2018

World Oil Outlook 2040

Organization of the Petroleum Exporting Countries

World Oil Outlook

2040

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Contents

List of boxes

List of tables

List of figures

Foreword

Cooperation is one of the cornerstones of OPEC's activities and, in this regard, the period since the publication of the **World Oil Outlook (WOO) 2017** has been a historic one for the Organization, as well as the global oil industry.

We have witnessed the ongoing commitment of 24 OPEC and non-OPEC producing countries (now 25, since the Republic of the Congo joined OPEC in June 2018) through the landmark **'Declaration of Cooperation'** to restore sustainable stability to the industry. The cooperative efforts have helped accelerate the return of balance to the global oil market, bring greater optimism to the industry, with investments now gradually picking up, as this year's publication highlights, and have had a positive effect on the global economy and trade worldwide.

The impact of the cooperation has exceeded even the most optimistic of projections. We have not only turned a page, but a new, exciting chapter is being authored in the history of the industry by OPEC and its non-OPEC partners. It is clear that the **'Declaration'** has now become a permanent feature of the global energy scene, establishing a novel framework for producing countries, whilst also taking into account the vital interests of consumer countries, as well as the global economy.

These endeavours were further reinforced at the **7th OPEC International Seminar** in **June 2018**, under the central theme: **'Petroleum – cooperation for a sustainable future'**, which brought together a 'who's who' of global oil and energy industry leaders. Held at the Hofburg Palace in Vienna the record-breaking Seminar showcased the importance of dialogue and stability to tackle the plethora of challenges facing the industry.

This year's WOO will be launched in Algiers, the capital of OPEC Member Country, Algeria, and a place many see as the birthplace of the **'Declaration of Cooperation'**. It was here on 28 September 2016, at the **170th (Extraordinary) Meeting of the OPEC Conference**, that OPEC Member Countries set forth on the path that eventually led to the **'Declaration of Cooperation'** on **10 December 2016**. It is fitting that Algiers plays host to the unveiling of the WOO 2018, as part of the celebrations to mark the second anniversary of the seminal Algiers meeting.

The importance of these recent developments, specifically in terms of helping achieve sustainable market stability, is clearly vital across all timeframes. While the focus for many is obviously on the short-term, we need to recall that the short- , medium- and long-terms are all interlinked. We cannot view any of them in isolation. Stability today begets stability tomorrow, which is vital given that our industry remains a growth business, with oil continuing to be a fuel of choice for the foreseeable future.

The **WOO 2018** analyzes the industry's various linkages, its shifting dynamics and considers developments in areas such as the **global economy**, **energy demand**, **oil supply** and **demand**, both in the **upstream** and **downstream**, **policy** and **technology** developments, and **environment** and **sustainable development** concerns. This all helps provide the framework for the WOO's Reference Case, including breakdowns by region, sector and timeframe.

With regard to the global economy, on the back of strong growth in emerging and developing economies the size of the global economy in **2040** is estimated to be more than double that of **2017**, with **China** and **India** seeing their overall weight in the global economy increase significantly.

With an expanding global population and the crucial need to reduce energy poverty, with almost **one billion people** still **without access to electricity** and **three billion lacking access to clean fuels** and efficient technologies for cooking, energy demand is anticipated to increase by around **33%** between **2015** and **2040**. There will be a variety of abundant energy resources to meet this demand growth.

Renewables are expected to see the largest annual average growth rate, although they start from a low initial base. It should be noted that many OPEC Member Countries are making significant investments in renewables, given their vast solar and wind resources.

Oil is presumed to remain the fuel with the largest share in the energy mix over the forecast period, led by demand from transportation and petrochemicals. Combined, **oil and gas** are still expected to make up more than **50%** of the global energy mix by **2040**.

Long-term oil demand is expected to increase by **14.5 mb/d** to reach **111.7 mb/d** by **2040**. This is slightly higher than last year's number, in spite of overall demand growth generally slowing over the projection period.

For supply, total non-OPEC liquid supply is projected to expand significantly, with the majority of the growth over the next decade coming from US tight oil. Global tight oil supply is projected to expand to **16 mb/d** by the **late 2020s**, making up almost 25% of non-OPEC supply by then.

The upshot is that the long-term focus for additional liquids remains on OPEC. In terms of crude, it is estimated that demand for OPEC crude rises by **7.3 mb/d** over the forecast period, and for all liquids the figure is **10.5 mb/d**. The share of OPEC crude in the global oil supply is expected to increase from **34% in 2017 to 36% by 2040**.

From the downstream perspective, around **18 mb/d** of capacity additions are estimated for the period **2018–2040**. Following trends in regional oil demand, the majority of the new additions are set to be located in the developing regions, predominantly in the Asia-Pacific and Middle East. Regions such as Africa and Latin America are also expected to see significant long-term downstream capacity additions.

At the same time, fast evolving trade patterns for crude oil and refined products will continue to change. Global crude exports are forecast to increase by around **5.5 mb/d** in the long-term, with the major contribution from the Middle East to the Asia-Pacific.

Given the demand and supply outlook, there is evidently the need for significant investments across the entire industry. Overall, the outlook sees oil investment requirements of almost **$11 trillion** over the period to **2040**. While investments picked up slightly in 2017 compared to the previous two years, and the expectations are for higher levels again in 2018, it is vital that as an industry we ensure there is timely and adequate investment so as not to lead to a supply shortage in the future.

Let me reiterate that OPEC Member Countries remain fully committed to investments across the whole value industry chain, and the issue of returning global investments is a core focus of the **'Declaration of Cooperation'**.

The **WOO 2018** also explores a number of sensitivity cases that could potentially impact the long-term energy mix, and the oil supply and demand outlook. These include the potential for higher energy demand in Africa, the possibility of faster and slower penetration of electric vehicles, the prospects for higher and lower tight oil growth, and the possibility for faster energy efficiency improvements and a quicker expansion in renewables.

Evidently one of the greatest challenges facing the industry, and humankind, going forward is climate change. OPEC remains fully engaged and supportive of the Paris Agreement. We firmly believe that a global consensus from the multilateral process remains the best and most inclusive way for all nations to collectively mitigate or adapt to the impacts of climate change based on the core principle of 'common but differentiated responsibilities' in a fair and equitable manner.

In this regard, OPEC is cognizant of the dual challenge of meeting growing demand for oil while constantly improving its environmental footprint. It is vital that we collectively develop and adopt technologies, as well as all-inclusive energy policies, that transform the environmental credentials of all energies. As this Outlook underlines, all forms of energy will be required in the future. It is not about choosing one form of energy over another.

As with all previous editions, the WOO is the product of cooperation between the various departments of the OPEC Secretariat and our Member Countries. The commitment and dedication of everyone involved in terms of the data, research, comprehensive analysis and design and editing of the publication should be highly commended. Their work is also an expression of the broader, ongoing commitment of the Organization to further discussions on energy outlooks, such as with the International Energy Agency (IEA) the International Energy Forum (IEF) and the Gas Exporting Countries Forum (GECF), and to widen our engagement with other energy stakeholders.

It was the legendary astronaut, Neil Armstrong, who once said: **"Research is creating new knowledge"**. This is the objective of the WOO; we see it as a valuable and informative reference tool that enables the Organization to share its views and analysis of the global oil and energy markets. This can then be leveraged to stimulate debate and foster knowledge-sharing, to drive further research in the years to come.

Mohammad Sanusi Barkindo
Secretary General

Executive Summary

Decelerating growth and ageing population mark future demographic change

Population growth, the size of the working-age population, urbanization levels and immigration play an important role in shaping the future energy and oil market. Global population is expected to increase from around 7.6 billion in 2017 to 9.2 billion in 2040. The majority of this growth will come from Developing countries, particularly from Africa, India and the Middle East. In the Organization for Economic Co-operation and Development (OECD) region, population is estimated to grow by 105 million in the period to 2040. It is important to note, however, that overall population growth will decelerate over the forecast period.

While the working-age population (age 15–64) is estimated to grow by around one billion people over the long-term, its relative share of the global population is expected to decline from 66% in 2016 to 63% in 2040.

Population by region *millions*

	2017	2020	2030	2040	Change 2017–2040
OECD	1,297	1,317	1,368	1,402	105
Developing countries	5,911	6,134	6,839	7,467	1,556
Eurasia	343	344	345	341	–2
World	**7,550**	**7,795**	**8,551**	**9,210**	**1,660**

Global GDP growth between 2017 and 2040 is expected to average 3.4% p.a., driven primarily by Developing countries

Global economic growth will mainly be driven by Developing countries while the OECD region is expected to see weaker growth on the back of a marginally declining working age population and a slow rise in labour productivity.

Global gross domestic product (GDP) between 2017 and 2040 is expected to increase at an average annual rate of 3.4%. This is slightly lower than the WOO 2017 assumption, mainly due to the expectation of less dynamic long-term labour market developments. Most of the growth until the end of the forecast period will be determined by labour productivity. Developing countries are expected to grow, on average, by 4.5% per annum (p.a.) over the forecast period, while growth in the OECD region averages 1.8% p.a.

Long-term annual GDP growth rates *% p.a.*

	2017–2023	2023–2030	2030–2040	2017–2040
OECD	2.0	1.8	1.7	1.8
Developing countries	5.0	4.6	4.0	4.5
Eurasia	2.3	2.4	2.3	2.3
World	**3.6**	**3.4**	**3.2**	**3.4**

Major regional shifts in the future economic picture are expected

The size of the global economy in 2040 is estimated to be more than double that of 2017. There will be major regional shifts in the economic picture over the forecast period. In 2017, OECD America accounted for 20% of global GDP, followed by OECD Europe and China both at 18%. Other Asia accounted for a further 10% while India had a share of 8%. During the forecast period, China's weight in the global economy is projected to increase by around six percentage points to reach 24%, while the weight of OECD America is estimated to drop to 15% and that of OECD Europe to 12%.

Energy policies, combined with the cost competitiveness of natural gas, put the coal industry under increasing pressure

Many countries, including ten[1] OPEC Member Countries, have ratified the Paris Agreement. In efforts to achieve climate objectives, the coal industry is under the most regulatory scrutiny. Consequently, the power industry is undergoing a paradigm shift; shutting inefficient plants and replacing them with modern technologies – or shifting toward other power sources altogether. The cost competitiveness of natural gas and renewables (particularly wind and solar), combined with supportive policies, have captured commercial interest across the globe. This shift is particularly evident in China, which has set a path toward achieving a future of 'blue skies'.

Road transportation sector under increasing regulatory scrutiny, with the establishment of more stringent emissions targets across various regions

In the road transportation sector, fuel quality and vehicle emissions standards continue to evolve in major consuming regions. Although the US is relaxing Corporate Average Fuel Economy (CAFE) standards, the European Union (EU), China, and India are continuing to increase fuel economy and vehicle emissions standards. Meanwhile, reflecting the fiscal realities of incentives programs, policies regarding electric vehicle across major consuming regions are undergoing a re-evaluation, as policymakers attempt to strike a balance between government support and the competitiveness of electric vehicles.

Energy policies support technology advancement, leading to efficiency improvements and emission reductions

Policymakers in energy consuming and producing countries employ various policy measures in order to simultaneously meet and balance their individual national priorities. These priorities include enhancing energy security, energy efficiency, economic development, alleviating energy poverty, and adhering to environmental objectives as embodied within global pacts such as the 'Paris Agreement'.

Evolutionary path of technology advancement broadens future energy panorama

Technological advancements will continue to evolve, in general, and provide a broader future energy panorama. The concerns around global warming have accelerated the development of energy paths toward lower emissions. The ongoing, and at least already partially successful, introduction of electric vehicles as a complement to the internal combustion engine (ICE) is an important development for the energy market, although in many aspects ICEs still have substantial potential for further developments. Tight oil plays are also an area of intense technology developments. Impressive advances have also been achieved in wind and solar for power generation. The ongoing revolution in information technologies (IT) will impact both supply and demand, towards higher efficiency, lower emissions and lower costs.

Total primary energy demand is expected to increase by 91 mboe/d between 2015 and 2040 to reach 365 mboe/d in 2040

The Reference Case sees energy demand increasing from 274 million barrels of oil equivalent a day (mboe/d) in 2015 to around 365 mboe/d in 2040, with an average annual growth of 1.2% p.a. Almost 95% of the increase is accounted for by Developing countries (including China and India), with an average annual growth of 1.9% p.a.

Total primary energy demand by region

	Levels (mboe/d)				Growth (% p.a.)
	2015	2020	2030	2040	2015–2040
OECD	108.8	113.1	112.1	109.6	0.0
Developing countries	142.6	160.3	197.3	228.2	1.9
Eurasia	22.3	23.7	25.4	26.9	0.7
World	**273.7**	**297.1**	**334.9**	**364.7**	**1.2**

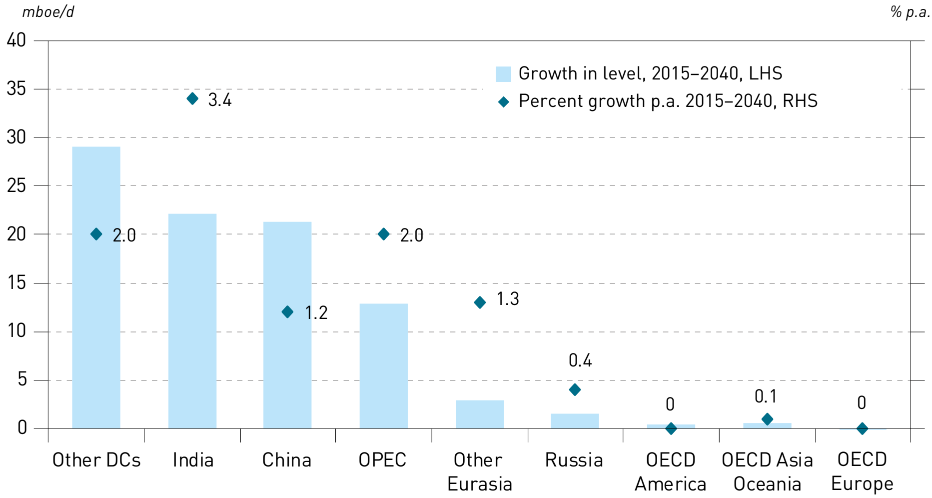
A modest increase of around 4.5 mboe/d is projected for Eurasia between 2015 and 2040, an average annual growth of 0.7% p.a. The OECD is estimated to witness only a small increase of less than 1 mboe/d, which points to stagnating energy demand in this country group as the market increasingly saturates. The imbalance between the world regions is the result of stronger population and economic growth, as well as accelerating urbanization rates in Developing countries, where an increasing number of people are expected to gain access to modern energy services.

Primary energy demand in China and India is the most significant contributor to overall energy demand growth

Energy demand in Developing countries is projected to increase by almost 86 mboe/d between 2015 and 2040, with India and China the most important contributors to this growth. Energy demand in India and China in this period is forecast to increase by 22 mboe/d and 21 mboe/d, respectively, which is more than 50% of the energy demand growth in Developing countries during this period.

At the same time, the group of Other Developing countries (excluding India, China and OPEC) is projected to grow by around 2% p.a., increasing by around 29 mboe/d over the forecast period. This includes countries at different stages of development, predominantly in Asia, Africa and Latin America. Significant growth is also expected in OPEC countries, increasing from 20 mboe/d in 2015 to almost 33 mboe/d in 2040. This comprises an annual average growth rate of around 2%.

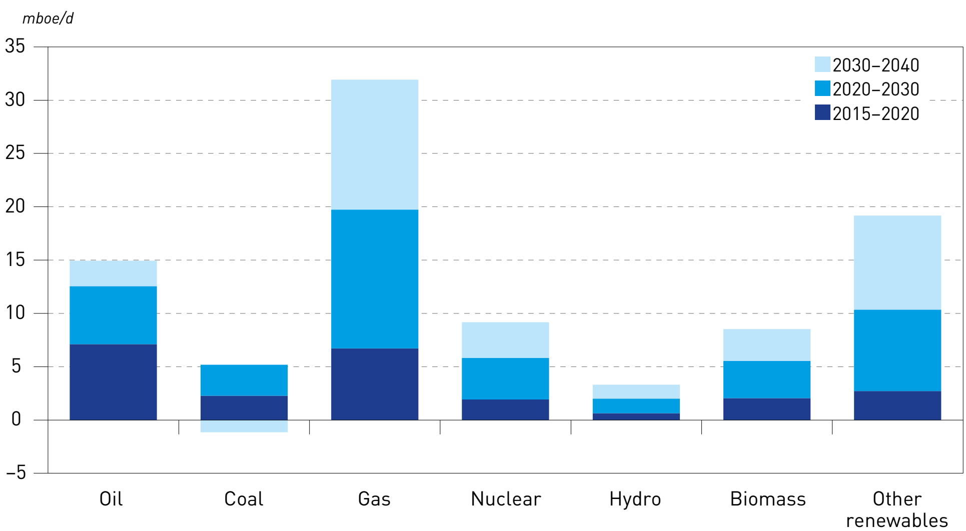
Growth in primary energy demand by region, 2015–2040



Natural gas and 'other renewables' show the largest growth in the long-term

The fuel with the largest estimated demand growth is natural gas, increasing by almost 32 mboe/d between 2015 and 2040, an annual average growth rate of 1.7%. Consequently, the share of natural gas in the global energy mix accounts for 25% in 2040, up 3.3 percentage points from 2015. 'Other renewables' are projected to have the highest average growth rate of around 7.4% p.a. during the forecast period. Nevertheless, due to the current low base, the increase in absolute terms is estimated at around 19 mboe/d between 2015 and 2040.

Growth in primary energy demand by fuel type, 2015–2040



Strong demand growth is also expected for nuclear, increasing by around 9 mboe/d, due to strong expansion in Developing countries and supported by the anticipated return of nuclear energy in Japan. The utilization of biomass (including solid biofuels, waste, biogas, liquid biofuels) is projected to increase by 8.5 mboe/d between 2015 and 2040. Coal has the lowest average growth of just 0.2% p.a. Moreover, coal is the only fuel projected to reach a global demand peak during the forecast period, hitting a high of around 82 mboe/d by 2030. Oil sees a relatively low average growth rate of 0.6% between 2015 and 2040. However, due to a large base, oil demand is expected to increase by almost 15 mboe/d to just above 101 mboe/d in 2040.

Oil retains the highest share in the global energy mix in the period to 2040

Oil is forecast to remain the largest contributor to the energy mix throughout the forecast period, with a share of nearly 28% in 2040, higher than gas and coal. Despite relatively low demand growth rates (especially for coal and oil), fossil fuels are projected to remain the dominant component in the global energy mix, with a share of 75% in 2040, albeit a drop of 6 percentage points from 2015.

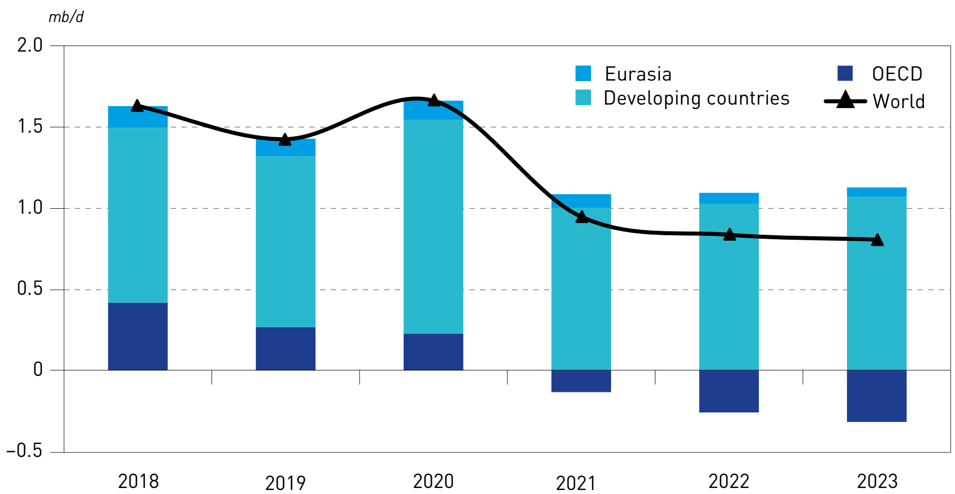
Coal will continue to be the largest source of CO_2 emissions

Total annual energy-related carbon dioxide (CO_2) emissions are set to increase from around 33 billion tonnes (bt) in 2015 to around 39 bt by 2040. Despite the low growth in global coal demand and its expected peak towards the end of the forecast period, coal is still forecast to be the largest source of CO_2 emissions, accounting for 15.7 bt of emissions in 2040. However, the largest increase in emissions, on an annual basis, is expected for natural gas (+3.3 bt) as demand for this energy source is set to increase significantly over the forecast period.

Medium-term oil demand growth to average 1.2 mb/d p.a.

Oil demand at the global level is expected to continue growing at healthy rates over the medium-term to reach a level of 104.5 million barrels a day (mb/d) by 2023. This is 7.3 mb/d higher than 2017 levels and represents an average annual increase of 1.2 mb/d.

Annual oil demand increments by region, 2018–2023



These solid global growth numbers, however, mask significant variations, as well as diverging trends, at the regional, sectoral and product levels. Oil demand from Developing countries is projected to grow at a relatively steady rate of around 1.1 mb/d each year over the medium-term, except for 2020, when the implementation of International Maritime Organization (IMO) regulations on lower sulphur limits in the marine bunker sector will likely provide a one-off spur for oil demand. Incremental oil demand in the OECD is projected to flip from the positive territory observed in the past few years, and which is projected to continue until 2020, to negative growth thereafter. The contribution of Eurasia to overall demand growth is marginal, in the range of just 0.1 mb/d p.a. on average.

Implementation of IMO regulations will challenge refiners and likely impact global demand levels

The implementation of the IMO regulations to limit the global sulphur content in all bunker fuels to 0.5%, effective January 2020, will not only pose a challenge to the refining industry, but it will also likely affect overall demand levels, especially in the one-to-two years following its implementation. Oil demand is expected to decelerate from 1.6 mb/d in 2018 to 1.4 mb/d in 2019. However, instead of a continued growth deceleration in 2020, incremental oil demand in this year is expected to bounce back to 1.7 mb/d, driven by specific market circumstances as a result of the IMO regulations. Nevertheless, this extraordinary growth in 2020 will largely be balanced out by lower incremental growth during the latter part of the medium-term period.

Oil demand projected to increase by 14.5 mb/d to reach 111.7 mb/d by 2040, but growth decelerates over time

Long-term oil demand is expected to increase by 14.5 mb/d, rising from 97.2 mb/d in 2017 to 111.7 mb/d in 2040. However, the Reference Case projections to 2040 show a contrasting picture between the three major regions: declining long-term demand in the OECD, a moderately rising to flattening oil demand pattern in Eurasia, which both stand in stark contrast to growing demand in Developing countries.

Driven by an expanding middle class, high population growth rates and stronger economic growth potential, oil demand in Developing countries is expected to increase by more than 22 mb/d between 2017 and 2040, rising from 44.4 mb/d in 2017 to 66.6 mb/d in 2040.

Long-term oil demand *mb/d*

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD	47.3	48.3	46.8	44.2	41.5	38.7	–8.7
Developing countries	44.4	47.9	53.1	58.1	62.6	66.6	22.2
Eurasia	5.4	5.8	6.1	6.3	6.4	6.4	1.0
World	**97.2**	**101.9**	**106.0**	**108.6**	**110.5**	**111.7**	**14.5**

Another important observation is the steadily decelerating oil demand growth at the global level. Global growth is forecast to slow from a level of 1.6 mb/d p.a. during the initial forecast years to 2020 to just 0.2 mb/d p.a. in the period from 2035–2040.

India is projected to see the largest additional oil demand and the fastest growth in the period to 2040

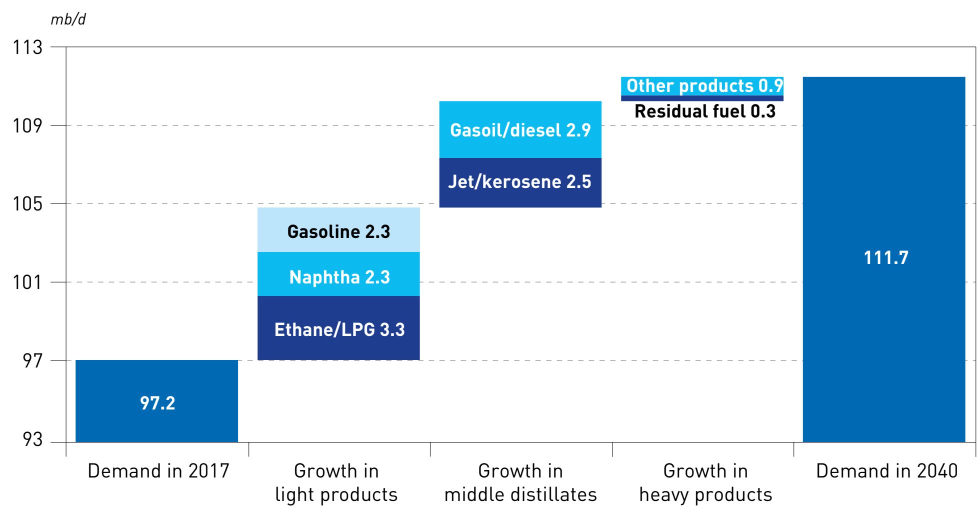
In terms of incremental demand over the forecast period, India is projected to have the fastest average demand growth (3.7% p.a.), as well as the largest additional demand of 5.8 mb/d. With this fast demand growth, India will likely pass the mark of 10 mb/d sometime towards the end of the forecast period. Despite this impressive growth, its total demand will still be far below the level of China.

Light products will continue to dominate the future product slate, with ethane/LPG leading the way

Compared to last year's Outlook, the faster expansion of the petrochemicals sector, the anticipated quicker penetration of electric vehicles and less long-term diesel consumption in the marine sector has further shifted the projected composition of oil demand. More than half of the incremental oil demand over the forecast period is expected to be satisfied by light products, which account for 7.8 mb/d out of a total demand growth of 14.5 mb/d.

Within the light products, demand for ethane/LPG is set to increase by 3.3 mb/d. It should be noted that this is the largest increase amongst all major products. The demand for middle distillates is expected to increase by 5.5 mb/d, which will be almost equally shared between gasoil/diesel and jet/kerosene. A growth of 1.2 mb/d is projected for heavy products.

