells, due to their long-term foreseeable high overnight investment costs.

Liquids supply

Key takeaways

In the medium-term:

- The effect of lower oil prices on non-OPEC supply is still being played out. This presents some uncertainty to the outlook. However, this year's projections are consistently lower than last year's outlook.
- Due to lower oil prices, non-OPEC total liquids supply shrinks by about 1 mb/d between 2015 and 2017, from 56.9 mb/d to 55.9 mb/d. The downward revision compared to the WOO 2015 reaches a maximum of 1.4 mb/d in 2019.
- By 2021, non-OPEC liquids supply reaches 58.6 mb/d. Of this total, the OECD contributes 44% (25.6 mb/d), non-OPEC developing countries contribute 29% (16.9 mb/d) and Eurasia's share is 24% (13.8 mb/d). The balance of 2.3 mb/d comes from processing gains.
- Due to the faster response of tight oil to price changes, supply from the US exhibits the highest annual growth over the medium-term but also the largest contraction in 2016. North America tight crude supply grows from 4.1 mb/d in 2017 to 4.8 mb/d in 2021 – a downward revision of 0.6 mb/d in 2017 and 0.4 m/d in 2021, compared to the WOO 2015.
- There is an upward revision of 2.3 mb/d in the demand for OPEC crude in 2021, compared to last year's outlook. OPEC crude supply rises by 1.7 mb/d, from 32 mb/d in 2015 to 33.7 mb/d in 2019. It then remains almost flat up to 2021.

In the long-term:

- Non-OPEC supply stays fairly flat in the long-term but declines post-2030. It reaches a maximum of 61.4 mb/d in 2027, before gradually decreasing to 58.9 mb/d in 2040.
- OECD peaks at 27.5 mb/d in 2027, while non-OPEC developing countries peak at 17.3 mb/d in 2024. Only Eurasia continues to grow over the long-term, reaching 14.7 mb/d in 2040.
- North America tight crude remains a major source of non-OPEC supply growth until 2030. It reaches a maximum of 6.3 mb/d in 2027, remains flat up to 2031, before gradually dropping off to 5.4 mb/d in 2040. Compared to the WOO 2015, this represents an upward revision of 1.2 mb/d in 2040 due to reduced costs and productivity improvements.
- OPEC crude rises over the long-term, reaching 41 mb/d in 2040. The share of OPEC crude in the total world liquids supply in 2040 is 37%, which is 3 percentage points higher than the 2015 level of 34%.

This Chapter provides the liquids supply outlook for the medium- and long-term. The medium-term considers the period up to 2021, while the long-term goes to 2040. The outlooks for non-OPEC crude and NGLs, other liquids and biofuels are assessed in detail. To address the uncertainties in the Reference Case, alternative non-OPEC supply scenarios will also be presented in this Chapter.

The medium-term Reference Case oil supply projections are developed using a large database of investment projects. The expected supply patterns combine incremental volumes from new projects with observed declines in existing fields.

The long-term outlook for non-OPEC supply is developed using estimates of the available resource base. The figures for ultimately recoverable reserves (URR) – consisting of cumulative production, proven reserves and reserves growth due to improvements in recovery rates and a re-evaluation of the amount of oil in place, plus estimates of discoveries yet to be made – are taken largely from the US Geological Survey (USGS). Estimates of URR have increased over time and this process is expected to continue due to technological developments such as horizontal, multilateral and extended reach drilling, hydraulic fracturing, intelligent completions and data integration.

It is to be noted that Gabon and Indonesia are no longer part of the non-OPEC category. Therefore, the WOO 2015 figures referred to in this Chapter have also been adjusted for comparability with this year's figures.

Medium-term outlook for liquids supply

The oil industry's reaction to the precipitous fall in oil prices in the second half of 2014 was rapid. Both upstream and downstream spending fell swiftly in 2015 and 2016. There was some recovery in prices in the first quarters of 2015 and 2016, but investor confidence is still low. The effect of lower prices on supply is still being played out and this presents some uncertainty to the outlook.

This section provides the liquids supply outlook up to 2021. It sums up crude and NGLs, other liquids and biofuels supply. The details of supply projections for each component will be discussed in the sections that follow.

The medium-term liquids supply outlook is summarized in Table 4.1. Non-OPEC total liquids supply is expected to shrink by about 1 mb/d, from 56.9 mb/d in 2015 to 55.9 mb/d in 2017, then gradually increases by about 2.7 mb/d to 58.6 mb/d in 2021. Of this overall total, OECD contributes 44% (25.6 mb/d) while non-OPEC Developing countries contribute 29% (16.9 mb/d) and Eurasia's share is 24% (13.8 mb/d). The balance of 2.3 mb/d comes from processing gains.

Figure 4.1 shows the contribution of the various supply components to the annual growth of non-OPEC liquids supply. Lower oil prices have the largest impact on non-OPEC crude supply, which is expected to decrease by about 1.1 mb/d from 2015–2017, but then grows by 1.5 mb/d between 2017 and 2021. Meanwhile, from 2015–2021, NGLs grow by 0.4 mb/d and other liquids by 1.1 mb/d.

Figure 4.2 provides the liquids supply annual growth for the various non-OPEC regions/countries. With the exception of 2017, the US & Canada shows the highest annual growth over the projection period. However, it also has the largest contraction in 2016. This illustrates the higher response to oil price changes of US tight oil output compared to other supply sources that are characterized by longer reaction times.

Table 4.1
Medium-term liquids supply outlook in the Reference Case *mb/d*

	2015	2016	2017	2018	2019	2020	2021
US & Canada	18.4	17.9	17.9	18.2	18.5	18.9	19.4
of which: tight crude	*4.9*	*4.2*	*4.1*	*4.2*	*4.3*	*4.5*	*4.8*
Mexico & Chile	2.6	2.5	2.3	2.3	2.3	2.2	2.2
OECD Europe	3.8	3.7	3.7	3.6	3.5	3.5	3.4
OECD Asia Oceania	0.5	0.4	0.4	0.5	0.5	0.6	0.6
OECD	**25.2**	**24.6**	**24.4**	**24.6**	**24.9**	**25.2**	**25.6**
Latin America	5.2	5.1	5.3	5.5	5.7	6.0	6.3
Middle East & Africa	3.4	3.3	3.4	3.5	3.6	3.6	3.6
Asia, excl. China	2.7	2.7	2.7	2.7	2.8	2.8	2.8
China	4.4	4.2	4.1	4.2	4.2	4.2	4.2
DCs, excl. OPEC	**15.7**	**15.4**	**15.5**	**15.9**	**16.2**	**16.6**	**16.9**
Russia	10.8	11.0	10.9	10.9	10.9	10.8	10.8
Other Eurasia	3.0	2.9	2.9	2.9	2.9	3.0	3.0
Eurasia	**13.8**	**13.9**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**
Processing gains	2.2	2.2	2.2	2.2	2.2	2.3	2.3
Non-OPEC	**56.9**	**56.0**	**55.9**	**56.4**	**57.1**	**57.9**	**58.6**
Crude	*42.5*	*41.5*	*41.4*	*41.6*	*42.0*	*42.5*	*42.9*
NGLs	*7.1*	*7.1*	*7.1*	*7.1*	*7.2*	*7.4*	*7.5*
of which: unconv. NGLs	*2.1*	*2.2*	*2.2*	*2.3*	*2.4*	*2.5*	*2.7*
Other liquids	*7.2*	*7.4*	*7.5*	*7.7*	*7.9*	*8.1*	*8.3*
Total OPEC supply	**38.2**	**38.9**	**39.4**	**40.0**	**40.4**	**40.6**	**40.7**
OPEC NGLs	*5.8*	*5.9*	*6.1*	*6.2*	*6.4*	*6.5*	*6.6*
*OPEC GTLs**	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*
OPEC crude	*32.0*	*32.7*	*33.0*	*33.4*	*33.7*	*33.7*	*33.7*
Stock change**	**2.1**	**0.8**	**0.0**	**0.0**	**0.2**	**0.2**	**0.2**
World supply	**95.1**	**95.0**	**95.3**	**96.4**	**97.6**	**98.5**	**99.4**

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

The impact of lower oil prices on Mexico (in the Rest of OECD category of Figure 4.2) was also high, with the country's production showing a higher contraction in 2015 than the normal decline rate over the years before the price fall (0.2 mb/d compared to 0.02 mb/d). In addition, a positive impact from the latest Energy Reform Bill has yet to be seen.

Following a slight decline in 2016, Latin America's growth, which is mainly coming from Brazil, is expected to resume in 2017 and then remain healthy up to 2021. Eurasia is the only region with positive growth in 2016, but then it is projected to stay almost flat for the rest of the period. China will continue to be

Figure 4.1
Non-OPEC liquids supply annual growth in the Reference Case

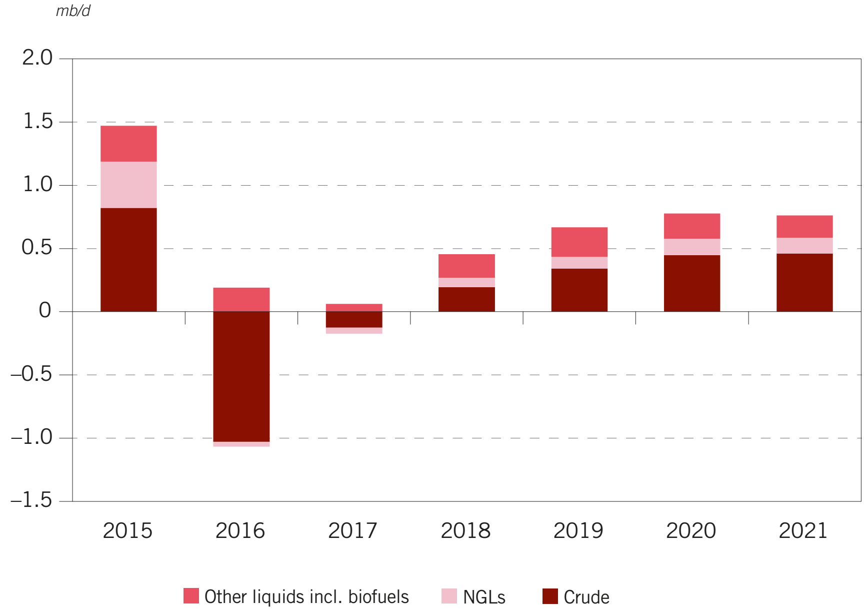
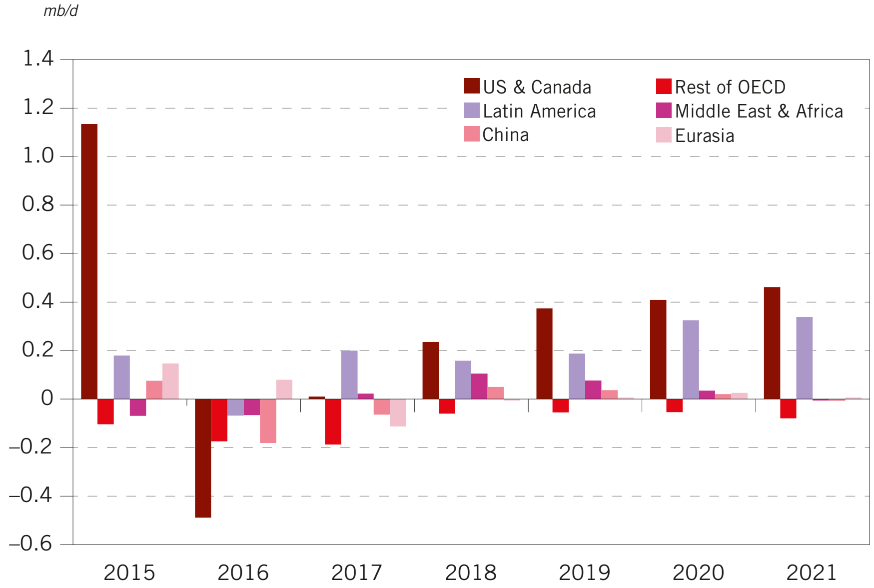


Figure 4.2
Non-OPEC liquids supply annual growth by region/country



in negative territory up to 2017 and then contribute very modest growth up to 2020.

Figure 4.3 shows the cumulative growth in non-OPEC liquids supply from 2016–2021, as well as the growth of tight crude, biofuels and other liquids, for various regions/countries. As expected and due to the assumed recovery in oil prices, the US & Canada shows the highest cumulative growth of about 1.5 mb/d over the projection period. Of that, the share of tight crude is projected to be nearly 0.6 mb/d. Other liquids grow by about 0.5 mb/d, which are mostly Canadian oil sands, while biofuels grow by 0.3 mb/d. There is little impact from lower oil prices on biofuels growth in the medium-term due to the fact that biofuels supply is predominantly determined by mandates.

Latin America's cumulative growth over the period is expected to reach 1.2 mb/d. As mentioned earlier, this will mainly come from Brazil. Mexico and OECD Europe (which is principally Norway and the UK) account for the highest contractions of about 0.3 mb/d each. Russia is also expected to show an overall contraction of over 0.1 mb/d, while China is expected to remain almost flat. The positive growth of 0.2 mb/d for the Middle East & Africa is in reality a return of lost production stemming from the political situation in Syria and Yemen.

Figure 4.4 compares this year's projections for non-OPEC liquids supply in the Reference Case to the projections of last year's outlook. As can be seen from the graph, this year's projections are consistently lower than last year's. Although non-OPEC liquids supply for 2015 is 0.6 mb/d higher than what was assumed last year, it is estimated to be 0.5 mb/d lower for 2016. The difference in projections increases to 1 mb/d in 2017, reaching a peak of 1.4 mb/d in 2019, before decreasing to 0.9 mb/d in 2021.

Figure 4.3
Growth in non-OPEC liquids supply, 2016–2021

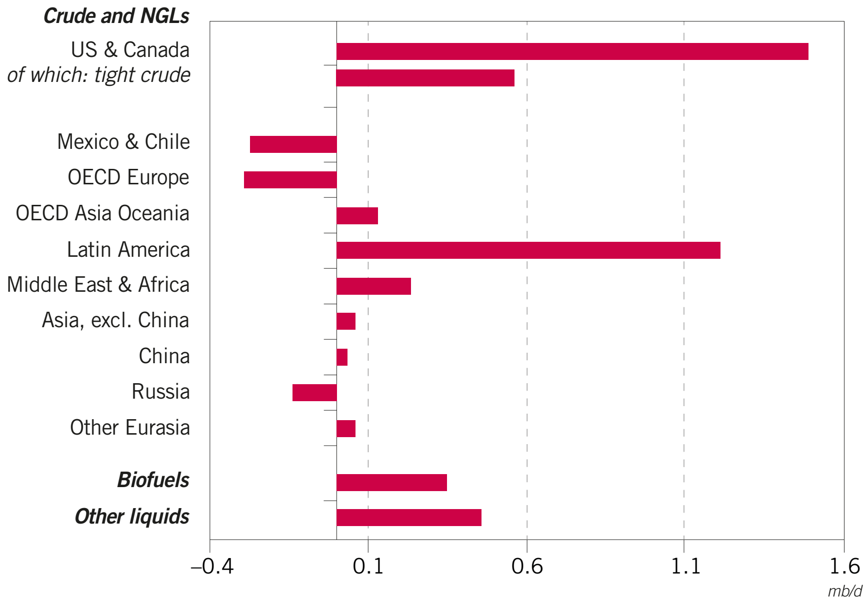


Figure 4.4
Non-OPEC liquids supply in the Reference Case, 2016 *versus* 2015 outlook

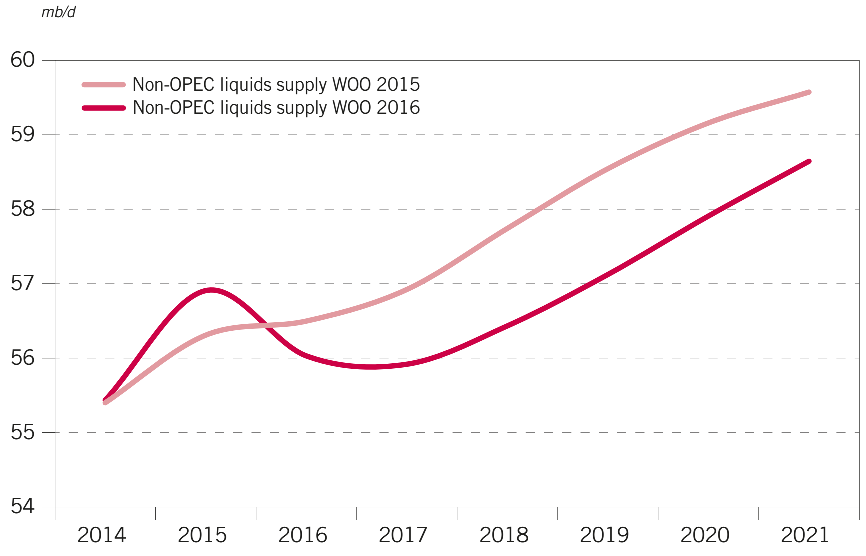
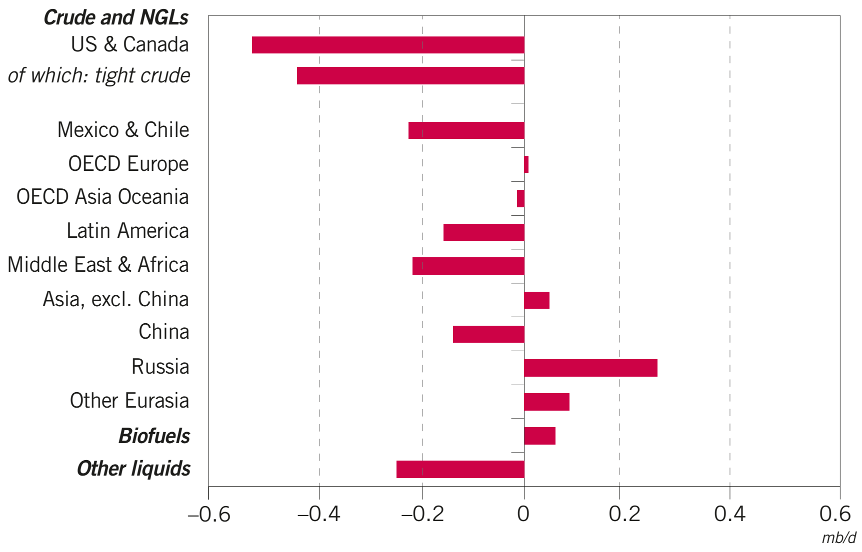


Figure 4.5
Year 2021 non-OPEC liquids supply in the Reference Case, 2016 *versus* 2015 outlook



This is a clear indication of the delayed supply response to lower oil prices. It took almost a year and a half of low oil prices before a real impact was observed in the supply. This delayed response was caused by the multi-year lead project times in conventional oil fields and by many other factors in North America's tight oil plays. Some of these factors include the hundreds of drilled, but uncompleted wells, as well as improvements in break-even prices and the prolonged support of financial institutions.

To shed more light on the main sources of these differences, Figure 4.5 shows the changes made to the projections for the year 2021 in this year's Reference Case compared to last year. The largest revision is a reduction of 0.5 mb/d in the projection for the US & Canada. This is mainly due to the reduction of 0.4 mb/d in the projections for tight crude. Another source of the reduction is in the category of other liquids, whose main component is the Canadian oil sands, which show a reduction of 0.2 mb/d. Mexico, Latin America and Middle East & Africa also contribute a reduction of 0.2 mb/d each. Finally, China's share of the reduction is about 0.14 mb/d.

By subtracting non-OPEC supply and OPEC NGLs from total world demand and the stock change, the quantity of required OPEC crude can be calculated. In the Reference Case, OPEC crude supply rises from 32 mb/d in 2015 to 33.7 mb/d in 2019. It then remains almost flat at 33.7 mb/d up to 2021, the end of the medium-term projection period. Comparing this to last year's outlook, and taking into account the fact that Gabon and Indonesia are now included in OPEC, this year's outlook sees demand for OPEC crude about 2.3 mb/d higher in 2021.

Long-term outlook for liquids supply

Moving to the long-term outlook, Table 4.2 summarizes this year's Reference Case projections up to 2040. Non-OPEC total liquids supply increases from 57.9 mb/d in 2020 to 61.1 mb/d in 2025. It reaches a maximum of 61.4 mb/d in 2027 then gradually decreases to 58.9 mb/d in 2040. Of this total, the OECD contributes 44% (25.9 mb/d) while non-OPEC Developing countries contribute 26% (15.3 mb/d) and Eurasia's share is 25% (14.7 mb/d). The balance of 5% (3 mb/d) comes from processing gains (Figure 4.6).

Focusing on specific regions and countries, US & Canada supply reaches a maximum of 21.6 mb/d in 2027 and then gradually decreases to 20.5 mb/d in 2040. Of this, tight crude supply reaches a maximum of 6.3 mb/d in 2027, remains flat up to 2031 and then gradually falls to 5.4 mb/d in 2040. Latin America's total liquids supply reaches a maximum of 6.8 mb/d in 2024, remains flat up to 2030 and then gradually drops to 6.4 mb/d in 2040. Kazakhstan's supply continues to grow to the end of the projection period reaching 2.7 mb/d in 2040. Africa's supply reaches a maximum of 2.3 mb/d in 2024.

Figure 4.7 shows the main contributors to the growth in non-OPEC liquids supply from 2016–2025 and 2025–2040. The contrast between growth and contractions for the two periods is clearly revealed, particularly for the US & Canada, Latin America (Brazil) and the Middle East & Africa.

As a result of non-OPEC supply developments, OPEC crude rises over the long-term, reaching 41 mb/d in 2040. Moreover, the share of OPEC crude in the total world liquids supply in 2040 is 37%, which is 3 percentage points higher than the 2015 levels of almost 34% (Figure 4.8).

Table 4.2
Long-term liquids supply outlook in the Reference Case *mb/d*

	2015	2016	2020	2025	2030	2035	2040
US & Canada	18.4	17.9	18.9	21.2	21.5	21.1	20.5
of which: tight crude	*4.9*	*4.2*	*4.5*	*6.0*	*6.3*	*6.0*	*5.4*
Mexico & Chile	2.6	2.5	2.2	2.1	2.0	1.9	1.9
OECD Europe	3.8	3.7	3.5	3.3	3.2	3.0	2.9
OECD Asia Oceania	0.5	0.4	0.6	0.6	0.6	0.6	0.6
OECD	**25.2**	**24.6**	**25.2**	**27.3**	**27.3**	**26.7**	**25.9**
Latin America	5.2	5.1	6.0	6.8	6.8	6.6	6.4
Middle East & Africa	3.4	3.3	3.6	3.6	3.5	3.3	3.2
Asia, excl. China	2.7	2.7	2.8	2.7	2.6	2.4	2.2
China	4.4	4.2	4.2	4.1	3.9	3.7	3.5
DCs, excl. OPEC	**15.7**	**15.4**	**16.6**	**17.3**	**16.8**	**16.0**	**15.3**
Russia	10.8	11.0	10.8	10.9	10.9	10.9	10.9
Other Eurasia	3.0	2.9	3.0	3.2	3.5	3.7	3.9
Eurasia	**13.8**	**13.9**	**13.8**	**14.1**	**14.4**	**14.6**	**14.7**
Processing gains	2.2	2.2	2.3	2.4	2.6	2.8	3.0
Non-OPEC	**56.9**	**56.0**	**57.9**	**61.1**	**61.1**	**60.1**	**58.9**
Crude	*42.5*	*41.5*	*42.5*	*44.2*	*43.4*	*41.6*	*39.6*
NGLs	*7.1*	*7.1*	*7.4*	*7.8*	*7.7*	*7.4*	*7.2*
of which: unconv. NGLs	*2.1*	*2.2*	*2.5*	*3.2*	*3.3*	*3.1*	*2.9*
Other liquids	*7.2*	*7.4*	*8.1*	*9.0*	*10.0*	*11.0*	*12.1*
Total OPEC supply	**38.2**	**38.9**	**40.6**	**41.5**	**44.6**	**47.9**	**50.7**
OPEC NGLs	*5.8*	*5.9*	*6.5*	*7.2*	*8.0*	*8.5*	*9.0*
*OPEC GTLs**	*0.3*	*0.3*	*0.4*	*0.5*	*0.6*	*0.7*	*0.8*
OPEC crude	*32.0*	*32.7*	*33.7*	*33.8*	*36.0*	*38.7*	*41.0*
Stock change**	**2.1**	**0.8**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**95.1**	**95.0**	**98.5**	**102.5**	**105.7**	**108.0**	**109.6**

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

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

Figure 4.9 shows the supply growth for the various sources of liquids over the periods 2016–2025 and 2025–2040. The greatest growth for 2016–2025 comes from tight crude, other crude and NGLs (including unconventional NGLs). From 2025–2040, conventional crudes, oil sands, NGLs and biofuels become increasingly important sources of supply growth, as opposed to tight crude, which shows a contraction over the period. A later section provides more details about tight crude prospects.

Figure 4.6
Year 2040 contributions to non-OPEC liquids supply

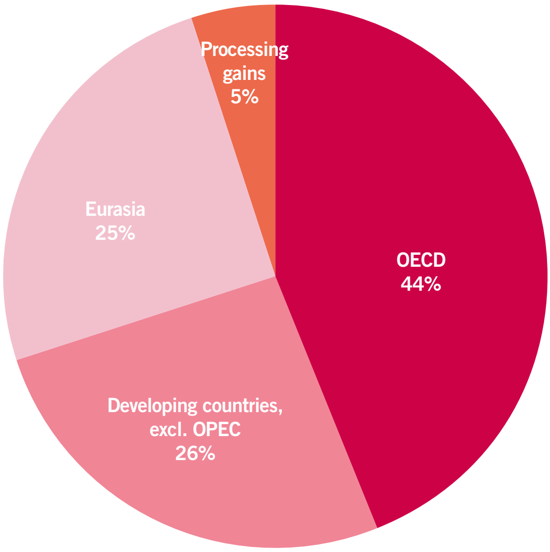


Figure 4.7
Regional growth in non-OPEC liquids supply 2016–2025 and 2025–2040

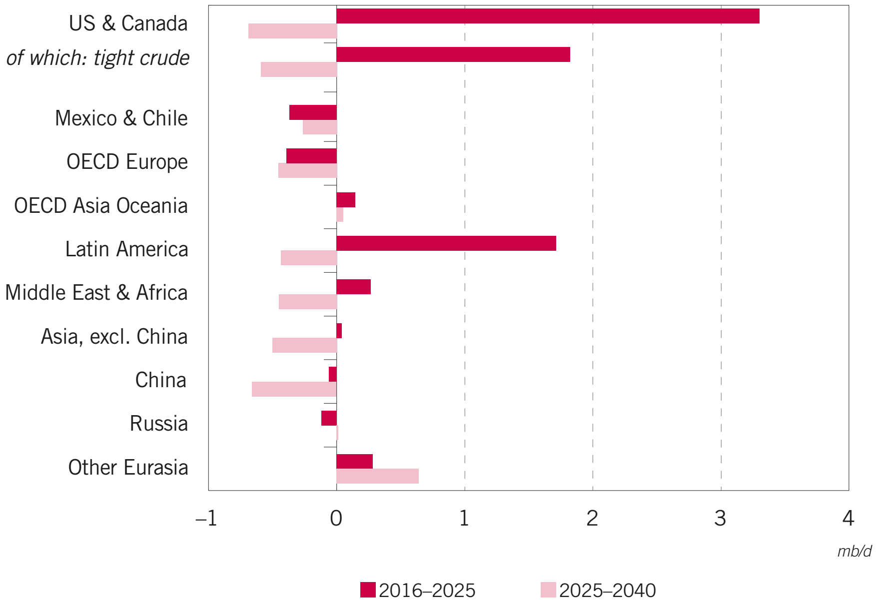


Figure 4.8
OPEC crude and other sources of liquids supply in the Reference Case

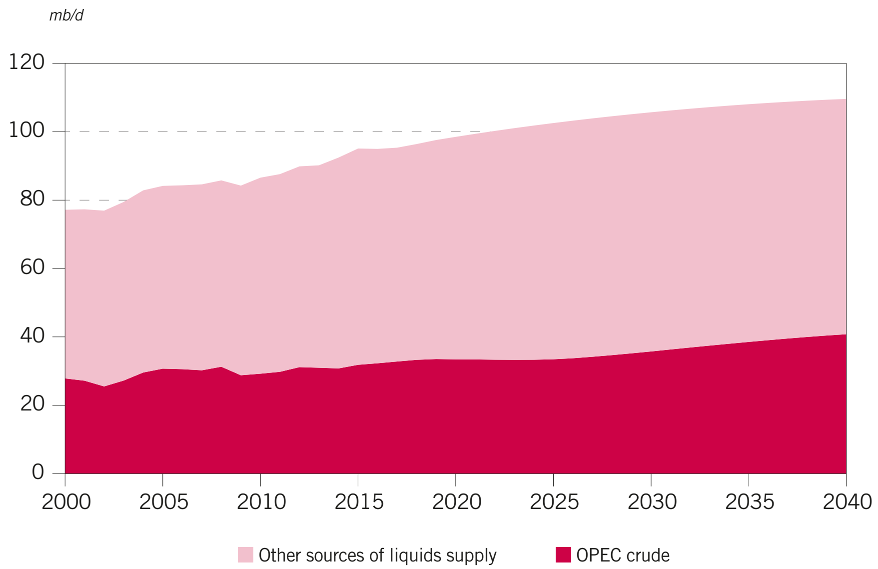
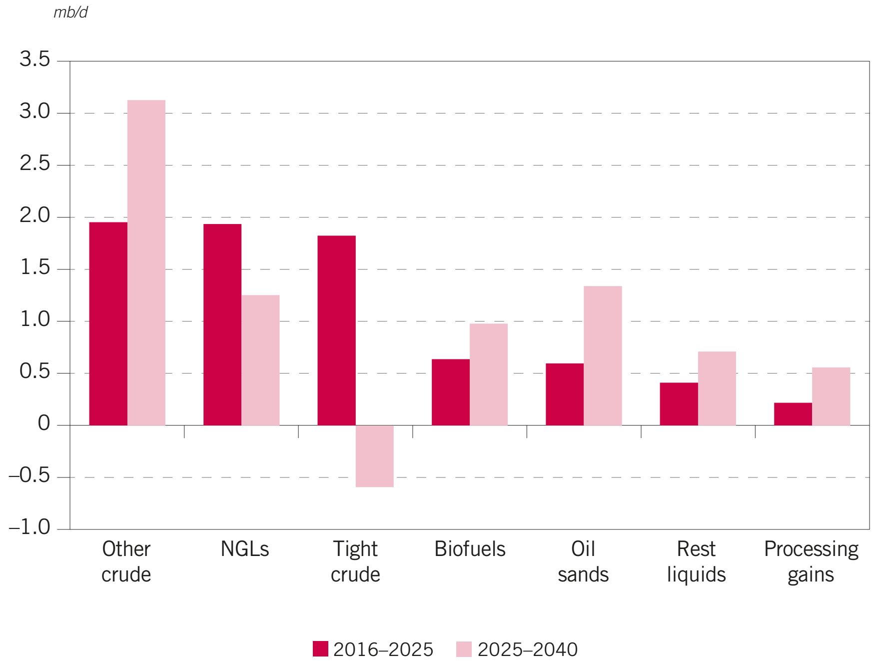


Figure 4.9
Changes in liquids supply



Medium-term outlook for crude and NGLs

This section provides the detailed prospects for non-OPEC crude and NGLs in the medium-term. As has been mentioned in the outlook for liquids supply, the impact of lower oil prices is still in transition, leading to a somewhat uncertain outlook. There has been an upward revision of 0.5 mb/d to non-OPEC crude and NGLs supply for the base year 2015, mainly due to higher than expected production from North America, Russia, Latin America and OECD Europe. Most notably, US supply is nearly 150,000 b/d higher, largely due to rising tight crude and unconventional NGLs production. Russia's 2015 production is also almost 130,000 b/d higher than anticipated by last year's outlook. Similarly, Norway and the UK showed better than expected supply with upward revisions of 30,000 b/d and 60,000 b/d, respectively (Figure 4.10).

Table 4.3 provides the detailed medium-term prospects by region/country for non-OPEC crude oil plus NGLs supply. After growing by about 1.2 mb/d in 2015, total supply in the Reference Case is projected to shrink by about 1 mb/d in 2016. It then gradually increases by about 1.6 mb/d, from 48.7 mb/d in 2016 to 50.3 mb/d in 2021.

Figure 4.11 summarizes the contribution of the various non-OPEC producing regions to the crude and NGLs supply over the medium-term. The US & Canada grow by about 1.1 mb/d, from 14.2 mb/d in 2016 to 15.3 mb/d in 2021. This growth comes mainly from tight crude and unconventional NGLs. Mexico's supply shrinks by about 0.3 mb/d over the medium-term. Similarly, supply from OECD Europe (mainly Norway and the UK) falls by a total of 0.4 mb/d by 2021. Latin America, on the other hand, shows an increase by about 1 mb/d reaching a total supply of about 5.5 mb/d in 2021, mainly from Brazil. Asia and Eurasia are projected to have a moderate decline, while Oceania and the Middle East & Africa are projected to have modest growth.

Figure 4.10
Changes to non-OPEC crude and NGLs supply in Reference Case projections for 2015 compared to WOO 2015

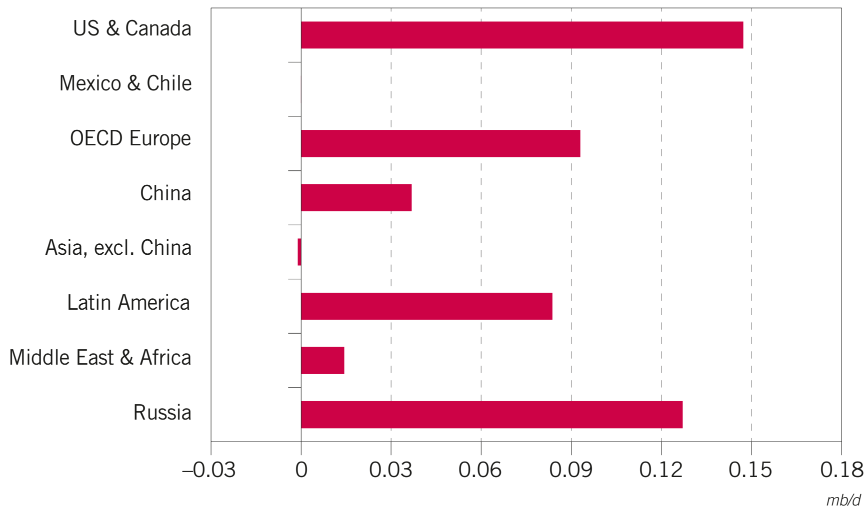


Table 4.3
Medium-term non-OPEC crude and NGLs supply outlook in the Reference Case
mb/d

	2015	2016	2017	2018	2019	2020	2021
United States	12.7	12.2	12.1	12.3	12.6	12.9	13.3
Canada	2.0	2.0	2.0	2.0	2.0	2.0	2.0
US & Canada	**14.7**	**14.2**	**14.1**	**14.3**	**14.6**	**14.9**	**15.3**
Mexico & Chile	**2.6**	**2.5**	**2.3**	**2.3**	**2.3**	**2.3**	**2.2**
Norway	1.9	2.0	1.9	1.9	1.8	1.8	1.8
United Kingdom	1.0	1.0	1.0	1.0	0.9	0.9	0.8
Denmark	0.2	0.1	0.1	0.1	0.1	0.1	0.1
OECD Europe	**3.4**	**3.3**	**3.3**	**3.2**	**3.1**	**3.1**	**3.0**
Australia	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Other Asia Oceania	0.1	0.1	0.0	0.0	0.0	0.0	0.0
OECD Asia Oceania	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**
OECD	**21.1**	**20.4**	**20.1**	**20.3**	**20.5**	**20.7**	**21.0**
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
Malaysia	0.7	0.7	0.8	0.8	0.8	0.8	0.7
Thailand	0.4	0.4	0.4	0.3	0.3	0.3	0.3
Vietnam	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Asia, excl. China	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**
Argentina	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Brazil	2.5	2.5	2.8	2.9	3.0	3.3	3.6
Colombia	1.0	0.9	0.9	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	0.3	0.3
Latin America	**4.6**	**4.5**	**4.6**	**4.8**	**4.9**	**5.2**	**5.5**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Oman	1.0	1.0	1.0	0.9	0.9	0.9	0.9
Syrian Arab Rep.	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Yemen	0.0	0.0	0.0	0.1	0.1	0.1	0.2
Middle East	**1.3**	**1.2**	**1.2**	**1.3**	**1.3**	**1.4**	**1.3**
Chad	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Congo	0.3	0.3	0.4	0.4	0.4	0.4	0.4
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
Sudan/South Sudan	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Africa other	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Africa	**2.0**	**1.9**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Middle East & Africa	**3.3**	**3.2**	**3.2**	**3.3**	**3.4**	**3.4**	**3.4**
Russia	**10.8**	**11.0**	**10.9**	**10.9**	**10.9**	**10.8**	**10.8**
Kazakhstan	1.6	1.6	1.5	1.6	1.6	1.7	1.7
Azerbaijan	0.9	0.8	0.8	0.8	0.8	0.8	0.8
Other Eurasia	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Eurasia	**13.7**	**13.8**	**13.6**	**13.6**	**13.6**	**13.7**	**13.7**
China	**4.3**	**4.1**	**4.0**	**4.0**	**4.0**	**4.0**	**3.9**
DCs, excl. OPEC	**14.7**	**14.3**	**14.4**	**14.7**	**14.9**	**15.2**	**15.5**
Total non-OPEC	**49.7**	**48.7**	**48.4**	**48.7**	**49.1**	**49.7**	**50.3**

Figure 4.11
Medium-term non-OPEC crude and NGLs supply outlook in the Reference Case

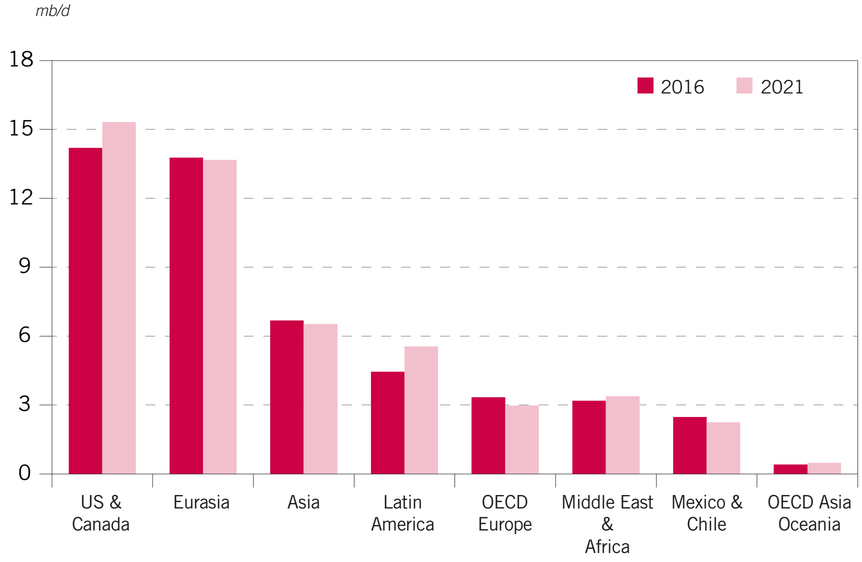


Figure 4.12
Non-OPEC crude and NGLs supply annual growth in the Reference Case

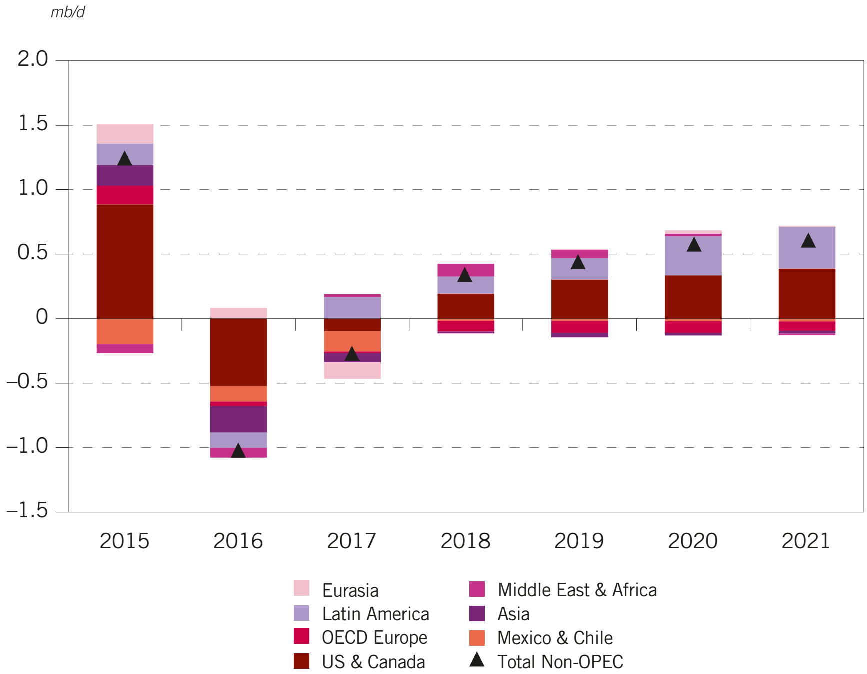


Figure 4.12 shows that overall supply growth in non-OPEC crude and NGLs was highest in 2015, when it reached above 1.2 mb/d. Growth then enters into the negative territory in 2016 and 2017, with supply shrinking by 1 mb/d and 0.3 mb/d, respectively. Due to the assumed recovery in oil prices, gradual positive growth starts again in 2018 when supply increases by about 0.3 mb/d. Between 2018 and 2021, non-OPEC crude and NGLs grow by an annual average of about 0.5 mb/d. Around 51% of the cumulative increase over the period is attributed to the US and Canada. The other major contribution comes from Latin America with a share of 38%. The balance is shared between Eurasia and the Middle East & Africa. Decreasing production over the medium-term is projected for Mexico, Europe and Asia.

What follows are brief summaries of the medium-term crude oil and NGLs supply for the main non-OPEC countries in the Reference Case. The outlook for tight crude in the medium- and long-term is also covered in a dedicated section after the section on the US, since it is the country with the highest tight oil production over the medium- and long-terms.

United States

One of the primary drivers of recent non-OPEC crude and NGLs output growth has been the US. As has been illustrated by the last five editions of the WOO, US supply growth potential was mostly the result of the development of tight oil (tight crude and unconventional NGLs), which grew by about 5.8 mb/d between 2010 and 2015, rising from 0.8 mb/d to 6.5 mb/d.

Since tight oil activities have been greatly impacted by sustained lower oil prices, it is expected that the US supply outlook over the medium-term will also be somewhat different than what was anticipated by the WOO 2015.

As is demonstrated by Figure 4.13, US crude oil and NGLs supply is expected to shrink by 0.5 mb/d in 2016 and by 140,000 b/d in 2017, and then gradually resume growth. It is expected to reach 13.3 mb/d in 2021. Compared to the WOO 2015, the difference in projections reaches a maximum of about 1.1 mb/d in 2018–2019 and the growth pattern also takes a different path (Figure 4.14).

Turning to the various components of US crude and NGLs production, Figure 4.15 provides the contribution of tight crude and unconventional NGLs, as well as the contribution of conventional crude and NGLs. As can be seen from the graph, each component has a different medium-term growth trend. While tight crude shows a decline in 2016 and 2017, conventional crude continues to grow steadily, although at a slow rate. In terms of NGLs, unconventional NGLs continue to grow steadily while conventional NGLs slowly decline.

These trends are mainly related to developments taking place in the major oil-producing areas of the US, which are principally 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.

Alaska is responsible for approximately 5% of total US crude production. After peaking in 1988 at around 2 mb/d, output has continued to decline. This is due to falling production in mature fields like Prudhoe Bay and Kuparuk. By 2015, production had fallen to around 0.5 mb/d and is projected to fall slightly to 0.4 mb/d in 2021. High levels of investment are needed in these fields to slow the decline over

Figure 4.13
US crude and NGLs production over the medium-term: 2016 *versus* 2015 outlook

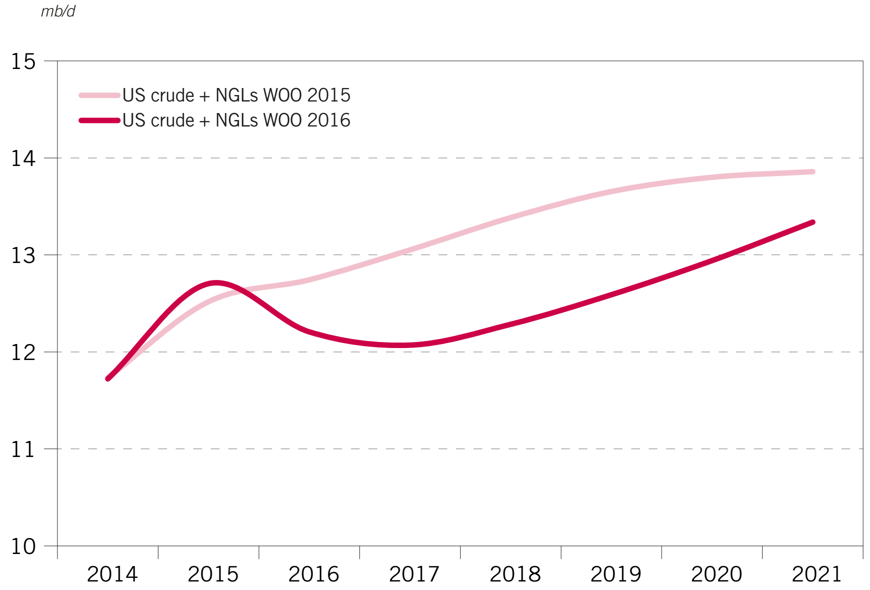


Figure 4.14
US crude and NGLs annual growth over the medium-term: 2016 *versus* 2015 outlook

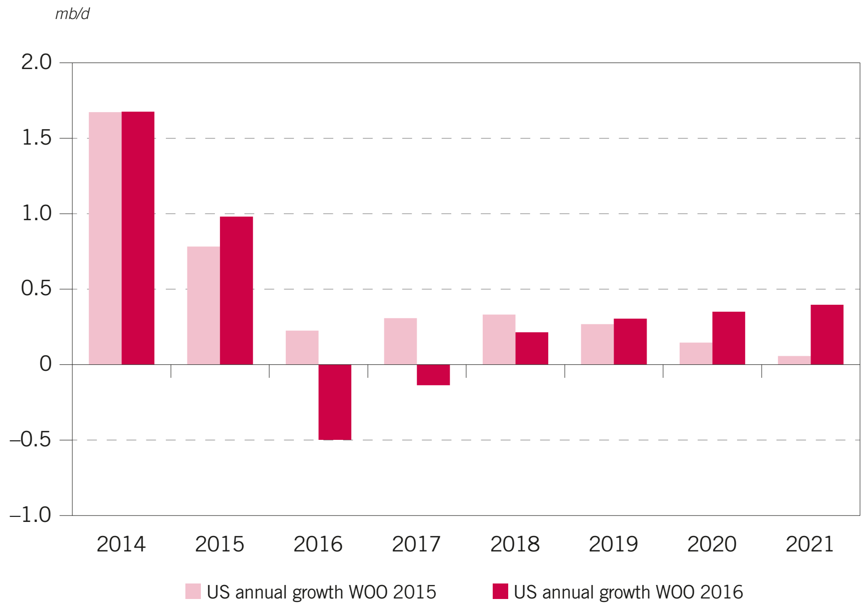
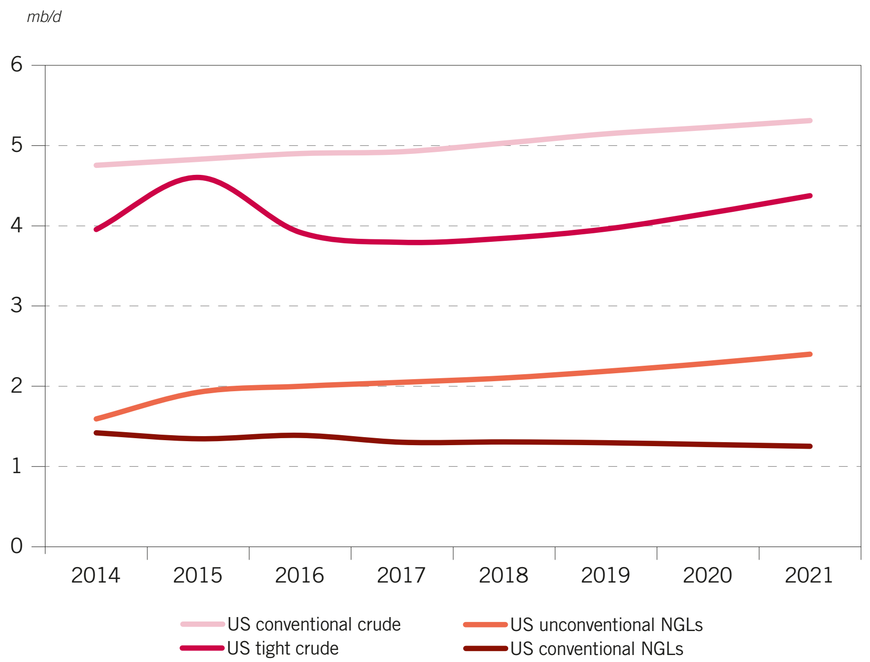


Figure 4.15
US components of crude and NGLs production over the medium-term



the medium-term. There is, however, some upside potential to the long-term outlook for Alaska from frontier plays in the Arctic National Wildlife Refuge.

In 2015, the Gulf of Mexico accounted for around 12% of total US crude production – that is, about 1.5 mb/d. Due to the start-up of previously initiated projects and despite lower oil prices, production from the Gulf of Mexico increased by about 144,000 b/d in 2015. It is expected to continue to grow in 2016 by about 136,000 b/d.

About 83% of total US crude production in 2015 came from the Lower 48 States. But due to lower oil prices and the resulting decline in tight oil production, their contribution to US production is anticipated to shrink in 2016 and 2017. It is then expected to go back to a positive growth pattern in parallel to the assumed recovery in oil prices.

More details about the medium- and long-term supply prospects for tight oil are provided in the following section.

Tight crude and unconventional NGLs supply prospects in the medium- and long-term

The production of tight crude and unconventional NGLs has been mostly confined to North America. This is expected to continue. Some output is anticipated over the long-term from Argentina's Vaca Muerta shale in the Neuquén Basin, as well as Russia's Upper Jurassic Bazhenov shale in the Western Siberian Basin. An upside supply scenario (discussed in more detail later in this Chapter) takes into account the Tarim and Junggar Basins in China, and the Burgos Basin in Mexico.

Table 4.4 and Figure 4.16 summarize the outlook for global tight crude supply in the Reference Case. After reaching a high of approximately 6.7 mb/d in 2030, production goes into a steady decline to reach 6 mb/d by 2040.

Table 4.5 and Figure 4.17 show the global unconventional NGLs supply outlook in the Reference Case. Production reaches a maximum of 3.3 mb/d in 2028 and declines gradually to 2.9 mb/d by 2040. Throughout the projection period, about 60% of unconventional NGLs output is coming from unconventional gas plays as opposed to oil plays.

Table 4.4
Global tight crude supply outlook in the Reference Case *mb/d*

	2015	2016	2020	2025	2030	2035	2040
US	4.60	3.92	4.16	5.54	5.81	5.50	4.96
Canada	0.30	0.28	0.36	0.49	0.51	0.50	0.48
Argentina	0.02	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	**4.92**	**4.23**	**4.55**	**6.25**	**6.73**	**6.55**	**6.01**

4

Figure 4.16
Global tight crude supply outlook in the Reference Case

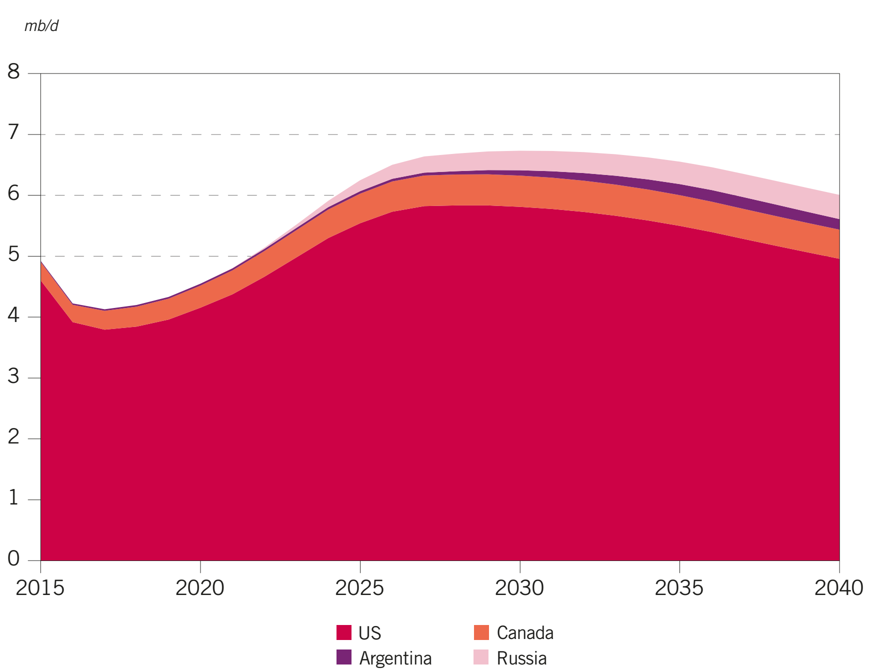
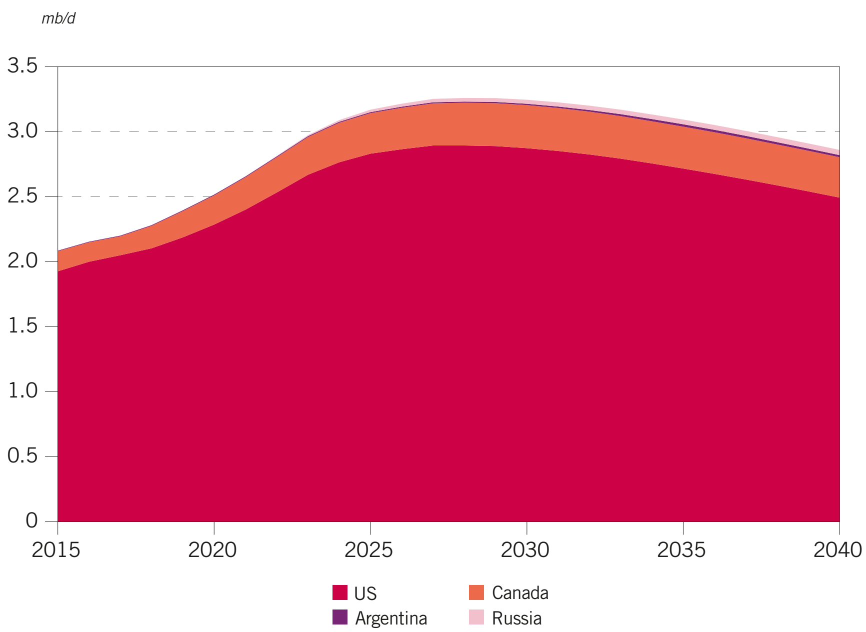


Table 4.5
Global unconventional NGLs supply outlook in the Reference Case *mb/d*

	2015	2016	2020	2025	2030	2035	2040
US	1.93	2.00	2.29	2.83	2.87	2.72	2.49
Canada	0.15	0.15	0.22	0.31	0.33	0.32	0.31
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	**2.09**	**2.15**	**2.52**	**3.17**	**3.25**	**3.09**	**2.86**

Figure 4.17
Global unconventional NGLs supply outlook in the Reference Case



The negative impacts of lower oil prices on the production levels of North American tight oil started to become apparent at the end of 2015 and continue today. Figure 4.18 shows the medium-term projections for tight crude production from North America in this year's Reference Case compared to last year's projections. As can be seen from the figure, North America's medium-term tight crude projections this year are somewhat lower. The difference compared to last year's projections is about 0.7 mb/d in 2018 and 2019.

Similarly, Figure 4.19 shows the comparisons of the medium-term projections for North America's unconventional NGLs production. It indicates lower production

Figure 4.18
North America's tight crude production over the medium-term: 2016 *versus* 2015 outlook

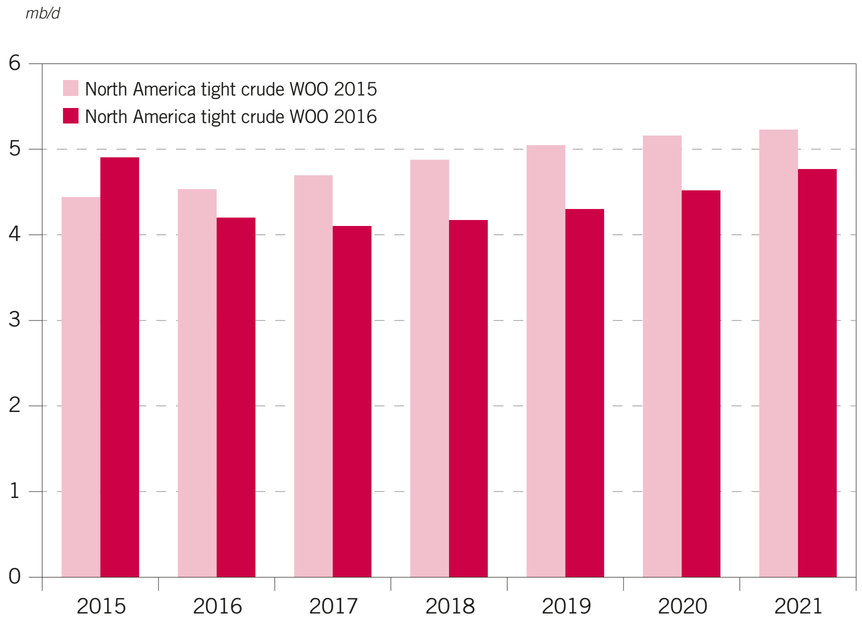
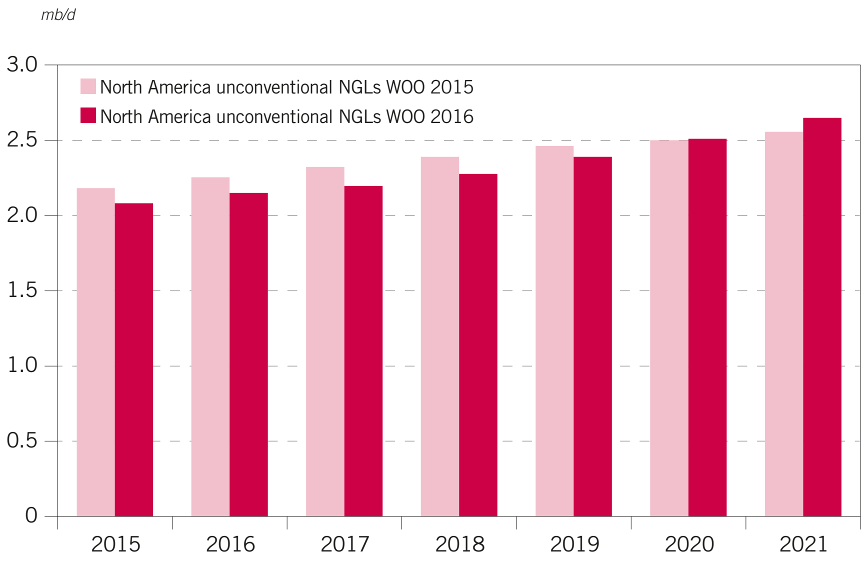


Figure 4.19
North America's unconventional NGLs production over the medium-term: 2016 *versus* 2015 outlook



in this year's WOO of about 0.1 mb/d up to 2019 and then modestly higher levels in 2020 and 2021.

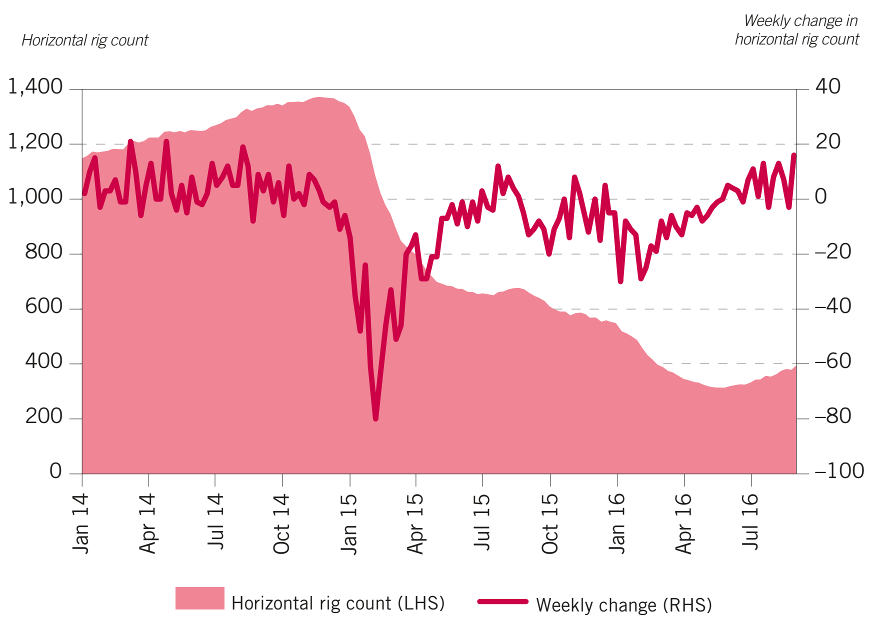
Turning to the most important indicators impacting supply prospects from tight plays – mainly the break-even prices, rig counts and the number of horizontal wells start-ups – a brief account is provided for each below.

Continuous improvement has been observed in the West Texas Intermediate (WTI) breakeven prices for the main plays. According to Rystad Energy's estimates, improvements since 2011 have been rapid; on average, costs have decreased by more than 50%. Despite this improvement, the oil price has dropped below this level, making it extremely difficult for operators to maintain their activities and sustain the same production levels. Furthermore, the steep gains in productivity are unlikely to be sustainable, though additional progress is possible. In addition, supply depends on the financial conditions available to producers and their willingness to hedge production at a price that makes tight oil production economically viable.

Figure 4.20 shows the US horizontal rig count since January 2014. The rig count in July 2016 was at 354, down from 662 one year ago. All plays have experienced a sharp rig count drop since oil prices began to fall in mid-2014. However, the rig count can be misleading and it is not by itself a good indicator. For a more reliable analysis, it should be combined with other indicators, such as the number of completed wells, well start-ups and well productivity.

Recent data show that the number of completed wells has generally been falling across all plays. Naturally, lower overall production can be expected from these plays, which explains the dramatic decrease in tight oil production over the past year.

Figure 4.20
US horizontal land rig count



The forecast for tight crude production in North America in the Reference Case is provided in Figure 4.21. In the US, production increases from about 3.9 mb/d in 2016 to peak at about 5.8 mb/d in 2028. It then gradually falls to 5 mb/d in 2040. Tight crude production from Canada reaches a plateau of about 0.5 mb/d in 2025 and then declines slightly in the period to 2040.

The long-term US tight oil production forecasts in the outlooks of 2015 and 2016 are contrasted in Figure 4.22. The 2016 outlook shows that US tight crude is expected to decline gradually over the long-term to 5 mb/d in 2040. In the

Figure 4.21
North America tight crude supply in the Reference Case

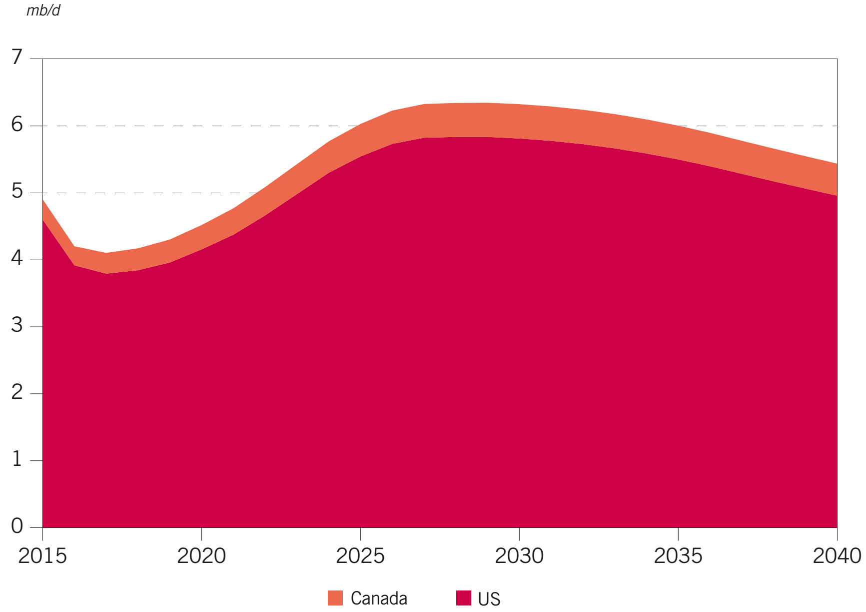
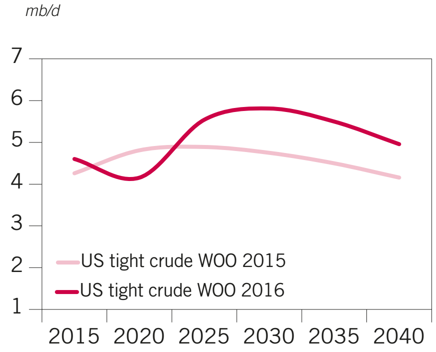
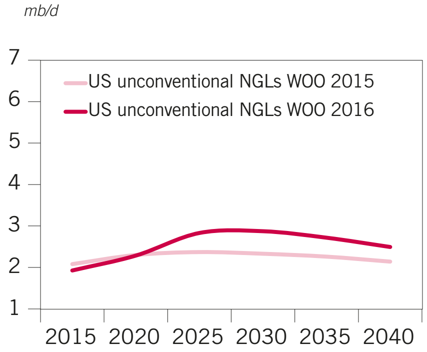


Figure 4.22
US tight oil production forecast: 2016 *versus* 2015 outlook





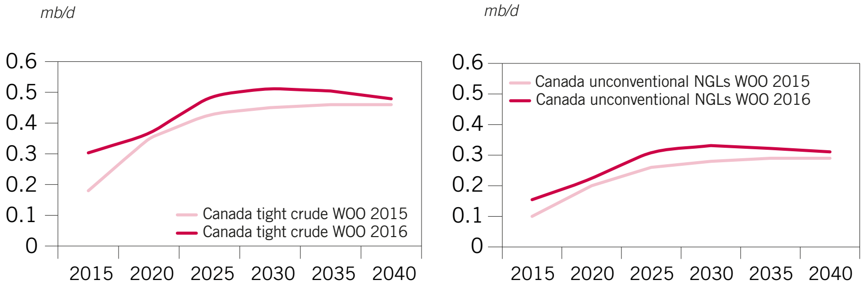
2015 outlook, it was projected at only 4.2 mb/d in 2040. In the 2016 outlook, unconventional NGLs are estimated at 2.5 mb/d in 2040, compared with 2.1 mb/d in the 2015 outlook. The higher projections in this year's outlook are due to productivity improvements in the sector, which lead to higher recovery per well. As referred to earlier, costs have also come down compared with previous years.

Canada

Due to the current lower oil price environment, Canada's production of crude and NGLs, excluding oil sands (see section on *other liquids supply*), shrank by about 100,000 b/d in 2015. This trend is expected to continue in 2016 with a further decrease of about 30,000 b/d. Mild growth of about 40,000 b/d is expected in 2017 followed by a gradual annual average decline of 10,000 b/d annually up to 2021. Most of these production changes are a result of natural declines in existing fields, as well as moderate tight oil developments over the medium-term.

Figure 4.23 provides a comparison of this year's outlook for Canadian tight oil production compared to WOO 2015. This year's Reference Case sees slower growth over the medium-term compared to last year. The updated forecast shows that Canada's tight crude production will grow by only 60,000 b/d between 2015 and 2020 compared to the anticipated growth of 170,000 b/d in last year's outlook. Over the long-term, this year's outlook shows higher production of about 60,000 b/d up to 2030 compared to last year's forecast. The difference then declines to only 20,000 b/d by 2040. In terms of unconventional NGLs projections, this year's outlook sees higher projections for both the medium- and long-term. Gradual growth is expected throughout the forecast period, reaching about 0.31 mb/d in 2040 compared to 0.29 mb/d in the WOO 2015.

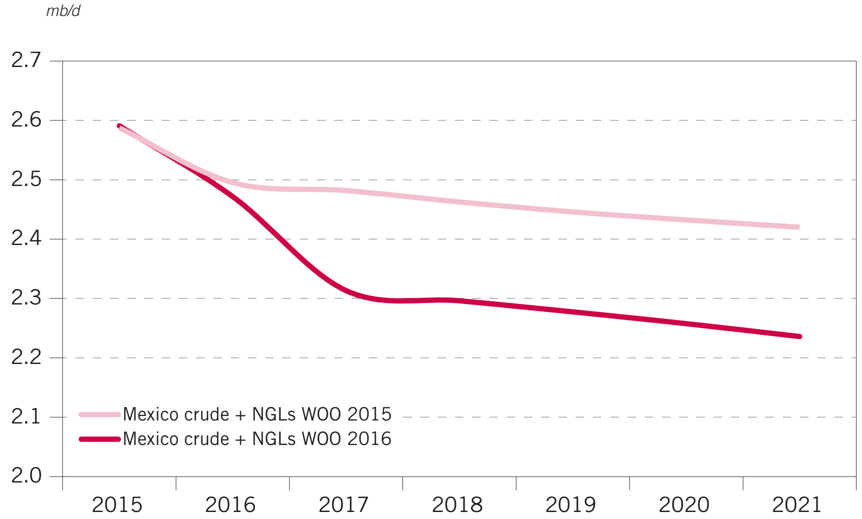
Figure 4.23
Canadian tight oil production forecast: 2016 *versus* 2015 outlook



Mexico

Crude oil and NGLs output from Mexico has been decreasing since 2004. Cantarell and Ku-Maloob-Zaap, the two largest fields in production, have experienced the largest declines. Cantarell reached its peak in 2003, at around 2.2 mb/d. Current production is now lower than 0.4 mb/d.

Figure 4.24
Mexico's crude and NGLs production over the medium-term: 2016 *versus* 2015 outlook



Despite some of the recent successes associated with Mexico's Energy Reform Bill, the drop in oil prices has complicated efforts to revive production. As a result, the decline in output is not expected to improve much over the medium-term.

Crude oil and NGLs production from Mexico is projected to fall from 2.6 mb/d in 2015 to around 2.2 mb/d in 2021. In comparison to last year's outlook, this year's Reference Case sees a lower prospect for Mexico's supply (Figure 4.24), mainly on the back of the prolonged lower price environment.

Box 4.1

Mexico's evolving energy reform: what lies ahead?

Mexico is amongst the world's largest energy producers. It holds third position in energy production in the OECD producing countries, behind the US and Canada. In 2015, Mexico produced around 2.6 mb/d of primary liquids supply of which 2.3 mb/d was crude oil production.

However, Mexico's total oil production has witnessed a steady and substantial decline since 2004 due to, *inter alia*, natural declines from its main large fields, challenges at its NOC Petróleos Mexicanos (Pemex) and a lack of access to technology.

Consequently, the Mexican Government enacted major constitutional reforms in December 2013 to address its declining domestic production, as well as many other challenges facing its oil sector. The most heralded was the restructuring of Pemex and the end of its 75-year monopoly.

However, the reform process has not been straightforward and the government has faced, and continues to face, a number of challenges. How these reforms evolve will be central to Mexico's oil industry future.

The oil sector

Mexico possessed 9,711 mb of proven oil reserves as of 31 December 2015,[33] which mainly consist of different grades of heavy crude oil. The most prolific basins in Mexico are located offshore of the southern part of the country, namely the Campeche Basin. The two main production areas are centred on Cantarell and Ku-Maloob-Zaap. On average, 1.8 mb/d of Mexico's total crude oil production is sourced offshore in the Bay of Campeche. Furthermore, there are substantial reserves in onshore basins in the northern part of the country.

Mexico is also believed to own significant yet to be developed hydrocarbon resources in the deep water Gulf of Mexico. However, in the current environment it is believed that Mexico's oil production is unlikely to grow before the mid-2020s. And looking further ahead, with a generally conservative and pragmatic outlook, the country could produce around 4.3 mboe/d of oil and gas by 2040, should everything materialize according to plan in terms of its energy reform, and the development of its mature, shale and deep water fields.

Although Mexico is not an oil-driven economy, oil exports constitute an important building block for its economy. In 2014, almost 11% of Mexico's export earnings were generated from the oil and gas sector. In 2015, Mexico's federal budget, like many other oil-producing countries around the globe, was based on a higher oil price ($79/b) than the actual average for the year. The declines in oil production and oil revenues have had a direct impact on Mexico's economy and the government's fiscal status.

Pemex

Pemex is Mexico's single biggest employer, with 160,000 staff, and a significant contributor to the country's economy and the government's budget (oil and gas industry earnings account for around 33% of government revenues).

The company was founded in 1938 and in the decades that followed Mexico saw its crude production rise steadily. It reached a peak of close 3.4 mb/d in 2004. Despite this growth, however, Pemex's performance over its history has been hampered by several factors, including: the persistent exploitation of relatively easy shallow water fields, the lack of maintenance of above-surface infrastructure, as well as other challenges.

Combined with financial difficulties, this has resulted in a major drop in crude oil production since 2004, with output levels at around 3 mb/d in 2010 and below 2.5 mb/d currently. It all underscores why the government has sought to restructure the company.

Pemex will continue to be Mexico's state-owned NOC, but reforms will change how it operates. It will be relatively autonomous in budgetary and administrative matters and will have to partake in bidding competition for new projects. It should be noted that Pemex was allowed first refusal on developing resources in Mexico prior to the initiation of the bidding process for private companies.

Mexico's energy reform: initial fruits

Mexico's energy reform aims to, *inter alia*, liberalize the oil and gas industry, restructure Pemex, broaden the regulatory authorities of both Mexico's Energy Ministry, or Secretaría de Energía, Mexico's national hydrocarbons commission, or Comisión Nacional de Hidrocarburos,[34] and create a new environmental protection agency, the Agencia de Seguridad, Energía y Ambiente.

As a result of the reforms, the government held bidding rounds in July 2015, which was the first time in 75 years that license contracts were offered to international oil and gas companies in the Gulf of Mexico. However, the first auction (Round Zero) fell short of expectations as only two out of 14 shallow water exploration blocks were awarded to consortiums, and these were devoid of major oil companies. The auction was evidently impacted by the lower oil price environment.

The government realized the shortcomings of Round Zero and adjusted the bidding terms to include more attractive fiscal terms, as well as addressing certain ambiguities, prior to the second round. As a consequence, the September 2015 auction produced a more favourable outcome, whereby three of the five shallow-water production blocks were awarded to a consortium involving a contract with Eni.

Despite the oil price actually being lower in September, compared to the time of the first auction, several factors worked in tandem for the government: the combination of improved fiscal terms[35] and relatively less risky ventures. Moreover, the first auction was mainly offering exploration blocks, while the second auction focused on production. These factors seemed to have established a more balanced auction and consequently compensated for the lower oil price.

The foundation for change for Mexico is already in place, with the approved energy reform of 2013. Although for some the change may have arrived late, the development can be viewed as a paradigm shift that will reap significant benefits. This includes the already mentioned liberalization of the oil and gas industry and the restructuring of Pemex, but also greater foreign direct investment, and more access to foreign technology and best practices.

To date, the efforts made by the Mexican Government to implement these reforms seem to be advancing according to plan. The global oil and gas industry is watching the developments with enthusiasm, with many clearly interested in Mexico's energy industry.

However, it is important not to lose sight of the fact that outcomes will depend on the proper implementation of the energy reform, and its adaptability in ensuring that regulations can be enhanced and improved upon in light of new realities in the oil and gas marketplace. This is especially true in the current lower oil price environment, which is evidently de-incentivizing to the oil and gas industry in general.

Norway

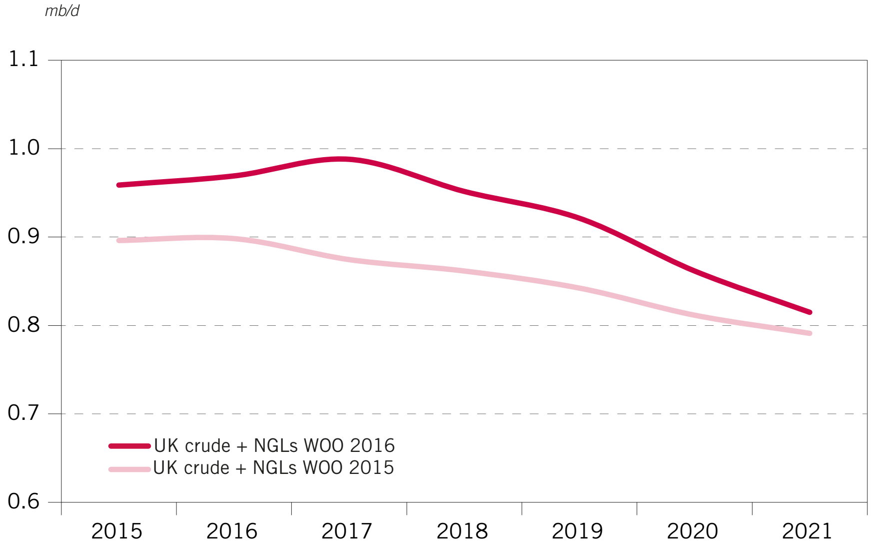
Despite lower oil prices, Norway's crude oil and NGLs production actually increased by about 60,000 b/d in 2015. This is mainly due to the modest increments coming from the ramp-up of the small upstream projects that were initiated in 2013 and early 2014. This trend is expected to continue in 2016, with a modest net increase in supply of 10,000 b/d. The natural decline will then take over causing an average annual decline in supply of about 30,000 b/d over the medium-term. The low decline rate is based on the expectation that the natural production decline rate will continue to be counteracted by small projects. Between 2016 and 2020, about 16 small new projects with various capacities are planned to come onstream.

Projects under planning and development include: Goliat, Ivar Aasen, Gullfaks Rimfaksdalen (Rutil/Brokitt/Opal), Flyndre, Gina Krog (Dagny), Gullfaks (Infill drilling), Oseberg (Infill drilling), Viper/Kobra(Alvheim), Astero (35/11-13), Oseberg (Western flank 2), Utgard (15/8-1), Maria, Yme (redeveloped), 6507/5-6S (Snadd N), Johan Sverdrup-Phase 1, 8/10-4S (Oda). Goliat was supposed to commence production in 2014 but is now expected to start up in 2016. It should add about 95,000 b/d by 2018. Another major development is Johan Sverdrup, which is intended to start up in 2020 with a capacity of 370,000 b/d.

UK

Similar to Norway, the UK's decline trend is expected to be counteracted by small projects. Despite lower oil prices, the UK's crude oil and NGLs production increased by about 104,000 b/d in 2015. It is projected also to increase by another 10,000 b/d in 2016 and 20,000 b/d in 2017. However, starting in 2018, the small

Figure 4.25
UK's crude and NGLs production over the medium-term: 2016 *versus* 2015 outlook



increments that are expected to come online will not offset the decline in mature fields. They will only help to slow the overall decrease. Between 2016 and 2020, a total of 30 new projects are planned to come online, representing an additional capacity of around 0.5 mb/d.

The projects under planning and development include: Alder, Stella , Laggan, Solan, Tormore, Conwy, Baroli, Clair Ridge, Flyndre Southwest, Schiehallion (redevelop), Loyal (redevelop), Harrier, Scolty, Cayley, Cawdor, Shaw, Catcher, Varadero, Burgman), K (Callater), Barra (Western Isles), Harris (Western Isles), Glenlivet, Cragganmore (Crawford redevelop) and Culzean.

The UK's crude oil and NGLs supply is projected to drop slowly over the medium-term and reach 0.8 mb/d in 2021. In comparison to last year's outlook, this year's Reference Case sees somewhat higher prospects for UK supply (Figure 4.25).

Australia

Australia's oil reserves are largely offshore along the coasts of Western Australia, Victoria and the Northern Territory. The largest producing basins are the Carnarvon, situated in the northwest, and the Gippsland in the southeast.

In recent years, Australia's crude oil and NGLs output has been decreasing, though this is only expected to continue until 2017, with output bottoming out at 0.35 mb/d. At that stage, 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 likely to reverse the decline. As such, output is projected to rise slightly in 2018 and the following years, eventually reaching 0.45 mb/d in 2021.

Asia/Far East

It is to be noted that Indonesia reactivated its membership of OPEC in 2015 and, as a result, it is no longer included in non-OPEC Asia. Comparisons to previous outlooks have had to be adjusted accordingly.

Excluding China, Asian crude oil and NGLs production in 2015 was supported by growth of about 90,000 b/d from Malaysia, Thailand and Vietnam. However, despite the additional supply from new projects in the next five years, which will be too small to help offset the decline, Asia's production is projected to stay almost flat at about 2.6 mb/d over the medium-term.

From 2016–2021, new projects in India, such as the Heera and South Heera redevelopments, and the MBA EOR project, are expected to add about 30,000 b/d. Output will, therefore, remain steady at slightly above 0.8 mb/d. New projects in Malaysia are anticipated to add approximately 110,000 b/d over the coming five years, leading to a growth ranging from 0.7–0.8 mb/d over the medium-term. Production in Brunei is expected to stay flat over the medium-term at about 0.1 mb/d. Similarly in Thailand and Vietnam, production is projected to hover around the 0.3 mb/d level.

Argentina

Although Argentina has experienced declines in its crude oil and NGLs production in recent years, new policies designed to attract investments may reverse the trend over the medium-term. Interest is high in the Vaca Muerta formation, which is bringing investments from several large companies. Tight oil production from the Vaca Muerta is expected to rise over the medium-term, possibly quicker than previously anticipated. However, uncertainties remain, particularly due to the effects of the lower price environment. The Reference Case sees Argentina's crude oil and NGLs production remaining flat at about 0.6 mb/d from 2016–2021.

Brazil

Brazil is the largest producing country in Latin America. It contributes almost 60% of the region's crude oil and NGLs production. Due to its pre-salt development plans, growth from Brazil is expected to last for many years. However, due to many factors including ongoing political issues, corruption scandals and lower oil prices, Brazil's crude oil and NGLs production showed signs of decline early this year.

Hence, this year's Reference Case sees a somewhat lower medium-term crude and NGLs supply outlook for Brazil than anticipated in the WOO 2015. As illustrated in Figures 4.26 and 4.27, the difference in projections reaches a maximum of about 0.27 mb/d in 2019.

Still, this year's Reference Case shows steady growth after 2016. Brazil's crude and NGLs production is projected to grow by 1.1 mb/d over the medium-term, rising from 2.5 mb/d in 2016 to about 3.6 mb/d in 2021. This is, however, 0.13 mb/d lower than last year's Outlook.

Figure 4.26
Brazil's crude and NGLs production over the medium-term: 2016 *versus* 2015 outlook

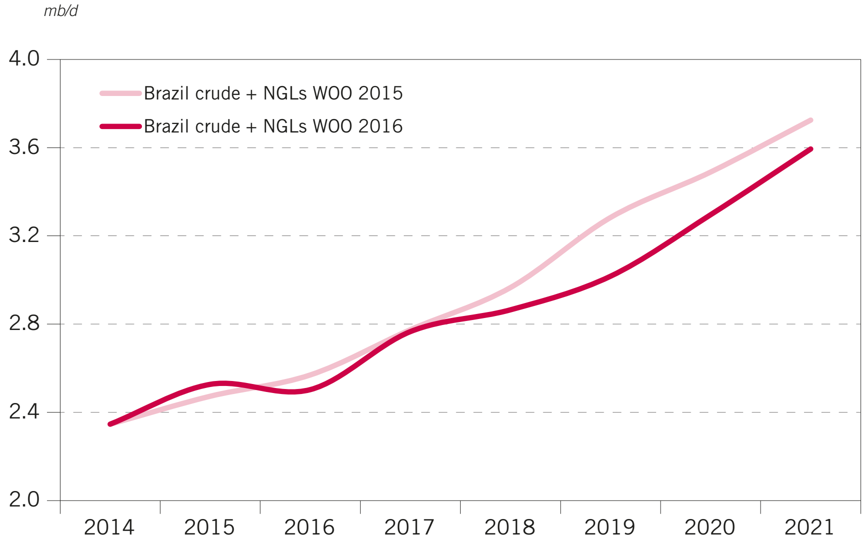
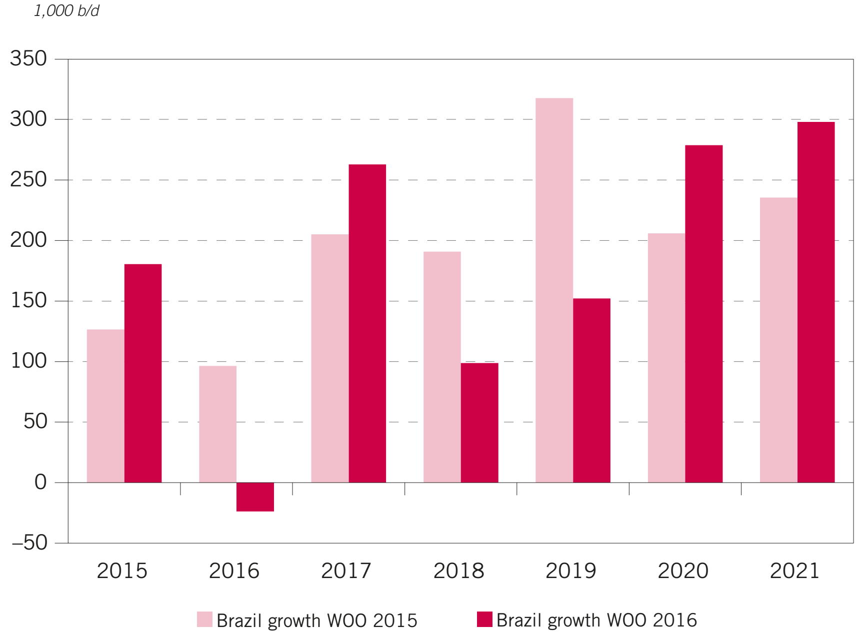


Figure 4.27
Brazil's crude and NGLs annual growth over the medium-term: 2016 *versus* 2015 outlook



Colombia

Colombia's proved reserves are situated mostly in the Llanos and Upper Magdalena basins. The main oil producing basins include the Llanos, Middle Magdalena, Upper Magdalena, Catatumbo, Putumayo and Lower Magdalena. Some of these, like the Lower Magdalena and Catatumbo basins, are mature and in decline.

This year's Reference Case shows a slight decline in Colombia's output of crude and NGLs over the medium-term, from 1 mb/d in 2015 to about 0.9 mb/d by 2021.

Middle East

Oman's crude oil and NGLs production is forecast to remain steady due to the application of enhanced oil recovery methods. Over the medium-term, production of about 0.9 mb/d is expected. In Bahrain, production is expected to remain constant at some 0.2 mb/d over the period, while expectations for Yemen's production are still marked by uncertainty given the country's geopolitical situation. However, as circumstances there improve, there is the potential to go back to its 2013 production level of 0.14 mb/d in a relatively short period of time. In Syria, oil output is projected to recover gradually, reaching about 0.1 mb/d by 2021.

Overall, non-OPEC Middle East crude oil and NGLs output is expected to remain at around 1.2–1.3 mb/d over the medium-term.

Africa

In June 2016, Gabon re-joined OPEC and, as a result, it is no longer included in the non-OPEC Africa category. Comparisons to previous outlooks must, therefore, be adjusted accordingly.

Crude oil and NGLs production from Africa remained at about 2 mb/d in 2015. However, Africa's production is projected to decline by about 40,000 b/d in 2016, on the back of lower oil prices, before slowly rising again to the 2 mb/d level in the period to 2021.

Planned projects in non-OPEC African countries over the medium-term include eight in Egypt, one in Sudan, one in Chad, five in Equatorial Guinea and three in Congo. The Moho North project in Congo is the largest of these, with an expected plateau rate of 90,000 b/d, followed by Ghana's Enyenra (x-Owo) with a plateau rate of 66,000 b/d.

Production profiles from Chad, Congo, Egypt and Equatorial Guinea are each projected to be relatively flat over the medium-term, at 0.1 mb/d, 0.4 mb/d, 0.7 mb/d and 0.3 mb/d, respectively. Output from Sudan and South Sudan is expected to remain at a level of about 0.25 mb/d over the period.

East Africa's emerging oil producing countries include Mozambique, Tanzania, Uganda, Kenya and Madagascar. The latter three will probably be the first to become oil producers.

Russia

This year's outlook sees a higher production profile from Russia over the medium-term. Regardless of the lower oil price environment, Russia's production grew by

Figure 4.28

Russia's crude and NGLs production over the medium-term: 2016 *versus* 2015 outlook

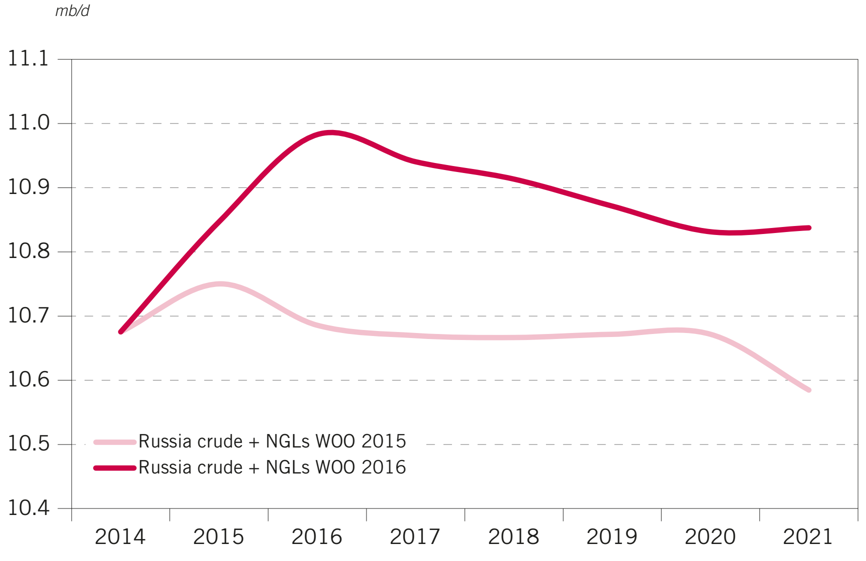
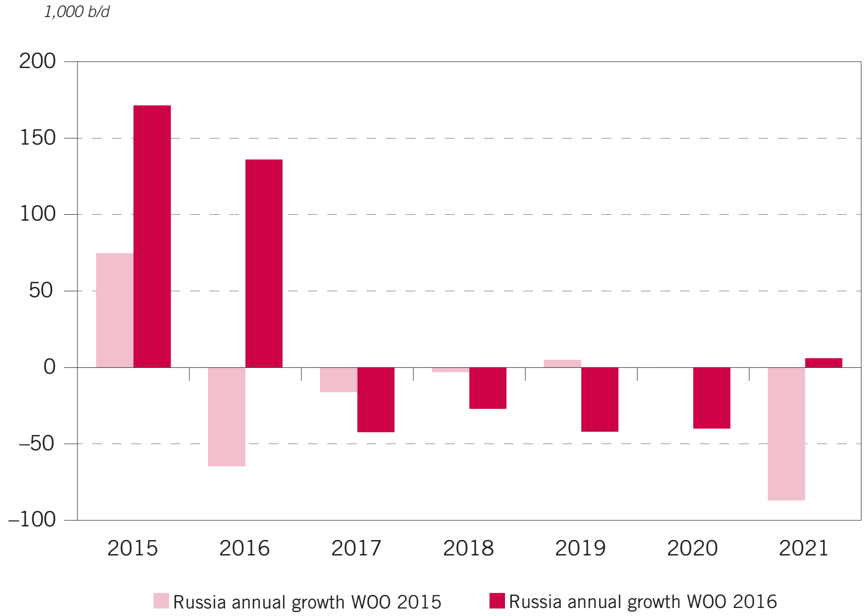


Figure 4.29
Russia's crude and NGLs annual growth over the medium-term: 2016 *versus* 2015 outlook



170,000 b/d in 2015. The impact of the sanctions and lower oil prices has not been as strong as originally anticipated. Figures 4.28 and 4.29 show the comparison between this year's projections and last year's outlook. The difference in growth is highest for 2016, leading to a maximum difference in overall supply of 0.3 mb/d in 2016. It should be noted, however, that Russian production has been steadily increasing since 2009. It is highly possible that Russia will be able to control the decline in production from its brown fields, as well as increase condensate and NGLs production from its gas fields. Nevertheless, the risk is still skewed towards the downside.

Azerbaijan

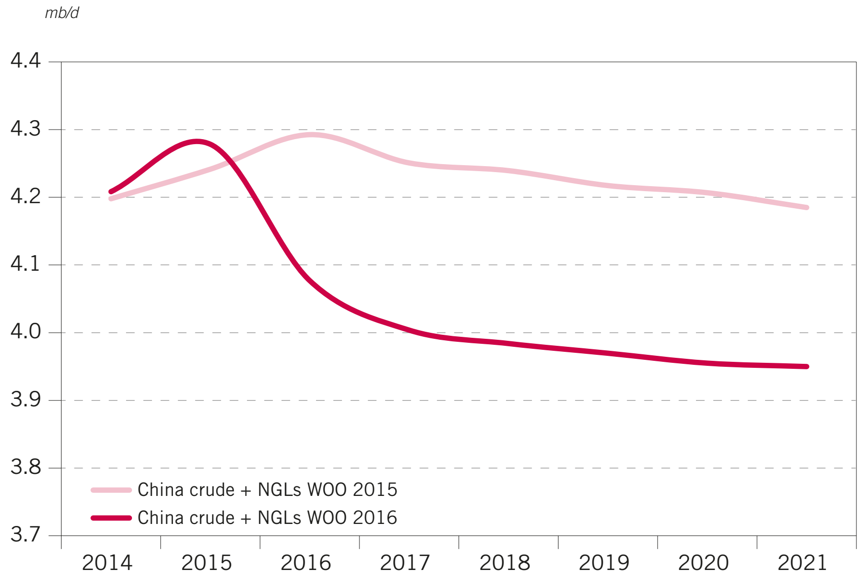
Azerbaijan's largest basins are located in the Caspian Sea. Output has fallen steadily in recent years, from 0.93 mb/d in 2011 to 0.87 mb/d in 2014.

Over the medium-term, crude oil and NGLs output is expected to decrease gradually to a level of 0.77 mb/d in 2021. Challenges with existing production and delays in launching new projects underpin the projections over the period.

Kazakhstan

Over the medium-term, a rise in crude oil and NGLs output from Kazakhstan will mainly come from Kashagan, the Tengiz expansion, and the Akote and Fedorovskiy blocks. Although Kashagan was brought onstream in 2013, production was

Figure 4.30
China's crude and NGLs production over the medium-term: 2016 *versus* 2015 outlook



quickly shut in due to pipeline problems. A resumption of output is expected in late 2016. As a result of lower oil prices, Kazakhstan's outlook remains the same as last year's in which crude oil and NGLs production was projected to reach 1.7 mb/d in 2020.

China

China's production has been greatly affected by lower oil prices. Lower investment levels have caused Chinese production to decline sharply over the first half of 2016. Hence, this year's outlook sees much lower supply prospects for China compared to last year (Figure 4.30). China's medium-term crude oil and NGLs production is projected to decline to less than 4 mb/d by 2021.

Long-term outlook for crude and NGLs

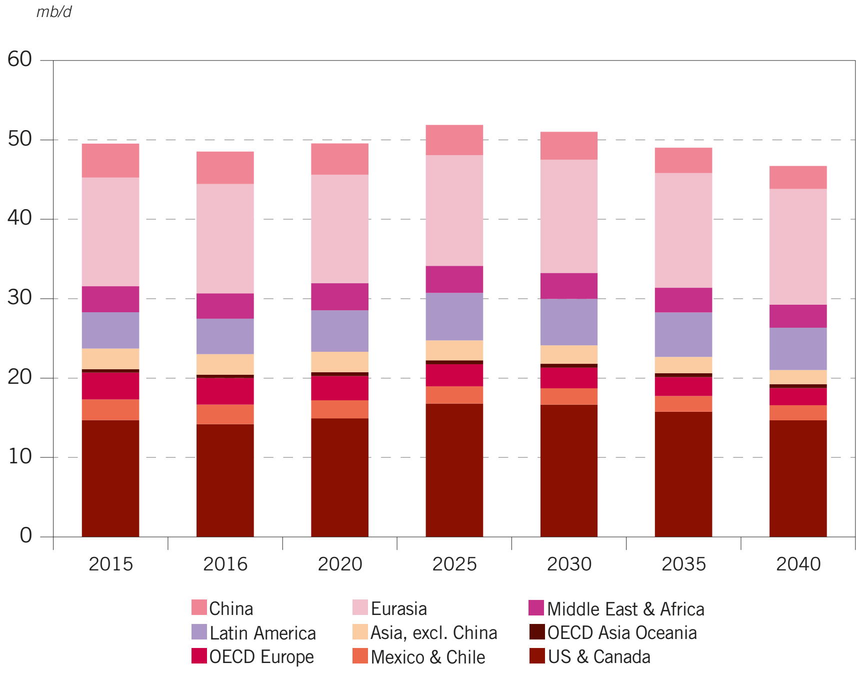
As mentioned earlier, long-term projections of crude oil and NGLs supply focus on URR, as estimated in recent geological assessments, to generate feasible production paths.

Table 4.6 and Figure 4.31 show the non-OPEC crude oil and NGLs supply projections over the long-term, that is, to 2040. Non-OPEC supply reaches a maximum of 52 mb/d in 2025 then declines to 46.8 mb/d by 2040. Of this total, OECD contributes 41% (19.2 mb/d) while non-OPEC Developing countries contribute 28% (12.9 mb/d) and Eurasia's share is 31% (14.6 mb/d).

Table 4.6
Non-OPEC crude and NGLs supply outlook in the Reference Case *mb/d*

	2015	2016	2020	2025	2030	2035	2040
United States	12.7	12.2	12.9	14.8	14.7	13.9	12.9
Canada	2.0	2.0	2.0	2.0	2.0	1.9	1.8
US & Canada	**14.7**	**14.2**	**14.9**	**16.8**	**16.7**	**15.8**	**14.7**
Mexico & Chile	**2.6**	**2.5**	**2.3**	**2.2**	**2.1**	**2.0**	**1.9**
Norway	1.9	2.0	1.8	1.7	1.5	1.4	1.3
United Kingdom	1.0	1.0	0.9	0.8	0.7	0.7	0.6
Denmark	0.2	0.1	0.1	0.1	0.1	0.1	0.1
OECD Europe	**3.4**	**3.3**	**3.1**	**2.8**	**2.6**	**2.4**	**2.2**
Australia	0.4	0.4	0.5	0.4	0.4	0.4	0.4
Other Asia Oceania	0.1	0.1	0.0	0.0	0.0	0.0	0.0
OECD Asia Oceania	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
OECD	**21.1**	**20.4**	**20.7**	**22.2**	**21.8**	**20.6**	**19.2**
Brunei	0.1	0.1	0.1	0.1	0.1	0.1	0.1
India	0.9	0.8	0.8	0.8	0.7	0.7	0.6
Malaysia	0.7	0.7	0.8	0.7	0.6	0.6	0.5
Thailand	0.4	0.4	0.3	0.3	0.3	0.2	0.2
Vietnam	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Asia, excl. China	**2.6**	**2.6**	**2.6**	**2.5**	**2.3**	**2.1**	**1.8**
Argentina	0.6	0.6	0.6	0.7	0.7	0.6	0.6
Brazil	2.5	2.5	3.3	4.1	4.1	4.0	3.9
Colombia	1.0	0.9	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	0.3	0.3	0.4	0.4	0.4
Latin America	**4.6**	**4.5**	**5.2**	**6.0**	**5.9**	**5.6**	**5.3**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Oman	1.0	1.0	0.9	0.9	0.8	0.8	0.8
Syrian Arab Rep.	0.0	0.0	0.1	0.2	0.2	0.2	0.2
Yemen	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Middle East	**1.3**	**1.2**	**1.4**	**1.4**	**1.3**	**1.3**	**1.2**
Chad	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Congo	0.3	0.3	0.4	0.4	0.3	0.3	0.3
Egypt	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Equatorial Guinea	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Sudan/South Sudan	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Africa other	0.3	0.3	0.4	0.4	0.4	0.3	0.3
Africa	2.0	1.9	2.0	2.0	1.9	1.8	1.7
Middle East & Africa	**3.3**	**3.2**	**3.4**	**3.4**	**3.3**	**3.1**	**2.9**
Russia	10.8	11.0	10.8	10.9	10.9	10.8	10.8
Kazakhstan	1.6	1.6	1.7	2.0	2.3	2.6	2.7
Azerbaijan	0.9	0.8	0.8	0.7	0.7	0.7	0.7
Other Eurasia	0.4	0.4	0.3	0.3	0.3	0.3	0.3
Eurasia	**13.7**	**13.8**	**13.7**	**13.9**	**14.3**	**14.4**	**14.6**
China	**4.3**	**4.1**	**4.0**	**3.8**	**3.5**	**3.2**	**2.9**
DCs, excl. OPEC	**14.7**	**14.3**	**15.2**	**15.7**	**15.0**	**14.0**	**12.9**
Total non-OPEC	**49.7**	**48.7**	**49.7**	**52.0**	**51.2**	**49.1**	**46.8**

Figure 4.31
Long-term non-OPEC crude and NGLs supply outlook in the Reference Case



Production from the US & Canada reaches a maximum of 16.8 mb/d in 2025. It then goes into a gradual decline, falling to 14.7 mb/d in 2040, mainly because of a projected long-term fall in tight crude production. In the OECD, crude and NGLs production drops from a high of 22.2 mb/d in 2025 to 19.2 mb/d in 2040, partly due to the declines from Mexico and the North Sea. Resource constraints are eventually expected to lead to declines in developing Asia, where supply falls to 1.8 mb/d by 2040. Latin America (mainly Brazil) maintains supply at levels higher than 5 mb/d over the long-term, while Russia sees steady output at about 10.8 mb/d, which includes some tight oil production from the Bazhenov shale. The Eurasia region as a whole exhibits a gradual increase in supply over the forecast period, reaching 14.6 mb/d by 2040, while China goes through a continuous decline to 2.9 mb/d by 2040.

Figure 4.32 provides the regional overall long-term growth in non-OPEC crude oil and NGLs supply. Latin America contributes the highest growth of 0.9 mb/d, followed by Eurasia with 0.8 mb/d. Meanwhile, the US & Canada shows growth of 0.5 mb/d, Oceania shows modest growth of 0.1 mb/d, while all other regions experience variable rates of decline over the long-term.

The impact of lower oil prices is partly reflected in reductions to the projections for this year compared to the forecasts carried out in the 2015 outlook (Figure 4.33 shows a comparison, with the 2015 numbers adjusted since Indonesia and Gabon are no longer in the non-OPEC category).

Figure 4.32
Non-OPEC crude and NGLs regional supply growth in the long-term, 2016–2040

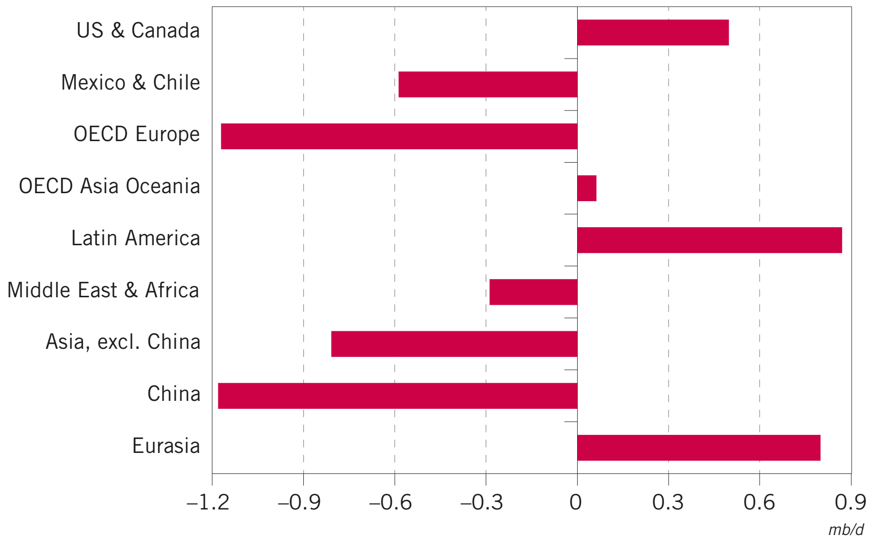
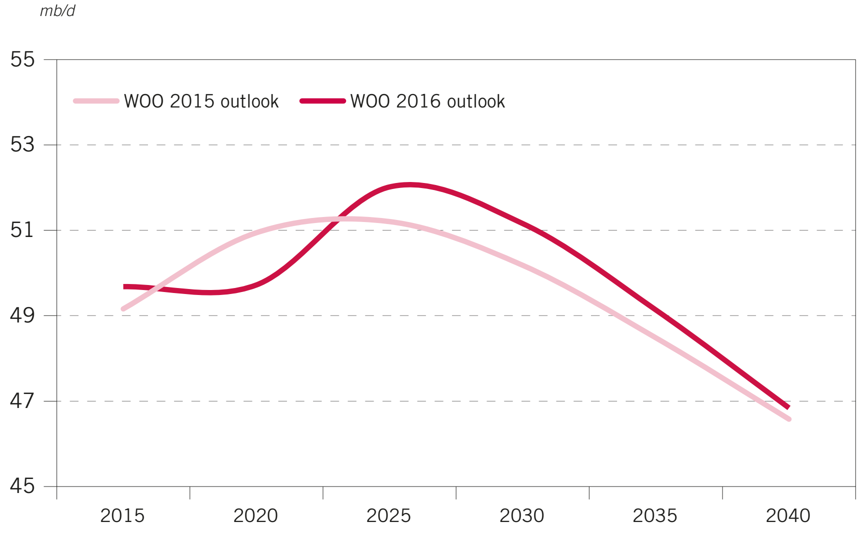


Figure 4.33
Non-OPEC crude and NGLs supply outlook, 2016 *versus* 2015 outlook



Medium-term outlook for other liquids supply (excluding biofuels)

The medium-term outlook for 'other' liquids – which includes all liquids other than crude, NGLs and biofuels, but which predominantly consists of oil sands, GTLs and CTLs – has been revised slightly downward compared to the one in WOO 2015. In this category, non-OPEC supply rises from 3 mb/d in 2015 to 3.4 mb/d in 2021 (Table 4.7), with most of the increase over that period coming from the oil sands (see *Focus* for more details on oil sands prospects). The marginally lower estimates compared with last year's WOO are mainly due to downward revisions for oil sands.

Current market circumstances have led to several delays and cancellations in oil sands projects, but projects under construction are, mostly, still going forward. Wildfires in the province of Alberta, which started in May 2016, have had only a short-term impact on supply.

In this year's outlook, oil sands production rises from 2.4 mb/d in 2015 to 2.7 mb/d in 2021. Relatively small amounts of CTLs and GTLs production are driven mostly by existing capacity, with new projects having unfavourable economic prospects under current market circumstances. The environmental impacts of CTLs development further weigh on its development. South Africa remains the largest producer over the period, with roughly flat production of 0.16 mb/d, followed by China, which reaches nearly 0.1 mb/d in 2021. The economics of GTLs production are becoming increasingly questionable, particularly in the recent low oil and gas price environments.

Long-term outlook for other liquids supply (excluding biofuels)

Over the long-term, non-OPEC 'other' liquids rise from 3 mb/d in 2015 to 5.5 mb/d in 2040 (Table 4.8). The latter figure represents a downward revision of 0.4 mb/d compared to last year's WOO, made partly on the back of the persistently lower oil

Table 4.7
Medium-term other liquids supply outlook in the Reference Case *mb/d*

	2015	2016	2017	2018	2019	2020	2021
US & Canada	2.6	2.6	2.7	2.7	2.8	2.9	2.9
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	**2.8**	**2.8**	**2.9**	**2.9**	**2.9**	**3.0**	**3.1**
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	0.1	0.1	0.1
China	0.0	0.0	0.1	0.1	0.1	0.1	0.1
DCs, excl. OPEC	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**
Non-OPEC	**3.0**	**3.0**	**3.1**	**3.1**	**3.2**	**3.3**	**3.4**

price environment and a slightly lower long-term price assumption, which has the overall effect of delaying supply of these non-conventional liquids.

Most of the long-term increase is seen in oil sands, which reach 4.4 mb/d in 2040 (or 80% of total 'other' liquids supply that year). Despite recent project deferrals and cancellations, production is expected to rise continuously over the forecast period. However, climate policies following the COP21 meeting provide an element of uncertainty to the forecast. Apart from oil sands, the remaining supply of 1.1 mb/d in 2040 is comprised of CTLs, GTLs, MTBE, oil shale and extra-heavy crude.

In terms of regional distribution, the OECD accounts for 4.8 mb/d by 2040, with Developing countries only supplying 0.7 mb/d in the same year. China is the largest contributor among such countries on account of its CTLs output. Despite having abundant coal reserves, environmental constraints continue to limit prospects.

Table 4.8
Long-term other liquids supply outlook in the Reference Case *mb/d*

	2015	2016	2020	2025	2030	2035	2040
US & Canada	2.6	2.6	2.9	3.2	3.6	4.1	4.6
OECD Europe	0.1	0.1	0.1	0.1	0.1	0.2	0.2
OECD Asia Oceania	0.0	0.0	0.1	0.1	0.1	0.1	0.1
OECD	**2.8**	**2.8**	**3.0**	**3.4**	**3.8**	**4.3**	**4.8**
Middle East & Africa	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Asia, excl. China	0.0	0.0	0.1	0.1	0.1	0.1	0.1
China	0.0	0.0	0.1	0.1	0.2	0.3	0.4
DCs, excl. OPEC	**0.2**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**
Non-OPEC	**3.0**	**3.0**	**3.3**	**3.9**	**4.3**	**4.9**	**5.5**

Focus

Opportunities and constraints for oil sands development

One of the primary drivers of non-OPEC output growth over the past decade has been the oil sands in Alberta, Canada. They are also called 'tar sands' and 'bituminous sands', and are mixtures of sand, water, clay and crude bitumen. In recent years, oil sands projects have delivered some significant growth on the back of technological advances, but despite this there remain several challenges that could hinder its continued rapid expansion.

The first is the fact the economic viability of the resource is questionable, given that it is one of the most capital-intensive sources of liquids in the world. This is especially true in a low oil price environment,

Another challenge relates to environmental issues concerning the methods employed in the extraction and processing of oil sands. Production often requires clearing large boreal forest areas and can result in higher amounts of GHG emissions relative to other energy sources. Over the long-term, producers face the challenge of dealing with potentially costly environmental impact mitigation policies that could be imposed on oil sands development.

Another factor that could limit oil sands growth is the potential lack of available inputs such as water, natural gas and diluents. However, technology can play a critical role in reducing the need for such inputs, while also reducing costs and mitigating the environmental impact.

The growth of oil sands supply will further depend on the availability of transportation infrastructure, including the pipelines and rail that are needed to get oil to market. On this issue, environmental, social and political opposition represent major obstacles.

To account for the uncertainties associated with developing long-term oil sands supply, upside and downside projections – for the 'other liquids' category, which is comprised mostly of oil sands – can be found in the scenarios section of this Chapter. In the supply projections of this 'Focus', only Reference Case figures are provided.

Production methods

Production of the dense and viscous oil sands is undertaken through either open-pit mining or in-ground recovery. Today, each method represents about half of the producible current oil sands capacity.

In the mining process, the oil sands are excavated and loaded onto large dump trucks that carry the payload away for processing. The trucks deliver the sands – around 500,000 tonnes daily – to onsite facilities where they are mixed with heated water and shaken to separate the substance into water, sand and bitumen. The bitumen is either mixed with diluents like NGLs, lighter crudes and chemicals and then transported as bitumen blends, or upgraded onsite and then transported as synthetic crude streams, mainly to refineries in Canada and the US.

Before the current truck and shovel method was employed, mining operations used dragline and bucket-wheel excavators that relied on conveyor belt systems to transport the oil sands to upgrade installations. These excavators have been mostly retired due to their high operating and maintenance costs. Mobility and flexibility has been greatly enhanced through the use of shovels and trucks. This switch was a major 1990s technological breakthrough that significantly improved the economic prospects of oil sands.

The vast majority of oil sands deposits are too deep for open-pit mining, which requires a depth of less than 100 metres. Therefore, the most promising method of recovery over the coming decades is steam assisted gravity drainage (SAGD), a form of steam stimulation. The process involves two horizontal wells drilled in parallel, one of which injects steam to heat and soften the oil sands, the other which then pumps the oil sands to the surface.[36]

Reserves and resources

Globally, the estimated recoverable resources of oil sands have been assessed at 650 billion barrels,[37] and approximately 80% of this is located in Alberta across a surface area of 140,000 square kilometres – covering the Athabasca, Peace River and Cold Lake areas. According to the Government of Alberta, proven oil sands reserves in the province amount to 166 billion barrels. The oil sands global resource base – or the 'oil in place' – is estimated to be in the order of 5 trillion barrels. Over 80% of this is thought to be located in North and South America, mostly in Canada and Venezuela.[38]

Short- and medium-term supply

Following the oil price drop, capital spending in the oil sands industry has fallen from approximately $25 billion in 2014 to $18 billion in 2015 and $13 billion in 2016. While supply is bound to be affected by drop in spending on new capacity, including some medium-term effects, the result will mostly play out over the long-term. This is due to the fact that the lead time for production, after investment decisions have been taken, is at least five years.

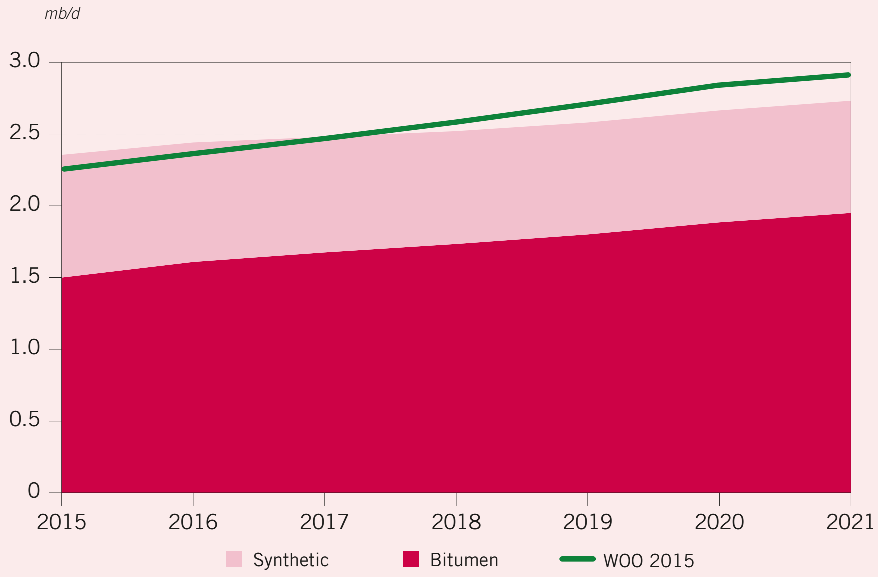
Despite the overall reduction in capital spending, projects under construction are, for the most part, still going ahead due to the high level of sunk costs associated with these capital-intensive ventures. Thus, it is estimated that new capacity may become available over the medium-term from various projects. These include Mackay River Phase 1; Foster Creek Phase G; Christina Lake Phase F; Hangingstone Expansion; Horizon Phase 2/3; Fort Hills Phase 1; Foster Creek Phase H; Christina Lake Phase G; Christina Lake Phase 3A; BlackGold Phase 1; and Narrows Lake Phase A.

It is worth noting that recent market circumstances have led to the shut-in of some production, although most companies can generally cover operating costs in the low price setting. Nevertheless, short- and medium-term supply can still face roadblocks. For example, oil sands production in 2016 was seriously affected by sprawling wildfires in Alberta. At the height of the disruption in May, over 1 mb/d was taken offline, but most of this has been brought back online in subsequent months.

Political factors in both Canada and the US also generate some uncertainty for oil sands growth. It remains to be seen, for example, if Canadian authorities will support the development of domestic pipelines to the east and west coasts (such as the proposed Energy East, Trans Mountain Expansion and Northern Gateway projects). This would enable access to markets in Europe and Asia. Moreover, it is not yet certain whether a new US President following November's election will pursue policies that favour or discourage the building of pipelines carrying oil sands crude to the US.

Taking these factors into account, the medium-term oil sands outlook in the Reference Case sees supply rising from 2.4 mb/d in 2015 to 2.7 mb/d in 2021

Figure 1
Oil sands medium-term outlook, 2015–2021



(Figure 1). This represents a slight downward revision compared to the WOO 2015, made mostly on the back of a persistent low oil price and reduced capital spending.

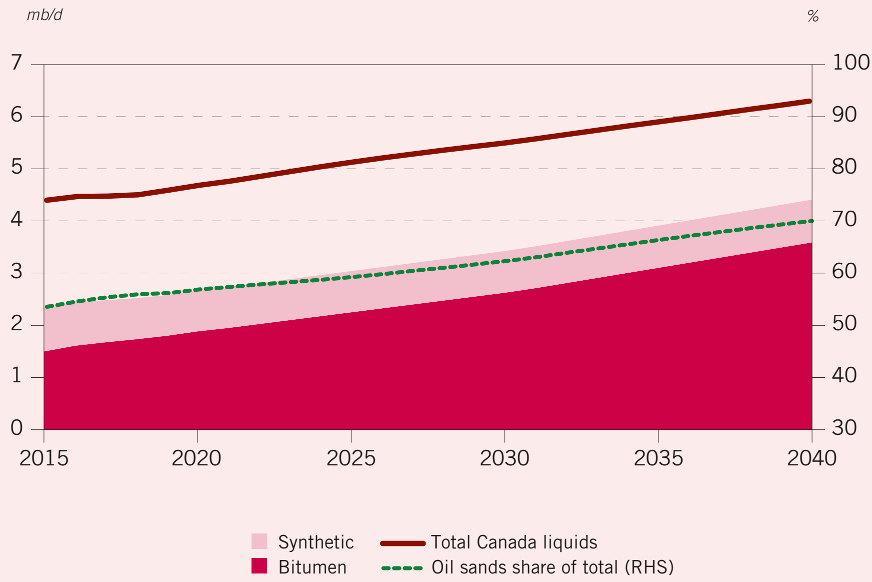
Figure 1 shows the distinction between bitumen and synthetic crude supply. Investment in upgrader plants has dropped, as producers have cancelled a number of plans over the past few years due to unfavourable economic conditions. As a result, the output of upgraded synthetic crude oil is expected to be relatively static. Instead, growth is projected to occur in diluted bitumen streams.

Long-term supply

The most significant factor to slow the oil sands production forecast beyond the medium-term is the current low oil price, which has led to the deferral or cancellation of projects totalling some 0.7 mb/d. Such projects include Foster Creek J & Christina Lake H; Telephone Creek and Grand Rapids; Narrows Lake; Corner; MacKay River; Sunrise Phase 2; Carmon Creek Phases 1 & 2; Carmon Creek Phases 3 & 4; Lindbergh Phase 2; Kirby North; and Kearl Mine debottleneck.[39]

Despite setbacks, oil sands are still thought to be one of the key long-term sources of non-OPEC supply growth. As seen in Figure 2, oil sands supply is projected to rise in the Reference Case from 2.4 mb/d in 2015 to 4.4 mb/d in 2040. Total liquids output from Canada is estimated at 6.3 mb/d in 2040. Thus, oil sands supply accounts for 70% of the total in that year, compared with about 55% at present.

Figure 2
Oil sands and Canada's liquids outlook, 2015–2040



The rate of oil sands production growth is steady over the long-term, somewhat in accordance with an assumed rise in the oil price. But the current sustained lower price has nonetheless decelerated growth projections compared to those made in prior years.

Last year's WOO projected oil sands supply at 4.7 mb/d in 2040, which is 0.3 mb/d higher than the current estimate. This already represented a downward revision compared to the WOO 2014, which expected production to reach 5 mb/d in 2040. The WOO 2014 forecast was carried out when oil prices were higher.

Other factors leading to downward revisions include the momentum in climate policy following the COP21 meeting in Paris, and the election of 'greener' administrations in Alberta's provincial government and Canada's Federal Government. Indeed, there is a risk that a highly demanding regulatory regime could impose costs that hinder future oil sands development to an even greater extent than envisaged at present.

Energy forecasting organizations in Canada have also been making downward revisions to their forecasts over the past few years, recognizing not just price and cost structures, but also the challenge represented by opposition to pipelines – particularly to the Northern Gateway, Trans Mountain Expansion, Energy East and Keystone XL pipelines. In fact, the latter pipeline was officially rejected by the US State Department in November 2015. The uncertainty is shown in the fact heavy crude exports from Western Canada to the US have been projected to be as high as 3.9 mb/d in 2035 or as low as 2.5 mb/d, depending on the development of pipeline infrastructure.[40]

Economics

The impacts of changes in policies, extraction methods, transportation systems (pipelines and rail), costs of capital and labour, and companies' financial performance present sources of uncertainty for the commercial viability of future oil sands supply.

When taking into account the price needed to recover capital and operating expenses, taxes and royalties, and to generate a return on invested capital, various sources estimate the average break-even price to be around $70–80/b. The greatest proportion of current costs is capital expenditures, followed by operating costs and then royalties. Breakeven prices for oil sands must be assessed in the context of the price for Western Canadian Select heavy crude streams, which trade at a significant discount relative to major benchmarks.

Like the rest of the petroleum industry, oil sands producers are looking for ways to reduce costs and improve efficiency as a result of lower oil prices. The very survival of some companies depends on technological advances, especially if they are forced to comply with increasingly stringent environmental requirements.

Environmental impacts

The rapid growth of oil sands production has created widespread concern in Canada and around the world about the associated environmental and climate impacts. Companies involved in the production of oil sands are pursuing ways of reducing the environmental impacts, but concerns remain.

As referred to earlier, oil sands mining requires the clearing of vast swathes of forests (though producers are later required by law to restore the lands used to conditions similar to their original state). The increased use of in-ground recovery via SAGD, however, could further alleviate land use impacts.

As with the tight oil industry, excessive water usage and contamination are prime concerns for oil sands development. To reduce the high density and viscosity of oil sands, large amounts of water are required. Although the water is typically re-used after being treated in tailings ponds, the ponds themselves have been a cause for concern due to their effect on wildlife, and the possible pollution of groundwater and nearby rivers.

The processing of oil sands typically creates a higher amount of atmospheric pollution than conventional oil. GHG emissions result from the burning of gas which is needed to power the processing facilities. However, a 'well-to-wheel' comparison shows that oil sands do not have a significantly higher impact than some other conventional crudes. For example, oil sands well-to-wheel emissions per barrel have been estimated at roughly the same level as those from the average barrel in the US.[41]

While sharpened environmental and climate policies involve costs that could suppress oil sands expansion, they may also aid the industry in gaining a 'social license' to operate, and thus help promote its future development. In 2015, the New Democratic Party in Alberta established a 'Climate Leadership Plan' that places a cap on emissions from oil sands. Such policies present a challenge but also a possible opportunity, as they could incentivize producers to improve technology in order to reduce emissions and, at the same time, enhance production.

Medium-term outlook for biofuels supply

The outlook for biofuels in the medium-term has undergone a minor upward revision compared to last year's WOO. This is despite the fact that biofuel prices have also fallen, in the low oil price environment, which has impacted producers even though in the low oil price environment biofuel prices have also fallen. Production is supported over the medium-term by government mandates and subsidies, so supply has been largely unaffected by low prices over the period.

As seen in Table 4.9, the Reference Case sees total non-OPEC biofuels supply rise from 2.1 mb/d in 2015 to 2.5 mb/d in 2021. The OECD accounts for 1.5 mb/d in 2021, most of that coming from the US at 1.1 mb/d and, to a lesser extent, Europe with 0.3 mb/d. The US does not experience much of an increase over the medium-term. This is on account of its lower ethanol blending requirements – as outlined in the US EPA RFS published in December 2015 – than the original levels envisaged when the RFS was set in 2007. However, the EPA in May 2016 proposed an increase in biofuels quotas for 2017.

Table 4.9
Medium-term non-OPEC biofuels supply outlook in the Reference Case

mb/d

	2015	2016	2017	2018	2019	2020	2021
US & Canada	1.1	1.1	1.1	1.1	1.1	1.2	1.2
OECD Europe	0.3	0.3	0.3	0.3	0.3	0.3	0.3
OECD	**1.3**	**1.4**	**1.4**	**1.4**	**1.5**	**1.5**	**1.5**
Latin America	0.6	0.7	0.7	0.7	0.7	0.8	0.8
Asia, excl. China	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DCs, excl. OPEC	**0.7**	**0.8**	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**
Non-OPEC	**2.1**	**2.2**	**2.3**	**2.3**	**2.4**	**2.5**	**2.5**

In Europe, biofuels production is driven by the goal that 10% of energy use in transport should come from renewable energy by 2020. Biofuels will account for most of that; but there is a cap of 7% on the total amount of agricultural-based biofuels permitted for transport. The cap reflects worries about the sustainability of crop-based biofuels, which have raised some concerns about the impact of their production on food prices.

Developing countries' production reaches 1 mb/d in 2021, comprised of 0.8 mb/d in Latin America (mostly Brazil) and the remainder in Asia. Even though full-cycle CO_2 emissions associated with biofuels use can often exceed those from gasoline-based cars on a unit-driven km, Brazil aims to boost the share of biofuels in energy use in an effort to reduce emissions as part of their INDCs for COP21. Based on that goal, biofuels supply is expected to remain steady despite the setbacks associated with low prices and Brazil's recent economic and political troubles.

Long-term outlook for biofuels supply

The concerns over first generation biofuels supply are expected to limit its long-term prospects. The major impediments to significant expansion in biofuels use relate to land requirements for its development, as well as concerns associated with land degradation and GHG emissions.

Although the environmental impacts of second and third generation biofuels would be far less, the technological and economic prospects for these advanced sources remain uncertain. Furthermore, the use of residues, manures and wastes used for second generation supply could still have adverse effects on ecosystems.

Table 4.10 shows that biofuels supply increases from 2.1 mb/d in 2015 to 3.6 mb/d in 2040. The OECD – represented mostly by the US and Europe, respectively, the most prominent ethanol and biodiesel producers – accounts for 1.9 mb/d of the total in 2040. Developing countries, represented predominantly by large ethanol supplier Brazil, account for 1.6 mb/d in 2040.

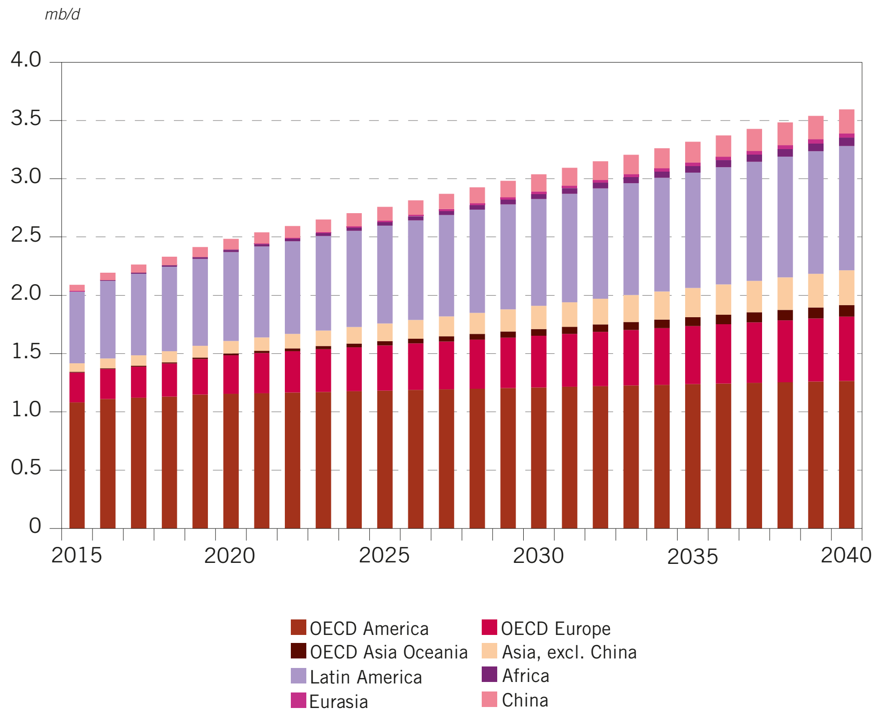
In the WOO 2015, total non-OPEC biofuels supply was projected to reach 3.7 mb/d in 2040. Thus, the current outlook has been revised down by just 0.1 mb/d. As in recent years, the future of biofuels will be determined by potential improvements in the conversion technologies needed for second and third generation biofuels. Production costs, determined by the availability of feedstocks and the type of technology used, will also be an important determinant.

Figure 4.34 provides a graphical representation of total biofuels output over the long-term in this year's outlook. Throughout the time horizon, supply is dominated by OECD America (mostly the US), followed by Latin America (mostly Brazil) and then OECD Europe. Asia is expected to capture a growing share of global supply as well. From 2015–2040, OECD America and Europe increase their output marginally – by 0.2 mb/d and 0.3 mb/d, respectively – while Latin America is expected to see growth of nearly 0.5 mb/d over the period.

Table 4.10
Long-term non-OPEC biofuels supply outlook in the Reference Case *mb/d*

	2015	2016	2020	2025	2030	2035	2040
US & Canada	1.1	1.1	1.2	1.2	1.2	1.2	1.3
OECD Europe	0.3	0.3	0.3	0.4	0.4	0.5	0.6
OECD Asia Oceania	0.0	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**	**1.9**
Latin America	0.6	0.7	0.8	0.8	0.9	1.0	1.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Asia, excl. China	0.1	0.1	0.1	0.2	0.2	0.2	0.3
China	0.1	0.1	0.1	0.1	0.1	0.2	0.2
DCs, excl. OPEC	**0.7**	**0.8**	**1.0**	**1.1**	**1.3**	**1.5**	**1.6**
Non-OPEC	**2.1**	**2.2**	**2.5**	**2.8**	**3.0**	**3.3**	**3.6**

Figure 4.34
Long-term non-OPEC biofuels supply in the Reference Case



Alternative non-OPEC supply scenarios

As with last year's outlook, there are still many uncertainties associated with the non-OPEC supply projections in this year's Reference Case. In the prolonged lower oil price environment, tight crude will continue to be the most affected. Two alternative non-OPEC supply scenarios (upside and downside) will be presented in this section to address some of the uncertainties in the Reference Case.

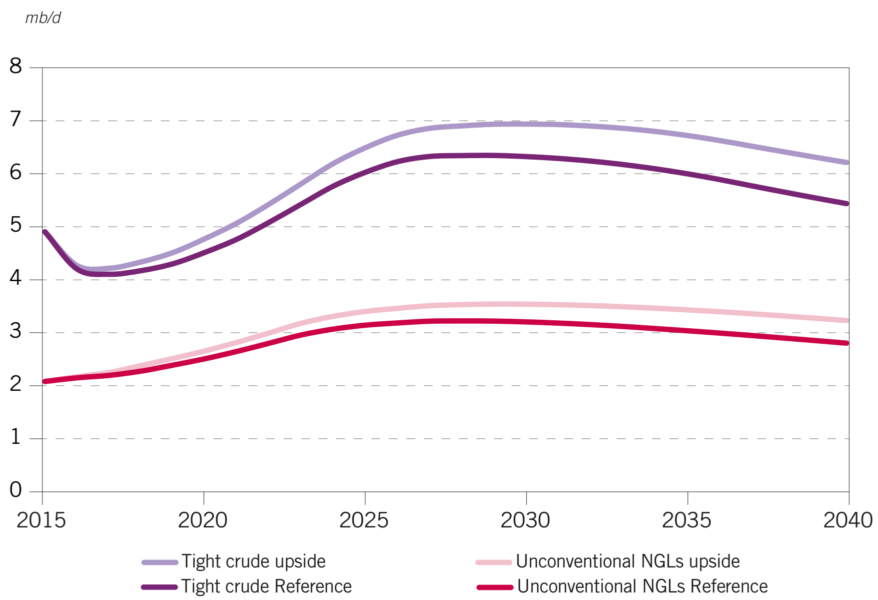
Upside supply scenario

A discussion of the upside potential of the various non-OPEC supply growth sources is provided in the following sections. Coverage is given to tight oil in North America, tight oil outside North America, conventional crude and NGLs, biofuels and other liquids.

Tight crude and unconventional NGLs in North America

Several factors are taken into account when developing the upside supply scenario for tight crude and unconventional NGLs. For instance, there is an increase in the assumed well counts, as well as changes in well spacing, the size of the resource plays and productivity gains. Such a scenario also assumes favourable policies and

Figure 4.35
Tight crude and unconventional NGLs supply in North America in the upside supply scenario



a sympathetic public attitude towards current controversial production techniques, particularly hydraulic fracturing.

Figure 4.35 shows the upside scenario and Reference Case projections for tight crude and unconventional NGLs in North America. Tight crude reaches a high of 6.9 mb/d by 2030 in the upside scenario, which is 0.6 mb/d higher than the Reference Case in that year. From that point forward, production goes into decline, dropping to 6.2 mb/d in 2040, which is about 0.8 mb/d higher than the Reference Case. Unconventional NGLs reach a maximum level of 3.5 mb/d in 2029, which is about 0.3 mb/d higher than the Reference Case. By 2040, production drops to 3.2 mb/d in the upside scenario and 2.8 mb/d in the Reference Case.

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

As in recent outlooks, the prospects for tight oil development outside North America remain limited. In the Reference Case, Russia and Argentina are expected to produce some tight oil over the long-term. Russia possesses a large resource base, particularly in the Bazhenov formation, and has experience with the associated extraction technologies. Argentina is also well-endowed with tight oil and has had some success in attracting foreign investments to the sector.

Figures 4.36 and 4.37 show the upside projections for global tight crude and unconventional NGLs, respectively. By 2040, Russia is expected to produce

Figure 4.36
Global tight crude supply in the upside supply scenario

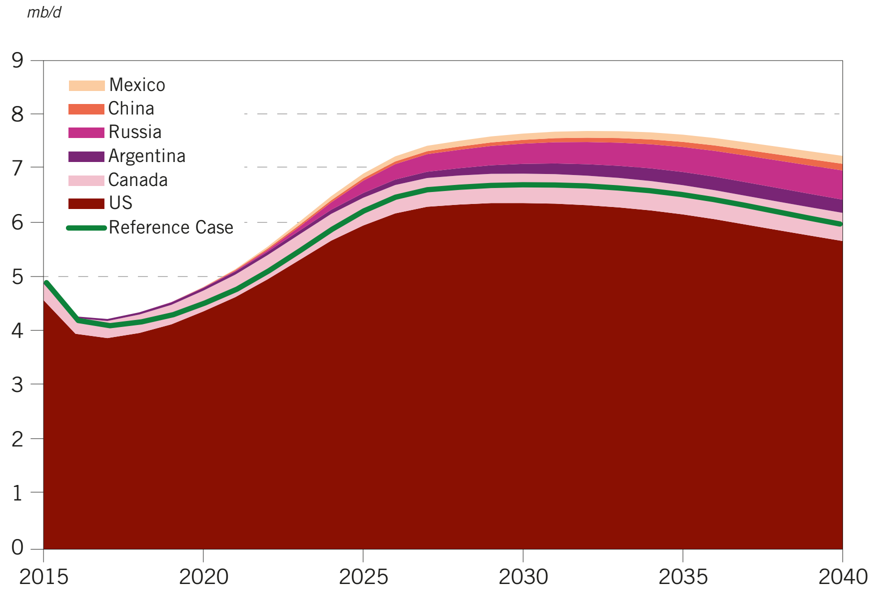
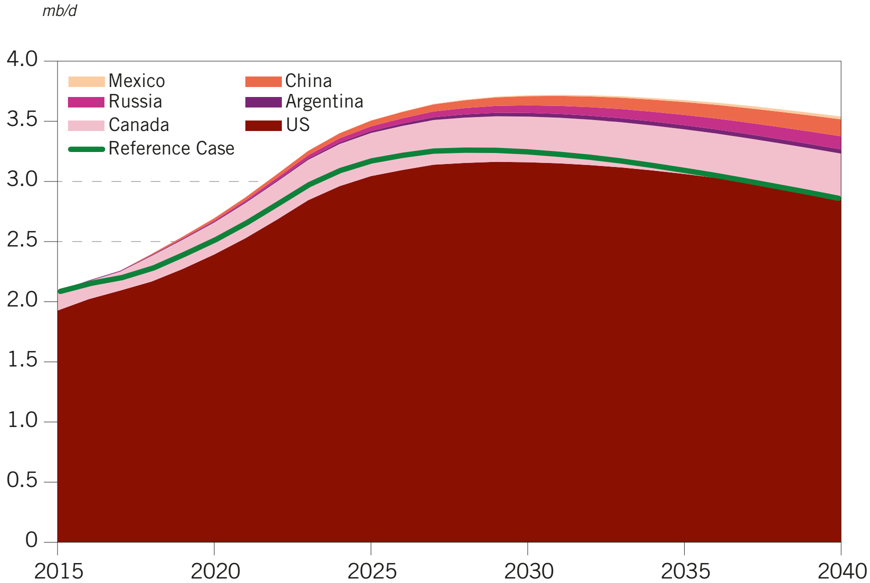


Figure 4.37
Global unconventional NGLs supply in the upside supply scenario



0.4 mb/d of tight crude in the Reference Case and over 0.5 mb/d in the upside scenario. Russia's unconventional NGLs production reaches a modest 40,000 b/d by 2040 in the Reference Case and 0.1 mb/d in the upside scenario.

Tight crude in Argentina is estimated at 0.17 mb/d in the Reference Case and 0.24 mb/d in the upside scenario, both by 2040. The country's unconventional NGLs reach 16,000 b/d in the Reference Case and 35,000 b/d in the upside scenario.

In the upside supply scenario, some production of tight oil supply is expected from Mexico and China. Mexico's energy reform is partly aimed at tight oil development, while China has hopes of exploiting its large shale gas formations and may, therefore, produce liquids from those plays. In this scenario, China produces a total tight oil quantity of 0.26 mb/d in 2040, much of it in the form of unconventional NGLs, while Mexico produces a total of 0.17 mb/d.

As a whole, the upside scenario projects global tight crude at 7.3 mb/d in 2040, compared with a total of 6 mb/d in the Reference Case. Total unconventional NGLs reach 3.5 mb/d by 2040 in the upside scenario *versus* 2.9 mb/d in the Reference Case. Figures 4.36 and 4.37 demonstrate that even in the upside scenario, the majority of tight crude and unconventional NGLs production over the long-term is from the US. The rest of the countries assessed account for 22% of the total in the case of tight crude and 19% in the case of unconventional NGLs.

Conventional crude and NGLs, biofuels and other liquids

Non-OPEC conventional crudes and NGLs could add up to 1.1 mb/d and 0.5 mb/d, respectively, by the end of the forecast period, most of it coming from North America, Latin America and Eurasia. These regions are all endowed with sizeable URRs. When combined with potentially favourable above-ground factors, and improved exploration and production technologies, these could lead to higher production than envisaged in the Reference Case.

Biofuels are also seen to have an upside potential of 0.36 mb/d, which would be the result of a speedier progress in implementing advanced biofuels technologies and from continued policy support. Other liquids, mostly represented by oil sands, have an upside potential of 0.43 mb/d by 2040. Here as well, improved technology – including methods to mitigate the environmental impacts of production – could lead to higher supply over the long-term.

Summary of additional non-OPEC supply in the upside supply scenario

Figure 4.38 shows the additional liquids supply in the upside scenario compared to the Reference Case. By 2040, the greatest upside potential is assigned to tight crude, with an extra 1.3 mb/d. Unconventional NGLs account for an additional 0.7 mb/d by then.

Combining the additions from all liquids sources considered, the total extra supply in the upside supply scenario amounts to some 4.3 mb/d by 2040. Figure 4.38 summarizes these additions according to the various sources of liquids supply. Generally, the factors that could lead to this higher level include continued technological progress and greater resource quantities than commonly assumed.