Demand growth by product category in the long-term, 2017–2040

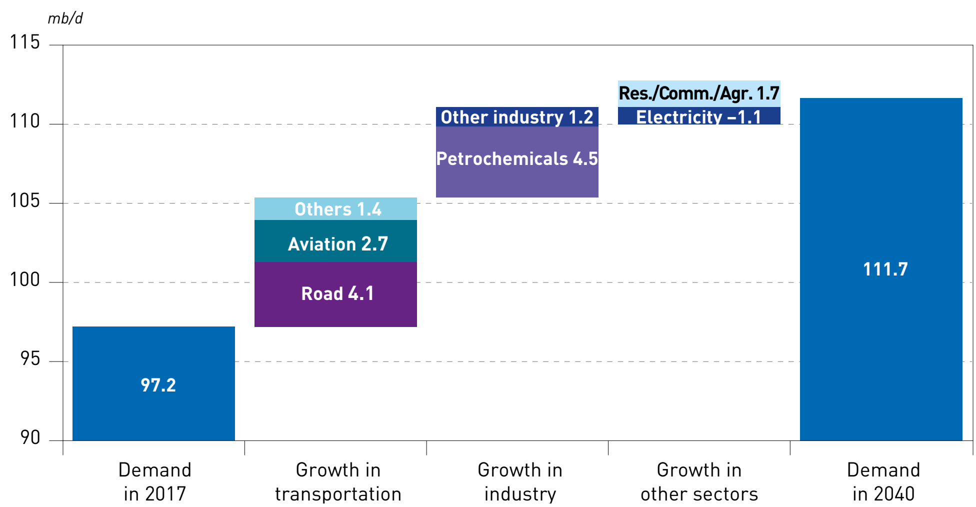


Road transportation continues to lead demand, but petrochemicals see the largest increase and aviation is the fastest growing sector

Among all transport modes, the largest demand for oil comes from road transportation. In 2017, this sector represented 45% of global demand with 43.6 mb/d and significant demand growth is expected in the long-term to reach 47.8 mb/d by 2040. This is followed by aviation, which is estimated to be the fastest growing sector, with average oil demand growth at 1.5% p.a.

Demand growth in industry is driven mainly by the petrochemical sector, with demand forecast to increase by 4.5 mb/d from 2017–2040. Oil demand in the rest of industry – comprising primarily iron and steel, glass and cement production, construction and mining – is anticipated to continue to face strong competition from alternative fuels. Global demand in 'other industry' is expected to increase by 1.2 mb/d between 2017 and 2040, representing an average growth rate of 0.4% p.a. Electricity generation is the only sector where declining demand is forecast at a global level.

Sectoral oil demand growth, 2017–2040



Total vehicle fleet is estimated to reach 2.4 billion by 2040

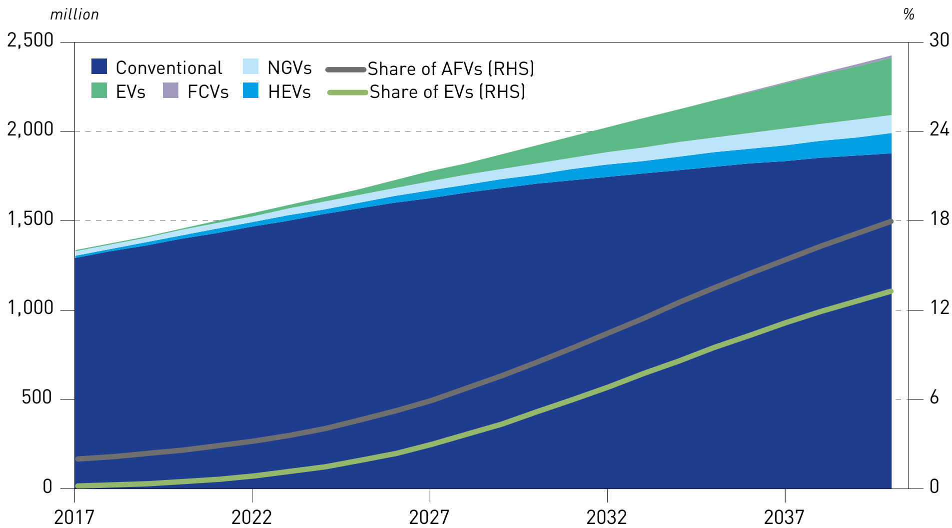
The increase in vehicle stock is the key driver contributing to the rise in oil consumption in the road transportation sector. The total vehicle stock is estimated to grow by around 1.1 billion between 2017 and 2040 to reach 2.4 billion vehicles. Out of this, passenger cars are estimated to grow by around 877 million, with 768 million cars in Developing countries. China is set for the highest increase in additional passenger cars over the forecast period, at 291 million, followed by Other Asia with an increase of around 167 million cars. The passenger car fleet in the OECD is foreseen to increase marginally.

The total commercial stock is forecast to more than double during the period 2017–2040, rising from 230 million vehicles in 2017 to 462 million by 2040. The majority of the increase comes from Developing countries, particularly from China, Other Asia, and India. The total amount of additional commercial vehicles in Developing countries is estimated to be around 183 million, which represents almost 80% of the total growth.

Share of electric vehicles in the total fleet is projected at around 13% by 2040

Electric vehicles, including battery electric and plug-in hybrid electric vehicles (PHEVs), are set to experience a significant growth in numbers and are forecast to reach around 320 million units in 2040. Out of this, passenger electric vehicles are estimated to account for more than 300 million in 2040, representing around 15% of the passenger fleet. Natural gas passenger cars are not expected to witness the same growth as electric vehicles, as there are only expected to be 77 million additional units on the road in 2040. An even slower expansion is projected for fuel cell vehicles (FCVs), which are forecast to remain a niche market over the forecast period.

Global road vehicle fleet composition, 2017–2040



Out of an expected 442 million commercial vehicles by 2040, a large majority of around 370 million will remain conventional. Natural gas vehicles (NGVs) are forecast to account for 6% of the commercial fleet by 2040. Electric vehicles are forecast to gradually increase their share and reach a high of 4% of commercial vehicles in 2040. Combined, the share of electric vehicles in the total fleet is projected at around 13%, while the penetration of alternative fuel vehicles (AFVs, including electric vehicles) is expected to reach around 18% by 2040.

Road transportation oil demand is sensitive to the expansion of electric vehicles

To account for uncertainty related to future penetration levels of electric vehicles, two alternative sensitivities have been developed: 'Electric vehicles fast penetration' and 'Electric vehicles slow penetration'. The implication of these sensitivity cases is fairly limited over the next ten years, within the range of 1 mb/d, but start widening during the last decade of the forecast period. The range of uncertainty is more than 4 mb/d by 2040.

Strong resurgence improves outlook for medium-term US tight oil growth

Medium-term non-OPEC supply is projected to grow by 8.6 mb/d from 2017–2023, an upward revision from the WOO 2017. This is due to US tight oil's stronger-than-expected recent performance, a healthier demand outlook, and more supportive prices. Total non-OPEC liquids supply is expected to rise from 57.5 mb/d in 2017 to 66.1 mb/d in 2023, of which 5.6 mb/d or 65% is in the US. In addition to the US, only a handful of other countries are forecast to drive non-OPEC medium-term supply growth, including Brazil (+1.4 mb/d), Canada (+0.8 mb/d) and Kazakhstan (+0.3 mb/d).

Non-OPEC supply peaks in late 2020s, mainly driven by the US tight oil outlook

Non-OPEC liquids supply is projected to peak at just below 67 mb/d in the late 2020s, as US tight oil supply peaks. Thereafter, it declines slowly to average 62.6 mb/d by 2040, with modest growth in Kazakhstan, Canada and Brazil insufficient to offset natural decline in most other parts of the non-OPEC supply picture. However, over the full 2017–2040 period, non-OPEC crude oil supply, including tight crude, is estimated to decrease by 1.1 mb/d, while natural gas liquids (NGLs), global biofuels and other liquids (including Canadian oil sands) each grow in a range of 1 to 3 mb/d.

Long-term liquids supply outlook

mb/d

	2017	2018	2019	2020	2023	2025	2030	2035	2040
US	14.4	16.1	17.4	18.4	20.0	20.2	19.6	18.2	16.9
of which: tight liquids	*7.4*	*9.1*	*10.4*	*11.5*	*13.4*	*13.9*	*13.9*	13.0	12.1
OECD	**25.7**	**27.6**	**29.1**	**30.2**	**32.3**	**32.6**	**32.1**	**30.5**	**29.0**
DCs, excl. OPEC	**15.5**	**15.6**	**16.1**	**16.3**	**16.9**	**17.0**	**16.9**	**16.5**	**15.7**
Eurasia	**14.2**	**14.2**	**14.3**	**14.3**	**14.4**	**14.6**	**14.7**	**14.8**	**14.9**
Processing gains	**2.2**	**2.2**	**2.2**	**2.4**	**2.5**	**2.5**	**2.7**	**2.8**	**3.0**
Total non-OPEC supply	**57.5**	**59.6**	**61.7**	**63.1**	**66.1**	**66.7**	**66.3**	**64.6**	**62.6**
Crude	*41.8*	*43.1*	*44.5*	*45.3*	*47.4*	*47.3*	*45.9*	43.5	40.7
NGLs	*8.0*	*8.6*	*9.0*	*9.2*	*9.7*	*9.9*	*10.2*	10.1	10.1
Global biofuels	*2.2*	*2.3*	*2.4*	*2.4*	*2.6*	*2.7*	*3.0*	3.3	3.6
Other liquids	*5.4*	*5.6*	*5.8*	*6.1*	*6.5*	*6.7*	*7.2*	7.7	8.2
Total OPEC supply	**38.9**	**38.8**	**39.0**	**39.3**	**38.6**	**39.5**	**42.5**	**46.0**	**49.3**
OPEC NGLs	6.0	6.1	6.2	6.3	6.6	6.9	7.6	8.3	8.9
*OPEC Other liquids**	0.2	0.3	0.3	0.3	0.4	0.5	0.5	0.5	0.5
Demand for OPEC crude	*32.6*	*32.5*	*32.6*	*32.7*	*31.6*	*32.1*	*34.4*	37.3	39.9
Stock change**	**–0.8**	**–0.4**	**0.5**	**0.5**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
World	**96.4**	**98.4**	**100.8**	**102.4**	**104.7**	**106.2**	**108.8**	**110.7**	**111.9**

* *This item includes other non-crude streams, such as GTL, methyl tetra-butyl ether (MTBE) and biofuels.*

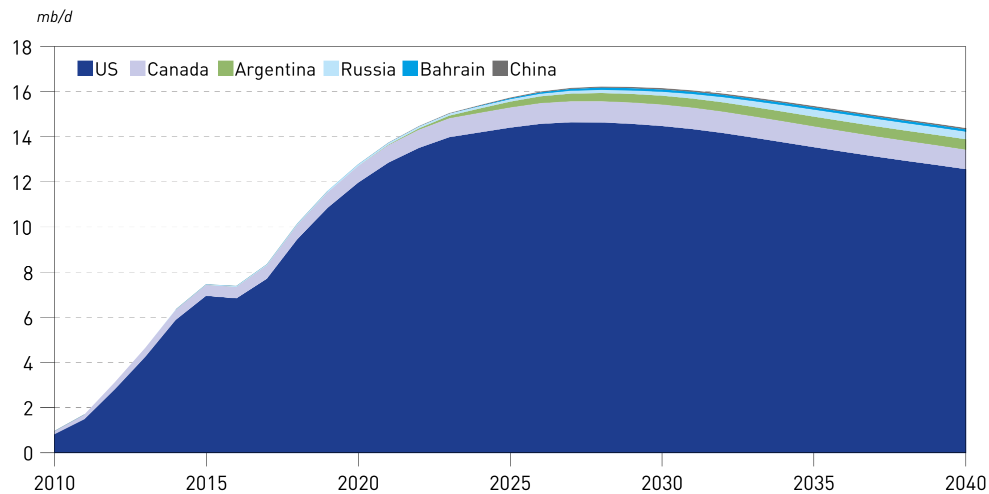
** *Stock change assumptions reflect commercial stock inventories, development of Strategic Petroleum Reserves (SPR), and the rising need for stocks as refinery capacity expands.*

Global tight oil to see a quarter share of non-OPEC supply at its peak

Global tight oil supply is set to grow to 15.6 mb/d by the late 2020s, thus making up nearly 25% of non-OPEC supply at its peak, or 15% of global supply. The overwhelming majority of this will be US tight oil, which is expected to constitute around 90% of global tight oil supply. Canada, already a significant producer of tight oil, is anticipated to contribute nearly 1 mb/d, while more modest volumes are envisaged to emerge in Russia, Argentina, Bahrain and China.

However, there is considerable uncertainty related to the outlook for US tight oil supply, which is dependent on prices, investment, technology, regulation and the resource base. Alternate sensitivity cases for tight oil suggest an upside/downside of around 1–2 mb/d in the late 2020s, and an even higher range of around +/– 3–4 mb/d in the long-term.

Global tight oil supply outlook

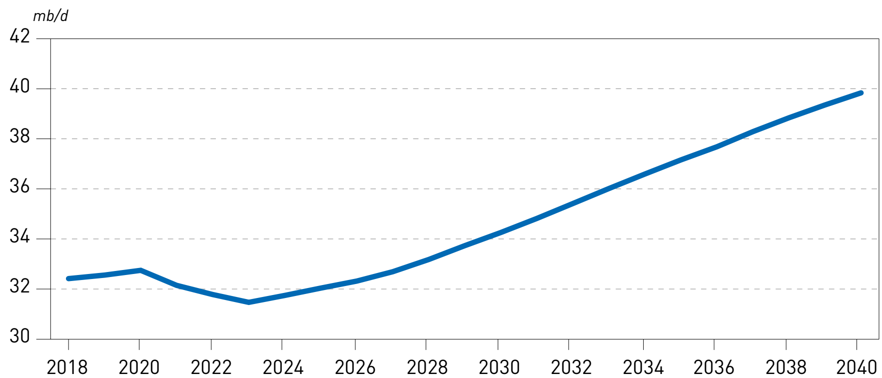


Demand for OPEC crude to decline in the medium-term, but recovers after US tight oil peaks

Given strong US and other non-OPEC medium-term supply growth, the implied demand for OPEC crude is estimated to decline from 32.6 mb/d in 2017 to 31.6 mb/d in 2023. However, it rises again to current levels in the latter half of the 2020s, when US tight oil, and as a result, total non-OPEC supply peaks.

Thereafter, a gradual decline in non-OPEC liquids supply, coupled with moderate, but sustained global demand growth, leads to a steady increase in demand for OPEC crude, which rises to nearly 40 mb/d by 2040.

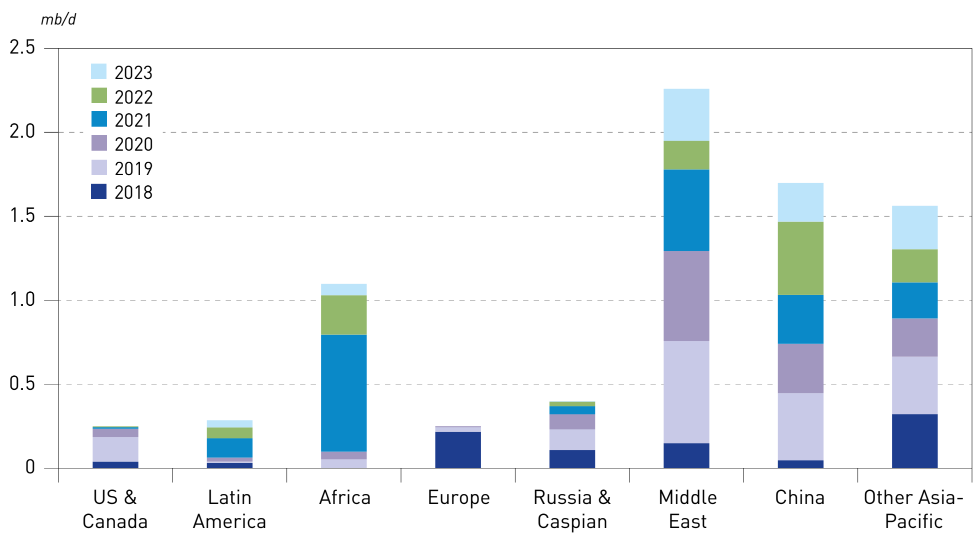
Demand for OPEC crude



Medium-term distillation capacity additions estimated at 7.8 mb/d, located mostly in the Middle East and Asia-Pacific

The pace and location of refinery investments continue to follow oil demand growth trends, with the majority of investments expected in developing countries underpinned by local demand. The level of medium-term additions and investments are expected to recover from the effects of the 2014–2016 crude oil price drop. From levels of no more than 1 mb/d annually for 2016 through 2018, additions for 2019 through 2021 are projected to average 1.6 mb/d p.a., before reverting to levels of 1 mb/d in 2022 and 2023. Over the medium-term period, total additions are projected at 7.8 mb/d.

Distillation capacity additions from existing projects, 2018–2023



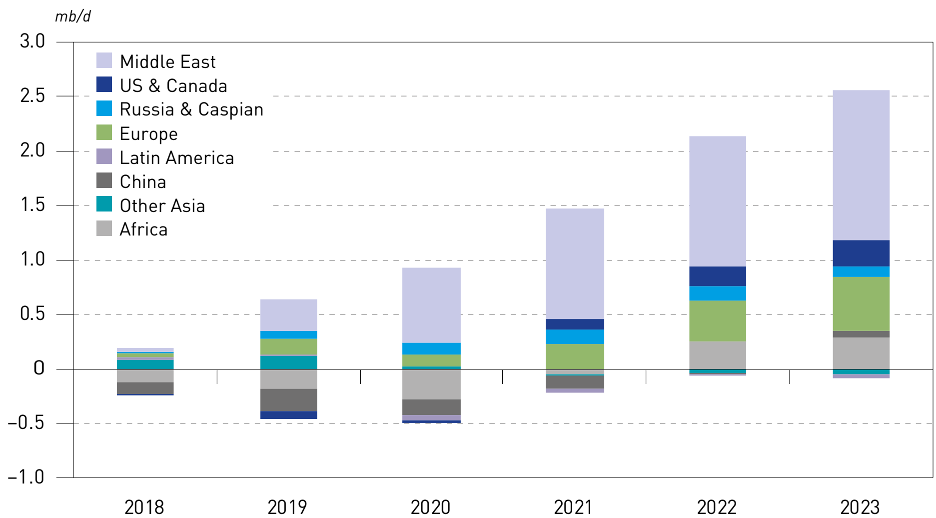
These additions will continue to show a pattern seen in previous Outlooks, with most concentrated in developing regions, predominantly the Asia-Pacific and the Middle East. Indeed, the trend will remain in line with the concentration of demand growth. Around 88% of the distillation capacity projects assessed as viable for the period 2018–2023 will be located in developing regions.

Medium-term outlook points at excess refining capacity towards the end of the period

Global demand growth from 2018–2023 is projected to average 1.2 mb/d p.a., whereas the requirement for incremental crude-based products, and hence crude runs, equates to 0.8 mb/d p.a. The net result is for an outlook where incremental refinery output potential and incremental refinery product demand are closely in balance through 2019, but a gap progressively opens up, especially from 2021 onward. By 2023, the cumulative 7.4 mb/d refinery production potential is 2.5 mb/d in excess of the requirement.

The largest excess builds are expected in the US & Canada and Europe, due to decreasing demand post-2020, and the Middle East, due to strong medium-term capacity additions. At the same time, some deficits are projected for Latin America and Asia-Pacific (excluding China) in 2023.

Net cumulative regional refining potential surplus/deficits versus requirements



Long-term distillation capacity additions projected at around 17.8 mb/d

Cumulative crude distillation capacity additions are projected to reach 17.8 mb/d by 2040, primarily in Developing countries (Asia-Pacific, Middle East, Africa and Latin America). It is important to recognize that the long-term additions are driven mainly by the shift in global demand from industrialized regions to developing regions. Therefore, declining oil demand in some regions, such as Europe and Japan, is projected to result in utilization rates coming under pressure. Consequently, a number of closures in these regions can be expected in the medium- and long-term.

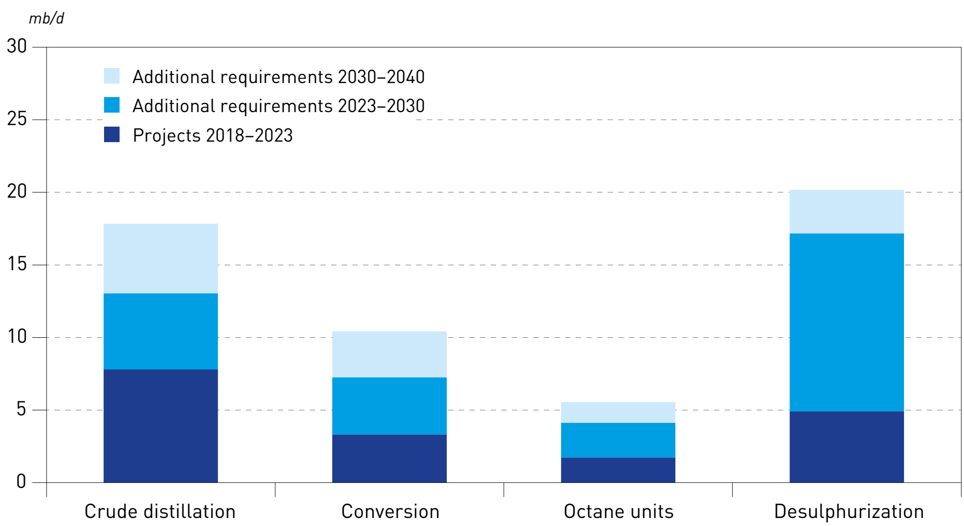
Refinery net closures estimated at around 1 mb/d in the medium-term

Total net closures of 1.0 mb/d are expected in the medium-term, slightly lower than in previous Outlooks. Several regions, including Europe and Japan, have gone a long way toward removing the worst regional capacity excesses. At the same time, upward medium-term demand revisions have led to fewer refinery closure announcements. The clear impact of these higher short- and medium-term demand outlooks is to diminish the need for refinery closures, relative to previous WOOs.

Secondary capacity additions rise in step with increasing demand and stricter product specifications

At the global level, projections for secondary capacity additions indicate the need to add some 10.4 mb/d of conversion units, 20.2 mb/d of desulphurization capacity and 5.5 mb/d of octane units in the period to 2040. The majority of these additions are expected to materialize before 2030, in line with demand growth and the implementation of stricter product specifications.

Global refining capacity requirements by process type, 2018–2040



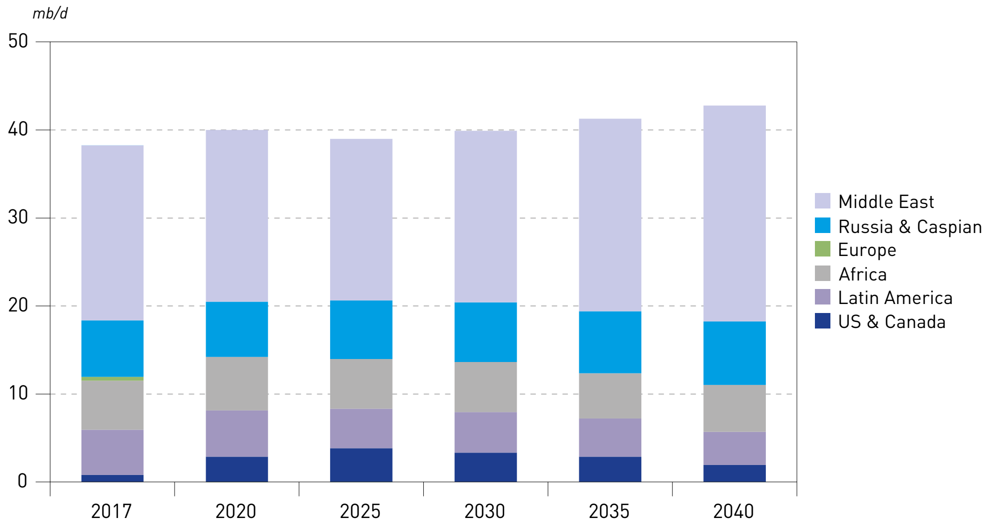
Global crude exports increase in the long-term, due to additional volumes from the Middle East destined for the Asia-Pacific

Global crude exports are expected to increase by around 5.4 mb/d, mostly driven by increasing demand and falling domestic supply in the Asia-Pacific. In the short-term, global crude exports are likely to increase to around 40 mb/d in 2020, up from 38.5 mb/d in 2017, driven by increasing export volumes from the US & Canada, which are estimated to grow by more than

2 mb/d between 2017 and 2020. By 2025, the global crude export level is projected to drop to around 39 mb/d, mainly due to lower volumes coming from Latin America and Africa, as more volumes are refined in these regions. At the same time, US & Canada crude exports are expected to peak at just under 4 mb/d in 2025.

Post-2025, global crude exports are expected to increase gradually to levels just below 43 mb/d, driven by increasing demand from the Asia-Pacific and increasing exports from the Middle East. Middle East crude exports are seen to increase by more than 6 mb/d between 2025 and 2040.

Global crude oil exports by origin, 2017–2040



Another region contributing to the increase of global crude exports is Russia & Caspian, with volumes estimated to rise to above 7 mb/d, mainly due to output increases in Kazakhstan. Traditional exporting regions, such as Latin America and Africa, are expected to see lower crude exports to global markets, as increasing domestic demand results in additional refinery runs in those regions.

Almost $11 trillion of investments in the oil industry are required up to 2040

Global oil upstream investments required over the period 2018–2040 are estimated at $8.3 trillion. Most of this is in non-OPEC countries, and over the medium-term they are estimated to invest on average around $350 billion p.a. The medium-term number for OPEC Member Countries is an estimated average of more than $40 billion p.a., and then over $60 billion annually in the long-term. Average annual long-term upstream investment requirements for non-OPEC are forecast to decline to around $280 billion on the back of declining crude supply. The OECD's share in global investment is anticipated to be more than 60% of the global total given the high costs – for both conventional and unconventional crudes – and decline rates.

The total investment volume of the three downstream categories – known projects, required additions and maintenance/capacity replacement – is estimated at just under $1.5 trillion in the period 2018–2040. Of this, $283 billion is expected to be invested in known medium-term projects, while $306 billion is anticipated to be invested into additions beyond known projects in the long-term. The investment requirement for maintenance and replacement is estimated at around $895 billion for the whole period 2018–2040.

Overall, including midstream investments of around $1 trillion, in the period up to 2040 the required global oil sector investment is estimated at almost $11 trillion.

Integrated and coherent approach is needed to achieve the SDG 7 targets

Energy has a prominent role in the 2030 Agenda for Sustainable Development. Sustainable Development Goal 7 (SDG 7) calls for universal access to energy and eradicating energy poverty. Nonetheless, the achievement of SDG 7 targets on the increased use of renewable energy and energy efficiency improvements will have significant effects on the future energy mix and levels. Coal is projected to be the most affected fuel as a reduction of about 65% in demand for coal is estimated to be necessary to achieve the SDG 7 targets on renewables and energy efficiency, along with an almost 15% decline in oil demand and a 13% reduction from gas in 2040, compared to the Reference Case projections. It should be noted that the corresponding global CO_2 emission reductions are not sufficient to put the world on a pathway consistent with a 2°C temperature target.