Figure 4.38
Additional liquids supply in the upside supply scenario compared to the Reference Case

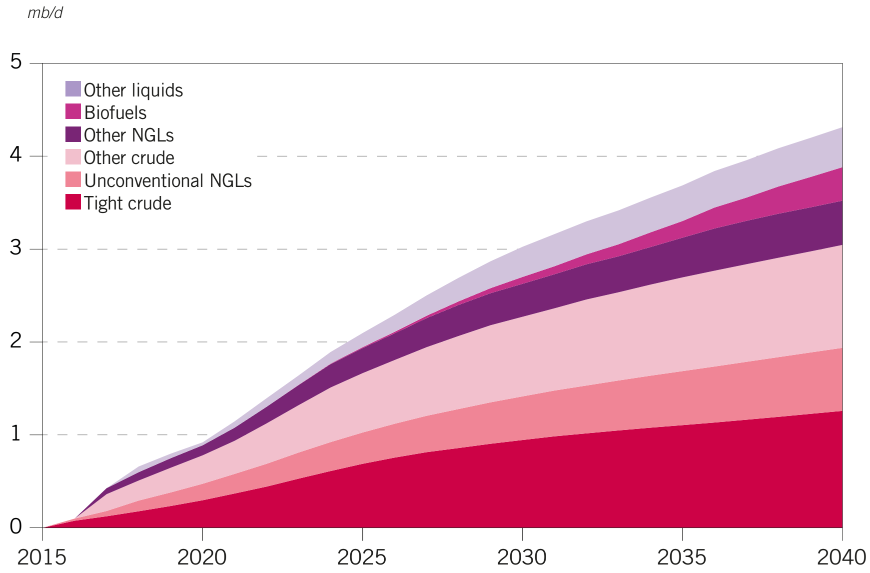
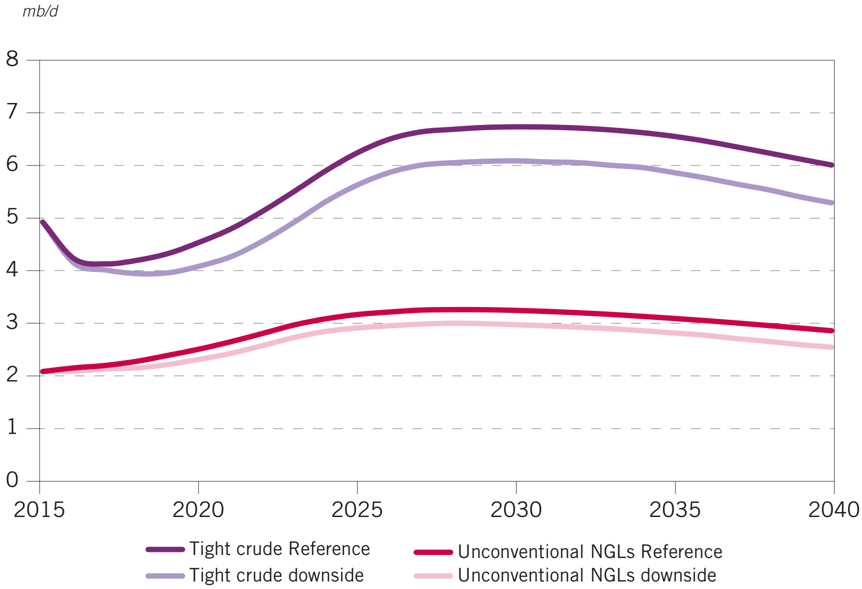


Figure 4.39
Tight crude and unconventional NGLs supply in the downside supply scenario



Downside supply scenario

In this scenario, the long-term downside projections are made for the same sources of liquids considered in the upside scenarios. Higher costs, resource depletion, and a lack of equipment and labour are among the different variables that could contribute to a lower supply level than estimated in the Reference Case.

Tight crude and unconventional NGLs in the downside scenario

In the tight oil sector, the main determinant leading to lower production would be a slowdown in drilling activity. Figure 4.39 shows the downside scenario for tight crude and unconventional NGLs compared to the Reference Case projections.

In the downside scenario, tight crude reaches a maximum of 6.1 mb/d in 2030 and then declines to 5.3 mb/d in 2040. This is 0.7 mb/d lower than in the Reference Case, which sees tight crude at 6 mb/d in 2040. Unconventional NGLs reach a high of 3 mb/d in 2028 in the downside scenario, before falling gradually to 2.5 mb/d by 2040 – compared to 2.9 mb/d in the Reference Case. It is to be noted that in the downside scenario there is no tight oil production outside North America over the long-term.

Conventional crude and NGLs, biofuels and other liquids

Some of the downside risk for conventional crude and NGLs stems from delayed or cancelled investments as a result of the lower oil price environment. Compared to the Reference Case, the downside scenario expects crude and NGLs supply to be about 0.7 mb/d lower in 2040. The reductions are attributed to regions like Latin America (Brazil), Eurasia (Kazakhstan) and OECD Europe (North Sea). Conventional NGLs, mostly from these regions, would be 0.3 mb/d lower by 2040 in the downside scenario compared to the Reference Case.

Biofuels supply is seen to be 0.5 mb/d lower by 2040 in the downside scenario. This would result from slower technical and commercial development of second and third generation technologies. Such a scenario could also play out due to reduced policy support on account of sustainability concerns associated with first generation biofuels.

Further downside risk arises from the ‘other liquids’ category, which again is mostly comprised of oil sands. In this case, supply is 0.6 mb/d lower in 2040 compared with the Reference Case. Lower oil sands output may result from commercial obstacles and unfavourable policies related to environmental concerns.

Summary of non-OPEC supply reductions in the downside supply scenario

Figure 4.40 shows the total loss of liquids supply in the downside scenario compared to the Reference Case. The largest reductions in this scenario occur in tight crude and conventional crude, each of which drop about 0.7 mb/d in 2040. The total loss of supply in this scenario is estimated at 3.1 mb/d in the same year.

Summary of alternative non-OPEC supply scenarios

Total non-OPEC liquids supply in the Reference Case (both upside and downside scenarios) over the long-term is shown in Figure 4.41. By 2040, output reaches

Figure 4.40
Reductions to liquids supply in the downside supply scenario

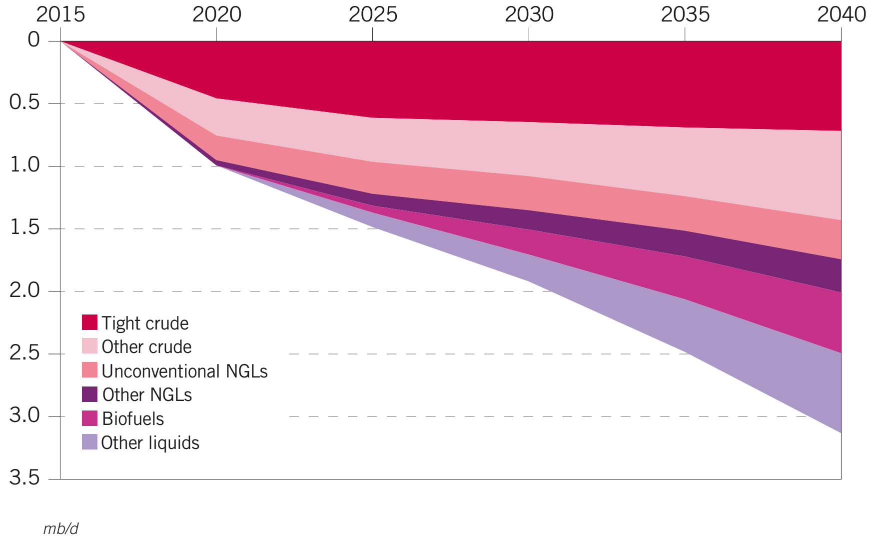


Figure 4.41
Non-OPEC supply in the Reference Case, the upside and downside supply scenarios

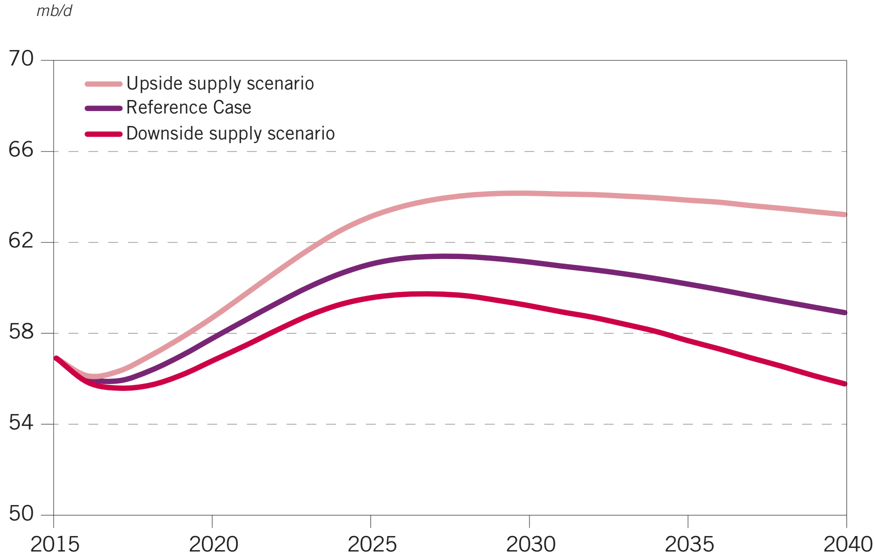
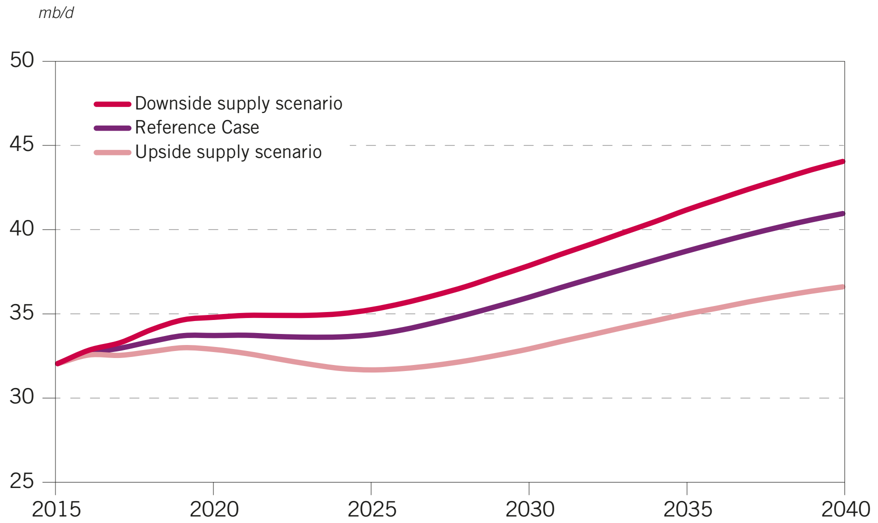


Figure 4.42
OPEC crude supply in the Reference Case, the upside and downside supply scenarios



58.9 mb/d in the Reference Case, 63.2 mb/d in the upside scenario and 55.8 mb/d in the downside scenario. The total range of non-OPEC liquids supply, therefore, is 7.4 mb/d in 2040. This highlights the uncertainties for supply that result from various factors, including costs, technologies, geology, policies and geopolitical developments. It should be noted that these scenarios also result in a range of requirements for OPEC crude over the long-term (Figure 4.42).

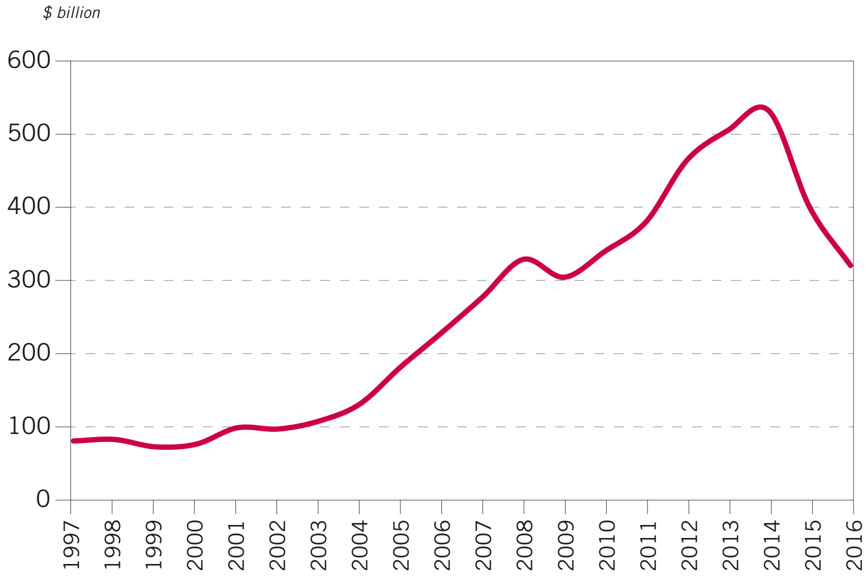
The requirement for OPEC crude in the Reference Case amounts to 41 mb/d by 2040. In the downside non-OPEC supply scenario, OPEC crude would rise higher than in the Reference Case. In such a scenario, OPEC crude output increases to 44.1 mb/d by the end of the forecast period. Alternatively, the higher non-OPEC supply scenario means that the requirement for OPEC crude will be lower. In this case, OPEC crude drops to 36.6 mb/d in 2040. The resulting range for OPEC crude in these scenarios again underlines the challenges for Member Countries in making investment decisions in a world full of uncertainties.

Upstream investment

The oil industry is one of the most capital-intensive industries with long- lead times, commonly three-to-five years, or sometimes longer. Tight oil is an exception with much shorter investment and cash flow cycles. The cyclical and long-term nature of the industry means it is vital to appreciate the link between the marginal cost, the price and investment. The industry needs stable and healthy oil prices to support investments in new projects.

At a global level, the annual upstream capital expenditure (CAPEX) was almost flat between 1997 and 2003 in the range of $90–$100 billion (Figure 4.43). From 2003, however, there was a decade or so marked by double-digit annual growth

Figure 4.43
Global upstream oil CAPEX



Source: *Rystad Energy UCube.*

for upstream investments, which was only interrupted in 2009 due to the global financial crisis. Between 2003 and 2014 the global annual oil upstream CAPEX increased five-fold, going from slightly over $100 billion to more than $500 billion.

However, the lower oil price cycle that started in mid-2014 has had clear downward implications on the industry's investment activity, with projects being deferred or cancelled. It has also been a period of cost deflation in the sector. Global oil upstream investment dropped by $130 billion in 2015, to around $400 billion. In 2016, it is expected that the investment decline will continue, though it will likely decelerate slightly. Recent estimates see a further drop of another $80 billion, to a total of $320 billion in 2016.

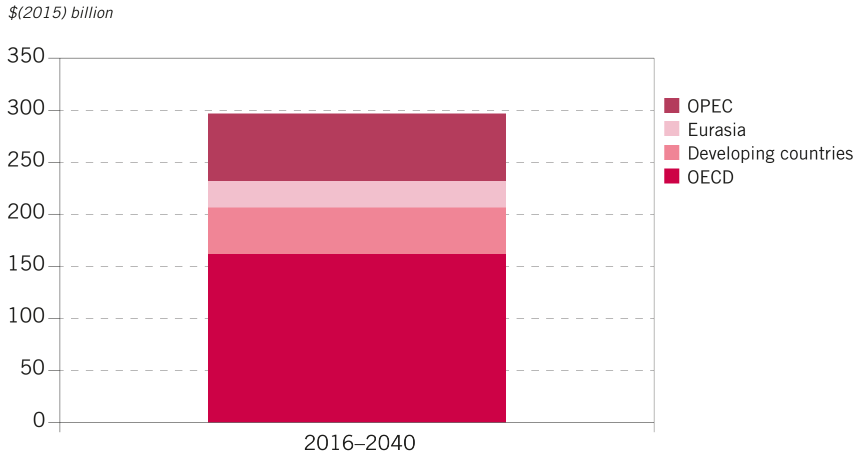
In line with the Outlook's assumption that oil prices will resume growth in the coming years, it is expected that the industry's investment activity will see an upturn. Moreover, it should be highlighted that oil demand is expected to increase by 16.4 mb/d between 2015 and 2040. This will require significant amounts of investment in the upstream, as well as in the mid- and downstream sectors.

In terms of costs, it remains to be seen how these will evolve in the future. The current low oil price environment has prompted a marked cost deflation across the industry on the back of efficiency improvements but also due to the pricing strategies of service companies. There is uncertainty about how much of the recent cost reductions will be permanent and how much of it will be temporary.

The assessment of upstream liquid supply investments up to 2040 is constructed using three variables. Firstly, based on supply projections described earlier in this Chapter, for each liquid stream (conventional crude and NGLs, tight oil, biofuels and other liquids) the supply growth from 2016–2040 is used. Secondly, taking into account the rate of natural decline of each liquid stream, the total gross supply growth per stream and region is estimated for the projected period. Thirdly, the anticipated cost per additional b/d for each liquid supply stream and region is used. Overall, for this year's Reference Case, the expected oil upstream investment requirements over the period 2016–2040 is $7.4 trillion (in 2015 dollars).

On an annual basis, the upstream investment requirement is estimated at almost $300 billion (Figure 4.44) with non-OPEC accounting for more than three quarters. While OPEC average annual investment requirements total $65 billion, in non-OPEC countries it adds up to around $230 billion. Within the non-OPEC countries, the bulk of the investment needs are anticipated in the OECD, with an average annual requirement of more than $160 billion as a result of higher exploration costs and steeper decline rates.

Figure 4.44
Annual upstream investment requirements for capacity additions in the Reference Case, 2016–2040

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Section Two

Oil downstream outlook to 2040

Distillation capacity

Key takeaways

- Distillation capacity additions for 2016–2021 total more than 7.3 mb/d, accompanied by around 1 mb/d of capacity resulting from debottlenecking.
- The Asia-Pacific (including China) is expected to add around 3.3 mb/d of new distillation capacity in the medium-term to 2021, while the Middle East should expand by 1.7 mb/d. At the same time other regions combined grow less, with total additions of some 2.3 mb/d.
- Some 2.6 mb/d of net refinery closures are assumed in the medium-term. The majority of closures are expected to occur in developed countries in Europe and the Asia-Pacific (e.g. Japan), as stagnating demand and competition from other regions puts pressure on refinery runs.
- Potential product output from these additions exceeds incremental refined product requirements by some 2.2 mb/d in the period 2016–2021. This indicates capacity overhang and rising competition for product markets at the global level.
- However, at the regional level, several regions are forecast to witness increasing capacity shortages, such as the Asia-Pacific (including China) and Africa.
- By 2040, a total of 19.5 mb/d of new global capacity is projected as needed, with almost 80% of the capacity already added before 2030, in line with projected oil demand.
- The majority of new long-term additions will be located in developing countries led by the Asia-Pacific and the Middle East, followed by Latin America and Africa.
- Mature markets such as the US & Canada and Europe are likely to see only limited capacity additions over the long-run.
- Because of regional demand declines, these capacity additions need to be accompanied by 8–10 mb/d of closures during the period 2016–2040 if viable utilization rates are to be maintained.
- Traditional markets, such as the US & Canada, Europe and developed Asia (notably Japan), are likely to accommodate the majority of required long-term refinery closures.
- The progressive reduction in demand growth rates over the long-term, together with increases in the supply of non-crude streams, steadily reduce the level of required refinery additions. Given the need for continuing closures, the long-term prospect could be for an era without any net increase in global refining capacity.

The downstream sector as defined in this Outlook starts from the supply points for crude and non-crude streams, and encompasses their transportation and refining, and the resulting product trade, delivery and consumption. The analysis presented in this Section starts from the supply and demand projections in the Reference Case developed in Section 1, and examines the evolution of the downstream sector over time. The emphasis is on developments in the refining sector, as well as on oil movements and trade.

The year 2015 was characterized by a global oil markets shock caused by the collapse of the oil price and its accompanying effects: oversupply and high oil stock levels, as well as widespread capital expenditure (CAPEX) cuts, but also strong demand. In the midst of this upheaval, the global refining and tanker sectors both registered a positive year. The drop in oil prices combined with global economic recovery led to higher-than-expected demand growth in 2015 of around 1.5 million barrels of oil per day (mb/d). This was the highest level since 2010. The majority of this growth came from non-OECD Asia, but there was also some from certain Organisation for Economic Co-operation and Development (OECD) regions such as the US and, to some extent, Europe. With incentives to process inexpensive crude – even if this meant incremental product was put to storage – refinery runs surged by around 2 mb/d over 2014 and moved closer to the 80 mb/d threshold. At the same time, refinery closures in 2015 limited the net increase in refining capacity to well below 1 mb/d. The result was increased utilization rates at the global level compared to 2014 and improved margins that, in the US and Europe at least, were the highest since the 'golden era' peak of 2007/2008.

Tanker demand was also buoyed in 2015. Increased refinery throughputs were a prime factor, as was the move to buy and place crude oil and products into storage in anticipation of future price increases. Inventory increases occurred to both strategic, as well as commercial reserves (notably in China), and resulted in a significant expansion in the use of tankers for floating storage. However, new tanker deliveries were also limited in 2015, further supporting freight rates, which rose especially for very large crude carriers (VLCCs).

These positive results in the two key elements of the downstream during 2015 raise a question about the likely sustainability of such improvements. Data for the first half of 2016 indicated refinery runs and margins staying firm, at least in the US and Europe. However, this appears to be changing in the second half of the year. The summer surge in gasoline demand, led by an all-time high in the US, has now passed and product inventories are high. These factors are weighing on refinery runs even though global demand is projected to rise by a healthy 1.2 mb/d in 2016. Thus, the expectation is that the good news that emanated from the refining sector in 2015 will start to fade.

This effect is more marked in the tanker sector. Freight rates for product tankers have dropped sharply since mid-year, driven by a combination of fleet growth and a decline in the rate of oil product stock build. The same is evident for crude oil tankers. For example, VLCC freight rates from the Middle East and Africa to the Far East, which had held at an average of around 65 Worldscale (WS) points from the beginning of 2015 through June 2016, dropped to the 40-point range in the period from July through September. Here again, additions to the fleet at a higher level than in 2015, together with an easing in refinery runs, appear to be the drivers.

These trends in 2016 tend to confirm that the 2015 surges in refining and tanker demand were, in part, a one-off result of market participants reacting to the sudden drop in oil prices. Consequently, those impacts cannot be expected to become an 'annual feature' of the industry going forward. As considered in this Section, the medium-term outlook sees refining capacity additions continuing to run ahead of demand growth, with implications for added pressure on refinery margins and increased competition for product markets over the next few years. The outlook for the tanker market is similar. Based on a strong order book, deliveries of new tankers are expected to be well in excess of scrappage levels, at least through 2017. The likely result is continued downward pressure on freight rates.

Over the longer term, the downstream is projected to be impacted by four key trends. First, recent energy efficiency/conservation mandates, which increasingly have been driven by climate change initiatives, are leading to an inevitable slowing in the pace of oil demand growth. Second, mature economies and declining demand in industrialized regions, combined with economic growth and continued population growth in developing regions, are leading to a continued regional demand shift, most notably away from US & Canada, Europe, Japan, Australasia and toward developing Asia. This brings major implications for both regional refining capacity requirements and for inter-regional crude oil and product trade. Third, non-crude supply – that is, natural gas liquids (NGLs), gas-to-liquids/coal-to-liquids (GTLs/CTLs) and biofuels – is expected to continue to grow over time, although the projected pace of growth has moderated. Nevertheless, the effect is still a reduction in the proportion of each new demand barrel that needs to be met by refining crude oil. In other words, these supplies progressively eat away at the 'call on refining'.

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A fourth important trend continues to be seen in the quality and mix of products. The recently completed move to advanced standards for gasoline and diesel quality in industrialized regions is now being mirrored in developing regions as they steadily increase the proportion of fuels that meet low and ultra-low sulphur (ULS) targets. This is generally in line with the Euro 4/5/6 standards. In parallel, the proportion of residual fuel in total demand has maintained its long-term decline trend, which has pointed to the need to upgrade heavy fuel to light, clean products. Inland use continues to shrink in most regions, with displacement by natural gas common. In addition, the MARPOL Annex VI global sulphur cap mandates a reduction in marine sulphur oxide (SO_x) emissions from either 2020 or 2025 (with a tightening from 3.5% to a maximum of 0.5% global fuel sulphur content or an equivalent reduction via exhaust gas scrubbing). The degree of change in the mix and quality of marine fuel will depend on the degree to which onboard scrubbers, which are allowed under the rule, are adopted. But this should lead to at least a partial move away from high sulphur residual type marine fuels toward lighter, lower sulphur distillate or intermediate fuels.

These are the primary challenges and trends faced by the downstream. As noted in Section One, uncertainty is also an ever-present factor – one which increases as projections are extended further out in time. Recognizing this, the chapters in Section Two present a Reference Case outlook for primary and secondary refining capacity, and also for inter-regional trade, driven by the above factors and by the projections for liquids supply and demand developed in Section One. The analysis for the medium-term is based on a comparison of refinery capacity additions – and thus potential incremental product output by year – with net potential incremental annual demand from 2016–2021.

The long-term analysis from 2020–2040 is based on a different approach, namely one using the World Oil Refining Logistics and Demand (WORLD) model.[1] The WORLD model represents the world as 23 regions. It provides an integrated simulation of the operations of the global downstream for horizons at five-year intervals to 2040. These include refining activity, capacity additions, investment and implied closures, as well as crude and product trade. As has been the case in previous Outlooks, for reporting purposes the model results are aggregated into seven major regions. (Annex C provides further details about the WORLD model's regional definitions.) Note that the regional definition used in Section Two is based on geographic criteria with the aim of capturing oil trade. It is thus different from that used in Section One.

Both the medium- and long-term assessments of distillation capacity are based on a thorough review of base capacity (as of January 2016), as well as additional capacity from known projects and reductions from refinery closures.

The medium-term analysis then solely uses the yearly additions to capacity from assessed projects for 2016–2021. (The potential output from the assessed capacity additions is compared with incremental 'liquids' demand – first in terms of total output from new distillation capacity *versus* total demand and then in terms of incremental product potential from secondary processing additions *versus* incremental demand by product.) The long-term analysis uses all three elements of capacity analysis – namely, base capacity, project additions and closures. The modelling process then adds further capacity, as needed, by region and by horizon, and also considers implied needed closures by region. The 2020 case uses the net available capacity projected as of end-2020, while the 2025–2040 cases use the net capacity projected as of end-2021. Again, these are first assessed in terms of distillation capacity requirements *versus* total 'liquids' demand and then in terms of secondary capacity relative to demand by product.

Base capacity

Overview

As in previous years, this year's Outlook includes a thorough update to base capacity (that is, distillation capacity and secondary units) by refinery worldwide, including new refineries that came onstream and closures that occurred in 2015.

Table 5.1 compares the January 2016 base capacity of 97.5 mb/d developed for this Outlook with assessments from other organizations. It is clear that the base capacity developed is very close to the base capacity assessed by BP in its June 2016 Statistical Review and by the International Energy Agency (IEA) in their February 2016 *Medium-Term Oil Market Report*, both of which were at 97.2 mb/d. What is also evident is how different organizations can arrive at different assessments. The fact is that no one source can be relied upon entirely. Refinery-by-refinery research is necessary to increase the accuracy of efforts to assess both distillation and secondary capacity. Therefore, there is always an element of arriving at a 'best estimate' for base capacity – and for projects and closures. This point is illustrated in Box 5.1, which describes special efforts

Table 5.1
Global refinery base capacity per different sources *mb/d*

Source	Reference date	mb/d(3)
IEA MTOMR, February 2016(1)	2015(2)	97.2
BP Statistical Review, June 2016	2015(2)	97.2
OPEC World Oil Outlook, November 2016	Jan 2016	97.5
Downstream Business, Hart Energy	Jan 2016	98.0
IHS	Jan 2016	95.9
Oil & Gas Journal, Refinery Survey	Jan 2016	89.5

(1) Medium-Term Oil Market Report.
(2) Not stated whether beginning or end of year; presumed end of 2015.
(3) Per calendar day.

made to deal with gaps and deficiencies in the data for three 'minor' but still important processes – namely, solvent deasphalting, and hydrogen and sulphur plant processing.

Capacity by process and region

Table 5.2 summarizes the 2016 base capacity developed and applied in the WORLD model cases. Figures 5.1–5.4 set out the same data by region. At the global level, today's refineries are increasingly 'complex' – that is, more refineries today have more secondary processing per barrel of primary distillation capacity than was the case in the past. The trend has been for most new large refineries to be built with high levels of upgrading, desulphurization, octane and related supporting capacity from the outset. Recent examples include new refineries in India and Saudi Arabia. Thus, base levels of secondary capacity are now substantial. As a percentage of crude (atmospheric) distillation capacity, vacuum distillation stands at an average of 38% worldwide, upgrading at 41%, gasoline octane units at 19% and desulphurization at 60%.

Within these averages, though, lies a wide range of geographical disparities as Table 5.2 and Figures 5.1–5.4 illustrate. Global refining distillation capacity stood at 97.5 mb/d as of 1 January 2016. Of this, US & Canada and Europe still comprise major proportions, respectively at 20 and 17.1 mb/d of capacity, which are equal to 20.5% and 17.5% of the global total. In the former region, total capacity has edged up in recent years even though ongoing rationalization has reduced the total number of refineries in operation.[2] In Europe, rationalization has entailed reductions in both the total number of active refineries and total operating capacity. In contrast, total Asian capacity has been steadily catching up to the level of US & Canada plus Europe. From around 21 mb/d in 2000, capacity for the total region now stands at 32.1 mb/d (32.9%), with China accounting for 13.1 mb/d (13.5%). This increase has been achieved despite the fact that capacity in Japan and Australia has been

Table 5.2
Assessed available base capacity as of January 2016

mb/d

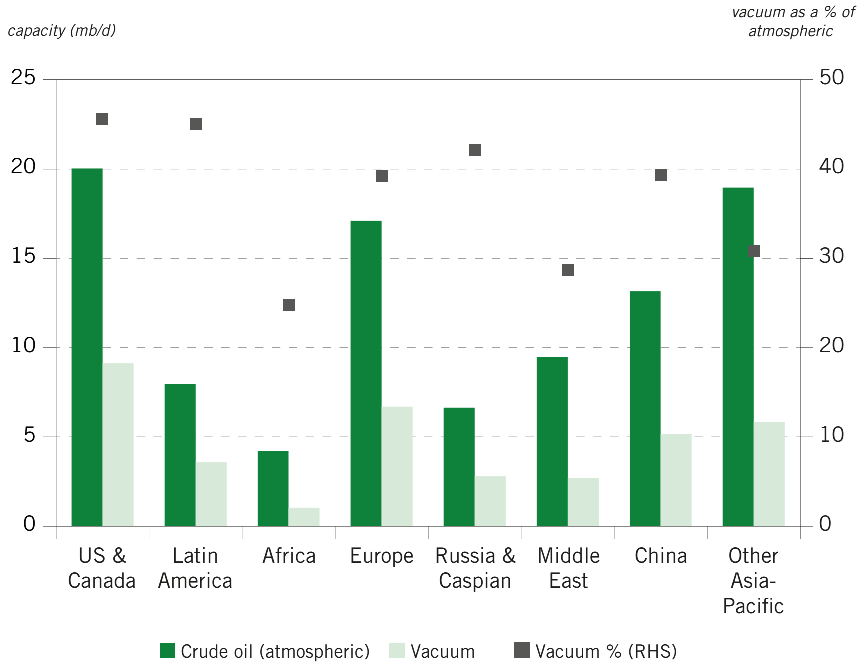
	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific	World
Distillation									
Crude oil (atmospheric)	20.0	8.0	4.2	17.1	6.6	9.5	13.2	19.0	97.5
Vacuum	9.1	3.6	1.0	6.7	2.8	2.7	5.2	5.8	37.0
Upgrading									
Coking	3.0	0.8	0.1	0.7	0.3	0.3	1.9	0.9	8.0
Visbreaking	0.2	0.4	0.2	1.6	0.5	0.6	0.2	0.5	4.1
Solvent deasphalting	0.4	0.1	0.0	0.1	0.0	0.2	0.1	0.1	1.0
Catalytic cracking	6.1	1.6	0.3	2.4	0.6	0.8	3.0	2.8	17.6
Hydrocracking	2.1	0.2	0.2	2.0	0.3	0.9	1.6	1.5	8.9
Gasoline quality									
Reforming	4.2	0.7	0.5	2.6	0.9	1.0	1.1	2.7	13.8
Isomerization	0.8	0.1	0.1	0.6	0.3	0.4	0.2	0.2	2.6
Alkylation	1.2	0.2	0.0	0.2	0.0	0.1	0.0	0.3	2.1
MTBE/ETBE	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.3
Desulphurization									
Naphtha	5.1	0.9	0.6	3.3	1.0	1.4	1.1	3.1	16.5
Gasoline	2.5	0.5	0.1	0.6	0.1	0.2	0.7	1.0	5.7
Middle distillates	6.0	2.1	0.8	5.8	1.6	2.4	3.0	6.0	27.7
Vacuum gasoil/ Residual	2.9	0.4	0.0	1.8	0.2	0.5	0.4	2.8	9.0
Sulphur (short tonnes/day)	40,524	7,738	3,634	19,103	5,670	14,892	8,594	30,898	131,052
Hydrogen (million scf/d)	6,064	1,413	407	4,580	829	2,688	2,656	5,545	24,181

Note: US capacity excludes the Torrance refinery which was closed most of 2015 and restarted early 2016.

declining as closures continue in those two countries (around 1.7 mb/d in total since 2000). Expansions have all been in developing Asia. Middle East capacity has seen a similar trend, rising from around 6.7 mb/d in 2000 to 9.5 mb/d today (9.7% of the global total).

Just as different regions have significantly different amounts of atmospheric capacity, so capacity for vacuum distillation and secondary processes varies widely, including as a proportion of atmospheric capacity. The US & Canada and Latin America regions stand out with the highest ratios of vacuum capacity to atmospheric capacity (45–46%) driven by the high proportions of heavy crudes processed in both

Figure 5.1
Distillation capacity by region as of January 2016



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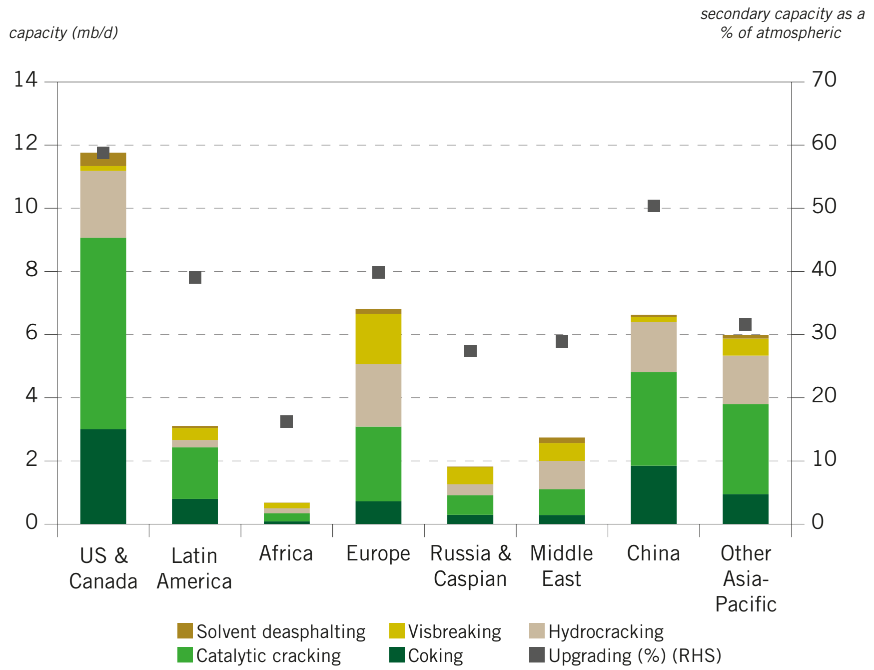
regions. In contrast, Africa has a relatively low percentage of vacuum to atmospheric capacity (25%), highlighting the relative simplicity of refineries in this region.

In terms of secondary units, the US & Canada region stands out as the most advanced upgrading region, both in terms of absolute upgrading capacity (11.8 mb/d) and in terms of secondary capacity as a percentage of atmospheric distillation (59%). Again, this relates to the combination of a relatively heavy crude slate with a long history of processing residual streams into clean products, most notably gasoline. At 50%, China's upgrading ratio is not far behind that of the US & Canada. All other regions – except Africa, which is at 16% – lie broadly in the 30–40% range. Since the 59% upgrading level of US & Canada represents near 'saturation' – that is, upgrading of 100% of the residual material (vacuum gasoil plus vacuum residuum) in the crude oil processed – the levels in other regions provide a gauge as to how far they have moved towards a similar goal. The underlying driver for all regions is the long-term decline in the use of heavy fuel oil, leaving only asphalt, lubes and waxes as the remaining outlets for 'non-upgraded' products.

The mix of upgrading unit types also varies from region to region. Coking capacity concentrations reflect the extent of processing of heavy, sour crudes while fluid catalytic cracking (FCC) units reflect the level of gasoline demand. With gasoline demand already in decline in Europe and projected to soon decline in the US & Canada region, the substantial concentrations of FCC units in those two regions mainly represent 'legacy' capacity and have been the subject of closures. In contrast, FCC units figure heavily in Asian refineries, often in the form of resid FCC

Figure 5.2
Upgrading capacity by region as of January 2016



(RFCC) capacity, to meet growing gasoline demand. While FCC units have traditionally dominated installed upgrading capacity and still comprise over 44% of the total today, recent additions have increasingly emphasized hydro-cracking, driven by high rates of growth in demand for diesel and jet. Global hydro-cracking capacity now stands at nearly 9 mb/d, over 22% of total upgrading (with coking at 20%). Europe has significantly more visbreaking capacity (1.6 mb/d or 40% of the total) than any other world regions. Generally, visbreaking capacity is 'legacy' capacity originally installed when there was an incentive to reduce the viscosity – and, hence, the production costs – of residual fuels when large heavy fuel markets were present. Solvent deasphalting, while not technically an upgrading process, directly affects the load on other upgrading units (cokers and FCCs) and so is included in the list. As discussed in Box 5.1, capacity can be difficult to pin down.

The US & Canada has the largest amount of octane unit capacity for enhancing gasoline quality, both in absolute terms (6.27 mb/d or 31% of the global total) and as a percentage of atmospheric capacity (33%). This again reflects the high demand for gasoline in the region. All other regions have noticeably low ratios in the range of 10–20%, which is in line with lower proportions of gasoline in total demand and, in some developing regions, lower octane ratings. China, at 10%, has the lowest ratio of all. However, the country's high proportion of RFCC units provides both volume and octane for gasoline blending. Catalytic reforming capacity dominates the category with much smaller proportions of isomerization, alkylation and methyl tertiary butyl ether/ethyl tertiary butyl ether (MTBE/ETBE) units.[3] Alkylation

Figure 5.3
Octane capacity by region as of January 2016

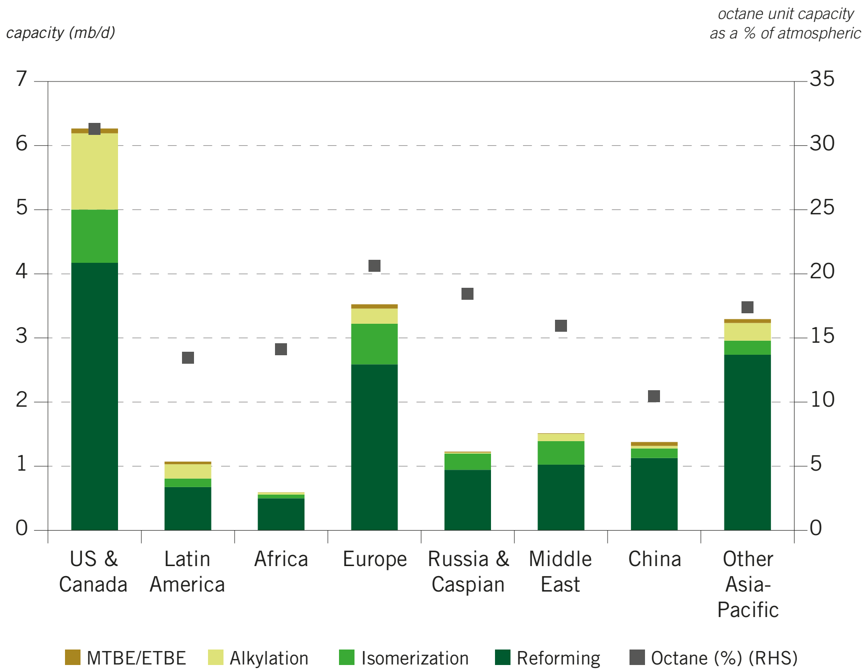


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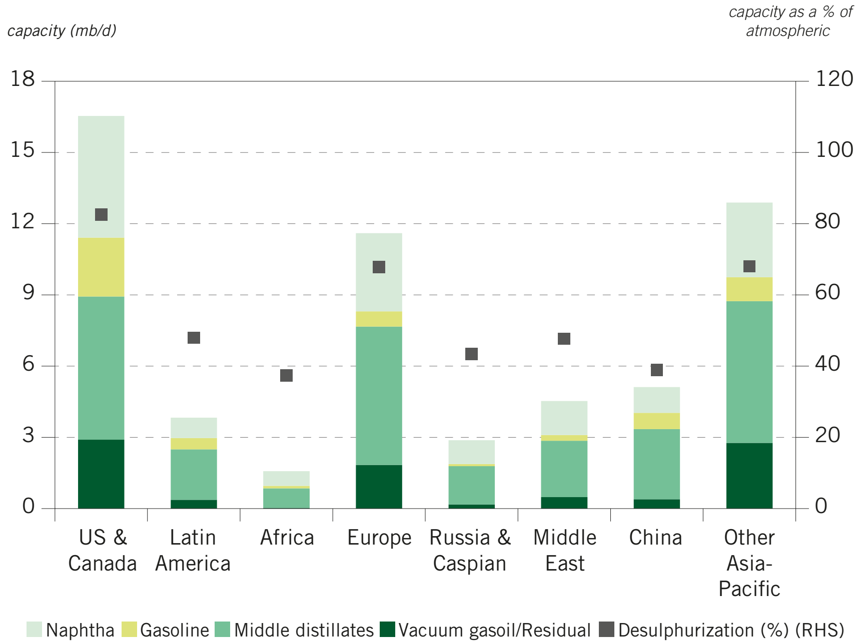
Figure 5.4
Desulphurization capacity by region as of January 2016



units rely on FCC units for feedstock and, therefore, capacity tends to be highest in regions with substantial FCC capacity. MTBE/ETBE capacity is small and comprises a mix of 'captive' in-refinery and 'merchant' plants.

Desulphurization capacity levels reflect both sulphur content in the crude oils processed and the extent to which regional fuel specifications are at low/ULS standards. It is thus to be expected that the major concentrations of distillation capacity are in US & Canada, Europe and Other Asia-Pacific, respectively at 83%, 68% and 68%. In Other Asia-Pacific, the high levels of desulphurization capacity are driven by the presence of tight sulphur standards for residual fuels in Japan and South Korea, as well as by ULS standards for gasoline and diesel across much of the region. Though lower, desulphurization levels now stand at 37% to 48% of atmospheric capacity in all other world refining regions. These levels reflect the progress that is being made toward universal low and ULS standards for gasoline and diesel.[4]

Box 5.1

Specific processes need additional capacity research

Given the need to research refining capacity by specific refinery, where possible, so as not to rely solely on published statistics, for this year's Outlook specific research was undertaken on units where there was a particular concern over the adequacy of data from primary sources. The following processes were the focus of this additional research.

Solvent deasphalting

Solvent deasphalting is often overlooked in published capacity data. The process extracts limited quantities of vacuum gasoil (VGO) that remain in vacuum residua. It thus has the effect of recovering additional VGO (albeit generally of low quality) and of reducing the volume of remaining vacuum residua that commonly is routed to a coker. It thus tends to reduce the loads on cokers, freeing up capacity to take in other feedstocks. A review of a range of secondary sources identified total global solvent deasphalting capacity of just over 1 mb/d. This represents a substantial increase over the roughly 0.6 mb/d previously in the database.

Hydrogen plant

Hydrogen plant data represent a particular challenge. One reason for this is that, in certain regions (most notably the US), there is substantial use of merchant hydrogen plant capacity – that is, outside refinery gates – which supplements the hydrogen generated by in-refinery hydrogen plant and catalytic reformers. For example, in the US Gulf Coast, there is a 1.4 billion standard cubic feet per day (scf/d) hydrogen supply and pipeline system – the biggest of its kind in the world – which supplies the region's refineries. Another reason is that the US Energy Information Administration

(EIA) requires refiners to report in-refinery hydrogen plant capacity, whereas for its Worldwide Refining Survey, the Oil & Gas Journal requests respondents to also take into account 'outside the fence' merchant capacity from which they receive hydrogen. Finally, the quality of reported hydrogen plant capacity data is quite variable. This is evident, for example, in China where only minimal hydrogen plant capacity is reported in the Oil & Gas Journal's January 2016 *Refining Survey*. (China is also one region where merchant capacity is starting to appear.)

Sulphur plant

Sulphur plant capacity data do not suffer from the inside/outside the refinery fence complexity of hydrogen plant data. According to data from the Oil & Gas Journal, a significant number of the world's refineries have some form of hydro-desulphurization capacity, but no reported sulphur plant capacity. This includes refineries in the US, Canada, Europe and Japan/Australasia. It would appear highly unlikely that so many refineries, particularly in industrialized regions, are operating with no sulphur plant. Hence, the implication is that hydrogen sulphide (H_2S) from desulphurization units is going to either fuel or flare.

A parallel approach to that followed for hydrogen plant data was also followed for sulphur plant data – that is, a 2015 case was used to assess and estimate gaps in the base sulphur plant capacity data. This was complemented by a review of information from major sulphur plant process vendors, together with data from Hydrocarbon Publishing and the Oil & Gas Journal. This data, plus the model results, helped establish a more complete picture of sulphur plant capacity in select target countries. As a result, upward adjustments to base 2016 capacity were made across several countries, with the largest changes applying to China and Russia.

Refinery projects

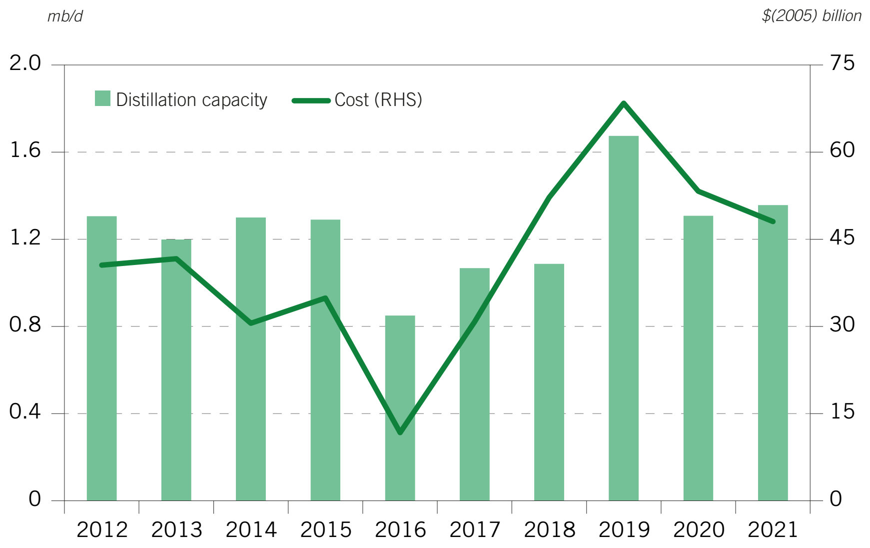
Refining capacity expansion – overview of additions and trends

Ongoing investments in the refining sector continue to emphasize capacity additions where there is growth in demand – namely in developing countries – and a pace of investment that is somewhat lower than it was two to three years ago.

In terms of the pace and scale of capacity additions, the 2013 and 2014 reviews of existing projects indicated that more than 8 mb/d of new distillation capacity would be added globally in the periods 2013–2018 and 2014–2019. The 2015 Outlook identified "a series of project deferrals … as a result of the crude oil price drop". Specifically, this referred to a slowing of firm new projects to 7.1 mb/d for the period 2015–2020. This year, the somewhat reduced pace of additions is maintained with 7.3 mb/d in firm projects expected from 2016–2021.

It is possible that additional project cancellations or delays (to beyond 2021) could still be forthcoming, especially if a second dip in oil prices were to occur within the medium-term period. Conversely, a surge in prices would not necessarily lead to an acceleration of major investments since refining companies are likely to want to

Figure 5.5
Recent and projected capacity additions and investments



see such a price increase confirmed over an extended period of time before making any final decisions to go ahead with projects (at least with large projects of, say, $1 billion plus in magnitude). That said, the fact that the rate of additions matches and even slightly exceeds the rate of additions seen in last year's review tends to reinforce the belief 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 [the] assessment was undertaken".

Figure 5.5 shows the recent history of capacity additions and associated total project investments plus the projection for these through 2021. This highlights the impact of the crude oil price drop as already noted. From 2012–2015, additions were relatively stable at 1.2–1.3 mb/d per annum (p.a.). In 2016, additions and investments drop sharply to 0.85 mb/d as companies reacted to the price drop and cut investments in light of reduced expectations and reduced cash flow. The forecast for 2017 and 2018 indicates a moderate level of recovery to just under 1.1 mb/d followed by a 'bump' from delayed projects in 2019 and, thereafter, a return to the typical recent level of around 1.3 mb/d. It is worth noting that the average rate of additions from 2016–2021 of just over 1.2 mb/d is only slightly below the average of just under 1.3 mb/d for 2012–2015, indicating a tendency for the industry to maintain or revert to a 'typical' rate of around 1.2–1.3 mb/d. This is occurring despite significant year-to-year variations, and despite a change by a factor of two in the crude price between 2015 and 2016 followed by an expected gradual recovery.

A detailed breakdown of the capacity additions projected for 2016–2021 is presented in Table 5.3 and Figure 5.6. (These do not account for potential capacity closures or for the additional capacity achieved through minor 'creep' debottlenecking, which are discussed separately.)

Table 5.3
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
2016	0.4	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.9
2017	0.1	0.0	0.0	0.0	0.1	0.2	0.3	0.4	1.1
2018	0.1	0.1	0.0	0.1	0.1	0.1	0.3	0.3	1.1
2019	0.1	0.1	0.1	0.0	0.1	0.5	0.5	0.3	1.7
2020	0.0	0.1	0.3	0.0	0.0	0.2	0.3	0.3	1.3
2021	0.0	0.1	0.2	0.0	0.0	0.5	0.3	0.2	1.4
2016–2021	**0.8**	**0.4**	**0.6**	**0.2**	**0.3**	**1.7**	**1.8**	**1.5**	**7.3**

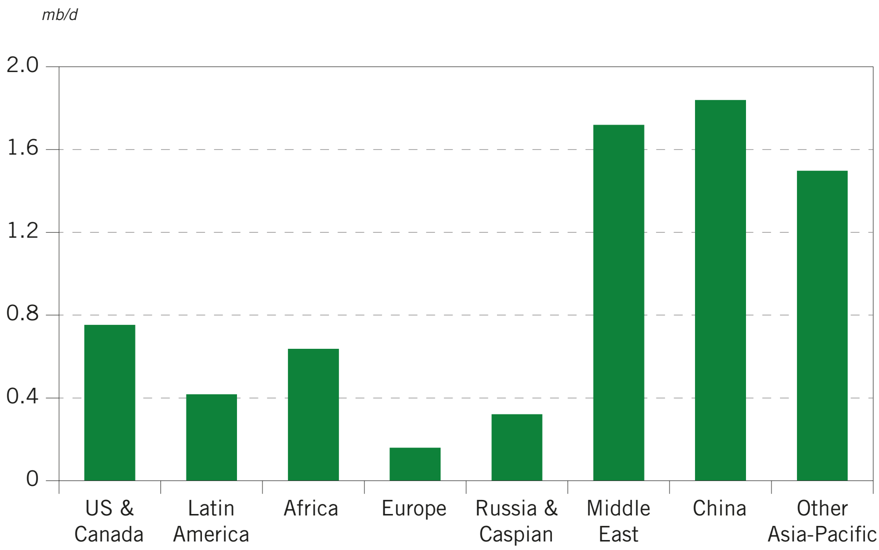
One caveat raised last year remains in place – namely that barely 50% of the 7.35 mb/d of projects assessed as 'firm' through 2021 are currently under construction (0.8 mb/d) or nearing the construction stage (2.8 mb/d). The remaining 3.75 mb/d comprises projects that are not yet near construction, but 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 2021. Since there is little time remaining to build major projects that would be up and running during the medium-term (that is, through year-end 2021), and thus be able to add to available capacity, there is potential – if anything – for reductions to occur to projected capacity due to delays and cancellations to projects expected to become available late in the period.

The projects continue the pattern seen in previous Outlooks with most projects concentrated in developing regions, predominantly in the Asia-Pacific and the Middle East. As detailed in Table 5.3 and Figure 5.6, 83% of the distillation capacity projects assessed as viable for the period 2016–2021 are located in the world's developing regions. Of the remaining 17%, a bit more than 10% is accounted for by projects in US & Canada, with a heavy emphasis on condensate splitters to handle increased volumes of light tight oil. Around 2% of additions are expected to occur in Europe (this essentially amounts to one project for a new refinery in Turkey) and somewhat more than 4% in the Russia & Caspian region.

The Asia-Pacific accounts for 45% of the new global capacity or over 3.3 mb/d through 2021. (This represents an increase from 40% and 2.9 mb/d between 2015 and 2020 seen in last year's Outlook.) Of this, China's share is projected at over 1.8 mb/d, while other countries in the Asia-Pacific add a further 1.5 mb/d. Across Asia-Pacific, the primary driver of refining projects is continuing demand growth. However, capacity surges, such as those in China, are likely to open up short periods when product exports increase.

That said, at 1.8 mb/d, China's 2016–2021 expansion is similar to that projected a year ago, but appreciably below the 2.2 mb/d projected in the 2014 outlook for 2014–2019. China appears to be settling in to a reduced capacity

Figure 5.6
Distillation capacity additions from existing projects, 2016–2021



growth rate. In part, this reflects new capacity recently brought onstream. But the shift also reflects the widely reported slowing in China's general rate of economic expansion and the associated slowdown in petroleum products demand growth. China's demand growth during 2015–2021 is the same (1.8 mb/d) as the level of capacity additions to 2021. Recognizing that refineries generally do not run at nameplate capacity, the implication is that China's product exports will drop and imports will increase, and/or that utilizations will need to rise across the country's refining sector.

For all other regions in the Asia-Pacific besides China, the projected additions of 1.5 mb/d compare with a projected medium-term demand increase of 2.1 mb/d. Thus, these regions as a whole look set to continue increasing product imports. It is important to note, however, that the 2.1 mb/d demand increase is net of a projected 0.7 mb/d demand decline in industrialized Asia (Japan plus Australasia) and an increase of 2.8 mb/d in the remainder of the region (India, with its appreciable growth, plus other developing countries).

The projected medium-term expansion continues to be substantial for the Middle East with 1.7 mb/d of new projects from 2016–2021. These sustained additions are being driven by a combination of growing local demand and policies in several countries designed to capture the value added from oil exports through refining. At 0.9 mb/d, the region's demand increase over the period justifies half of the investments taking place. Part of the new capacity will be used to reduce product imports, but the net effect of the additions should still be an appreciable increase in regional potential to market products (as well as crude oil) internationally in the near future. These additions come on top of significant new refinery capacity in the region. Especially if continued post-2021, expansion projects should materially alter the region's long-term crude *versus* product export balance, substantially cutting the former while boosting the latter – and producing the inverse effect in importing countries.

At a little over 0.4 mb/d, Latin America's medium-term crude distillation capacity additions are almost identical to the regional demand increase over the period as a whole. However, as further discussed under the section below titled *Medium-term outlook*, significant variations are expected from year to year.

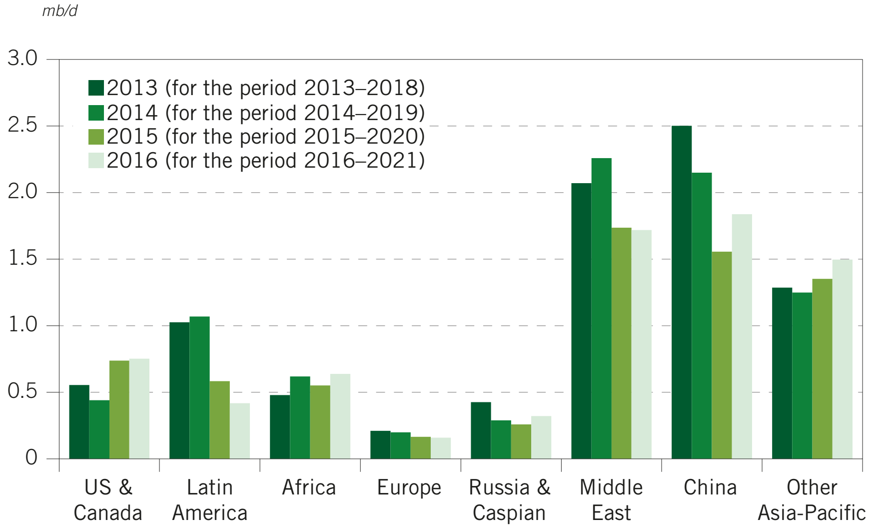
However, the 0.4 mb/d of demand and capacity increase for Latin America in this year's Outlook represents a reduction from the 'balance' of 0.6 mb/d projected last year for 2015–2020. That, in turn, was a reduction from the 2014 Outlook. The downward trend in demand growth reflects less optimistic assumptions regarding economic growth in some Latin American countries. In parallel, the continued reductions in the region's firm refinery projects stem primarily from economic difficulties in Brazil supplemented by developments elsewhere in the region. Figure 5.7 brings home this reduction in the region's pace of capacity additions.

In contrast, medium-term capacity additions in the US & Canada region remain around 0.75 mb/d. However, these comprise predominantly new condensate splitters designed to handle the recent large increase in US production of light tight oil and condensates (and introduced in part to circumvent the US crude export ban that was in effect until December 2015). These grades are not well suited to existing US refinery configurations and, therefore, splitters were introduced in part to enable less desirable light fractions to be exported while retaining the heavier fractions for processing in the region's generally complex domestic refineries. As discussed later in this Chapter, the extent to which splitter projects will continue is now an open question given the elimination of light crude and condensate supply growth, which is a result of lower crude prices and the ending of the US crude oil export ban.

In Africa, there are over 40 listed projects under consideration. However, those which look firm for 2016–2021 total only somewhat over 0.6 mb/d. This is below the projected demand increase of just under 0.7 mb/d for the period. On this basis, the outlook continues to be for further increases in regional net product imports. Furthermore, the projects considered relatively firm are slated for start-up late in the period.

Conversely, there is potential in Russia & Caspian to moderately increase net product exports over the medium-term, since distillation capacity additions at 0.3 mb/d exceed demand growth of 0.1 mb/d. Arguably more significant is the extensive rearrangement of crude oil, and product export and excise duties, in Russia, combined with tightening domestic transport fuel standards. This is encouraging refiners to make investments geared to overhauling and upgrading their refineries. One intended impact of this is to cut production of residual fuel, which is becoming economically unattractive under new tax regulations, while boosting production of higher grade fuels (especially diesel) which meet the required standards for the European export market. Recent reports of reductions in heavy fuel exports from Russia indicate that the tax changes are already having an effect. Over the period 2016–2021, Russian refineries should be able to reduce production of residual fuel by some 0.3 mb/d while raising total gasoline and distillates output by close to 0.5 mb/d. This should lead to yet further reductions in fuel oil exports offset by growth in other exports, especially of diesel fuel. Medium-term additions in the Caspian are primarily centred 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.

Figure 5.7
Distillation capacity additions from existing projects WOO 2013, 2014, 2015 and 2016 assessments



In Europe, a number of projects are underway, but these are predominantly small- to mid-scale upgrading and quality improvement additions primarily emphasizing diesel, and exhibit a complete absence of distillation capacity expansion. This is not surprising given the environment of declining demand and high costs faced by European refiners, which have led to a string of closures over the past several years. The one exception is a single project in Turkey that will add close to 0.2 mb/d of capacity.

As noted already, Figure 5.7 shows a comparison of the 2016 assessment of existing refining projects to those from the previous three Outlooks. The continuing reductions in capacity additions projected for Latin America over the medium-term imply continuing US product exports to Mexico, the Caribbean and South America. The pace of additions in Asia (outside of China) over the past four years has been stable to moderately increasing. In contrast, as noted, the pace in China has dropped as a result of a general slowdown in economic growth and liquids demand growth.

Excluding China, the pace of additions globally has also slackened, from 1 mb/d p.a. in 2013–2018 (WOO 2013) and 2014–2019 (WOO 2014) to around 0.9 mb/d p.a. in 2015–2020 (WOO 2015) and 2016–2021 (WOO 2016). Much of this reduction relates to the Middle East. The 2015 and 2016 Outlooks indicate lower medium-term additions than were projected in the previous two years. In part, this is related to significant new capacity in the region which came onstream during 2014 and 2015. However, the rate of medium-term additions in the Middle East is still averaging around 0.3 mb/d p.a. This is the equivalent of one medium to large new refinery each year. Put another way, while Middle East expansions are expected to slow, they still comprise over 30% of total global expansions forecast outside of China, with implications for continuing shifts in the patterns of international crude and product trade.

Among the remaining world regions, Europe and the Russia & Caspian have broadly maintained their very limited levels of medium-term capacity additions (recognizing again that the rate of additions in Europe is zero with the exception of one project in Turkey). For Africa, the level of additions over the medium-term period continues to average around 0.6 mb/d, which equates to around 0.1 mb/d p.a.

The trend is for a continuing medium-term shift of new refining capacity to developing countries, and for developments in several regions to lead to shifts in the patterns of international crude and product trade.

Review of projects by region

Asia-Pacific

As noted above, the pace of medium-term distillation capacity additions in the Asia-Pacific region as a whole is projected to slightly increase to 3.3 mb/d for 2016–2021. This reflects some additional projects in India, other developing countries in the region and China. As noted earlier, China's current outlook for around 1.8 mb/d (or 0.3 mb/d per year) of additions over the medium-term is at a lower level than that which existed two to three years ago. That said, China's willingness to plan joint ventures with foreign partners, notably oil exporting countries, remains a strong component in its refinery projects.

In 2015, there was only one project completed by the Chinese oil majors (Sinopec, CNPC/Petrochina, China National Offshore Oil Corporation (CNOOC) and Sinochem): a 100,000 b/d crude distillation unit at Sinopec's Jiujiang refinery. The expansion included a 34,000 b/d residual fuel hydrotreatment unit and a 48,000 b/d hydrocracking unit. Major projects in China that came onstream in 2014 centred on two new refineries and one expansion. These were, respectively, Sinochem's 240,000 b/d refinery in Quanzhou and PetroChina's 200,000 b/d refinery in the south-western city of Pengzhou, as well as Sinopec's major expansion of its Shijiazhuang refinery located in the northern Hebei province, which enabled it to process 160,000 b/d *versus* its former 100,000 b/d.

Currently five major refinery expansion projects are underway:

- Expansion of Yatong Petrochemical's Dongying refinery – from 42,000 b/d at present to 142,000 b/d by the end of 2016;
- Expansion of Sinopec's Hainan Refinery by 75,000 b/d (expected completion 2016);
- 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 CNOOC's Huizhou refinery in the Guangdong province by 200,000 b/d (expected completion in 2017), though the ethylene plant at this complex was already completed in the fourth quarter of 2015; and
- Expansion of Petrochina's Huabei refinery in Renqiu City in Hebei Province by 100,000 b/d (expected completion 2017).

In addition, there is a range of joint venture grassroots refinery projects underway. PetroChina and Saudi Aramco have continued work on a grassroots refinery in Anning (near Kunming), Yunnan province. Its size was recently increased from 200,000 b/d to 260,000 b/d and start-up is expected in October 2016. Construction of the refinery is linked to the new 440,000 b/d Myanmar-China crude oil pipeline – completed in 2014 and successfully tested in early 2015 – which is designed to bypass the Strait of Malacca.

Sinopec, Kuwait Petroleum and France's Total have proposed a 300,000 b/d integrated refinery located in the port city of Zhanjiang in Guangdong province. The joint venture seems to be facing an uncertain future, but the project may still survive. Completion is now expected in 2020, having slipped from an originally anticipated completion date 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. These latter projects, however, are at early stages of development and thus speculative. Additionally, Petrochina has announced that a previously planned PetroChina and Petróleos de Venezuela S.A. (PDVSA) joint venture for the construction of a 400,000 b/d refinery in Jieyang, Guangdong province, has been cancelled. Overall, these trends are consistent with a pattern of deferring and even cancelling projects in China and contribute to the lower rate of projected additions by major refiners.

These primary projects are likely to be supplemented by capacity changes among China's small, independent, so-called 'teapot' refineries. In February 2015, the Chinese National Development and Reform Commission released a set of rules in order to prompt such teapot refineries to either increase in size or shut down. The ruling stated that, in order to apply for crude import quotas, each crude distillation unit must have a design capacity of 40,000 b/d. There is little hard evidence to indicate that the impact of this has been on the capacity of teapot refineries, but recent reports point to significant crude oil volumes being imported by them under newly allowed government quotas.

In India, the India Oil Company Ltd. finally completed its 300,000 b/d Paradip project in 2015. The refinery experienced numerous delays over the course of its construction and took nearly 16 years to build. Separately, Chennai Petroleum Corp. Ltd. is undertaking a residual fuel upgrading project at its Manali Refinery in Madras. The project aims to increase the percentage of high sulphur crude that the refinery can process and additionally maximize distillate yield. It is expected to enter service in 2017. Delays have set Nagarjuna Oil Corp's Cuddalore refinery expansion in Tamil Nadu – which will add 120,000 b/d of distillation capacity – back to 2017. Other major projects coming onstream later include Bharat Petroleum and Oman Oil Company's expansion of their Bina refinery, Bharat Petroleum's expansion of its Kochi refinery, and the India Oil Company's expansion of its Koyali refinery in Gujarat province. In 2015, a 1.2 mb/d mega-project for the Maharashtra region was announced. The government has mandated that the state-run Indian oil companies work together on the project. While no timeline has yet been announced, due to the immense scale of the project, it is not expected to be completed before 2025.

Elsewhere in Asia, Petron completed a $2 billion upgrading project at its 180,000 b/d Bataan refinery in Limay in the Philippines. The project has enabled the refinery to double its gasoline output to 36,000 b/d and, according to Petron, "allows the Petron Bataan Refinery to fully utilize its production capabilities by converting all negative margin fuel oil into high-margin products such as gasoline, diesel, and petrochemicals". Additionally, CPC (Chinese Petroleum Corporation, Taiwan) will add 150,000 b/d by 2017 at its Talin refinery in Taiwan to offset the closure of its 205,000 b/d Kaohsiung refinery, which occurred in January 2016.

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 2018. In July 2016, a spokesman for Vietnam's Binh Dinh province said the planned 660,000 b/d refinery in the city of Nhon Hoi had been postponed due to excessive project delays. Thai state-oil company PTT cited political changes in Vietnam and uncertainty in the global oil markets as reasons for the hold-up of this $20 billion project. Furthermore, Saudi Aramco recently withdrew from a planned joint venture with PTT. The project is expected to be re-evaluated later this year.

In Malaysia, Petronas is planning to build a world-scale Refinery and Petrochemical Integrated Development (RAPID) project in the state of Johor. The 300,000 b/d project is expected to enter service in 2020. In 2016, PT Pertamina and Saudi Aramco announced a contract for the upgrade and expansion of the Cilacap refinery in Java, Indonesia. This project, however, is slated for completion post-2021. Other projects in the Asia-Pacific region include plans for greenfield refineries in Indonesia and Vietnam, but these are unlikely to be completed by 2021.

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 ULS diesel, is a joint venture between Saudi Aramco and Sinopec. A grassroots refinery project in Jazan Industrial City, Saudi Arabia, with a capacity of 400,000 b/d, is moving ahead and is expected to enter service in 2018. Additionally, Saudi Aramco has revived its plan to proceed with a $2 billion clean fuels plant at the existing 550,000 b/d Ras Tanura facility, which the company had temporarily postponed because of the drop in oil prices. Saudi Aramco is also expanding its Petro Rabigh refinery/petrochemical complex and is implementing a clean fuels project at its Riyadh refinery. Sabic and Saudi Aramco are studying the construction of a fully integrated crude-oil-to-chemicals project with an estimated cost of $30 billion.

The United Arab Emirates (UAE) also has a number of significant projects underway. An expansion of Abu Dhabi Oil Refining Company's (Takreer) existing facility in Ruwais, UAE, became operational in early 2015. This expansion added 417,000 b/d of distillation capacity, more than doubling the refinery's size. The refinery is designed to process mostly Murban light sour crude oil. A significant upgrade of the Jebel Ali 120,000 b/d condensate refinery is also set to occur, which would add 20,000 b/d of additional capacity and enable the production of refined products to Euro 5 standards. The project is estimated to enter service in 2016. 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, 44,000 b/d of net new distillation capacity will be added. The major impacts, however, will come from substantial additions to hydro-cracking and desulphurization 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. Kuwait also plans to shut its 200,000 b/d Shuaiba refinery by April 2017.

Oman has a major upgrading project underway at its Sohar refinery, which will increase throughput by 82,000 b/d. Completion is expected in 2017. The Oman Oil Company, along with the International Petroleum Investment Company, has long-term plans 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. Iran has a similar phased ongoing project for a greenfield condensate splitter project – the Persian Gulf Star – in Bandar Abbas. The facility is slated to come onstream in three stages of 120,000 b/d each, with the first stage likely to enter into operation in 2016. Additionally, Iran is building a 480,000 b/d gas condensate refinery called Siraf in the city of Assaluyeh. The refinery will consist of eight 60,000 b/d processing units. The first 120,000 b/d stage is expected to enter service in 2019. The National Iranian Oil Refining & Distribution Company also has projects underway 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, as well as in Erbil, Iraq. Iraq is also in negotiations with several investors to build four new refineries with a total capacity of 750,000 b/d. The scheduling of these projects is expected, however, to be beyond the medium-term timeframe. Several other minor projects that are geared more towards secondary process units rather than crude distillation are expected to come onstream in the medium-term.

Since 2010, the Middle East has added 1.4 mb/d of refining capacity. In the period 2016–2021, capacity is projected to increase by a further 1.7 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 Petróleos Mexicanos (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 government-imposed spending cuts attributed to the sharp decline in oil prices. In December 2015, PEMEX subsequently announced an ambitious $23 billion plan to upgrade all of its refineries in the coming years, including expansion and modernization in order to produce more clean fuels. The PEMEX Tula Hidalgo refinery, however, appears to be the only PEMEX refinery currently undergoing a modernization programme. The project is estimated to add 25,000 b/d of distillation capacity to the refinery (315,000 b/d at present) and is slated to enter service in 2019.

PEMEX is understood to be committed to the completion of both the clean fuels programme and other upgrades, but the timing of these is now uncertain and may well take place post-2021. Nevertheless, various projects specifically related to upgrading gasoline and to raising ULS diesel output have been completed. The availability of locally produced light sweet crude oil from the US, which was initially allowed under a special permit in 2015 and then freely allowed after the lifting of the US export ban, could affect future refinery investment plans in Mexico. Adding US light/very light crudes into the Mexican refinery feed mix would increase production of needed light products, help reduce the desulphurization load and could potentially reduce the need for extensive upgrades. Given PEMEX's recent $23 billion announcement, despite their constrained cash position stemming from the drop in oil production and falling prices, it remains to be seen how this situation plays out.

The first stage (115,000 b/d distillation train) of the 230,000 b/d joint refinery project between Petrobras and PDVSA in Abreu e Lima in Pernambuco, Brazil, entered service in 2015. The second stage involves replication of the 115,000 b/d distillation train and is due to enter service in 2018. Aside from the first stage of the Abreu e Lima refinery, the rest of the Brazilian downstream sector has not fared well. One project that has been affected is the new Itaborai Petrochemical Complex (COMPERJ) near Rio de Janeiro, a refinery designed to process heavy oil from the Marlim field. The 165,000 b/d first phase was previously reported as being 85% complete, but construction work on the project, which has already cost Petrobras $11 billion, virtually stopped in late 2014 because of ongoing corruption scandals. Petrobras says that it will cost an additional $4.3 billion to complete the first stage of this project and the company is currently seeking investment partners. This first 165,000 b/d stage is now forecast to enter service in 2021, while the second phase is not expected to be onstream in the medium-term. Since the precipitous drop in oil prices, Brazil's Petrobras has announced the suspension of the greenfield Maranhao (Premium I) and Ceara (Premium II) refineries in Brazil's north-eastern states of Maranhao and Ceara. Each project was initially was slated for 300,000 b/d. Since the announcement, sources have said that Iran has expressed interest in investing in the construction of the two greenfield refineries. It remains an open question, however, whether these investment plans will materialize or whether they will remain on hold indefinitely.

In Ecuador, Petroecuador completed a modernization programme project at the Esmeraldas refinery in late 2015. The project equipped the plant to run at nameplate capacity and, additionally, enabled it to nearly double the fuels that can be exported by improving fuel quality specifications. The plans for a grassroots 200,000 b/d refinery dubbed Refineria del Pacifico, however, continue to languish. In 2014, it was announced that the project would be a joint venture involving Petroecuador, China National Petroleum Corporation (CNPC) and PDVSA. However, plans for CNPC to become part of the project did not materialize and the project is now on hold until it is funded.

In Colombia, Ecopetrol completed an expansion and upgrading project at its Cartagena refinery in the first quarter 2016. The refinery now has a 165,000 b/d capacity compared to its previous rating of 80,000 b/d. The expansion project also involved the installation of several secondary units including a delayed coking unit, a catalytic cracking unit and a naphtha hydrotreater. In contrast, another upgrading project at Ecopetrol's Barrancabermeja-Santander refinery is currently on hold because of budgetary cutbacks due to the decline in oil prices. In a March 2016 Ecopetrol filing, the company cited that the project was suspended "until the oil price environment allows investments to be made in such a major project". Llanopetrol has obtained relevant permits for the construction of the 40,000 b/d Meta refinery in Villavicencio, Colombia. Assuming construction commences soon, commissioning is expected by 2019.

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. PDVSA has also commenced work on a planned expansion and modernization project at its 190,000 b/d Puerto La Cruz refinery in eastern Venezuela. The project aims to enable the refinery to run 210,000 b/d of heavy crude oil from Venezuela's Orinoco Belt. Some additional capacity will also be realized through expansion projects at existing refineries at Santa Ines and Barinas in Venezuela, and La Plata in Argentina.

The cumulative effect of these projects is an increase of somewhat over 0.4 mb/d in Latin America's crude distillation capacity through 2021, compared to end-2015 levels. This is a lower rate of expansion than that in the 2015 WOO which, in turn, was a reduction compared to 2014. In addition, this downward trend 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. In December 2015, it was announced that private equity company ArcLight Capital, along with commodities trader Freepoint, had purchased the Hovensa refinery complex. The former 650,000 b/d refining behemoth has since been converted into a large storage hub and, in a 10-year strategic deal, China's Sinopec has leased 75% of the 12 million barrels of current operational storage at the shuttered refinery. 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, cut export tariffs for crude oil and clean products starting 1 January 2015. These changes were 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. During 2015, Lukoil started up a 120,000 b/d crude distillation unit at its Volgograd refinery, boosting capacity to 290,000 b/d. Of the remaining number of projects focused on distillation capacity, the most significant are the expansions 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, which will be fed from the Eastern Siberia-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.

Apart from the expansion of crude distillation units, many projects in Russia are focused on adding conversion and desulphurization units. This is because most Russian refineries are simple and thus yield high quantities of heavy fuel that are at a disadvantage under the new petroleum tax structure. In 2015, Lukoil completed a 40,000 b/d catalytic cracking complex at its 340,000 b/d Nizhny Novgorod refinery in Kstovo. Aligned with the recent crude distillation capacity increase at its Volgograd refinery, Lukoil also expects to commission a vacuum gasoil (VGO) deep conversion complex in 2016. The project includes a 70,000 b/d VGO hydrocracker and units for hydrogen production and sulphur recovery. Rosneft, Lukoil and TAIF-NK are also planning several projects with start-up dates in 2016 and 2017, including at least two world-scale hydrocrackers.

In total, Russian companies are set to add 450,000 b/d of conversion units in the period through 2021, which is far ahead of the 200,000 b/d of additions to crude distillation. As indicated in the project descriptions, the conversion additions are heavily oriented toward hydrocracking, at 237,000 b/d, plus 126,000 b/d of coking and 86,000 b/d of FCC capacity. (In addition, three hydrocrackers were started up in 2014 with a combined capacity of 120,000 b/d.) On top of these, an estimated additional 450,000 b/d of desulphurization capacity will be available in Russia by 2021. This will not only serve to meet tightening fuel specifications for domestic markets, but will also expand the ability to produce Euro 5 products for exports, notably to Europe. Combined with the substantial upgrading additions and the emphasis on hydrocracking, the outlook is for a major shift in Russian refinery production and exports away from heavy fuel (as intended by the new rules) and towards diesel (primarily) that will meet European standards. This, therefore, should impact the distillate supply balance into Europe in particular.

Beyond Russia, the need for upgrading and modernizing ageing refineries also exists in the Caspian region. Refineries there 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 2021. Moreover, the capacity expected to be gained through these projects – 0.1 mb/d total – is relatively small. A total of five expansion projects in Kazakhstan (Atyrau, Pavlodar and Shymkent refineries), Tajikistan (Danghara) and Uzbekistan (Bukhara) should add a combined additional capacity of 106,000 b/d by 2019. Beyond these, proposals for other new refineries have been put forward – two in Kazakhstan and the other in Turkmenistan – but they are at an early stage with completion not likely until after the medium-term period.

US & Canada

Medium-term crude distillation capacity additions from existing projects in the US & Canada are expected to be 0.75 mb/d. These continue to be dominated by developments with regard to the challenge of processing production of tight oil extra-light crudes and condensates. Addressing the issue, US refiners and midstream companies have shifted investments towards building relatively simple condensate splitters. These are primarily aimed at relieving 'light ends' processing limits in existing refineries while also maintaining and providing medium to heavy boiling range fractions to help sustain utilization rates at existing conversion units.

Table 5.4
US stabilizer/splitter projects

Company	Location	Capacity *1,000 b/d*	Estimated completion
Buckeye and Trafigura	Corpus Christi, TX	50	2016
Magellan	Corpus Christi, TX	50	2016
Centurion Terminals	Brownsville, TX	50	2016
Targa Resources	Houston, TX	35	2017
GOTAC	Corpus Christi, TX	35	2017
Castleton Commodities	Corpus Christi, TX	100	2017
Total potential capacity		**320**	

Projects recently completed include a 25,000 b/d splitter at Marathon's Canton refinery (completed December 2014), a 35,000 b/d splitter at Marathon's Catlettsburg refinery (completed mid-year 2015), the second of two splitters (100,000 b/d in total) at Kinder Morgan's Galena Park terminal in Texas (mid-year 2015) and a 100,000 b/d splitter at the Phillips 66 Sweeny refinery in Texas (December 2015). Several other stabilizer/splitter projects have been announced and are in various phases of progress (Table 5.4).

The 320,000 b/d of additions as projected in the Table are well below the 580,000 b/d of expected additions that were listed in the 2015 Outlook. The reduction in the planned level of additions stems from two developments. Firstly, the reduction in the crude oil price has caused US crude and condensate production to plateau and now moderately decline, reducing the need for additional splitters. Secondly, in December 2015 the US Congress and President Obama repealed the four-decades-old US Crude Oil Export Ban as part of a government spending and tax bill. This reduced the incentive to split light crudes and condensates, and then export the products as a means to circumvent the ban. The repeal of the ban, in addition to broader capital budget cuts by companies and a somewhat less optimistic outlook for crude production growth in the US, casts doubt on whether the remaining listed projects will all materialize.

Beyond new condensate splitters, developments in US shale have also created other refining projects. In April 2015, the Dakota Prairie 20,000 b/d refinery by Calumet/MDU Resources started up in Dickinson, North Dakota. This is the first grassroots refinery in the US since 1976. The refinery is of modular construction and is designed to process locally sourced Bakken crude oil into diesel fuel in order to satisfy local markets. In a similar vein, Meridian Energy Group announced in early 2016 that it would soon begin construction of a 55,000 b/d greenfield refinery in Belfield, North Dakota. This project also aims to make use of locally sourced Bakken crude oil.

However, all has not gone well for these small new refinery projects. In late June 2016, Tesoro – which already owns a refinery in Mandan, North Dakota – announced it would purchase the Dakota Prairie facility which had been struggling financially. Tesoro indicated it would improve and integrate operations to raise profitability.

In August 2014, ExxonMobil announced a 20,000 b/d expansion at its Beaumont refinery in Texas as a means to process increased volumes of light crude. This expansion is expected to enter service in 2017. In July 2016, it was announced that the refinery plans to increase production of ULS fuels by approximately 40,000 b/d through the installation of a selective cat naphtha hydro-refining unit. However, this is a far cry from the previously announced plan to more than double the current 344,000 b/d capacity at the refinery that has been scrapped due to falling oil prices and corresponding cuts to Exxon's capital budget. A range of other projects mainly combine minor distillation expansions with upgrading and clean fuel revamps. Several entail increasing the ability to process very light crudes. Projects completed in 2015 include the following:

- Valero completed a 15,000 b/d hydrocracker expansion at its Port Arthur refinery (Texas);
- Valero completed a multi-year expansion project at its McKee refinery (Texas) enabling it to process an additional 20,000 b/d of crude (from 170,000 to 190,000 b/d);
- A debottlenecking project at HollyFrontier's Navajo refinery in Artesia (New Mexico) boosted the refinery's capacity from 80,0000 b/d to 100,000 b/d and additionally added naphtha fractionation and hydrogen generation units; and
- A new delayed coker was installed at National Cooperative Refinery Association's McPherson refinery (Kansas), which commenced operations in February 2016. When combined with other improvements at the plant, the expansion is expected to boost refining capacity to 100,000 b/d from its current 85,000 b/d level.

Firm projects outstanding include the following:

- Marathon's Robinson refinery (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;
- Flint Hills' Corpus Christi (Texas) refinery 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;
- Holly Frontier's refinery in Woods Cross (Utah) has been expanded by 14,000 b/d to a total refining capacity of 45,000 b/d. The project was completed in the second quarter of 2016 at an estimated capital cost of $375 million. A second envisaged investment includes an additional 15,000 b/d crude capacity expansion at some point beyond 2018;
- 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; and
- Chevron received final regulatory approval in 2015 to complete a $1 billion revamp project at its 257,000 b/d Richmond refinery (California). The modernization project will replace some of the refinery's older equipment, but the capacity and basic operations will remain unchanged.

Refinery projects geared towards reconfiguring refineries – especially in the Midwestern US – 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, northeast of Edmonton, Alberta. This first of three 50,000 b/d stages is expected to start up in the 2017–2018 timeframe. The second and third stages are in the planning phase and will likely stretch beyond the medium-term horizon of 2021. The NWR project is unusual in that it upgrades oil sands bitumen in one facility to primarily ULS diesel, with extensive use of hydro-processing, gasification and carbon capture and storage (CCS), to establish a low carbon footprint for refined products. The economics of the Sturgeon plant have been the subject of public debate in Alberta in light of lower oil prices. However, recent change in the provincial government has revitalized discussions over the merits of obtaining the value-added finished products and the employment benefits of refining oil sands within the region.

Plans for large new bitumen upgrader refineries also exist elsewhere in Canada. Kitimat Clean Ltd. proposes the construction of an advanced $22 billion, 550,000 b/d refinery at Kitimat on the coast of British Columbia. A feasibility study was completed in December 2014 and Kitimat is already an active oil port. Kitimat is also the stated terminus for the proposed Enbridge Northern Gateway crude pipeline from Edmonton. However, as discussed later in Chapter 7, the pipeline project now looks extremely unlikely to proceed. In response to the lack of progress on the Northern Gateway, in late 2015 Kitimat Clean announced it had reconfigured its speculative project to instead rely on the receipt of raw bitumen by rail (delivered in heated rail cars). Furthermore, it announced that it was in talks with CN Rail about using an existing rail line to Kitimat. (It is worth noting that every major crude-by-rail accident from Lac Mégantic onward has involved light Bakken crude oil not heavy 'rail bit' or undiluted bitumen.)

Thus, the Kitimat project remains alive. The refinery would 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 to liquefy it for export, provided at least one project goes ahead. In addition to the value-added, increased employment and low carbon emissions benefits, the project would replace the export of oil sands crude streams with exports of clean refined products. This would have far fewer environmental consequences in the event of a spill.

A second 'green refinery' project is being considered near Kitimat: Pacific Future Energy is assessing the construction of an export-oriented 200,000 b/d bitumen refinery. In June 2016, and after review with First Nations and other stakeholders, the project developers submitted updated project documents to federal and provincial regulators, initiating review processes that could take up to two years. The 'green' credentials for the design centre on the use of natural gas as fuel, avoidance of FCC and coking (both of which produce coke) in favour of hydrocracking, gasification of remaining pitch into liquid fuels and the potential use of carbon dioxide (CO_2) removal from off gases. Again, the refinery feedstock would be minimally diluted bitumen delivered by rail.

A third project has equally interesting 'twists'. Eagle Spirit Energy has proposed a 1 mb/d pipeline from Alberta to Prince Rupert, a deep water port located northwest of Kitimat and directly on the coast. (Kitimat is some 80 kilometres (km) from the coast up a large inlet.) The Eagle Spirit project claims strong First Nations backing. It relies on a number of key factors. Firstly, the Alberta Royalty Review Panel is reported to have recommended in January 2016 that partial upgrading of bitumen be made a priority, specifically upgrading sufficiently in order to enable pipeline transport without the use of diluent. The Eagle Spirit project would tie in to additional partial upgrading facilities. These would provide partially upgraded crude oil for input to the pipeline, which it is claimed would also be able to carry conventional crude and potentially refined products. (The Trans Mountain pipeline to Vancouver, British Columbia, transports both crude oils and products.) Secondly, it is proposed that the Eagle Spirit line share a corridor with one of the four natural gas pipelines from Alberta to Kitimat now being proposed, thereby reducing regulatory hurdles and costs. Thirdly, the crude oil (and products) carried on the pipeline could be exported to Asia via a short Great Circle route from Prince Rupert – or could be used as feedstocks to the Kitimat Clean or Pacific Future Energy refineries if built.

It remains to be seen whether any of these ambitious schemes develop into firm projects. If any of these are completed, they would have the effect of providing additional outlets for Western Canadian crude (see Box 7.2) and of increasing the flow of Canadian crudes and products to Asia.

Africa

As stated in previous Outlooks, 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 an evident need and potential for more refining facilities. Despite this, there are currently only a few projects under construction or at an advanced planning stage in Africa.

The largest project under construction is Angola's Lobito refinery. The first stage calls for 120,000 b/d of distillation capacity coming onstream in 2019. The total 200,000 b/d design capacity will be reached after completion of the project's second phase, which involves 80,000 b/d of distillation capacity in addition to several upgrading units. The timing of this project remains open to question though. In May, Sonangol was reported as awarding the contract for the design and engineering work to Engineers India Limited. In late August, however, it was announced that Sonangol had suspended construction on the refinery "to reassess the development and implementation". Another greenfield refinery project – dubbed the 'Prince of Kinkakala' refinery in Ambriz, Angola – was announced by Sonangol. It tentatively involves 400,000 b/d of processing capacity and will likely entail a partnership with a Chinese state oil company. Stated completion is 2019, but the project is at an early stage and, therefore, considered speculative.

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 90,000 b/d units at Tiaret, Biskra, Ghardaia and Hassi Messaoud – and upgrades at existing facilities as well. The United Kingdom's (UK) Amec Foster Wheeler was awarded front end engineering and design (FEED) contracts for three refineries at Biskra, Tiaret and Hassi Messaoud. However, while the Tiaret project appears likely to reach completion in 2019, other projects appear to be still uncertain or to have shifted beyond 2021.

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. In late March, the Nigerian National Petroleum Corporation (NNPC) was reported as being in talks with Chevron, Total and ENI regarding potential assistance to restart and revamp refineries at Port Harcourt, Warri and Kaduna. Of several possible refining projects, one that may materialize in the medium-term is the grassroots 650,000 b/d Dangote refinery and an associated greenfield fertilizer plant in Lagos. If built, this refinery would be Nigeria's first privately owned and operated refinery.

In Uganda, a 30,000 b/d initial (60,000 b/d eventual) capacity greenfield refinery project and associated oil products pipeline was previously announced. However, in July 2016, negotiations reportedly broke down between the Ugandan government and the Russian company Rostec, which was charged with financing and construction of the $4 billion project. The government reportedly turned to a Korean group that had also been bidding. It remains unclear whether or not the project will now move forward. Failure of the project to progress could adversely impact oil production in the country.

In West Africa, the Limbé refinery in Cameroon is being expanded and upgraded to increase capacity from 42,000 b/d to 70,000 b/d. The project, due for start-up in 2016, will allow the refinery to process local crude and condensate, rather than imported feedstocks, while also improving overall utilization.

Plans are also underway in South Africa to upgrade Sapref's Durban refinery (a project of Shell and BP) and the Natref refinery (a project of Sasol and Total). These are aimed at upgrading gasoline and diesel fuel qualities to comply with the South African government's clean fuels specifications. However, while the Sasolburg project is now slated for 2017 completion, the Durban refinery project has been delayed to 2019. The major project in the region, however, is PetroSA and Sinopec's proposed 360,000 b/d Mthombo project. The refinery, which would be located near Port Elizabeth, would be designed to process sour crudes while producing clean products to Euro 5 standards. Like other projects on the continent, the project aims to reduce the country's growing product imports. The project has not yet reached an advanced stage and start-up now looks unlikely before 2020.

In summary, it is estimated that around 0.6 mb/d of new crude distillation capacity will be available in Africa by the end of 2021. Whether or not the large Dangote project progresses in a timely manner remains a major consideration, as it will affect how much new capacity is in fact brought onstream in the medium-term.

Europe

Over the past few years, Europe has been the centre of much refinery closure activity. This is expected to continue at some level for the foreseeable future. Indeed, almost 1 mb/d of additional closures are projected for Europe in the 2016–2021 period (see *Assessed refinery closures*). Altogether 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 SOCAR (the state oil company of Azerbaijan) and Turcas Petrol. This project is expected to be completed by 2018.

Besides this project, there are several other upgrading projects – mainly in Northern 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 targeting sulphur content. In 2015, Lukoil completed a heavy residue hydrocracking complex at its 196,000 b/d Burgas refinery in Bulgaria. The project included a 50,000 b/d residual asphalt hydrocracking unit and a number of other secondary units. Additionally, Neste Oil completed a major turnaround to optimize the refinery's performance and facilitate the company's planned $500+ million plan to closely integrate operations at the Porvoo and Naantali refineries in Finland. This integration effort is expected to be completed in 2019. Shell made the final investment decision in December 2015 on a solvent deasphalter unit at its Pernis refinery in Rotterdam, Netherlands. Completion is expected around year-end 2018. ExxonMobil is currently expanding hydrocracking capacity at its subsidiary Esso Nederland's 191,000 b/d refinery in Rotterdam. According to a proposal for the expansion filed with Dutch authorities, hydrocracking capacity at the plant would increase by 40% to around 70,000 b/d. Construction of the expansion began in June 2016 and a prior announcement indicated start-up of the new facility in 2018. While the project will not change the refinery's capacity, it will boost the facility's ability to process heavy VGO.

ExxonMobil continues work on its Antwerp refinery expansion project in Belgium. Fluor began work on the new delayed coker unit in December 2014. Amec Foster Wheeler was awarded an engineering, procurement and construction contract for the upgrade project and expects construction to be completed in December 2016. The Total Antwerp refinery upgrade project continues to move forward and is forecast to be commissioned in early 2017. Kinetic Technologies began construction on the expansion's new desulphurization unit in February 2015 and Praxair was awarded a contract in January 2016 to supply industrial gases to the facility.

Assessed refinery closures

This section reviews the recent history of refinery closures, the prospects for additional firm closures based on announcements and refinery capacity that is considered at potential risk of closure by virtue of recent sales or other announcements (refinery 'closure watch list'). This leads to an updated assessment for total refinery closures for 2016–2021. (The sections that follow provide a review of the potential for further closures in both the medium- and long-term, based on our medium-term assessment and long-term modelling projections.)

Table 5.5 and Figure 5.8 summarize recent closures since 2012 and projected closures through 2021. Note that the total closures level of 2.6 mb/d shown for

Table 5.5
Net refinery closures, recent and projected, by region *mb/d*

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total 2016–2021
US & Canada	0.1	0.1	0.2	–	–	–	0.1	0.1	–	0.0	0.2
Latin America	0.6	–	–	–	–	–	0.0	–0.2	–	–	–0.2
Europe	1.0	0.2	0.4	0.3	0.1	–	0.2	0.4	0.2	0.0	1.0
Russia & Caspian	–	–	–	0.3	–	–	0.0	0.0	0.1	0.1	0.2
Africa	–	–	–	–	–	–	–	–	–	–	–
Middle East	–	–	–	–	–	0.2	–	0.1	–	–	0.3
Asia-Pacific	0.1	0.1	0.6	0.1	1.0	–	–	–	–	–	1.0
Total	**1.7**	**0.4**	**1.2**	**0.6**	**1.1**	**0.2**	**0.4**	**0.5**	**0.3**	**0.1**	**2.6**

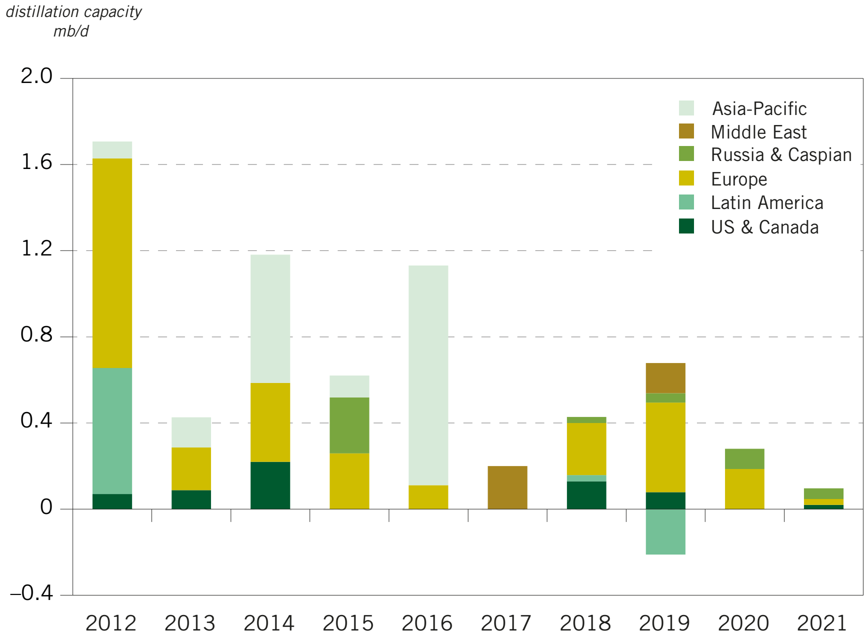
Note: *2019 closures include the restart of the 235,000 b/d Aruba refinery, that is, a 'negative' closure. Thus, gross closures from 2016–2021 are somewhat over 2.8 mb/d.*

2016–2021 allows for the restart of the 235,000 b/d Aruba refinery in 2019. Gross closures for the medium-term period thus equate to some 2.84 mb/d. This level is lower than the 3.8 mb/d assumed for the period 2015–2020 in the 2015 Outlook. However, with oil prices projected to recover gradually, this year's Reference Case outlook has 2020 global 'liquids' demand 0.9 mb/d higher than was projected a year ago and 2021 demand over 1 mb/d higher. This projection for increased medium-term demand, which is evident also in outlooks from other entities such as the IEA and Energy Information Administration (EIA), therefore, indicates higher refined product demand and potentially that fewer closures are needed – at least over the next five years or so. Reflecting this, the incidences of newly announced closures and refineries 'for sale' (and, hence, put on a closure 'watch list') appear to be slowing. In addition, the average pace of closures of almost 1 mb/d p.a. from 2012–2015 and the 1.1 mb/d of closures in 2016 do not appear to be sustainable. Consequently, the updated closures outlook has the pace of closures from 2016–2021 of around 0.4 mb/d.

Of the close to 3 mb/d of gross closures through 2021, the Asia-Pacific is projected to experience the most with 1 mb/d. These are predominantly already-planned closures in Japan resulting from the government requirement that refineries increase their ratio of residue upgrading to atmospheric distillation. Since the demand trend in Japan is flat to declining, Japanese refiners have been responding by closing existing crude distillation units rather than adding new upgrading units. In addition to the ongoing shuttering of much capacity in Japan this year, the 100,000 b/d Petrobras refinery on the island of Okinawa (Japan) is slated to close in the near future. CPC's 205,000 b/d Kaohsiung refinery in Taiwan closed on 1 January 2016, while BP's 102,000 b/d Bulwer refinery in Australia closed in mid-2015.

Significant closures, nearly 1 mb/d to 2021, are projected to continue in Europe, again driven by declining demand. While still substantial, this represents

Figure 5.8
Refinery closures recent and projected by region*



* *No closures are expected in Africa.*

5

an appreciable slowing in the annual rate of closure from 0.45 mb/d in 2012–2015 to 0.16 mb/d per year in 2016–2021. Lower oil and natural gas prices have reduced the scale of (but not eliminated) the competitive disadvantage European refiners have been experiencing relative to refineries in the US and Middle East. In 2015, Tamoil's 55,000 b/d Collombey refinery in Switzerland shut permanently. Eni's 100,000 b/d Gela refinery in Sicily is being converted to a biofuels plant and Total's 160,000 b/d La Mede refinery in Marseille, France, is also being converted to a biofuels plant. Additionally, Total is in the process of halving production at its Lindsey refinery in the UK (from 200,000 b/d to 100,000 b/d).

Closures are also projected for the US & Canada, particularly as a recent demand boost starts to reverse and the prospect of long-term decline becomes evident. For the Russia & Caspian region, closures will be driven by continued flat demand and the Russian 'tax manoeuvre', which is designed to force refineries in the country to rationalize and upgrade their facilities. The projected closures in the Middle East are very specific. The planned closure of Kuwait National Petroleum Company's 200,000 b/d Shuaiba refinery is slated to occur in April 2017, a short time before the Clean Fuels Project – already well underway – is due for start-up (2018–2019). The Clean Fuels Project aims to transform two Kuwaiti refineries located 10 miles apart into an integrated merchant refining complex. As part of the integration project, the Mina al-Ahmadi refinery will shed 140,000 b/d and the Mina al-Abdulla refinery will add 184,000 b/d – resulting in a net gain of 44,000 b/d and a total of 800,000 b/d refining capacity at the integrated Mina al-Ahmadi and Mina al-Abdulla complex.

WORLD model results provide a cross-check on whether the assumed level of closures by 2021 is appropriate or whether there is a need for more (or fewer). The 2020 Reference Case projects global average utilizations at 81.4% and a test case run for 2021 at 79.4%. There are appreciable variations from region-to-region, but the overall level suggests that allowing for 2.6 mb/d of net closures (over 2.8 mb/d gross) projected for 2016–2021 appears reasonable.

Medium-term outlook

As previously described, global incremental distillation capacity resulting from existing projects was assessed at 7.35 mb/d for the six-year period from 2016–2021. This is slightly above last year's projection of 7.1 mb/d for 2015–2020 and appreciably below the 8.3 mb/d assessed two years ago for 2014–2019. As noted, this lower level now evident is a consequence of project delays resulting from the recent crude price drop. Adding in an allowance for some additions to be achieved through 'capacity creep',[5] the total medium-term increment to crude distillation units is projected to be around 8.2 mb/d for 2016–2021 plus extensive secondary units.

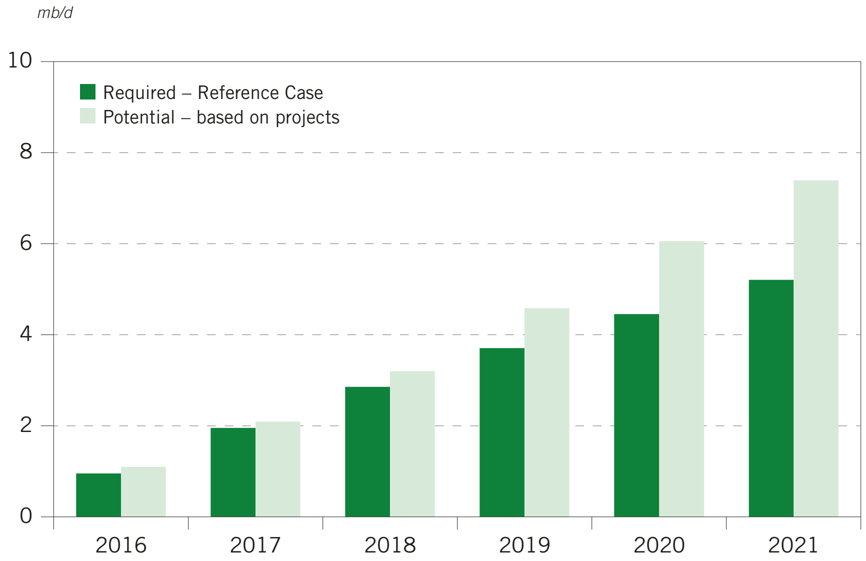
These additions, broken down by year, are used to project potential annual incremental crude runs and associated refinery yields. These are then compared to those for incremental demand in order to establish incremental refining supply *versus* demand balances, globally and by region. This Chapter addresses balances looking solely at distillation capacity, crude runs and total demand. Chapter 6 takes secondary processing into account and presents the associated incremental production/demand balances by product.

Figure 5.9 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 that the new projects could be expected to sustain.[6]

On this basis, for 2016–2021 potential incremental crude runs average approximately 1.2 mb/d annually (like last year), leading to cumulative potential incremental runs of 7.4 mb/d. The assessed potential crude runs are based on the assumption that only high probability projects will be coming onstream by 2021. It is, therefore, possible that some additional moderate scale projects could arise over the next couple of years that may add to the capacity coming onstream *versus* the capacity indicated in the outlook. Conversely, given the current uncertainties, it is also possible that delays could push back some high probability projects, reducing the capacity available. The assessed 7.4 mb/d of cumulative potential through to 2021 is considered a balanced outlook.

Compared to the potential from refining, annual global demand growth in the six years from 2016–2021 is projected to average just over 1 mb/d. However, close to 15% of the growth will be covered by incremental supplies from biofuels, NGLs and other non-crude streams, leaving a little over 85%, or around 0.87 mb/d annually on average, to come from crude-based products. 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 2018, but where, thereafter, a gap progressively opens up. Thus, by 2021 the cumulative 7.4 mb/d refinery

Figure 5.9
Additional cumulative refinery crude runs, required* and potential**



* *Required: based on projected demand increases.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

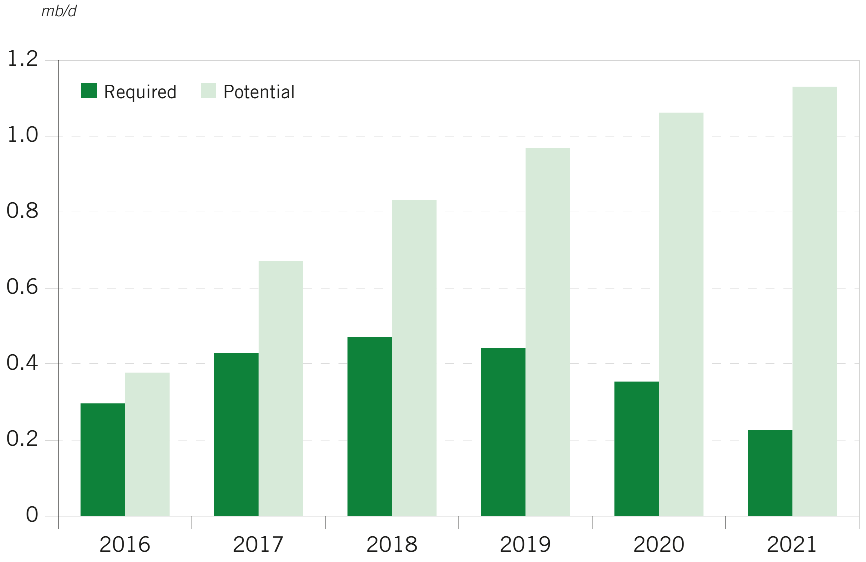
production potential is 2.2 mb/d in excess of the 5.2 mb/d that refineries are projected as being required to produce.

This is significantly less than the 4 mb/d overhang by 2018 projected in the 2013 WOO and the 3 mb/d cumulative overhang by 2019 projected in the 2014 WOO. But it is still closely in line with the 2 mb/d overhang by 2020 projected a year ago. The situation thus appears to have stabilized – for now – wherein incremental refining potential matches requirements for the next 2–3 years but exceeds requirements in the latter part of the medium-term. A primary factor is that the recent drop in crude prices has had the effect of deferring projects by a few years to later in the medium-term period. Again, the additional refinery output potential is projected at 1 mb/d average for 2016–2018, but at an average of 1.35 mb/d for 2019–2021. The message thus remains that these projections point to a period of rising international competition for product markets, albeit on a reduced scale, as well as the need to continue refinery closures if depressed refining margins are to be averted.

This realignment in the refining supply-demand balance is also evident regionally. The contrasts between regions remain stark. Figures 5.10–5.13 present a comparison of four major world regions from 2016–2021. Firstly, Figure 5.10 shows added refinery production potential in the US & Canada of 0.4 mb/d in 2016, rising to 1.1 mb/d by 2021. This potential compares with incremental requirements that peak in 2018 at close to 0.5 mb/d, but then taper off to 0.2 mb/d by 2021.

As previously discussed, incremental refinery potential in the region is focused primarily on splitter capacity additions in response to the tight oil boom.

Figure 5.10
Additional cumulative refinery crude runs, US & Canada, required* and potential**



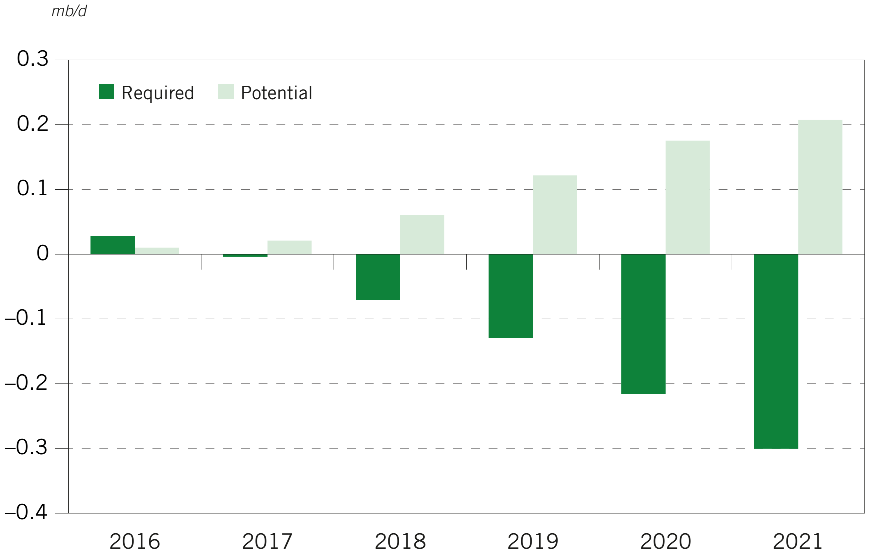
* *Required: based on projected demand increases assuming no change in refined products trade pattern.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

Incremental requirements reflect expected short-term additions to demand followed by a flattening out towards the end of the medium-term period. The former are being driven especially by higher demand for gasoline which again hit a record, at 9.7 mb/d, in summer 2016. This was slightly above 2015's summer peak which itself was a record.

US & Canada biofuels supply is projected to grow by a modest 0.1 mb/d over the medium-term period. NGLs supply, however, is expected to increase by 0.4 mb/d. When some allowance for modest increases in process gain is added, non-crudes supply are seen to add close to 0.5 mb/d over the period. These 'eat into' the required incremental refined product output, markedly expanding the gap as the period progresses from 2016 to 2021. This widening gap is more marked than it was a year ago since this year's outlook for 2016–2021 shifts the projection a year ahead – and pushes it further into the period when the US & Canada demand is projected to slacken while non-crudes supply continues to grow. Like last year, the outlook implies either US/Canadian refinery utilization reductions – and potential closures – and/or further increases in product exports as the time horizon moves from 2016 to 2021.

In Europe, a similar growing disparity is evident between incremental refinery potential and demand (Figure 5.11). Increases in refinery potential remain minimal. However, courtesy of the drop in oil prices, this year's Outlook embodies a higher demand base. Despite this, the disparity between incremental refinery potential and incremental requirements reaches 0.5 mb/d by 2021. The decline in requirements of 0.3 mb/d by 2021 is made up of a drop in demand of around 0.2 mb/d and a

Figure 5.11
Additional cumulative refinery crude runs, Europe, required* and potential**



* Required: based on projected demand increases assuming no change in refined products trade pattern.
** Potential: based on expected distillation capacity expansion; assuming no closures.

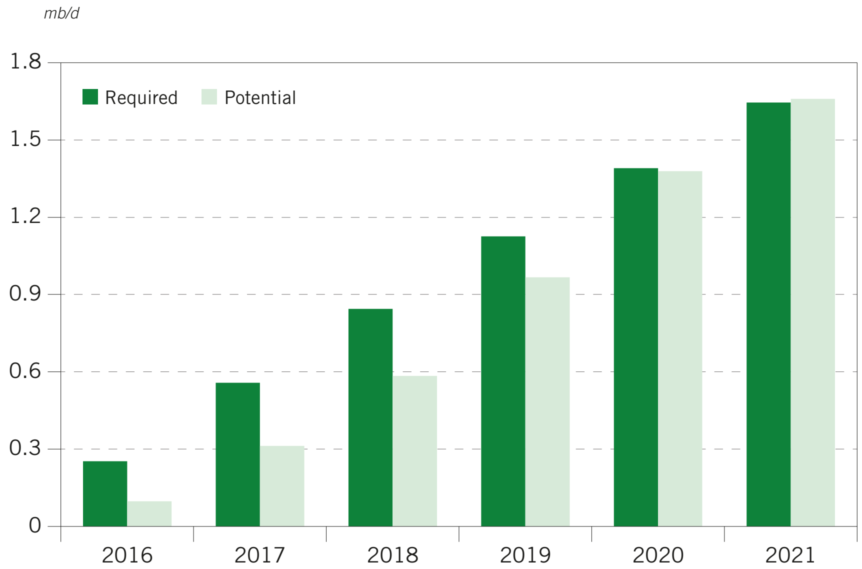
projected increase in biofuels supply of close to 0.1 mb/d. As in previous years, this projection continues to signify a need for additional refinery closures in Europe.

Figures 5.12–5.14 show the corresponding outlooks for the Asia-Pacific – first China alone, then the Asia-Pacific (excluding China) and then for all of the Asia-Pacific. At a scale of 1.6–3.6 mb/d cumulative by 2021, the increases in both incremental refinery potential and required refinery crude runs based on regional demand stand in marked contrast to the flat to declining situation in Europe and to the 'short-term only' requirements increase in the US & Canada.

The shifts in incremental demand stemming from lower levels of economic growth in China and increases elsewhere in Asia (notably India) are equally evident in this year's Outlook. The projected pace of growth in China for required incremental refined product output continues to drop as does potential from capacity additions. Significant capacity has recently come onstream in China, arguably contributing to a slower pace of additions over the next few years. The effect is that, even with the reduced rate of growth in required product output, potential from new capacity lags incremental requirements through 2019, before essentially catching up to cumulative demand growth in 2020–2021. It remains to be seen whether projects currently slated to start up in 2020 and 2021 will indeed do so. Any slippage would maintain a situation in which incremental refinery potential continues to lag incremental requirements.

As Figure 5.13 shows, in the Asia-Pacific (excluding China) growth in potential refinery output reaches 1.55 mb/d by the end of the medium-term period.

Figure 5.12
Additional cumulative refinery crude runs, China, required* and potential**



Required: based on projected demand increases assuming no change in refined products trade pattern.
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

Figure 5.13
Additional cumulative refinery crude runs, Asia-Pacific excl. China, required* and potential**

Required: based on projected demand increases assuming no change in refined products trade pattern.
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

Figure 5.14
Additional cumulative refinery crude runs, Asia-Pacific, required* and potential**

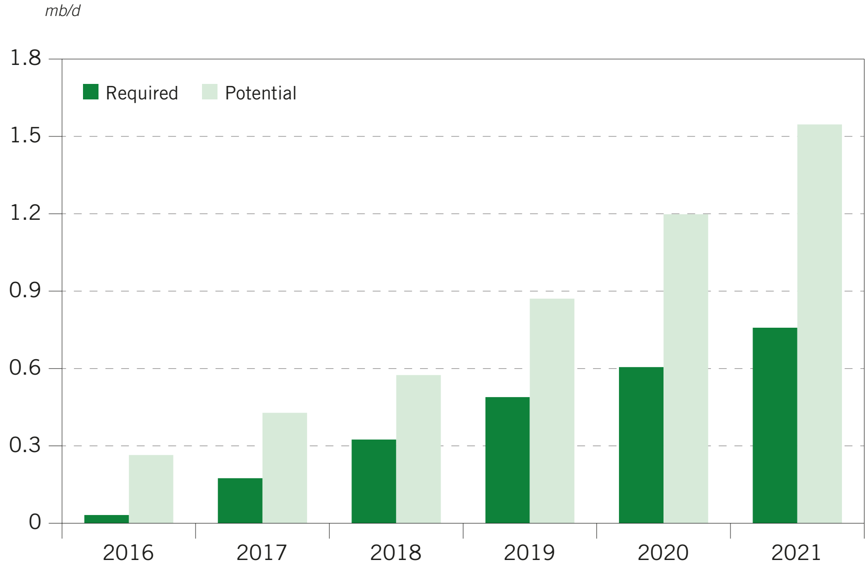
* *Required: based on projected demand increases assuming no change in refined products trade pattern.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

The demand outlook for the Asia-Pacific (excluding China) has been raised in part because of stronger projected growth in India. Thus, this year's outlook has cumulative incremental requirements that approach 1.9 mb/d by the end of the period (that is, 2021). As a result, a small potential-*versus*-required deficit of under 0.1 mb/d in 2016 grows steadily to over 0.35 mb/d by 2021.

Figure 5.14 shows the aggregate effect across the whole Asia-Pacific region. As would be expected from combining the above two outlooks, a situation emerges wherein incremental refinery potential lags incremental refined product requirements across the whole period. The level ranges from 0.3–0.5 mb/d depending on the year. Total Asia-Pacific demand growth masks the demand declines in Japan and Australasia, which are projected at close to 0.7 mb/d total in the period 2016–2021. One implication, however, is that having the Asia-Pacific region as a whole in deficit could curb the need for further refinery closures in Japan and Australia, especially if these countries are able to export product economically to developing countries in Asia. (This indeed is the long-term projection based on the modelling analysis discussed later in this Chapter.)

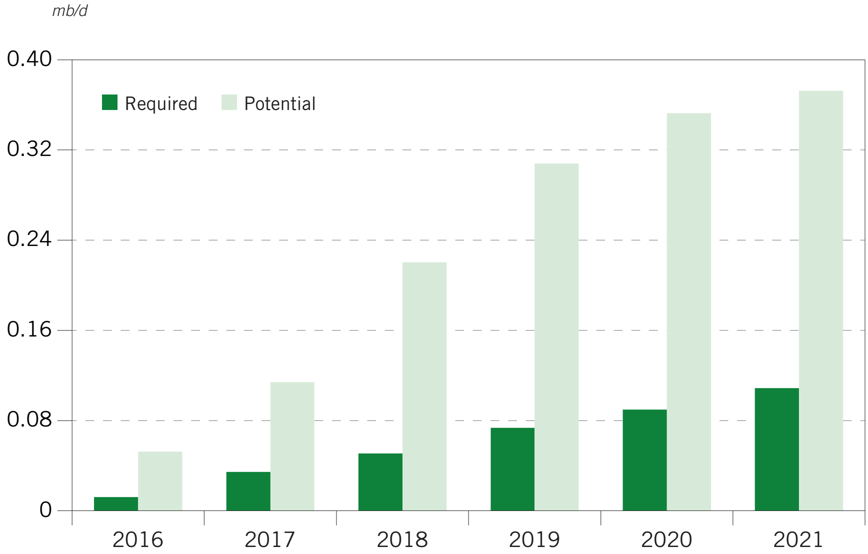
Figure 5.15 summarizes the outlook for the Middle East. The picture from the outlooks of the last two years, in which potential output from sustained refinery capacity additions runs well ahead of incremental requirements, is maintained. As a result, excess incremental refinery output potential over and above incremental requirements by 2021 is projected at a substantial 0.8 mb/d.

Figure 5.15
Additional cumulative refinery crude runs, Middle East, required* and potential**



* *Required: based on projected demand increases assuming no change in refined products trade pattern.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

Figure 5.16
Additional cumulative refinery crude runs, Russia & Caspian, required* and potential**



* *Required: based on projected demand increases assuming no change in refined products trade pattern.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

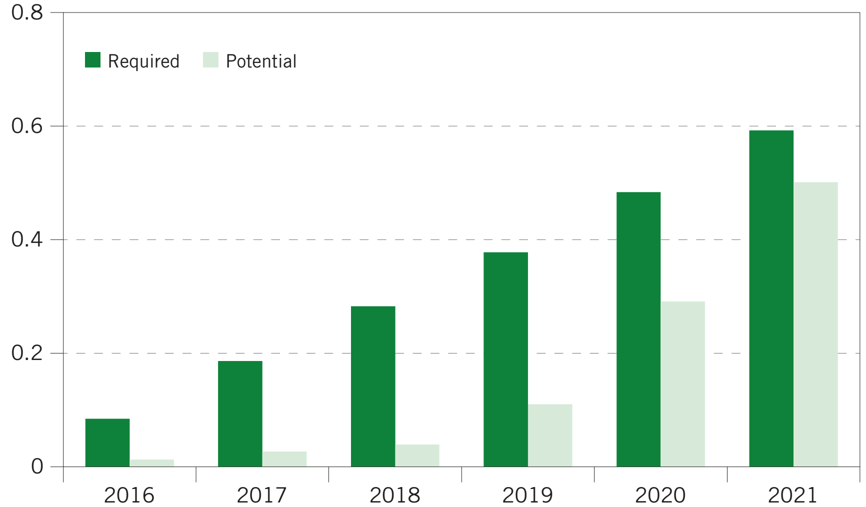
Figures 5.16, 5.17 and 5.18 present the outlooks for the Russia & Caspian region, Africa and Latin America, respectively. In the Russia sub-region (excluding the Caspian region), the outlook is little changed: namely, that a combination of flat demand with appreciable refinery investment prodded by recent tax and duty changes is leading to a situation where incremental refinery output exceeds incremental requirements. The excess grows steadily to around 2019, when it stabilizes at around 0.25 mb/d. Since projected capacity additions in Russia over the medium-term are focused more on upgrading and quality improvement – and since the tax changes encourage production of clean products at the expense of residual fuel – Russia should be in an improving position to export clean and ULS 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 and not to the Caspian. In the latter subregion, the few projects that are considered likely to go ahead will only add limited additional capacity and refinery output potential. Set against moderate demand growth, Caspian incremental refinery potential is likely to be roughly in line with incremental requirements.

While Africa is a major crude oil producing and exporting region, the outlook there continues to show refining potential well below incremental requirements, although new projects could improve the situation toward the end of the medium-term period. Incremental requirements are projected to run at close to 0.1 mb/d per year, reaching nearly 0.6 mb/d by 2021. Conversely, incremental potential refinery output is projected to be minor until 2020–2021 when expected projects close much of the gap. Thus, the outlook remains that over the short-term

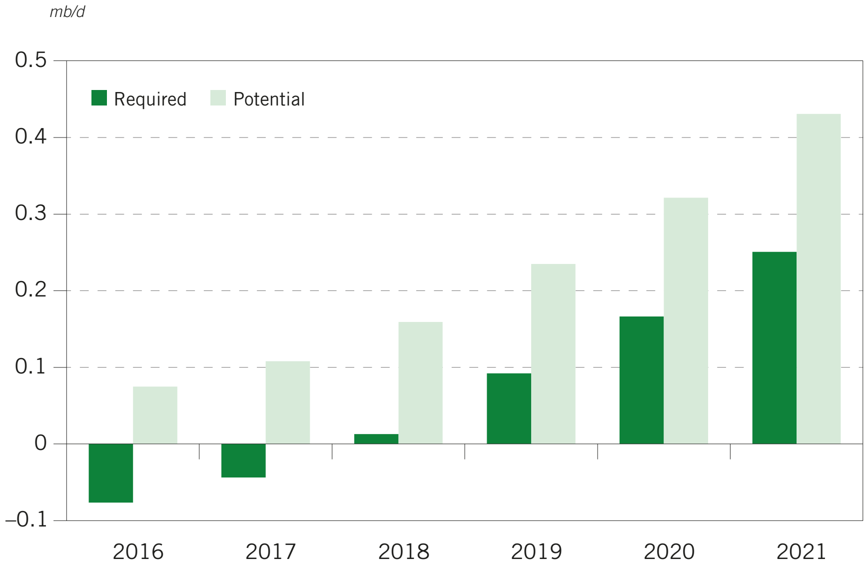
Figure 5.17

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



* Required: based on projected demand increases assuming no change in refined products trade pattern.
** Potential: based on expected distillation capacity expansion; assuming no closures.

Figure 5.18
Additional cumulative refinery crude runs, Latin America, required* and potential**



* *Required: based on projected demand increases assuming no change in refined products trade pattern.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

Africa will continue to need – and provide a market for – growing product imports. This opportunity looks set to rise from under 0.1 mb/d in 2016 to close to around 0.25 mb/d in 2018/2019, before being reduced by the advent of new refinery capacity within the region.[7]

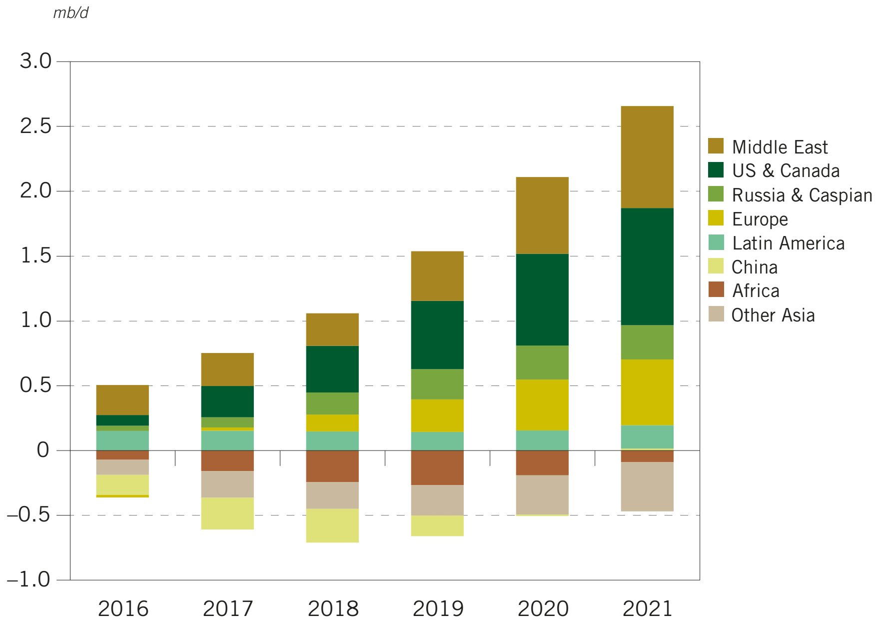
For the medium-term, Latin America presents yet another picture, one which differs from that in any other region. The outlook as of a year ago was that a reduced level of projects would lead to incremental refinery potential output closely matching incremental requirements across the period. Further difficulties in the region are leading to a modest further reduction in the pace of new capacity additions. But the major change is a more pessimistic outlook for demand changes as a result of economic problems and slowing economic growth rates in several countries of the region. Incremental requirements for refined products are expected to be initially negative – that is, demand reductions are projected in 2016 and 2017, followed by a gradual return to limited growth by 2021. The net effect is an incremental requirement of –0.1 mb/d in 2016 moving to a cumulative +0.25 mb/d by 2021. The small excess of incremental refining potential over requirements averages around 0.15 mb/d for the period, and should lead to a slight reduction in regional product imports and/or a small increase in product exports.

Bringing these regional outlooks together, five regions have an excess of refined product potential *versus* requirements: US & Canada (0.9 mb/d by 2021), Middle East (0.8 mb/d), Europe (0.5 mb/d), Russia & Caspian (0.3 mb/d) and

Latin America (0.20 mb/d), for a total of close to 2.7 mb/d by 2021. In contrast, China is essentially in a deficit of up to 0.25 mb/d 2016–2019, before achieving a cumulative balance in 2020–2021. The Asia-Pacific and Africa are the only two regions in deficit (respectively –0.4 and –0.1 mb/d by 2021, although the Africa deficit has narrowed from close to –0.3 mb/d on the presumption of significant new projects). Thus, worldwide the outlook is for incremental refined product potential based on projects to exceed incremental refined product requirements by some 2.2 mb/d by 2021.

Figure 5.19 summarizes this outlook. It highlights how the net excess of refining potential expands persistently over the medium-term period, with the Middle East, the US & Canada and Europe being the main causes although for different reasons. As such, it maintains a situation that has applied and been described in the past several Outlooks – namely one of increasing excess refining capacity and thus competition for product markets as one moves three to six years out. The recent crude oil price drop has led to project delays and cancellations and, arguably, has put back the time when incremental refining capacity excess becomes substantial. Today, the excess is expected to build particularly as one reaches 2019 and beyond. Again, careful monitoring of refinery projects *versus* demand growth is called for to gauge whether this growing excess will 'evaporate' as the time draws nearer (via project slippage and/or further demand growth) or whether it will in fact occur. As the outlook stands, it implies reduced utilizations and/or more closures plus increasing competition for product export markets.

Figure 5.19
Net cumulative regional refining potential surplus/deficits *versus* requirements



Long-term outlook

After a significant drop from the 8.3 mb/d (excluding 'creep') for 2014–2019 in the 2014 Outlook to 7.1 mb/d of additions for 2015–2020 in the 2015 Outlook, this year's projection of 7.35 mb/d of additions for 2016–2021 slightly exceeds last year's level. One implication of this is that refiners acted relatively quickly in 2015 to cancel or defer selected projects as a result of the crude oil price drop. Moreover, it is apparent that the sustained relatively subdued price levels through mid-2016 on balance have not led to further reductions in the overall pace of additions. But as discussed under *Refinery projects* earlier, only 40% of the 7.35 mb/d of additions to 2021 fall in the first three years (2016–2018), while 60% fall in the last three years (2019–2021). This 'bunching' of projects in the second half of the medium-term period indicates there may be potential for further delays, especially if crude oil prices are slow to recover.

The outlook still represents an excess of over 2 mb/d in incremental refining potential over incremental requirements by 2021. Consequently, significant additional refinery closures are still seen as needed. As set out in Table 5.5, refinery closures for 2016–2021 have been estimated at 2.6 mb/d. This represents a slowing in the pace of projected needed closures. In part this is because the substantial 3.9 mb/d of closures that occurred in the period 2012–2015 arguably reduced the excess refining capacity significantly. In addition, the pick-up in demand growth will surely encourage marginal refineries to hang on and defer closing. Selected closures were also assumed for the 2022–2025 period, around 1.4 mb/d or 0.35 mb/d p.a. on average, somewhat below the 0.45 mb/d p.a. average assessed for 2016–2021. No closures were assumed beyond 2025. All model runs for the long-term outlook (2020–2040) presented in this Chapter, therefore, embody closures of 2.6 mb/d for the medium-term to 2021 plus 1.4 mb/d for 2022–2025 for a total by 2025 of 4 mb/d (and for 2020 around 2.5 mb/d).[8]

The January 2016 base refinery capacity was assessed at 97.5 mb/d. Allowing for closures in the 2016–2020 period and some 6 mb/d of projects by 2020 leads to a net projected capacity of 101.1 mb/d for 2020. The 2025 base capacity includes further closures plus an additional 1.35 mb/d of project additions to arrive at a net projected base capacity (before any model capacity additions) of 100.8 mb/d. The 2025 base capacity is applied for all model cases from 2025–2040.

Capacity additions

Based on these assumptions, the Reference Case projections for distillation capacity additions from modelling results are summarized in Table 5.6 (organized by period from 2015–2040). Figure 5.20 presents the corresponding projections by region and period. 'Assessed projects' in the table refers to those refining projects that are considered firm – that is, constructed and onstream by the stated year. In this Outlook, this means 6 mb/d by 2020 and 7.35 mb/d by 2021. 'New units' represent the further additions – that is, major new units plus debottlenecking – that are projected to be needed over and above assessed projects. The addition of new units is developed through optimization modelling that balances the refining system for each time horizon.

Over and above the 6 mb/d of assessed projects by 2020, the 2020 model case indicates a further 1.1 mb/d will be required (partly representing 'capacity creep') for total distillation capacity additions to 2020 of 7.1 mb/d. The 2025, 2030, 2035 and 2040 cases add an additional 4 mb/d, 2.8 mb/d, 2.3 mb/d and 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 19.5 mb/d by 2040.

Table 5.6 maintains the pattern clearly evident in previous Outlooks, namely that there is a steady reduction in the annual pace of refinery capacity additions needed over time. 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 as non-crude supply streams. As Table 5.6 shows, the pace of demand growth is projected to drop steadily over time, from 5.3 mb/d (just under 1.05 mb/d annually) in the period 2015–2020 to an annual average of 0.6 mb/d in 2025–2030 and an annual average of 0.3 mb/d in 2035–2040. It is, therefore, not surprising that the projected required rate of refinery capacity additions drops from an annualized 1.4 mb/d from 2015–2020 to below 1.1 mb/d for 2020–2025, then to the 0.5 mb/d range by 2030 and to the 0.4 mb/d level by the late 2030s.

These are nameplate capacity additions and refineries invariably achieve long-run utilization rates that are well below 100%. If the new capacity were to achieve an average utilization rate of around 87% from 2015 through 2040, the

5

Table 5.6
Global demand growth and refinery distillation capacity additions by period in the Reference Case

mb/d

	Global demand growth	Distillation capacity additions starting 2016			
		Assessed projects*	New units	Total	Annualized
2015–2020	5.3	6.0	1.1	7.1	1.4
2020–2025	4.0	1.3	4.0	5.3	1.1
2025–2030	3.1	0.0	2.8	2.8	0.6
2030–2035	2.3	0.0	2.3	2.3	0.5
2035–2040	1.6	0.0	2.0	2.0	0.4

	Global demand growth	Cumulative distillation capacity additions			
		Assessed projects*	New units	Total	Annualized
2015–2020	5.3	6.0	1.1	7.1	1.2
2015–2025	9.4	7.3	5.1	12.5	1.1
2015–2030	12.5	7.3	7.9	15.3	1.0
2015–2035	14.9	7.3	10.2	17.5	0.8
2015–2040	16.4	7.3	12.2	19.5	0.8

* *Firm projects exclude additions resulting from capacity creep. Assessed projects are split between 2015–2020 and 2020–2025.*

incremental crude runs achieved would very closely match incremental product demand, by period and overall. However, as stated, incremental product demand will be met in part by increases in the supply of non-crudes (NGLs, biofuels, CTL/GTL and other supply streams) plus processing gains. Between 2015 and 2040, these sources of supply are projected to grow from 15.5 mb/d to 21.3 mb/d – that is, by 5.8 mb/d – correspondingly cutting the incremental need for refined products.

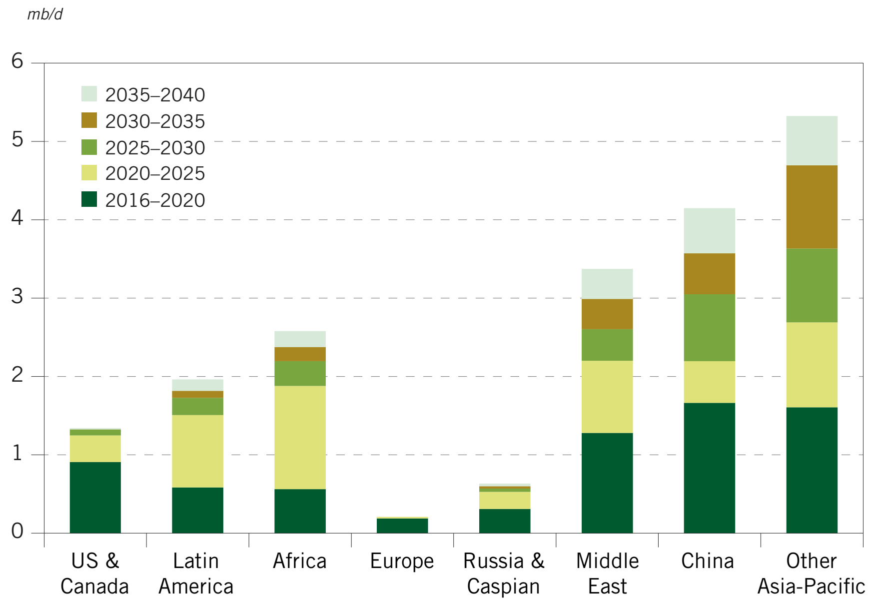
The reason, of course, why rational increases in needed refining capacity are well in excess of requirements when viewed purely at the global level is that demand growth is in regions where new capacity is warranted. These new refineries, overwhelmingly in developing regions (led by Asia), will compete with existing facilities in the US & Canada and Europe as demand in those regions continues to decline. The model results indicate that utilizations will decline in those two regions with implications for continued closures (see *Projected refinery closures* later). As a result, the long-term potential for incremental product exports from US & Canada and Europe is projected as limited (an additional 1.5 mb/d by 2040, over 2020 levels). This is a relatively minor amount compared to the 13.2 mb/d of demand growth in developing Asia between 2020 and 2040, and also the 1.6 mb/d in Latin America and 1.9 mb/d in Africa.

In short, while continued competition for product export markets can be expected and will put pressure on utilizations and margins, this does not look set to dominate where refineries are built over the long-term. The inexorable slowing in the pace of necessary refinery capacity additions over time means that whoever invests first in new capacity may well win over the long-term. This is because it will be increasingly difficult to justify significant new capacity as the pace of total requirements slows – and given that there will be extensive competition from existing modern, complex units that have already partially depreciated.

As illustrated in Figure 5.20, 46% of 2016–2020 capacity additions are projected for the Asia-Pacific region, 18% for the Middle East, 8% for Latin America and 8% for Africa. The US & Canada contributes 13%, but the majority of those additions are condensate splitters. The Russia & Caspian and Europe contribute 3% and 4%, respectively.

For additions from 2020–2040, the share taken by the Asia-Pacific rises further to 50%, driven by regional demand growth. The Middle East, Africa and Latin America have respective shares of 17%, 16% and 11% in this period, with domestic regional growth again an important factor. Thus, over the whole forecast period, the Middle East's share of additions is projected to remain stable in the 17–18% range. The surge in the percentage share in Africa is driven in part by identified projects expected to come online in 2021 followed by sustained further capacity growth indicated in the modelling results. In contrast, Latin America's share is expected to rise modestly over the longer term (at 11% for 2020–2040 *versus* 8% for 2016–2020). The share for the Russia & Caspian region is projected to decline from somewhat over 4% of global additions in 2016–2020 to around 2.5% from 2020–2040, the consequence of flat to declining demand. For the US & Canada region, the 2020–2040 share drops to 3.5%, with only minimal additions post-2030 due to steady regional demand decline. 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.

Figure 5.20
Crude distillation capacity additions in the Reference Case, 2016–2040



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 opportunities to export products. Secondly, the pace at which new refining capacity needs to be added will drop steadily. Post-2025, the rate of new additions needed will drop to the equivalent of one or two new refineries per year worldwide. In practice, this is likely to mean that almost no new refineries will be built. Rather, as has been evident in the US, Europe, Japan and Australia for some time, expansions (such as they are) will come from debottlenecking of existing facilities plus retirement of older, less efficient crude trains or whole refineries.

The 7.3 mb/d of assessed (firm) projects was taken from a total 'inventory' of announced refinery distillation additions that exceed 20.5 mb/d. The 20.5 mb/d is up from last year's 17 mb/d 'inventory', indicating some degree of resilience or optimism even with the lower oil prices. It is also worth noting that the 20.5 mb/d of current listed projects exceeds the 19.5 mb/d of total new capacity that has been assessed as required in the whole period from 2016–2040. Thus, either many of the projects currently listed will need to be deferred or cancelled, or the risk of over-building will remain.

As previously noted, it is important to recognize that the long-term additions projected as needed are being driven more by the shift in global demand from industrialized regions to developing regions than by outright global demand growth itself. For this reason, global capacity additions continue to match and indeed exceed global demand growth in the longer term even though non-crude supplies continue to increase (Table 5.6). 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. Crude oil tanker freight rates have recovered moderately since their lows in 2012/2013, but continue to be at relatively low levels by historical standards. Product rates on major routes have been essentially flat since 2009. The assumption in the modelling analysis was that the crude and product tanker markets will gradually recover to a more balanced state by the early 2020s.

However, should the current depressed state persist over 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 and help keep more industrialized region refineries open. A rapid rebound in the tanker market would have the opposite effect. It would widen the differential between crude and product freight, curbing the ability of refiners in Europe, the US and Japan to compete and, hence, potentially raise the levels of new capacity that would be economic in demand growth regions (Box 7.1 provides further discussion of the tanker market outlook).

As stated, the majority of future refining capacity expansions to 2040 are projected to be required in the Asia-Pacific region – 9.5 mb/d out of a global total of 19.5 mb/d. Expansions here continue to be dominated by China and India. Regional expansions are well below the 15.3 mb/d increase in Asia-Pacific demand to 2040. This figure itself is made up of a demand decline in Japan and Australasia of 1.8 mb/d plus an increase in Asia's growth regions of 17.1 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 with some 3.4 mb/d of total additions from 2016–2040. This is somewhat ahead of a projected regional demand increase of 2.9 mb/d. Driven by a series of major projects expected to come onstream by 2021, capacity additions in the Middle East are 'front-loaded', 1.3 mb/d by 2020 and a further 0.9 mb/d by 2025, followed by increments of around 0.4 mb/d for each period 2025–2030, 2030–2035 and 2035–2040. One implication of this is that Middle East product exports can be expected to increase between now and 2025, and any product imports decline. Moreover, the substantial refining capacity increases could lead to product exports partially displacing crude exports from the region.

In Latin America, projected capacity additions of 2 mb/d over the forecast period are very closely in line with the outlook for a somewhat reduced demand increase of 1.9 mb/d. However, 0.35 mb/d of future demand will be covered by a growing supply of biofuels. Nevertheless, regional crude throughputs are projected to rise by 1.9 mb/d from 2015–2040. This reflects a projected gradual increase in utilizations over the period. Also, net imports are projected to drop by 0.3 mb/d between 2015 and 2040, offsetting the growth in biofuels supply and leading to growth in refinery crude runs essentially matching growth in demand at 1.9 mb/d.

Total distillation capacity in Africa is projected to rise 2.6 mb/d by 2040 compared to base capacity at the end of 2015. These additions comprise 0.6 mb/d of new capacity in the period to 2020 and a further 1.3 mb/d by 2025. These significant additions, especially early in the period, are partly the result of current known refinery projects. Compared to these capacity additions, demand is projected to rise by 2.5 mb/d over the same period. Even with these expansions and rising utilization rates, increases in regional refinery throughputs – at 2.2 mb/d for the period 2015–2040 – 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. The situation for Africa is exacerbated because the region is starting from very low overall refinery utilization levels. This is consistent with the fact that many of its refineries face the challenge of being old and small-scale, with relatively low complexity and low energy efficiency. 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.

Crude runs and refinery utilizations

The projected global and regional long-term refinery crude throughputs and related utilizations are presented in Table 5.7. At the global level, throughputs rise from 78.9 mb/d in 2015 to 83.3 mb/d in 2020 and then to 89.9 mb/d in 2040. As emphasized elsewhere, the rate of the annual increase in refinery crude runs is projected to steadily decline due to the 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 0.9 mb/d. This is sustained by a further increase in 2020 demand (98.3 mb/d in this year's Outlook *versus* 97.4 mb/d in last year's). However, the annual rate of increase slows from 2021–2030 to not much above 0.4 mb/d and then drops nearly to 0.2 mb/d from 2031–2040. The annual rate of increase from 2031–2040 is well below the level of somewhat under 0.4 mb/d projected a year ago.

The main driver behind this projected low rate of increase in crude runs post-2030 is a change in the shape of the demand outlook. At 105.5 mb/d, this year's projection for 2030 demand is 1.3 mb/d above last year's 104.2 mb/d. This year's projection for 2040 demand is 109.4 mb/d, which is moderately below last year's 109.7 mb/d. Again, the shape of this year's demand outlook, with more growth medium-term, but less in the long-term, further reinforces how much lower future refinery additions will need to be in the longer term *versus* where they are currently.

The corresponding outlook for global refining utilizations is for a moderate improvement at the global level by 2020, but a gradual decline from then on through 2040. How utilizations in fact evolve will depend on the actual realization of both projects and closures. Regarding long-term capacity additions over and above assessed projects, it is important to bear in mind that those generated in the modelling correspond to additions that are considered necessary to balance demand – but no more – allowing for realistic utilizations that tend to differ from region to region and over time. Secondly, this outlook has presumed no further closures after 2025, as any estimation beyond this timeframe was deemed too speculative.

Table 5.7
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
2015	78.9	17.9	5.7	2.3	12.7	6.0	7.3	10.6	16.3
2020	83.3	18.6	6.3	2.9	12.3	6.0	8.0	11.9	17.3
2025	85.8	18.4	6.9	3.6	12.0	5.9	8.7	12.5	17.8
2030	87.6	18.1	7.1	3.9	11.6	5.9	9.2	13.5	18.3
2035	89.0	17.3	7.4	4.2	11.4	5.9	9.6	14.1	19.1
2040	89.9	16.7	7.6	4.5	10.9	5.8	10.1	14.8	19.5

	Crude unit utilizations *% of calendar day capacity*								
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
2015	80.9	89.4	71.4	53.6	74.3	90.7	76.8	81.0	86.2
2020	81.7	88.9	71.6	61.2	76.4	88.2	76.9	80.6	89.1
2025	81.0	88.6	72.9	58.9	75.3	87.1	77.7	82.2	87.0
2030	80.6	86.8	74.2	61.0	73.3	85.8	79.0	84.1	85.3
2035	80.2	83.3	75.7	64.5	71.9	85.0	79.9	85.4	84.8
2040	79.6	80.3	77.0	65.6	68.9	84.1	80.9	86.5	84.3

Overall, somewhat lower utilizations are projected globally and in most regions across the 2015–2040 period as compared to last year. A key reason is that research and comparison with third party sources led to a higher assessed (end-2015) base capacity and to a more complete assessment of 2015 (base year) utilizations by region. The latter led to 2015 base year utilizations being reset to lower levels in most regions except the US & Canada and the Russia & Caspian where they have moved up. One implication of the projected utilization levels (discussed further under *Industry implications* later) is that more closures will be needed longer term.