In this context, an integrated and coherent approach is needed for implementing 'win-win' strategies to achieve the SDG 7 targets. International cooperation, as well as the provision of means of implementation regarding financial support, technology transfer and capacity building are equally important to achieving SDG 7 targets.

Key assumptions

Key takeaways

- The global population is projected to increase from a level of around 7.5 billion in 2016 to 9.2 billion in 2040. This is around 54 million more than assumed in last year's Outlook.
- The majority of this population growth will come from Developing countries (more than 90%), particularly the Middle East & Africa (41%, excluding OPEC countries), and India. The Organisation for Economic Co-operation and Development (OECD) region is forecast to increase by 112 million in the period to 2040.
- While the working-age population (age 15–64) is estimated to grow by around 1 billion people over the long-term, its relative share of the global population is expected to decline from 66% in 2017 to 63% in 2040.
- The global economy entered a phase of stronger growth in 2017. Compared to the five-year average Gross Domestic Product (GDP) growth from 2012–2016 of around 3.4%, and growth in 2016 of only 3.2%, world economic growth stood at a significantly higher rate of 3.7% in 2017. Taking the ongoing rebound into consideration, 2018 growth is forecast at 3.8%.
- The significant growth expansion of 2017 and 2018 is forecast to end in the medium-term, with global growth forecast to mean-revert to past year averages. Global GDP growth is forecast to be at 3.4% in 2023.
- Global GDP growth between 2017 and 2040 is expected to increase at an average rate of 3.4%. This is slightly lower than last year's assumption, due mainly to the expectation of less dynamic long-term labour market developments. Average growth in the period 2023–2030 stands at 3.4% per annum (p.a.). In the 2030s, lower employment growth, coupled with lower labour productivity growth, is expected to reduce average global GDP growth to 3.2% p.a.
- Most of the global growth will be driven by the Developing countries in the period to 2040. These countries are expected to grow, on average, by 4.5%.
- Policymakers in energy consuming and producing countries, and developed and developing economies, employ various policy measures in order to simultaneously meet and balance their individual national priorities. These priorities include enhancing energy security, energy efficiency, economic development, alleviating poverty, and adhering to environmental objectives as embodied within global pacts such as the Paris Agreement. The Reference Case reflects energy policies that are currently enacted, while recognizing that they may evolve over time.
- The Reference Case assumes an evolutionary development of existing technologies, while also considering new technologies as upcoming elements of the global energy future.

For the energy industry as a whole, and for the oil industry, in particular, the past year since the publication of OPEC's World Oil Outlook (WOO) 2017 has been a challenging one.

On the one hand, increased geopolitical tensions amid threats of sanctions and tariffs, weakened alliances and a general sense of greater uncertainty as a result of mixed signals from policymakers, have changed the political climate. On the other, this is taking place against the background of a generally healthy global economy and steady technological advancements.

From an energy perspective, increased economic activity, especially in developing economies, continues to support rising energy and oil demand, even while some concerns have emerged about the beginning of an economic slowdown, amid some stock market jitters and signs of a looming trade war.

On the policy front, some emerging trends are quite visible. Even though the US has stated its intention to pull back from the 'Paris Agreement', and relaxed its previously strong push for more renewable energy and tighter environmental and efficiency standards, other parts of the world appear to be moving in the opposite direction. In fact, as if to compensate for moves by the US, China and Europe are notably showing a stronger commitment to promote environmental stewardship and a gradual transition towards more sustainable development and energy use, while at the same time maintaining economic growth.

With regard to oil specifically, oil prices have made a recovery over the course of the past year on the back of a more stable market environment. This stability has been helped in part by the historic 'Declaration of Cooperation'[2] between OPEC and non-OPEC producers. Moreover, there has also been a continued rebound in global oil demand growth, which throughout 2017 and 2018, has been well above the average levels observed before the oil price collapse in 2014.

On the supply side, the key theme is the sustained recovery and significant growth in US tight oil production, as well as a sharp rise in the country's crude exports to as much as 2–3 mb/d. Somewhat overshadowed by the US and other tight oil production, which is projected to peak at a full 25% of non-OPEC supply in the late 2020s, other sources of meaningful supply growth include Brazil, Canada and Kazakhstan, particularly after US tight oil production peaks.

From the medium-term oil demand perspective the outlook is uncertain. Initial projections for 2019 have been revised lower, amid slightly lower economic growth, the progressing electrification of road transport and the ongoing substitution of oil by gas and other sources of energy. It should be noted, however, that weaker road transportation-related oil consumption could to some extent be offset by a very healthy outlook for demand from the petrochemical sector, which is booming in key regions of the world.

Broadly speaking, the downstream part of the oil industry continues to experience healthy margins, and a continued expansion, with numerous refinery new builds and expansion projects underway. However, the industry will be challenged by the approaching International Maritime Organization (IMO) deadline that will impose sulphur limits on global shipping, which has the potential to tighten markets significantly, albeit this is not expected to be for a lenghty period.

In all these areas, advances in technology play a big role, as do potentially disruptive innovations in mobility, sustainability and inter-connectivity. Evolving energy policy developments are potentially equally important, and require constant monitoring.

As always, the WOO 2018 does not strive to provide all the answers to the questions being posed to the industry. Its aim is to try and put all these challenges and issues into a meaningful context, thus hopefully clarifying where further work, focus and development is necessary, and shedding some light on what OPEC Member Countries and other energy stakeholders may be confronted with in the future.

1.1 Population and demographics

Demographic trends have significant implications on economic growth and energy consumption, particularly in the long-term. Globally, the world is experiencing an ongoing slowdown in the population growth rate and an expanding ageing population. It should be mentioned that these overall trends are not homogeneous across regions, and various countries are at different stages of transition. The OECD region and some developing countries have already experienced these changes, but the transition in many other regions is expected to begin in the near future. As an input to the WOO analysis, the major demographic elements consisting of population growth rate, working population, urbanization, and immigration have been investigated in detail.

Based on projections extracted from the United Nations (UN) Population Division's 2017 Revision of World Population Prospects, global population is expected to increase from a level of around 7.5 billion in 2016 to 9.2 billion in 2040 (Table 1.1). This is around 54 million more compared to last year's WOO.

This additional 1.7 billion people nevertheless represents less than a 1% annual increase, which is in line with the fact that world population is growing at an unprecedentedly low rate. Regionally, the majority of this growth will come from Developing countries (more than 90%), particularly from the Middle East & Africa (41% excluding OPEC countries), and India.

In the OECD region, 112 million people are forecast to be added in the period to 2040, mostly in OECD America. Eurasia's population is projected to marginally decrease to 341 million. Russia is expected to experience a drop of 8 million, while Other Eurasia is anticipated to see an increase of 7 million by 2040.

The population growth dynamics are shown in Figure 1.1. China's population grew by 199 million inhabitants during the period 1992–2016, whereas this growth is set to fall to a level of 14 million for the period 2016–2040. China has the most pronounced slowdown in population growth within the emerging economies. India, which added 418 million people to the global population over the past 24 years, is assumed to see its growth contribution shrink to 281 million for the period from 2016–2040.

The OECD is anticipated see its population grow by 112 million over the period from 2016–2040, a much lower level than the 197 million observed from 1992–2016.

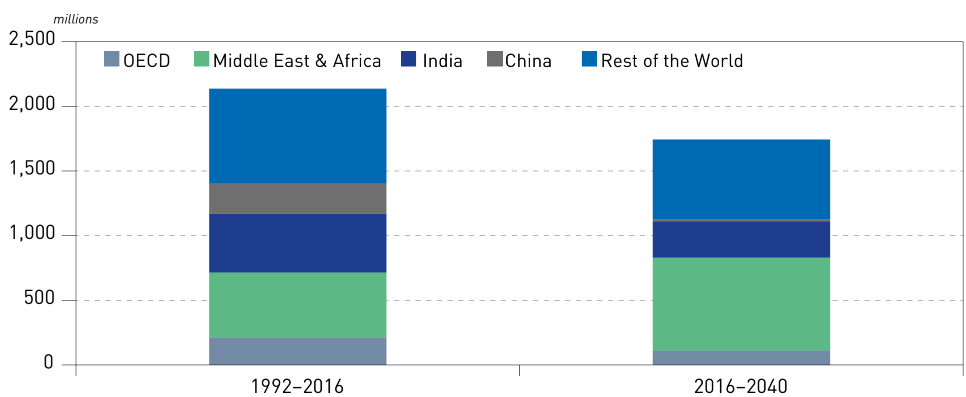
Table 1.1
Population by region

millions

	Levels						Growth
	2016	2020	2025	2030	2035	2040	2016–2040
OECD America	508	525	547	566	584	599	91
OECD Europe	567	575	580	584	587	588	22
OECD Asia Oceania	216	217	218	218	217	215	0
OECD	**1,290**	**1,317**	**1,344**	**1,368**	**1,387**	**1,402**	**112**
Latin America	442	458	476	491	504	514	72
Middle East & Africa	1,032	1,138	1,279	1,429	1,586	1,750	718
India	1,324	1,383	1,452	1,513	1,565	1,605	281
China	1,404	1,425	1,439	1,441	1,434	1,417	14
Other Asia	1,155	1,211	1,278	1,338	1,391	1,437	283
OPEC	479	520	572	627	683	742	264
Developing countries	**5,835**	**6,134**	**6,496**	**6,839**	**7,162**	**7,467**	**1,632**
Russia	144	144	143	141	138	136	–8
Other Eurasia	198	201	203	204	205	205	7
Eurasia	**342**	**344**	**346**	**345**	**343**	**341**	**–1**
World	**7,467**	**7,795**	**8,186**	**8,551**	**8,893**	**9,210**	**1,743**

Source: United Nations (UN) Population Division's 2017 Revision of World Population Prospects. OPEC estimates.

Figure 1.1
World population growth 1992–2016 vs. 2016–2040

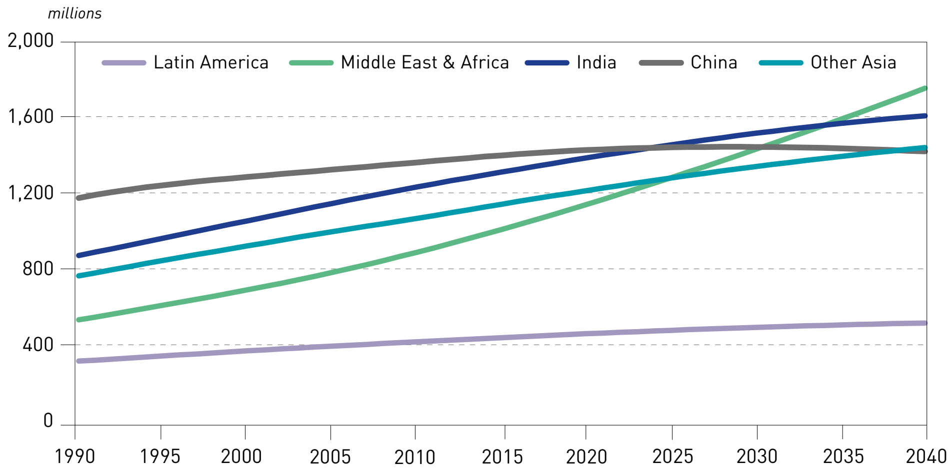


Source: UN Population Division's 2017 Revision of World Population Prospects. OPEC estimates.

The reverse is observed in the Middle East & Africa (excluding OPEC), which is expected to add 718 million people in the period between 2016 and 2040, compared to the 471 million added from 1992–2016. The Middle East & Africa region is currently witnessing a rapid rate of population growth, with this trend expected to continue until the end of the projection period. This development leads to the Middle East & Africa occupying the largest share of population by region in 2040.

Looking at historical and projected trends, spanning from 1990 to 2040 (Figure 1.2), India's population will surpass that of China in 2024 and is expected to have the second-largest share by 2040, after the Middle East & Africa. The same occurrence can be observed in the share of working-age population. In absolute terms, the Middle East & Africa (excluding OPEC) will see the largest population growth in the long-term.

Figure 1.2
Population trends in developing Asia and Middle East & Africa, 1990–2040



Source: UN Population Division's 2017 Revision of World Population Prospects. OPEC estimates.

While the working-age population (age 15–64) is estimated to grow by around 1 billion people over the long-term forecast period, its relative share of the global populace is estimated to decline from 66% in 2016 to 63% in 2040 (Table 1.2). This phenomenon is observed across all regions, albeit with different patterns and levels. Notably, China's working-age population is expected to decline by 131 million people. The Middle East & Africa, with around 493 million additional working-age people by 2040, compared to 2016, is anticipated to experience the highest growth, followed by India with around 224 million.

It is also important to take account of urbanization trends, which have profound implications on economic development, social issues, and energy consumption. Moreover, urbanization is

Table 1.2
Working population (age 15–64) by region

millions

	2016	2020	2025	2030	2035	2040
OECD America	336	344	352	358	366	373
OECD Europe	370	370	367	361	354	347
OECD Asia Oceania	138	136	133	130	126	120
OECD	**844**	**851**	**852**	**849**	**845**	**840**
Latin America	297	309	321	329	335	338
Middle East & Africa	578	646	741	846	957	1,071
India	874	925	983	1,029	1,068	1,098
China	1,013	1,002	996	974	928	882
Other Asia	758	801	849	891	927	955
OPEC	292	316	351	389	427	464
Developing countries	**3,812**	**4,000**	**4,241**	**4,458**	**4,641**	**4,810**
Russia	99	95	91	89	89	87
Other Eurasia	134	132	132	133	134	133
Eurasia	**233**	**228**	**223**	**222**	**223**	**221**
World	**4,889**	**5,078**	**5,316**	**5,529**	**5,710**	**5,871**

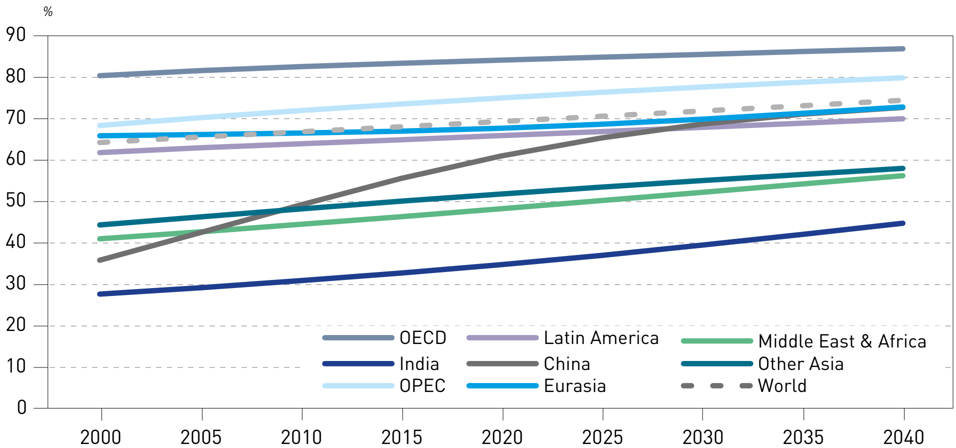
Source: UN Population Division's 2017 Revision of World Population Prospects. OPEC estimates.

closely linked with better access to energy and is a factor for energy poverty alleviation. It should be mentioned that there is no standard approach to define urban population across all countries, as many use their own definition and calculation. Thus, urbanization in the WOO is expressed in terms of the urban rate, which underlines the level of the total population living in urban areas in percentage terms.

Figure 1.3 shows the global and regional trends of urbanization. The OECD region is by far the most urbanized region with more than 80% living in urban areas. OPEC Member Countries also stand at a level above the current average global level of close to 75%. Urbanization rates in Latin America and China are currently slightly below the global average. Other Asia and Middle East & Africa regions are on an ascending trend, with expectations for a significant expansion in urbanization levels in the coming decades. Notably, India's urbanization rate has been the lowest, and although it is set to rise considerably in the coming decades, it is expected to remain the lowest in 2040. Looking at China's historical data reveals that this country has witnessed a dramatic change in urbanization. The rate was as low as India before 1990, but since then it has experienced significant growth. Moreover, it is expected to grow further, albeit with a decelerating rate, to reach close to the global average in 2040.

Migration is also another major aspect of demographic changes. Table 1.3 depicts the net migration measured as the variation of population, as per UN 2017 estimates, between the

Figure 1.3
Urbanization rate for selected regions, 2000–2040



Source: UN Population Division's 2017 Revision of World Population Prospects. OPEC estimates.

Table 1.3
Net migration by region in the medium variant *% of regional population*

	2020	2030	2040
OECD America	1.1	2.3	6.2
OECD Europe	1.2	1.8	4.5
OECD Asia Oceania	0.7	1.4	4.0
OECD	**1.1**	**1.9**	**5.1**
Latin America	–0.3	–0.6	–1.3
Middle East & Africa	–0.3	–0.4	–0.8
India	–0.2	–0.4	–0.8
China	–0.1	–0.3	–0.7
Other Asia	–0.5	–0.9	–2.0
OPEC	0.1	0.2	0.3
Developing countries	**–0.2**	**–0.4**	**–1.0**
Russia	0.6	1.0	2.6
Other Eurasia	–0.4	–0.8	–1.9
Eurasia	**0.0**	**0.0**	**–0.1**

Source: UN, Department of Economics and Social Affairs, Population division (2017).

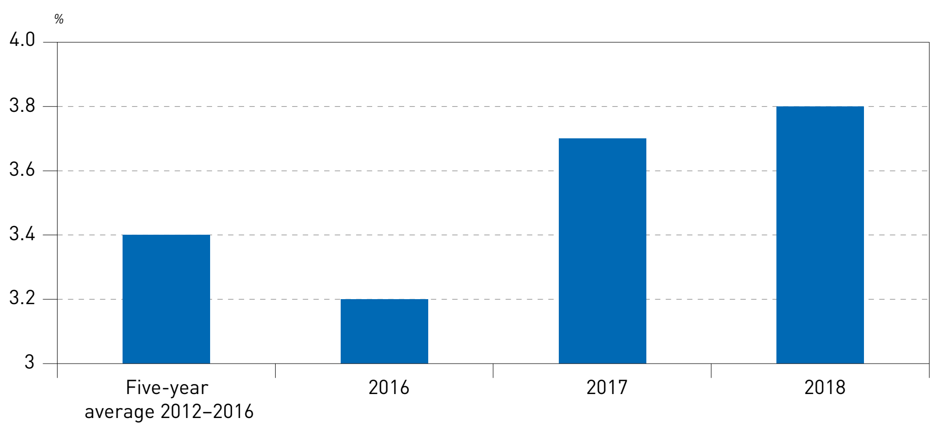
medium variant and zero migration variant. The OECD is anticipated to witness a high positive net migration rate by 2040 of around 5%, whereas the developing world is expected to see a negative rate, corresponding to an outward movement of population of almost 1%. Russia is forecast to see a rise in net migration, while Other Eurasia is estimated to witness a negative rate. In total, the overall rate is negative for Eurasia.

1.2 Economic growth

1.2.1 Current situation and short-term growth

The global economy entered a phase of stronger growth in 2017. This comes more than ten years after the great financial crisis, which began in 2007 with the US sub-prime crisis. Since then, governmental-led support across the world, alongside accommodative monetary policies, primarily from the central banks of major OECD economies have built the foundation for the recovery. Compared to a five-year average global GDP growth of around 3.4% from 2012–2016 and growth in 2016 of only 3.2%, world economic growth stood at a significantly higher rate of 3.7% in 2017 (Figure 1.4).

Figure 1.4
Global GDP growth rate



After slowing growth in the first quarter of 2018 in major OECD economies, the growth dynamic has resumed and is forecast to be sustained for the remainder of the year. Taking the rebound into consideration, 2018 growth is forecast to reach 3.8%. This is a considerable growth-level appreciation for the second consecutive year, compared to the lower growth levels in previous years.

However, some soft economic spots became visible in mid-2018 and as these challenges have emerged, the risk to short-term global economic growth is skewed to the downside. The main areas of concern include political uncertainties, such as trade-related developments that warrant close monitoring. Moreover, the consequences of possible further monetary policy decisions in the US, the Euro-zone and probably in Japan too, together with expectations for financial tightening in China, will also need to be closely observed.

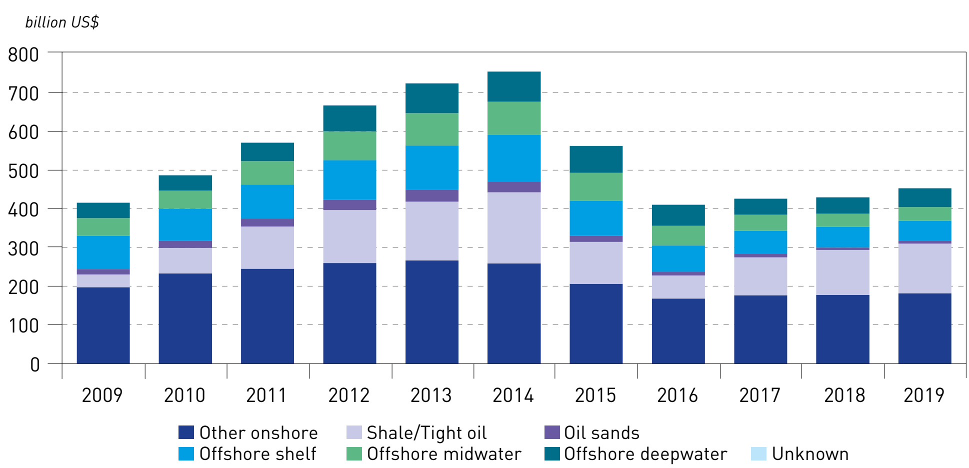
In terms of the strong growth dynamic in 2017 and 2018, numerous factors have provided the base for this development. Among the most important factors was that the monetary stimulus from G4 central banks (the US Federal Reserve (Fed), the European Central Bank (ECB), the Bank of Japan (BoJ) and the Bank of England (BoE)) has been a key element in not only providing growth in their respective economies, but importantly also fuelling growth in major emerging economies, such as China, India and Brazil, and to a lesser extent in Russia.

Additionally, the oil market recovery that has been stimulated by the ongoing 'Declaration of Cooperation' between OPEC and participating non-OPEC producers, has also played a vital role in the global economic growth momentum. It should be noted that oil producing economies, including large oil producers in the OECD, such as the US and Canada, account for more than a third of the global economy.

Hence, the considerable drop in oil prices from 2014–2016, and its impact on output values and the consequent decline in energy market-related investments, were highly negative for global growth and were not compensated for by a rise in consumption. OPEC's efforts, together with non-OPEC participating countries in the 'Declaration of Cooperation', to stabilize the oil market has led to a more balanced oil market and a rising contribution from the oil sector to global economic growth.

Analysis of non-OPEC investment by supply segment shows that at an amount of more than $400 billion, specifically with a major increase in tight oil investments, the contribution to global GDP solely from this segment will again reach around 0.5 percentage points in 2018 (Figure 1.5).

Figure 1.5
Non-OPEC investment by supply segment



Source: OPEC Secretariat and Rystad Energy.

More importantly, this effect has become visible in the US economy, whose primarily oil market-related investments (mining, shaft and wells) have approximately doubled in 2018 to $122 billion, having reached a low point in 2016 of around $60 billion, according to data from the Bureau of Economic Analysis.

It is also important to reference that the legacies from the great financial crisis have to some extent been overcome. The labour market has improved globally, wages have generally been rising, commodity prices have appreciated again and wealth-related measures, such as house prices and equity market indices have also risen.

Given these developments, alongside the strong recent growth levels, and as inflation has started picking up again in key economies, major central banks have either already initiated, or indicated, some monetary tightening. It is the expectation of a normalization of monetary policies that may lead to lower global growth in the medium-term. The impact may be felt in emerging economies, in particular – and to a lesser extent also in developing economies – which were notable beneficiaries of the monetary stimulation programs initiated by the central banks of the G4 economies.

1.2.2 Medium-term economic growth

The significant growth expansion of 2017 and 2018 is forecast to end in the medium-term, with global growth forecast to mean-revert to past year averages, due to a variety of reasons.

First, monetary tightening is expected to continue and is forecast to lead to a slowing in economic activity in the respective central bank's domiciled economies, but even more so in those emerging economies that have benefited from the increased capital inflows in recent years. This will apply to the monetary supply of all G4 central banks. While some of the US Fed's monetary tightening may be compensated by recent fiscal stimulus in the US, this will be less likely beyond 2019. Moreover, the fiscal stimulus – provided via the 'Tax Cuts and Jobs Act', as well as the 'Bipartisan Budget Act' – may lead to interest rates rising even faster, as it may push up inflation, worsen the US sovereign debt situation and, hence, it could lead to a weakening US sovereign credit profile. Another potential drag to US and global economic growth in the medium-term may come from rising protectionism and trade barriers. For more information, see Box 1.1.

Another important aspect that will need to be considered for the medium-term forecast is slowing productivity growth rates, primarily in advanced economies. Minimal population growth and only minor productivity gains will make it challenging to achieve considerably higher growth rates in advanced economies over the medium-term (Figure 1.6).

Moreover, the lack of fiscal space limits the ability of governments to stimulate the economy due to very high sovereign debt levels across the world, and in some major economies, for example, the US, they are even rising.

In the second half of the medium-term period, it is estimated that the global economic growth potential stands at around 3.5% (Table 1.4). The current global growth level of 3.8% is at a significantly higher rate and is considered not to be sustainable in the coming years. By

Box 1.1

Warning signs: Rising protectionism

The potential rise of considerable protectionism is threatening the strong pick-up in growth that the global economy experienced in 2017 and 2018. While the base for the broad-based economic recovery has come from the unprecedented monetary easing programs of the G4 central banks, which began after the financial crisis about ten years ago, the recovery in global trade in the past few years has been another significant element in lifting economic growth to the recent high growth levels.