Figure 5.20 and Table 5.7 highlight the variation in outlooks between major regions. Consistent with the last two years' projections, crude throughputs in the US & Canada are projected to rise in the medium-term to 2020 as the region benefits from capacity additions (mainly condensate splitters), slight growth in domestic crude supplies (+0.2 mb/d in 2020 over 2015) and slightly rising regional demand (+0.4 mb/d in 2020 over 2015). Demand is projected to peak at around 22.7 mb/d in 2018–2019 before starting to decline. By 2030, demand is expected to be

20.6 mb/d, so around 2 mb/d below the 2018–2019 peak. Post-2030, demand decline accelerates with a further 2.7 mb/d drop to reach 17.9 mb/d by 2040.

Declining domestic demand ushers in a long gradual decline in crude throughputs, which becomes marked after 2025 and accelerates post-2030. From 18.6 mb/d in 2020, throughputs drop to 18.1 mb/d in 2030 and to 16.7 mb/d by 2040. Nonetheless, utilizations remain well above 80% until after 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 4.7 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 be well above 3 mb/d towards the end of the period.

Declining demand in Europe exacts a toll of sustained reductions in crude runs, from 12.7 mb/d in 2015 to 10.9 mb/d by 2040 – that is, a net decline of 1.8 mb/d. Over the same period, demand declines from 14.9 mb/d to 12.7 mb/d, a net decline of 2.2 mb/d. Since the projected reduction in runs is modestly below the reduction in demand, the implication is that net imports to Europe will moderately decline. Nonetheless, the sustained decline in domestic demand, 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 contribute to reductions in runs and utilizations in the region.

5

Between 2012 and 2015, some 1.8 mb/d of capacity closed in Europe. To this, a further 0.95 mb/d of closures was projected to be added by 2020. As a result, utilizations in that year move up to 76.4% (higher in north-western Europe and lower in other parts of the continent). Thereafter, utilizations steadily decline and – assuming no further closures – reach a meagre 69% by 2040. The implication is, of course, that substantial additional closures (in the region of 2–2.5 mb/d) are potentially necessary for Europe by 2040, over and above the assumed 0.95 mb/d to 2020, as the region's refineries continue to lose throughput.

The primary drivers of throughput reduction in both the US & Canada and Europe continue to be the expectations for progressively declining transport fuel consumption and, to a much smaller degree, rising supplies of biofuels and the use of alternative vehicles. Refiners in both regions continue to face a drive toward higher transport fuel efficiency standards. In the US, the updated Corporate Average Fuel Economy (CAFE) standards should achieve marked improvements. However, the recent surge in sales of larger vehicles, especially sports utility vehicles, may undermine this goal. Conversely, the US Environmental Protection Agency (EPA) has announced initiatives targeted at tightening emissions standards and fuel efficiency for both jet aircraft and trucks.[9] For the US & Canada region, this year's Outlook has combined gasoline, jet/kerosene and gasoil/diesel demand shrinking from 16.3 mb/d in 2015 to 13.3 mb/d in 2040, a drop of 3 mb/d. The decline projected for European demand for the corresponding fuels is also significant, from 9.7 mb/d in 2015 to 9 mb/d in 2040. This is primarily driven by an assumption of faster penetration of alternative vehicles, such as plug-in hybrids and battery electric vehicles (BEVs).

In the US, the picture regarding the RFS-2 (Renewable Fuel Standard) mandate remains unchanged: that is, it 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 a little over 0.1 mb/d between 2015 and 2040 – and much of that occurs after 2025.

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 0.25 mb/d in 2015 to over 0.55 mb/d in 2040. Globally, biofuels supply is projected to grow from just under 2.2 mb/d in 2015 to nearly 3.7 mb/d in 2040, shaving 1.5 mb/d from demand for refinery products.

Japan and Australasia, the third major industrialized region, will also experience continued demand contraction, in the form of a relatively severe 34% drop from 5.4 mb/d in 2015 to 3.6 mb/d in 2040. In the tables and figures in this Outlook, the region and its demand is masked by its 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 Rest of Asia sub-region, which is dominated by India. In the former, demand of 9.3 mb/d in 2015 grows to 13.2 mb/d in 2040, a 41% increase. In contrast, in the Rest of Asia sub-region, demand of 4.9 mb/d in 2015 transforms into 11.7 mb/d by 2040, a 140% increase. 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 region, refinery crude runs are projected as essentially flat throughout the period with a very small decline after 2030. Demand increases only slightly, from 4.1 mb/d in 2015 to 4.4 mb/d in 2040. In addition, the 'tax manoeuvre', with its impacts on export duties, is having the effect of increasing the attractiveness of exporting crude *versus* running incremental crude to export mainly heavy fuel oil. Thus, there is now pressure for Russian refiners to avoid/eliminate skimming type runs where the products would go for export. Adding to close to 0.3 mb/d of closures in 2015, approaching 0.2 mb/d of additional closures were assumed by 2020 reflecting expected continued pressure to rationalize capacity. Noting the absence of any assumed closures longer term, Russia & Caspian utilizations are projected to slowly decline, but from a high initial level, at least in Russia.

It is the developing regions that have all the significant gains in refinery throughputs from 2015 to 2040: Latin America with 1.9 mb/d, Africa 2.2 mb/d, the Middle East 2.8 mb/d, China 4.15 mb/d and Other Asia 3.2 mb/d (a mix of declines in Japan and Australasia but increases elsewhere in the region). Overall, these gains total 14.2 mb/d and far exceed the combined 3 mb/d of crude run declines in US & Canada and Europe. Associated with the throughput gains, utilizations in developing regions are projected to gradually increase.[10]

Projected refinery closures

As previously described, a grand total of around 2.5 mb/d of refinery closures was assumed by 2020 and 4 mb/d by 2025. These numbers were built in to the modelling cases. The outlook for long-term regional refinery utilizations already discussed clearly demonstrates a need for continuing refinery closures, beyond those built in to the modelling, especially in the industrialized regions where demand is projected to continue to decline. A WORLD model report feature ‘back-calculates’ the implied closures needed within a region to reach a user-input level of utilization. This parameter is currently set to 80% as representing the lowest utilization level considered viable. Thus, any region with a utilization level from the model results below 80% will have some level of implied needed closures.

Several regions indicate a need for potential additional closures by 2040 in order to achieve an 80% utilization level. As discussed elsewhere, US & Canada refineries are projected to be relatively resilient with overall regional utilizations still above 80% by 2040 despite a regional demand decline. However, specific sub-regions are vulnerable. The most evident is the US East Coast (PADD1), where a number of refineries narrowly averted closure some 2–3 years ago. The modelling projections indicate that these vulnerabilities will impact over the longer term as local demand declines and as the refineries remain exposed to international competition. Over 0.2 mb/d of closures are projected for this sub-region. This is possibly a floor as previous analyses have shown higher potential for closures, up to 0.7 mb/d. The higher figure equates to potential closure of the sweet crude cracking refineries on the East Coast. By way of comparison, Eastern Canada refinery utilizations are projected as remaining above 80% throughout the period. However, here it must be recognized that a number of refinery closures have taken place in recent years.

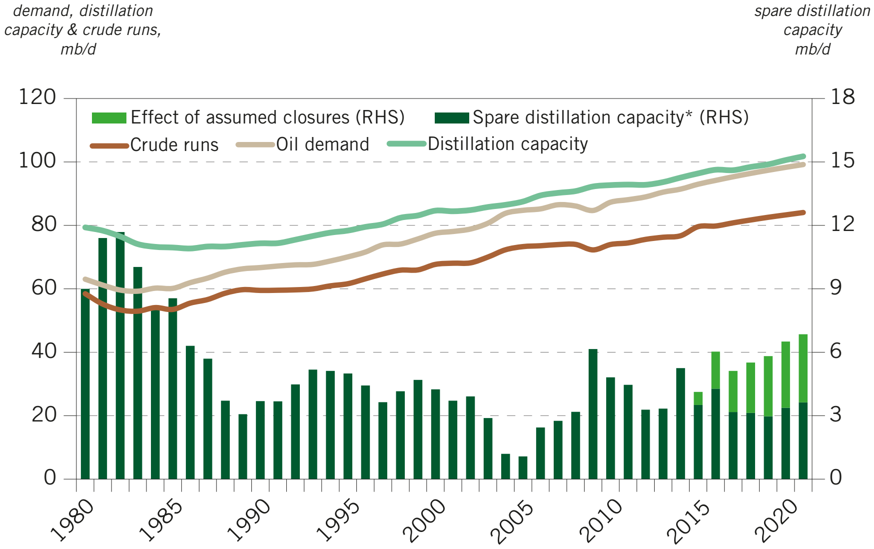
Elsewhere in the US & Canada region, refineries in the relatively isolated Rocky Mountain region look vulnerable as regional demand declines and the refineries there have little ability to move product to other regions. Equally, refineries on the US West Coast could be vulnerable, particularly in California. For example, Assembly Bill 32 (California Global Warming Solutions Act of 2006) is currently a matter of legal dispute, but its intent, should it be upheld, is to cut the carbon intensity of fuels in California and thus cut the output of refined product. The modelling projections indicate US West Coast (PADD5) refineries responding to local demand decline by exporting more products – to the tune of around 0.5 mb/d to Asia by 2040. Should they not able to do so, regional throughputs would drop and closures would likely result. In the US Gulf Coast, (PADD3), overall utilizations are projected to remain just above 80%, but within the region smaller sweet crude refineries look vulnerable, especially as US tight oil production declines longer term.

In Western Canada, the inland Alberta refineries, several of which are closely linked to production operations, are generally considered safe. However, Chevron has recently put up for sale its 55,000 b/d refinery at Burnaby, which is a coastal suburb of Vancouver, British Columbia. The future of Western Canadian refining may hinge in part on whether the Trans Mountain pipeline expansion (from 300,000 b/d now to 890,000 b/d) does go ahead and whether such an expanded system would carry more products. (For years, the Trans Mountain line has carried both crude oils and products.) If that were to happen, it would open up coastal and Asian product markets to refineries in the Edmonton area and increase competition on the US West Coast. Recognizing that the US and Canadian refining sectors are dynamic, and that unprofitable refineries are likely to be shut down, the overall range of long-term closures could lie in the range of 0.5–1 mb/d.

In Europe, modelling results point to a need for over 2 mb/d of additional closures over the long-term. These are very much in line with – and driven by – the 2 mb/d reduction in demand projected for the period 2020–2040. The other region that is an obvious candidate region for continuing closures, Japan plus Australasia, shows a rather different picture. Recent and announced closures totalling 2 mb/d through 2016 bring the region's base capacity down to some 3.7 mb/d, a quite substantial percentage reduction, and the remaining refineries are more complex. Regional demand is projected to decline by 1.25 mb/d 2020–2040, but modelling results indicate 2040 utilizations rates above 80%. Contributing to this is an expected near elimination of net product imports by 2040, a combination of increased gross product exports and reduced gross imports. The implication is that the combination of substantial recent and planned closures, together with a modest product trade shift, look to be enough to avoid the need for additional (as yet unannounced) closures in the region through 2040.

A potential for some 0.6 mb/d of long-term closures is projected for Latin America. These will be spread across the area, but with the main concentration in the northern part of the region. In light of the region's very low overall utilization levels today, for Africa to achieve overall average utilization of 80% by 2040 would require nearly 1.5 mb/d of capacity closures according to the modelling. Such a level of closure is arguably primarily an indication of the old and inefficient capacity in the region that needs to be replaced with modern, efficient – and generally larger – facilities. In the Russia & Caspian, some 0.5 mb/d of closures from 2015–2021 were built in to the modelling analysis. As a result, little by way of additional closures is indicated as needed except potentially in the Caspian where, again, the need is to replace ageing, inefficient refineries.

Figure 5.21
Global oil demand, refining capacity and crude runs, 1980–2021



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

Summing closure needs across the world's regions indicates a need to close some 4.5–5.5 mb/d of capacity over the long-term. This has to be added to the 4 mb/d already built in to the modelling base capacity, indicating that total closures are needed somewhere in the range of 8–10 mb/d from 2016–2040. This equates to an annual average rate of 0.3–0.4 mb/d for 2016–2040, a level that is moderately below the 0.43 mb/d average included for 2016–2021. While continued closures in the industrialized regions can be expected to be a major requirement, it is also clear that significant closures are needed in other regions if efficient levels of refinery operations are to be reached and maintained.

The medium-term implications of assumed closures at the global level are summarized in Figure 5.21. If all assumed closures occur, then the gap between required crude runs and available distillation capacity at an 85% average utilization level would represent a degree of spare/surplus capacity moderately below the historical average. For 2016–2021 spare capacity would average around 2.9 mb/d, though it would be moving up at the end of the period. This compares to, and is below, the long-term average from 1990–2015 of 3.8 mb/d, a period which encompassed expansions and the recent major recession plus wide variations in oil prices. Conversely, adding the capacity assumed to be closed by 2021 back in would increase spare/surplus capacity to close to 7 mb/d, a level not seen since the mid-1980s. This is well above the averages seen since 1990. In short, spare capacity is very sensitive to the level of actual closures that go ahead. These in turn will impact refinery margins.

Industry implications

Several trends and implications for the industry are evident when various factors reviewed in the preceding sections are brought together. First, the industry continues to exhibit a pattern of investing more in capacity over the medium-term than incremental demand requirements would indicate is necessary. The medium-term capacity 'overhang' has dropped in the past few years, but for now appears to have levelled out at around 2 mb/d when focusing on the end of the medium-term period (that is, 5–6 years out). Second, at the regional level, stark contrasts emerge as capacity excesses build in the US & Canada and Europe, while capacity/product deficits are experienced in the Asia-Pacific region, with its sustained demand growth, as well as in Africa.

These factors and trends carry over into the long-term. Two major drivers are evident: a steady slowdown in the rate of liquids demand increase – and with that, the net new capacity needed annually – and the relocation of capacity from industrialized to developing regions as more closures are needed in the former and more new capacity in the latter.

A total of some 8 mb/d or more closures are indicated as needed over the long-term in order to establish and maintain efficient utilization levels in all regions. A key question is whether these will occur. There is often resistance to closures because of a desire to preserve local employment and maintain the production of refined products. Both the medium- and long-term projections highlight the dangers to worldwide refining margins if all projects are implemented and substantial closures are not made in the coming years. Yet recent pressures on margins have led to significant closures, so the same could – or should – continue to happen in the future. In other words, recent history provides some reasons for optimism that the closures that are needed will indeed occur.

As noted, future closures will be required in developing, as well as in industrialized regions. The question is whether the same discipline regarding closures seen recently in Europe and elsewhere will be applied. A potential related issue is whether the associated need to move to smaller numbers of larger refineries can readily occur. This has been the long-term trend in, for instance, the huge US market. But can it be repeated elsewhere – in countries and regions with far smaller consumption levels?[11] In many developing countries, existing refineries are relatively small and can be isolated. Replacing these over time with large, modern facilities would imply a potentially significant degree of centralization. This could result in either the elimination of refineries in certain regions of a given country or smaller countries ending up with no refineries and relying entirely on products imported from large regional or global facilities. In addition, significant new in-country – and potentially cross-border – product distribution infrastructure (such as pipelines, terminals and marine bunkers) would need to be developed. There are many national and regional considerations associated with the achievement of such shifts, which leaves open the question of the degree to which they will be realized.

What appears certain is that the slowdown in needed capacity additions – from around 1 mb/d p.a. currently to around 0.4 mb/d p.a. post-2025, and as low as 0.2 p.a. mb/d post-2035 – will require adjusting to a low growth world, reinforcing the emphasis on competitiveness and efficiency. Ironically, it will also require having capacity in place early on so as to deter competitors by making it more difficult for them to justify adding new capacity when competing against existing facilities that have already incurred ‘sunk costs’. It is noteworthy that, at 0.3–0.4 mb/d, the long-term annual average closure rate indicated as needed is in line with – or even ahead of – the projected need for long-term annual capacity additions. This points to the arrival of a post-2030 era when there could be no net increase in global refining capacity, but rather a net shrinkage.

Secondary capacity additions

Key takeaways

- In the medium-term (2016–2021), the capacity of secondary units follows the increase in distillation capacity (conversion 3 mb/d; desulphurization 5.1 mb/d; and octane units 1.3 mb/d).
- The majority of secondary capacity additions will be located in the Asia-Pacific and the Middle East, in line with distillation capacity expansion. However, significant upgrades are also expected in the Russia & Caspian, as the region is increasingly focusing on the export of high-quality products, supported also by the recent change in Russia's tax regime.
- Over the long-term (2016–2040), higher proportions of secondary processing will be needed, following changes in the quality standards for fuels such as gasoline and diesel, but also due to lower residual fuel demand.
- The regional distribution of secondary additions is very much in line with those for distillation, with the Middle East and Asia-Pacific accounting for 60–65% of the global totals during the period 2016–2040.
- More than 11 mb/d of conversion capacity will be required between 2016 and 2040, with a lower proportion for coking, as a result of an outlook for a somewhat lighter crude slate. Hydro-cracking additions are sustained throughout the period, whereas a relative slowing in gasoline growth leads to FCC additions being 'front-loaded' with 75% needed before 2030.
- Required desulphurization additions are estimated at over 23 mb/d in the long-term.
- Octane additions are steady over the forecast period until 2040 and total nearly 5 mb/d, driven by an expected progressive rise in pool octanes.
- The pending MARPOL Annex VI global sulphur cap adds numerous additional uncertainties regarding capacity requirements and utilizations for secondary units. There are three major uncertainties: options over timing (2020 or 2025), the method of compliance, and as a consequence, fuel type and quality.
- Between 2016 and 2040, the refining sector is estimated to need to invest a total of over $1.5 trillion. Of this, $265 billion is required for investments in known projects, around $385 billion for additions beyond firm projects, and just under $900 billion for maintenance and replacement.
- Mirroring the projected steady demand growth decline, required investments in new capacity taper off substantially over the forecast period.

Chapter 5 addressed the medium- and long-term outlook for distillation capacity. This Chapter reviews the associated outlook for secondary capacity.

Medium-term outlook

Substantial amounts of new secondary processing are either accompanying new distillation capacity, as in wholly new refineries and major expansions, or are being implemented in order to upgrade existing refineries, often with limited or no added distillation capacity. Broadly, all upgrades and essentially all the new grassroots refineries evident today are geared to achieving a high degree of conversion, desulphurization and other quality improvements through secondary capacity additions. With a few exceptions, the aim is to produce predominantly light, clean products to advanced standards.

Table 6.1 shows that the 7.3 mb/d of new distillation capacity from assessed projects by 2021 will be accompanied by an additional 3 mb/d of conversion units,

Table 6.1

Estimation of secondary process additions from existing projects, 2016–2021

mb/d

	By year		
	Conversion	**Desulphurization***	**Octane units**
2016	0.2	0.5	0.1
2017	0.6	1.0	0.2
2018	0.5	1.1	0.2
2019	0.8	1.2	0.4
2020	0.5	0.7	0.2
2021	0.4	0.7	0.2
	By region		
	Conversion	**Desulphurization***	**Octane units**
US & Canada	0.2	0.1	0.0
Latin America	0.3	0.5	0.1
Africa	0.2	0.4	0.2
Europe	0.2	0.1	0.0
Russia & Caspian	0.5	0.5	0.1
Middle East	0.5	1.8	0.5
China	0.7	0.9	0.3
Other Asia	0.5	0.8	0.2
Total world	**3.0**	**5.1**	**1.3**

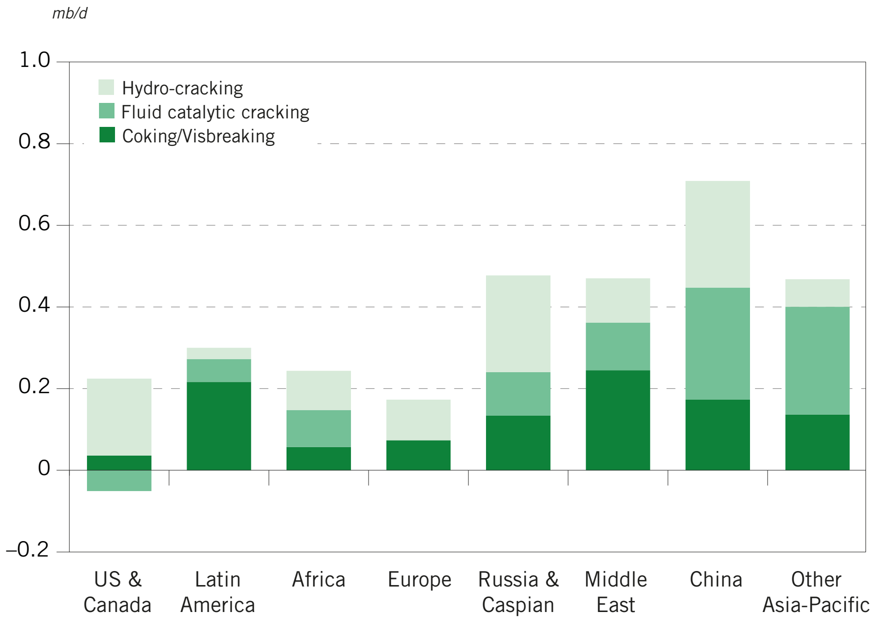
* *Desulphurization capacity in this table includes naphtha desulphurization.*

5.1 mb/d of desulphurization capacity and 1.3 mb/d of octane units. Figure 6.1 portrays the geographic distribution of the conversion capacity additions. As of early 2016, the total conversion capacity in place equated to around 40% of global crude distillation capacity, desulphurization to about 70% and octane units to approximately 18.5%. The make-up of current firm projects is remarkably similar with conversion at 41% of new distillation capacity, desulphurization at 70% and octane units at 18%. These levels are also broadly similar to those seen in the past two years' Outlooks, indicating a 'levelling out' in secondary processing additions relative to distillation capacity – at least for now.

Conversion units

The 3 mb/d of additions to global conversion units for the period 2016–2021 are split relatively evenly between coking and hydro-cracking units, with each close to 1.1 mb/d and FCC at around 0.9 mb/d. Recognizing that a single large project can affect the mix of conversion project additions, the outlook is very similar to that of last year. As such, it sustains the moderate shift away from hydro-cracking as the leading source of additions *versus* recent years. By way of comparison to the even mix of projects now evident, between 2010 and 2015, the net increase in global FCC capacity was less than 0.6 mb/d, whereas the increase for coking was 1.3 mb/d and for hydro-cracking it was 1.7 mb/d. The factors behind this changing trend may include the extent to which significant recent hydro-cracker additions have helped to reduce distillate tightness, as well as the shift maintained in this year's Outlook towards a somewhat reduced growth in distillates demand going forward.

Figure 6.1
Conversion projects by region, 2016–2021



As shown in Figure 6.1, additions in each of the three conversion unit categories are expected in all regions except the US & Canada and Europe where there are no projected FCC additions. In fact, FCC additions in the US & Canada are net negative because of announced FCC unit closures in US refineries as components of project revamps. The limited conversion additions that are projected for the US & Canada are focused on hydro-cracking. These developments are expected despite a short-term surge that has pushed US gasoline demand to record levels. Over the medium- to long-term, though, the region's gasoline demand is expected to decline. In addition, the growth in light tight oil production has added to supplies of naphtha. These have provided a growing source of potential gasoline blendstock that has resulted in more emphasis being placed on catalytic reforming and isomerization to improve naphtha octane, rather than on incremental FCC capacity to supply gasoline. In Europe, the substantial regional gasoline surplus means there is little or no incentive to add to gasoline supply. In both regions, the emphasis remains on raising distillates yields (jet/kerosene and gasoil/diesel).

Significant conversion additions are projected for China, Other Asia-Pacific, the Middle East and Russia. The additions in Russia are driven both by the recent 'tax manoeuvre' that encourages the production of clean fuel for export and discourages fuel oil production, as well as by the prospects for raising diesel/gasoil exports to Europe, which is, and will remain, short of this product. In the Middle East, the conversion additions are geared towards adding value and, in doing so, meeting growing regional demand and supplying clean products for export. In China and Other Asia-Pacific, the additions are geared more towards satisfying domestic demand.

With respect to coking unit additions, all regions are expected to see some level of additions, with Latin America, Russia & Caspian, China and Other Asia-Pacific leading the way. Given the current lightening of the global crude slate, it will be interesting to see how these additions play out over the medium-term in terms of coker utilization levels. One change that could act to raise and even strain throughputs of cokers (and desulphurization units) is the pending introduction of the global marine fuel standard for 0.5% sulphur fuel. The MARPOL Annex VI standard is currently slated to go ahead in 2020, but could be deferred to 2025.[12] Given the expectation that on-board scrubber penetration will still be limited by 2020, and assuming shippers will, as obligated under the rule, try to achieve full compliance with the Annex VI standard, the shift could create a scramble to dispose of excess high sulphur intermediate fuel oil (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 arguably a key aspect (see Box 6.1 for further insights).

Desulphurization units

As stated, medium-term desulphurization unit additions equate to 70% of new distillation capacity. OECD countries have largely completed implementing ULS standards for gasoline and on-road diesel, and are now moving towards such standards for off-road diesel, as well as heating oil. This leaves the continuing shift of the developing countries towards Euro 3/4/5/6 standards as the main force driving hydro-treating capacity expansion.

Additions in the US & Canada and Europe total only 0.2 mb/d over the medium-term period. In contrast, the Middle East is at 1.8 mb/d and Asia at 1.7 mb/d as an array of new refinery projects and upgrades come online, including the al-Zour project in Kuwait which comprises substantial resid desulphurization capacity. Additions in the Russia & Caspian region are at 0.5 mb/d driven, as with conversion additions, by the effects of the new tax regime and by regulations to achieve ULS gasoline and diesel standards. New desulphurization capacity in Africa and Latin America is projected at 0.4 and 0.5 mb/d, respectively, and spread across a range of projects. This indicates further progress on these continents towards tighter fuel sulphur standards.

The concentration of additions in mainly non-OECD countries partly reflects recent trends towards cleaner products within these regions, but also the efforts of export-oriented refineries to provide low or ULS products for customers in developed – and, increasingly, developing – countries.

Octane units

Octane unit additions are at 18.3% of incremental distillation, again in line with the level for base refinery capacity. While the lead phase-out is essentially complete, octane levels are being raised and/or total gasoline output increased across essentially all developing regions. In line with this, additions are again overwhelmingly in the Middle East and Asia (0.5 mb/d each), followed at a much lower level by Africa and Latin America (0.2 mb/d and 0.1 mb/d, respectively). In addition, the 0.9 mb/d of FCC additions by 2021 will serve to add an appreciable volume of higher octane blendstocks in the form of FCC gasoline (plus feedstock for alkylation units).

The 1.3 mb/d of octane unit additions is comprised mainly of catalytic reforming at 1 mb/d, or almost 75%. The remainder is split between isomerization (0.2 mb/d), alkylation (0.1 mb/d) and MTBE units (0.03 mb/d). In Europe, MTBE consumption levels are flat while, in the US, the use of MTBE was effectively banned in 2006 – although some 40,000 b/d is still exported from merchant units on the US Gulf Coast. There continues to be interest in expanding MTBE use, primarily in Asia, as a means to meet rising gasoline pool octanes. Thus, the potential for a growing role for MTBE is worth monitoring, including whether this could represent an opportunity for exporters (see also *Long-term secondary capacity additions*).

Implications for refined products supply/demand balances

In assessing the effects of capacity additions on regional product balances, it should be remembered that refiners have, to some extent, the flexibility to optimize their product slate depending on market circumstances and seasons, either by altering feedstock composition and/or by adjusting process unit operating modes. With this in mind, Table 6.2 presents an estimation of the cumulative potential incremental output of refined products resulting from existing projects. These are grouped into major product categories, under the assumption that these new units are run at 90% utilization rates. Close to half (45%) of the increase by 2021 is for middle distillates (3.3 mb/d) and another 2.5 mb/d (33%) for light products,

Table 6.2
Global cumulative potential for incremental product output,* 2016–2021

mb/d

	Gasoline/Naphtha	Middle distillates	Fuel oil	Other products	Total
2016	0.4	0.3	0.0	0.1	0.9
2017	0.8	0.8	–0.1	0.4	1.9
2018	1.3	1.4	–0.3	0.6	3.0
2019	1.7	2.2	–0.3	1.1	4.7
2020	2.1	2.8	–0.3	1.5	6.0
2021	2.5	3.3	–0.2	1.8	7.4

* *Based on assumed 90% utilization rates for the new units.*

specifically naphtha and gasoline. The ability to produce fuel oil is set to decrease slightly, by 0.2–0.3 mb/d, assuming that new secondary units are fully used at the 90% level, while the ability to produce 'other products' is projected to rise by 1.8 mb/d.

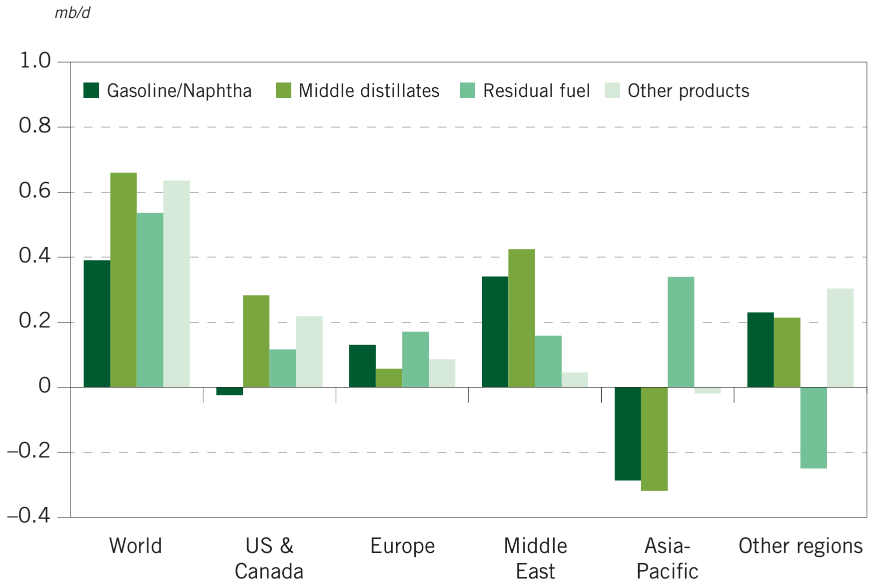
Figure 6.2 compares the potential additional regional outputs by major product group from the assessed projects (as detailed in Table 6.2), against the projected incremental regional demand for the period 2016–2021. In assessing net incremental requirements by product, Figure 6.2 takes into account product supply coming from non-refinery streams, notably additional biofuels, CTLs, GTLs and NGLs. The results are presented by product group as a net surplus/deficit, both globally and regionally. It should be noted, however, that the resulting surpluses/deficits are affected by declining product demand in some regions, which in the balance acts as 'additional refining capacity'; for example, gasoline/naphtha and fuel oil surpluses in Europe.

Globally, the outlook is for a cumulative surplus in each of the four product categories by 2021. Together, they total 2.2 mb/d. This trend towards a growing excess of refinery output potential over refined product requirements is exactly that described in Chapter 5, since it is based on the same underlying figures. But it is expressed here from the perspective of the main product groups rather than total product potential. This medium-term surplus is moderately below the level projected a year ago for the period 2015–2020 (2.5 mb/d), but still indicates an increase in competition for product markets.

By region, the picture remains one where there are surpluses in most products across most regions. Surpluses of 0.35–0.4 mb/d by 2021 for each of gasoline/naphtha and middle distillates in the Middle East are similar in magnitude to the deficits for the same two product groups in the Asia-Pacific. This has clear implications for product import/export trade. With its growing export refinery capacity, the aggregate surplus in the Middle East is projected to be almost 1 mb/d by 2021.

The Asia-Pacific is projected to have a cumulative deficit of 0.3 mb/d. This comprises deficits of around 0.3 mb/d for each of gasoline/naphtha and

Figure 6.2
Expected surplus/deficit* of incremental product output from existing refining projects, 2016–2021



* *Declining product demand in some regions contributes to the surplus. This is especially the case for gasoline/naphtha and fuel oil demand in Europe, which show emerging surpluses despite few capacity additions in the region. Gasoline and fuel oil are affected in other regions as well.*

middle distillates, which are partly offset by a significant surplus (over 0.3 mb/d) of residual fuel. The remaining regions, the US & Canada, Europe and 'other regions' (comprising the Russia & Caspian, Africa and Latin America) are each expected to have aggregate surpluses in the range of 0.45–0.6 mb/d in 2021.

Europe displays small surpluses across all products groups including middle distillates, which were showing an incremental deficit a year ago. This swing reflects a modest reduction in projected distillates demand in the region. The US & Canada shows small surpluses in middle distillates, residual fuel and 'other products', while being essentially in balance on gasoline/naphtha. The surpluses in middle distillates and 'other products' indicate the continued potential for exports growth. The 'other regions' remain collectively in surplus on naphtha/gasoline, distillates and 'other products', but short on residual fuel (by 0.25 mb/d).

Last year's Outlook stressed that the "balances show a continuation of projects that produce too much naphtha/gasoline", but also that the projected cumulative surplus was lower, at 0.8 mb/d by 2020. In this year's Outlook, the gasoline/naphtha cumulative surplus has dropped again, to 0.42 mb/d by 2021. Whereas last year it showed the highest cumulative surplus among the four product groups, this year it shows the lowest. Middle distillates, residual fuel and 'other products' have maintained cumulative surpluses of around 0.55–0.65 mb/d over the period. The primary reason for the drop in the cumulative gasoline/naphtha surplus is a large increase in projected gasoline/naphtha demand. Specifically, 2020 demand is projected in this year's Outlook to be almost 1 mb/d higher than that projected a year ago for 2020, with the main changes being demand increases in Asia for gasoline and naphtha.

For middle distillates, the main changes are the noted increases in the Asia-Pacific deficit and the swing in Europe from a small deficit to a small surplus. Overall, incremental middle distillates demand growth is projected to slow *versus* last year's Outlook, with 2020 demand 0.25 mb/d lower. Nonetheless, the overall middle distillates surplus is essentially the same as last year (0.65 mb/d *versus* 0.6 mb/d). The overall surplus for 'other products' is likewise little changed, at around 0.45 mb/d in this year's Outlook, compared to 0.55 mb/d last year.

For residual fuel, the picture is also little changed, both in terms of the global cumulative surplus (at 0.55 mb/d) and the regional patterns of surpluses and deficits. Every region is projected to be in surplus except for the 'other regions' group. The deficit of 0.25 mb/d in the 'other regions' is offset by surpluses elsewhere, which total nearly 0.8 mb/d. As has been pointed out in the previous two Outlooks, this indicates that upgrading capacity additions are not keeping up with changes in refined product demand.

Conversion additions continue to run at around 40% of the crude distillation capacity increase across the medium-term. These additions are broadly trailing incremental residuum supply from crude while fuel oil demand is dropping – hence the residual fuel surplus. As further discussed in Box 6.1, the residual fuel outlook in 2020 is a matter of considerable debate. It depends on whether the International Maritime Organization (IMO) goes ahead with the 0.5% sulphur global cap in 2020 or defers the timing to 2025.

These regional imbalances have implications for product trade, particularly for increasing movements of gasoline/naphtha and middle distillates from the Middle East to Asia. Beyond that, surpluses in essentially every region, apart from a residual fuel deficit in 'other regions', point to increasing competition for product markets. The relatively even balance of surpluses by product category at the global level implies product margins may stay fairly stable over the medium-term, with the potential exception of naphtha/gasoline where a narrower surplus may moderately strengthen margins for that product group.

Long-term secondary capacity additions

Overview

Refining capacity is measured first and foremost by distillation capacity. However, it is the supporting capacity for conversion and product quality improvement that plays a crucial role in processing raw crude fractions into increasingly advanced finished products – and which delivers most of a refinery's 'value-added'. In fact, given the general trend towards lighter products and more stringent quality specifications, these 'secondary' processes have become a key gauge of the refining sector's capability to meet demand.

Essentially all major projects for new refineries and large expansions comprise complex facilities with high levels of upgrading, desulphurization and related secondary processing. This enables them to generate high yields of light clean products which, almost invariably, can be produced to the most advanced specifications, such as the Euro 5 and now Euro 6 standards. In addition, many new refineries are being designed to be able to process heavy, low quality and often high total 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 towards the same aims – upgrading to reduce residual fuel output and achieve quality improvements for clean products. Together, these factors are leading to high levels in the proportion of secondary capacity per barrel of distillation.

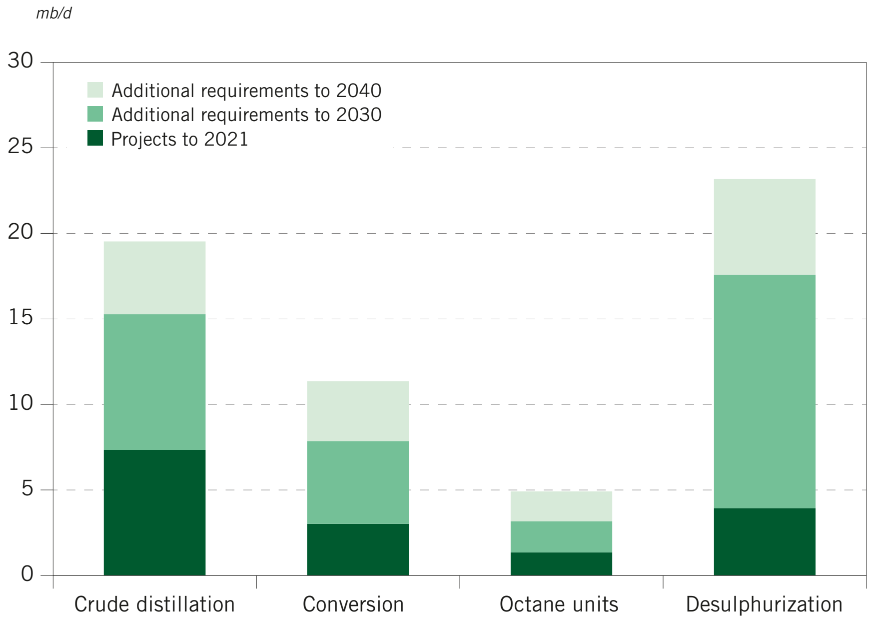
One exception to this trend is the high volume of new condensate splitter capacity currently being built. Additions are potentially as much as 0.6 mb/d in the US, to handle tight oil condensates, and up to 0.5 mb/d in the Middle East (although in both regions lower figures were considered as firm in the Reference Case). This, together with the sustained reduction in residual fuel demand as a percentage of total demand, creates a pattern wherein total conversion additions as a percentage of new distillation capacity increases over time. As shown in Table 6.3, existing projects to 2021 have conversion additions at 41% of new distillation capacity. Against this, from 2021–2030, the level is 61% and from 2030–2040 the figure is

Table 6.3
Global capacity requirements by process, 2016–2040
mb/d

	Existing projects to 2021*	Additional requirements 2021–2030	Additional requirements 2030–2040	Total additions to 2040
Crude distillation	**7.3**	**7.9**	**4.3**	**19.5**
Conversion	**3.0**	**4.8**	**3.5**	**11.4**
Coking/Visbreaking	1.1	0.5	0.6	2.2
Catalytic cracking	0.9	2.9	1.2	5.0
Hydro-cracking	1.1	1.4	1.7	4.1
Desulphurization**	**3.9**	**13.7**	**5.6**	**23.2**
VGO/Resid	0.7	2.0	1.5	4.2
Distillate	2.6	11.1	2.8	16.5
Gasoline	0.7	0.6	1.2	2.5
Octane units***	**1.3**	**1.8**	**1.7**	**4.9**
Catalytic reforming	1.0	0.8	0.9	2.8
Alkylation	0.1	0.5	0.3	1.0
Isomerization	0.2	0.1	0.3	0.6
MTBE	0.0	0.4	0.2	0.6

* *Existing projects exclude additions resulting from 'capacity creep'.*
** *Naphtha desulphurization not included.*
*** *New units only (excludes any revamping).*

Figure 6.3
Global secondary capacity requirements by process type, 2016–2040



82%. The percentage steadily increases because of the reduction in the rate of new distillation capacity added over time.

In contrast, in the later period, 2030–2040, secondary additions per barrel of distillation fall back for desulphurization units. This is based on the projection that, by 2030, the world's regions will have very largely completed the shift to ULS fuels. Octane units maintain appreciable additions both pre- and post-2030. This is based on the projection that, in the long-term, gasoline octanes across the world will progressively increase to (or near) the levels currently seen in the more industrialized countries. Moreover, levels in industrialized countries themselves are expected to move up in order to achieve improved engine thermodynamic efficiencies (see *Product quality developments* for further discussion).

The Reference Case projections for future required secondary processing through 2040 are presented in Table 6.3 and Figures 6.3–6.7. Similar to those for crude distillation units, projections for secondary process units take into account the 4 mb/d of refinery closures assumed by 2025. These remove not only distillation but also, in many cases, the 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 11.4 mb/d of conversion units, over 23 mb/d of desulphurization capacity and nearly 5 mb/d of octane units in the period to 2040. This is above the refining base as of the end of 2015. The trend towards higher levels of secondary processing is driven by long-term growth in demand for light low-sulphur products combined with flat to declining residual fuel demand.

Conversion units

This year's Outlook continues to project an easing in global distillates demand growth by 2040 and a partial shift in favour of gasoline. In addition, this year's Outlook has a somewhat strengthened upward trend over time in gasoline octane (see *Product quality developments*). These factors combined lead to a further reduction in the amount of new hydro-cracking capacity projected as needed, with 4.1 mb/d of total additions from 2016–2040 *versus* 5.4 mb/d from 2015–2040 in the WOO 2015, and to a corresponding increase in projected FCC additions, with 5 mb/d from 2016–2040 *versus* 4.1 mb/d for 2015–2040 last year. Thus, compared to a year ago, the required hydro-cracking *versus* FCC additions by 2040 have essentially inverted.

The 2.2 mb/d of projected additions for coking/visbreaking, which comprises predominantly coking, is somewhat down *versus* the 2.9 mb/d projected a year ago (for the period 2015–2040). Crude slate revisions are a factor in this. Based on updated crude production projections, the global crude slate quality is no longer projected to drop below 34° API by 2040, but rather closer to 34.5° API. The effect is to reduce the total yield of residual fractions by approximately 1 mb/d. The global crude sulphur level is also projected to be slightly lower. These changes, in turn, reduce the load on, and the need for, additional coking, as well as for VGO and resid desulphurization. The level of coking/visbreaking additions drops from 1.1 mb/d in the six-year period 2016–2021 to half that level in each of the periods 2021–2030 and 2030–2040.

Box 6.1

IMO regulations: new rules slowly being clarified?

The goal of the impending IMO MARPOL Annex VI global sulphur cap is to reduce maximum SO_x emissions from marine fuels burned in all areas outside Emissions Control Areas (ECAs), which already have a maximum 0.1% fuel sulphur limit. The regulation will cover the vast majority of marine fuel burned. While there remain uncertainties relating to the rule and its potential impacts on refining and oil markets, many of which were discussed in last year's Outlook (WOO 2015 Box 7.1), the past year has seen developments that are slowly bringing some clarity to the rule and its potential impacts.

As written, the IMO rule contains three uncertainties. The first is the timing of its implementation. This is stated as 1 January 2020, but with the caveat that it could be dropped back to January 2025. The second is that the rule allows for two methods of compliance with the sulphur emissions standard – either burn 0.5% sulphur fuel or burn high sulphur fuel (maximum 3.5%) and use exhaust gas scrubbers. The third is that the rule specifies only a fuel sulphur level of 0.5%. For both shipping companies and refiners, this leaves open the question as to what class of fuel to purchase or sell.

The standard (ISO 8217) that covers marine fuels allows a wide range of accepted fuel types from various diesel grades to a range of progressively heavier residual type grades (often referred to as IFO). To date, the broad assumption has been that the 0.5% global fuel would be predominantly marine diesel, fitting within one of the existing accepted ISO 8217 grades. However, recent experience with ECA fuels shows suppliers have also offered 0.1% sulphur residual-type IFO fuels and even 'hybrid' grades, which often closely resemble VGO.

How the implementation of the rule plays out could materially impact needed additions for coking, hydro-cracking, desulphurization and ancillary units. The key factor is the volume of residual type high-sulphur IFO bunkers that will be switched over time to marine distillates or heavier grades at 0.5% sulphur. To date, the uncertainties in the rule and its timing have created a lack of incentive for shippers to install scrubbers, and for refiners to install upgrading and desulphurization capacity specifically targeting 0.5% global marine fuel. One concern for refiners has been that the advent of the rule could cause a spike in marine distillate/IFO price differentials, thereby creating a rush to install scrubbers that would cause any justification for 0.5% fuel investments to largely evaporate.

Recent developments, however, have been providing stakeholders with additional – although somewhat conflicting - material on which to base a decision. Three recent analyses have projected the volumes of high sulphur marine fuel needing to be converted to global 0.5% fuel. In its February 2016 *Medium-Term Oil Market Report*, the IEA estimated 2 mb/d of marine heavy fuel would need to be converted to distillates in 2020. Two additional analyses were completed in July of this year.[13] These studies included a detailed review of the potential to install on-board scrubbing systems, thereby narrowing the uncertainty, at least for 2020, regarding the volume of high sulphur fuel that could be used with scrubbers *versus* that which would need to be switched to the 0.5% global standard. An EnSys-Navigistics study put the total volume of high sulphur IFO that would need to be converted to 0.5% compliant fuel in 2020 at around 4 mb/d assuming full implementation of the global sulphur cap. The conclusion of a CE Delft study is believed to be similar.

It should be noted that a 'switch volume' of 4 mb/d does not mean that 4 mb/d of residuum would need to be converted to distillates. Therefore, the estimates from the IEA and the other studies may be closer than they at first appear. The volume would be lower because IFO already contains volumes of distillate boiling range blendstocks, and because it is not a given that the compliant fuel would all need to be distillate. Heavier fuels could also be supplied, as already noted. The key target is the 0.5% sulphur level.

In terms of timing, at an October 2016 meeting of its Marine Environmental Protection Committee, the IMO should either have decided on the implementation date (2020 or 2025) or have set a timetable to do so if additional analysis was warranted. This should clarify one key parameter, namely the timing of implementation.

Nevertheless, other uncertainties will remain. A need to supply large volumes of compliant fuel could lead to a period of substantial market tightness as the industry adapts, affecting not only marine fuels but gasoil/diesel, jet/kerosene and residual fuels across all sectors and world regions. Arguably complex refineries, especially those geared towards distillate fuels, would experience high margins. The reverse would be true for simpler refineries, especially those processing higher sulphur crudes and producing significant yields of high sulphur residual fuel. Prices for such fuels could be expected to be heavily depressed and those for distillates to be high. Diesel-IFO differentials, which spiked as high as $90/barrel (b) (that is, $600/tonne) in 2008, provide a reference point.

These uncertainties will continue to be monitored carefully, but the current Reference Case assumes adoption of the global standard in 2020, with progressive rather than total instant compliance, and that scrubbers will be relatively successful over the long-term.

Over the periods 2021–2030 and 2030–2040, the pace of both hydro-cracking and coking/visbreaking additions is relatively steady. In contrast, FCC additions are relatively 'front loaded' in the period 2021–2030 and then lower post-2030. This is the result of the relative rates of growth in gasoline demand, 3 mb/d from 2015–2030, but only 0.6 mb/d from 2030–2040.

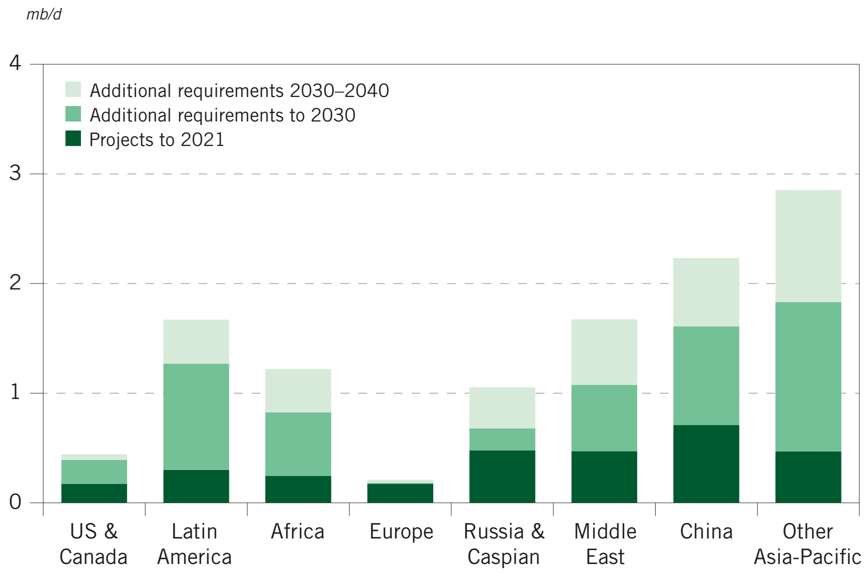
The hydro-cracking process has high capital, process energy and hydrogen costs. Over the longer term, the need to keep investing in additional hydro-cracking capacity, relative to distillation, can be expected to sustain distillate margins relative to crude oil.

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.

As seen in previous Outlooks, the projections allow for an increased role for FCC units in producing propylene, which is a high growth product, and also for a shift to operating modes that yield more distillates. This latter is projected to occur in part because of a steady increase in the proportion of resid feed to FCCs over time, as VGO is increasingly diverted for use as hydro-cracker feedstock. Compared to VGO, resid in FCC feed tends to yield more 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 FCC yield flexibility widens further over time.

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 80% range, through the period to 2040. FCC unit utilizations are projected to spike at around an 81% global average close to 2020, spurred by short-term gasoline demand growth. They then gradually trend downwards to the 75% range post-2030. This trend is consistent with the anticipated reduction in long-term gasoline growth, particularly the gasoline demand decline in the US & Canada. Utilizations on coking units are projected to dip from close to an 80% global average in 2015 to around 73% by 2020. This is driven in large part by significant capacity additions. Then, in the period from 2025–2030, they dip a little further, largely due to a lightening of the global crude slate. Finally, in the 2030–2040 timeframe, they recover

Figure 6.4
Conversion capacity requirements by region, 2016–2040



to the high 70% range as the global crude slate becomes heavier and the product slate continues to get lighter.

The regional distribution of future total conversion capacity additions is presented in Figure 6.4. Additions are minimal in Europe and minor in the US & Canada, some 0.4 mb/d. Requirements will be led by the Asia-Pacific, at around 45%, or 5.1 mb/d of the total future additions to 2040. Significant additions are also projected for Latin America, Africa, Russia & Caspian and the Middle East, in the range of 1–1.7 mb/d in each region. In all these regions, as well as in the Asia-Pacific, capacity growth is relatively steady over the period to 2040, reflecting the expected progressive trend toward lighter products and away from residual fuel oil.

Coking additions are projected to be spread across developing country regions, but led by Latin America as heavy crude production continues to expand there. FCC additions are likewise projected to be spread across developing country regions, but with the largest additions in China and Other Asia-Pacific. The overall pattern is similar for hydro-cracking additions, with the leaders being Latin America, the Middle East and Other Asia-Pacific.

Across all conversion units, there is some risk of stranded investments. In the case of FCCs, the modelling results point to the need for additions to occur pre-dominantly before 2030, and then to slow thereafter. Declining gasoline demand in the US & Canada, Europe and Japan/Australasia poses a clear risk to these regions, with implications for unit and refinery closures.

Hydro-cracking and coking additions also carry a degree of risk that goes beyond the normal uncertainties associated with economic and oil demand growth. As highlighted in Box 6.1, the needed additions for these units are subject in part to the timing and scale of conversion of marine IFO to distillates under the MARPOL

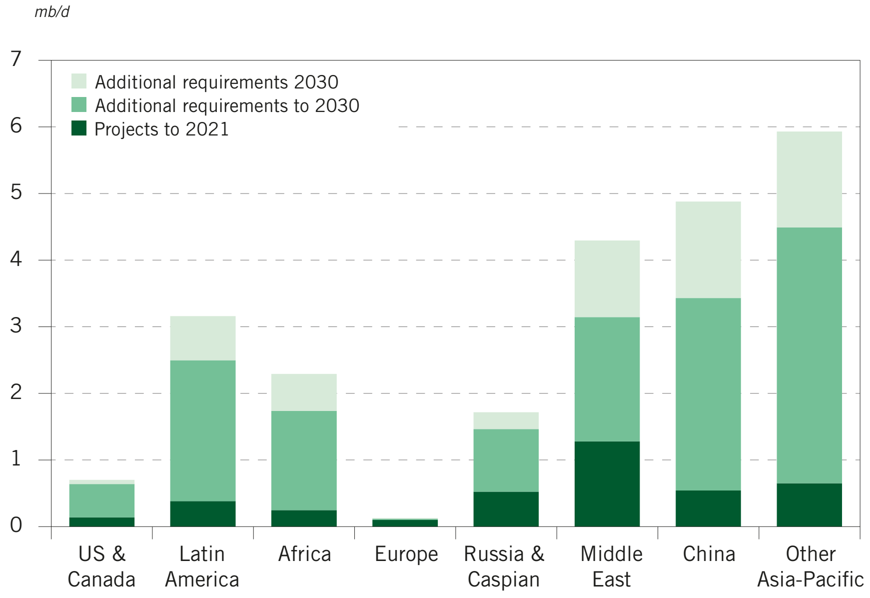
Annex VI rule. Current Reference Case assumptions assume a progressive switch, with around 1 mb/d of IFO converted to distillates by 2025. Thereafter, only limited increases are anticipated in line with growth in total marine fuel consumption. This is sufficient to drive part of the coking, hydro-cracking and ancillary investments that are embodied in the model-based capacity additions.

However, a near universal acceptance of on-board scrubbing would reduce these volumes, potentially making associated capacity additions redundant. Equally, should there be a process/catalyst breakthrough that enables high sulphur IFO to be desulphurized at a much lower cost than is possible today, then a significant proportion of the hydro-cracking, coking and supporting investments would no longer be needed. They would be replaced by resid desulphurization. A significant shift over the longer term to LNG would reduce total petroleum-based marine fuel demand. This would exert further pressure on upgrading unwanted IFO to clean fuels and would also eat into markets for marine distillates.

Desulphurization units

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, heating oils and marine fuels, desulphurization additions represent the largest capacity increases among all process units over the

Figure 6.5
Desulphurization capacity requirements* by region, 2016–2040



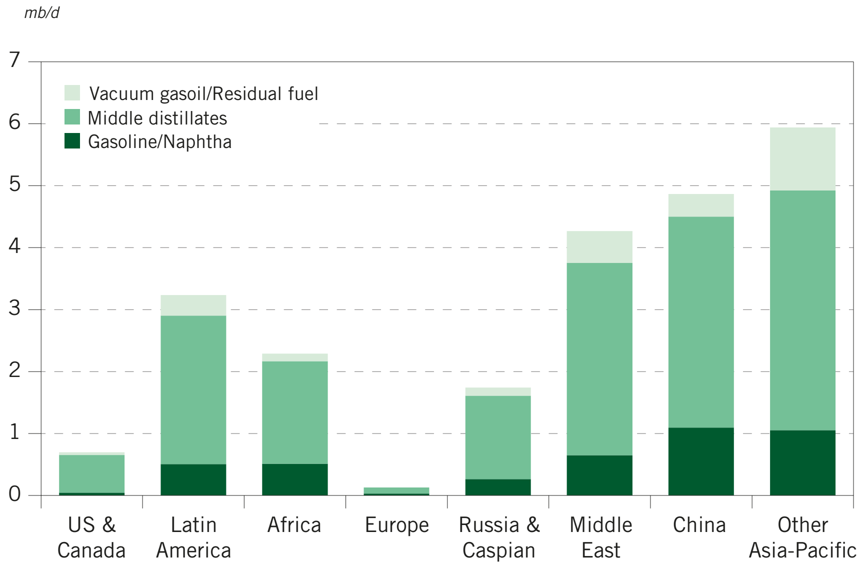
* *Projects and additions exclude naphtha desulphurization.*

forecast period. With OECD regions already largely at ULS standards for gasoline and diesel, the focus is now shifting to non-OECD regions as they move progressively towards low and ULS standards for domestic fuels, and build export capacity to produce fuels at advanced ULS standards. Over and above the 3.9 mb/d of desulphurization capacity included in assessed projects to 2021 (Table 6.3 and Figure 6.3), a further 13.7 mb/d is projected to be needed by 2030, and an additional 5.6 mb/d between 2030 and 2040. This leads to additions totalling 23.2 mb/d by 2040, which compares to 19.5 mb/d of total crude distillation capacity additions by 2040.[14]

Two points stand out. Firstly, while major new refinery projects are designed with significant desulphurization capacity built in, the high level of total desulphurization additions relative to distillation points to substantial desulphurization additions at existing refineries as they have to meet progressively tighter fuel sulphur standards. Secondly, there is a visible and considerable slowing in the pace of desulphurization capacity additions in the decade from 2030–2040, when compared to 2021–2030. This underlines the assumption that most regions will see gasoline/distillate fuel volumes reach ULS standards by 2030.

In terms of the regional breakdown (Figure 6.6), total additional global desulphurization capacity of 23.2 mb/d by 2040 is projected to be led by the Asia-Pacific at 10.8 mb/d, of which China comprises 4.9 mb/d. The Middle East follows with around 4.3 mb/d and then Latin America with 3.2 mb/d, driven by the expansion of the refining base, demand, and stricter quality specifications for

Figure 6.6
Desulphurization capacity requirements* by product and region, 2016–2040



* *Projects and additions exclude naphtha desulphurization.*

both domestic and exported products. Significant additions are also projected for the Russia & Caspian region (1.7 mb/d), which is in line with the region's tightening domestic 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 2.3 mb/d of desulphurization additions as the region also moves towards tighter standards for transport fuels. The 0.7 mb/d requirements for the US & Canada comprises less than 0.2 mb/d from current projects, plus additions largely to deal with high sulphur oil sands crudes. The lowest desulphurization capacity additions are projected for Europe, a minimal 0.1 mb/d over the forecast period, where transport fuels are already at ULS standards and refinery throughputs are projected to continue to decline.

In respect to the main product categories, of the over 23 mb/d of global desulphurization capacity additions between 2016 and 2040, some 71%, or 16.5 mb/d, are for distillate desulphurization, followed by 4.2 mb/d for gasoline sulphur reduction. The remainder, 2.5 mb/d, is for VGO/resid processing (Figure 6.6). It is important to note that opportunities to revamp existing distillate desulphurization units could impact the capacity addition levels indicated as needed.

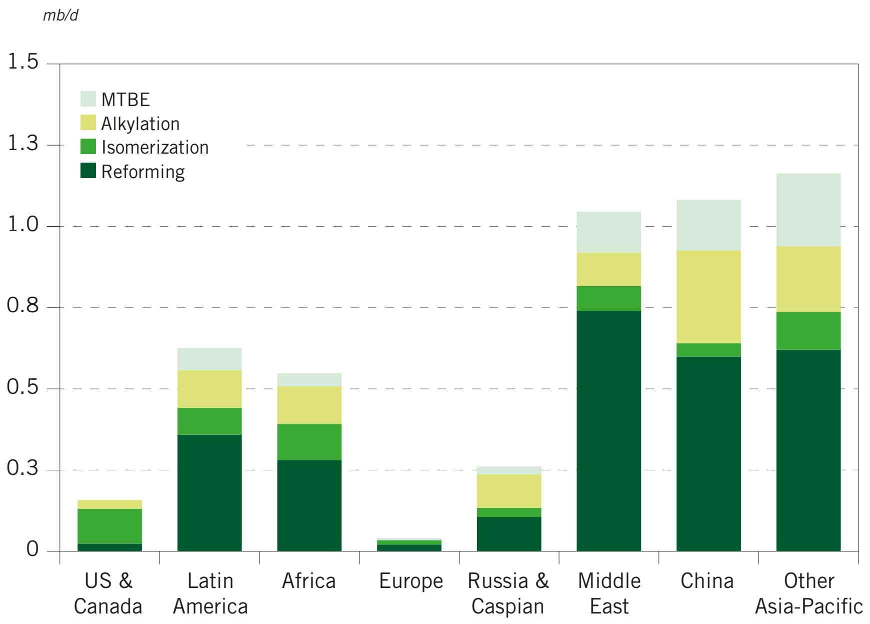
It should be highlighted that the modelling incorporates relatively conservative assumptions regarding the ability of refiners worldwide to repurpose existing distillate desulphurization units into ULS services. These opportunities are very dependent on such issues as the configuration and age of existing units. However, the performance of distillate desulphurization catalysts continues to advance. Such trends could open up opportunities to revamp existing units to a greater degree than assumed in this Outlook. The effect would be to reduce overall costs and the level of requirements for wholly new capacity.

Octane units

For the last category of secondary processes, future requirements for octane units will be close to 5 mb/d throughout the forecast period (Figure 6.7). The majority of these units will be needed in the form of catalytic reforming at 2.8 mb/d, with alkylation at 1 mb/d and isomerization and MTBE units each at 0.6 mb/d. As discussed under *Product quality developments*, these additions are driven in large 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. Latin America and Africa are also projected to have significant octane unit additions as their gasoline standards rise. Projected MTBE capacity additions (included in the reporting for the first time this year) follow the same geographical distribution as for the other octane units. Of the 0.6 mb/d of total additions through to 2040, nearly 0.5 mb/d is in the Asia-Pacific and the Middle East, with the remaining additions spread between Latin America and Africa. There are no additions projected for the US & Canada. The US has the refinery and/or merchant feedstocks, but MTBE use was effectively banned in 2006. It means that all MTBE capacity has been shut down except for about 40,000 b/d of Gulf Coast merchant units whose product is exported.[15]

Figure 6.7
Octane capacity requirements by process and region, 2016–2040



Product quality developments

A key driver for the secondary capacity additions is the evolution of product quality over time. In this regard, while the global trend toward low and ULS transport fuels continues, there are specific developments that can, and will, materially impact refining over the medium- and long-term. What follows is a summary of global quality trends, as well as a special focus on the outlook for gasoline octane.

Overview of global quality trends

Over the past few decades, regulations have been enacted and vehicles specifications have been altered to improve the quality of petroleum transport products and reduce emissions.

Throughout the 1980s and 1990s, and into the early 2000s, lawmakers first in industrialized, and then in developing countries, focused on removing lead, a common octane enhancer, from gasoline due to its detrimental effects on exhaust systems and human health. By 1996, less than 50% of the world's gasoline contained lead and, today, less than 1% of gasoline does. The removal of lead by refiners allowed vehicle manufacturers to introduce the catalytic converter, which converts exhaust hydrocarbons (HC), carbon monoxide (CO) and nitrogen oxides (NO_x) into water (H_2O), carbon dioxide (CO_2) and nitrogen (N_2).

In recent years, a major product quality focus has been the removal of sulphur from transport fuels. The sulphur in fuels produces SO_x when combusted. Due to pollution and health concerns, sulphur in on-road fuels is now heavily regulated, with 10–50 parts per million (ppm) ULS gasoline and diesel used throughout the world's industrialized regions. There is also the growing adoption of low sulphur and ULS fuels in developing countries: they now follow what is generally some version of the Euro 3/4/5/6 standards.

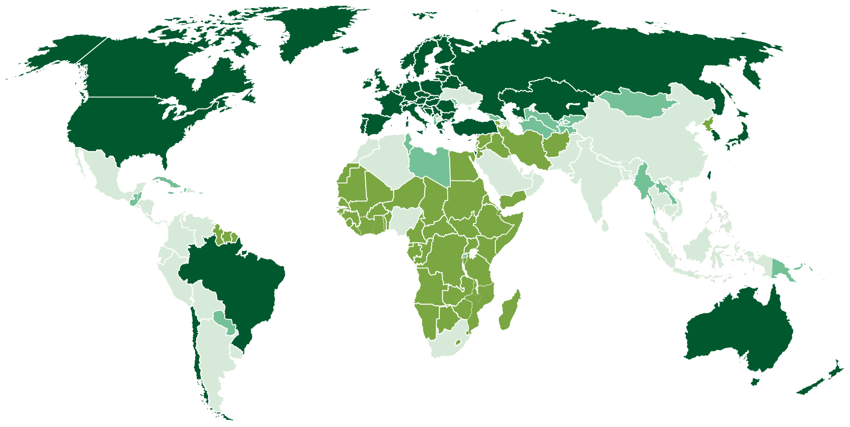
The trend towards improving vehicle fuel quality has also focused on reducing gasoline benzene and aromatics content, as well as increasing octane. Along with regulating on-road fuels, most governments have been tightening regulations for off-road diesel and heating oil. Off-road diesel fuel specifications now target the reduction of polyaromatics and particulates, in addition to improving the cetane rating.

The European Committee of Standards (CEN) has been at the forefront of fuel and emissions regulations. In 1992, the CEN produced a directive, known as Euro 1, which was used as a legal framework to regulate fuels and emissions. The directives set standards for fuels in terms of lead, sulphur, aromatics and renewables content, among other fuel quality and emissions standards. The CEN standards are periodically updated to reflect changes in specifications, such as the mandatory reductions in sulphur content and particulate matter. The 'Euro' directives have been adopted by other governments outside the EU and have thus evolved as a global basis for gasoline and diesel standards. Compared to the initial Euro 1 standards, the Euro 6 NO_x standards, for example, represent reductions of 92–94% and the diesel mass of particles standards represent 97%. These reduction levels are striking and highlight the substantial progress that has been made.

Figure 6.8 illustrates current comparative fuel emissions standards by country. As is evident, stringent (Euro 5, 6 or similar) standards apply across most countries in the northern hemisphere, plus Australasia, Brazil and Chile, while intermediate

6

Figure 6.8
Current emission requirements for new vehicles



- Stringent (Euro 5/V and 6/VI; US Federal; Japanese standards)
- Less stringent (Pre-Euro, Euro 1/I to 4/IV)
- Not regulated
- No information

Source: *'Global Fuel Quality Developments', Stratas Advisors, 11th Global Partners Meeting of the Partnership for Clean Fuels and Vehicles (PCFV), 6–7 June 2016, London, UK.*

standards apply in the rest of Latin America and much of Asia. To date, Africa and the Middle East contain the largest proportions of countries with varying degrees of progress in moving towards stringent international standards, constrained as they are by local circumstances and differing levels of economic development.

Euro 6, implemented in 2015, furthered the EU fuel and emissions standards. For gasoline, the directives mandate fuel quality specifications, such as limiting the fuel sulphur content to 10 ppm and mandating minimum octane ratings. In addition to direct fuel quality specifications, the directives limit the levels of CO, NO_x, total HC, particulate matter and other exhaust components. The sulphur content for on-road diesel has been regulated and kept at 10 ppm since Euro 5 in 2009. Off-road diesel met the same regulation in 2011. The Euro 6 directive allows 20 ppm sulphur emissions for non-road machinery, such as water vessels and agricultural equipment.

The US Federal Government applies its own set of fuel and emissions standards. Similar to the Euro directives, the US has put forward regulations in 'tiers'. Currently, the applicable US standard is Tier 2, which limits the sulphur content in gasoline to 30 ppm. With the advent of Tier 3 regulations in 2017, the sulphur content in gasoline will drop to 10 ppm. With respect to diesel in the US, the standard is now 15 ppm. The US standards also limit emissions of NO_x, CO, total HC and particulate matter.

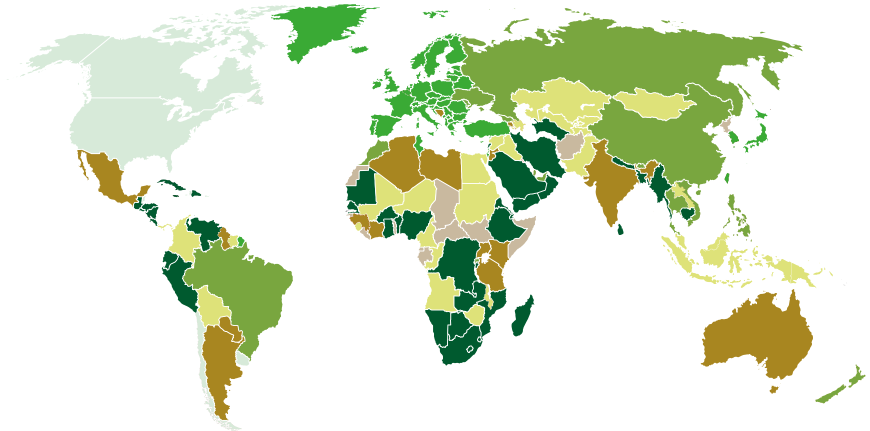
California has special emissions concerns and maintains a leading position with respect to emissions and GHG regulation. The California Air Resources Board (CARB) standards for gasoline and diesel are tighter than the US federal standards. For instance, the current CARB gasoline sulphur standard is 20 ppm. Across the border in Canada, fuel quality regulations are generally closely aligned with those in the US and the EU. Gasoline and diesel sulphur limits were set to 15 ppm in 2015.

China, the world's largest automotive market, currently has a national standard called China IV, which is similar to Euro 4, that has a 50 ppm sulphur content limit for gasoline and diesel. However, regions and cities in China are allowed to develop and implement their own more stringent fuel quality standards without national approval. These more stringent standards have been put in place in a few major provinces such as Beijing and Shanghai where pollution is a serious concern. In these areas, the standard is generally China V, which closely resembles Euro 5 with sulphur limits of 10 ppm. A nationwide transition to the China V standard is expected by the end of 2017.

India's fuel quality and emission limits are currently mandated by the Bharat Stage 3 nationwide standard and the more stringent Bharat Stage 4 standard in select cities. These are similar to Euro 3 and Euro 4, respectively. Currently, apart from selected cities, regions have mandates for 350 ppm diesel and 150 ppm gasoline. The Bharat Stage 4 sets diesel and gasoline sulphur levels to 50 ppm in major cities. This is planned to be accepted nationwide in 2017. India has proposed plans to bypass Bharat Stage 5 and implement the Bharat Stage 6 standard, which is similar to Euro 6, by 2020. The proposal aims to reduce both gasoline and diesel sulphur content to 10 ppm.

Significant gasoline and diesel quality specification improvements are also ongoing in other countries around the globe, particularly in Latin America, the Middle East and Russia, as these regions move progressively toward more advanced standards. Figures 6.9–6.12 illustrate the expected regional evolution to 2020 of sulphur limits in gasoline and on-road diesel, respectively.