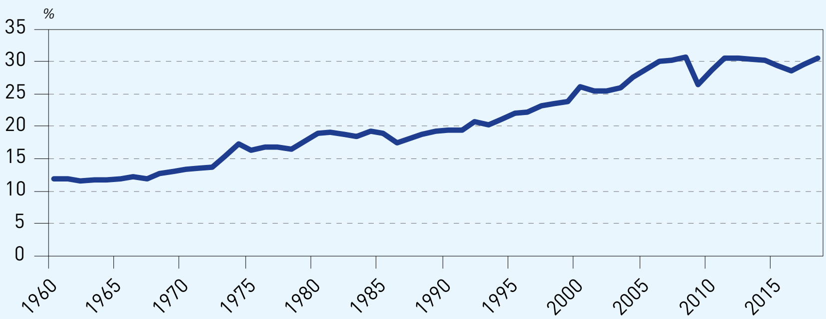
Global exports have risen since the 1960s – and more notably since around the establishment of the World Trade Organisation (WTO) in 1995 – and account for about 30% of global GDP today. Hence, their future evolution is significant to global GDP growth. Quantifying the impact of global trade barriers on global economic growth is complex and the margin of error may be significant, as a variety of dimensions need to be considered. Among those dimensions are:

- The type of trade barriers (tariff versus non-tariff barriers);
- The magnitude of the barriers;
- The products and countries affected;
- Effect on finished versus intermediate goods;
- The consumer groups that may be affected (which income/wealth level as consumer behaviour and price-elasticity may differ);
- How governments spend the additional income in the case of tariffs (neutralizing negative effects);
- The sectors affected;
- The duration of the trade barriers;
- The substitutable nature of imported products and the possiblity of substituting a trade barrier of imported goods domestically;
- How exporters retaliate to trade barriers;
- The impact that trade barriers may have on inflation and monetary policies;
- The reaction of currency exchange rates on trade barriers and their effect on trade values; and
- The reaction of asset markets and their impact on equity and debt-related financing and global wealth-levels.

While this is not an exhaustive list, it provides some idea concerning the complexity of the economic impact that trade barriers may have in a world that is increasingly interconnected and today relies on globally integrated value-chains. Any disruption in trade could cause unforeseen consequences in these global value chains with an impact on production flows. Perhaps even more importantly, even proposals to implement trade barriers may impact financial markets in such a way that it has a negative impact on the global economy.

This may be witnessed in the ongoing trade disputes, which are primarily focused on the US, in relation to China, the EU, Mexico, Canada, Japan and South Korea, among

Figure 1
The share of global export to GDP (%)



others. Growing uncertainty in the respective economic environments may lead to a decline in business and consumer confidence, potentially lowering investments and capital flows. This could ultimately lead to slowing global economic growth, even if it is only in anticipation of major trade disruptions.

It is also important to see if trade barriers affect finished goods or intermediate goods. As global value chains are increasingly integrated, barriers on intermediate goods, in particular, could cause disruptions in certain value chains that will be challenging to counteract. While finished goods, compared to intermediated goods and services, had an almost equal share to global GDP back in 1989, the share of intermediate goods and services has increased significantly since.

Escalating trade disputes are forecast to hurt global growth considerably, and could even lower global growth in 2019, with a consequential knock-on effect in the subsequent years.

Figure 2
Composition of global trade in 2016

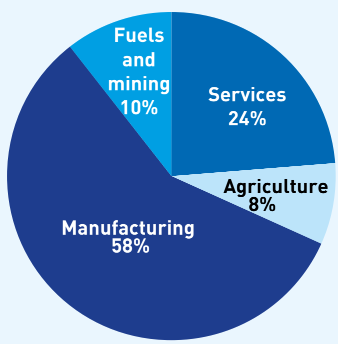
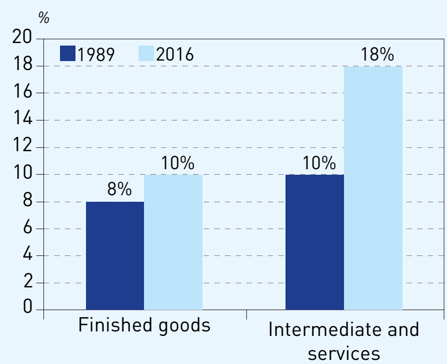
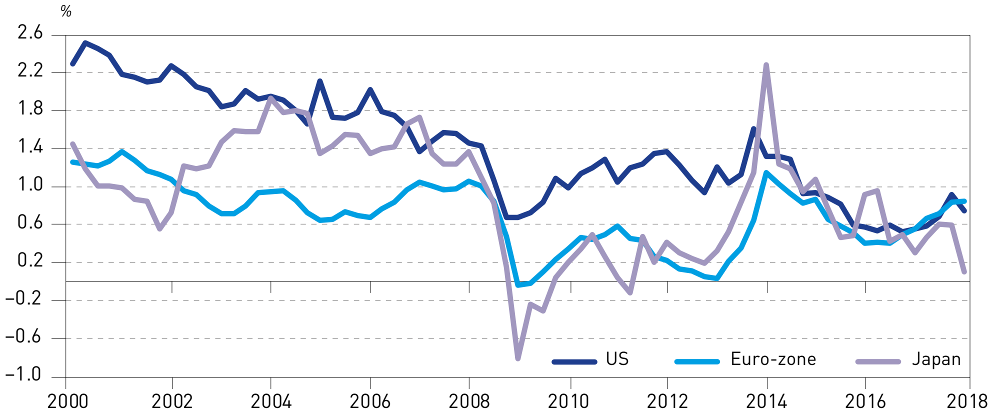


Figure 3
The share of global export to GDP



Source: Figure 2: WTO and World Bank.
Figure 3: BoE using data from, Johnson and Noguera (forthcoming), Powell (2016), World Input-Output Database (2016 release) and BIS. Numbers are in current US$.

Figure 1.6
Productivity growth, five-year moving average



Sources: US: Bureau of Economic Analysis/Bureau of Labor Statistics;
Euro-zone: Statistical Office of the European Communities;
Japan: Cabinet Office/Ministry of Health, Labour & Welfare and Haver Analytics.

Table 1.4
Medium-term annual real GDP growth rate

% p.a.

	2017	2018	2019	2020	2021	2022	2023
OECD America	2.2	2.7	2.4	2.1	2.0	2.0	1.9
OECD Europe	3.0	2.3	2.1	2.0	1.9	1.8	1.7
OECD Asia Oceania	2.2	1.9	1.7	1.6	1.6	1.5	1.5
OECD	**2.5**	**2.4**	**2.2**	**2.0**	**1.9**	**1.8**	**1.8**
Latin America	1.9	1.9	2.3	2.6	2.6	2.5	2.5
Middle East & Africa	3.2	3.3	3.2	3.2	3.2	3.3	3.4
India	6.3	7.3	7.4	7.3	7.1	7.0	7.0
China	6.9	6.6	6.2	6.0	5.8	5.7	5.5
Other Asia	5.0	4.8	4.6	4.5	4.4	4.4	4.3
OPEC	1.5	2.2	2.3	2.6	2.8	2.9	3.1
Developing countries	**5.0**	**5.1**	**5.0**	**5.0**	**4.9**	**4.9**	**4.8**
Russia	1.5	1.8	1.8	1.8	1.8	1.8	1.7
Other Eurasia	3.8	3.4	3.1	2.9	2.8	2.7	2.7
Eurasia	**2.5**	**2.5**	**2.4**	**2.3**	**2.2**	**2.2**	**2.2**
World	**3.7**	**3.8**	**3.6**	**3.6**	**3.5**	**3.5**	**3.4**

taking the growth trends in the various economies into consideration, the medium-term growth trend is expected to gradually move back towards the global growth potential.

In summary, the uncertainty in this medium-term forecast is manifold, with risks skewed to the downside and any upside appearing to be limited. The expectation of monetary tightening, in combination with elevated global debt levels, the limited fiscal space and the obvious limitations to productivity growth are the major uncertainties. In addition, concerns about global trade, rising geopolitical risks and the uncertainties concerning commodity price levels are risks that may impact medium-term global growth.

OECD America

In OECD America, the US constitutes the largest economy, and it will evidently shape medium-term global economic development. The Tax Cuts and Jobs Act of December 2017 and the Bipartisan Budget Act of February 2018 will have a notable impact in this respect. These two fiscal measures coincide with an already relatively well-established underlying growth and are forecast to push growth up by around 0.5 percentage points in 2018.

This means that the US has much more front-loaded growth, compared to last year's medium-term WOO forecast. While last year it was forecast that growth will gradually accelerate towards the end of the medium-term period, this year's forecast shows the opposite. Moreover, the fiscal space will be limited in the coming years and the sovereign debt situation is forecast to worsen, leading to possible repercussions in the medium-term growth momentum.

While growth in 2018 and 2019 will be lifted by the considerable fiscal stimulus measures, this support will taper off towards the back end of the forecast period. In addition, the already ongoing monetary tightening from the US Fed is forecast to continue, weighing on US medium-term growth.

Canada and Mexico are forecast to slow down slightly too, impacted by a deceleration in trade with the US and given that the significant recent appreciation in commodity prices, which constituted a relatively important support growth element, is likely not to be sustained at the same magnitude going forward. With respect to trade, the outcome of the ongoing North American Free Trade Agreement (NAFTA) negotiations will constitute another important element that needs to be considered in the region's growth forecast. For now, it is assumed that trade will remain an important growth driver in North America, with no material alteration in its relative contribution to economic growth.

OECD Europe

OECD Europe experienced significant growth of 3.0% in 2017, after 2.0% in 2016. This strong development, which was partially due to a cyclical recovery, in combination with the support of very accommodative monetary policies and a recovery in global trade, is likely to slowdown in the medium-term. An important factor for this slowing trend is expected monetary tightening, mainly by the ECB and probably by the BoE, which may lead to more muted growth in the coming years.

Moreover, political uncertainties, not only in the Euro-zone, but the EU as a whole are expected to continue. Brexit-related developments are forecast to weigh on EU growth, including in the UK, with negotiations ongoing. The UK is currently experiencing a period of low-growth transition, which is anticipated to continue in the medium-term. Some slowdown in investment, amid the expectation of less monetary stimulus, and a gradually maturing labour market are also aspects that will likely slow growth compared to 2017 and 2018. In most EU economies, sovereign debt levels also remain high and, therefore, major growth enhancing fiscal measures are not to be expected.

Some ongoing weakness in parts of the EU banking system may impact medium-term growth negatively too. The ongoing fragile situation in some European banks' balance sheets, particularly in Italy, in combination with rising regulatory demands, may result in very restrictive policy by banks to provide credit to the private sector. This year's medium-term growth forecast has been lifted at the front-end, while the growth numbers for the latter medium-term years are generally in line with last year's growth trend.

OECD Asia Oceania

In OECD Asia Oceania, Japan's future growth is the major interest. Japan's development, in combination, with the future economic development of China – which is forecast to decelerate in the coming years – will provide a strong guideline for the region's future growth. Given the ongoing challenges in the Japanese economy, and the expected decelerating trend in China's growth, OECD Asia's growth pattern is forecast to slow down from the relatively high growth levels seen in 2017 and 2018. Beyond this year, it is anticipated to continue at only around previous year's average growth levels of around 1.5%.

The region's other important economies, Australia and New Zealand, will also likely be impacted by this slowing growth momentum, thus, accentuating this trend. While the growth forecast at the beginning of the medium-term period has been lifted, the growth numbers for the latter years of the medium-term are about in line with the levels observed in the past several years.

Latin America

In Latin America, a medium-term recovery is anticipated after relatively low average growth in recent years. This rebound is backed by Brazil's cyclical recovery and the expectation of a positive impact from the country's ongoing structural reforms in the coming years. The outcome of Brazil's presidential elections will also be very important for the country's future development.

While the situation in Argentina has worsened in 2018, structural reform support, in combination with financial aid from the International Monetary Fund (IMF) and consequently, an improving domestic situation, may help Latin American growth in the medium-term. However, in both economies uncertainties remain. For example, the latest request for IMF-support from the Argentinian government is fuelling some concern, as its sovereign debt level has increased significantly in recent years.

Given that these two countries constitute the two largest regional economies, their development is of critical importance and may not be counterbalanced by anticipated higher growth levels of other smaller economies in the region. As uncertainties for the region have risen, when compared to last year's forecast, growth is forecast to be lower in the medium-term.

Middle East & Africa

In the Middle East & Africa region, the future path of commodity prices, in combination with foreign investments, will be the most important driving elements. In this respect, the development of China in its role as the major foreign investor and China's need for natural resources will be of great importance. Positively, improving domestic demand in the region and the rise of the region's middle class is expected to provide a key supporting factor in the coming years. On the flip side, some countries' high sovereign debt obligations and debt services may be a constraint for some of the economies' growth developments.

The current forecast anticipates that the region's geopolitical issues will not further impact growth. Key commodity prices are also expected to slightly appreciate, in line with the trend of the global economy, while wealth distribution and diversification slowly improve the economic structure of the region too. The appreciating growth trend differs only marginally from last year's forecast.

India

Through recent structural reforms, including the demonetization efforts in 2016 and the introduction of the sales tax, India has laid down some important groundwork for future expansion, with the medium-term growth forecast to remain around or above 7%. Therefore, India is estimated to exceed China's overall growth performance in the medium-term. Growth in India will be led by domestic consumption and the rise of its middle class. The homogenization of the sales tax will certainly be growth enhancing in this respect, as it has improved transparency for end-consumers and companies alike.

Moreover, the facilitation of foreign investments will also be supportive, although there remains room for improvement in reforms to attract foreign capital as there are still several sectors that have a limitation on foreign ownership.

Challenges to the expected growth momentum will be developments in monetary tightening by the US Fed and probably the other G4 central banks, which will likely have an impact on capital flows and the Indian rupee. Moreover, albeit to a lesser extent, trade-related developments, in terms of rising protectionism, is an area that may impact the Indian economy negatively. Finally, and in combination with possibly monetary tightening and a potential weakening of the rupee, the future development of commodity prices will be essential to India's growth.

Given the stronger than expected negative impact from structural reforms that led to a lower base for GDP growth in 2017, the medium-term forecast has been slightly revised down, compared to last year.

China

China will remain of central importance to medium-term global economic development. The importance is threefold, namely the country's generally rising economic weight in the global economy, its importance as a trading partner and finally its weight as a commodity consumer. Hence, the development of China's economy is considered to be of even greater importance than its pure economic weight in global GDP would suggest. After relatively robust growth in 2017, which was the first year since 2010 that witnessed a growth appreciation on the previous year, the economy is expected to slowly mature, with the growth rate then decelerating. Importantly, this development is supported and managed by the Chinese leadership. The growth that is envisaged for 2018 is around 6.6% .

With the economy moving from a focus on external trade and investments towards one that is more domestically oriented, led by private household consumption, the government has highlighted on several occasions that there will be a need to level out the current economic imbalances, mainly in the banking sector, the real estate market and to reduce provincial government debt, while at the same time also continuing to improve the social safety net and accelerate wealth distribution. It should be also noted the signs of growing global trade protectionism, and its possible impact on China's development, is an area that will need to be closely monitored.

With these issues in mind, growth is forecast to slow over the coming years. As China's growth surprised to the upside and lifted its base in 2017 and 2018, the medium-term growth level has been slightly raised, when compared to last year's medium-term forecast.

Other Asia

Other Asia, constituting one of the most dynamic growth regions in the world, will continue to benefit from a solid expansion in China and India, but will also be impacted by the expected gradual slowdown in China and the weakening growth trend in the OECD. This slight softening will also materialize after very strong growth of 5.0% in 2017. The region is expected to slightly decelerate at the back end of the medium-term curve.

Due to the more accentuated slowdown in OECD growth, as well as some lower growth trends in Asian trading partners, the region's growth forecast has been revised slightly down, when compared to last year's medium-term growth forecast.

OPEC

GDP growth in OPEC Member Countries is forecast to accelerate over the medium-term as a result of healthy oil demand and global growth. With oil prices expected to remain at generally higher levels (compared to the period 2015–2017), with a further diversification of Member Countries' economies, as well as ongoing improvements in wealth distribution, in combination with a rising population, OPEC Member Countries are forecast to continue see healthy growth. Over the medium-term, the growth will improve from levels of 2.2–2.3% in 2018 and 2019 to figures around 3% by the end of the period.

Eurasia

In Eurasia, Russia has benefitted from the rebalancing of the oil market, hence, it has better growth numbers for 2018 and 2019, compared to last year's medium-term growth forecast. As the second most dominant single oil-exporting country, it is forecast to benefit from increasing demand in commodities. However, the dynamic of rising political uncertainty in recent years has continued, impacting investments and the Russian rouble.

Considering the latest rounds of sanctions and continued muted domestic demand, the economy is forecast to grow a little bit less over the total medium-term period, when compared to last year's Outlook. Growth will be maintained at around this year's growth level, slightly below 2%. Considering the slowing global growth trend and the ongoing challenging situation of the Russian economy, the other Eurasian economies are forecast to follow a similar growth pattern.

1.2.3 Long-term economic growth

Looking to long-term growth developments, assumptions will mostly be defined by:

- productivity growth;
- demographic trends; and
- developments in the labour market.

Global GDP growth between 2017 and 2040 is expected to increase at an average rate of 3.4%. This is slightly lower than last year's WOO assumption, due mainly to the expectation of less dynamic long-term labour market developments. Compared to medium-term growth average of 3.6%, a slowdown in the growth dynamic at the end of the medium-term period in 2023 until the end of the decade leads to growth of 3.4% on average in the 2023–2030 period. In the 2030s, lower employment growth, coupled with lower labour productivity growth, is expected to reduce average global GDP growth to 3.2% (Table 1.5).

Most of the growth until the end of the forecast period will be determined by labour productivity. It accounts for around 80% of the global growth contribution. Regionally, disparities are observed

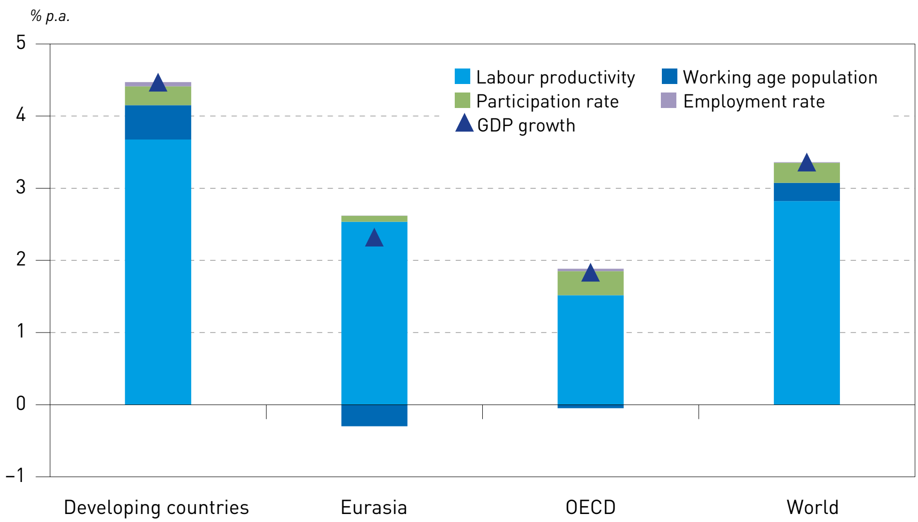
Table 1.5
Long-term annual real GDP growth rate in the Reference Case

% p.a.

	2017–2023	2023–2030	2030–2040	2017–2040
OECD America	2.2	2.1	2.0	2.1
OECD Europe	2.0	1.6	1.6	1.7
OECD Asia Oceania	1.6	1.4	1.2	1.4
OECD	**2.0**	**1.8**	**1.7**	**1.8**
Latin America	2.4	2.4	2.4	2.4
Middle East & Africa	3.3	3.7	3.6	3.6
India	7.2	6.8	5.9	6.5
China	6.0	4.9	3.7	4.7
Other Asia	4.5	4.1	3.7	4.0
OPEC	2.6	3.2	3.1	3.0
Developing countries	**5.0**	**4.6**	**4.0**	**4.5**
Russia	1.8	2.0	2.0	2.0
Other Eurasia	2.9	2.9	2.6	2.8
Eurasia	**2.3**	**2.4**	**2.3**	**2.3**
World	**3.6**	**3.4**	**3.2**	**3.4**

in terms of the sources of growth. For most regions, growth is mainly driven by labour productivity. For some other regions, such as the Middle East & Africa and OPEC, low labour productivity growth is compensated by positive demographic developments and their spill-over into the labour market. It should also be noted that a declining working age population significantly limits growth potential in countries and regions such as China, Russia, OECD Europe and OECD Asia Oceania.

Figure 1.7
Long-term GDP growth rates by components, 2017–2040



As in the growth assumptions of past years, most of the global growth will be driven by Developing countries in the period to 2040. These countries are expected to grow, on average, by 4.5% during this period on the back of higher labour productivity growth and a more optimistic demographic outlook. Within Developing countries, India is expected to remain the fastest growing with an average growth of 6.5% p.a., driven by a rapidly expanding working age population. The growth rate is, however, lower than in last years' WOO, when growth of 6.8% was anticipated.

China is the second most rapid growing developing economy, at 4.7% p.a. However, its growth decelerates steadily as its working age population declines so that in the last decade of the forecast period the country's economic growth is anticipated to average only 3.7%. Growth in Other Asia and OPEC remains relatively strong, driven mainly by an increase in the working age population and to a lesser extent by labour productivity growth.

For Latin America, it is expected that the economic challenges experienced in recent years may continue to some extent. The economic structures, particularly in Brazil and Argentina, have shifted, a circumstance that will likely affect growth in the long-term. Between 2020 and 2025, growth is expected to increase to the range of 2.5–2.6% p.a. as labour productivity improvements accelerate. In the 2020–2030 period, growth is forecast at 2.5%. Beyond this, in the last decade of the forecast period, the gloomier employment growth picture somewhat limits economic expansion. The overall growth in the period up to 2040 is forecast at 2.4%, considerably below the long-term growth assumption in last year's WOO of 2.8%.

In the Middle East & Africa, growth remains strong on the back of a favourable demographic outlook, with an average 3.6% p.a. over the forecast period. Productivity growth in this region will, however, remain low, at below 1% for the period to 2040, so an improvement on that front may lift growth further.

Growth in the OECD region averages 1.8% p.a. over the period 2017–2040. A marginally declining working age population, and only slowly improving labour productivity, albeit with an improving participation rate, support generally low growth prospects. In fact, the labour force participation rate is highest in OECD countries, particularly in OECD Asia Oceania, mainly because of high and rising female participation. Further female participation and potentially the rising participation of older individuals, as a result of increasing pressure on the social security systems and/or an increasing retirement age, will likely see a further expansion in the participation rate.

The counterbalancing effects of growth enhancing factors provide a relatively stable growth rate over the forecast period. Within the OECD region, OECD America leads the growth prospects with an average growth of 2.1% p.a. While in OECD Europe and OECD Asia Oceania increasing economic activity is limited by a declining working age population, the economic outlook in OECD America will be supported by expanding employment via immigration, although the latest political initiatives may limit this factor.

This positive factor of a rising labour force is counterbalanced with only slow productivity growth. Therefore, OECD America exhibits relatively similar growth rates over the forecast period, while growth rates in OECD Europe and in OECD Asia Oceania decelerate more considerably in the last decade.

In Eurasia, the economic growth outlook is limited by an unfavourable demographic picture, particularly in Russia, where the working age population is expected to steadily decline. Some labour productivity gains, however, are assumed to counterbalance this negative trend. Overall, GDP growth is forecast to average 2.3% in the long-term, with Russia at 2.0% p.a. and Other Eurasia at 2.8% p.a.

This year's GDP growth assumptions were revised down slightly on average, compared to last year's WOO. This is the result of updated short-term figures and an anticipation of a less favourable development in the global labour force. More frontloaded growth in the US, supported by a considerable fiscal stimulus, in combination with still relatively accommodative monetary policies, has shifted stronger growth towards the early years of the forecasting period.

Moreover, structural shifts in Latin America, as well as in other developing economies, have lowered their growth abilities in this year's economic growth forecast.

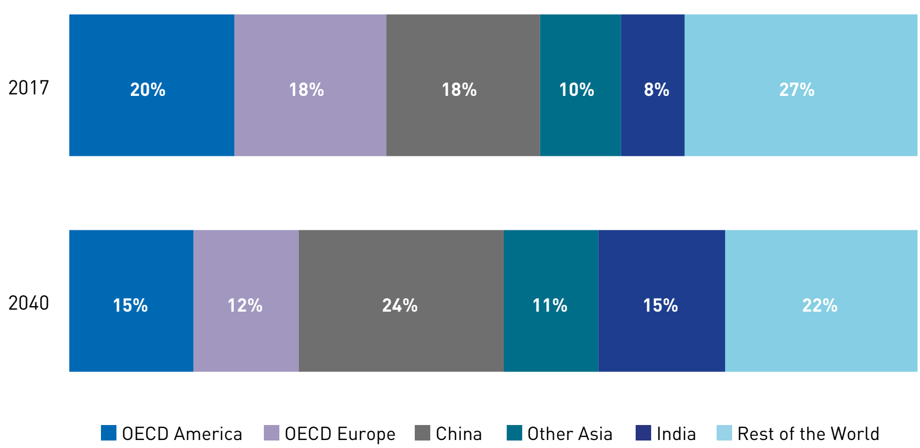
For the world, average GDP growth for the period 2017–2040 has been revised down by 0.1 percentage point from 3.5% to 3.4%. There are also important differences for some regions. Growth prospects for the OECD have been revised down from 2.0% to 1.8%, with the largest changes in OECD America, which experienced a 0.4 percentage point growth revision on the back of lower productivity assumptions.

Large downward revisions were also applied to Latin America, Russia and India, which have seen structural shifts in their economies in the past years. On average, this has led to less favourable developments in the labour force and to a lesser extent slowing productivity growth. Other Asia has been revised up by 0.2 percentage points, backed largely by a rise in productivity growth assumptions.

The assumed GDP growth figures imply that the total size of the global economy in 2040 will be 214% that of 2017. In particular, world GDP is forecast to increase by $128.7 trillion (2011 purchasing power parity (PPP)), expanding from $113.4 trillion (2011 PPP) to $242.2 trillion (2011 PPP). Developing countries are estimated to account for three-quarters of the global GDP growth over the forecast period. Furthermore, one of every two additional dollars of GDP (2011 PPP) is expected to come from China and India. (Figure 1.8)

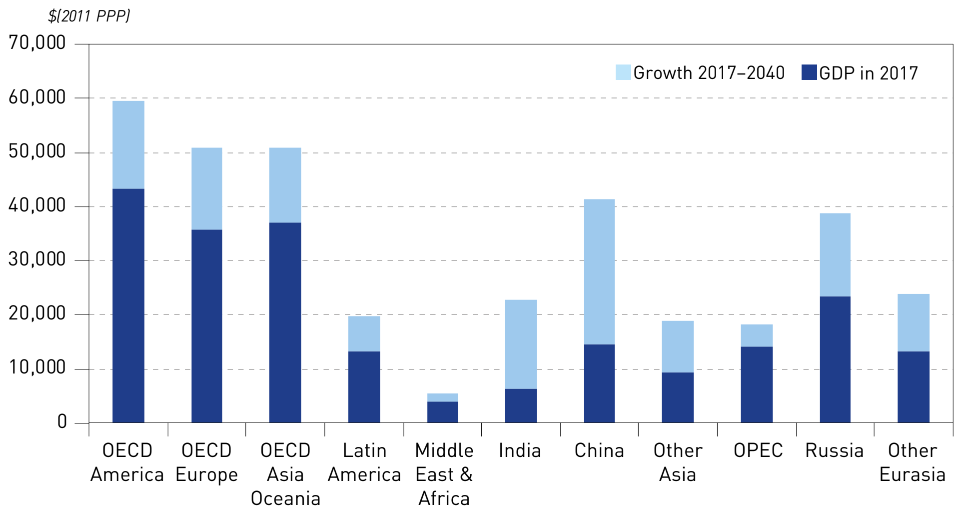
In 2017, OECD America accounted for 20% of global GDP, followed by OECD Europe and China, both with 18%, then Other Asia with a relative weight of 10% and India with 8%. The expected much higher growth of Developing countries in the long-term means that the weight of OECD America is estimated to drop to 15% and that of OECD Europe to 12%. On the other hand, China's weight in the global economy is forecast to increase by around 6 percentage points to 24%. India's weight is forecast to rise by around 8 percentage points to 15%.

Figure 1.8
Distribution of the global economy



As analysis from previous years has shown (Figure 1.9), the picture for average income (measured as GDP per capita) does not vary significantly. This comes despite the fact that there will be major regional shifts in the economic picture over the forecasting period and the GDP composition is anticipated to change notably. OECD America is forecast to remain as the region with the highest GDP per capita, followed by OECD Europe and OECD Asia Oceania. However, sometime around 2035, China is projected to surpass the per capita income of Russia. The region of Middle East & Africa is expected to remain the region with by far the lowest income per head, with a tenth of the GDP per capita that is achieved in OECD America on average over the forecast period.

Figure 1.9
Real GDP per capita in 2017 and 2040



The main changes will occur in India and China. India's income level is expected to increase almost threefold, reaching around $22,500 (2011 PPP) in 2040. Even more impressive is the level that will be achieved by China on a per capita basis with GDP per capita of around $41,300, closing some of the gap to the OECD. Overall, global average income is expected to increase by 75%, from around $15,000 (2011 PPP) in 2017 to around $26,300 (2011 PPP) in 2040.

1.3 Energy policies

In this Chapter, there is a brief overview of energy market policies that have been taken into account when providing analysis relating to regions, sectors and fuels. Moreover, this year the WOO also provides a dedicated Chapter on policy issues (Chapter 8) that offers more specific details on this important topic.

The evolution of energy markets over time is significantly impacted by government policies, which are used as mechanisms to stimulate change beyond purely market-driven forces. Policymakers in energy consuming and producing countries, and developed and developing economies, employ various policy measures in order to simultaneously meet and balance their individual national priorities. These priorities include enhancing energy security, energy efficiency, economic development, alleviating poverty, and adhering to environmental objectives as embodied within global pacts such as the Paris Agreement.

Consequently, the Reference Case reflects energy policies that are currently enacted, while recognizing that they may evolve over time. Every year, the medium-term projections are updated to account for freshly established policies, and to evaluate the outcomes of previously enforced policy measures. As such, the WOO is also evolutionary and aims to proactively reflect policy developments as they emerge over time, and anticipate their future trajectory.

Since the release of the WOO 2017, many countries around the world have ratified the Paris Agreement, and have converted their Intended Nationally Determined Contributions (INDCs) to Nationally Determined Contributions (NDCs). OPEC Member Countries are among this list, with ten[3] Member Countries having ratified the Paris Agreement to date, and proactively share best practices in order to achieve sustainable development and maintain stable energy access.

The ratification of the Paris Agreement reflects a growing global movement toward harmonizing economic, social, and environmental development, across both developing and developed countries. As a result, energy policies and targets have been announced at the national and state level in efforts to progress toward meeting various countries' NDCs. While governments explore policy options and weigh national priorities, some of these targets continue to shift and evolve.

Paris Agreement

The US offers a clear example of the evolutionary nature of policies, as the incoming presidential administration swiftly utilized the Congressional Review Act[4] among other mechanisms to redirect the nation's path. Against the backdrop of President Trump's 'America First' policy agenda, on 1 June 2017, the President announced a public statement indicating the withdrawal of the US from the Paris Agreement. This statement was followed by the formal submission of communication to the UN indicating that the US intends to withdraw from the accord as soon as it is eligible to do so under the terms of the Agreement. While announcing the withdrawal from the Agreement, the president expressed his assertion that the climate accord undermines the US economy and its sovereignty, but left room for potential renegotiation of different terms in the future.

Although the intention of the US to withdraw from the Agreement has been communicated officially to the UN, technically, the soonest that the withdrawal can take effect is November 2020; in fact, one day after the next US presidential election.

However, even before a technical departure from the Paris Agreement, the US federal government is undertaking policies that are not necessarily aligned with the goals outlined within the country's NDC. In the meantime, individual US states, cities, corporations, and private entities are free to set their own environmental policy agenda. To illustrate, according to a November 2017 report by the America's Pledge project, an initiative co-chaired by California's Governor and the UN Secretary General's Envoy for Cities & Climate Change, 20 states, 110 cities, and over 1,000 private companies and academic institutions have proclaimed their intentions to support the US NDCs.

Meanwhile, after the US announced its withdrawal, the EU, China, and India all reinforced their commitment to uphold their commitments to the Paris Agreement. Miguel Arias Cañete, the EU Climate Commissioner, issued a statement indicating that the "EU and China are joining forces to forge ahead on the implementation of the Paris Agreement and accelerate the global transition to clean energy". For its part, India also underscored its pledge to uphold its NDCs.

1.3.1 Policies related to demand

Since the previous WOO, fuel quality and vehicle emissions standards have continued to take shape in major consuming regions. While the US is experiencing an easing of fuel economy standards, the EU, China, and India continue to move toward increasing fuel economy regulations and vehicle emissions standards. In the meantime, electric vehicle policy across major consuming regions continues to undergo a re-evaluation, with policymakers attempting to strike a balance between government support and electric vehicle competitiveness.

In the US, on 2 April 2018, the Environmental Protection Agency (EPA) officially announced its rejection of Obama-era 'second phase' Corporate Average Fuel Economy (CAFE) standards for 2022–2025 Model Year cars, which would require a fleet-wide average of 54.5 miles per gallon (mpg). The EPA reviewed these standards and concluded they are "too high" and would freeze them at the 2020 level, 41.7 mpg, through to 2026. As these new standards are less stringent than previously determined by the Obama administration, they may potentially lend support for long-term oil demand growth in the US road transportation sector. However, there are uncertainties affecting the potential fuel economy standards and their application in the US.

The rule-making process to formally establish these new CAFE standards is anticipated to face legal objections from California. The state has traditionally been able to obtain a waiver from the EPA to set higher CAFE standards than those at the federal level, and other states are able to choose to follow California's lead. Consequently, in March 2017, California's Air Resource Board announced that it would follow the Obama-era (54.5 mpg) standards, and 13 other states (in addition to the District of Columbia), comprising about 30% of new US vehicle sales, stated that they would follow suit. The EPA pledged it would challenge California's waiver to set its own standards, and complex legal obstacles are expected to ensue.

On the other hand, in India, policymakers are increasing fuel emissions standards and accelerating their evolution. After gradually imposing Bharat IV (equivalent to Euro 4) fuel quality standards since 2010, in April 2017, the government enacted a nationwide implementation of Bharat IV fuel quality standards. Bharat IV standards limit sulphur content of fuel to 50 parts per million (ppm) from 350 ppm under the previously applicable Bharat III, and emissions of hydrocarbon, nitrogen oxide (NO_x) and particulate matter are also reduced under Bharat IV standards.

The Indian government ambitiously aims to leap-frog; to Bharat VI (Euro 6 equivalent) standards, skipping the Bharat V (corresponding to Euro 5) transition entirely, by 2020, which is four years ahead of the initial schedule. The Bharat VI standards limit sulphur levels to 10 ppm maximum and require an almost 70% reduction in NO_x emissions.

Similarly, following the running of a 2013 pilot program, in January 2017, Chinese authorities established nationwide China V gasoline and diesel fuel quality standards. These standards are similar to Euro V standards. By July 2020, regulators hope to establish even more stringent fuel standards under the nationwide China VI guidelines. The fuel quality program is well underway, as Beijing began rolling out the China VI standards as of January 2017.

Diesel vehicles continue to face tightening regulations, particularly following the 'dieselgate' controversy, as evidenced by EU legislators establishing stricter guidelines on the monitoring and testing of vehicles. This stance is evident in the European Parliament passing a proposal in April 2017 that requires EU member states to finance vehicle exhaust testing centres, and permits EU officials the right to conduct spontaneous checks and penalize offenders with levies. In August 2017, the European Commission announced that new vehicle models must abide by more stringent on-road emissions tests as of 1 September 2017.

In February 2018, Rome joined some other European capitals, including Madrid, Athens, and Paris by announcing a ban on diesel vehicles by 2024. During the same month, the federal court in Germany permitted the cities of Stuttgart and Dusseldorf to ban older internal combustion engine (ICE) vehicles, even though a federal policy on this issue does not exist. The ruling allows for such bans to take place if they are deemed by the cities to be crucial to reducing air pollution.

Meanwhile, the budgetary burdens of electric vehicle promotion in many major energy consuming regions are resulting in a debate amongst policymakers as to the endurance of the electric vehicle industry without government support.

For example, some European countries that are exploring the phasing out of tax incentives for alternative vehicles include Denmark, the Netherlands, and Norway. Denmark is transitioning away from tax incentives for alternative fuel vehicles by way of a five-year phase-out period, from 2016 to 2020. The Netherlands also anticipates a removal of tax incentives for electric vehicles by 2020, which means that electric vehicles would be subject to registration, motor vehicle and carbon dioxide (CO_2) taxes after 2020.

During negotiations on the country's 2018 budget, Norway explored the potential to introduce a $10,500 electric vehicle tax, dubbed by the media as the 'Tesla Tax', on electric vehicles weighing over two tonnes. The purpose of the tax proposal, which failed to materialize in the final fiscal budget, was to compensate for the damage that heavy electric vehicles cause to highway infrastructure, and reveals the budgetary pressures facing countries offering hefty financial incentives to the uptake of electric vehicles.

Meanwhile, electric vehicles are taking centre stage in future Indian transportation policy targets, albeit with some discrepancies. Electric vehicles have been supported by government policies since 2010, when the Ministry of New and Renewable Energy introduced a 20% subsidy for the vehicles through the Alternate Fuels for Surface Transportation Programme. This incentive programme was followed by the National Electric Mobility Mission Plan, which aims to achieve 6–7 million total electric vehicle[5] sales by 2020 and establish Indian automobile manufacturers as industry leaders in related technologies.

To that effect, in April 2017, India's Minister of Power, Piyush Goyal, announced that "by 2030, not a single petrol or diesel car should be sold in the country". However, about one year later, at the launch of India's 'national e-mobility program' in March 2018, the target was scaled down to 30% (instead of 100%) of new electric vehicle sales by 2030. The minister explained that the main purpose behind the announcement is to encourage investment in India's domestic electric vehicle and battery industry.

Meanwhile, in China, the Ministry of Industry and Information Technology set a target for electric vehicles to make up 20% of new vehicle sales by 2025. As early as 2019, Chinese regulators endeavour for electric vehicles to represent 10% of total vehicle sales. One year later, by 2020, regulators plan for five million electric vehicles to be sold (compared to the 440,714 electric vehicles sold in 2017).

In order to achieve these targets, the Ministry of Industry and Information Technology established a strategy dubbed by analysts as the 'cap-and-trade'[6] electric vehicle policy. Within this strategy, automobile manufacturers that manufacture or import over 30,000 vehicles per year are required to obtain and maintain a minimum electric vehicle score, which is based on the production of different forms of zero and low emission vehicle models.

The 'cap-and-trade' policy was originally planned to come into effect in 2018, but in September 2017 it was postponed to 2019, presumably in response to international and local reactions from automobile manufacturers who petitioned the government for more time to prepare for compliance.

The strain of financial subsidy programs on the Chinese government's budget is also evident. Policymakers were reportedly planning to withdraw local electric vehicle subsidies from provinces in 2018. However, the central government decided to maintain local incentives for electric vehicle uptake in the 2018 budget. By 2020, a complete phase-out of incentives is planned, beginning with 20% reductions of subsidies every two years between 2017 and 2020.

1.3.2 Policies related to supply

On the supply front, and in line with the Trump administration's 'energy dominance' strategy, which envisages opening up more federal lands to hydrocarbons exploration and production, the White House released two Presidential Proclamations on 4 December 2017 regarding the reduction of the size of two National Monuments in Utah respectively; the Bears Ears National Monument (BENM) (created by President Barack Obama) and the Grand Staircase – Escalante (created by President Bill Clinton). The latter monument consists of approximately 1.7 million acres (of which President Trump reduced by 50%), and the former monument is roughly 1.35 million acres (of which President Trump reduced by 85%). It should be noted that the Bureau of Land Management (BLM) announced on 15 June 2017 that the compliance dates for the implementation of this rule had been postponed until January 2019.

Additionally, on 22 February 2018, the BLM released a proposal to ease the Obama-era Methane Waste and Prevention Rule, which was issued in November 2016. The Rule would require oil and gas companies to reduce methane flaring, leaks, and venting from their activities on public (federal and tribal) lands. The rule is part of the Obama administration's Climate Action Plan, which set a target for a 40% in emission reductions from oil and gas operations by 2025. However, on 4 April 2018, a federal court rescinded reporting requirements relating to the measuring and reporting of methane gas that is captured, vented, or flared, among other provisions of the Rule.

While these declarations and legislative bills have taken shape in the US, in essence, economics and technology prevail when it comes to the commerciality of natural resource development. As such, in the absence of breakthrough market dynamics, the federal regulatory environment alone is not expected to significantly impact the future of the US tight oil industry. This reality is evident in that significant US tight oil supply emerged under the previous presidential administration's regulatory environment, one that has been described as overly burdensome for the industry.

The nature of federalism in the US generally establishes states as the prime authorities over the regulatory environment within their territories, as long as the minimum federal standards are met. Given that federal regulations are not only being relaxed, but already considered liberal toward the tight oil industry, the onus falls on state level regulators to govern the industry. Even then, energy companies have already voluntarily established standards that are stricter than those imposed by federal and state regulators, indicating that such standards may result in efficiency and/or reputational gains.

1.4 Technology and innovations

Proven technologies, as well as new innovations, have always been important drivers for the energy industry as a whole and, the oil industry, in particular. The WOO looks to review, analyze and incorporate the impacts of existing technologies into medium- and long-term projections. Moreover, it also aims to provide input on new technology innovations and scientific discoveries.

The Reference Case assumes an evolutionary development of existing technologies, while considering new technologies as upcoming elements of the global energy business. The following provides a brief overview of technology, with more detailed analysis in Chapter 7.

1.4.1 Conventional and renewable power generation

Conventional power generation remains by far the most important segment for the provision of electric energy. Simultaneously, it is an important consumer of primary energy, mainly coal and gas. Oil has a very limited role in this segment and is mainly used for transport and petrochemical products. It should be noted, however, that conventional power generation is approaching its technology limits when considering efficiency.

Supercritical coal-fired power plants have already attained efficiency of 45% and beyond. Although combustion temperatures of more than 1,000°C would in theory allow substantially higher efficiency from a pure physical point of view, technical limitations and especially the need for high temperature heat exchangers – coal-fired power plants are so-called externally fired thermal engines – impose a limit that is difficult to overcome. Moreover, there are also challenges from a financial point of view.

In terms of natural gas, it has evidently seen its use in power generation increase; in some regions it has even been able to replace coal given abundant and cheap natural gas resources, especially in the US. Additionally, it should be noted that most of the reduction in CO_2 emissions in the US over the last ten years is down to the shale gas boom that has pushed gas to replace coal, albeit not from an ecological viewpoint. It has essentially been due to finance.

It is important to recognize, however, that Combined-Cycle Gas Turbine (CCGT) technology used for large power plants is already the most efficient, reaching 62.2% net efficiency (the current world best). This success means that efficiency is already close to the thermodynamic limit imposed by physical laws, thus limiting further technology development in this area. Engineers are aware that further potential efficiency gains are less than 10% at most; hence, all further improvements will likely be very difficult, costly and in the end will not provide further major breakthroughs. Nevertheless, they will remain by far the least CO_2-emitting fossil-fuelled power plants, an advantage that should not be underestimated as countries and regions look to tackle climate change.

Renewables have appeared mainly for two reasons: energy security for countries that do not own substantial conventional energy resources, for example, those in Europe, and as a strategy to reduce Greenhouse Gas (GHG) emissions. As a consequence, important investments – often through substantial direct and indirect subsidies – have been made to develop new technologies in this area to make these renewables competitive. The success of investments into technologies – mainly wind and solar – has helped drive down the power generation costs of these renewables faster than expected.

Wind turbines, for example, have expanded the range of wind speeds that can be accommodated, both for low-speed and high-speed wind. In appropriate areas – mainly near-coastal or offshore – a capacity factor of nearly 50% can be achieved. In the case of solar, the efficiency of photovoltaic (PV) cells is constantly increasing while their production costs have undergone a steep decline over the past 10–15 years. It can be expected that the costs of wind and solar power will decline further in the foreseeable future and will soon meet grid parity, at least 'behind the meter', in favourable cases.

Nevertheless, the most serious drawback for wind and solar remains: the disadvantage of a limited (in the case of wind) or non-existent baseload capability (in the case of solar). Power storages, which may capture and later reproduce power at the required cost and capacity level, do not exist and it is expected that it will be difficult to provide them in the foreseeable future, although battery storage is making some progress. Nevertheless, given current and near-future battery technology – mainly lithium-ion – competitive large-scale power storage seems to be very unlikely when compared to fossil-fuel back-up plants.

The alternatively proposed strategy of interconnecting the largely distributed renewable power generation continent-wide – or in the future potentially worldwide by means of high-voltage direct current transmission lines would obviously require substantial technology development and investments. In addition, it would probably trigger protests from the affected population, as well as ecologists. Such large-scale grids can also be viewed as somewhat contradictory to the original principle of renewables that foresaw their use for local power generation and local consumption. Therefore, the Reference Case takes into account such secondary effects impacting the straightforward expansion of renewable power.

Even with a considerable up-scaling of the use of renewables for power generation – they have recently been the energy source with the highest build-up at the global level, surpassing coal and gas – fossil fuels will remain essential to satisfy the world's energy demand in a reliable and secure way. To reduce GHG emissions, and to comply with the Paris Agreement, carbon capture and storage (CCS), as well as carbon capture and utilization (CCU), has garnered more space in public discussion as a means to avoid the direct release of CO_2 into the Earth's atmosphere.

Mainly in conjunction with enhanced oil recovery (EOR), such technologies may provide a 'win-win' situation: reducing GHG and maintaining the production of already mature oil and gas fields. Some oil and gas producers have had positive experiences with re-injecting CO_2 into oil wells over several decades, which suggests that CCS is a safe and technically viable strategy. However, for geological and political reasons, CCS is likely to remain applicable only in certain locations.

The Reference Case also pays attention to nuclear power, currently undergoing further development, mainly by China, Russia and India. As a nearly CO_2-free energy source – power plant construction and the continuous mining of uranium and its processing and enrichment causes some GHG – it is again considered an additional pillar of reliable power generation. It should be mentioned that nuclear power is nearly carbon-free, although not renewable. The build-up of nuclear capacity is based on so-called inherently safe third and fourth generation reactor types to avoid the serious accidents that have occurred in the past.

1.4.2 Residential and industrial consumers

The primary energy consumption of residential and industrial consumers is not often part of the main energy discussion, although it evidently takes up a substantial share of global energy consumption. One reason is that residential consumers employ a broad variety of energy resources – from fire wood to state-of-the-art heat pumps and thermo-solar systems – and typically require low-grade energy (low-temperature thermal energy instead of electric power). In a similar way, the major share of industrial energy consumption refers to heat at various temperature levels. Examples range from the heating and hot water requests of households, through dairy and juice plants that need heat for pasteurizing purposes, up to the broad range of requirements for chemical and petrochemical industries, where heat is an essential element for running the necessary chemical reactions.

In recent years, combined heat and power generation (CHP) has become more attractive and more advanced technical solutions have become available. Large industrial users typically employ gas turbines whose exhaust heat is captured for thermal applications, while smaller users – for example, condominiums and hospitals – rely on reciprocating piston engines. The expansion of district heating systems has generated a substantial request for such CHP plants, which may even be based on the combustion of non-recyclable waste, or so-called 'waste-to-energy' projects.

1.4.3 Road transportation – the main consumer of oil

While for stationary energy supply a broad variety of technologies and sizes exist, the options narrow substantially the more mobile an application becomes. While large ships still offer space for steam generators and other heavy units, airplanes naturally have to reduce engine weight and size to a minimum, with road transportation sitting in between the two.

ICEs have been developed to avoid the large external furnaces and heat exchangers required for steam power plants. Over the last 100 years or so, they have become very successful and have displaced all other types of drive, including electric drives – which had been a serious competitor at the beginning of the passenger car era – and steam engines, which triggered the railroad revolution in the early 19th century.

The secret of the ICE's success has been the combination of a compact, cheap and reliable engine, with an abundant and economical oil-based fuel. The Reference Case assumes that the general dominance of these engines will remain for the foreseeable future, but does take into account the current discussions, developments and possible future advancements of electric mobility.

The advent of powertrain electrification is already a reality – encompassing hybrid electric vehicles (HEV), plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV) – and technology development is undergoing a significant push, which will see it continue to advance its role in the road transportation sector. However, these advances are not only expected to contribute to the new segment of electric or partially-electric mobility, but also to an accelerated development of the traditional ICE in view of both fuel efficiency and pollution.

ICEs remain the one and only power source for HEVs, while PHEVs and mainly BEVs rely on electric power and as, a consequence, incorporate batteries of increasing capacity. Battery costs are still falling, and in a significant manner, with discussions now shifting towards the supply of the employed materials, mainly lithium and cobalt.

Today, manufacturers are already offering a far broader range of partially or fully electrified models, or have announced ambitious electrified car model programs for the near future. Both elements are driving the acceptance of electrified vehicles; consequently, the Reference Case shows an upward revision mainly for PHEVs and BEVs. Nevertheless, ICE powered vehicles are expected to remain the cheapest vehicles for many decades and continue to dominate the fleet.

It should also be noted that the Reference Case has revised slightly downward the share of diesel passenger vehicles, compared to last year's WOO, following recent emission discussions and the announcement by several car manufacturers to focus more priority on electrified or partially electrified vehicles, rather than diesel development in the future.

Shared mobility, expedited by internet-based systems, is growing swiftly, mainly in urbanized areas and this may reduce the number of vehicles, although not necessarily the amount of passenger kilometres travelled. It is, therefore, currently unclear whether energy consumption for urban traffic may decrease or increase in the long-term. Car sharing, for example, may not only replace existing vehicles, but may also be used as an alternative to sometimes uncomfortable or temporarily unavailable public transport, for example, during the night.

Considering GHG emissions, as well the potential to reduce pollution, natural gas shows certain advantages. Some car manufacturers have, therefore, announced they will reinforce their offer of models using Compressed Natural Gas (CNG) as a fuel. The Reference Case has, consequently, upwardly-revised the penetration of such CNG vehicles.

While the passenger car sector can be dictated by a customer's emotions – over models, aesthetics, extras etc. – the market for commercial vehicles can be very different. Fleet managers usually decide based on a thorough overall cost analysis. Because fuel costs play an important role, diesel engines have been the near exclusive choice for commercial vehicles due to their higher efficiency. Additionally, some governments favour diesel fuel over gasoline in terms of taxes. Adding the higher energy density on a per-volume base makes diesel by far the most economic technology for commercial vehicles.

The importance of such cost arguments for the commercial sector, is shown by the fact that with oil prices at a generally sustained high-level during the period 2011–2014, liquefied natural gas (LNG) gained greater attraction as an alternative to diesel beyond the established markets. In general, the Reference Case assumes that heavy-duty diesel engines have already reached an efficiency level that leaves only little room for improvement in terms of evolutionary technology development. However, some shift from diesel fuel towards LNG may occur.

1.4.4 Air transportation – taking off

Today, air transportation relies entirely on fossil fuels; only a few tests have been made to investigate and – in the end – demonstrate that fuels derived from biomass may be suitable for this sector.

The first plane flight in history took place because engine technology was by then sufficiently advanced, in view of power-per-mass, to lift the plane and the engine into the sky. This focus on low weight has continued ever since and, as a consequence, gas turbines are today the engines exclusively used for commercial airliners. They offer by far the best ratio of power-to-weight. Only some older and smaller propeller planes still use piston engines.

Nevertheless, the era of electrification is also beginning in this segment, with the first small test planes equipped with electric motors running on battery power. Hybridization is also a focus, for example, in the case of helicopters, where engine-outs are among the most critical situations for fatal crashes.

It is important to realize that the overall weight of the powertrain including the energy reservoir – engine plus fuel, in the case of combustion engines, and electric motor plus battery in the case of electrified planes – is the decisive parameter. Today, and for the foreseeable future, flight gas turbines together with oil-based fuel will not be matched by electric powertrains.

Weight substantially affects fuel consumption and payload – the heavier the plane, the lower the payload (passenger numbers or tons of freight that can be transported). Technology advances have already allowed the replacement of the traditional aluminium framework with carbon fibre reinforced composites that provide the same strength at lower weight. Together with innovative wing design – notably the so-called winglets or sharklets at the wing tips – the specific fuel consumption (energy content of the burnt fuel per passenger or ton per distance) of today's commercial airliners is at a historical low. Future technology developments that are considered in the Reference Case comprise geared fans and further stretched wings; for example, Boeing's 777X employs for the first time foldable wing tips.

Improving flight management and the more densely spaced flight control, not least due to the increasing number of reliable satellite-based global navigation systems (GPS, Galileo, GLONASS, etc.) are also expected to advance air traffic control and navigation substantially. For example, the actually flown distance may be reduced and idle engine operation diminished. However, these technology advances are anticipated to occur at an evolutionary pace until the end of the WOO forecast period in 2040.

1.4.5 Marine transport – the backbone of global business

Modern large ICEs for marine transport are the most efficient combustion engines – without a so-called bottoming cycle – and may achieve efficiencies even beyond 50%. Well-known bottoming cycles or Waste Heat Recovery (WHR) engines are the steam turbines of CCGTs, which capture the exhaust heat of the main combustion engine – the gas turbine – to generate additional power. Even when employing available WHR engines, future improvements are limited. Hull innovations and air lubrication are more perhaps promising and may contribute to reduce fuel consumption in the future.