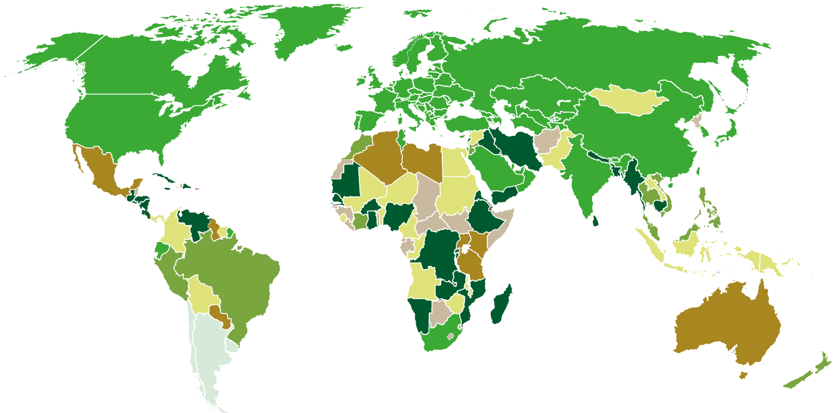
Figure 6.9
Maximum sulphur limits in gasoline, 2016



0–10 ppm 11–30 ppm 31–50 ppm 51–150 ppm
151–500 ppm 501–2,500 ppm No information

Source: *'Global Fuel Quality Developments', Stratas Advisors, 11th Global Partners Meeting of the Partnership for Clean Fuels and Vehicles (PCFV), 6–7 June 2016, London, UK.*

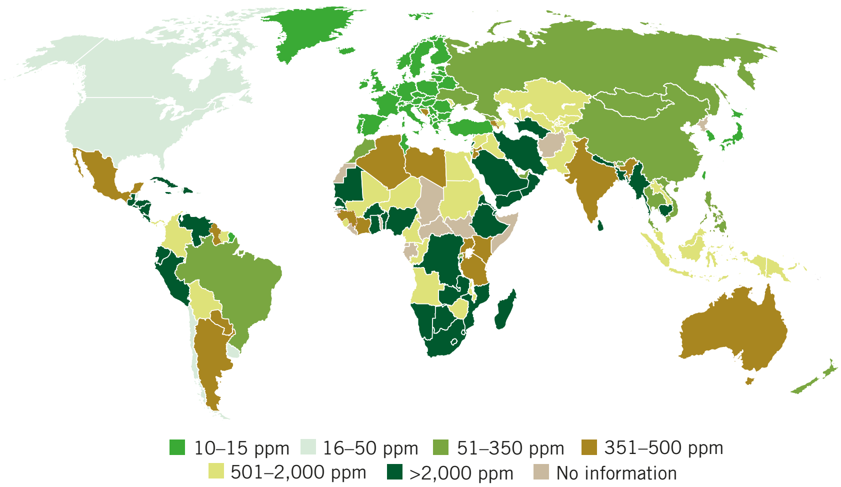
Figure 6.10
Maximum sulphur limits in gasoline, 2020



0–10 ppm 11–30 ppm 31–50 ppm 51–150 ppm
151–500 ppm 501–2,500 ppm No information

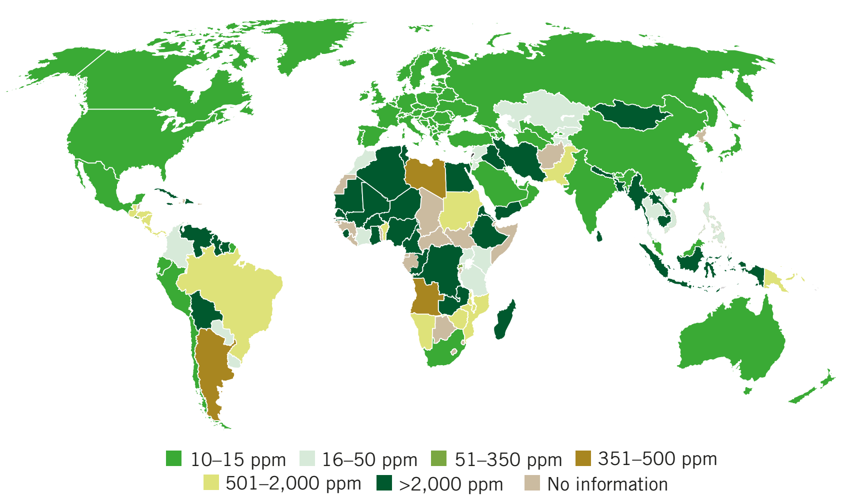
Source: *'Global Fuel Quality Developments', Stratas Advisors, 11th Global Partners Meeting of the Partnership for Clean Fuels and Vehicles (PCFV), 6–7 June 2016, London, UK.*

Figure 6.11
Maximum sulphur limits in on-road diesel, 2016



Source: *'Global Fuel Quality Developments', Stratas Advisors, 11th Global Partners Meeting of the Partnership for Clean Fuels and Vehicles (PCFV), 6–7 June 2016, London, UK.*

Figure 6.12
Maximum sulphur limits in on-road diesel, 2020



Source: *'Global Fuel Quality Developments', Stratas Advisors, 11th Global Partners Meeting of the Partnership for Clean Fuels and Vehicles (PCFV), 6–7 June 2016, London, UK.*

Gasoline octane & additives

Octane trends

Octane rating is a significant fuel quality specification that indicates how much compression a gasoline-type fuel can withstand before detonating (igniting). A higher octane rating signifies fuel that can withstand a higher compression without pre-igniting. High-octane fuels can be used with heightened engine compression ratios, which in turn will increase vehicle thermodynamic efficiency, provided the engine is tuned correctly. The octane ratings of gasoline have evolved in various countries, while staying relatively constant in others.

In Europe, a research octane number (RON) of 95 is the standard for 'regular' gasoline, while relatively small volumes of 98 RON 'premium' fuel are also sold. The 95 RON standard dates back to a CONCAWE[16]/auto manufacturers/government joint initiative in the 1970s to find, and settle on, a gasoline octane rating that would be the optimum in terms of matching vehicle engine requirements with a refiner's ability to supply.

The US does not mandate a minimum octane number, but fuel producers and vehicle manufacturers have settled on a standard for 'regular' gasoline of 87 (R+M)/2. This equates to 92 RON.[17] 'Regular' gasoline, similar to that in Europe, accounts for 82% of gasoline consumption. Mid-octane grade is 89 (R+M)/2, equivalent to 94 RON, and premium octane is typically at 92–93 (R+M)/2, roughly 97–98 RON. These standards have been maintained for many years – before, during and after the phase-out of lead, the reformulated gasoline programmes and MTBE removal/ethanol adoption.

In 1952, the Japanese Industrial Standards (JIS) Committee began regulating the country's gasoline octane ratings. Initially the octane number was 60+ MON for regular and 72+ MON for premium, equivalent to 70+ and 82+ RON, respectively. As Japanese vehicles progressed and higher compression ratios in engines were required, the octane measurement method changed from MON to RON and the JIS set new octane limits. In 1961, the regulations were set at 80+ RON for regular and 90+ RON for premium. In 1965, the Japanese Ministry of International Trade and Industry (METI) liberalized the importation of passenger cars. This ushered in the use of even-higher octane fuels – 85 RON and 95 RON – to accommodate the varying specifications of imported vehicles. The JIS committee altered the standard octane rating one last time in 1986 – to 89+ RON for regular and 96+ RON for premium.

Thus, octane ratings vary quite appreciably across the major industrialized regions, with Europe's levels the highest (95 RON for 'regular'), the US (and Canada) at 92 RON for 'regular' and Japan at 89 RON for regular. This is a six-octane span, which in refining terms is highly significant.

In developing countries, gasoline octane ratings have been improving from levels that were historically well below the ratings applied in industrialized regions. For example, India has incrementally increased its minimum octane rating. In 2005, the Bharat Stage 2 mandated 88 RON nationwide. But currently, under Bharat Stage 3 (which was set in 2010), India requires 91 RON gasoline. The country plans to move to 95 RON premium by 2020.

Increasingly, global vehicle and engine manufacturing, plus emissions reduction and fuel economy initiatives, are driving the worldwide automotive industry toward unified standards affecting both industrialized and developing regions. In this regard, the industry appears to be headed toward increased octane levels, despite the fact that long established standards have been the case in the US, Europe and other industrialized countries.

To meet ambitious new average fuel economy requirements and tailpipe GHG emissions standards, changes are required in fuel and vehicle technologies. One major way manufacturers are looking to improve efficiency and decrease emissions of gasoline-powered vehicles is by producing smaller engines with higher compression ratios, usually with some form of turbo-charged and/or super-charged configuration. Increasing the compression ratio of the engines requires fuel with a higher octane rating to accommodate the increased pressure load without self-igniting and causing engine knock. This means that the gasoline and engine have to be designed so that they work optimally together and deliver the required performance. High-octane fuels, in conjunction with downsized high compression engines, can deliver better fuel economy and fewer emissions than the same engines using regular gasoline. Manufacturers such as Ford Motor Company indicate that the best results are achieved by a combination of higher octane fuel and an engine optimized for that fuel. Applied in this way, raising the octane rating would thus lower well-to-wheel carbon intensity, as well as allow for a higher renewable content in the fuel.

Researchers at the Massachusetts Institute of Technology (MIT), through funding provided by oil company BP, published a paper outlining the economic and environmental benefits of higher-octane gasoline.[18] The team considered boosting the typical octane range from 92–98 RON (87–93 [R+M]/2) to 98–103 RON (93–98 [R+M]/2). The researchers estimated that, by 2040, 80% of the light-duty vehicles in the US would utilize higher-octane fuels. It was also projected that the higher-octane fuel would be more efficient, allowing vehicles to consume 3–4.4% less gasoline. Based on oil refinery modelling, the researchers found that producing higher-octane fuel would increase a refinery's emissions by 8%, but net CO_2 emissions would be reduced by 2.5–4.7% by 2040 compared to 2012. In line with this, the Worldwide Fuel Charter, which is produced by the European Automobile Manufacturers' Association, the Alliance of Automobile Manufacturers, the Truck and Engine Manufacturers Association and the Japan Automobile Manufacturers Association, asserts that "vehicles currently designed for 91 RON gasoline could improve their efficiency by up to 3% if manufacturers could design them for 95 RON instead".

Ethanol, a renewable fuel with a RON of 113, has seen increased use as a fuel octane enhancer. Among other examples, it has been blended into gasoline at a 5% volume level in India, and at a 10% volume level in the US and Europe. In the US, the EPA is putting forward a 15% standard in order to enable additional absorption of ethanol by eliminating the 10% volume 'blend wall'. Most of the world's vehicle fleet can handle a 10% ethanol content in gasoline without engine alterations. However, engine design/modification is required to accommodate fuels with higher ethanol content. Such is the case in Brazil where vehicles are equipped with 'flex fuel' engines due to the gasoline there containing 18–25% ethanol. ('Flex fuel' vehicles are also sold in the US.)

Government laboratories, automaker researchers and universities have demonstrated that using 20–40% ethanol in fuel could deliver the octane enhancement needed for maximized efficiency. The EU is examining the potential for a concerted move toward automobiles designed to run on high-octane, high ethanol content gasoline. As discussed in a recent study[19] for the European Commission, increased turbocharger boost with engine downsizing and the use of very high compression ratios will continue to spur higher octane fuels. However, for many gasoline vehicles currently on the market – particularly those built pre-2012 – potential damage to engines and catalytic converters could occur with the use of ethanol blends higher than 10%. The European Commission study examines the transition to E20 (20% ethanol content) and cites that the cost to optimize engines to run E20 is under €50 per vehicle if the change is incorporated at the design stage. As the report acknowledges though, a lead time of 4–5 years would be required for manufacturers to design such engines.

The overall implication from these initiatives is that we can expect to see gasoline octane trend upward over the long-term in both developed and developing regions. These initiatives also highlight the need for the automotive industry to be able to deploy relatively standard efficient engine technologies, rather than an array of different engine options. This year's Reference Case embodies an upward trend, which is somewhat strengthened *versus* the long-term trends used in previous years.

Gasoline octane enhancers

In dealing first with the phase-out of lead and then, subsequently, further octane increases, refiners worldwide have had a history of enhancing gasoline octane using a number of different approaches. These have centred on using reformate from catalytic reformers, butane, MTBE, ETBE, and other ethers and alcohols, notably ethanol. Other sources of increased octane have been the rising volumes of FCC gasoline and alkylate, plus isomerized naphtha streams. In selected global regions, octane is, or has been, enhanced using methanol and the manganese additive methylcyclopentadienyl manganese tricarbonyl (MMT). Developing countries use the above octane enhancers on occasion as imported blendstocks. The use of enhancers is dependent on economics and local regulatory specifications.

By volume, ethanol is the most common octane enhancer in the world. In 2015, the figure was 1.6 mb/d and in the Reference Case it is projected to grow to 2.5 mb/d by 2040. In recent years, the use of ethanol has grown significantly in the US, the EU and Brazil. The next leading gasoline octane enhancer is MTBE. In the 1970s, MTBE was the predominant octane enhancer as it is a low-cost, high-octane gasoline additive. However, it was phased out in the US, Japan and Canada when it was found to contaminate water supplies. MTBE is still used in Europe, Mexico, the Middle East and Africa. In less developed regions of the world, the use of MTBE continues to grow. The third largest gasoline octane enhancer by volume is methanol. The use of methanol mostly occurs in China.

As discussed under *Long-term secondary capacity additions* earlier, modelling projections are for several processes, including MTBE production, to play a role in meeting the assumed increases in gasoline octane over time.

Gasoline additives

Small volume gasoline additives represent an active area of product development and application, which also has potential to impact the performance of, and emissions from, gasoline and other fuels. Fuel detergent additives, which clean the engines of carbon deposits, are a case in point. Carbon deposits typically build up in fuel injectors and intake valves, causing reduced fuel efficiency, acceleration and power, as well as increasing emissions, rough idling and motor repairs.

One current programme highlights the potential impact of these additives. The 'Top Tier Detergent Gasoline' programme, which currently only operates in North America, sets higher levels of detergent than the minimum required by the EPA for US gasoline. For gasoline marketers to sell Top Tier gasoline, all gasoline grades sold must meet the programme's standards, not just the high-octane blend. Forty-six licensed retail brands currently sell Top Tier gasoline. Major automotive manufacturers including BMW, General Motors, Fiat Chrysler, Honda, Toyota, Volkswagen, Mercedes-Benz and Audi all recommend the use of 'Top Tier Detergent Gasoline' in their US owner's manuals.

The American Automobile Association (AAA) conducted an independent study to understand the impact of fuel detergents on engine cleanliness. The study analyzed the use of non-Top Tier gasoline containing minimum additive concentrations and Top Tier gasoline containing heightened concentrations of detergent. The AAA concluded that, after 4,000 miles, the engine that operated on non-Top Tier gasoline had 19 times more carbon deposits than the engine with Top Tier fuel. The study also concluded that "long-term use of a gasoline without an enhanced additive package can lead to reductions in fuel economy of 2–4%, drivability issues, and increased emissions." Additionally, the fuel brands surveyed indicated that Top Tier gasoline was priced at an average of three US cents more per US gallon – which is well below one cent more per litre – than non-Top Tier gasoline over a 12-month period.

Thus, detergent and possibly other additives have the potential to improve transport fuel efficiency going forward, as well as to impact consumption.

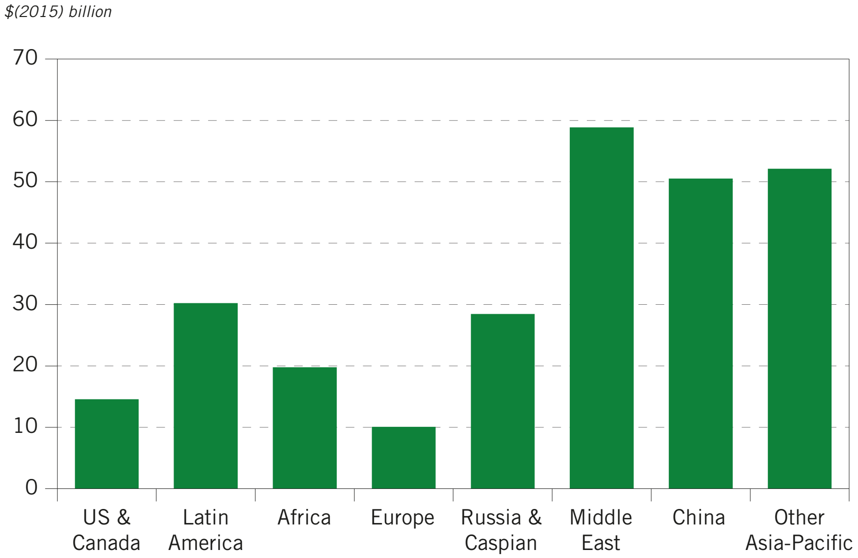
Downstream investment requirements

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 and be brought onstream during the period 2016–2021. The second category relates to the 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 category covers the maintenance of the global refining system and related necessary capital replacement.

Regarding firm projects in the period 2016–2021 (Figure 6.13), the highest investment contribution is expected to come from the Asia-Pacific region, driven by its strong oil demand growth. Investments of more than $100 billion are projected for the whole region by 2021, of which approximately half is located in China and the rest in the Asia-Pacific region. Substantial investments, close to $60 billion, are also foreseen for the Middle East over the period 2016–2021, again driven by large-scale projects, oriented to supplying exports of advanced products, as well as to meeting regional demand. Together, investments from firm projects in these two regions, the Asia-Pacific and the Middle East, represent 60% of the global total from 2016–2021.

In Latin America, projects in the period 2016–2021 should lead to investments amounting to $30 billion. Despite some recent deferrals and cancellations in the

Figure 6.13
Cost of refinery projects by region, 2016–2021



region, Brazil's Petrobras still has a number of ongoing projects, and additional projects are seen in Mexico, Colombia, Ecuador, Peru and Argentina. In the Russia & Caspian region, projects include some limited new distillation capacity, but these mainly emphasize conversion and quality improvements, with total investments to 2021 of just below $30 billion. Projected investments in Africa through to 2021 are seen at around $20 billion. A large share of this is attributed to two projects – Dangote in Nigeria and the Sonangol's Lobito project in Angola. Delays in either of these projects would substantially cut the region's total medium-term investment.

In the developed world, investments are subdued. In Europe, out of a number of projects with a total investment of around $10 billion, the new SOCAR refinery in Turkey is by far the largest, with the rest comprising smaller upgrading and quality investments spread across the region. In the US & Canada, a large share of investments is accounted for by condensate splitters, underpinned by the recent increase in domestic supply. Total investments of around $15 billion are projected over the timeframe 2016–2021.

In summary, a total of around $265 billion of investments are expected in the category of firm projects.[20]

Over and above the assessed projects, further refining capacity additions are needed through the long-term in order to maintain market balance at the global and regional level. These are projected via the outlook's modelling process. In total, these investments are estimated at around $385 billion in the forecast period until 2040 (Figure 6.14). The geographical distribution broadly mirrors that of the medium-term projects. In line with oil demand expectations, the largest share of these investments is located in developing regions, while developed regions are likely to see only limited investments.

Overall, the largest portion of additional refining capacity investments by 2040 should occur in the Asia-Pacific, with almost $180 billion. This is close to half the global investment total. Around one-third ($63 billion) is forecast to be located in China. This is a moderate downward revision compared to last year's Outlook, and in line with the downward adjustment to the region's projected oil demand growth. The balance of the Asia-Pacific investments are distributed between the region's other developing countries, led by India which in the long-term should remain an important market for new refinery projects.

In the Middle East, new investment is projected to be sustained through the longer term, although at a pace below that of the surge experienced recently. Around $60 billion of refining investment, above firm projects, is estimated in the period to 2040.

Latin America and Africa are also expected to invest considerably in refining capacity over the long-term. The region is forecast to see some $50 billion of investments, above firm projects, while Africa will see a slightly lower level of around $45 billion. Both regions currently rely heavily on product imports and thus most new investments must compete with products from the established refining bases in the US and Europe, and with the growing capacity in the Middle East and India. Based on strictly economic considerations, as opposed to national security or employment goals, the effect of this extensive international competition is to curb investment in the two regions such that they are both projected to still be net product importers in the long-term.

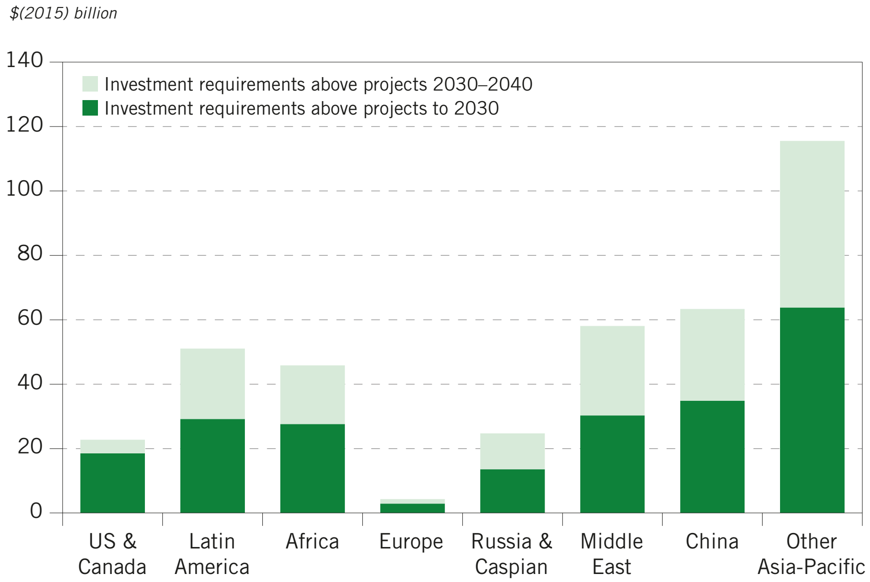
The Russia & Caspian region is expected to invest around $25 billion, above firm projects, to 2040. This more moderate level is due to several factors. The first is a domestic demand profile that shows only minor growth (somewhat over 0.2 mb/d) in the period 2020–2030 and then a small decline (0.05 mb/d) between 2030 and 2040. Secondly, the new tax regime in Russia makes exporting crude oil as attractive as exporting clean products, given the same levels of export duty. And thirdly, there is a demand decline in Europe, Russia's primary product export market.

Investment activity in the US & Canada, beyond firm projects, is expected to be around $23 billion by 2040. This comprises limited distillation debottlenecking together with secondary processing that is mainly oriented towards raising distillate output and dealing with the growth in Canadian heavy crude supply. The bulk of this activity is expected to have occurred by 2030, which is consistent with demand declining over the long-term. In Europe, only minor investments of around $4 billion are envisaged, beyond firm projects, to 2040. This covers minor additions to existing facilities. Again, the region's demand decline limits the need for new capacity.

In total, the first two categories of investments make up around $650 billion, which is the level needed to accommodate long-term demand growth, with its embedded shift to developing regions, plus associated product quality improvements. At $650 billion, total 'direct' investment to 2040 for additional capacity is some $50 billion below last year's assessment. This reduction is the net effect of several factors.

One factor is simply the fact that this year's Outlook is for one less year (2016–2040 in place of 2015–2040). A second factor is that this Outlook has slighter lower demand projected by 2040 (109.4 mb/d *versus* 109.8 mb/d). And a third factor is the slightly lighter projected long-term crude slate, which would necessitate less upgrading and desulphurization investments. Partially offsetting these factors

Figure 6.14
Projected refinery direct investments* above assessed projects



* *Investments related to required capacity expansion, excluding maintenance and capacity replacement costs.*

is a 0.6 mb/d reduction in projected 2040 non-crudes supply (primarily biofuels, plus some CTLs/GTLs and NGLs), which increases the load on refining. Clearly, investment requirements will also be affected by the levels of refinery closures and the evolution of future capacity construction costs. The assumption employed in the projections for investment costs is that per barrel costs will increase at a moderate pace over the forecast period.

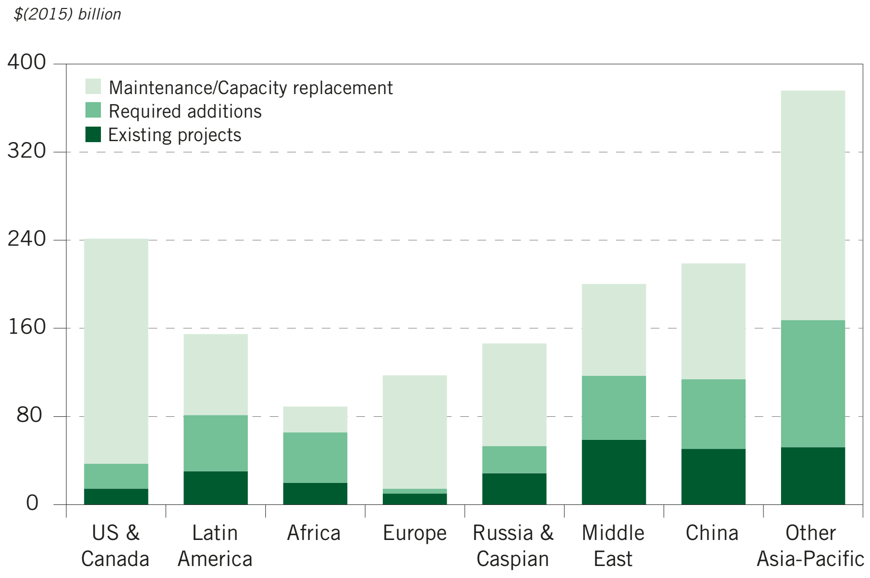
The phasing of these investments is notable. Firstly, they are front-loaded. Allowing for some limited additions by 2021, beyond firm projects, brings the total assessed investment to close to $300 billion by 2021. This equates to some 45% of the direct investments projected to be needed in total between 2016 and 2040. Secondly, the level of required investment declines progressively through the long-term, in line with the steady decline in incremental capacity needs. From an annual rate of investment for 2016–2021 that is not far below $50 billion p.a., the pace drops significantly, especially after 2025. For the period 2025–2030, the annual rate of investment is projected at just under $20 billion p.a., which then tapers off further to around $15 billion p.a. in the period 2035–2040.

Finally, maintenance and the replacement of installed refining capacity over the entire forecast period at the global level will require investments of just under $900 billion. The assessment of this category of investment is based on the assumption that the annual capital required for capacity maintenance and replacement is around 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. These costs and their regional distribution are presented in Figure 6.15, along with costs for firm projects and for required additions beyond projects.

The distribution of maintenance and replacement costs follows the regional base and capacity addition patterns depicted throughout this Chapter. Total costs to 2040 are highest in the US & Canada and Other Asia-Pacific, at around $200 billion each, but for different reasons. The level in the US & Canada primarily reflects an already-existing large and sophisticated capacity base, whereas the high level for Other Asia-Pacific reflects a combination of already installed capacity with substantial additions to that base over the long-term. In a similar vein, projected levels for Latin America, the Middle East and China, at around $70–100 billion, are broadly similar to those for Europe, as well as for the Russia & Caspian region.

In summary, all three categories of refinery investment requirements combined are estimated at somewhat over $1.5 trillion in the period 2016–2040. Of this, $265 billion is needed for investments in known projects, around $385 billion for additions beyond firm projects and just under $900 billion for maintenance and replacement.

Figure 6.15
Total refinery investments in the Reference Case, 2016–2040



Oil movements

Key takeaways

- Inter-regional crude and products movements grow faster than global demand. This partly reflects the shift in demand over time to developing regions, led by the Asia-Pacific.
- Global crude trade grows by just below 8 mb/d 2015–2040, of which exports from the Middle East and imports to the Asia-Pacific comprise the biggest share.
- The Middle East remains the largest crude export region in the long-term, supported by Asian demand with eastbound volumes of almost 21 mb/d in 2040, from just above 14 mb/d in 2015. At the same time, flows to traditional outlets such as the US decline.
- Export volumes from Africa and Latin America decline to some extent in the long-term due to increasing domestic demand and an expansion of domestic refining capacity, as well as a decline in ageing production areas.
- In line with a decline in product demand in industrialized regions, combined crude oil imports into the US & Canada, Europe, Japan and Australasia drop by around 3 mb/d 2015–2040.
- Crude exports from the US & Canada increase from virtually zero to more than 2 mb/d in 2040. This is a consequence of the lifting of the US crude oil export ban combined with potential increases in Canadian crude export capacity.
- After a peak at around 6.5 mb/d in 2020, crude inflows into the US & Canada are expected to decline to around 3.5 mb/d in 2040 due to an upswing in domestic production and a decline in demand.
- Europe is expected to reduce its imports by some 1 mb/d in the period 2015–2040 due to lower demand and despite a decline in indigenous production.
- The Asia-Pacific remains the main import destination with growth of almost 9 mb/d over the forecast period. China alone accounts for the majority of the growth, while the rest is distributed across the region (dominated by India).
- Crude trade patterns are sensitive to developments in logistics, especially from Russia & Caspian to China and the Pacific, where expansions are going ahead, and out of Canada where four high-profile projects are all subject to uncertainty.
- Product movements are expected to decline in the medium-term as new refining capacity in demand centres are projected to come online. This should limit requirements for imported barrels. In the long-term, total flows of products should recover gradually, following the growth in demand.

Factors impacting actual movements and projections

The ability to move crude oil, products and intermediate streams between regions economically is what makes the downstream a truly integrated global system. It is built on the capacity to move large parcels of oil liquids between almost any two regions of the world, whether over short or long distances, and via a variety of transport modes. These inter-regional movements enable physical supply, as well as trade and competition, as they respond to price signals and limit open market price differentials (for the same or similar streams) between regions.

Various factors affect the direction and volume of these trade movements. These include demand levels; the production and quality of crude and non-crude streams; product quality specifications; refining sector configurations (including additions); trade barriers or policy-driven incentives; the capacity of existing transport infrastructure (such as ports, tankers, pipelines and railways) and its economics; ownership interests; term contracts; price levels and differentials, freight rates; and, at times, geopolitics. There is an interplay among these features which determines the volumes traded between regions at any given time. It also creates a sector that functions with a mix of actions ranging from stable, long-term movements to rapidly changing, market-driven 'arbitrage' trading.

The refining sector is a key element in this regard. In general, the economics of oil movements and refining results in a preference for locating refining capacity in consuming regions due to the lower transport costs for crude oil compared to oil products. This leads to the majority of trade – especially over long distances – involving crude oil. However, when costs or other hurdles exist to building the required refining capacity, or where there are substantial regional supply/demand imbalances, the result can be significant products trade.

For producing and consuming countries alike, there is an emphasis on securing supplies of refined products through local refining rather than imports, regardless of the economic factors. This is particularly the case for oil consuming countries. For producing countries, there is the additional consideration of seeking to increase domestic refining capacity in order to not only cover domestic demand, but also to benefit from the export of value-added products instead of just crude oil. As an extension of this strategy, 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 where long-term contracts for feedstock supply can be arranged.

The relationships between the various factors mentioned can result at times in oil movements that are far from being the most economic or efficient in terms of minimizing overall global costs. In contrast, movements generated by the WORLD model are all based on an optimization procedure that seeks to minimize global costs across the entire refining/transport supply system, in accordance with existing and additional refining capacity, logistical options and costs.

Generally, few constraints are applied to crude oil and products movements in the WORLD model, especially in the 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 realities (such as the constraints resulting from ownership interests, term contracts, etc.) and a modelling approach that looks longer term (with few restrictions on movements and which operates by minimizing global costs) mean it is necessary to recognize that model-projected oil movements do not fully reflect short-term factors. They may, therefore, predict trade patterns that are not direct extensions of those that apply today. Historical volatility in tanker freight rates and the difficulties in predicting where they may be in two, five or 10 years add to the uncertainties in projecting future oil movements.

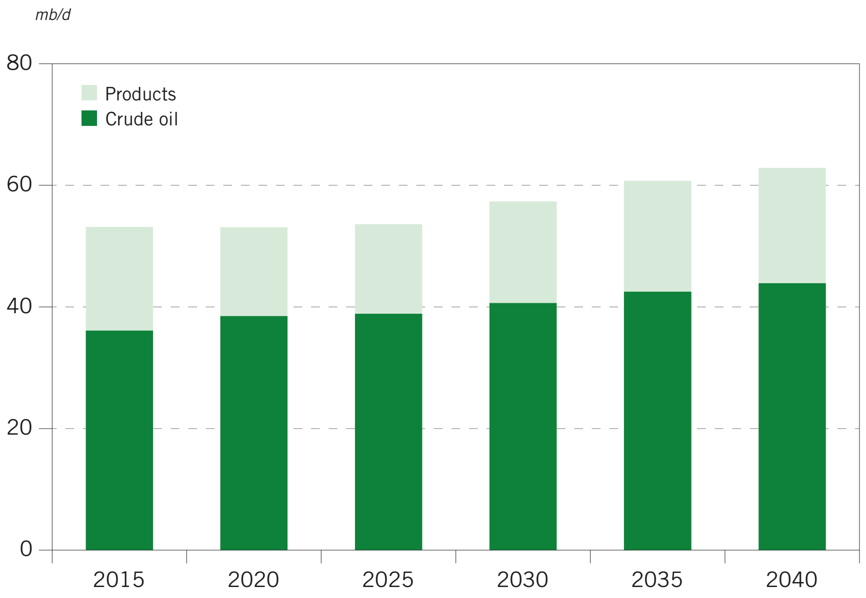
Nevertheless, the model-based results presented in this Chapter should provide a useful indication of future trends in crude oil movements, which necessarily function to resolve regional supply and demand imbalances in both crudes and products. These projections are, of course, dependent on the Reference Case assumptions used in this Outlook, which, if altered, could materially impact projected movements. Key elements in this are the volumes and qualities of both crudes produced and the products consumed by region, and how these change over time. Another element is the location and capability of refining capacity. Over the longer term, the relative economics of building new refinery capacity in different regions, and the capability of existing refineries to export and compete against imports, all affect the trade patterns of crude and products. There is an interplay between freight and refining costs. Broadly, higher freight rates tend to curb inter-regional trade and encourage more refining investment, while lower freight rates tend to enable greater trade and competition between regions, and serve to provide those regions with spare refining capacity with more opportunities to export products.

As set out in Annex C, the WORLD model represents the world as 23 regions and captures trade movements between them. For reporting purposes, these regions are aggregated into seven regions.[21] This necessarily eliminates from the reported trade activity those movements that are 'inter-regional' at the 23-region level, but which become 'intra-regional' at the more aggregated seven-region level. This is why the final reported level of trade activity is somewhat lower at the seven-region level *versus* the 23-region level.[22]

Figure 7.1 provides an overview of global oil trade to 2040 as projected from the modelling and as reported on a seven-region basis. What is evident are shifts in the volumes of both total crude oil and products trade between 2015 and 2025, followed by a pattern of gradual increase in crude and products trade over the long term.[23] The rather sharp changes between 2015 and 2020, and then on to 2025, stem mainly from developments in the US & Canada region. These are reviewed in detail later. On average, crude oil trade is projected to grow at a pace somewhat ahead of that for liquids demand, around 0.8% p.a. for crude movements *versus* 0.7% p.a. for liquids demand from 2015–2040. Breaking this down into periods, average annual crude trade growth is at around 0.9% p.a. from 2025–2035 before dropping to the 0.6% p.a. level from 2035-2040. In comparison, demand growth slows more markedly and steadily, from 1.1% p.a. from 2015–2020 to 0.8% p.a. from 2020–2025 and then progressively down to 0.3% p.a. from 2035–2040. The main driver of the sustained higher growth rate for crude trade is continuing growth in demand in – and, hence, crude oil imports into – Asia. For 2025–2040, these grow by 6 mb/d, well ahead of export declines into Europe and the US & Canada. (Declines in crude oil imports into the US & Canada are partially offset by growth in crude exports from the region.)

Growth in product movements averages around 0.5% p.a. in the 2015–2040 period. A relatively strong period is indicated post-2025 when rising exports from the Middle East, the US & Canada, Europe and, to a lesser degree, Russia &

Figure 7.1
Inter-regional crude oil and products exports, 2015–2040



Caspian feed growing demand in Asia and Africa. Before 2025, product movements are projected to be flat to declining as a wave of expected refinery capacity additions across world regions (see Chapter 5) results in a net reduction in product trade. Over the whole forecast period (2015–2040), crude oil movements increase around 8 mb/d and product movements increase just below 2 mb/d.

The impact of ending the US crude oil export ban

The rather sharp changes evident in crude movements between 2015 and 2020, and then through to 2025 (Figure 7.1), stem mainly from developments in the US & Canada region.

The 2015 trade patterns reflect the US crude oil export ban, which was in place until December 2015. Crude movements from Canada to the US were substantial, at over 3.1 mb/d. Also, as Canada was the only export destination effectively open to US crudes, exports of US crude and condensate to Canada averaged 0.4–0.5 mb/d. However, crude oil exports from the US & Canada to third-party destinations as a whole totalled only around 60,000 b/d.

With the lifting of the export ban, new crude trading patterns are emerging. (Last year's Outlook assumed the export ban would stay in place.) These represent an important shift that will impact import/export patterns in the short- and long-term. Data for the first half of 2016 show that US crude and condensate exports to Canada dropped back to around 0.3 mb/d, but total exports rose to the 0.5–0.6 mb/d level (despite a decline in US crude and condensate production). Non-Canadian destinations through June comprised mainly Latin America and Europe with small volumes to Asia.[24] The data and press reports for 2016 trade are all in line with current model projections, which show the lifting of the ban is enabling the emergence of two-way export-import trade whereby light and super-light US crude exports open room for imports of the heavier, sour crudes that many US refineries process. This development looks set to remain in place.

Supply and demand elements of the Reference Case outlook – specifically a dip then a rise and a plateau in the US & Canada crude and condensate supply, and a peak, then a progressive decline in regional product demand – look likely to cause significant swings in crude trade patterns and volumes between 2015 and 2025. Between 2015 and 2020, US & Canada total crude supply is projected to increase only minimally (by 0.2 mb/d), a consequence of a drop in US production, which is only expected to start recovering in 2018, along with modest growth in Canada. Over the same period, crude exports rise more than 1.2 mb/d driven by the cross-trade incentive already described. This leads to a reduction of around 1 mb/d in the US & Canada crude used locally. In parallel, the US & Canada demand rises (by 0.4 mb/d), accompanied by a rise in crude runs of more than 0.6 mb/d. To meet the extra runs and replace the US crude now being exported, crude imports rise significantly (by 1.7 mb/d) compared to 2015. The additional crude imports are projected to be supplied by Latin America, Africa and the Middle East. The advent of this cross-trade phenomenon, augmented by the short-term rise in US & Canada crude runs, accounts for 3 mb/d out of a total of 4.7 mb/d in increased crude trade in 2020 *versus* 2015. (The remaining growth in crude movements is primarily related to the long-term upward trend in Asian product demand and related crude oil imports.)

Equally evident in the projections is that the increase in US & Canada crude oil imports projected for 2020 over 2015 then inverts between 2020 and 2025. In this period, US & Canada crude oil supply is projected to rise in the Reference Case by a substantial 2 mb/d – increasing from 13.2 mb/d in 2020 to 15.2 mb/d in 2025 – as higher oil prices encourage more US tight oil production and as Canadian production continues to move up. Conversely, US & Canada demand drops by 0.8 mb/d, having peaked around 2018, and crude runs decline slightly by 0.2 mb/d. The 2 mb/d rise in crude supply is projected to go primarily into local use (1.7 mb/d) with 0.3 mb/d to increased exports. In line with the increased use of domestic crude and the small decline in refinery runs, imports necessarily drop by 1.9 mb/d. The reductions again are in exports from Latin America, Africa and the Middle East. (These reductions are roughly offset by increases in other crude export trade, notably to Asia. The net effect is essentially flat total global crude trade – perhaps even some contraction – during the 2020–2025 period after appreciable growth in 2015–2020.)

Overall, the projection is for a spike in US & Canada crude oil imports from just below 5 mb/d in 2015 to around 6.6 mb/d in 2020, then back down to under 5 mb/d by 2025. Thereafter, the downward trend in crude oil imports and the upward trend in exports are both projected to continue. Under the Reference Case, US & Canada crude supply plateaus somewhere above 15.5 mb/d in the 2030–2035 period and then declines slightly by 2040. From 2025–2040, crude runs are expected to decline by around 1.6 mb/d. The combination of a plateau of stable high production with gradually declining crude runs leads both to a drop in crude oil imports to around 3.5 mb/d by 2040 and to a gradual rise in crude oil exports from around 1.6 mb/d in 2025 to above 2 mb/d over the 2035–2040 period.

In short, US & Canada crude oil exports look set to become a long-term factor in the market. The change in US legislation has been a key factor, but so will be the evolution of regional crude oil export logistics. As discussed later and in Box 7.2, the modelling assumes that some – but not all – of the major Canadian export pipelines will go ahead, enabling substantial exports to both Asia and Europe. Extensive US export facilities for crude oil (as well as for products and NGLs) have recently been put in place, notably along the Gulf Coast. US crude export volumes do not, therefore, appear to be subject to any physical limits. In addition, the recent Panama Canal expansion should reduce the cost of oil movements to Asia.

These projections highlight both the effect of the lifting of the US crude oil export ban, which has led to significant new crude trade, and the sensitivity of crude exports to the US & Canada to both crude production levels and product demand levels in that region. Clearly, changes in any of these parameters *versus* what has been assumed in this Outlook will result in corresponding alterations to the US & Canada crude oil import/export outlook. As it stands, this outlook will affect both trade volumes and associated tanker capacity requirements (see Box 7.1).

Box 7.1

Tanker markets: tough times continue

The crude tanker market gained momentum during 2015, after several years of weakness and depression, with dirty freight rates reaching their highest levels since 2010. This seemed to spread some optimism among market participants. However, when looking at the fundamentals, the near-term does not look rosy for the tanker market.

The plain fact is that across all tanker classes no freight rates have returned to anywhere near their pre-recession levels. The peak in freight rates in 2008 was followed by a strong slump in 2009 due to a contraction of global oil demand in the midst of the financial and economic crisis. In 2010, prices for dirty freight recovered temporarily, in line with both the recovery of the world economy in the aftermath of the crisis and strong demand from Asia. However, after 2010, freight rates dropped again and remained depressed for several years, mainly due to large additions to transportation capacity. The annual average growth rates of Very Large Crude Carriers (VLCC) and Suezmax fleet capacities in 2011 and 2012 were significantly above their long-term averages with an estimated growth rate of around 6% p.a.

The first signs of renewed support for the dirty freight market came during 2014 and continued in 2015. The main reason for the change was strong global oil demand, increasing refinery runs, as well as ample crude supplies combined with additional demand for floating storage. At the same time, due to weak market conditions in the years prior to 2014/15, the growth of transportation capacity was modest. VLCC capacities increased only by around 2% p.a. in 2014 and 2015, a far cry from the levels seen in years prior. Suezmax capacities even saw contractions in 2014. Some support also came from the volatility of oil and product prices during 2015, which seemed to support freight rates as more (short-term) arbitrage opportunities opened up between the regions.

Another important parameter of the freight market, the ton-mileage, climbed to record levels in 2015. Ton-mileage measures tons (barrels) transported by distance travelled, and translates directly into tanker fleet dead weight ton (dwt) capacity required. This means that with increasing transport distances, the demand for ton-mileage – and, hence, fleet dwt capacity – will rise. This was indeed the case in 2015 as Atlantic Basin and Middle Eastern cargoes travelled increasingly to the Asia-Pacific and less to the US. This was a direct consequence of rising domestic supply in the US and Canada, which displaced some of the West African and Middle Eastern barrels. As a result, freight rates for cargoes travelling to Asia profited significantly. Prices for VLCCs on the Middle East-Asia and West Africa-Asia routes both increased to around 65 Worldscale (WS) points in 2015, which was more than 20 WS points higher than levels in 2013.

Nevertheless, the medium-term outlook for the freight market seems subdued due to several reasons. Lower medium-term demand growth relative to 2015 and ample oil in storage are both likely to weigh on global dirty freight rates. Based on the order book, capacity additions should be strong during 2016 and 2017, with VLCC capacity growing by around 6% and 5%, respectively. This is much higher than in the 2014/15 period. Similar developments can be seen in other vessel classes, notably Suezmax. These trends should contribute to lower freight rates. This is partly the consequence of the relatively good performance of the freight sector during the last two years, with more participants ordering new vessels and thus putting pressure on the freight market.

The effects of this development have already been seen with freight rates declining significantly in the second half of 2016. Rates for vessels on voyages to the Asia-Pacific from the Middle East and West Africa were both seen at around 35 WS in September 2016, down from the strong levels between 80 WS and 90 WS seen in December 2015. Looking into the supply/demand fundamentals and the capacity outlook, the situation is not likely to improve in 2017.

Looking further ahead, the future of the freight market depends on a number of factors. First, the long-term oil demand outlook seems supportive, although growth rates are expected to be lower compared to recent history. The regional distribution of demand shows that demand growth will emerge predominantly in the Asia-Pacific. As a result, this will lead to higher flows of crude to Asia, especially from the Middle East, which translates into higher ton-mileage demand. Moreover, the US & Canada region is expected to play an increasing role on the international (seaborne) crude market. Over the long-term, this should add some support to freight rates. However the increase and then decrease in US & Canada crude oil imports between 2015 and 2025 will swing the market around (as discussed later in more detail). Meanwhile, the speed of the development of infrastructure will also have a significant impact in the long-run. The expansion of pipelines such as ESPO from Siberia to Asia or Trans Mountain pipeline in Canada to the Pacific Coast will have a considerable impact on the movements of seaborne crude and future freight rates. Regarding available tanker capacity, around one-third of the current fleet should have been scrapped by the middle of the next decade, as vessels approach the end of their lifetime. In this respect, the speed of capacity for new-build relative to scrappage rates will be a crucial factor for the long-term freight market.

The main text of the Outlook describes how crude oil export/import trade to 2020 surges, then pulls back to 2025, before moving into a pattern of steady but slowing growth. It also considers how product trade drops back between 2015 and 2020, driven by the arrival of substantial new refinery capacity, before increasing and eventually trailing off in the long-term, in line with declining liquids demand. All these shifts affect required tanker capacity.

Demand for VLCC capacity is projected to drop by around 5% between 2020 and 2025, affected by US & Canada import/export developments. Thereafter, they are seen increasing at around 1% p.a. through the long-term, driven mainly by growing movements from the Middle East to Asia. At the other end of the scale, demand for product tankers (typically 30,000–40,000 dwt) is projected to drop sharply between 2015 and 2020, and then recover by 2030, before gradually declining later in the forecast period in line with slowing global demand growth. Taken together, Aframax and Suezmax tankers maintain a roughly level percentage of total tonnage required, falling off only late in the period as the VLCC trade from the Middle East to Asia becomes increasingly dominant. The discontinuities in the 2020–2025 period thus have important implications for the increased instability in tanker freight rates, especially at each end of the size scale.

Logistics developments

As noted, the form in which logistics infrastructure evolves can have a substantial impact on crude oil and product movements. This is especially the case with pipelines – and, today, rail systems – which move crude oils, as well as products and NGLs, from deep inland to coastal terminals, thereby opening up access to new international markets and providing flexibility. Two regions that have been the focus of continuing attention because of their potential to alter inter-regional crude trade (see the 2014 and 2015 Outlooks) are the Russia & Caspian and North America.

Russia & Caspian

Russia shares an extensive border with China, one of the world's largest oil consuming regions, and a leading market for growth. Currently, Russia has four principle routes to reach international markets: the Baltic Pipeline System (BSP-1) to the Baltic Sea; the Druzhba pipeline, which was originally designed to serve a number of Central European countries – Poland, Slovakia, the Czech Republic, Hungary and (eastern) Germany; the Black Sea's Transneft pipeline system that reaches important terminals at Novorossiysk and Tuapse; and the ESPO pipeline, inaugurated in 2009. The first three routes were developed to facilitate shipments primarily to Europe and the Mediterranean, while the last route takes crude oil to Asian markets. It is clear that the centre of gravity for oil demand in Eurasia is rapidly shifting eastward, with demand declining in Europe and growing in Asia.

Developing the ESPO pipeline is one of the building blocks of Russia's strategy to unlock its East Siberian oil reserves and reach Asian markets. 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. Some 0.3 mb/d of this flows to China through a spur pipeline to Daqing. The remainder flows to the port of Kozmino on the Pacific Coast. The third stage of the overall ESPO expansion (ESPO-3) – which will increase the capacity from Taishet to Skovorodino (main line) to 1.6 mb/d and increase the Skovorodino to Kozmino Bay line to 1 mb/d – is ongoing and scheduled for completion by 2020. In addition, branches to the Komsomolsk and Khabarovsk refineries are planned to be completed with a 140,000 b/d link to the former due by 2018 and a 120,000 b/d link to the latter planned by 2019. An additional planned facility – the Far East Petrochemical Company, which is set to be located near Kozmino Bay – would also take crude oil from the line. The line to China has also been expanded, with extra pumping stations allowing the flow to increase to 0.45 mb/d and to be further expanded to 0.6 mb/d by 2017. In tandem with this eastwards expansion, Transneft is also looking to increase the capacity of the pipelines connecting fields in West Siberia with the ESPO. The modelling undertaken for this Outlook has 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.

Trading, which was once limited to Rosneft and CNPC, has seen various new actors get involved over the years. China is certainly the largest player now, having grown its imports from ESPO significantly in 2015. Chinese 'teapot' refiners have also been active participants in the ESPO market. Japan and South Korea are important buyers too, while a number of smaller Asian countries have also purchased ESPO Blend crude.

Some expansion of eastbound export-oriented pipeline capacity is expected in the Caspian countries. Already under construction is a joint project of the Kazakh state oil company KazMunayGas and CNPC, which is designed to double the existing line between Kazakhstan and China from the current 0.2 mb/d to 0.4 mb/d. This expanded pipeline, together with the ESPO, will provide more than 2 mb/d of eastward oriented crude exports from the Russia & Caspian region by 2020. Plans beyond 2020 are uncertain at this point, but the prospects for growing production in the Caspian region, combined with Asian demand growth, make it likely that this infrastructure will be further expanded. For the purposes of this Outlook, further expansions in export capacity to the Asia-Pacific from the Caspian region over the long-term have been assumed.

North America

On 26 June 2016, the Panama Canal expansion opened, allowing larger ships to navigate through the isthmus. The $5.4 billion expansion took nine years to complete and more than doubled the cargo capacity of the canal. One of the primary objectives of the expansion was adding a third set of locks to the canal in order to accommodate ships carrying around 14,000 containers (compared to the old locks, which could only handle ships with 5,000 containers). With respect to oil transit quantities, the prior Panamax vessels – which were the largest tankers that could navigate the locks before the expansion – could only carry 300,000–500,000 barrels. The new 'Neo-Panamax' (or 'Post-Panamax') vessels – which are the largest ships allowed in the newly expanded locks – can transport an additional 100,000 barrels for a total of 400,000–600,000 barrels. Nevertheless, the expanded canal is still unable to accommodate VLCCs or Ultra-Large Crude Carriers (ULCCs). Thus, the Panama Canal expansion will have less of an impact on crude oil trade, which relies mainly on VLCCs, than on oil product movements.

Other developments in logistics in the region reflect the growth in recent years of Canadian oil sands and North American tight oil. In the US, this has been constituted by a massive build-out and re-orientation of the crude oil logistics system, primarily so that large new production volumes may be taken to the coasts (instead of bringing imported crudes inland from the coasts). Pipeline capacity within Western Canada, cross-border into the US and then east to Sarnia and Montreal, has also been expanded. Substantial crude-by-rail capacity has also been developed in parallel, especially from the Bakken and other US producing regions to the coasts, and to carry Western Canadian production to Eastern Canada and US destinations.

This array of developments has led to excess capacity in some locations – notably, total pipeline-plus-rail Bakken take-away capacity – and, generally, to adequate capacity (for now) to move both US and Canadian crudes to coastal markets. The primary exception is Western Canadian crude oil production which remains largely landlocked. The 300,000 b/d 'Line 9' reversal has increased the volume of Western Canadian crude that can reach Sarnia and (via shuttle tanker) Montreal. Together with new rail capacity to the area, this has resulted in the beginning of small-volume marine shipments out of Montreal to overseas markets (notably Europe). On the West Coast, the capacity to reach open water is still minimal and will remain so until the expansion of either the Trans Mountain pipeline or other pipeline (or rail) projects to coastal ports goes ahead. Cross-border pipeline flows from Western Canada into the US are also at close to capacity. According to the June 2016 Outlook of the Canadian Association of Petroleum Producers, Western Canada's takeaway capacity only narrowly exceeds current production. Box 7.2 examines how this may play out over the next several years depending on the progress of four high-profile export projects that have been meeting strong resistance.

The advent of broadly adequate capacity, accompanied by reduced cash flow (due to the drop in oil prices) and cuts to US production, has led to a marked slowdown in the pace of infrastructure development in 2015/2016. Moreover, several projects (both pipeline and rail) that are currently active have come under intense regulatory scrutiny, often in combination with extensive grass-roots resistance. One example is the Dakota Access Pipeline, which would take an initial 450,000 b/d of Bakken crude to Illinois and then, by means of a converted natural gas pipeline, to the Gulf Coast. Despite being partially constructed, this line has become the subject of disputes and litigation, putting its future in question. Similarly, a number of projects for crude-by-rail off-loading terminals on the US West Coast have increasingly run into regulatory hurdles, leading to delays and, potentially, cancellations. Until recently, projects that were entirely within the US or Canada, and/or were reversals or expansions of existing lines, or which used existing rights of way, have tended to move ahead without great difficulty. But the examples of current projects facing regulatory hurdles raise the question of whether this will continue to be the case going forward.

Against this backdrop, the Reference Case outlook is for combined US & Canada crude and condensate production to grow from 13 mb/d in 2015 to over 15.5 mb/d by 2030, before dropping back moderately by 2040. This indicates a need for additional capacity with the main challenge being the movement of Canadian crudes. Nameplate total crude-by-rail loading capacity in September 2016 stood at close to 3.5 mb/d of which 0.75 mb/d is in Western Canada and much of the rest in the Bakken region. Off-loading nameplate capacity was well beyond 4 mb/d. Of this, half is on the US Gulf Coast, though appreciable capacity also exists on US East and West Coasts (excluding Western Canada). As a result of the pipeline capacity build-out and the decline in US production described, crude-by-rail volumes have dropped and utilizations are low. In principle, this capacity should, therefore, provide a buffer with which to absorb and handle production growth. Additionally, it is worth noting that Canadian and US regulators have put forward new coordinated standards aimed at increasing rail-car and overall crude-by-rail safety after a string of accidents. It remains to be seen whether these standards will be enough to quell concerns sufficiently to support a new round of crude-by-rail expansion when needed.

Box 7.2

Pipelines & policies: getting Canada's oil out

Four major projects have been proposed to supply additional export pipeline capacity for Western Canadian Sedimentary Basin (WCSB) crudes: Trans Mountain and Northern Gateway to the British Columbia coast, Energy East to Montreal and the Atlantic, and Keystone XL to the US Gulf Coast. These 'big four' show adequate commercial support, but face an uphill battle against environmentalists and government review processes.

The $6.8 billion Trans Mountain pipeline expansion proposed by Kinder Morgan in 2013 has the ability to increase the pipeline's throughput capacity from 300,000 b/d to 890,000 b/d and carry oil sands streams, as well as light/medium crudes and products, from Edmonton, Alberta, to a port near Vancouver, British Columbia. Currently, the Trans Mountain pipeline is the only crude system that serves Canada's West Coast. Today it delivers primarily via a spur pipeline to US refineries in Puget Sound and has very limited 'over-the-dock' capacity to load onto tankers. The expansion would encompass the construction of an additional line parallel to the current system. Adding capacity to the Western Canadian seaboard would allow greater volumes of oil sands and other Western Canadian crudes to reach the growing Asia-Pacific market. Kinder Morgan has progressively raised the planned capacity to 890,000 b/d via open seasons that have demonstrated strong commercial support from – and incentives for – shippers to move WSCB crudes to markets in Asia.

After nearly three years of review, in May 2016, Canada's National Energy Board (NEB) published its recommendation that the Canadian Federal Government's review panel approve the Kinder Morgan Trans Mountain pipeline expansion. The recommendation, however, includes 157 conditions that Kinder Morgan must meet in order to construct and operate the expanded pipeline system, 49 of which are related to the environment. Some of the most noteworthy conditions are that Kinder Morgan must offset all emissions produced while constructing the pipeline; enhance its marine oil spill response fleet; and consult with indigenous (that is, 'First Nation') groups about environmental protection. Nevertheless, the NEB has clearly stated that "the benefits of the project would outweigh the residual burdens" and that the pipeline is in the "Canadian public's interest".

The Canadian Federal Government now has until December 2016 to make a decision on the pipeline expansion project. In the meantime, since Canada's NEB published its recommendation to approve the project, the project has seen increased public opposition. The City of Vancouver, the Squamish First Nation and the group of lawyers known as 'Ecojustice' have all filed separate legal motions asking the Federal Court of Appeal to stop the NEB from allowing the expansion to move forward. Canadian Prime Minister Trudeau has said he supports getting resources to international markets, but not without the backing of First Nations and environmental groups. Despite this resistance, if all regulatory hurdles are completed in a timely manner, the 715-mile expansion project is expected to enter service by year-end 2019. In September 2016, the Prime Minister offered potential support to the project when he stated he would like to see one major crude oil pipeline project move ahead within his current term – and specifically mentioned the Trans Mountain expansion.

The Northern Gateway project was proposed by Enbridge in 2006 to enable up to 525,000 b/d of crude to flow from Bruderheim, Alberta (near Edmonton), to a West Coast port in Kitimat, British Columbia, north of Vancouver. The 730-mile pipeline project has been facing an array of roadblocks and difficulties after initially being approved by the federal cabinet in 2014. The pipeline had a targeted in-service date of 2019, but now that date is uncertain. Indeed, it now appears unlikely the project will ever be built.

In June 2016, the Canadian Federal Court of Appeal overturned the previous Conservative federal cabinet's decision to approve the $6.5 billion Enbridge project. The Court cited that the decision was made without adequate consultation with First Nations. The ruling found "that Canada offered only a brief, hurried and inadequate opportunity … to exchange and discuss information and to dialogue". The new Liberal Federal Government will soon make a decision on whether the project will continue any further. Prime Minister Trudeau previously denounced the project, stating before his election to office that, "If I win the honour of serving as Prime Minister, the Northern Gateway Pipeline will not happen". Furthermore, Enbridge's request for a three-year extension on its Northern Gateway Permit was suspended by the NEB. The extension was requested in order to enable greater legal and regulatory certainty, while Enbridge solicited support from aboriginal communities. If construction does not begin, Enbridge's current permit will expire in late 2016 and this will likely be the final nail in the coffin of the Northern Gateway project.

TransCanada set forth a proposal in 2013 to move 1.1 mb/d of oil sands from Alberta and Saskatchewan to refineries and terminals on Canada's Eastern Coast. The project – named Energy East – would allow Western Canadian crude to reach markets in Eastern Canada, as well as (via tanker) the US East Coast, the US Gulf Coast and other international eastern hemisphere markets including Europe and India (most notably, the Essar and Reliance complexes via Suez). The 2,800-mile pipeline is estimated to cost $12.1 billion and has a targeted in-service date of 2020. The segment of the project running from Alberta to the Ontario-Quebec border, constituting nearly 70% of the total length, would be implemented by converting an existing 42-inch TransCanada natural gas pipeline to crude oil. Given the generally easier permitting requirements for the conversion or reversal of existing lines, and/or for using existing rights of way, the expectation is that the segment that entails conversion of the existing line will encounter less difficulty. This means that the main focus – and the main object of any potential resistance – will be on the segment that would be a new line from the Ontario-Quebec border to the Canadian East Coast. This segment would run largely through the province of Quebec, which has established 'green' goals and policies.

In June 2016, the NEB started its 21-month review of TransCanada's Energy East pipeline in order to determine if the line is in the public interest. Its recommendation will be released in March 2018, with a final decision coming from the Governor in Council by September 2018. Based on its current status, TransCanada has estimated that start-up for the system will occur in 2020.

After seven years of review, Keystone XL's northern leg was rejected by the US Obama Administration in November 2015. The project planned to move 700,000 b/d of Canadian crude from Hardisty, Alberta, to Steele City, Nebraska, from where it would use the now-built southern section of the line down to the US Gulf Coast. TransCanada has since opened a claim under the North American Free Trade Agreement to recover $15 billion in costs and damages due to the rejection of its Keystone XL pipeline project. A favourable outcome for TransCanada would not, however, reverse the pipeline decision. So in addition, TransCanada has filed a lawsuit in US federal courts asserting that the rejection was unconstitutional. The main goal of the lawsuit is to invalidate the permit denial and prevent any future president from blocking the pipeline's construction. Irrespective of these lawsuits, Keystone XL is unlikely to 'resurface' as a physical project unless there is a change to a Republican Administration after the November 2016 US election.

This situation leaves two of these 'big four' projects essentially out of the running and the other two having to clear multiple hurdles in order to gain approval. Thus, the outlook for the future availability of Canadian export pipeline capacity has deteriorated. In contrast, although it has been curbed somewhat by low crude oil prices, the outlook for WCSB crude supply is for continuing growth, thus relying on additional volumes being moved by rail, at least in the next few years.

The evolution – or lack thereof – of the 'big four' pipeline projects and their associated reliance on rail will also have an impact on those areas where the WCSB crudes are routed. Trans Mountain and Northern Gateway would each increase outlets to Asia by around 0.5 mb/d. Energy East would add over 1 mb/d into Atlantic Basin markets including Europe (and potentially onwards, notably to India). Keystone XL would increase capacity to the US Gulf Coast. Without these lines, rail movements will limit destinations mainly to the US, predominantly the Gulf Coast (although Suncor has been shipping railed crude out of Montreal to Europe).

This 2016 Outlook has assumed that neither the Northern Gateway nor Keystone XL projects will be built, and that the Trans Mountain expansion and Energy East project will both go ahead and be fully operational by 2021 and 2023, respectively. Some limited additional capacity to the Canadian West Coast was assumed after 2030. This was added in to reflect current speculative proposals for either new pipelines or additional rail capacity to the British Columbia coast. It remains to be seen whether or not these projects develop and how, and what the associated impacts might be on crude oil movements and economics.

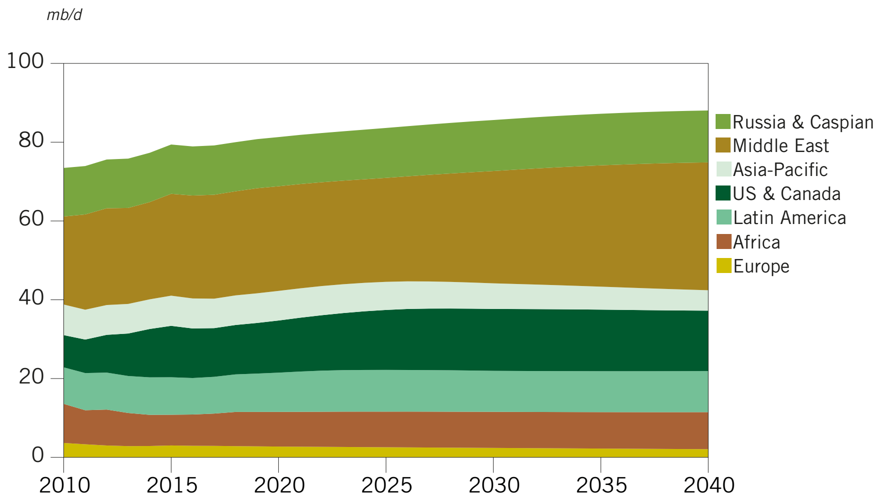
Crude oil movements

Projected movements between major world regions are driven by assumptions in the Reference Case, as well as projections of future regional supply and demand, the level and configuration of operational refining capacity (as set out in Chapters 5 and 6), and future developments in oil transport infrastructure. As discussed under *Logistics developments*, two areas where new transport capacity could have a significant impact on future oil flows are Eurasia and North America. The planned expansion of pipeline capacity in these two regions and the speed of their development appear to be critical and will influence seaborne oil flows.

Figures 7.2 and 7.3 provide a summary of the regional breakdown for crude oil production in the period 2015–2040. The Middle East is expected to witness the biggest increase in crude oil production during this period, rising some 6.6 mb/d between 2015 and 2040. However, in the medium-term, Middle Eastern output is expected to increase only slightly (below 1 mb/d until 2020). In the next decade, and then until the end of the forecast period, the Middle East is likely to ramp up production significantly as other producing regions either stagnate or enter decline. Around 4 mb/d of production should be added in the last decade of the outlook. In terms of production growth, the second largest region is the US & Canada. This can be attributed to growth in tight crude and unconventional production. In the medium-term, production in the US & Canada is expected to decline after 2015 mainly due to lower output from US tight oil. Nevertheless, in line with assumed rising prices, the region as a whole is expected to recover to around 13 mb/d in 2020, which is only slightly higher than 2015. In the long-term, the US & Canada is expected to add significant volumes, comprising not only of tight oil, but also Canadian oil sands. Output is thus seen peaking at 15.7 mb/d just before 2035 with a moderate decline afterwards.

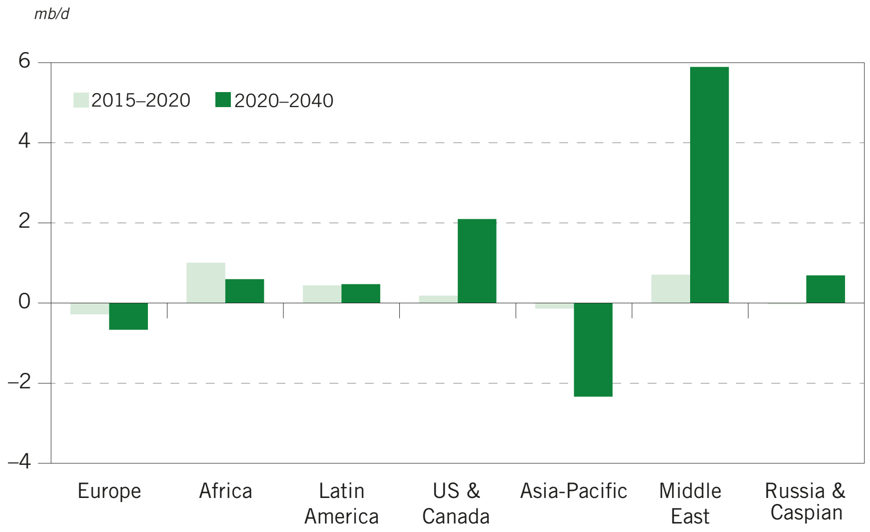
Another important region in terms of additional volumes is Africa, which sees total growth of around 1.6 mb/d growth between 2015 and 2040. The majority of additions are front-loaded, with an increase of around 1 mb/d already by 2020. This can be attributed to new field additions, as well as to the recovery of outaged production in Libya. In Latin America, additions of just below 1 mb/d between 2015 and 2030 are projected, which will be followed by stagnating levels in the last decade of the outlook. In the region, Venezuela and Brazil are expected to remain the driving forces behind this growth. Such growing regions are expected to offset the declines seen in other countries like Mexico.

Figure 7.2
Crude oil* supply outlook to 2040



* *Includes condensate crudes and synthetic crudes.*

Figure 7.3
Change in crude oil* supply between 2015 and 2040



* *Includes condensate crudes and synthetic crudes.*

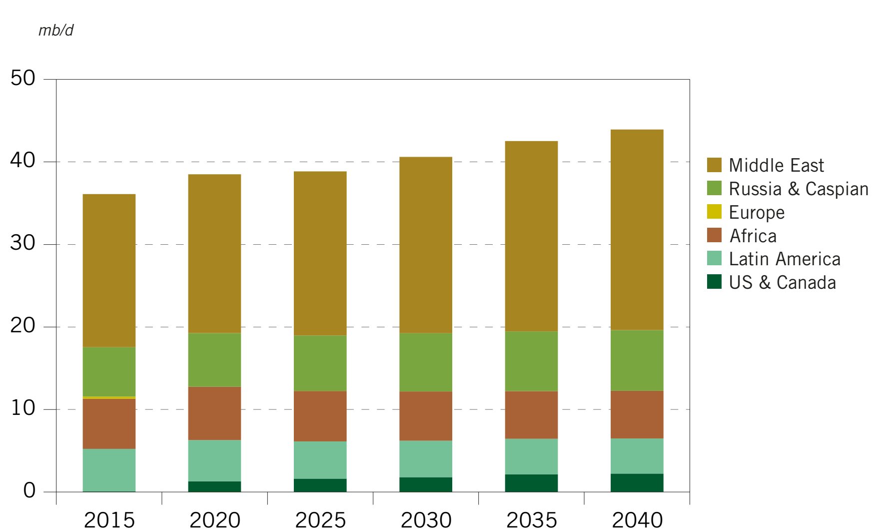
The Russia & Caspian region is expected to only show modest increases, mostly between 2020 and 2030, as new developments (in Russia and Kazakhstan) offset the decline in ageing fields. The region is expected to grow from around 12.5 mb/d in 2015 to 13.2 mb/d in 2040.

Meanwhile, Europe and the Asia-Pacific regions are set to show a decline throughout the forecast period. In Europe, although production increased in 2015 due to heavy investments in new fields in the North Sea, the long-term outlook looks gloomy with a decline of just below 1 mb/d until 2040. The major reason for this is the natural decline rate of offshore production combined with significant upstream CAPEX cuts following recent oil price developments. In the Asia-Pacific, output is expected to remain at stable levels until 2020, when declines are expected amounting to around 2.5 mb/d during the period 2020–2040. This is seen to be a consequence of ageing production, predominantly in China.

In summary, global crude oil production is expected to increase by some 8.5 mb/d between 2015 and 2040. While some regions are in decline (such as Europe and the Asia-Pacific) and are expected to lose around 3.5 mb/d, other regions are projected to add more than 12 mb/d over the reporting period. The Middle East is the leading source of new additions with more than 50%, or 6.5 mb/d, while the US & Canada is a new important source of additional supply.

Turning to crude oil movements between the seven major regions, total export volume is projected to increase by around 2.5 mb/d between 2015 and 2020, then stagnate until 2025, before increasing by another 5 mb/d until 2040. In total, as presented in Figure 7.4, the change in traded volume at the global level during the period 2015–2040 is just below 8 mb/d, representing an increase from 36 mb/d in 2015 to just below 44 mb/d by 2040.

Figure 7.4
Global crude oil exports by origin,* 2015–2040



* *Only trade between major regions is considered.*

In Figures 7.5–7.9, the regional outlooks for crude oil exports are presented for traditional exporting regions, but also for the US & Canada, where export volumes to international markets are seen gradually increasing. In Figures 7.10–7.12 crude imports for the major importing regions (that is, the US & Canada, Europe and the Asia-Pacific) are presented. Figure 7.13 then shows the development of crude oil net imports/exports for all seven world regions over the long-term. These projected crude oil movements are driven by the regional supply and demand patterns assumed in the Reference Case, both short- and long-term, as well as by the assumptions regarding developments in both refining capacity (as per Chapter 5) and infrastructure (such as pipelines).