Recently agreed IMO regulations (see section 3.1.3 for more details) that focus on reducing sulphur dioxide (SO_2) emissions may be complied with by using scrubbers or by burning cleaner fuels. LNG is one of the obvious candidates, but it currently lacks bunkering infrastructure at a global level. Nevertheless, all large engine manufacturers already offer dual-fuel engines that may run either on liquid fuel or LNG.

1.4.6 Technologies related to oil production

Given the far larger variety of applications on the demand side, there has been a correspondingly broader range of technologies than on the supply side. Nevertheless, technology developments on the supply side should not be underestimated just because they garner less media or public attention.

The most prominent developments on the supply side in recent years have been the advent of tight oil as a consequence of technology developments that efficiently combine the already known technologies of directional drilling and hydraulic fracturing. This advancement has made available oil resources that were formerly considered uneconomic or even inaccessible. Current and ongoing technology improvements, as well as the steep learning curve of the involved companies, have brought down production costs significantly. Moreover, technology improvements are targeting issues like the use of hazardous proppants or venting associated gas, for example, to convert tight oil production into a more environmentally friendly business. The same applies to oil sands, where in-situ methods are taking over and bringing down production costs, as well as helping reduce the environmental impact.

As has been mentioned already, the combination of CCS/CCU and EOR may substantially increase the production of mature oil fields and considered a 'win-win' situation.

1.4.7 IT, big data and artificial intelligence

The single-most important technology –based revolution over the course of the last few decades has been the fast development of microelectronics in association with highly innovative data processing methods. For instance, today's average smartphones would have been considered only a few decades ago as supercomputers. The energy business, in general, and the oil business, in particular, is no exception when it comes to the application of IT power.

Looking ahead, the general movement towards collecting and processing a vast amount of data from a broad variety of sources to provide an overall and detailed picture, so-called 'Big Data' strategies, will play an increasingly important role in the future. The logical next step – Artificial Intelligence (AI) – is currently under development and will likely significantly improve production as a whole, as well as the maintenance-intense oil and gas business, in particular. Autonomous and intelligent robots may also take over an important amount of currently hazardous or time-consuming labour, while the analysis of data collected in the course of exploration runs can be analyzed in a more automated manner through AI.

Energy demand

Key takeaways

- The OPEC Reference Case sees total primary energy demand increasing from 274 million barrels of oil equivalent per day (mboe/d) in 2015 to around 365 mboe/d in 2040, which is an increase of 91 mboe/d or average annual growth of 1.2% p.a.
- Almost 95% of the increase in the total primary energy demand is accounted for by Developing Countries (including China and India) with an average annual growth of 1.9% p.a. over the forecast period.
- Energy demand in India and China is expected to increase by around 22 mboe/d and 21 mboe/d, respectively, in the period 2015–2040, which is more than 50% of the energy demand growth in Developing countries.
- Developing countries are projected to increase its share in global energy demand from 52% in 2015 to around 63% in 2040.
- The fuel with the largest demand growth is natural gas, increasing by almost 32 mboe/d between 2015 and 2040, with an annual average growth rate of 1.7%.
- Other renewables (mainly solar, wind and geothermal) are projected to have the highest percentage growth rate at around 7.4% p.a. on average in the forecast period. Nevertheless, due to the low initial base, the increase in absolute terms is calculated at around 19 mboe/d between 2015 and 2040.
- Oil sees a relatively low growth rate of 0.6% on average between 2015 and 2040. However, due to a large base, oil demand is still expected to increase by 15 mboe/d between 2015 and 2040.
- Fossil fuels (coal, oil and gas) are projected to remain the dominant part of the energy mix at the global level, with a share of 75% in 2040, albeit decreasing from above 81% in 2015.
- Global coal demand is expected to grow only slightly throughout the outlook period from 2015–2040, and is expected to peak after 2030.
- Nuclear energy demand is anticipated to increase by more than 9 mboe/d in the forecast period, with an annual average growth rate of around 2% p.a.
- Biomass and hydropower demand are projected to increase by 8.5 mboe/d and 3.3 mboe/d, respectively, between 2015 and 2040.
- Total annual energy-related CO_2 emissions are set to increase from 33 billion tonnes (bt) in 2015 to around 39 bt by 2040, with coal remaining the largest source of CO_2 emissions, accounting for 15.7 bt of emissions in 2040.

2.1 Major trends in energy demand

The future development of the global energy system and the related energy mix will be influenced by several factors, such as demographic and economic development, the availability of different fuels, global and regional energy policies, including those related to climate change, as well as technological development. In addition, changing consumer behaviour and evolving lifestyles could significantly determine energy demand patterns in the long-term. Production costs and potential substitution effects between the fuels should also not be overlooked. Finally, geopolitical concerns in many countries remain an important driving force in forming the future energy mix.

While a large number of global energy market participants recognize the challenges related to climate change and agree with the necessity to reduce CO_2 emissions through the so-called 'energy transition', concrete pathways and timelines remain unclear. While some market participants are projecting a rather fast energy transition, supported by the falling cost of renewables, others are pointing at the "massive infrastructural needs"[7], related to the inertia of the global energy system. However, all parties recognize the importance of some crucial technological pre-requisites for the increasing deployment of renewable sources, such as potential further developments in energy storage.

Climate change-related policies are evidently a major policy issue with a large number of countries/regions giving strong support to the 'Paris Agreement', including the EU and China, and despite the decision of the current US administration to pull out. In a recent meeting between the EU and China in July 2018, both parties reconfirmed support for the Paris Agreement. The core challenge relates to the numerous uncertainties, and how this play out in terms of finding a path to move forward.

In many cases, climate change policies overlap with energy policies targeting local pollution. For instance, the Chinese government decided to shut down a large number of old and inefficient coal power plants burning low-quality coal during 2017 and to switch to natural gas in the short-term. In Germany, the top administrative court allowed local authorities to ban diesel cars in order to protect the local air quality in early 2018, which could potentially affect more than 10 million older diesel vehicles. Other large energy consumers such as India also face significant local air pollution problems, which could in turn lead to policy measures that affect the energy mix towards more climate friendly technologies.

As a consequence, the energy mix is shifting in different ways. The most obvious solution is to increase the share of low-polluting substitutions, including renewables, but also nuclear and natural gas. However, some countries will also continue to rely on fuels such as coal, while at the same time increasing the efficiency of energy transformation and introducing modern pollution management. In line with this, China promotes so-called 'clean coal', which aims for air quality improvement and to centralize power and heat generation in state-of-the art units with high transformation efficiency. As a consequence, these strategies will lower the consumption of the primary fuel, while at the same time possibly increasing the supply of final energy.

The expansion of the electric vehicle sector continued in 2017 with more than 1 million units added. China contributed to more than half of the global additions, which is in line with its strong policy support for electric vehicles. This global trend is likely to continue in 2018, with even more electric vehicles added to the global fleet.

However, the long-term picture for electric vehicles remains somewhat uncertain, due to a number of factors such as economics, the cost of electric vehicles relative to conventional vehicles, concerns regarding range and charging infrastructure, as well as the continuity of the governmental support. Overall policies related to the road transportation sector and the further development of conventional engines provides another layer of uncertainty in the years to come.

Renewable production costs continued to decline in 2017 (especially for utility-scale PV) with some new renewable projects delivering power at costs lower relative to fossil fuels. Record low auction prices were recorded, with solar PV falling as low as $0.03/kilowatt hour (kWh) in several countries in the Middle East and Latin America.

Taking all these factors into consideration, the OPEC Reference Case sees energy demand increasing from 274 mboe/d in 2015 to around 365 mboe/d in 2040 (Table 2.1). This is an increase of 91 mboe/d, or average annual growth of 1.2% p.a. Almost 95% of the increase is accounted for by Developing Countries (including China and India), with an average annual growth of 1.9% p.a. A modest increase between 2015 and 2040 is projected for Eurasia at around 4.5 mboe/d, with average annual growth of 0.7% p.a. OECD countries are likely to see only a small increase

Table 2.1
Total primary energy demand by region

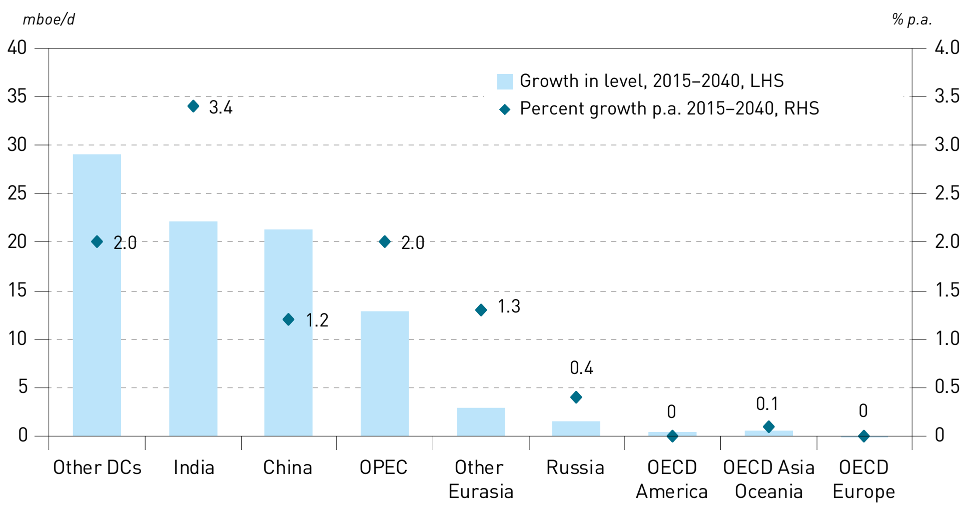
	Levels *mboe/d*				Growth *%p.a.*	Share of global energy demand *%*			
	2015	**2020**	**2030**	**2040**	**2015–2040**	**2015**	**2020**	**2030**	**2040**
OECD America	55.0	56.9	56.6	55.4	0.0	20.1	19.1	16.9	15.2
OECD Europe	35.6	37.5	36.7	35.5	0.0	13.0	12.6	11.0	9.7
OECD Asia Oceania	18.2	18.7	18.8	18.7	0.1	6.6	6.3	5.6	5.1
OECD	**108.8**	**113.1**	**112.1**	**109.6**	**0.0**	**39.7**	**38.1**	**33.5**	**30.1**
China	60.8	66.8	76.9	82.2	1.2	22.2	22.5	23.0	22.5
India	16.9	20.7	29.9	39.1	3.4	6.2	7.0	8.9	10.7
OPEC	20.0	22.0	28.0	32.8	2.0	7.3	7.4	8.4	9.0
Other DCs	44.9	50.8	62.5	74.1	2.0	16.4	17.1	18.7	20.3
DCs	**142.6**	**160.3**	**197.3**	**228.2**	**1.9**	**52.1**	**54.0**	**58.9**	**62.6**
Russia	14.4	14.9	15.5	16.1	0.4	5.3	5.0	4.6	4.4
Other Eurasia	7.9	8.8	9.9	10.8	1.3	2.9	3.0	2.9	3.0
Eurasia	**22.3**	**23.7**	**25.4**	**26.9**	**0.7**	**8.2**	**8.0**	**7.6**	**7.4**
World	**273.7**	**297.1**	**334.9**	**364.7**	**1.2**	**100**	**100**	**100**	**100**

of less than 1 mboe/d, which points to stagnating energy demand in this regional group as the market is already energy efficient and population growth is limited.

The imbalance between the global regions is the result of stronger population and economic growth, as well as accelerating urbanization rates in Developing countries, where an increasing number of people are expected to gain access to modern energy services. At the same time, OECD countries see slower GDP growth going forward, which in combination with increasing energy efficiency efforts and a rather saturated market leads to stagnating long-term energy demand.

Looking in more detail (Figure 2.1), energy demand in Developing countries is projected to increase by almost 86 mboe/d between 2015 and 2040, with India and China the two most important growth contributors. Based on the OPEC Reference Case, energy demand in India and

Figure 2.1
Growth in primary energy demand by region, 2015–2040



China will increase by around 22 mboe/d and 21 mboe/d, respectively, in the period 2015–2040. This is more than 50% of the energy demand growth in Developing countries over the forecast period.

Demand growth in both countries has been revised down from the last Outlook, especially in China. A downward revision of close to 3 mboe/d in China for 2040 is in line with a less optimistic GDP growth outlook, as well as increasing efforts to replace inefficient energy transformation units with central and highly efficient units, which will reduce primary energy demand growth. In addition, an upward revision in 'other renewables' in China contributes to a further reduction in primary energy demand. Similarly in India, more optimism on 'other renewables' and less coal additions, means a slight downward primary energy demand revision of around 0.6 mboe/d in 2040.

At the same time, the group of 'Other Developing countries' (excluding India, China and OPEC) is projected to grow by around 2% p.a. This is an increase of around 29 mboe/d over the forecast period. This includes countries at different stages of development, predominantly in Asia, Africa and Latin America. Significant growth is also expected in OPEC countries, which see an increase from 20 mboe/d in 2015 to almost 33 mboe/d in 2040. This comprises an annual average growth rate of around 2%.

Developing countries as a group are projected to increase its share in global energy demand from 52% in 2015 to around 63% in 2040. The growing importance of Developing countries on the global energy scene also means a drop in the relevance of OECD regions. Energy demand in OECD countries is expected to see marginal medium-term growth, which is then expected to turn negative in the last decade of the outlook. Consequently, the OECD market share in global energy demand is projected to fall from around 40% in 2015 to 30% in 2040.

Looking at the projected demand for single energy sources, the Reference Case assumes a significant change in the overall composition of the energy mix (Table 2.2 and Figure 2.2).The further expansion of renewables and natural gas is expected, while demand for coal and oil is anticipated to slow or even become negative in some regions. The fuel with the largest demand growth is natural gas, increasing by almost 32 mboe/d between 2015 and 2040. This corresponds to an annual growth rate of 1.7% p.a. Consequently, the share of natural gas in the global energy mix is calculated at 25% in 2040, up by 3.3 percentage points from 2015.

'Other renewables' are projected to have the highest average percentage growth rate of around 7.4% p.a. over the forecast period. Nevertheless, due to the low starting base, the increase in

Table 2.2
World primary energy demand by fuel type

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2015	**2020**	**2030**	**2040**	**2015–2040**	**2015**	**2020**	**2030**	**2040**
Oil	86.3	93.4	98.9	101.3	0.6	31.5	31.4	29.5	27.8
Coal	76.9	79.2	82.1	81.0	0.2	28.1	26.7	24.5	22.2
Gas	59.4	66.1	79.1	91.3	1.7	21.7	22.3	23.6	25.0
Nuclear	13.5	15.4	19.3	22.6	2.1	4.9	5.2	5.8	6.2
Hydro	6.7	7.4	8.7	10.0	1.6	2.5	2.5	2.6	2.7
Biomass	26.9	29.0	32.5	35.5	1.1	9.8	9.8	9.7	9.7
Other renewables	3.9	6.6	14.3	23.1	7.4	1.4	2.2	4.3	6.3
Total	**273.7**	**297.1**	**334.9**	**364.7**	**1.2**	**100**	**100**	**100**	**100**

absolute terms is calculated at around 19 mboe/d between 2015 and 2040. This will lead to a significant increase in the share of 'other renewables' to above 6% in 2040, from below 1.5% in 2015.

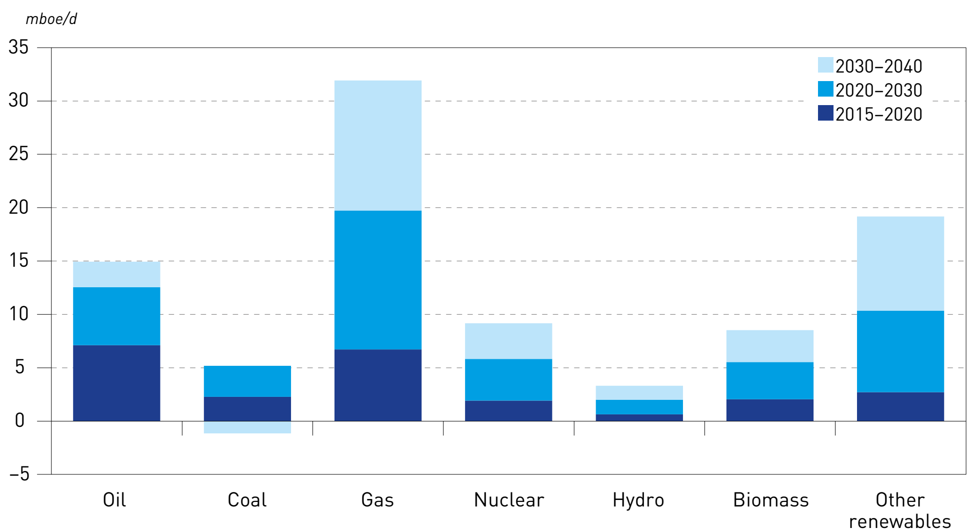
Strong demand growth is also expected for nuclear, with an average growth rate of 2.1%. This equates to an expansion of just above 9 mboe/d in the outlook period, based on strong expansion in Developing countries and supported by the expected return of nuclear energy in Japan.

According to the Reference Case, the utilization of biomass (including solid biofuels, waste, biogas, liquid biofuels) is expected to increase by 8.5 mboe/d between 2015 and 2040. Better waste management in Developing countries, and in line with increasing urbanization, as well as state support for several kinds of biomass-based fuels, such as liquid biofuels and biogas, is the major reason for expanding biomass usage. Hydropower is expected to increase by around 3.3 mboe/d, mostly in Developing countries, based on still untapped resources.

Oil[8] sees a relatively low growth rate of 0.6% on average between 2015 and 2040. However, due to a large initial base, oil demand is expected to increase by almost 15 mboe/d to just above 101 mboe/d in 2040. Consequently, the share of oil in the energy mix is projected to decline from around 31.5% in 2015 to just below 28% in 2040. Nevertheless, oil is expected to remain the fuel with the largest share in the energy mix in 2040, ahead of both gas and coal.

Coal is the fuel with the lowest average growth rate of just 0.2% p.a. Moreover, coal is the only fuel projected to reach its peak at the global level during the forecast period. According to the Reference Case, coal demand will reach its peak level of around 82 mboe/d by 2030, and then decline marginally in the last decade of the outlook.

Figure 2.2
Growth in primary energy demand by fuel type, 2015–2040



Despite relatively low demand growth rates (specifically for coal and oil), fossil fuels are projected to remain the dominant part of the global energy mix. The share of the three fossil fuels is expected to drop from above 81% in 2015 to a share of 75% in 2040. For oil and gas combined, the share is estimated to say fairly static at around 52–54% for the entire forecast period.

The slowdown in energy demand for fossil fuels is partly driven by the increasing efficiencies and the energy transformation in power generation, as well as in transportation. While being in line with the more efficient use of primary energy, increasing efficiencies are also targeted by various environmental policies aimed at reducing local air pollution. For instance, these include phasing out old inefficient coal boilers with the intention to replace them with more efficient, large coal units with modern environmental standards. Such measures do result in lower primary energy demand, although this does not automatically translate into lower final energy demand.

Furthermore, the projected expansion of renewables (predominantly solar and wind) disproportionally cuts the demand for fossil fuel energy sources. Part of this shift, however, is related to the fact that this Chapter considers energy demand from the primary side which accounts differently for transformation losses between fossil fuels and renewables.

In this regard, it is also worth mentioning that this year's downward revision to primary energy demand by some 7 mboe/d to just below 365 mboe/d in 2040 can to a great extent be explained by the increasing penetration of renewables and the assumed higher efficiencies, especially in power and heat generation. By implication, this means that the downward revision to primary energy demand in this Outlook, compared to last year projections, is less pronounced when considering final energy demand.

2.2 Energy demand by region

Based on the Reference Case, the evolution of primary energy demand at the regional level is different due to a variety of reasons. The current structure and the level of technological development in major regions, as well as differences in economic and population development, combined with resource availability, are the major reasons for these variances. Tables 2.3–2.5 show primary energy demand by fuel type for the major regions: OECD, Developing countries and Eurasia.

While OECD and Developing countries had an identical share in terms of fossil fuels in the 2015 energy mix (81%), the shares across the three fossil fuels shows major differences. The energy mix in Developing countries was dominated by coal (almost 38%) in 2015, reflecting the availability of the fuel and is also partly accounted for by the domestic use of coal for heating and cooking. At the same time, the most dominant fuel in the OECD's energy mix was oil (38%) in 2015, which reflects the level of economic development. In Eurasia, natural gas was the most important fuel in 2015, at 47% of the energy mix, based on the region's massive gas resources.

At the same time, there are other obvious differences, such as a relatively high share (close to 10%) of nuclear energy in OECD countries in 2015, while the share of nuclear energy in Developing countries is estimated at only 1%. On the other hand, the share of biomass in

Table 2.3
OECD primary energy demand by fuel type, 2015–2040

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2015	2020	2030	2040	2015–2040	2015	2020	2030	2040
Oil	41.2	42.8	38.8	33.6	–0.8	37.9	37.9	34.6	30.6
Coal	19.0	17.7	14.9	12.6	–1.6	17.4	15.6	13.3	11.5
Gas	27.7	29.4	30.8	31.8	0.6	25.4	26.0	27.4	29.0
Nuclear	10.3	10.7	11.4	11.8	0.5	9.5	9.4	10.2	10.8
Hydro	2.4	2.5	2.7	2.9	0.7	2.2	2.2	2.4	2.6
Biomass	6.2	6.9	8.1	9.1	1.5	5.7	6.1	7.2	8.3
Other renewables	2.0	3.1	5.4	7.9	5.7	1.8	2.7	4.8	7.2
Total	**108.8**	**113.1**	**112.1**	**109.6**	**0.0**	**100**	**100**	**100**	**100**

Developing countries was at 14% in 2015, which is partly due to the high usage of traditional biomass, such as wood, in the residential and commercial sector, predominantly in rural areas. Quite the reverse is true in OECD countries, with a biomass share of just under 6% in 2015. This is mostly used in power and heat generation, as well as in the production of biofuels and biogas.

Table 2.4
Developing countries primary energy demand by fuel type, 2015–2040

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2015	2020	2030	2040	2015–2040	2015	2020	2030	2040
Oil	40.1	45.1	54.1	61.7	1.7	28.1	28.1	27.4	27.0
Coal	53.9	57.4	63.1	64.5	0.7	37.8	35.8	32.0	28.3
Gas	21.2	25.7	36.8	47.6	3.3	14.9	16.0	18.7	20.8
Nuclear	1.5	2.9	5.7	8.1	7.0	1.1	1.8	2.9	3.6
Hydro	3.9	4.3	5.4	6.5	2.1	2.7	2.7	2.8	2.9
Biomass	20.1	21.4	23.6	25.4	0.9	14.1	13.4	12.0	11.1
Other renewables	1.9	3.5	8.5	14.5	8.5	1.3	2.2	4.3	6.3
Total	**142.6**	**160.3**	**197.3**	**228.2**	**1.9**	**100**	**100**	**100**	**100**

Table 2.5
Eurasia primary energy demand by fuel type, 2015–2040

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2015	2020	2030	2040	2015–2040	2015	2020	2030	2040
Oil	5.0	5.5	5.9	6.0	0.7	22.3	23.1	23.1	22.2
Coal	4.0	4.1	4.1	3.9	–0.2	18.0	17.3	16.0	14.4
Gas	10.5	11.0	11.6	12.0	0.5	47.2	46.6	45.6	44.7
Nuclear	1.6	1.8	2.2	2.7	2.0	7.4	7.7	8.7	9.9
Hydro	0.5	0.5	0.6	0.6	1.0	2.2	2.2	2.2	2.3
Biomass	0.6	0.7	0.8	1.0	1.7	2.8	2.8	3.2	3.5
Other renewables	0.0	0.1	0.3	0.8	12.2	0.2	0.3	1.1	2.8
Total	**22.3**	**23.7**	**25.4**	**26.9**	**0.7**	**100**	**100**	**100**	**100**

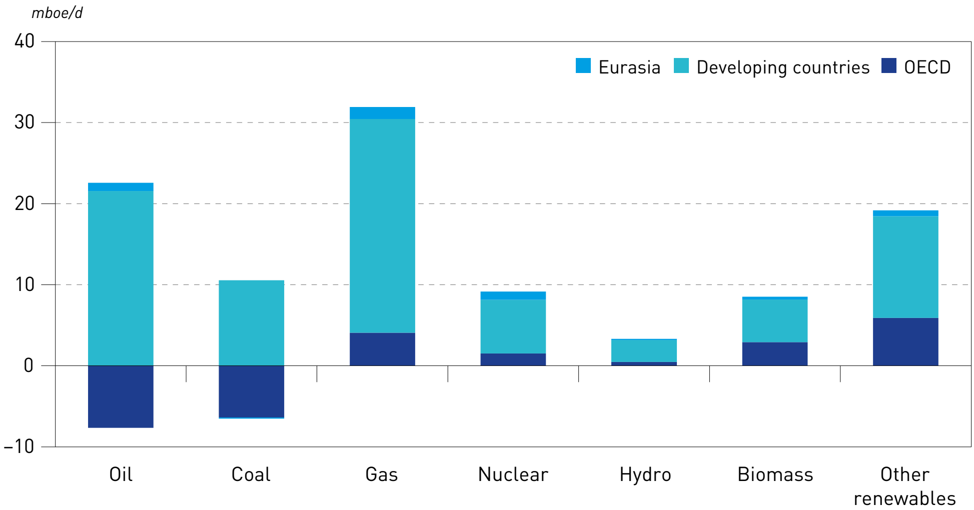
To some extent, those starting points determine the evolution of long-term regional energy demand. Future economic development and population growth, as well as technological developments, are other major driving forces. Finally, national and regional energy policies, in combination with global initiatives such as the Paris Agreement to limit carbon emissions, are also influencing the path of future energy demand.

Figure 2.3 shows demand growth for different fuels by major regions. Demand growth in Developing countries at around 86 mboe/d in the period 2015–2040 accounts for almost 95% of the expansion. Energy demand in Developing countries is expected to increase across all fuel types, led by natural gas (26.5 mboe/d), oil (21.5 mboe/d) and 'other renewables' (12.5 mboe/d).

In terms of the growth rates, it is 'other renewables' that exhibits the highest average growth rate at 8.5% p.a., followed by nuclear at 7% p.a. Both 'other renewables' and nuclear start from relatively low absolute levels in 2015, which is why their overall increment is lower compared to fossil fuels.

In the OECD, the overall growth is just under 1 mboe/d between 2015 and 2040. However, this is the result of two opposite trends in OECD regions. On the one hand, demand for some fuels is anticipated to increase, such as 'other renewables', with projected growth of almost 6 mboe/d over the forecast period. Limited gains are also expected for natural gas, biomass and nuclear, with demand growth of 4 mboe/d, 3 mboe/d, 1.5 mboe/d, respectively. However, the region is also expected to reduce its reliance on traditional fossil fuels, with oil and coal demand, anticipated to decline by around 7.5 mboe/d and 6.5 mboe/d, respectively.

Figure 2.3
Growth in energy demand by fuel type and region, 2015–2040



Finally in Eurasia, energy demand is projected to increase by around 4.5 mboe/d, or 0.7% p.a. on average, between 2015 and 2040. The increase is driven by economic development and supported by the region's vast energy resources.

Regarding specific countries, it is China and India that remain the driving forces of future energy demand. In these two countries combined energy demand is estimated to increase by almost 44 mboe/d between 2015 and 2040, which is more than half of the projected growth for the group of Developing countries. Consequently, China and India are projected to reach a combined energy demand of around 121 mboe/d in 2040. This is around 53% of energy demand in Developing countries and around 33% of global demand in 2040. It underscores why developments in these two countries are of great importance for the overall energy demand outlook.

In China (Table 2.6), energy demand is expected to increase by more than 21 mboe/d in the period from 2015–2040. However, while growth in the first part of the period remains strong, the demand increment in the last decade is projected to slow markedly, as the market becomes increasingly saturated. One of the most significant developments is an expected peak in China's coal demand after 2030. This is in line with official targets to limit the installed coal capacity, as well as to increase its efficiency of existing power plants. As a consequence, the country's share of coal in the energy mix is anticipated to decline from above 65% in 2015 to 47% in 2040. At the global level, however, China is expected to remain the most dominant consumer of coal, with a share of around 48% in 2040, albeit down four percentage points from 2015.

Table 2.6
China primary energy demand by fuel type, 2015–2040

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2015	2020	2030	2040	2015–2040	2015	2020	2030	2040
Oil	11.0	12.8	14.7	16.1	1.5	18.0	19.1	19.2	19.5
Coal	39.8	40.7	41.5	39.1	–0.1	65.6	60.9	54.0	47.5
Gas	3.2	4.4	7.1	9.3	4.4	5.3	6.6	9.3	11.3
Nuclear	0.9	2.0	4.3	6.1	8.0	1.5	3.1	5.6	7.4
Hydro	1.9	2.1	2.4	2.7	1.4	3.2	3.1	3.2	3.3
Biomass	3.0	3.1	3.2	3.6	0.8	4.9	4.6	4.2	4.4
Other renewables	0.9	1.7	3.6	5.3	7.1	1.6	2.6	4.7	6.4
Total	**60.8**	**66.8**	**76.9**	**82.2**	**1.2**	**100**	**100**	**100**	**100**

At the same time, the OPEC Reference Case sees increases in natural gas, nuclear and 'other renewables' in China, which will be mostly used for electricity and/or heat generation. Natural gas is projected to more than double its share in the mix, from around 5% in 2015 to above 11% in 2040. A strong focus on generally carbon-neutral fuels is estimated to bring an additional 5 mboe/d of nuclear energy and 4.5 mboe/d of renewables, respectively, by 2040.

In India (Table 2.7), overall energy demand growth is projected at more than 22 mboe/d in the period from 2015–2040. Unlike China, where energy demand slows in the last decade of the outlook, Indian energy demand remains robust throughout the forecast period.

However, India starts from a much lower base of around 17 mboe/d in 2015, with a large share of the population still lacking access to modern energy services. This is also why India's average energy demand growth is projected to expand at almost 3.5% p.a., significantly higher than China's at around 1.2% p.a.

Coal is expected to account for almost half of the energy demand growth in India, around 10.5 mboe/d, as the country faces soaring electricity demand growth. This is the reason why the share of coal in the Indian energy mix is anticipated to increase slightly in the long-term, reaching a level around 46.5% in 2040. Significant increases are also expected in terms of oil and natural gas demand, around 6 mboe/d and 2 mboe/d, respectively. Oil demand growth is driven by transportation and the petrochemical industry, while natural gas will be predominantly used in the power generation sector. A significant contribution is also projected in the 'other renewables' sector, with growth of 1.8 mboe/d. Due to the

Table 2.7
India primary energy demand by fuel type, 2015–2040

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2015	2020	2030	2040	2015–2040	2015	2020	2030	2040
Oil	3.9	5.0	7.3	9.9	3.7	23.3	24.0	24.4	25.2
Coal	7.6	9.5	14.0	18.1	3.5	44.9	45.9	46.8	46.4
Gas	0.9	1.1	2.0	3.0	4.9	5.3	5.5	6.8	7.7
Nuclear	0.2	0.3	0.7	1.2	7.4	1.2	1.7	2.4	3.0
Hydro	0.2	0.3	0.5	0.6	3.6	1.4	1.5	1.5	1.5
Biomass	3.9	4.2	4.4	4.4	0.4	23.2	20.0	14.7	11.2
Other renewables	0.1	0.3	1.0	1.9	11.3	0.8	1.4	3.3	5.0
Total	**16.9**	**20.7**	**29.9**	**39.1**	**3.4**	**100**	**100**	**100**	**100**

low base, the estimated growth rate for 'other renewables' is above 11 % p.a. on average for the period 2015–2040.

2.3 Energy demand by fuel

2.3.1 Oil

For the second consecutive year, long-term oil demand projections have been revised upward, while the other two major components of the global energy mix, coal and natural gas, have experienced downward revisions. The reasons for the slightly higher expectations for future global oil demand are discussed in detail in Chapter 3.

It is important to note, however, that the figures shown in this Chapter are not directly comparable with those shown in Chapter 3. There are a number of reasons for this. Firstly, Chapter 2 uses energy equivalent units (mboe/d) to make the correct comparison between the various fuel types. In Chapter 3, however, oil is expressed in volumetric units (million barrels per day (mb/d)). Secondly, the definition of oil in Chapter 2 is different from that used in Chapter 3 (and Chapters 4–6). While Chapter 2 deals with the origin of energy, the other chapters consider the liquids fuel outlook. In that sense, while in Chapter 2 biofuels are considered as biomass, coal-to-liquids (CTLs) as coal and gas-to-liquids (GTLs) as gas, in Chapters 3 (and Chapters 4–6) they are all part of the liquids outlook.

As discussed in detail in Chapter 4, the outlook for the future combined supply of biofuels, CTLs and GTLs has also been revised downward in this year's WOO, albeit marginally. The net effect of these revisions is that demand for oil-based products (as considered in this Chapter) is consistently higher throughout the forecast period, compared to levels projected last year.

Measured on an energy content basis, oil demand is anticipated to grow by almost 15 mboe/d in the period between 2015 and 2040 to reach a level above 101 mboe/d in 2040. This makes oil the third largest contributor to energy demand growth, surpassed only by gas and 'other renewables'. In relative terms, oil demand is set to grow on average at 0.6% p.a. between 2015 and 2040. This is the second lowest growth rate among all major energy sources and only half the growth rate for total energy demand. Therefore, oil's share in the global energy mix is anticipated to decline, from almost 32% in 2015 to below 28% in 2040. Despite this drop, and due to the current high base demand, oil's share is estimated to remain higher than any other fuel over the forecast period.

As already mentioned, details on regional, sectoral and product level oil demand are provided in Chapter 3, while oil supply developments are covered in Chapter 4.

2.3.2 Coal

Global coal demand increased slightly in 2017, which was mostly due to demand increases in Asia, predominantly India. At the same time, it declined in North America and many European countries due to higher coal prices and increasing competition from natural gas in power generation. Rising coal prices in 2017, which increased to their highest levels since 2013, have also pressured internationally traded coal. Despite the slight increase in coal demand during 2017, the share of coal in global energy demand declined somewhat due to the stronger expansion of other fuels, such as natural gas and renewables.

Coal prices continued to increase in the first half of 2018, coming close to the highs seen during 2011 of more than $120/tonne in Northwest Europe.[9] The rising trend for coal prices was largely influenced by lower supply from some regions, such as South Africa, and stronger-than-expected demand due to lower hydropower performance in some parts of the world.

One of the most important coal markets is China, due to its large share in both global coal demand and production. Any significant shifts in Chinese coal usage or output has an immediate effect on other world's markets. Although China's coal demand increased marginally in 2017, the country is increasing its efforts to reduce coal's share in its energy mix. A large amount of coal-fired capacity was taken offline in 2017 in order to reduce local pollution. Many of those plants were smaller, old and inefficient coal-fired units, using mostly low-quality coal, thus, contributing significantly to local air pollution. This is part of a broader plan to cap coal-fired capacity at 1,100 gigawatts (GW) by 2020. Furthermore, the Chinese government has decided to stop or delay more than 100 GW of previously planned and under construction coal power projects by 2020. This is in line with the series of medium to long-term actions that the government is taking to achieve its 13th Five Year Plan (FYP) climate related goals.

In India, coal demand increased strongly last year, driven by increasing electricity demand. However, Indian coal-unit operators faced difficulties in providing sufficient supplies of coal as domestic production underperformed. This led to more imports from Australia, South Africa and Indonesia to fill the supply gap. In addition, production costs of coal-fired power plants – especially old and less efficient units – were seen above the production costs of renewables.

In Europe and North America, coal faced competition from natural gas over the last year. This was especially the case in the US, where the natural gas price averaged well below $3 per million British thermal units (mBtu). In Europe, gas prices increased less than coal prices, which in combination with increasing CO_2 prices gave more support to gas-fired power plants.

Looking forward, global coal demand is expected to grow slightly throughout the outlook period from 2015–2040, at an average growth rate of 0.2% p.a. This translates into demand growth of around 4 mboe/d. In relative terms, the share of coal in primary energy demand is expected to decline from above 28% in 2015, to less than 27% in 2020, and then 22% in 2040, as many countries shift away from coal.

In terms of regions, growth is projected only for Developing countries, which is expected to see a demand increase of almost 11 mboe/d over the forecast period. At the same time, however, due to stronger demand growth for other fuels, the share of coal in the energy mix for Developing countries is projected to decline from almost 38% in 2015 to 28% in 2040.

The growth of coal in this country group is almost entirely accounted for by India, where coal demand is seen to increase by 10.5 mboe/d, from around 7.5 mboe/d in 2015 to 18 mboe/d in 2040. This translates into an average growth rate of 3.5% p.a. over the forecast period. Despite some problems in the short-term related to domestic coal supply and infrastructure, strong economic and energy demand growth is expected to give support to coal demand growth in India. It should be noted, however, that the country is putting some efforts into reducing air pollution caused by coal power plants, which is why a number of older and inefficient plants are expected to be retired in the medium-term.

In the medium- to long-term, India plans to shift to cleaner coal plants (supercritical and ultra-supercritical) with modern air pollution management. However, this could potentially increase the country's dependency on imports of higher quality thermal coal, as local coal plants produce mainly high ash and low calorific value. The plans for coal expansion are also linked to the availability of fuel (domestic and imported), as well as to the development of renewables (solar and wind) in the country.

In China, coal demand is expected to peak at around 41.5 mboe/d in 2030, up from almost 40 mboe/d in 2015. In the last decade of the outlook, coal demand is then projected to decline to 39 mboe/d. The main reason for the slowdown and then a decline in coal demand are the aforementioned efforts to limit the share of coal in the energy mix. The most important sector is power generation, where the government is seeking to limit overall coal capacity and increase its efficiency. Furthermore, coal demand in the industrial sector is likely to come under pressure with the country increasingly moving away from energy-intensive sectors.

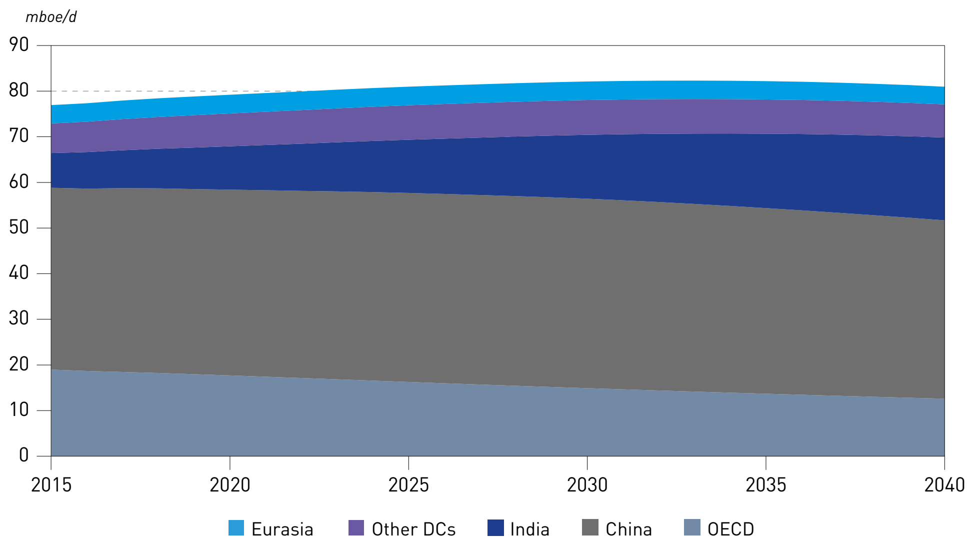
Finally, the start-up of the Chinese emissions trading system in late 2017, which covers power generators (first phase), could potentially lead to more pressure on coal-fired generation and coal consumption in the 'other industrial' sector (in the subsequent phase). In line with the stagnation of coal in China, its share in the country's total energy mix is expected to shrink by almost 17 percentage points to less than 48% by 2040. Nonetheless, China is estimated to remain the largest coal consumer in the world in 2040, with almost 50% of global coal demand.

Developing countries (excluding China and India) are also projected to witness a marginal rise in coal consumption. The OPEC Reference Case projects an increase of around 1 mboe/d over the forecast period. This includes limited medium-term expansion of coal-fired generation in some African countries, such as Morocco, Mozambique and South Africa.

Coal demand in OECD countries is projected to decrease by more than 6 mboe/d between 2015 and 2040. This would bring coal's share down to 11.5% in 2040; a drop of almost 6 percentage points. Increasing competition from gas in regions, such as the US, and planned decommissioning of old coal power plants, especially in Europe, would lead to lower coal demand in the OECD region.

In the US, coal is projected to face competition from cheap gas and renewables in the long-term. This is despite the less aggressive policies of the current US administration against coal-fired plants. As a result, it is expected that coal demand in OECD Americas declines by nearly 2% p.a. on average between 2015 and 2040. In OECD Asia Oceania, coal demand is also set to decrease, albeit at lower levels, close to 1% p.a. on average. Support for coal comes from Japan, which is only expected to gradually restore its nuclear generation in the medium- and

Figure 2.4
Coal demand growth by major region, 2015–2040



long-term. According to its national energy plan, Japan will construct additional coal plants over the next decades to provide 26% of Japan's electricity in 2030.

In Europe, stricter rules at the EU level and higher carbon prices are set to push more coal plants into unprofitability. Initiatives at the country level, for example, the UK, France, Finland, the Netherlands, Portugal and Italy, are pointing to a phase-out of coal-fired plants in the next 10–15 years. Some other countries, such as Poland are still expected to remain heavily reliant on coal, although no major expansion is expected in the long-term. Some EU countries, such as Germany and Spain, prevented planned closures of some coal power plants in order to keep them as back-up capacity.

Furthermore, the reform of the EU Emissions Trading System (ETS) (the so called 'ETS Market Stability Reserve') will reduce the number of allowances from 2019. This has already pushed CO_2 prices upwards, reaching levels above €20/tCO_2 in mid-2018 after years of low levels below €10/tonnes CO_2 (tCO_2). Consequently, OECD Europe's coal demand is likely to decrease by almost 2.5 mboe/d between 2015 and 2040. Coal's share in this region's energy mix is estimated to be below 9.5% in 2040, down from almost 16% in 2015.

2.3.3 Natural gas

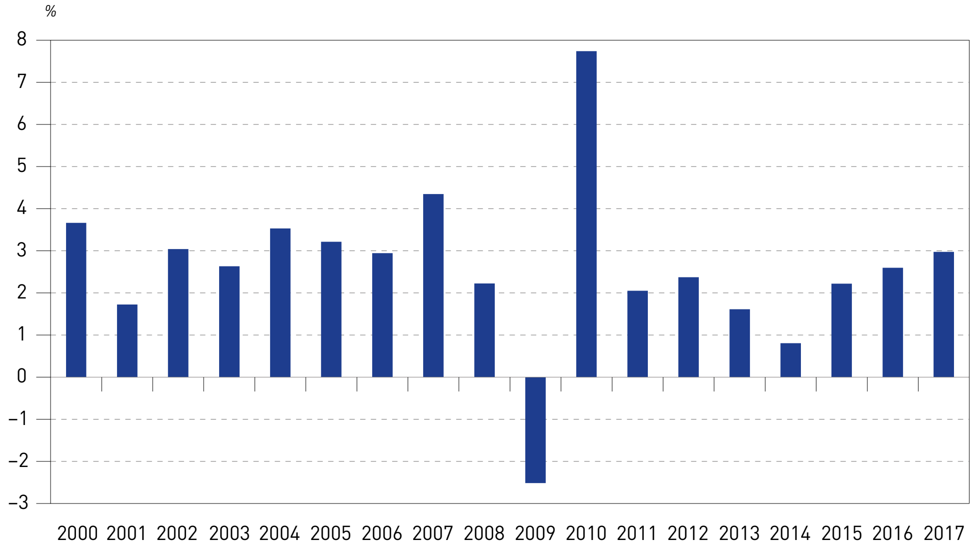
The expansion of natural gas demand continued in 2017 with a healthy global growth rate of around 3% year-on-year (y-o-y), or 1.8 mboe/d. This is the highest level recorded since 2010 (Figure 2.5).

Looking at the regional details, growth was driven by a variety of forces, such as environmental-related regulation in some regions, the start-up of new gas-fired power generation, as well as the improving competitive position of gas against coal in several important markets. These drivers are not one-off events, but are projected to remain important in shaping the long-term future of gas demand. The majority of the gas demand increase occurred in three regions – China, the Middle East and Europe – which covered almost 85% of the global y-o-y gas consumption increase in 2017.

The year 2017 was an example of how energy policy in one country can impact global energy markets with China's gas demand increasing strongly. This was mainly the consequence of the government's aim to reduce air pollution, the so-called 'battle for the blue skies'. The target to reduce local air pollution published in the 2013 'Action Plan on Prevention and Control of Air Pollution' focused on a relatively short period (to end-2017) and aimed to move away from polluting energy carriers, predominantly coal. While the country initially focused on large facilities (upgrades of large coal-fired power plants, refinery upgrades and additions of large renewable capacities), during 2017 authorities also targeted small – largely not regulated – and inefficient coal-fired facilities in North China.

These (mostly inefficient) facilities had been used predominantly for heating, as well as for process-heat production. They had been fired mostly by low-quality, high-polluting coal, which contributed a great deal to the local air pollution. At the same time, those facilities also provided around 70% of the heating demand in North China. In order to reduce local air pollution, the government urged those facilities either to switch to natural gas, or to permanently shut down.

Figure 2.5
Global natural gas demand growth



Source: BP Statistical Review of World Energy.

The result was a significant shift to natural gas. Consequently, China's gas demand increased by more than 15% in 2017 versus the previous year. This equates to more than 0.5 mboe/d, which is the highest ever annual increase in Chinese gas demand. Besides some problems in the Chinese midstream sector – pipeline constraints, seasonal storage capacity and regasification capacity – the effect of the sudden gas demand increase had an immediate effect on the global gas market. Chinese LNG imports increased by more than 40% in 2017, relative to 2016, absorbing 15 billion cubic meters (bcm) of additional LNG in 2017. As a result, Asian LNG spot prices increased strongly in the fourth quarter of 2017 and the first quarter of 2018, rising to almost $11/mBtu, the highest level since late 2014.

In Europe, gas consumption rose by almost 6% in 2017, as gas-fired power plants gained a competitive advantage against coal in the power generation mix despite higher gas prices in 2017. This can be explained by a stronger relative increase in coal prices. Consequently, gas-fired power generation increased in several countries including large consumers such as Germany, Italy, the Netherlands, as well as Turkey.

Similarly, gas consumption in the Middle East increased by almost 6% in 2017, which was mostly due to the increase in gas-fired power generation given the commissioning of new units. Furthermore, countries in the region are increasingly trying to substitute oil burning with gas in the power generation sector, which is resulting in the faster deployment of natural gas resources in the region.

Other regions showed modest or even negative growth during 2017. Interestingly, US natural gas consumption inched down in 2017, due to somewhat lower demand from the power generation sector. Nevertheless, gas-fired power generation remained the most important source of US power generation in 2017, ahead of coal. Another supportive factor for the country was the US gas price, which remained at low levels, averaging around $3/mBtu in 2017.

Looking forward, natural gas consumption is expected to continue to increase in the medium- and long-term, predominantly in developing countries. According to the OPEC Reference Case, overall natural gas consumption is set to increase by around 32 mboe/d between 2015 and 2040, the highest increase of all energies.

The increasing availability of gas – including LNG supplies – and the environmental credentials of this fuel favour a global expansion in the medium- and long-term. Due to its low CO_2 emissions, relative to coal, natural gas is expected to play a major role as a so-called transition fuel, increasingly substituting for coal in the power generation sector. Furthermore, the strong performance of the petrochemical industry is expected to require additional volumes of natural gas, as well as the increasing utilization of gas for heating purposes. In addition, more potential is seen in the transportation sector, including marine bunkers, especially in the long-term.

Table 2.8 portrays the long-term Reference Case outlook for gas demand. Global gas demand is expected to increase from just over 59 mboe/d in 2015 to 91 mboe/d in 2040, which is more than a

Table 2.8
Natural gas demand by region, 2015–2040

	Levels *mboe/d*				Growth *%p.a.*	Share of global gas demand *%*			
	2015	2020	2030	2040	2015–2040	2015	2020	2030	2040
OECD America	16.1	17.0	18.1	18.9	0.6	27.1	25.7	22.8	20.7
OECD Europe	7.8	8.8	9.1	9.1	0.6	13.2	13.3	11.5	10.0
OECD Asia Oceania	3.8	3.6	3.6	3.7	0.0	6.3	5.4	4.5	4.1
OECD	**27.7**	**29.4**	**30.8**	**31.8**	**0.6**	**46.6**	**44.5**	**38.9**	**34.8**
China	3.2	4.4	7.1	9.3	4.4	5.4	6.7	9.0	10.2
India	0.9	1.1	2.0	3.0	4.9	1.5	1.7	2.6	3.3
OPEC	8.8	10.0	13.5	16.2	2.5	14.7	15.2	17.0	17.8
Other DCs	8.3	10.1	14.1	19.0	3.3	14.0	15.3	17.9	20.8
DCs	**21.2**	**25.7**	**36.8**	**47.5**	**3.3**	**35.7**	**38.8**	**46.5**	**52.1**
Russia	7.3	7.4	7.4	7.5	0.1	12.3	11.1	9.4	8.2
Other Eurasia	3.2	3.7	4.2	4.5	1.4	5.4	5.6	5.3	5.0
Eurasia	**10.5**	**11.0**	**11.6**	**12.0**	**0.5**	**17.7**	**16.7**	**14.6**	**13.2**
World	**59.4**	**66.1**	**79.2**	**91.3**	**1.7**	**100**	**100**	**100**	**100**

50% increase in 25 years. In 2040, gas is projected to become the second largest energy source and reach an estimated share of 25%, up by more than 3% percentage points from 2015. Demand growth in Developing countries accounts for more than 80% of the overall growth.

In China, natural gas demand is projected to increase by around 6 mboe/d between 2015 and 2040, to reach slightly above 9 mboe/d. This equates to an average annual growth rate of almost 4.5%. Additional demand is likely to emerge in all major sectors, such as power generation, industrial usage and the residential & commercial sector, in line with the economic development of the country and the its increasing environmental awareness. However, the government is believed to plan to increase so-called 'clean coal burning', which includes constructing large and efficient coal units with effective pollution control. This will put a cap on the expansion of gas in the heat and power generation sector. Furthermore, the planned increase in biomass and waste utilization, as well as renewables, could also dampen gas demand growth in the medium- and long-term.

Overall, the importance of natural gas in the energy mix is projected to increase significantly with the share of gas at above 11% in 2040, up from around 5% in 2015. In order to secure supplies, China is not only expected to increase gas imports (piped and LNG), but also to invest heavily in domestic production, part of which is likely to come from shale gas.

Gas demand in other Developing countries (excluding China and OPEC Member Countries), is expected to rise in line with increasing energy demand, predominantly power generation. In total, gas demand is set to increase from above 9 mboe/d in 2015 to around 22 mboe/d in 2040. This represents an average annual growth rate of around 3.5%. This includes growth in the power generation and industrial sectors, predominantly in Africa and non-OECD Asia. In India alone, gas demand is projected to increase by some 2 mboe/d over the forecast period, to reach 3 mboe/d in 2040. This comprises an average annual growth rate of almost 5%.

In OPEC countries, gas will play a major role in the future energy mix, as the fuel is available at affordable price levels in most of the countries. As economies develop, and power demand growth increases on the back of this, there is expected to be a boost for gas-fired power generation. Moreover, a large part of the additional power demand is driven by the need for additional freshwater, specifically through water desalination in the Middle East.

The expansion of natural gas in power generation will also help to reduce the utilization of oil and oil products in this sector, mostly in the Middle East. Based on low Middle East gas prices, gas demand is also set to increase in the petrochemical sector, where gas is used as feedstock. Consequently, gas demand in OPEC countries is anticipated to almost double, from just under 9 mboe/d in 2015 to above 16 mboe/d in 2040.

In OECD regions, the long-term future of gas demand is mixed. While in OECD America and OECD Europe gas demand still has some potential to increase, gas demand in OECD Asia Oceania is set to stagnate throughout the forecast period.

In OECD America, the major driver of gas demand growth is US unconventional gas production, which provides sufficient gas volumes at relatively low prices. This will underpin the further expansion of gas in the power generation and industrial sectors. Based on the expansion of US natural gas production, significant new gas-fired capacities have recently been built with more than 9 GW coming online only during the last year.[10] This is why the Reference Case assumes natural gas demand growth in OECD America of almost 3 mboe/d between 2015 and 2040, to reach a level of around 19 mboe/d. With these prospects, gas is set to become the largest used fuel in OECD America, ahead of oil in the last decade of the outlook period.

In OECD Europe, natural gas should see modest average growth of around 0.6% p.a. between 2015 and 2040. Consequently, gas demand is anticipated to reach levels above 9 mboe/d in 2040, up from 7.8 mboe/d in 2015. The increase is expected to come mostly from the power generation sector, where it should partly fill the gap opened up due to the decommissioning of coal and nuclear power plants.