Globally, the Middle East will remain the largest oil exporter in the long-term (Figure 7.4). Total export volumes are seen increasing from around 18.5 mb/d in 2015 to around 24.3 mb/d in 2040. With regards to their regional distribution (Figure 7.5), Middle Eastern exports are dominated by flows to the Asia-Pacific region, with the share increasing from 77% in 2015 to 86% in 2040. In absolute terms, the volumes moving to the East increase from around 14 mb/d in 2015 to almost 21 mb/d in 2040. Noteworthy, too, are the volumes moving to the US & Canada, which increase to 2.7 mb/d in 2020, but then gradually decrease to 1.1 mb/d in 2040 as domestic supply increases and demand shrinks. The causes of this pattern are discussed more fully under the section: *The impact of ending the US crude oil export ban*. Exports to other regions remain relatively stable, with Europe expected to remain an important outlet for Middle Eastern crude with volumes broadly around 1.5 mb/d from 2020 onwards. Uncertainties that could impact these flows centre on the scale to which the Russia & Caspian region expands routes to the East. Finally, it is forecast that domestic use of crude in the Middle

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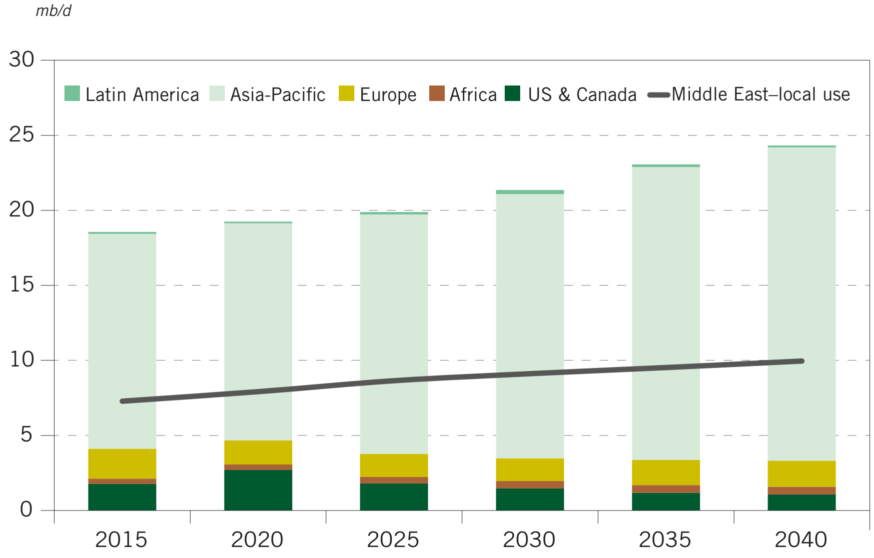
Figure 7.5
Crude oil exports from the Middle East by major destinations, 2015–2040

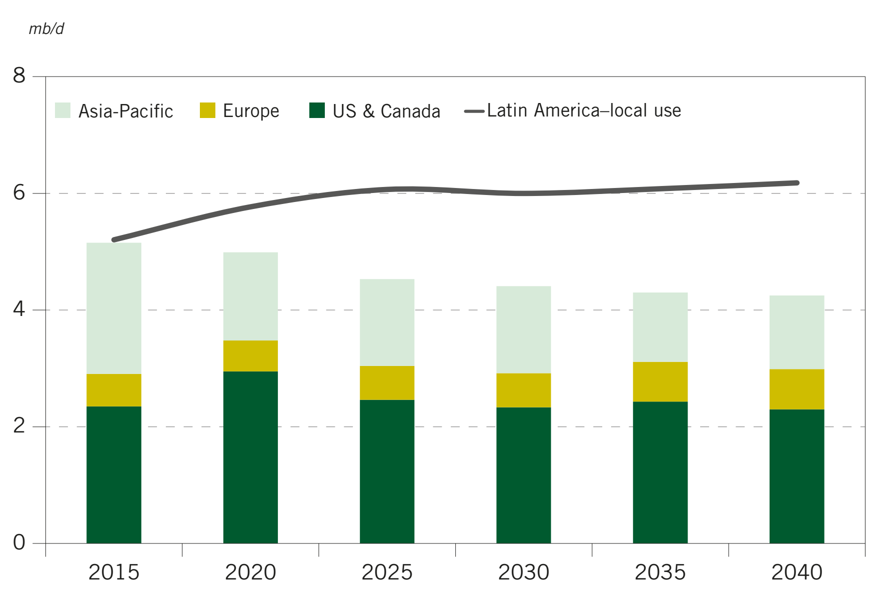


East will increase from just above 7 mb/d in 2015 to 10 mb/d in 2040. This will be driven by growth in local demand, but also by rising refining capacity in the region, part of which is export-oriented.

Crude oil exports from Latin America (Figure 7.6) are projected to experience a gradual decrease from some 5.2 mb/d in 2015 to a level of around 4.3 mb/d by 2040. This pattern is partly due to the rise in domestic crude use, which increases from 5.2 mb/d in 2015 to 5.8 mb/d in 2020 and even further to 6.2 mb/d in 2040. This is in line with growing demand and rising refining capacity in the region. Flows to the US & Canada, which is the major outlet for Latin American crude, increase temporarily in 2020 to almost 3 mb/d, but decrease in 2025 to 2.5 mb/d and then further to 2.3 mb/d in 2040. This is explained by the combination of a medium–term peak and then a decline in US & Canada demand occurring in parallel with a bottoming out and then recovery of crude and condensate production. Nevertheless, due to the physical proximity of US markets – most notably along the Gulf Coast – and the characteristics of Latin American crudes, which are mainly heavy grades, and desirable feedstocks for complex US refiners, exports to the US seem to be more robust.

Latin American crude movements to Europe are expected to increase slightly in the long-term, reaching some 0.7 mb/d. This will occur despite shrinking European oil demand and derives largely from an increase in coking capacity in Europe – from both recent additions and firm projects, which fit the need for heavy, sour crudes. Finally, the Asia-Pacific represents a 'balancing region' for Latin American crude due to the greater proximity of alternative markets such as US & Canada and Europe. Flows to the Asia-Pacific, therefore, decline gradually from levels above 2 mb/d in 2015 to below 1.5 mb/d in 2040 due to the lower availability of crude

Figure 7.6
Crude oil exports from Latin America by major destinations, 2015–2040



for exports. It is worth noting that exports of heavy Latin American crudes are also driven in part by demand for asphalt in other regions.

Russia & Caspian crude oil production is projected to increase from 12.5 mb/d in 2015 to around 13 mb/d by 2030 and then to plateau. At the same time, regional demand is essentially flat, increasing only a nominal 0.3 mb/d from 2015–2030, but generally remaining at a plateau, while crude runs decrease slightly, driven by the current ongoing modernization and upgrading programme, and by a flat demand profile (Figure 7.7). As a result, total crude oil exports are expected to grow by over 1 mb/d from 2015-2030 and then stabilize at around 7.3 mb/d. Based on the eastward pipeline capacity expansions assumed for this region (see *Logistics developments*), crude oil exports from the Russia & Caspian to the Asia-Pacific increase substantially to nearly 3.5 mb/d by the end of the forecast period from 1.3 mb/d in 2015. The increases to the Asia-Pacific lead to declines to Europe and also to the US & Canada. Exports to Europe are expected to drop from around 4.2 mb/d in 2015 to around 3.6 mb/d by 2040, while exports to the US & Canada are over 0.3 mb/d in 2015, but disappear after 2020. 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 in Russian exports to Europe. As it stands, the projection highlights the eastward pivot in the volume of Russia & Caspian crude exports relative to Europe. While exports to the Asia-Pacific were only 30% of volumes moving to Europe in 2015, they are expected to be broadly equivalent by 2040.

Projected exports of crude oil from Africa are presented in Figure 7.8. They show an initial increase followed by a gradual decline. Volumes first increase from 6.1 mb/d in 2015 to 6.5 mb/d by 2020. This stems from a strong surge in crude supply, which rises more than 1 mb/d to reach 8.8 mb/d by 2020, which is partly absorbed by

Figure 7.7
Crude oil exports from Russia & Caspian by major destinations, 2015–2040

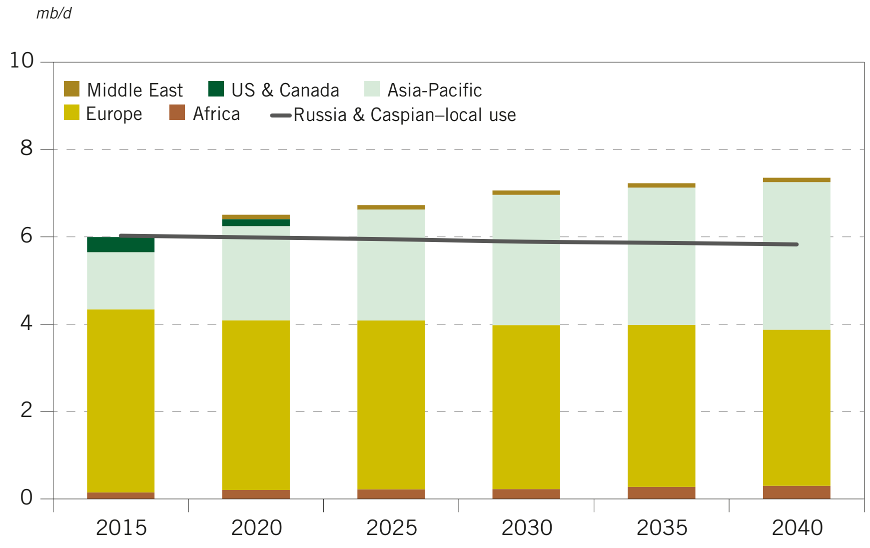
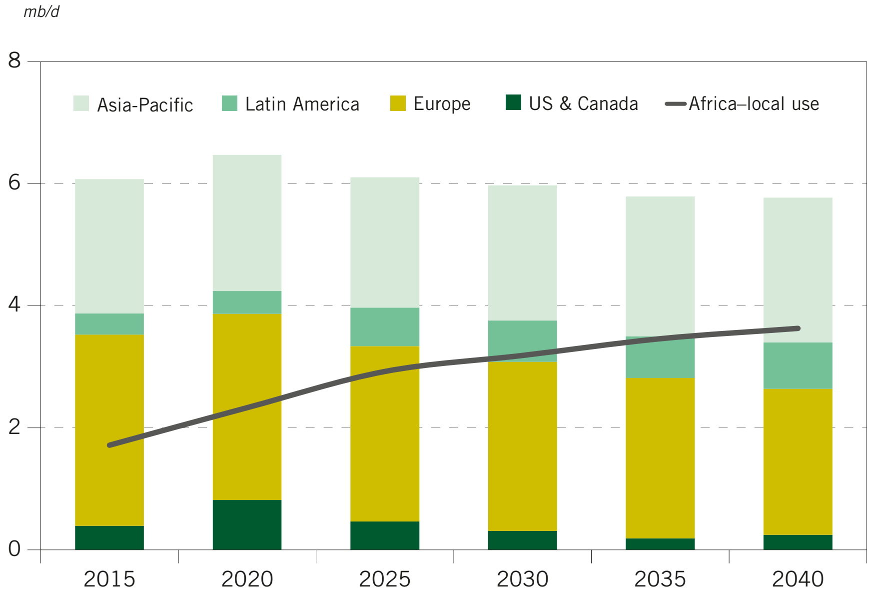


Figure 7.8
Crude oil exports from Africa by major destinations, 2015–2040



increases in regional crude runs due to assumed large new projects coming onstream (most notably, the Dangote and Lobito refineries). After 2020, local crude processing continues to rise throughout the forecast period, driven by demand growth, while production is projected to plateau at around 9.3 mb/d. As a result, export volumes become increasingly constrained due to the rise in domestic crude use and so crude oil exports show a gradual decline to around 5.8 mb/d by the 2035–2040 period. After peaking in 2020 at around 0.8 mb/d, crude exports from Africa to the US & Canada progressively decline. The projected recovery in North American tight oil production growth is expected to eliminate imports of light African crudes, keeping only limited volumes of medium gravity imports. African exports to Europe are projected to decline in the longer term as a result of progressive reductions in European refinery runs. In contrast, exports to the Asia-Pacific are expected to remain steady while those to Latin America slowly increase. These developments are subject to several factors, including the ability of – and extent to which – African refiners can raise refinery capacity (as well as crude runs) in competition with product exports potentially available from an array of other sources.

Key trends in future crude oil movements from the perspective of major crude importing regions are presented in Figures 7.9–7.12. The dominant feature is declining crude imports to both the US & Canada and Europe, which are more than offset by large import increases to the Asia-Pacific.

As reported in the WOO 2015, the US & Canada region is projected to gradually reduce its crude imports and to actively engage as an exporter, as well as an importer of crude oil. In this Outlook, the US & Canada region is, therefore, viewed from both the import and export perspectives. Figures 7.9 and 7.10 amplify the discussion set out under *The impact of ending the US crude oil export ban*.

As previously discussed, the US & Canada region's crude oil export volumes and destinations are subject to the availability and development of additional export pipelines and crude-by-rail capacity. The capability to export US crudes (mainly from the Gulf Coast) is now substantial. As set out in Box 7.2, Canada's export capacity is potentially more problematic. Taking a 'middle ground' approach, it is assumed that two of four major pipeline projects would go ahead – namely, the Trans Mountain expansion and Energy East – plus some limited further capability to export off the Western Canadian coast in the long-term. Since the lifting of the US crude oil export ban in December 2015, US Canadian crude oil and condensate exports to third-party destinations have already exceeded 0.5 mb/d (from less than 0.1 mb/d in 2015). Driven by a recovery in production followed by a plateau for much of the forecast period – together with gradually falling crude runs resulting from declining regional demand – the outlook is for export levels to steadily rise. The projections indicate US & Canada crude exports at well above 1 mb/d by 2020, then rising to over 2 mb/d by 2035–2040.

The Asia-Pacific is the principal target destination of exports, reaching 1 mb/d by 2025, and remaining at or above that level from 2025 for the rest of the forecast period. The assumption of Canadian West Coast pipeline expansions (such as Trans Mountain by 2020, followed by an additional, but limited expansion later in the period) is a major factor. These expansions will enable Western Canadian heavy oil/oil sands streams to comprise the bulk of the flow to destinations in Northeast Asia.[25] However, exports to Asia from the US are also indicated. Declining demand and refinery runs on the US West Coast free up Alaskan – and potentially even Californian – crudes for export to Asian markets. Also, limited volumes of Bakken or other domestic US crudes could be exported from the US West Coast assuming currently planned crude-by-rail terminals there are developed. In a similar manner, the assumed Energy East pipeline is seen helping to enable flows of Western Canadian crude to Europe – potentially at around 0.5 mb/d. Crude supplies to Latin America are also indicated at around 0.5 mb/d. Aided by short transit distances and a good fit with heavier Latin American crudes, these are projected to be mainly exports of Eagle Ford or similar light crudes and condensates to Mexico and/or the greater Caribbean region.

As previously described, crude oil imports to the US & Canada (Figure 7.10) show a peak around 2020 followed by a steady decline. Flows from Latin America, Africa and the Middle East all follow this pattern of peaking around 2020 and then declining thereafter. The effect, however, is least marked for Latin American crudes whose flows are still projected to be near 2015 levels (2.3 mb/d) in 2040. Proximity and a close fit with extensive Gulf Coast and West Coast capacity geared to processing heavy sour crudes are major factors that sustain this trade. In contrast, imports from Africa and the Middle East display more marked declines over time as US & Canada production remains stable at over 15 mb/d after 2025, while crude runs decline. The modelling projections indicate that crude imports from the Middle East will drop from around 1.8 mb/d in 2015 to just over 1 mb/d in 2040. These import levels will, however, depend on such factors as ownership interests in refineries, but also the volumes in which Western Canadian and US inland crudes reach the US West Coast, potentially replacing Middle East imports from there. (In 2015, the US West Coast imported 0.4 mb/d of Middle Eastern crudes.) The significant decline in US crude imports and the growth in exports from both countries are leading factors

Figure 7.9
Crude oil exports from the US & Canada, 2015–2040

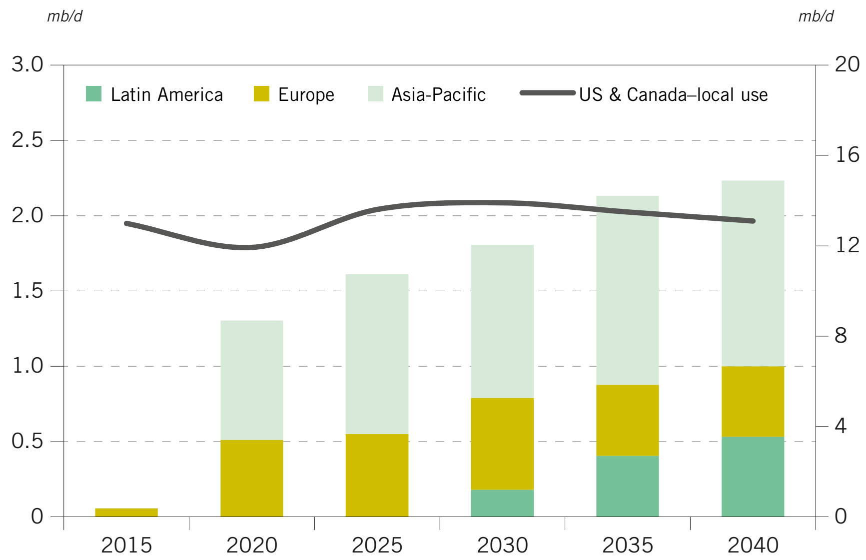


Figure 7.10
Crude oil imports to the US & Canada by origin, 2015–2040

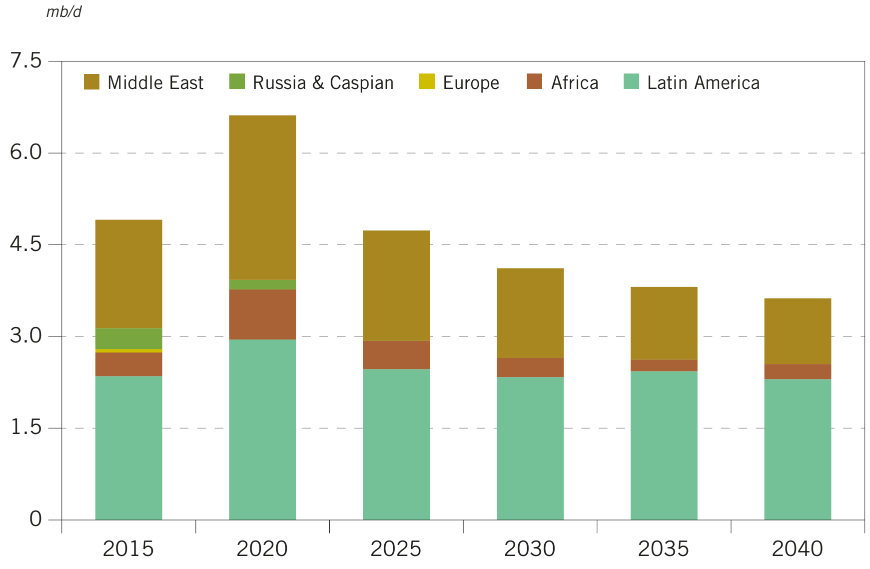
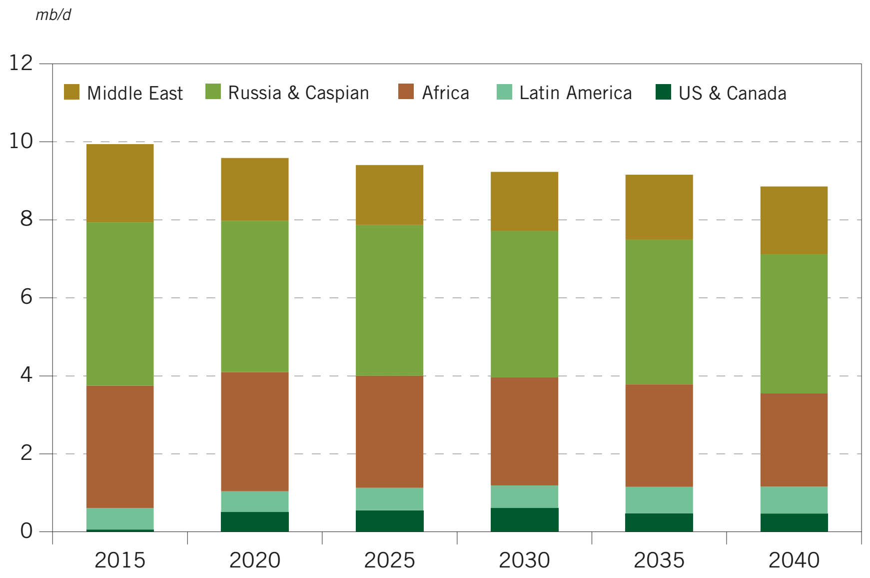


Figure 7.11
Crude oil imports to Europe by origin, 2015–2040



in shifting the patterns of global crude trade as recent events have already begun to indicate.

Figure 7.11 summarizes the expected future crude oil movements into Europe.[26] The region is characterized by a sustained decline in demand and, hence, crude runs which decrease from 13 mb/d in 2015 to 11 mb/d by 2040. In parallel, regional production declines by 0.9 mb/d, which leads crude oil imports to decline by 1.1 mb/d 2015–2040. Over this period, imports from Latin America remain broadly stable at around 0.6 mb/d while 'new' imports from US & Canada reach 0.5 mb/d by 2020 and remain at that level through the period. Consequently, it is crude imports from the main established importers into Europe – namely Africa, Russia & Caspian and the Middle East – that are most heavily impacted, dropping by 1.6 mb/d in the period 2015–2040.

Figure 7.12 presents projected crude oil imports for the Asia-Pacific region. As pointed out in previous Outlooks, the Asia-Pacific will dominate the rest of the world as the largest crude importing region over the entire forecast period. The import pattern is characterized by steady increases that bring total crude imports to a level of 29 mb/d from just above 20 mb/d in 2015. These sustained and substantial increases are in marked contrast to the declines in imports to the US & Canada and to Europe.

Figure 7.12 confirms the WOO 2015 observation of the Asia-Pacific as the major oil trade partner of the Middle East. It will supply almost 21 mb/d to the region in 2040, increasing by almost 50% from 2015 levels. Nevertheless, other crude exporting regions will also play significant roles in supplying the region. Increased flows, mainly via the ESPO pipeline, will progressively increase imports from the Russia & Caspian region, with the result that by 2040 it becomes the second

Figure 7.12
Crude oil imports to the Asia-Pacific by origin, 2015–2040

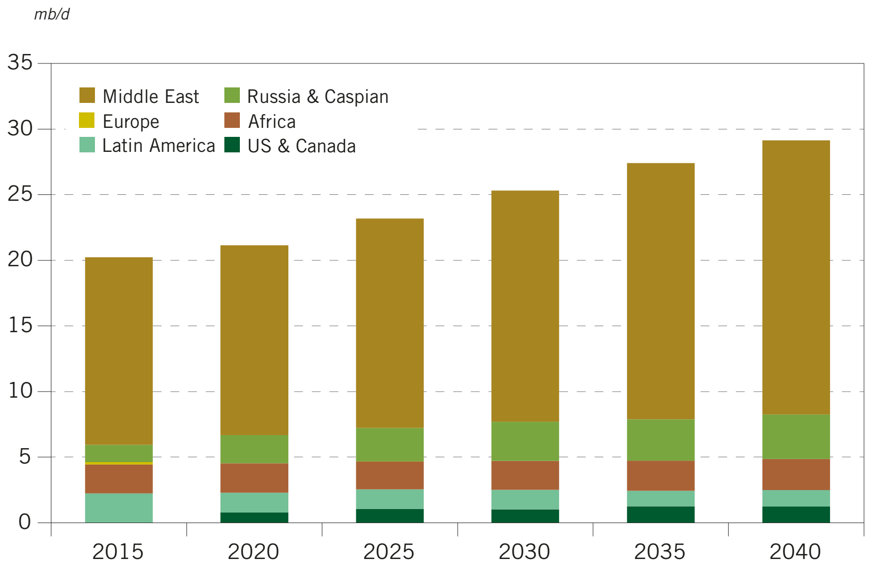
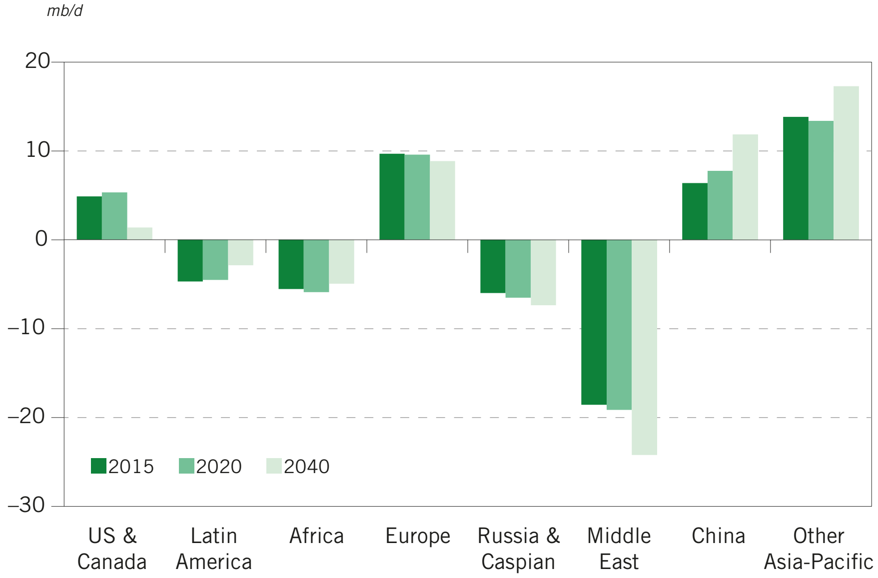


Figure 7.13
Regional net crude oil imports, 2015, 2020 and 2040



largest exporter to the Asia-Pacific at around 3.4 mb/d. Another significant exporter is Africa, whose exports will remain broadly around 2.3 mb/d throughout the period. As with Europe – and, again, assuming export routes to the Pacific Coast are available – imports from the US & Canada are seen evolving to eventually reach around 1.2 mb/d by 2040. These will tend to displace imports from Latin America, which are seen decreasing from a level of 2.2 mb/d in 2015 to 1.3 mb/d in 2040.

The net effect of all inter-regional crude oil imports and exports expressed in terms of net crude imports is summarized in Figure 7.13. The patterns summarize the regional trade projections already discussed.

Product movements

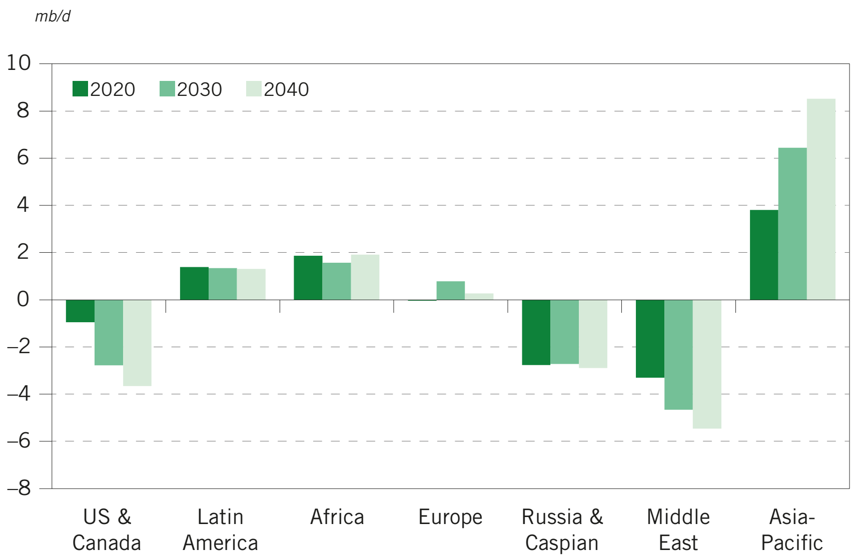
Compared to the respective crude oil flows, product trade between the seven major regions is significantly lower as refined products are produced and mostly consumed locally. In addition, the transportation of clean products is more costly relative to dirty freight, which suppresses the long-haul movements of products. In total, product trade is expected to increase by some 2 mb/d over the long-term, moving from around 17 mb/d in 2015 to 19 mb/d in 2040. This compares to crude oil movements of around 36 mb/d in 2015 and 44 mb/d in 2040.

Product flows between major regions are expected to decline initially (to around 2020) and then remain flat until 2025 (Figure 7.1), despite growing oil demand. The major reason for this is the refining capacity expansion in developing regions, such as the Asia-Pacific, Latin America and Africa, which leads to lower requirements for imported material. Moreover, importing regions such as the US & Canada and Europe, witness declining demand over this period that will result in lower imports of refined products. Nevertheless, in the long-term (after 2025) product trade is expected to increase as oil demand growth in developing countries outweighs refinery new builds. In total, product movements rise by around 4 mb/d between 2025 and 2040.

At the regional level, there are several recognizable trends in global product movements over the medium- to long-term (Figure 7.14). The most significant development is the growth in the Asia-Pacific's net-imports, which are anticipated to more than double from the levels of 4 mb/d in 2020 to around 8.5 mb/d by 2040. Increasing net-imports, combined with the expansion of local refining capacities, should cover the region's oil demand growth, which is estimated at around 12 mb/d between 2020 and 2040. The largest share of the additional imports should be covered by supplies from the Middle East, which is currently the most important product supplier to the Asia-Pacific. Additional imports could also come from the US & Canada, as well as the Russia & Caspian, which is increasingly turning to the east. On the product level, the Asia-Pacific is likely to import a range of light products such as LPG and naphtha, in line with the developing petrochemical sector, but also middle distillates.

At the same time, Latin America and Africa are both likely to remain significant net-importers of refined products between 2020 and 2040. In Latin America, product net-imports are projected to level out at around 1.4 mb/d between 2020 and 2040, while in Africa product net-imports are seen stable at just below 2 mb/d over the same period. This is the result of projected refining capacity additions in both regions, which move broadly in line with long-term demand growth. In Africa the

Figure 7.14
Net imports of liquid products by region, 2020–2040



net-imports even decline temporarily around 2025 when the new refining capacity is expected to come online.

In Europe, declining demand and refinery closures are likely to result in moderate net-imports (below 1 mb/d) of products in the long-term, compared to a balanced system around 2020. European refiners are projected to come under increasing pressure not only from a decline in domestic demand, but also competition from elsewhere, such as the US, the Middle East and Russia. On the product level, Europe is expected to import mostly middle distillates, while exporting gasoline.

Turning to product net-exporters, two regions continue to dominate the scene – the Middle East and the Russia & Caspian, while the US & Canada with increasing net-exports will emerge as a new and important player on the global scene. Mirroring developments in the Asia-Pacific, net-exports from the Middle East are set to increase from around 3.5 mb/d in 2020 to 5.5 mb/d in 2040. The increase is the effort of several countries in the Middle East to build up their refining capacity with the clear intention to export refined products. Proximity to consuming markets in Europe, Asia and Africa, as well as ample crude oil supplies are clear competitive advantages for Middle Eastern refiners. Major products exported are LPG and naphtha for petrochemical use (predominantly in Asia), as well as middle distillates.

The Russia & Caspian region is expected to remain a significant global net-exporter of products. This is due to expected further growth in crude supplies, refinery upgrades and stagnating demand. The region is likely to increase product exports slightly until 2040, although overall net-exports will remain below 3 mb/d. The product slate is expected to shift more towards high-quality products and away from fuel oil, which is in line with tax regulations and refinery upgrades. Exports from the Russia & Caspian are projected to increasingly turn to the Asia-Pacific with reductions in volumes on the voyage to the Atlantic basin, especially the US & Canada.

In the US & Canada, net-exports are projected to increase to above 3.5 mb/d in 2040, up from around 1 mb/d in 2020. Refiners from the US & Canada will be able to compete on international markets as they benefit from increasing domestic oil supplies, as well as the high complexity of the refining system. Rising net-exports are also the consequence of decreasing demand. Product exports from the US & Canada will mostly comprise middle distillates and LPG.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Section Three

Uncertainties and challenges

The Paris Agreement: guidance on future policies

Key takeaways

- The Paris Agreement outlines the world's response to tackle climate change.
- Across the Intended Nationally Determined Contributions (INDCs), two policies are common: improvements in energy efficiency and a reduction of emissions through changing the energy mix and/or expansion of sinks in the land sector.
- To assess the implications of potential future policy changes, two scenarios were developed. In Scenario A, policies support emission reductions at a faster pace than that assumed in the Reference Case. The emphasis is on first achieving emission reductions through improved energy efficiency and then targeting fuel substitution.
- The second scenario – Scenario B – foresees the timely implementation of the INDCs by all Parties, while both conditional and unconditional targets included in the INDCs are implemented according to the stated plan.
- In the Reference Case, global energy demand is projected at 382 million barrels of oil equivalent per day (mboe/d) by 2040, which declines to some 371 mboe/d and further to 355 mboe/d in the alternative scenarios (Scenario A and Scenario B).
- Demand for all fossil fuels at the global level is projected to decline relative to the Reference Case projections under both Scenarios A and B, while the share of renewable energy sources, as well as nuclear energy, will increase, thereby partially compensating/substituting for the energy demand loss in fossil fuels.
- Since most of the substituting fuels generate electricity, they tend to substitute coal and gas, which leads to a higher demand reduction in coal and gas compared to oil.
- The combined substitution effect of renewables and nuclear energy is reflected in a demand increase of almost 8 mboe/d in Scenario A and more than 14 mboe/d under Scenario B, compared to the Reference Case.
- Coal is projected to be the most affected fuel under both scenarios as it provides the most cost-effective emissions mitigation option.
- In Scenario A, oil demand will reach 107 million barrels per day (mb/d) in 2040, which is 2.5 mb/d less than in the Reference Case. In Scenario B, oil demand peaks in 2029 at 101 mb/d and then declines to 98 mb/d by 2040, which is around 11 mb/d lower than in the Reference Case.
- Compared to the Reference Case, the reduction in total energy-related carbon dioxide (CO_2) emissions in Scenario B could reach the level of almost 8% by 2030 and about 14% by 2040.

Setting the context

In 2010, at COP16 in Cancun, Mexico, Parties of the United Nations Framework Convention on Climate Change (UNFCCC) agreed to stabilize global warming at a maximum temperature rise of 2°C above pre-industrial levels, and to consider lowering that maximum to 1.5°C in the near future. In the years that followed, the Parties gradually built on this and other related decisions, with negotiations leading to COP21 in 2015 and the Paris Agreement, which outlines the world's response to tackle climate change. It is a significant legally binding instrument that is expected to affect many aspects of people's lives and the world's economies, including future energy demand and the energy mix.

The Paris Agreement seeks to enhance the implementation of the UNFCCC. In doing so, it calls for the stabilization of the rise in the global average temperature to well below 2°C above pre-industrial levels and for efforts to be pursued to enhance the temperature target further to 1.5°C. The Agreement also provides a powerful context within which its objectives should be pursued – namely, achieving sustainable development and eradicating poverty. Within this context, the Agreement considers the differences among countries and calls on the Parties to reflect on 'equity' and the 'principle of common but differentiated responsibilities and respective capabilities, in the light of different national circumstances'[1] when they take actions.

Actions by the Parties as called for in the above context should be 'inscribed' by the Parties in their Nationally Determined Contributions (NDCs). NDCs are a key pillar in implementing the Paris Agreement. They contain the list of actions the Parties would make in contributing to the fulfilment of the Agreement's objectives.

The design of the NDCs under the Paris Agreement is based on the already existing Intended Nationally Determined Contributions (or so-called INDCs). The INDCs were called for by a decision taken by the Parties in 2014 at COP19 in Warsaw. The INDCs are related to the NDCs, insofar as Parties were invited to communicate their first NDC no later than when the Party ratifies, accepts, approves the Paris Agreement or deposits its instrument of accession to the Agreement. If a Party has communicated its INDC prior to joining the Agreement, that Party shall be considered to have satisfied the above provision, unless that Party decides otherwise. Hence, the content of the INDCs will have a significant effect on the implementation of the Paris Agreement when it comes into force.

The Paris Agreement entered into force on 4 November 2016, 30 days after it has received its minimum ratification requirement of at least 55 Parties, representing at least 55% of GHG emissions. With the entry into force of the Paris Agreement, the first session of the Conference of the Parties serving as the meeting of the Parties to the Paris Agreement (CMA 1) will be convened in Marrakech, Morocco, at COP22.

In this context, specific targets, actions and policy changes included in INDC submissions to the UNFCCC provide an important indication or guidance on of the future policy direction of countries across the globe. To some extent, this guidance is reflected in the build-up of the Reference Case projections of future energy demand levels and its mix, the details of which are presented in Section One. It is primarily on the basis of assuming stricter policies aimed at achieving emission reductions, guided by the INDCs, that this year's Outlook projections for long-term global energy demand are lower than those for the WOO 2015. Moreover, there is also a further shift in the composition of the energy mix towards less emitting fuels and renewable energy, as compared to previous projections.

This Chapter aims to further explore the implications of potential policy changes related to INDCs and accelerated technology development for both future energy demand and the future energy mix. To do this, a scenario-based approach is adopted as a means to understand the direction of future policies included in the INDCs. The analysis provides ample room for interpreting the way forward when the Paris Agreement is implemented.

Intended Nationally Determined Contributions

INDC submissions cover nearly all Parties to the UNFCCC. Out of 197 Parties, 189 have submitted their INDCs.[2] INDCs contain different types of contributions ranging from specific actions, policies and targets to scenario-based actions, policies and targets, in one or more areas and with varying timelines. Some INDCs, particularly those of developing countries, also highlight the support needs and conditions for achieving their indicated targets (conditional INDCs).

The broad-based nature of INDCs introduces uncertainties in terms of how their aggregate effect might contribute to the objectives of the Convention, and later on, to the objectives of the Paris Agreement. However, such broad-based contributions also provide an extensive opportunity for the Parties to cooperate by better matching the needs of developing countries with the means of implementation to be provided under the Paris Agreement. Table 8.1 presents the key features of the INDCs for major economies.

As part of their INDCs submissions, many Parties have also described the implementation policies of their INDCs. Across INDCs, two policies are common: improvements in energy efficiency and the reduction of emissions through changing energy mix and/or expansion of sinks in the land sector. Out of the 189 Parties that have submitted their INDCs, 167 Parties have mentioned improvements in energy efficiency, while 161 Parties have indicated policies to reduce emissions or expand sinks in the agriculture and/or Land Use and Land Use Change and Forestry (LULUCF).

Since this analysis primarily focuses on the implications of potential policy changes resulting from the INDCs on the future energy mix (thus reflecting emissions only from the energy sector), it is important to keep in mind that total global anthropogenic emissions are attributed to both the energy sector and the non-energy sector. In 2014, about 67% of the global emissions of GHGs were attributed to the energy sector and the remaining 33% to the non-energy sector (including agriculture, forestry and waste).[3] Accordingly, analysis of mitigation measures potentially arising from future implementation of the INDCs presented in this Chapter is limited to the emissions resulting from changing energy demand and the energy mix. It does not cover mitigation measures attributed to the non-energy sectors of the INDCs.

The experiences gained in the process leading to the INDCs identified areas in which developed countries could support developing countries. The Paris Agreement provides possibilities for a cooperation platform among the Parties to implement their commitments under the Agreement when INDCs are transformed into

Table 8.1
Key features in the INDCs of major Annex I and non-Annex I Parties to the UNFCCC[4] representing over 60% of the global emissions in 2012

Annex I Party	Key features of the INDC
US	Reduce GHG emissions by 26–28% below its 2005 level in 2025 and make best efforts to reduce its emissions by 28%
EU (28 Member States)	At least 40% domestic reduction in GHG emissions by 2030 compared to 1990
Russia	Limiting anthropogenic GHGs to 70–75% of 1990 levels by 2030 might be a long-term indicator, subject to the maximum possible account of absorbing capacity of forests
Japan	Japan's INDC towards post-2020 GHG emission reductions is at the level of a reduction of 26% by fiscal year (FY) 2030 compared to FY 2013 (25.4% reduction compared to FY 2005) (approximately 1.042 billion t-CO_2 eq as 2030 emissions)
Non-Annex I Party	**Key features of the INDC**
China	Peak CO_2 emissions around 2030 and make best efforts to peak early Lower CO_2 emissions per unit of GDP by 60–65% from the 2005 level Increase the share of non-fossil fuels in primary energy consumption to around 20% Increase the forest stock volume by around 4.5 billion cubic metres on the 2005 level
India	Reduce the emissions intensity of its GDP by 33–35% by 2030 from the 2005 level
Brazil	Intend to commit to reduce GHG emissions by 37% below 2005 levels in 2025 Subsequent indicative contribution: reduce GHG emissions by 43% below 2005 levels in 2030
South Africa	GHG emissions to peak between 2020 and 2025, plateau for approximately a decade and decline in absolute terms thereafter Emission range: 398–614 mt CO_2e in the period 2025–2030

NDCs. There are remarkable opportunities for cooperation among developed and developing countries under the Paris Agreement. One of the key areas for such cooperation is technology transfer to reduce emissions and/or expand sinks in the non-energy sector. There are also many opportunities to reduce emissions in the energy sector by closing the technological gap between developed and developing countries. Closing the technological gap can lead to improvements in energy efficiency and a reduction of the greenhouse gas (GHG) footprint of national economies. In 2011, for every dollar of GDP, non-OECD countries consumed 2.5 times more energy compared to Organisation for Economic Co-operation and Development (OECD) countries. There is a similar gap between the non-OECD and OECD countries in the GHG footprint of GDP. In 2011, non-OECD countries in comparison to OECD countries emitted 2.9 times more GHG per dollar of GDP.[5]

Scenario-based analysis of policies guided by the INDCs

As outlined earlier in this Chapter, INDCs include a variety of policies and targets. These range from economy-wide mitigation targets, expressed either in absolute or relative emission reduction targets (relative to a given base year or to a level supposedly achieved under a 'business-as-usual' scenario), through to targets expressed in terms of energy intensity, up to targets measured on a per capita basis (again either relative to the level in a given base year or to an absolute level).

Moreover, some Parties also submitted specific strategies, plans and actions as to how to achieve these targets, although in the majority of these submissions an indication of related policies was either vague or not included. This provides flexibility for possible implementation paths and, therefore, for building scenarios to reflect the likely implications of potential changes in future policies, as well as related technology developments and the support provided by policymakers to new technologies. Thus, in addition to the Reference Case, two alternative scenarios were developed for the Outlook to reflect such possibilities.

While both scenarios are motivated by INDC submissions, it should be noted that they cannot be strictly linked to the full implementation of INDCs, since the analysis provided in this Chapter covers only energy-related policies and emissions. It does not cover emissions/sinks resulting from non-energy policies.

The first scenario – Scenario A – depicts a situation in which policies targeting emission reductions are associated with stronger technology developments and transfer components. Hence, these policies support emission reductions at a faster pace than that assumed in the Reference Case, albeit at a slower rate than what would be necessary to achieve all targets stated in the INDCs. For example, in some INDCs there are conditions attached to the achievement of stated targets, and under Scenario A, the progress in fulfilling these conditions is slower than originally anticipated. In some others – although there is no condition attached – there is an inadequate policy infrastructure and/or inadequate regulations in place, which take time to develop. Moreover, a delay is also assumed to arise from uncertainties in investment and in the availability of technologies. As a result, the targets declared in the INDCs are not fully met in a timely manner and, in most cases, the completion of these targets is deferred to later years than initially intended.

For example, China in its INDC submission stated an intention to achieve its peak carbon dioxide (CO_2) emissions around 2030. Under Scenario A, this is projected to be achieved by around 2035. Similarly, the US Clean Power Plan is assumed to progress under this scenario. However, obstacles resulting from current lawsuits, as well as the complexity of the plan and the potential inconsistency in retaining past policies with future administrations, result in an implementation delay. For various reasons, other countries such as Mexico, South Korea, Brazil and India could also experience shifts in the pace of policy implementation.

Furthermore, under Scenario A the emphasis is on first achieving emission reductions through improved energy efficiency and then targeting fuel substitution. However, the reduction in overall energy demand is limited as investments are assumed to be lower and the speed of technological development, as well as its deployment and transfer, is slower than that required to achieve timely compliance with intended targets.

The second scenario – Scenario B – foresees no delay in the implementation of the INDCs by all the Parties. Both conditional and unconditional targets included in the INDCs are implemented according to the stated plan. This scenario is more carbon restrictive compared with Scenario A.

In Scenario B, the development of technology and its deployment are assumed to be supported by adequate investments. It is further assumed that policymakers adopt the necessary measures to ensure timely achievements of all the set targets. This leads to a further reduction in overall energy demand, through intensified improvements in energy efficiency, but also with greater fuel substitution compared to Scenario A. In addition, in Scenario B the increased use of renewable energy is much more pronounced, while technology transfer and additional support to developing countries is also assumed to take place so that the conditional INDCs of several developing countries are also met (albeit without consideration of how this support for technology transfer might be provided). It also includes an assumption of faster progress in oil-related technologies, such as an accelerated penetration of alternative vehicles, higher efficiency improvements in conventional engines and energy saving measures across other sectors of consumption.

It is also important to emphasize that, although the INDC submissions to the UNFCCC only cover the period up to 2030, the scenario analysis assumes the continuation of trends resulting from policy measures adopted in the process of implementing INDCs in the period beyond 2030. Therefore, the shifts in the energy mix do not stop in 2030. The projections extend these changes for the rest of the forecast period to 2040. This extension of projections is, however, more an extrapolation of trends rather than an assumption of a much stricter enhancement of mitigation actions.

Bearing in mind the many possible ways that exist to achieve INDC targets and the often vague formulations that allow for various interpretations, Tables 8.2–8.4 present the Reference Case global energy demand and the likely implications of INDCs on the future energy mix and the demand levels under the two alternative scenarios.

Table 8.2
World primary energy demand by fuel type in the Reference Case

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	85.1	90.7	96.7	99.8	0.6	31.1	30.3	28.2	26.1
Coal	77.7	82.7	88.9	91.5	0.6	28.4	27.6	25.9	23.9
Gas	59.6	66.9	84.0	101.7	2.1	21.8	22.3	24.4	26.6
Nuclear	13.2	15.5	19.5	23.4	2.2	4.8	5.2	5.7	6.1
Hydro	6.6	7.6	8.9	9.9	1.5	2.4	2.5	2.6	2.6
Biomass	28.2	30.7	34.6	38.1	1.2	10.3	10.2	10.1	10.0
Other renewables	3.4	5.7	11.0	17.9	6.6	1.3	1.9	3.2	4.7
Total	**273.9**	**299.9**	**343.6**	**382.1**	**1.3**	**100.0**	**100.0**	**100.0**	**100.0**

Table 8.3
World primary energy demand by fuel type in Scenario A

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	85.1	90.7	95.6	96.2	0.5	31.1	30.3	28.5	25.9
Coal	77.7	81.9	82.9	81.8	0.2	28.4	27.4	24.7	22.1
Gas	59.6	66.7	82.0	96.0	1.8	21.8	22.3	24.4	25.9
Nuclear	13.2	15.6	19.8	25.5	2.6	4.8	5.2	5.9	6.9
Hydro	6.6	7.6	8.9	10.2	1.7	2.4	2.5	2.6	2.8
Biomass	28.2	30.8	35.0	39.8	1.3	10.3	10.3	10.4	10.7
Other renewables	3.4	5.8	11.8	21.3	7.3	1.3	1.9	3.5	5.7
Total	**273.9**	**299.0**	**336.0**	**370.7**	**1.2**	**100.0**	**100.0**	**100.0**	**100.0**

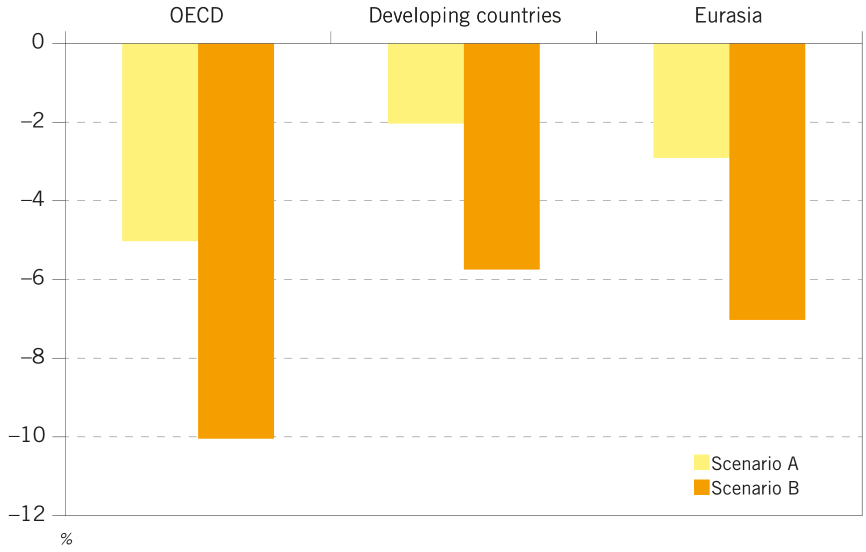
Table 8.4
World primary energy demand by fuel type in Scenario B

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2014	2020	2030	2040	2014–40	2014	2020	2030	2040
Oil	85.1	90.3	91.9	88.0	0.1	31.1	30.3	28.0	24.8
Coal	77.7	81.3	78.9	74.2	–0.2	28.4	27.3	24.1	20.9
Gas	59.6	66.6	79.6	89.2	1.6	21.8	22.4	24.3	25.1
Nuclear	13.2	15.6	20.5	27.7	2.9	4.8	5.2	6.2	7.8
Hydro	6.6	7.6	9.0	10.5	1.8	2.4	2.5	2.8	3.0
Biomass	28.2	30.8	35.4	41.0	1.4	10.3	10.3	10.8	11.5
Other renewables	3.4	5.8	12.6	24.4	7.8	1.3	1.9	3.8	6.9
Total	**273.9**	**297.8**	**327.8**	**354.9**	**1.0**	**100.0**	**100.0**	**100.0**	**100.0**

These results demonstrate a progressive decline in total energy demand in the more carbon-restricted scenarios. In the Reference Case, global energy demand is projected to be 382 mboe/d in 2040. This declines to 371 mboe/d in Scenario A and further to 355 mboe/d in Scenario B. It should also be noted that this is on the basis that measures targeting improved energy efficiency, as well as changes in consumer behaviour, will increasingly be adopted across countries, although the rate of implementation of such measures will naturally differ among countries.

Figure 8.1 summarizes the level of energy demand reductions for both scenarios relative to the Reference Case in 2040. It shows that in both scenarios the strongest

Figure 8.1
Global primary energy demand reduction relative to the Reference Case in 2040

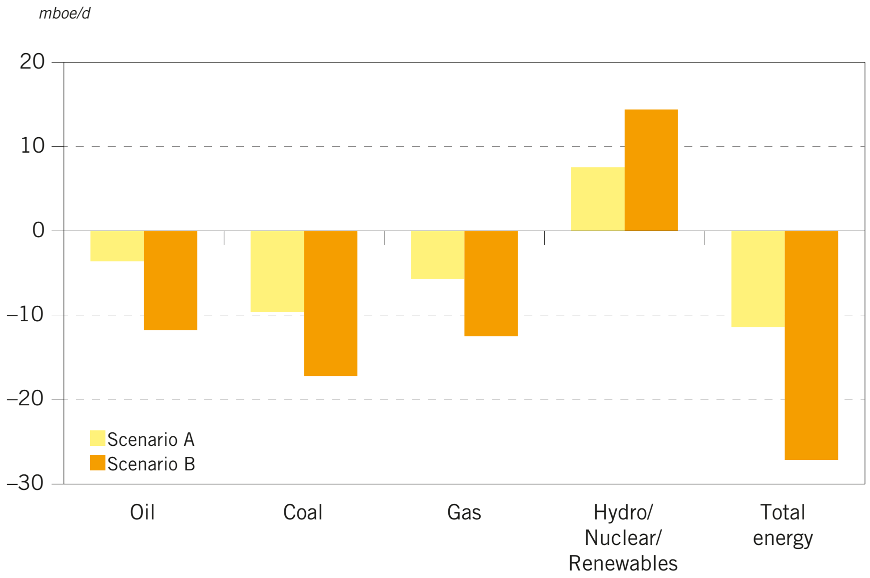


energy efficiency measures are adopted in the OECD regions. For Scenario A, it is in the range of 5% of overall savings and for Scenario B it is around a 10% reduction, compared to the Reference Case. The reduction in energy demand is assumed to be lower in Eurasia followed by Developing countries, as countries in these regions are expected to allocate their scarce resources between investments to improve energy access to the energy poor and investments for energy efficiency improvements. It should be noted that the level of energy efficiency improvements assumed in the design of these scenarios is still significantly below the technical potential for energy savings,[6] but significant investments would be necessary to achieve this level of improvement.

In regards to major energy sources, achieving the INDC targets will have significant effects on the future energy mix. The range of changes in global primary demand for major fuels under the two alternative scenarios relative to the Reference Case is summarized in Figure 8.2. Broadly speaking, demand for all fossil fuels at the global level is projected to decline relative to the Reference Case projections under both Scenarios A and B. In addition to the demand decline for fossil fuels, the share of renewable energy sources, as well as nuclear energy, will increase, thereby partially compensating/substituting for the energy demand loss from fossil fuels. The nature of these fuel substitutions is a key factor in shaping the energy mix. As most of the substituting fuels generate electricity, they tend to substitute coal and gas in electricity generation. This means there is more demand reduction in coal and gas compared to oil.

The combined substitution effect of renewables and nuclear energy compared to the Reference Case is reflected in an increase of 7.5 mboe/d for these fuels in Scenario A and by 14.4 mboe/d in Scenario B. 'Other renewables' (primarily in

Figure 8.2
Change in global primary demand for major fuels relative to the Reference Case by scenario, in 2040



the form of wind and solar) expand the most on the basis of a policy shift in these scenarios. Under Scenario B, for example, this energy source increases by 6.5 mboe/d by 2040 compared to the Reference Case, followed by nuclear energy (4.3 mboe/d) and biomass (2.9 mboe/d). The smallest increases in this category are projected for hydro energy (0.7 mboe/d) due to the limited options that exist for additional production of this energy source.

Coal is projected to be the most affected fuel under both scenarios as illustrated in Figure 8.3. This is because coal provides the most cost-effective mitigation option given the availability of technology and the accessibility of alternative fuels with a lower emission footprint. These options offer significant technological and financial flexibility for mitigation in coal-based electricity generation, which is reflected in a significant demand reduction already in Scenario A. In this case, the demand reduction for coal is around 3 mboe/d by 2025 and close to 10 mboe/d by 2040, compared to the Reference Case. In this scenario, global coal demand is projected to peak before 2030.

The declining trend for coal demand – in principle driven by the same reasons given for Scenario A – is even more pronounced in Scenario B. Here, coal demand peaks shortly after 2020 at around 81 mboe/d and then declines continuously thereafter to 74 mboe/d by 2040. The bulk of this decline is projected to take place in China (a drop of 6.8 mboe/d between the Reference Case and Scenario B by 2040) followed by OECD Asia Oceania (–2.6 mboe/d), OECD America (–2.3 mboe/d), OECD Europe (–1.6 mboe/d) and India (–1 mboe/d).

Contrary to coal, natural gas is less affected in Scenario A. The level of demand decline is more visible in Scenario B. As shown in Figure 8.4, primary demand for natural gas declines by less than 6 mboe/d by 2040 in Scenario A compared

Figure 8.3
Global primary coal demand by scenario, 2015–2040

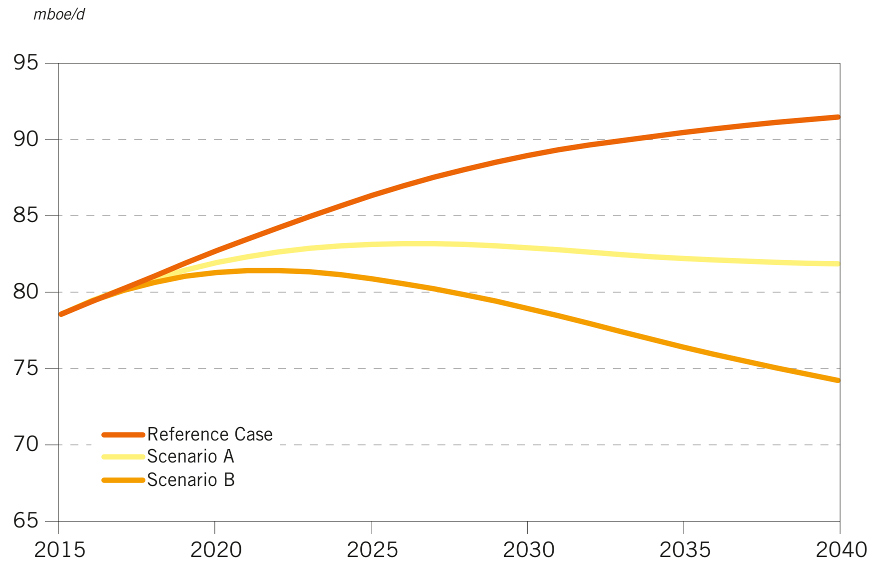
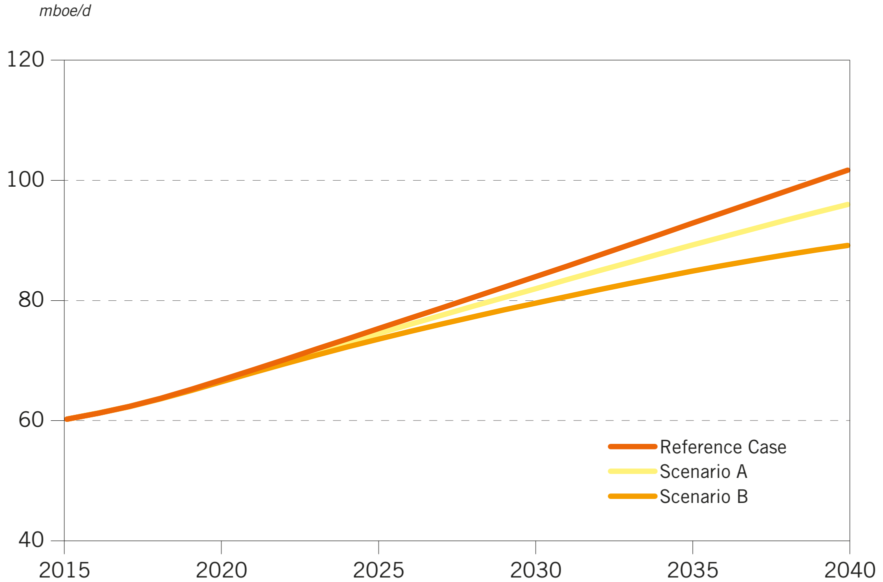


Figure 8.4
Global primary gas demand by scenario, 2015–2040



to the Reference Case, while the additional reduction in Scenario B is close to 7 mboe/d.

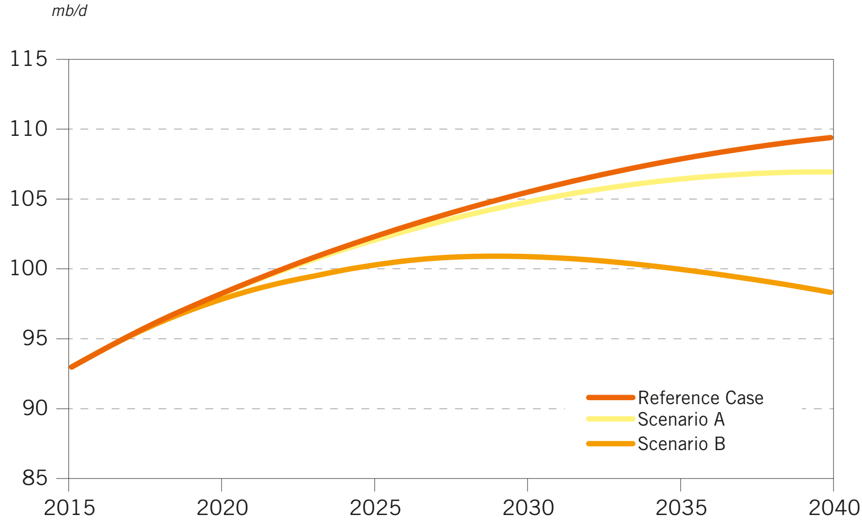
Nevertheless, it should be stressed that demand for natural gas continues rising significantly in both scenarios (and in the Reference Case) over the entire forecast period. In fact, natural gas records by far the largest increase in the amount of additional energy provided in all three estimates. There is an expansion of 42 mboe/d in the Reference Case, 36 mboe/d in Scenario A and 30 mboe/d in Scenario B, with all figures representing increases between 2014 and 2040. However, while this statement holds true at the global level, there are some variations at the regional level as natural gas demand is projected to decline in OECD Europe, OECD Asia Oceania and in Eurasia (particularly in Russia) under Scenario B.

Implications for oil

Focusing on oil, it is preferable to use volumetric bases rather than energy content. In doing so it is important to recall that the definition of oil demand (or rather, liquids demand) expressed on a volumetric basis is slightly different from the one expressed on energy bases.[7]

As mentioned earlier, the two alternative scenarios will have significant implications on the overall energy landscape and on each of the fuel types. For oil, the demand outlook would be reduced from the levels projected in the Reference Case. As shown in Figure 8.5, in Scenario A oil demand in 2040 will reach 106.9 mb/d, which is 2.5 mb/d less than in the Reference Case. Furthermore, between 2030 and 2040 demand growth decelerates significantly so that demand actually plateaus at the end of the forecast period. In Scenario B, oil demand peaks in 2029

Figure 8.5
Oil demand in the Reference Case and alternative scenarios

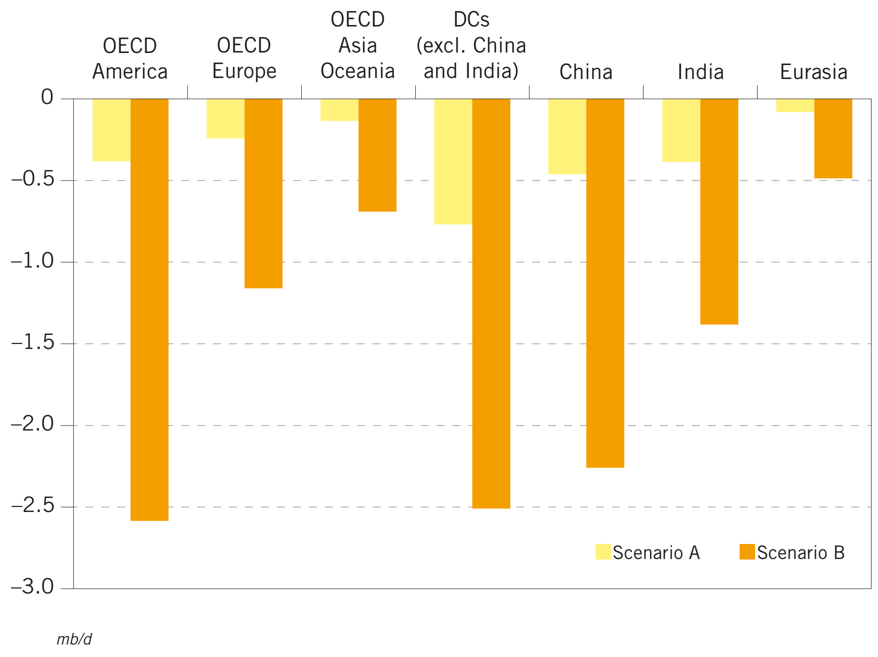


at 100.9 mb/d and then declines to 98.3 by 2040. This is 11.1 mb/d lower than in the Reference Case.

In Scenario A, the oil demand reduction compared to the Reference Case is mainly a result of efficiency improvements in all sectors of consumption. However, it is in the road transportation sector where it would be most visible. In fact, out of the 2.5 mb/d of oil demand reduction by 2040, 1.2 mb/d is anticipated to come from this sector as a result of faster improvements in fuel efficiency and a moderately higher penetration of alternative fuel vehicles (AFVs) relative to the Reference Case. In particular, in this scenario an average 20% additional improvement in baseline fuel efficiency is assumed. Moreover, the penetration of battery electric vehicles (BEVs) is around 1 percentage point higher than in the Reference Case. By 2040, BEVs would account for 7.2% of the passenger car fleet, up from 6.7% in the Reference Case.

In Scenario B, the introduction of policies that support achieving the INDC targets is combined with the assumption of an accelerated technology development and its transfer across countries. Similar to Scenario A, this would have implications for oil demand in each sector of consumption with the road transportation again in the frontline. In this sector, demand is expected to drop by 6.2 mb/d by 2040 as a result of the higher fuel efficiency improvements and a much faster penetration of AFVs then assumed in both the Reference Case and Scenario A. In this case, the share of BEVs in the world passenger car fleet is assumed to reach around 22% by 2040. In some regions, such as OECD America and OECD Asia Oceania, one out

Figure 8.6
Oil demand reduction in the alternative scenarios compared to the Reference Case by 2040



of every two passenger cars sold by the end of the forecast period is anticipated to be a BEV. In Europe and China, the sales of BEVs represent almost 40% of total passenger car sales by 2040.

As mentioned earlier, in Scenario A, oil demand will drop by 2.5 mb/d in 2040 compared to the Reference Case. Regionally, the OECD will account for around 30% of this drop. This is on the back of further efficiency improvements across all oil consuming sectors and, in particular, the road transportation sector in OECD America, coupled with a higher penetration of AFVs.

In Developing countries, oil demand under Scenario A is 1.6 mb/d lower than in the Reference Case by 2040 (Figure 8.6). In China and India, the demand drop is 0.5 mb/d and 0.4 mb/d, respectively. Similar to the case of the OECD region, the lower oil demand in these countries is mainly due to further efficiency improvements in sectors like 'other industry' and residential/commercial/agriculture as they play an important role in the sectoral demand of these two countries.

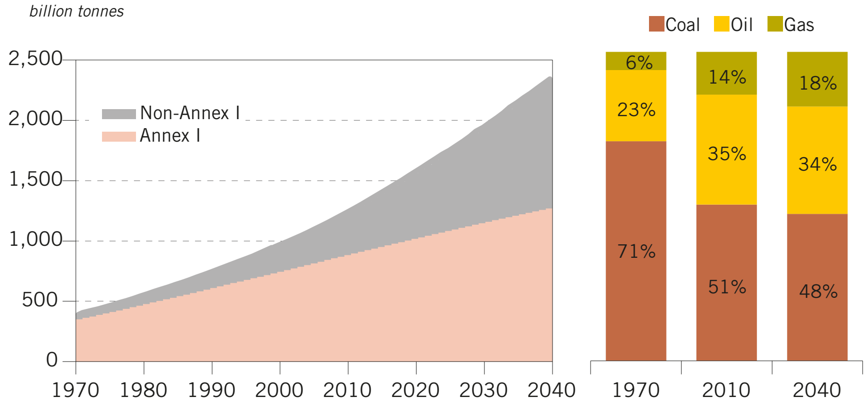
Under Scenario B, the reduction in oil demand, compared to the Reference Case, is more evenly distributed between the OECD and Developing countries. Out of a total oil demand decline of 11.1 mb/d by 2040, the OECD accounts for 40%. Within the OECD, OECD America – as a technology leader, but also as the largest market – sees the biggest decline with a drop of 2.6 mb/d by the end of the forecast period. In Developing countries, oil demand in China, another technology leader, sees the largest drop, with a reduction of 2.3 mb/d in 2040.

Potential implications on CO_2 emissions

The mitigation component of the INDCs has been the subject of several studies[8] in terms of its aggregate effect on meeting the temperature target of the Paris Agreement and in terms of its impact on the energy sector. The UNFCCC Secretariat in its analysis[9] of the INDCs of the 189 Parties estimates that the aggregate effect of the INDCs in comparison to the pre-INDC trajectories is 2.8 (0.0–6.0) gigatonnes

8

Figure 8.7
Cumulative CO_2 emissions in the Reference Case, 1970–2040



of CO_2 equivalent (Gt CO_2eq) in 2025 and 3.3 (0.3–8.2) Gt CO_2eq in 2030. A study by the United Nations Environment Programme (UNEP) found a similar estimate of the mitigation potential of INDCs.[10] The study estimated an additional mitigation requirement of 8.7 (with a range of 4.5–13.3) Gt CO_2eq in 2025 and 15.2 (with a range of 10.1–21.1) Gt CO_2eq in 2030 for achieving the 2°C target of the Paris Agreement under the least-cost scenarios.

Figure 8.7 shows energy-related cumulative CO_2 emissions for the Reference Case over the period 1970–2040. It shows the majority of cumulative CO_2 emissions are related to coal consumption, accounting for almost 50% of the total in 2040. In addition, Annex I countries[11] are likely to account for around 55% of energy-related cumulative CO_2 emissions by the end of the projected period.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report, a total carbon budget of approximately 1,000 Gt CO_2eq is available for future emissions within the 2°C pathway.[12] Annex I Parties have used a significant portion of the historical carbon budget. Therefore ‘equity’ is an important element that should be reflected upon when implementing the NDCs.

Figure 8.8 shows the potential CO_2 emission reductions under both Scenario A and Scenario B compared to the Reference Case. It is assumed that in the Reference Case annual energy-related CO_2 emissions are likely to reach the level of almost 40 Gt CO_2 in 2030 and surpass 42 Gt CO_2 in 2040. For comparison, annual emissions were around 33 Gt CO_2 in 2014. Considering the contributions included in the INDCs, as broadly measured by Scenario B, total energy-related CO_2 emissions are projected to increase until at least 2030. By then, the current commitments by the Parties are expected to lead to CO_2 emission reductions from energy use, compared to the Reference Case. The reduction could reach the level of about 14% by 2040.

In addition, it should be noted that while per capita emissions in Annex I Parties reduce gradually over the period 2015–2040, even by 2040 under Scenario B per

Figure 8.8
Impact on CO_2 emissions

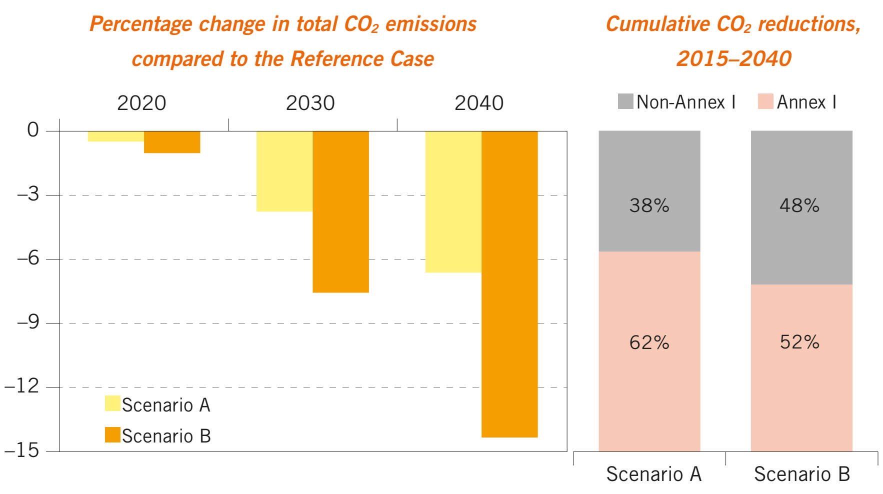
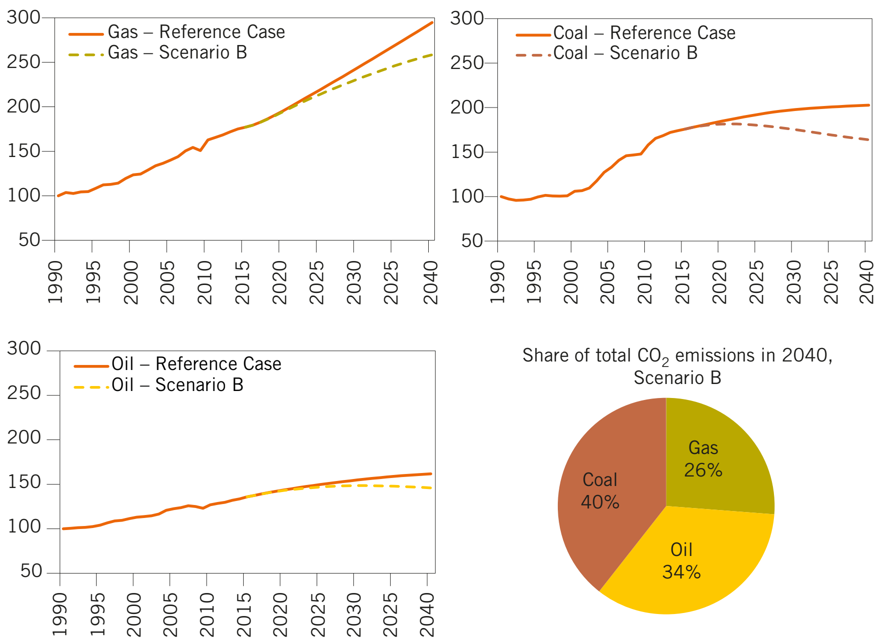


Figure 8.9
Decomposition of CO_2 emissions, 1990=100



capita emissions from Annex I Parties are projected to be still about one-and-a-half times that of Non-Annex I Parties.

In this regard, it is important to recall that the Paris Agreement calls for "equity" for all Parties in the implementation of their INDCs. Each country should be allowed to develop in a sustainable manner. Therefore, it is critical to ensure that all countries and future generations will have equitable access to development opportunities.

Furthermore, sustainable development is a collective endeavour and can only be achieved through collective efforts – the Paris Agreement provides an effective platform for such collective efforts by establishing mechanisms for financial support and technology transfer from developed to developing countries for mitigation and adaptation. Of paramount importance, alleviating energy poverty needs to take centre stage in climate policies. Today, billions of people still rely on biomass for their basic needs, and over one billion still have no access to electricity. The COP21 outcome calls for "the need to promote universal access to sustainable energy in developing countries, in particular in Africa".

The future emission reduction pathways rely significantly on sizable emission reductions from coal-based electricity generation. As Figure 8.9 shows, CO_2 emissions originating from coal use are likely to be reduced significantly under Scenario B. Given the sheer size of emissions from coal-based electricity generation, this sector offers sizable cost-effective mitigation opportunities for Parties to achieve energy-related emission reductions.

Box 8.1

CCS deployment supports Paris Agreement implementation

The long-term goals of the Paris Agreement include holding the global temperature rise to well below 2°C (or even 1.5°C) above pre-industrial levels, reaching a global peak in GHG emissions as soon as possible, and attaining emissions neutrality in the second half of the 21st century.

The level, type and scope of climate actions that countries commit to are defined nationally through their INDCs. Nevertheless, the INDCs submitted by Parties to the UNFCCC prior to the Paris Conference (COP21) have been assessed[13] as not being ambitious enough to achieve the 2°C temperature target. A potentially important technology that can provide significant additional mitigation opportunities in a cost-effective way is carbon capture and storage (CCS).

The deployment of CCS could further reduce CO_2 emissions, especially in the power generation sector. The power generation sector accounts for a significant share of the world's primary energy demand, and there are cost-effective means to significantly reduce emissions in this sector. Therefore, decarbonization of power generation should receive particular attention in addressing climate change.

Recent evidence shows that the planned expansion of coal power plants could release more than 6.5 $GtCO_2$ per year. When existing plants are included, the total emissions from coal power generation is estimated at 12 $GtCO_2$ in 2030; accounting for almost 30% of the permissible emission levels in 2030 under a 2°C temperature target.[14] To implement the Paris Agreement, the deployment of CCS technology is therefore vitally important.

In light of the above, many Parties have already highlighted in the INDCs their intention to enhance GHG sinks. In this context, ten Parties[15] have mentioned CCS as a priority area in their INDCs. Despite these developments and the fact that the concept of utilizing CCS technology as a mitigation option with large-scale application emerged in the 1980s, various challenges continue to hinder the wide-scale deployment of CCS. These refer mainly to institutional, technical and financial matters.

At present 15 large-scale CCS projects are in operation and seven projects are under construction and scheduled for launch before the end of 2017. The seven projects under construction are expected to increase the existing capture capacity of around 28 million tonnes of CO_2 per year by more than 40%. Another 11 projects are in the advance planning stage and 12 projects are in the early planning stage. These are estimated to reach a capture potential of more than 80 million tonnes per year after 2020.[16]

Most of the projects currently in operation relate to natural gas processing and hydrogen production. However, new projects widen the coverage, increasingly moving to the power generation, chemical, refining sectors. The first project in the power generation sector started operation in Canada in 2014. Another two projects are in the advanced construction stage, while an additional 10 projects in the power sector are in the planning stage or under consideration. This is a clear indication of the potential for CCS that exists in the power sector.

Countries such as Norway, the US, European Union (EU) Member States, Canada, Australia and Japan have already introduced supportive policies to enable the delivery of CCS projects. At the same time, CCS is admitted as a project activity under the Clean Development Mechanism (CDM) of the UNFCCC. However, financial resources remain relatively low. Since 2007, about $13 billion have been invested in CCS projects compared to approximately $1,800 billion in renewable power generation technologies.[17]

Strengthening the supporting institutional structures along with research and development (R&D) efforts could reduce the cost of CCS deployment for CCS to be a viable component in a global low emissions portfolio. It is equally important to allocate additional international financial resources to enable the further development and deployment of CCS projects and allow the widespread use of this technology in developing countries too. In this context, the Paris Agreement could play a critical role in gearing its support mechanisms to promote CCS development and deployment.

Uncertainties, hurdles and opportunities

Key takeaways

- The oil and energy industries face many challenges and uncertainties today, and looking long-term, it is evident that there are many they will need to confront in the future.
- Oil market instability creates global economic hardship and uncertainty for oil producing countries in their efforts to make appropriate and timely investments.
- Medium- to long-term economic growth is subject to a host of uncertainties that could lead to different outcomes for the global economy from those presently envisaged. A recent example is the UK's 'Brexit' decision, which has created great uncertainty for the UK economy and that of Europe.
- The uncertainties associated with energy and environmental policies at both national and international levels cloud the outlook for energy demand and supply, especially in the long-term. In particular, possible climate policies following COP21 have the potential to reduce energy consumption levels and alter the energy mix substantially.
- Technological advancement, some already expected and some unforeseen, plays an important role in the energy industry and may shift outcomes significantly. In the oil industry, technological progress led to the rapid rise of tight oil, a resource that arguably continues to exceed expectations.
- In the downstream sector, there is uncertainty about the reaction of refiners to the need for capacity rationalization and changes in the quality of the global crude slate.
- Regulations pertaining to product quality specifications present another challenge for refiners, particularly if stringent requirements are introduced in response to climate change.
- The development of additional routes for oil movements may considerably affect trade patterns. Accordingly, both refiners and shippers face challenges associated with possible swings in crude trade.
- The extent of uncertainty in the energy industry highlights the continuous desire for OPEC to participate in international dialogue with all stakeholders. Producer-consumer dialogue, as well as producer-producer dialogue, is beneficial to all parties involved and will help to achieve market stability.

The scenarios presented in earlier Chapters account for several of the uncertainties that cloud the future energy landscape. While the uncertainties can cause challenges, and impediments, they may also present opportunities.

Although there are numerous variables affecting the global oil market, in particular, it is important to recognize economic growth prospects, the cost of capital and services, technological developments and energy policies. It should also be noted that the oil price is an important determinant for the industry as it provides a signal for sound investment decisions. Given the industry's interlinked nature, several of the uncertainties for the upstream sector are also relevant to the downstream sector.

This Chapter covers some of these fundamentally important drivers. In addition, since the issues and developments are taking place in a dynamic world, which means dialogue among all stakeholders is as important as ever. So, the Chapter closes with a summary of the OPEC Secretariat's engagement with the international community over the past year.

Low oil price challenges

Despite many important macroeconomic and geopolitical events during the period between 2010 and mid-2014, oil prices stayed remarkably stable. However, in mid-2014 they started to decline as excess output, primarily of light sweet crudes, entered the market. The OPEC Reference Basket (ORB) fell from above $100/b in the first half of 2014 to its recent lowest level of $22.48/b in January this year.

Low oil prices present significant challenges and uncertainties. The price environment of the past two years has led to significant reductions in investments across the oil industry. In 2015, the reduction in upstream capital expenditure was in the range of 25% (compared to 2014), while in 2016 further reductions of more than 20% are anticipated. This raises concerns about the sustainability of adequate supply levels in the coming years, particularly if the lower price environment extends for a longer period. If investments stay at lower levels it could potentially result in 'boom and bust' development – a scenario that is undesirable for both producers and consumers. In this respect, both oil price levels and the volatility of prices are important factors. Moreover, a stable oil market is paramount to avoid detrimental effects on the global economy.

The extent of the impact of low oil prices on the world's future energy mix is uncertain, since the relationship between oil prices and energy investments is complex. At times of steady oil demand growth, investments are undertaken to continue matching future demand requirements. However, in a world of lacklustre economic growth and a low oil price environment, producers face challenges related to making appropriate and timely investment decisions. This challenge is made particularly acute due to the varied industry lead times and payback periods for different types of projects.

Low oil prices also have repercussions for those energy sources that compete for market share in the same end uses as oil, such as biofuels and non-conventional liquids, including coal-to-liquids (CTLs) and gas-to-liquids (GTLs). Moreover, natural gas prices are affected in regions like Europe and Asia, where pricing is often based on oil indexation. Nuclear energy and renewables, such as wind and solar, are used primarily to generate electricity, and often compete with natural gas. Hence, renewables may become less competitive as a consequence of lower gas prices.

Finally, it should also be mentioned that while the oil price is obviously subject to the balance of fundamentals and upstream investment, the role of oil as an asset class continues to play a role. Going forward, the evolving impact of financial markets on oil prices, along with the efforts to increase oversight and enhance regulation will be a factor that continues to influence oil market stability.

With changing trends in oil demand, supply and trade, including the increasing importance of Asia as a demand centre (see Box 9.1), there is some uncertainty about the evolution of pricing benchmarks.

Box 9.1

Evolving Asian oil benchmarks

For the purposes of crude trading, a benchmark crude or marker crude is a crude oil that serves as a reference price for buyers and sellers. The agreed price for both long-term and spot crude sales are calculated on the basis of a reference price that is then adjusted to take into account the quality – depending on sulphur content and viscosity – as well as the location of the crude. The primary marker crudes are West Texas Intermediate (WTI) and Brent, as well as Dubai. Other marker crudes have been adopted over time, such as BWAVE (oil futures), Oman, Mars, Light Louisiana Sweet (LLS), Urals and the Argus Sour Crude Index (ASCI), although most of these are linked through various financial layers to one of the primary crude markers.

Broadly speaking, WTI is the key benchmark for the North America region and Brent for the North Sea. For many years, Malaysia's Tapis crude was a key benchmark in the Asia-Pacific region; however, declining production have seen sellers and buyers shift to using Brent as a reference. Since the late 1980s, crude oil exports from the Middle East to Asia have been priced on the basis of Dubai crude, using the Platts Dubai assessment as a base for Official Selling Price Formulae (OSPF) for many Middle East producers.

In recent years, the eastward shift in global oil trade towards Asia has renewed longstanding discussions around Asian oil benchmarks.

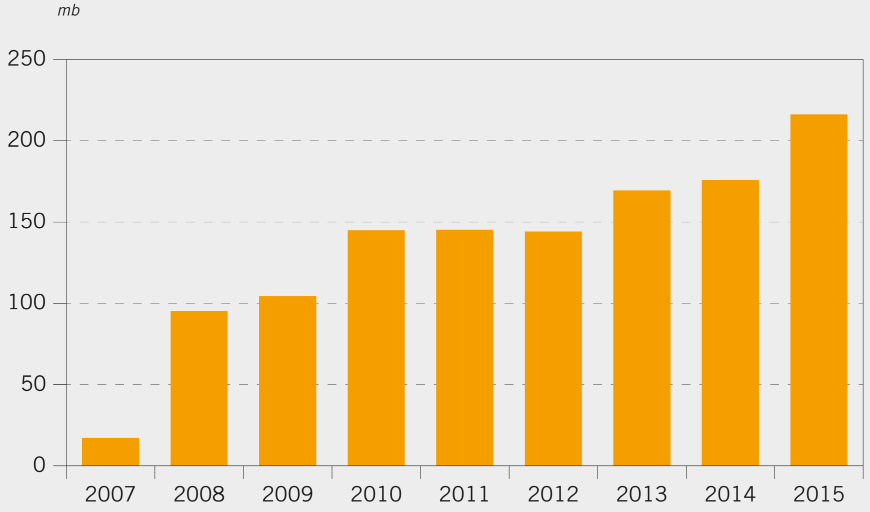
In 2013, China became the world's largest oil importer and since that time Chinese companies have become increasingly active in the international market. In addition to state-owned oil companies – such as China National Petroleum Corp. (CNPC), China National Offshore Oil Corp. (CNOOC), and China Petroleum & Chemical Corp (Sinopec) – which have been importing oil for many years, more recently the country's independent refiners – commonly referenced as teapot refiners – have been granted import licenses that allows them to directly import crude oil, rather than buy it from one of the state-owned companies. These companies include Shandong Dongming Petrochemical Group, Lihuayi Group Co. Ltd and Panjin Beifang Asphalt Fuel Co. This has added some 1 mb/d to China's imports.

Mirroring these developments and China's growing share of oil demand in world oil trade, the trading arms of the state-owned companies have been increasingly active in the Dubai benchmark price assessment process – including PetroChina's Chinaoil and Sinopec's trading arm Unipec – which have joined longstanding participants such as Shell, Reliance, Vitol, Total, BP, Mercuria and Gunvor.

Efforts have also been made in recent years to develop alternative Asian crude oil benchmarks based on a futures market established in the region that would serve the same oil price discovery function as the Nymex or the Intercontinental Exchange. While the market has not yet coalesced around any single option – to the degree that they have for WTI and Brent – ongoing efforts are being made on a number of options. These include the Dubai Mercantile Exchange (DME), which was established in 2007, offering a futures contract for Oman crude. The DME Oman contract has a physical delivery mechanism, meaning that if the contract is held past settlement the buyer can take delivery of physical barrels. Average daily trading volumes for the contract, however, are well below those for Nymex WTI and Intercontinental Exchange Brent. Nevertheless, DME Oman has the largest physical delivery for any energy futures contract, with some 216 million barrels delivered last year (Figure 1).

Another initiative has been the effort to establish a crude futures contract in China. The Shanghai International Energy Exchange, known as the INE, has been preparing to launch its first international crude oil contract. The exchange aims to create a Chinese commodities market that is fully open for trading to foreign investors. The INE contract size will be set at 100 barrels, compared to a standard size of 1,000 barrels for Nymex WTI, Intercontinental Exchange Brent and DME Oman. This is seen

Figure 1
DME Oman physical delivery volumes



Source: Dubai Mercantile Exchange.

as an effort to attract small-pockets of local investors. The contract will also have a physical delivery mechanism that is planned to accept seven different crudes including Dubai, Oman, Upper Zakum, Yemen's Masila, Qatar Marine, Basrah Light and China's Shengli. The contract will be priced in yuan rather than dollars.

Elsewhere, the St. Petersburg International Mercantile Exchange (SPIMEX) – which will launch a crude futures contract based on Russian Urals in 2016 – has also stated that it has plans to launch a futures contract based on crude delivered through the Eastern Siberia-Pacific Ocean (ESPO) pipeline, which sends Russian crude to Asia.

It will always be challenging to predict the direction that markets will take on issues such as benchmarks. However, developing and maintaining markers that are relevant to the fundamentals of a region, as well as provide sufficient liquidity to prevent undue distortions or unwarranted fluctuations in prices will continue to be essential to ensure robust and smooth functioning markets.

Economy: a source of uncertainty

The Reference Case portrays the most plausible oil market outlook, including the central assumptions for economic growth. As highlighted in Chapter 1, medium-term global Gross Domestic Product (GDP) growth is assumed to gradually recover and accelerate to 3.7% per annum (p.a.) in 2021. Moreover, long-term estimates show that global economic growth for the period 2015–2040 is projected to average 3.5% p.a. However, economic prospects remain a key source of uncertainty in the energy landscape.

This is particularly true in the medium-term, with economic uncertainty skewed to the downside. The sources of this uncertainty are diverse. Some are scars left over from the 2008/2009 financial crisis, while others are new; some are specific for emerging economies and others are more evident in the OECD region; and, some could potentially have a significant impact on energy markets. A brief description of a few of these is presented here.

The UK's decision to leave the EU (Brexit) has added a significant amount of uncertainty to the outlook for the UK and other European economies. The development is an unprecedented event and there evidently remain many areas of uncertainty, both economic and political, which will continue to unfold in the years ahead.

The economic implications of Brexit may lead to limited business formation, along with reduced investment and hiring. Falling asset prices combined with lower consumer and business confidence may further exacerbate an economic slowdown in the UK. While a depreciating currency may provide some relief to UK exporters, the UK's trade policy will have to be reconfigured with the formation of new trade agreements. These may be less favourable to UK exporters. Within this new trade policy paradigm, the possible relocation of some financial services from London to the Euro area would also negatively impact the UK economy. A decrease in EU immigrants to the UK, often young and of a working age, would also likely imply the need to raise taxes and/or cut spending to accommodate the health and pensions costs associated with an ageing UK population. Finally, at the global level, Brexit may result in a shift away from UK sterling financial assets towards safe havens like the US dollar and the sovereign debts of US, Germany and Japan. It is evident that the global risk of a fallout from Brexit is likely to be a concern for the financial markets amid growing risk aversion and tighter financial conditions.

There are also uncertainties related to the outlook for China. While China posted an average annual GDP growth rate above 9% p.a. for the period 2000–2015, the pace of growth is forecast to ease to 6.1% in 2017 and to further decline to 5.7% by 2021. The country's success in navigating a steady path relies on the smooth progress of structural reforms and necessary policy stimulus. The downside risk of a sharper-than-expected slowdown in economic growth remains. It is clear that there are indicators that need to be carefully monitored. To begin with, China has seen record budget deficits and there are indicators of housing bubbles in some large cities. Total debt is also reaching fairly alarming levels, over 250% of GDP, most of which is private debt. This private debt is largely corporate debt. If this balloons further, it could lead to a disincentive for corporations to borrow further, even in an environment of very low interest rates. This could, in turn, cause economic growth to stagnate.

Furthermore, due to the country's large shadow banking sector, which effectively allows for loans to be reclassified as investments and, thus, recorded off the balance sheet, the potential risk of credit defaults may be underestimated. In addition, in the past two years, the country's foreign reserves have fallen by 19%, which amounts to a capital outflow of over $760 million. Further capital flight concerns remain a risk, especially if the US dollar strengthens further amid overall increases in global risk aversion and any ensuing capital flight to safe havens. Finally, the downside risks of a sharper-than-expected slowdown could have implications for spillover effects in the rest of the region, as well as globally.

In advanced economies, the current rather low interest rates, together with rapidly increasing public debt, leaves very limited room for counter-cyclical measures. Given this, episodes where monetary policy is constrained by the lower bound for interest rates could become more frequent and prolonged. This could leave advanced economies more exposed to external and internal shocks. Furthermore, low inflation rates, together with doubts about the impact of monetary easing in the real economy, also cast some doubts on the medium-term economic outlook.

The economic situation in commodity exporting countries also remains fragile. While between 2000 and 2010 commodities indices, broadly speaking, almost doubled, the trend reversed from 2014 onwards. Since then, the overall primary commodities index has dropped 44%, with the food price index declining 15%, the metal price index 34% and the energy price index 56%. This has clearly affected the outlook for commodity exporting countries. Fiscal imbalances and increasing debt levels, together with diminishing foreign reserves, leave these countries more exposed, with limited room to overcome possible downside shocks.

At the same time, there remains uncertainty as to the pace of recovery of capital flows to emerging markets. These inflows are seen as a fundamental growth driver for these economies, as well as an indicator of how resilient these countries are to outflows. The year 2014 marked the first year since 1995 that capital outflows surpassed inflows to emerging markets, with a net loss of $111 billion. In 2015, this trend accelerated and capital outflows totalled around $700 billion. While for 2016 the situation has improved, it is still expected that net outflows could reach $500 billion.

It should not be forgotten that geopolitical developments could impact future global growth prospects. Conflicts in Eurasia, Middle East and Africa, as well as the rise of extremist parties in some parts of Europe, and the current refugee situation the Middle East and North Africa region and Europe could potentially represent an important source of risk.

Having said this, it should also be highlighted that the global economic situation has also upside potential in the medium-term. The effect that policy reforms could have in countries such as China and India could stimulate growth in these countries and have positive spillover effects elsewhere. Similarly, an improving political situation in Brazil, as well as in parts of the Middle East and Africa, could boost growth. In the OECD region, improving productivity could also improve growth expectations.

Uncertainties and implications of policy measures

As described in Chapter 1, every year the Outlook reviews energy policies already in place and considers others that have the potential to be implemented. In many cases, there are uncertainties arising from factors such as unrealistic targets, a lack of implementation strategies or non-favourable political conditions – thus generating challenges for the energy landscape. What follows are some examples of the policies that raise questions regarding their impact on the future energy mix.

A major policy event last year was the COP21 Agreement in Paris and the related submissions of the INDCs to the UNFCCC. As outlined in the scenarios presented in Chapter 8, efforts to achieve emission reductions – whether through increased fuel efficiency, accelerated development of alternative energy sources or changing consumer behaviour – have the potential to substantially restrain energy and oil demand growth. Moreover, uncertainties on the future energy mix, in general, and oil demand, in particular, go far beyond the options and measures expressed in the INDCs. To start with, there is a high level of uncertainty on the strength of the link between the carbon concentration levels and the global temperature rise which, in turn, determines the available carbon budget and the amount of fossil fuels that could be consumed.

Related to this are issues of specific policies that need to be put in place to achieve intended targets for emission reductions. These often give preference, or pose a disadvantage to, certain fuels. This is not purely on the basis of related emissions, but also takes into consideration issues such as a government's revenue, energy security, import dependency, job creation, geopolitical considerations, etc. All these issues have significant implications on the development of the future energy mix and, combined, pose a great level of uncertainty for specific fuels.

This is well illustrated by several recent decisions taken by policymakers in major consuming countries. In the US, the Renewable Fuel Standards (RFS) Programme for the calendar years 2014, 2015 and 2016, published in December 2015, sets out 18.11 billion gallons as the minimum amount of renewable fuel to be consumed during 2016. This is a significant jump from the 16.93 billion gallons target for 2015. However, the future direction of the RFS is an unknown, which creates uncertainty about the role of biofuels and other renewables in the US energy market.

In the transportation sector, the European Commission initiative to apply the World-Harmonized Light Duty Vehicle Test Procedure in its territory from 2017 is generating some debate about the implications for automakers, which fear the policy may set unrealistic targets. The EU will be the pioneer on the implementation of this test procedure, and its results may influence other prominent consuming countries.

In India, efficiency measures in the transport sector are linked to rising levels of pollution, but their impact is unclear. For example, the two sets of Corporate Average Fuel Consumption standards for cars or the implementation of the Bharat Stage VI standards are just a few of the efforts initiated by the government to improve air quality in the country. However, more efficient vehicles and cleaner fuels are expected to lead to higher prices and costs, which many of the country's population may not be able to afford.

The 'China Six' quality standards for motor gasoline and diesel state that sulphur content should not be higher than 10 parts per million (ppm). In order to accomplish these targets, however, domestic refineries need to upgrade their installations. Given that China uses a controlled pricing system, which changes on occasion due to variations in the oil price, private refinery investment may need to tread with caution.

As widely reported in recent years, the evolution of electric cars has resulted in incentive agreements between governments and some automobile producers. However, it is not clear how nations will increase electricity production in order to supply the energy for those vehicles. In addition, there is uncertainty about how long governments will maintain the subsidies needed for consumers to purchase electric vehicles. Additionally, as their popularity grows, the question arises whether governments could begin to apply taxes on these vehicles, and how might this impact demand for them?

There is also uncertainty stemming from the long-term energy plans of several countries and regions. For instance, the EU's new Renewable Directive and its bioenergy sustainability policy for 2030 is expected to be presented later this year. These will provide a framework to achieve the binding EU-level target of having at least 27% renewable energy by 2030. However, the new Directive still has to contend with many uncertainties that were witnessed during the first version of the Renewable Directive for 2020. For example, challenges are presented by the legislative and policy frameworks required, as well as by the cooperation among EU members, which is needed to ensure the timely and cost effective achievement of the targets.

China's 13th Five-Year-Plan (FYP) was approved on 5 March 2016. However, a detailed 13th FYP for oil and gas has yet to be published. As mentioned in the *Focus* in Chapter 1, some clues suggest energy efficiency and technological innovations will be the key for the success of the Plan's energy initiatives. It is expected that specific targets will be set by the relevant authorities during the coming year, but uncertainties remain.

In Japan, the 'Energy Mix Plan 2030', adopted in July 2015, expects the country's share of nuclear power to increase to 20–22% of the electricity supply by 2030. However, there is still some uncertainty – partly arising from public opposition – about the prospects for nuclear energy's share in this sector.

Finally, low oil prices have resulted in the reduction of fossil fuel subsidies in many countries. Low oil prices also resulted in low prices for petroleum products, making it easier to reduce subsidies. However, this movement could be risky for governments that have not taken the respective countermeasures to support the economic impact. Moreover, changing market circumstances mean that future policies related to subsidies are uncertain, as it is still unknown how governments will react as oil prices recover.

Uncertainties associated with technological progress

The Reference Case assumes an evolutionary development of existing or readily available technologies over the next 25 years. However, industrial history underscores the fact that disruptive inventions – often the result of hard work, trial and error, and sometimes chance – can impact the energy scene. Diesel engines and gas turbines, for example, had once been considered impossible due to technical limitations. The exploitation of tight oil has advanced much faster than expected and is now at a lower cost level than only a few years ago. It is, therefore, essential to be aware of uncertainties imposed by technical developments in the future that may considerably change the energy picture. The following provides details of some of the important developments to monitor.

On the supply side, tight oil and shale gas developments, mainly in the US, represent the most important recent impact on global oil and gas supply. Further improvements in horizontal drilling, as well as more efficient fracturing, may not only boost the yield of existing wells, but allow the application of this technology in geographic areas that are currently considered as not feasible. Enhanced Oil Recovery (EOR) applied to conventional oil fields, with the large-scale injection of CO_2 and steam, may also substantially increase the further yield of mature oil fields. In particular, those regions with traditional very low exploitation costs can benefit from these technologies at moderate additional costs.

In terms of natural gas, liquefied natural gas (LNG) requires not only large investments, but also large amounts of energy for liquefaction, transport and regasification. Against the background of low gas and LNG prices, producers are striving to improve technology and operational efficiencies. Options being discussed include the standardization of equipment and the introduction of flexible technologies like floating LNG for both production and consumption.

Despite the Fukushima disaster in Japan, there has been talk in some quarters of a nuclear renaissance in some regions. In part, this is due to the ongoing discussions concerning global warming. However, it is evident that any revival will require more innovative and commercially mature technologies, as well as solutions to the still unsolved problem of the final storage of nuclear waste.

From the perspective of biofuels, it remains unclear whether they will play an important role in the energy future. First and second generation biofuels have to date shown a disappointing yield and turned out to be overly expensive. Despite some optimism in prior years surrounding third generation biofuels made from algae, technical challenges associated with conversion efficiency remain.

As already highlighted, the two types of renewable energy with the greatest potential by far are solar and wind. Today, the commercial PV cells mainly used (mono or poly crystalline silicon) have typically a peak efficiency of 15–20%. However, R&D in this area has been intense and lab prototypes with up to 46% peak efficiency already exist. It could be the case that cells that are able to at least double current PV efficiency will be commercially available by the end of the 2020s or early 2030s.

It is possible that by the 2030s offshore wind power costs will be approximating that of onshore wind power. Given its potential, with, for example, offshore wind power in Western Europe having the highest potential of all renewable power sources, this could have a significant impact. However, there remain several constraints that need to be tackled and overcome, such as increased deployment costs, and durability due to climate and wave impacts, among others. Moreover, connections to the land-based grid are necessary and may require large investments and extended approval procedures.

In terms of renewables, the intermittent nature of the energies remains a challenge. As a consequence of this intermittency, the efficient and cheap storage of energy has become a key component of future renewable power generation. The development of a scalable, efficient and cheap storage technology has the potential to accelerate the penetration of renewable energy in power production.

Technology improvements also impact energy demand. In the road transportation sector, the requirement to provide internal combustion engines (ICEs) as clean as gasoline engines and as efficient as diesel engines has recently led to the development of de-throttled spark ignited (SI) engines by means of Exhaust Gas Recirculation (EGR). However, both wall heat and exhaust losses must still be reduced to a fraction of today's values if such ICEs are to have the potential to put pressure on BEVs and fuel cell vehicles (FCVs) for an extended time period. If they do, it could shift the common acceptance of these alternative vehicles further into the future.

The current standard technology for the electrification of road transportation is Li-Ion batteries. This is expected to continue to be the case for the foreseeable future. The increasing demand for powerful batteries, for both transport stationary applications, has caused the lithium price to rise significantly. It has led to R&D into other battery forms. The successful development of alternatives, mainly Al-Ion batteries that use aluminium, may change the outlook substantially. This is because aluminium is available in abundant quantities at a lesser cost than lithium. It is possible that the first commercial Al-Ion batteries will become available by the end of the 2020s or early 2030s.

It is also important to underscore the role of energy efficiency and technologies that could further reduce specific primary energy consumption per task. The use of IT may progress further with the increasing demand of intelligent solutions across all consumption sectors. Future intelligent grids may be able to co-ordinate many interacting participants, both on the producer and consumer side, and thus reduce energy usage. For example, transportation of all kinds could benefit from optimized cooperation of traffic participants.

Downstream challenges

Similar to the upstream, the crude oil price drop has led to the deferral of many downstream projects with the result that refining capacity additions in the period 2016–2018 are seen at low levels, which is then followed by a rebound in 2019–2021. Overall, the potential output from incremental capacity exceeds the incremental needed product by over 2 mb/d by 2021. Whether this overhang in fact materializes remains to be seen, but the consequences of such an overhang are likely to be a period of increased competition for product markets, reduced margins and increased pressure for refinery closures. The key question is whether, and to what degree, refiners will adapt their plans as the 2019–2021 period approaches.

Recent WOOs have pointed to the gasoline/diesel imbalances inherent in the demand projections and to the resulting stress on the refining system to increase distillate production relative to gasoline – with implications for the choice of upgrading and other investments. Those outlooks have also pointed to the fact that the very presence of high requirements for incremental distillate, relative to gasoline, would create significant premiums for distillate products. This could, in turn, cause the market to rebalance in favour of gasoline.

In 2016, however, emerging concerns over nitrogen oxide (NO_x) and other emissions from diesel vehicles in European capitals and the Volkswagen diesel emissions scandal are arguably softening growth projections for diesel. In parallel, the drop in oil prices has boosted gasoline demand, at least in the short-term. As a result, while this year's outlook sees gasoline plus naphtha demand growth to 2040 as relatively unchanged, at 6 mb/d, that for jet/kerosene plus gasoil/diesel is at 8.7 mb/d. This is well below last year's 10.4 mb/d growth for 2014–2040.

This swing back towards a closer balance between the two major light product groups is affecting the mix of fluid catalytic cracking (FCC) *versus* hydro-cracking investments. Recent additions have favoured the latter, putting in place significant additional capacity to produce distillate. Looking ahead, the proportions for new additions are more even. For refiners, this is a clear case of the demand mix 'shifting under their feet'. It has created uncertainty over the likely return on any investment geared specifically to either gasoline or distillate – and a need to be nimble in managing change.

A very specific and potentially critical instance of demand mix uncertainty lies in the International Maritime Organization (IMO) rule to implement a global fuel standard for marine fuel in either 2020 or 2025. This calls for the sulphur level on all marine fuel consumed outside ECAs to be at a 0.5% maximum, in place of today's 3.5%, or for equivalent SOx emissions reductions to be achieved via the use of on-board exhaust gas scrubbers, which enable shippers to stay with high (3.5%) sulphur fuel. (The limit for consumption within ECAs has been at 0.1% sulphur since 1 January 2015, but vessels are also permitted to install scrubbers as an alternative to burning 0.1% sulphur fuel.)

This situation leaves refiners uncertain as to when compliance will be achieved, and how, by low sulphur fuel or by scrubber use. In addition, there is also the question as to whether low sulphur fuel will be mainly marine distillate – as has been commonly assumed to date – or will include heavier fuels that meet the 0.5% sulphur standard. The issue with heavier low sulphur fuels is that vessel operators are concerned to ensure the fuels that they use do not create onboard operating issues. A number of problems have been experienced in the recent past with 1% sulphur residual-type emission control area (ECA) fuels. This experience could lead to 0.5% sulphur heavy fuels being adopted slowly, and only once on-board trials have demonstrated success.

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 still limited, and where refiners have no clear basis for investing potentially substantial sums to convert high sulphur intermediate fuel oil (IFO) to 0.5% marine distillate or IFO. Recent studies have concluded that scrubber penetration will remain limited by 2020. The industry is thus facing the prospect that substantial volumes – potentially of the order of 4 mb/d – of high sulphur IFO will need to be converted in 2020, or 2025, and that the refining sector would be challenged to respond.

A potential IMO decision in October 2016 should clarify the timing. A 2020 implementation date, in particular, would leave shippers and refiners with 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. This very prospect though presents a headache for refiners since wide distillate to high sulphur fuel differentials would very likely cause a rush to install onboard scrubbers. In turn, this would push demand for low sulphur marine fuel (potentially mainly distillate) towards high sulphur fuel (mainly heavy fuel) over a period of a few years. The result is that refiners remain reluctant to invest specifically to meet the needs of this rule. 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.

Added to these uncertainties over the transport fuel demand mix, the downstream is facing the challenge of coping with steadily slowing refined product demand growth. A first issue is that the total share of biofuels, GTLs, CTLs, natural gas liquids (NGLs) and other non-crudes continues to rise. In the Reference Case, 35% (5.8 mb/d) of the 16.4 mb/d global liquids demand increase between 2015 and 2040 will be met by growth in non-crudes and processing gains. This eats into the 'call on refining', steadily reducing the proportion of crude oil that needs to be refined per barrel of incremental product.

The progressive slowing of demand growth through the forecast period – from just over 1 mb/d per year from 2015–2020 to just over 0.6 mb/d per year from 2025–2030 and then to 0.3 mb/d per year from 2035–2040 – is another challenge for the downstream. This is further emphasized by subtracting the growth in non-crude supply and process gains, when the net demand growth for refined products actually becomes 0.75 mb/d from 2015–2020, 0.4 mb/d from 2025–2030 and less than 0.2 mb/d from 2035–2040. The only reason required refining capacity additions are shown at 0.4 mb/d for 2035–2040 (Table 5.6) is that while demand continues to decline in industrialized regions, new capacity is needed to meet demand growth in developing regions.

Globally, the refining sector will need to meet the challenge of remaining viable, while dealing with a rate of expansion that drops by more than a factor of three between today and the late 2030s. It is also worth noting that the Reference Case outlook itself, upon which these projections are based, contains appreciable uncertainties. As discussed extensively in Section 1, the pace of development of new transportation technologies is accelerating and there is the potential for action related to climate change. For refiners – and hence the related crude and product transport sector – these translate into yet more uncertainty on everything from product performance specifications to product mix to demand levels.

Moreover, refiners are not only facing a steady deceleration in total global demand, they are also facing a long-term shift in demand location – that is, a decline in industrialized regions offset by growth in the developing regions, led by the Asia-Pacific. Inevitably this is forcing refiners in the US & Canada, Europe, Japan and Australasia to either increase international product exports or cut (i.e. eventually close) throughputs, while refiners elsewhere in the Asia-Pacific, Middle East, Africa and Latin America are expected to continue to expand capacity. The former are expected to lose over 8 mb/d of demand between 2015 and 2040, while the latter to experience growth of over 24 mb/d. In line with this, demand shifts from the Atlantic to the Pacific Basin. An essentially 50:50 split in 2015 becomes a 40:60 split by 2040. Strikingly, this equates to a 2 mb/d demand loss in the Atlantic Basin and an 18.5 mb/d gain in the Pacific.

It is therefore not surprising that this outlook points to the need for continuing refinery closures. In the period 2012–2015, refiners in the US & Canada, Europe, Japan, Australia, Taiwan, as well as the Caribbean and Russia, closed 4 mb/d of capacity, and another 1 mb/d is slated to close in 2016. This equates to an annual rate of 1 mb/d over the last five years. Over the longer term, a lesser, but still appreciable, annual closure rate of around 0.4 mb/d is seen as needed if refining regions are to maintain viable utilizations. For 2016-2040, this leads to total required closures in the range of 8–10 mb/d. In other words, refinery closures will continue to be a feature of the sector, both in the short- and long-term.

One key challenge is going to be that some of these closures will be needed in developing, as well as developed regions. This, and the argument that progressively larger refineries are needed in order to minimize costs (recently new refineries have been built or are planned mainly at the 300,000–600,000 b/d scale), could be at odds with local aims to maintain domestic refined product supply and employment. If refiners and governments continue to operate inefficient ‘excess’ facilities, the industry may suffer as a whole.

This outlook also brings home how US tight oil, allied to the December 2015 lifting of the crude export ban, is adding new features, options and variability to international refining and crude trade. The exports of US light crudes and condensates enable increased imports of heavier, sour crudes through a form of swap trade. These new source of crudes are being tested by refiners in Latin America, Europe and Asia.

In parallel, major pipeline projects to export crude from Western Canada are all experiencing varying degrees of resistance, and even rejection in the case of Keystone XL. Nevertheless, on the basis that the two most probable projects go ahead (Trans Mountain Expansion and Energy East), additional volumes of mainly heavy western Canadian crudes will be able to flow both west to the Asia-Pacific and east to the Atlantic Basin. These pipelines, or equivalent via rail, logistics developments out of Canada, plus the new export situation in the US, should bring more than 2 mb/d of new supply streams onto international markets over the long-term.

The advent of US tight oil production has been seen by some to add a new element of ‘swing’ production to the market. The Reference Case itself embodies a short-term decline in US tight oil supply, as a result of the crude price drop, followed by a recovery and plateau driven by the projected recovery in crude prices that is an element of the Reference Case. Placed alongside a peak and then a decline in US & Canada product demand, and hence refinery runs, this has the effect of bringing a projected peak in crude imports into the region around 2020, followed by a steady decline. Based on this scenario, the outlook is for appreciable swings in crude trade, primarily impacting Latin America, Africa and the Middle East and associated peak-then-decline impacts on required tanker capacity. As they work their way through, these fluctuations will represent a challenge to both refiners and shippers.

The projected flat to declining demand in the Atlantic Basin, alongside substantial demand growth in the Pacific Basin, points to a potential long-term realignment of trade patterns. The global logistics and trading system needs to be able to route progressively increasing volumes of crude oil into the Asia-Pacific region. Potential Canadian logistics developments – if they are permitted – are one potential means to add around 0.5 mb/d of supply, or possibly as much as 1 mb/d that would have only a short marine transit to northeast Asia. The expansion of the ESPO pipeline, together with other lines from the Caspian, look set to bring some 2 mb/d of crude into the Asia-Pacific by 2020, and well over 3 mb/d by 2040. The main burden is projected to fall on Middle East exporters for whom crude oil volumes to the Asia-Pacific are expected to rise from somewhat over 14 mb/d in 2015, to just under 21 mb/d in 2040. In parallel, total product trade into the Asia-Pacific is indicated as rising by as much as 5 mb/d by 2040.

These and related trade developments will, in turn, impact the tonne-miles and the capacity demanded of the world's tanker fleet, the mix of vessels required and the associated loading/off-loading port and terminal capacities required. Given the shift in demand to the Asia-Pacific and the resulting tonne-miles, it is projected that capacity requirements will run ahead of the rate of global demand growth. Again this global pace masks trade declines into industrialized regions and growth into, and out of, developing regions. Just as the refining sector is faced with the challenges presented by the numerous expected supply and demand changes, the transport and logistics sector will need to adapt too.

In short, the factors discussed will continue to alter the shape of the downstream sector and its key elements – refining/processing activity, investment, trade and economics. The Reference Case provides a valuable and plausible 'central' outlook. However, the differences in the outlook from year-to-year bring home the message that the one constant is change. The key parameters of the downstream do not stand still. Consequently what actually happens five, 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 be ready to adapt to new developments as they occur.

Dialogue and cooperation

OPEC has long understood that dialogues between energy stakeholders are vital in order to discuss pertinent international energy issues like market stability, the fundamentals of supply and demand, economic prospects and environmental matters. However, in today's symbiotic world, more is needed in order to derive benefits for all entities in the energy industry. Proactive and effective dialogue is central to the functioning of the industry, while helping to maintain its delicate balance.

Taking this into account, OPEC's priority continues to be focused on the enhancement of current partnerships, as well as on the development of future opportunities for cooperation. The Organization regularly participates in international dialogue through several high-level gatherings, as well as more technical meetings. This past year has seen a plethora of events, with organizations such as the International Energy Agency (IEA), the International Energy Forum (IEF), the Joint Organisations Data Initiative (JODI) programme, the Vienna Energy Club and the G20. Dialogues were also held with the EU and Russia.

OPEC has helped to organize a number of events with the IEA and the IEF. The first this year was the 6th IEA-IEF-OPEC Symposium on Energy Outlooks, which was held at the IEF Secretariat in Riyadh in February 2016. The Symposium, which connected many experts from industry, government and academia, provided the setting for a lively exchange of views on energy market developments.

In March 2016, the OPEC Secretariat organized and hosted the 5th IEA-IEF-OPEC Workshop on the Interactions between Physical & Financial Energy Markets. As in the past, the workshop featured prominent experts who presented detailed information and shared views on the complex and evolving issues of physical and financial markets.

In September 2016, the 15th IEF Ministerial Forum, a biennial high-level event featuring high-level energy officials and experts, took place in Algiers under the theme 'Global Energy Transition: An Enhanced Role for Energy Dialogue'. This followed the 14th IEF Ministerial Forum, held in May 2014 in Moscow.

The 3rd IEA-IEF-OPEC Symposium on Gas and Coal Market Outlooks is due to take place in late-2016 in Paris. The objective of the Symposium is to foster dialogue on gas and coal market outlooks and enhanced market transparency, to take stock of current developments in gas and coal market competition, and to discuss other key topics including regulation and sustainability.

OPEC has also continued its active participation in the JODI programme. Examples of areas to which OPEC contributes are the JODI-Oil and JODI-Gas World Databases. The latest technical meeting was held July 2016 at the OPEC headquarters in Vienna.

OPEC also holds the coordinating role for the meeting of the Vienna Energy Club in late-2016. The gathering is an opportunity for Vienna-based international organization to share their views on energy issues.

As in past years, OPEC's active participation in the G20 has helped ensure broader and more inclusive outcomes on the energy initiatives being pursued, with impacts on the energy market, in general, and the oil market, in particular. Under China's Presidency of the G20 in 2016, the Energy Sustainability Working Group has focussed its activities on six work streams, namely: Energy Access; Clean Energy; Energy Efficiency; Market Transparency; Reform of Inefficient Fossil Fuel Subsidy; and Global Energy Interconnection.

OPEC's participation in bilateral talks with different countries and groups, be they producers or consumers, continues to expand. In December last year, after the publication of the WOO 2015, OPEC and India initiated their first Energy Dialogue. The 1st High-Level meeting took place with the Ministry of Petroleum and Natural Gas in New Delhi. The 2nd High-Level Meeting will take place in Vienna, including a technical meeting as part of the agenda.

The Organization has also been successful in sustaining the momentum of the energy dialogue with China, with the 2nd High-Level Meeting under preparation. This follows the 1st High-Level Meeting held in Vienna in September 2015 with China's National Energy Administration (NEA).

In July 2016, the Secretariat hosted the 2nd Technical Meeting on Asian Energy and Oil Outlooks in Vienna. The meeting offered a valuable chance to have a focused discussion on current Asian energy developments and prospects, including related policy issues. The contributions of senior experts from China, South Korea, Japan, India, the Asia Pacific Energy Research Center (APERC) and the Economic Research Institute for ASEAN and East Asia (ERIA), as well presentations from the OPEC Secretariat, enabled a valuable exchange of information and viewpoints.

OPEC also continues to promote its close links with the EU. Recent activities include the 12th EU-OPEC High-Level Meeting, which took place in Vienna in March 2016. Both parties emphasized that the Energy Dialogue, which was inaugurated in 2005, has come a long way since its establishment and is more important than ever in the current context of energy markets.

The 5th High-Level Meeting of the OPEC-Russia Energy Dialogue took place in Vienna in October 2016. Both sides exchanged views on global short-term oil market developments and long-term prospects, now regular features of the Dialogue. Formally established in 2005, the Dialogue provides a valuable occasion to share energy outlooks and specialized subjects of interests affecting oil and energy demand and supply.

International dialogue and cooperation is appreciated for its ensuing benefits to all parties involved, and for its contributions to achieving market stability. OPEC's involvement in these global meetings and events underscores the crucial fact that security of demand and security of supply are intertwined. The future of the energy industry is of the essence, especially amidst the various looming challenges and opportunities that await its stakeholders.

Footnotes

Section One

1. The previous policy relaxation concerned married couples where both partners had no siblings.
2. *World Population Prospects: Key findings & advance tables, 2015 Revision*, United Nations, Department of Economic and Social Affairs, Population Division, New York, New York, 2015. Available at: https://esa.un.org/unpd/wpp/publications/files/key_findings_wpp_2015.pdf
3. The Gini coefficient is used to measure the dispersion of GDP per capita across the 11 regions with the aim of analyzing income inequality across them. A Gini coefficient of zero expresses perfect equality, a situation in which all values are the same (for example, in which every region has the same income per capita), while a Gini coefficient of 1 represents maximal inequality.
4. Lakh is a unit in the Indian numbering system equal to 100,000.
5. "China coal consumption drops again", *The Guardian*, 29 February 2016. Available at: https://www.theguardian.com/environment/2016/feb/29/china-coal-consumption-drops-again.
6. "Global coal consumption fell in 2015; oil's market share rose to a 16-year high", Institute for Energy Research, 15 June 2016. Available at: http://instituteforenergyresearch.org/analysis/global-coal-consumption-fell-2015-oils-market-share-rose-16-year-high.
7. "New French energy policy to limit nuclear", *World Nuclear News*, 18 June 2014. Available at: http://www.world-nuclear-news.org/np-new-french-energy-policy-to-limit-nuclear-1806144.html.
8. *2016 Hydropower Status Report*, International Hydropower Association, London, UK, 2016. Available at: https://www.hydropower.org/2016-hydropower-status-report.
9. Ibid.
10. Schiffer, Dr. Hans-Wilhelm, "2050 by 2050: What are the energy scenarios?", PowerPoint presentation at the World Hydropower Congress in Beijing, 20 May 2015. Available at: https://hydropower.devcloud.acquia-sites.com/sites/default/files/publications-docs/Hans-Wilhelm-Schiffer-World-Energy-Council-2050-by-2050-World-Hydropower-Congress.pdf.
11. *Renewables 2016: Global Status Report*, Renewable Energy Policy Network for the 21st Century (REN21), Paris, France, 1 June 2016. Available at: http://www.ren21.net/wp-content/uploads/2016/06/GSR_2016_Full_Report_REN21.pdf.
12. "The Power to Change: solar and wind cost reduction potential to 2025", International Renewable Energy Agency (IRENA), Abu Dhabi, UAE, June 2016. Available at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf.

13. “2030 climate & energy framework”, European Commission, Brussels, Belgium, 22 September 2016 (last update). See: http://ec.europa.eu/clima/policies/strategies/2030/index_en.htm.
14. The Human Development Index (HDI) was developed by the United Nations Development Program (UNDP) to provide a summary measure of average achievements in key dimensions of human development (such as life expectancy, education and standard of living).
15. *World Development Indicators 2016*, World Bank, Washington, DC, 2016.
16. The extreme poverty line is set at $1.90 per day in 2011 PPP terms, which represents the mean of the poverty lines found in the poorest 15 countries ranked by per capita consumption.
17. *The State of Food Insecurity in the World 2015: Meeting the 2015 international hunger targets – taking stock of uneven progress*, Food and Agriculture Organization (FAO), Rome, Italy, 2015.
18. *Human Development Report 2015: Work for Human Development*, United Nations Development Programme (UNDP), New York, New York, 2015.
19. “A growing number of children and adolescents are out of school as aid fails to meet the mark”, Policy Paper 22 / Fact Sheet 31, Institute for Statistics / Education for All Global Monitoring Report, United Nations Educational, Scientific and Cultural Organization (UNESCO), Paris, France, July 2015.
20. UNDP, op. cit.
21. Threshold levels of electric power consumption of 250 kWh per year for a rural household of five persons, and 500 kWh per year for an urban household of five, are often used in the literature.
22. “Africa far from sustainable energy for all, but showing signs of progress”, World Bank, Washington, DC, 17 February 2016. Available at: http://www.worldbank.org/en/news/feature/2016/02/17/africa-far-from-sustainable-energy-for-all-but-showing-signs-of-progress. Accessed on 3 July 2016.
23. *The 2030 Development Agenda: Energy access a keystone*, Pamphlet Series Issue 40, OPEC Fund for International Development (OFID), Vienna, Austria, 2016.
24. The term MSEs refers to entities that largely rely on family members with limited use of non-household members.
25. Reeg, Caroline, *Micro and small enterprises as drivers for job creation and decent work*, Discussion Paper 10/2015, German Development Institute, Bonn, Germany, 2015. Available at: https://www.die-gdi.de/uploads/media/DP_10.2015.pdf.
26. Hogarth, R. and Granoff, I., *Speaking Truth to Power: Why energy distribution, more than generation, is Africa’s poverty reduction challenge*, Working Paper 418, Overseas Development Institute, London, UK, 2015.
27. “Waste and Spoilage in the Food Chain”, Decision Intelligence Document, Rockefeller Foundation, New York, NY, May 2013.

28. *The State of Food and Agriculture: Innovation in family farming.* Food and Agriculture Organization (FAO), Rome, Italy, 2014.
29. A literature review is provided in: Scott, A., Darko, E., Lemma, A. and Rud, J.P., "How does electricity insecurity affect businesses in low and middle income countries?", Briefing 1, Overseas Development Institute, London, UK, 2014.
30. Ibid.
31. *Mini-grid Policy Toolkit: Policy and business frameworks for successful mini-grid roll-outs*, EU Energy Initiative Partnership Dialogue Facility (EUEI PDF), Eschborn, Germany, 2014.
32. Gabon, which was included in the Middle East & Africa last year, is also included in OPEC this year. However, given that oil demand in Gabon is relatively minor, it does not materially impact this figure.
33. According to OPEC's *Annual Statistical Bulletin 2015*.
34. CNH was established in November 2008 as a regulatory agency that possesses technical autonomy to oversee and evaluate all hydrocarbon exploration, development and production activities in Mexico.
35. The improved fiscal terms managed to produce a balanced outcome combining a reasonable sum of royalties, while still maintaining profitability. However, caution should be stressed, especially when low oil prices are paired with low initial profit share, as royalties may hinder companies' abilities to recoup their costs.
36. Butler, R.M., "SAGD Comes of AGE", *Journal of Canadian Petroleum Technology*, July 1988, Vol. 37, No.7, pp. 9–12.
37. Meyer, R.F. and Attanasi, E.D., "Heavy Oil and Natural Bitumen – Strategic Petroleum Resources", United States Geological Survey Fact Sheet 70–03, 2003.
38. Meyer, R.F., Attanasi, E.D. and Freeman, P.A., "Heavy Oil and Natural Bitumen Resources in Geological Basins of the World", United States Geological Survey Open File Report 2007–1084, 2007.
39. *Market Snapshot: Oil Sands Production to Increase, but Effects of Low Oil Prices are Evident*, National Energy Board of Canada, Calgary, Alberta, Canada, December 2015.
40. *Heavy Barrel Competition in the US Gulf Coast: Can Canadian Barrels Compete?*, Study No. 157, Canadian Energy Research Institute, Calgary, Alberta, Canada, May 2016.
41. Findlay, J.P., "The Future of the Canadian Oil Sands: Growth Potential of a Unique Resource Amidst Regulation, Egress, Cost, and Price Uncertainty", OIES Paper WPM 64, Oxford Institute for Energy Studies, Oxford, UK, February 2016.

Section Two

1. The World Oil Refining Logistics and Demand (WORLD) model is supplied by EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys.
2. In the US, roughly 10% of the refineries operating in 2000 have closed. In Canada, the percentage is higher.
3. Around 150,000 b/d of polymerization capacity also exists worldwide, mainly in US & Canada and Europe. While there have been some new technologies emerging (for example, DIPE units), much of the capacity comprises older 'legacy' units.
4. To meet the 'ultimate' ultra-low sulphur standards of 10–30 ppm, essentially all blendstocks produced from crude oil have to be desulphurized even if the crude oil itself is 'low sulphur'.
5. '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 year's 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 2016 through 2021. Some sources refer to much higher levels of capacity creep, but these stem from a rather variable definition of 'capacity creep', which sometimes includes not only larger projects but every expansion that is not a new refinery. The conservative estimate of 'capacity creep' applied here is tightly linked to the very detailed list of projects that was used for capacity assessment. In other words, what other sources typically consider to be within the category of capacity creep (that is, 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, in order to cover minor expansions that are 'under the radar' of the detailed projects lists. As a result of adding in the effect of capacity creep, crude distillation capacity is projected to increase by approximately 8.2 mb/d by 2021 from the base level at the end of 2015.
6. A 90% level is considered the maximum sustainable utilization rate over the longer period for a region.
7. This outlook is especially sensitive to the progress of the large Dangote project.
8. Candidates for closure were picked from the refinery database, based on a risking assessment. 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 or not a refinery had been reported as under consideration for sale or closure was also an important factor.

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9. In June 2015, the US EPA announced it was working with the International Civil Aviation Organization, a body of the United Nations, to develop GHG emissions standards for civil aviation aircraft. In August 2016, the EPA and the Department of Transportation's National Highway Traffic Safety Administration jointly announced finalized standards for heavy- and medium-duty vehicles. The standards call for a 25% reduction in heavy-duty vehicle carbon emissions, somewhat less for medium-duty vehicles. Currently, the heavy-duty truck sector has high growth, vehicles average around six miles per US gallon and contribute around 20% of total transport sector GHG emissions despite comprising only 5% of total vehicles.
10. The decline in Other Asia-Pacific after 2020 reflects appreciable run reductions in Japan & Australasia, partially offsetting gains elsewhere in the region.
11. According to EIA data, the number of operable refineries in the US has more than halved from 301 in 1982 to 141 in 2016 while capacity has slightly increased. Initial capacity of 17.9 mb/d in 1982 dipped to 15.5 mb/d around 1990 and has since gradually grown, reaching 18.3 mb/d in 2016.
12. The International Maritime Organization could rule on the timing of this at a meeting of its Marine Environmental Protection Committee in October 2016.
13. "Assessment of Fuel Oil Availability – Final Report", CE Delft, Delft, Netherlands, July 2016, and "Supplemental Marine Fuel Availability Study – Final Report", EnSys Energy in conjunction with Navigistics Consulting, 15 July 2016.
14. The stated gasoline desulphurization additions exclude those for naphtha desulphurization, which is mainly associated with a front-end step in catalytic reforming. Naphtha desulphurization capacity additions were included in Table 6.1.
15. MTBE has been the cause of wide ranging ground-water contamination in the US and a raft of related lawsuits. By way of comparison, authorities in Europe examined the risks of using MTBE in gasoline and concluded these were manageable, apparently because of the existence of extremely tight storage controls and monitoring. With gasoline octanes needing to be raised, there is discussion in a number of regions regarding increasing MTBE use since it is a high octane component that also 'dilutes' adverse gasoline properties including sulphur, benzene and total aromatics. MTBE is an allowed gasoline component under the Euro 5/6 regulations. Thus, since most countries are implementing regulations based on the Euro standards, this in itself would appear to allow for a role for MTBE. Certainly, the 0.6 mb/d of MTBE modelling additions is consistent with the appreciable growth in the compound's use.
16. CONCAWE stands for CONservation of Clean Air and Water in Europe, which was established in 1963 to carry out research on environmental issues relevant to the oil industry.

17. The (R+M)/2 octane rating refers to taking the average of two octane tests, Research (RON) and Motor (MON). These generally yield results where the Research octane is 10 octane numbers above the Motor octane – hence, the typical situation where (R+M)/2 octane is five numbers below Research octane. The (R+M)/2 measure is also at times referred to as 'Anti-Knock Index' or AKI.
18. Speth, Raymond L. et al, "Economic and Environmental Benefits of Higher-Octane Gasoline", *Environmental Science & Technology*, 2014, 48 (12), pp. 6561–6568.
19. The impact of higher levels of bio components in transport fuels is seen in the context of Direction 98/70/EC of the European Parliament and the European Council dated 13 October 1998, which relates to the quality of petrol and diesel fuels and amends Council Directive 93/12/EEC.
20. It should be mentioned that this cost has been estimated on the assumption that all investments related to a specific project are only considered at the time of 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.
21. The seven regions that are the basis of the crude and product trade reporting are: US & Canada, Latin America, Africa, Europe, Russia & Caspian, Middle East and Asia-Pacific.
22. For example, crude oil trade reported at the 23-region level for a 2015 WORLD model case, run in association with this Outlook, showed inter-regional trade volume at close to the 43 mb/d. The 23-region level translates to around 36 mb/d when trade reporting is converted to the seven-region basis.
23. The crude trade volumes referenced here reflect total crude oil trade, which comprises conventional and non-conventional crude oils and condensates. Product trade volumes include finished products, intermediates and non-crude supply streams. Together, the latter equate to total non-crude 'liquids' trade.
24. Since non-US refiners outside Canada have had essentially no experience with processing US crude oils, there is inevitably a period of purchasing test cargoes before it is possible for more sustained trade patterns to emerge. Nonetheless, the movements of generally light and super-light US crudes to Latin America are logical in that these streams can be blended with the region's heavy crudes to enable more light products to be produced in regional refineries. For Europe, US light sweet crudes are a good fit to replace declining North Sea production. The expansion of the Panama Canal, now in effect, is likely to make exports of US crudes and condensates to Asia more attractive.
25. Marine distances from British Columbia to Japan, northern China and elsewhere in north-eastern Asia are short.

26. Under the regional definitions in the WORLD model, Europe includes Ukraine, Moldova and the Baltic states. Therefore, reported flows into Europe include crude oil imports into these states.

Section Three

1. Article 2 of the Paris Agreement.
2. The EU submitted one INDC representing its 28 Member Countries.
3. Developed from *The Emissions Gap Report 2015: A UNEP Synthesis Report*, United Nations Environment Programme (UNEP), 2015. Available at: http://uneplive.unep.org/media/docs/theme/13/EGR_2015_301115_lores.pdf.
4. Details on INDCs for all Parties are available at: http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx
5. Calculated using the EIA's historical data in 2012 on primary energy used, GHG emissions and GDP. (GDP is expressed in market exchange rates.) Available at: http://www.eia.gov/forecasts/ieo/ieo_tables.cfm.
6. For example, the study on *Energy efficiency and energy saving potential in i ndustry from possible policy mechanisms* (prepared by ICF Consulting Limited, London, UK, and dated 1 December 2015) concluded that the technical potential for energy reduction in the EU's industry sector is in the range of 20%, while economic potential is in the range of 8–10%. See: https://ec.europa.eu/energy/sites/ener/files/documents/151201%20DG%20ENER%20Industrial%20EE%20study%20-%20final%20report_clean_stc.pdf. Several other studies indicate similar, sometimes higher, potential.
7. The calculation of total energy demand and its composition (energy mix) primarily considers the 'origin of energy'. Therefore, specific fuels are associated with their source of energy – that is, biofuels are part of biomass, CTLs are part of coal and GTLs are part of gas. However, on a volume basis – and in line with industry standards – oil demand and supply expressed in barrels includes all these fuels. Therefore, figures presented in barrels are higher than the ones in barrels of oil equivalent (although, taking into account the differing definitions and varying conversion factors, they are in fact consistent).
8. Apart from the *UNFCCC's Synthesis report on the aggregate effect of the intended nationally determined contributions*, dated 30 October 2015, the European Commission, the World Resources Institute, UNEP and other institutions are among those who have assessed the impact of INDCs on global emissions.
9. *Aggregate effect of the intended nationally determined contributions: an update*, FCCC/CP/2016/2, UNFCCC Secretariat, Bonn, Germany, 2 May 2016. Available at: http://unfccc.int/resource/docs/2016/cop22/eng/02.pdf.
10. *The Emissions Gap Report 2015: A UNEP Synthesis Report*, United Nations Environment Programme (UNEP), 2015.
11. 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

12. "IPCC, 2013: Summary for Policymakers", in: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)], Cambridge University Press, Cambridge, UK and New York, New York, US.
13. See for example, the UNFCCC's *Synthesis report on the aggregate effect of the intended nationally determined contributions*, FCCC/CP/2015/7, October 2015.
14. van Breevoort, P. et al, *The Coal Gap: Planned coal-fired power plants inconsistent with 2°C and threaten achievements of INDCs,* Climate Action Tracker Update, 2015.
15. These are: Bahrain, Canada, China, Egypt, Iran, Malawi, Norway, Saudi Arabia, South Africa and the UAE.
16. *The Global Status of CCS 2015, Summary Report*, Global CCS Institute, Docklands, Australia, 2015.
17. Ibid.

FT

Annex A
Abbreviations

AAA	American Automobile Association
AAR	Association of American Railroads
AC	Air conditioning
ADP	Ad Hoc Working Group on the Durban Platform for Enhanced Action
Amegas	Mexican Association of Gasoline Entrepreneurs
APA	Ad Hoc Working Group on the Paris Agreement
APERC	Asia Pacific Energy Research Center
API	American Petroleum Institute
ASCI	Argus Sour Crude Index
b/d	Barrels per day
bcm/y	Billion cubic metres per year
BEV	Battery electric vehicles
boe	Barrels of oil equivalent
BSP-1	Baltic Pipeline System
bt	Billion tonnes
CAAM	Chinese Association of Automobile Manufacturers
CAFC	Corporate Average Fuel Consumption
CAFE	Corporate Average Fuel Economy
CAPEX	Capital expenditure
CARB	California Air Resources Board
CCPP	Combined Cycle Power Plants
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CDM	Clean Development Mechanism
CEF	Connecting Europe Facility
CEN	European Committee of Standards
CMA	Meeting of the Parties to the Paris Agreement
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
COP	Conference of the Parties
COMPERJ	Rio de Janeiro Petrochemical Complex
CPC	Chinese Petroleum Corporation
CPC	Communist Party of China
CPPCC	Chinese People's Political Consultative Conference

CTLs	Coal-to-liquids
CSP	Concentrated solar power
CTO	Coal-to-olefins
dm	Decimetre
DME	Dubai Mercantile Exchange
dwt	Dead weight ton
E&P	Exploration and production
EC	European Commission
ECA	Emission Control Area
EGR	Exhaust Gas Recirculation
EIA	Energy Information Administration (US)
EOR	Enhanced oil recovery
EITI	Extractive Industries Transparency Initiative
EPA	Environmental Protection Agency (US)
ERIA	Economic Research Institute for ASEAN and East Asia
ESPO	Eastern Siberia-Pacific Ocean
ETBE	Ethyl tertiary butyl ether
EU	European Union
EU ETS	EU Emissions Trading System
FAME India	Faster Adoption and Manufacturing of Hybrid & Electric Vehicles in India
FCC	Fluid catalytic cracking
FCEV	Fuel cell electric vehicles
FCV	Fuel cell vehicles
FDI	Foreign direct investment
FEED	Front end engineering and design
FYP	Five-Year-Plan
G20	Group of 20
GDP	Gross Domestic Product
GHG	Greenhouse gas
GNI	Gross National Income
GTLs	Gas-to-liquids
Gt	Gigatonne
GW	Gigawatt

H_2O	Water
H_2S	Hydrogen sulphide
HC	Hydrocarbons
HDI	Human Development Index
HEV	Hybrid electric vehicle
IATA	International Air Transport Association
ICAO	International Civil Aviation Organization
ICE	Internal combustion engine
IEA	International Energy Agency
IEF	International Energy Forum
IFO	Intermediate fuel oil
IMO	International Maritime Organization
INDC	Intended Nationally Determined Contribution
IOC	Indian Oil Corporation
IOCL	India Oil Company Ltd.
IPCC	Intergovernmental Panel on Climate Change
JIS	Japanese Industrial Standards
JODI	Joint Organisations Data Initiative
km	Kilometre or kilometres
kWh	Kilowatt hours
LCCs	Low Cost Carriers
LLS	Light Louisiana Sweet
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LULUCF	Land Use and Land Use Change and Forestry
MARPOL	International Convention for the Prevention of Pollution from Ships
mb/d	Million barrels per day
mboe	Million barrels of oil equivalent
METI	Ministry of Economy, Trade and Industry (Japan)
MIT	Massachusetts Institute of Technology
MMT	Methylcyclopentadienyl manganese tricarbonyl

MOMR	Monthly Oil Market Report (OPEC)
MON	Motor octane number
MSEs	Micro-and-small enterprises
mt	Million tonnes
MTBE	Methyl tertiary butyl ether
MTO	Methanol-to-olefins
MTOMR	Medium-Term Oil Market Report (IEA)
MW	Megawatts
N_2	Nitrogen
NBS	National Bureau of Statistics of China
NEA	National Energy Administration
NEB	National Energy Board (Canada)
NEMMP	National Electric Mobility Mission Plan 2020
NEV	New Energy Vehicle
NGLs	Natural gas liquids
NGV	Natural gas vehicle
NOCs	National Oil Companies
NO_x	Nitrogen oxides
NPC	National People's Congress (China)
NTP	National Transformation Plan
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)
ORTM	OPEC Road Transportation Model
OSPF	Official Selling Price Formulae
OWEM	OPEC World Energy Model
p.a.	Per annum
PCIs	Projects of Common Interest
PDVSA	Petróleos de Venezuela S.A.
PEMEX	Petróleos Mexicanos

PHEV	Plug-in hybrid electric vehicles
pkm	Passenger kilometre
ppm	Parts per million
PPP	Purchasing power parity
PV	Photovoltaic
R&D	Research & Development
RAPID	Refinery and Petrochemical Integrated Development
RFCC	Resid fluid catalytic cracking
RFS	Renewable Fuel Standard
RON	Research Octane Number
RPK	Revenue Passenger Kilometre
SAGD	Steam assisted gravity drainage
SCF	Standard cubic feet
SDGs	Sustainable Development Goals
SFC	Specific fuel consumption
SI	Spark ignited
Sinopec	China Petrochemical Corporation
SOCAR	State Oil Company of Azerbaijan
SO_x	Sulphur oxides
SPIMEX	St. Petersburg International Mercantile Exchange
SPR	Strategic Petroleum Reserves
SUV	Sport utility vehicle
TAN	Total acid number
TEU	Twenty foot equivalent unit
tkm	Tonne kilometre
UAE	United Arab Emirates
UK	United Kingdom
ULCCs	Ultra-large crude carriers
ULS	Ultra-low sulphur
UN	United Nations
UNDP	UN Development Programme
UNFCCC	UN Framework Convention on Climate Change
URR	Ultimately recoverable resources
USGS	US Geological Survey

VGO	Vacuum gasoil
VLCCs	Very large crude carriers
VMT	Vehicle miles travelled
WCSB	Western Canadian Sedimentary Basin
WHR	Waste heat recovery
WLTP	World-Harmonized Light Duty Vehicle Test Procedure
WOO	World Oil Outlook (OPEC)
WORLD	World Oil Refining Logistics Demand Model
WS	Worldscale
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
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
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
Gabon
Indonesia
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

A

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

American Chemical Society (ACS)

American Petroleum Institute (API)

Argus

Asia-Pacific Economic Cooperation (APEC)

Association of American Railroads (AAR)

Baker Hughes

Bank of International Settlements

Barclays Research

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)

China National Petroleum Corporation (CNPC)

Citigroup

Climate Action Tracker

Consensus forecasts

Deloitte

Deutsche Bank

Deutsches Institut für Wirtschaftsforschung eV

Dubai Mercantile Exchange

East-West Center (EWC)

The Economist

Economist Intelligence Unit online database

Elsevier

Energy Research Institute of the Russian Academy of Sciences (ERI RAS)

Energy Intelligence Group

EnSys Energy & Systems, Inc

Ernst & Young

European Automotive Manufacturers Association (ACEA)

European Commission (EC)

European Council

European Environment Agency

Eurostat

Evaluate Energy

Financial Times

Gas Infrastructure Europe (GIE)

Gazprom

Geothermal Energy Association

Global Carbon Capture and Storage Institute (GCCSI)

Global Commission on the Economy and Climate

Global Wind Energy Council

Goldman Sachs

Haver Analytics

HSBC

International Commodities Exchange

IEA Monthly Oil Data Service (MODS)

IEA World Energy Outlook

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

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

International Atomic Energy Agency (IAEA)

International Civil Aviation Organization (ICAO)

International Council on Clean Transportation (ICCT)

International Gas Union

International Group of Liquefied Natural Gas Importers

International Maritime Organization (IMO)

International Monetary Fund (IMF)

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 (METI)

Japan Automobile Manufacturers Association, Inc (JAMA)

Joint Aviation Authority (JAA)

Joint Organisations Data Initiative (JODI)

Kennedy School of Government, Harvard University

National Association of Motor Vehicle Manufacturers of Brazil (ANFAVEA)

National Development and Reform Commission (NDRC)

National Economic Research Associates, Economic Consulting

National Energy Administration of the People's Republic of China (NEA)

Navigant Research

Nexant

NGV Global

Norway, Ministry of Finance

Norway, Ministry of Petroleum and Energy

New York Mercantile Exchange

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

OPEC Annual Statistical Bulletin (ASB)

OPEC Fund for International Development

OPEC Monthly Oil Market Report (MOMR)

OPEC World Oil Outlook (WOO)

Overseas Development Institute (ODI)

Oxford Institute for Energy Studies

Petrobras

Petroleum Economist

PFC Energy

Platts

Port of Fujairah

Port of Rotterdam

PricewaterhouseCoopers

REN21 – Global Status Report 2016

Reuters

Rockefeller Foundation

Rystad Energy

Seatrade

Siemens AG

Singapore, Maritime and Port Authority (MPA)

Society of Petroleum Engineers (SPE)

Standard Chartered

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 Educational, Scientific and Cultural Organization (UNESCO)

UN Environment Programme (UNEP)

UN Framework Convention on Climate Change (UNFCCC)

UN International Labour Organisation (ILO)

UN Statistical Yearbook

UN World Tourism Organization (UNWTO)

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 (WHO)

World LPG Gas Association

Wood Mackenzie

World Nuclear Association

World Resources Institute

World Trade Organization (WTO), International Trade Statistics

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