Finally, in OECD Asia Oceania, gas demand is likely to remain static over the forecast period, hovering at levels around 3.7 mboe/d in 2040. While gas may replace some coal power plants, for example, in Australia and South Korea, the restart of nuclear power plants in Japan, as well as the expansion of renewables, should reduce the need for additional gas in this region over the long-term.

Lastly in Eurasia (including Russia), natural gas demand is projected to increase from around 10.5 mboe/d in 2015 to 12 mboe/d in 2040. This is based on the continuous economic development and the availability of cheap gas in the region. Natural gas is projected to remain the most dominant fuel in the region's energy mix, with its share at levels around 45% in the long-term.

2.3.4 Nuclear

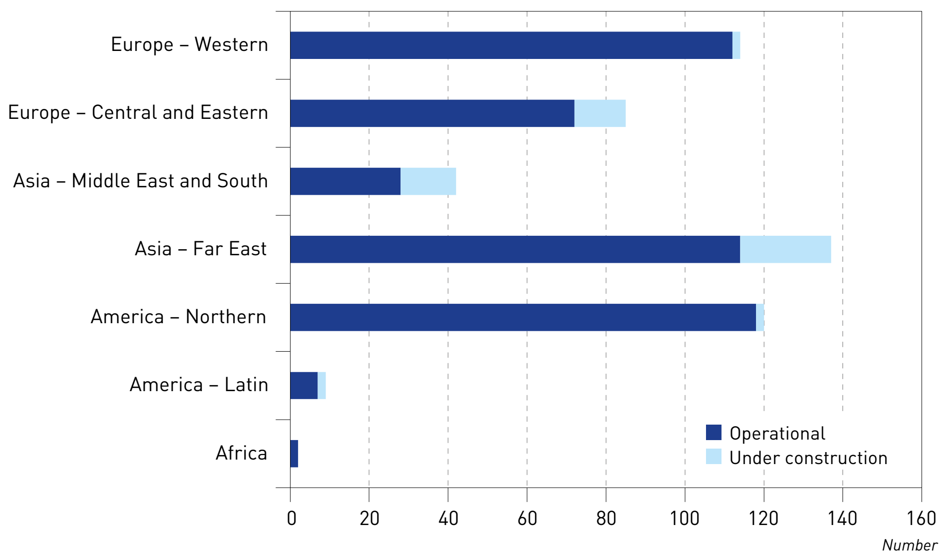
Nuclear power capacity is increasing globally with over 55 reactors currently under construction, mainly in Asia, Europe, the Middle East, Latin America and North America.

Nevertheless, the nuclear sector has evidently suffered some setbacks in recent years. Political and social resistance, as well as regulatory considerations, have led to the closures of some power reactors, particularly in Europe and Japan. Furthermore, while technological advancements have led to a significant decline in production costs in other energies, such as renewables, there have not been any indications that costs will fall for new nuclear plants. Although there have been some technological advancements, higher and more complex safety regulations for the operation of nuclear plants have kept costs high.

This is why the levelized costs of new nuclear plants are higher relative to other power generation technologies, including wind and solar. Nevertheless, nuclear energy does offer some distinct advantages. It is nearly carbon-free, which is a clear advantage relative to fossil fuels, especially coal. It also provides stable baseload power supply, which is an advantage relative to intermittent energy sources, such as wind and solar. Some countries also see it as a secure source of baseload power generation, which can reduce dependency on imported fossil fuels, such as coal or natural gas.

Nuclear provided around 10% of power generation worldwide in 2017. According to statistical data provided by the International Atomic Energy Agency (IAEA), there are currently 453 nuclear reactors operating in 30 countries with total a capacity of over 397 GW as of 2018 (Figure 2.6). From these, the majority of installed reactors are located in developed countries in Europe, Asia and North America, with the US and France holding around 100 GW and 63 GW, respectively.

Figure 2.6
Number of nuclear reactors by region, 2018



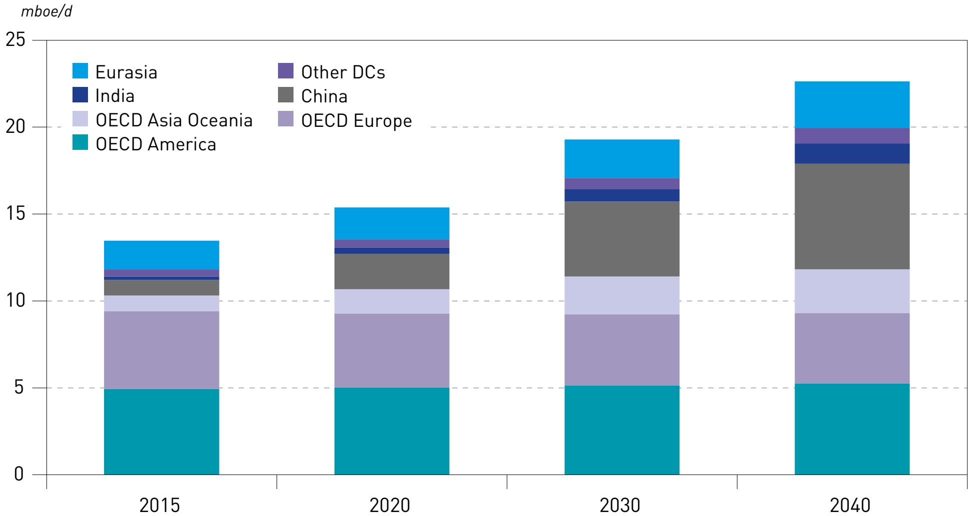
Source: International Atomic Energy Agency (IAEA).

Among developing countries, it is China that has a significant nuclear capacity – nearly 40 GW in 2018. At the same time, a number of countries have permanently shut down parts of their nuclear capacity such as the US (34 reactors), the UK (30 reactors), Germany (29 reactors) and Japan (18 reactors), which in total represent 70% of the global shutdowns.

Currently, there are over 55 reactors under construction, with a total capacity of nearly 58 GW. The majority of these units are located in Asia, mainly China (15 reactors) and India (7 reactors). According to the OPEC Reference Case, nuclear energy is expected to increase from some 13.5 mboe/d in 2015 to almost 23 mboe/d in 2040, an increase of more than 9 mboe/d (Figure 2.7). Consequently, the average annual growth is estimated at around 2.1%, which is higher than the overall average energy demand growth of 1.2% p.a.

Developing countries are projected to increase nuclear energy demand by around 6.5 mboe/d in the forecast period from 2015–2040. The largest single contributor to this growth is China, where demand for nuclear is set to increase by more than 5 mboe/d. This is in line with

Figure 2.7
Nuclear energy demand by major region, 2015–2040



official targets to increase the country's share of nuclear energy, as well as the large number of reactors under construction. This includes third generation models, with a successful finalization of these also potentially giving China the opportunity to export technology to other countries.

Demand for nuclear energy in India is set to increase by around 1 mboe/d between 2015 and 2040, to reach 1.2 mboe/d. The expansion is in line with the government's commitment to increase its nuclear power capacity as part of its development program. In March 2018, the government stated that the target for nuclear capacity in India is set at around 22.5 GW by 2032, albeit far below the initial ambitious plan of 63 GW for the same year. In other countries of the Developing countries group (mostly Asia), nuclear demand is also set to increase, though the levels are much less significant.

Overall, demand for nuclear energy in the OECD is expected to increase by around 1.5 mboe/d to almost 12 mboe/d in 2040. Nevertheless, the picture in the OECD sub-regions varies, underscoring different trends.

In OECD America, the demand for nuclear energy is expected to increase by 0.4 mboe/d over the forecast period. This trend is supported by new builds (two reactors under construction in the US), but also plant lifetime extension programs. In OECD Europe, demand for nuclear energy is estimated to fall by around 0.5 mboe/d in the long-term to 4 mboe/d in 2040. Some of the traditional producers of nuclear energy, such as Germany, France and Belgium, have decided to reduce their reliance on this energy source with no new investments expected in the long-term. A number of other countries are expected to remain nuclear-free, such as Italy, Austria and Portugal. At the same time, some other countries such as Slovakia, Turkey and Finland have several reactors under construction, but this is nowhere near the level to counter closures elsewhere.

Demand for nuclear energy in OECD Asia-Oceania is expected to increase by more than 1.5 mboe/d between 2015 and 2040, an average growth of 4.2% p.a. This is mostly due to the expected gradual restart of nuclear units in Japan, but also new builds (South Korea and Japan combined have six reactors under construction as of 2018). Nevertheless, it should be noted that demand for nuclear energy in this region will reach a level of around 2.5 mboe/d in 2040, which is still only 10% above the level recorded in 2010, prior to the Fukushima nuclear disaster.

In Eurasia, demand for nuclear energy is expected to increase significantly, around 2% p.a. on average. This translates into growth of more than 1 mboe/d. The availability of nuclear power in this region and its importance in terms of technology transfer favours this development. The majority of the expansion is anticipated to take place in Russia with six reactors currently under construction. Other countries such as Ukraine and Belarus are also expected to contribute, with several units expected to be commissioned in the years to come.

Finally, it is important to stress that there are still significant uncertainties regarding the decommissioning of old units and nuclear waste, due to unclear regulation and long-term energy policies. This is valid especially for developed countries, with a large number of old nuclear units.

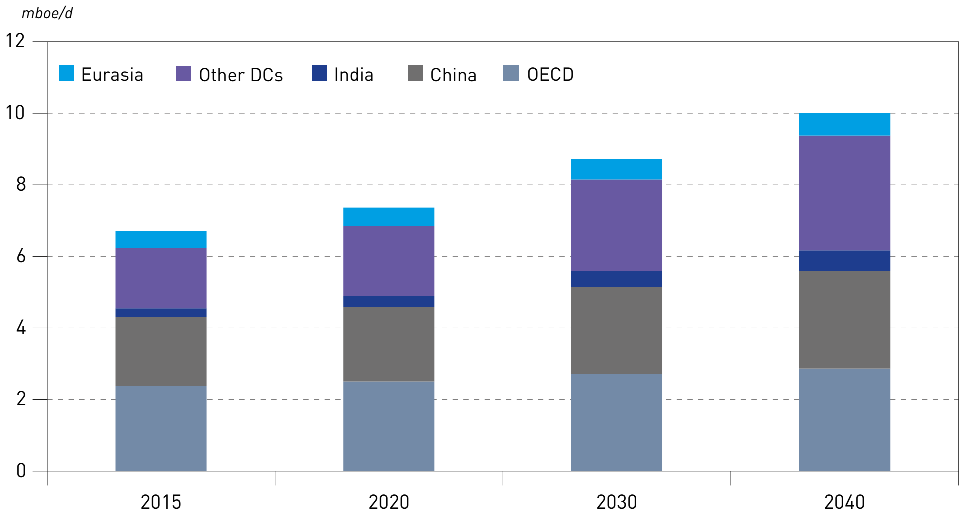
2.3.5 Hydropower

In 2017, global hydropower capacity increased by almost 22 GW, to above 1,250 GW.[11] The increase was mainly due to developments in large developing countries, such as China and India, but also in smaller developed countries, such as Portugal. China remained the country with the largest installed hydropower capacity in 2017 (almost 350 GW), followed by the US, Brazil and Canada.

In terms of the new installed capacity, 3.2 GW was for pumped storage plants, which are of great importance for balancing power systems. Pumped storage is likely to become even more relevant in the future with the expected increase in intermittent energy sources, such as wind and solar. Recent years have seen technological improvements in this area, such as increasing digitalization to optimize the operation of pumped storage in connection with intermittent energy sources. Further innovations are becoming increasingly popular, such as floating solar panel installations on hydropower reservoirs (floatovoltaics), which can reduce cost and escalate the efficiency and stability of power to grids.

Looking forward, global hydropower demand is estimated to increase by more than 3 mboe/d between 2015 and 2040, to reach 10 mboe/d in 2040 (Figure 2.8). OECD countries, where the majority of the resources have already been utilized, is expected to only see an increase of around 0.5 mboe/d in the forecast period. The additional potential is expected in OECD Europe (Turkey, Austria and Norway) and OECD America.

Figure 2.8
Hydropower demand by major region, 2015–2040



Developing countries are anticipated to increase their hydropower output by 2.7 mboe/d over the forecast period. China alone is forecast to add around 0.8 mboe/d, while India is expected to rise by some 0.3 mboe/d, to reach 2.7 mboe/d and 0.6 mboe/d in 2040, respectively. The rest of the additions in Developing countries – around 1.4 mboe/d over the forecast period – will likely be dispersed through Asia, Latin America and Africa. This includes medium-term based projects in countries such as Peru, Chile, Cameroon, Ethiopia and Rwanda.

In OPEC, demand for hydropower is estimated to double between 2015 and 2040, albeit from a low basis of 0.2 mboe/d in 2015. The majority of the projects are located in the Middle East, for example, Iran and Iraq, as well as Africa, for example, Angola. The IR Iran has around 100 dams under construction and some of these projects will be commissioned in the medium-term.

Finally, it should not be forgotten that hydropower is dependent on the impacts of climate change and potentially drought, as has already witnessed in some regions, for example, in Central and Latin America, including Brazil.

2.3.6 Biomass

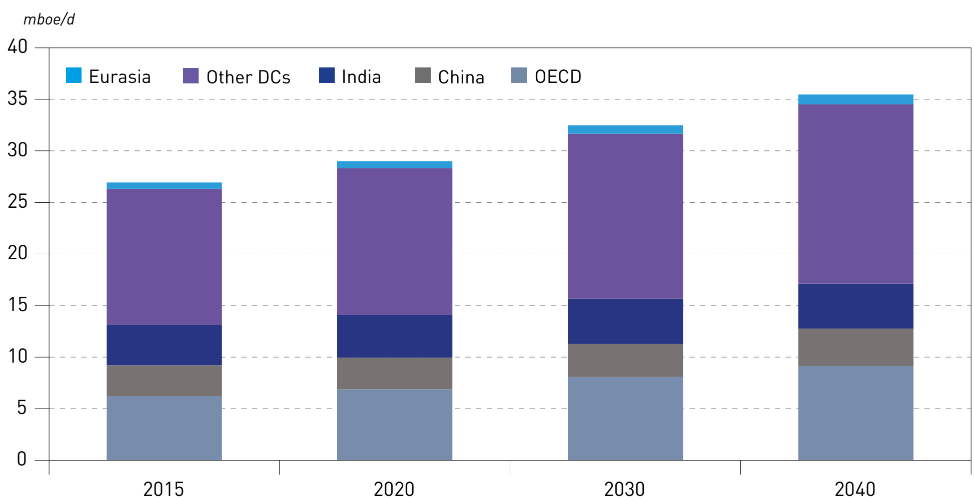
Global biomass demand was estimated at around 27 mboe/d in 2015, of which almost 75% was located in Developing countries. This is mostly accounted for by traditional biomass, including wood, charcoal and waste, used for cooking and heating. Biomass usage in OECD countries is mostly concentrated in power and heat generation, as well as in the production of biomass and biogas.

Biomass demand is projected to increase by 1.1% p.a. on average between 2015 and 2040, which is similar to overall energy demand growth. Consequently the share of biomass in the global energy mix is set to remain stable at just below 10% over the forecast period. In absolute terms, demand for biomass is expected to rise by around 8.5 mboe/d, with Developing countries alone increasing by almost 5.5 mboe/d (Figure 2.9). However, overall energy demand in Developing countries increases at a higher level, meaning that the share of biomass in its energy mix is estimated to fall from around 14% in 2015 to 11% in 2040.

The increase in Developing countries is the result of two opposing trends. First, the expansion of traditional biomass usage is expected to remain limited as the population in these countries increasingly gain access to modern energy services. In some developing countries this may even lead to a decline in demand for traditional biomass. Second, Developing countries are expected to move strongly towards the advanced use of biomass, including waste management, which becomes increasingly important with higher degrees of urbanization. Furthermore, developing agricultural industries in countries like India and Brazil will likely contribute to the more efficient use of residuals in the long-term, with modern processes and higher efficiency of biomass usage, for example, through district heating projects.

At the same time, OECD biomass demand is expected to increase by almost 3 mboe/d between 2015 and 2040, mostly in the US and Europe. The increase in biomass demand can be attributed to the growth in biofuels, as well as biomass usage for power/heat and biogas production. The growth is also in line with regulations on biofuels being blended with transportation fuels, as well as overall renewable targets. The share of biomass in the overall energy mix in OECD is likely to increase from below 6% in 2015 to 8.3% in 2040.

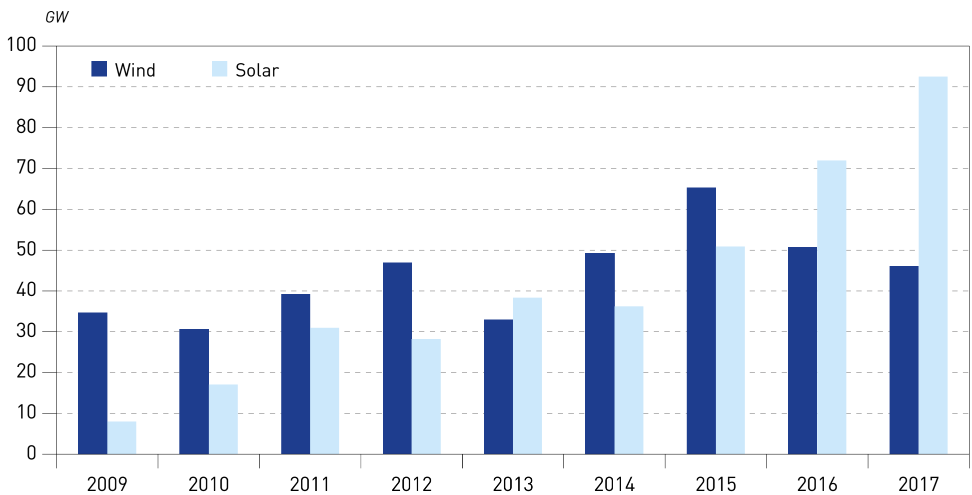
Figure 2.9
Biomass demand by major region, 2015–2040



2.3.7 Other renewables

Installed renewable capacity (solar and wind) increased in 2017 to reach a new record high level based on policy support and decreasing costs, especially for solar power plants, but wind plants too. However, these two leading renewable technologies witnessed somewhat different annual growth trends in 2017. Global solar capacity increased by around 95 GW in 2017, an all-time high, while global wind capacity increased by 47 GW (Figure 2.10), which continues the slowdown in increments witnessed in 2016.

Figure 2.10
Annual wind and solar capacity additions, globally



Source: BP Statistical Review of World Energy.

Based on figures from the BP Statistical Review of World Energy, the growth in solar power capacity in 2017 was driven by China, with 53 GW installed, which is more than half of last year's global additions. The development was supported by China's policy to expand its renewable capacities and reduce its reliance on fossil fuels.[12] India also recorded a strong increase in solar capacity, with almost 10 GW added in 2017, which is more than double relative to the increment recorded in 2016.

At the same time, developed countries saw a slowdown in solar capacity additions. In North America, around 11 GW was added in 2017, down from almost 15 GW in 2016. Solar capacity additions in Europe have been stagnating, falling to below 10 GW in recent years, a far cry from additions of more than 23 GW in 2011.

The major reason for the decline in developed countries were energy policy uncertainties, for example, in the US, and declining financial support for new projects in Europe, for example, in the UK and Germany.

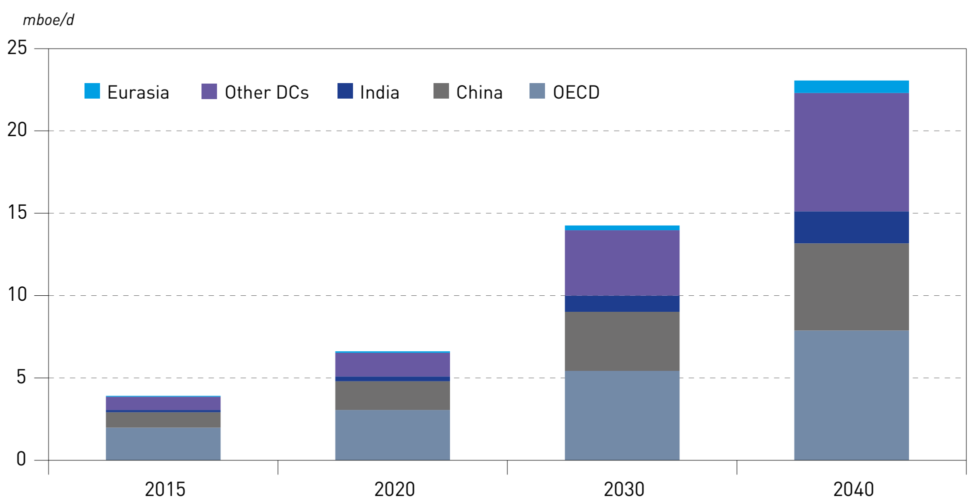
In terms of wind capacity, in 2015 there was 65 GW of newly installed capacity. Since then, however, new additions have declined, reaching a level of 47 GW in 2017, as some countries approach their targets for the years to come.

The majority of the global wind instillations since 2010 have been located outside of the OECD,[13] mostly in Asia. As of 2017, China has 164 GW of wind capacity, after adding 15 GW in 2017, which is 36 GW short of the official 200 GW target for 2020. Europe's wind capacity growth increased slightly in 2017, mostly due to more offshore wind installations. North America saw a decline in wind capacity additions, which can be attributed to the country's greater policy uncertainty. India is another important market for wind power, adding over 4 GW in 2017. In 2017, the country also introduced wind auction schemes as a shift from feed-in tariffs to competitive tendering.

Despite all the additions, the current share of 'other renewables' in global primary energy demand is relatively low and was estimated at around 1.5% in 2015. In 2017, the share of 'other renewables' did increase somewhat, but still remained at levels below 2%. The OPEC Reference Case projects strong growth for 'other renewables' in the decades ahead, supported by falling costs and policy support, with an estimated average annual growth rate of around 7.4% p.a.

In absolute terms, 'other renewables' are expected to increase from around 4 mboe/d in 2015 to 23 mboe/d in 2040 (Figure 2.11). Consequently, the share in 2040 will increase significantly relative to current values, but due to the low initial base, it is still expected to be below 6.5% of total primary energy demand in 2040.

Figure 2.11
'Other renewables' demand by major region, 2015–2040



Both the OECD and Developing countries are expected to see strong long-term growth in 'other renewables'. The major reason is the continuous policy support, both locally and globally, as well as the falling costs of renewables, which has brought them to grid parity in some regions.

Demand for 'other renewables' in the OECD is expected to increase from around 2 mboe/d in 2015 to nearly 8 mboe/d in 2040. Various policies support this development, including the EU's targets on GHG reductions (40% by 2030, compared to 1990 levels), as well as the EU ETS mechanism, which makes fossil fuel-based generation more expensive and, therefore, less competitive. The competitiveness of renewables will also play a major role in overcoming the hurdles emerging due to less governmental support, for example, the phase out of wind subsidies in the UK, with several industry sources projecting a subsidy-free future for wind generation.

The share of 'other renewables' in OECD Europe's energy mix in 2040 is estimated to reach levels of around 8.5% in the OPEC Reference Case, only one percentage point lower than the share of coal in this region. OECD America and OECD Asia Oceania are also expected to see an increase in 'other renewables' in the long-term, with energy mix shares in 2040 rising to 6% and 8.5%, respectively. Important factors related to uncertainties are associated with new US policies, such as import duties for solar modules from China and the fate of the US Clean Power Plan (CPP).

In Developing countries, the increase in 'other renewables' demand is spread across the group. Once again, China and India are estimated to have the largest increments in 'other renewables' demand over the forecast period, in line with the size of the countries. China is expected to add around 4.5 mboe/d, while India's demand is anticipated to increase by almost 2 mboe/d, including large investments in offshore wind. Additions in India are also favoured by the low production costs of renewables, relative to old (and less efficient) coal power plants. The increments in the two countries account for roughly half of the 'other renewables' demand increase of 12.5 mboe/d in Developing countries. Other regions of this country group, such as Africa, also have large available resources, with several ongoing supportive renewable programmes, including financing and technical support.

Eurasia is also expected to increase its consumption of 'other renewables' over the forecast period. The region has vast resources in terms of renewables; however, expansion is seen to be limited due to a lack of supportive energy policies and investments. The OPEC Reference Case estimates an increase from almost zero in 2015 to 0.8 mboe/d in 2040.

Globally, the actual growth of 'other renewables' remains uncertain and will likely depend on energy policies and cost developments. Moreover, their technical integration into the energy system will become increasingly important with rising volumes of intermittent supply. This translates into the expanding importance of balancing mechanisms, such as energy storage (for example batteries and pumped storage) or back-up power supply (fossil fuel-based plants).

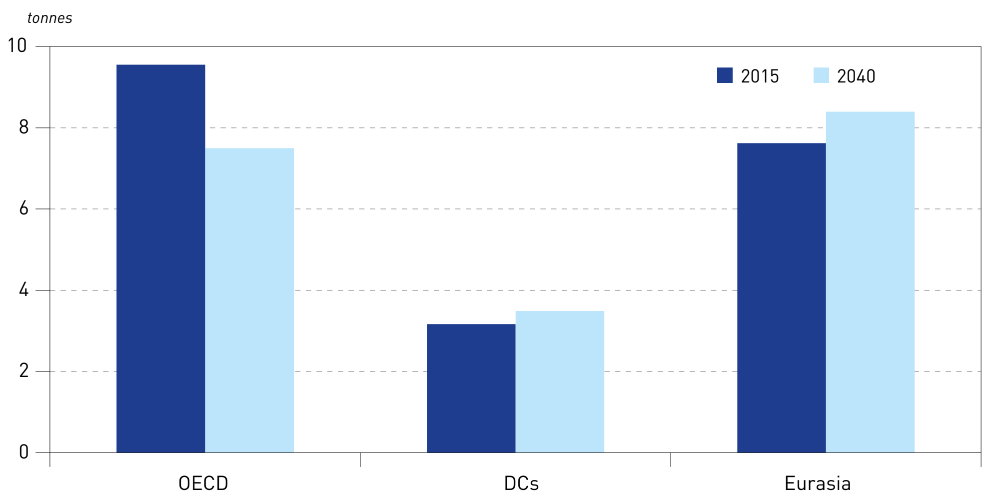
2.4 Energy-related CO_2 emissions

The major trends in future energy demand outlined in this Chapter will evidently have implications on the path of energy-related emissions. While emissions are expected to be on a rising trend over the next decade, the decelerating growth in oil demand combined with peak coal demand, the continued growth in nuclear and hydropower and the accelerated growth in 'other renewables', will broadly offset the growing emissions related to the increased use of natural gas over the last five years of the forecast period. By then, global emissions are expected to start plateauing at a level around 39 bt of CO_2.

In summary, total annual energy-related CO_2 emissions are set to increase from 33 bt in 2015 to around 39 bt by 2040. Despite the estimated low growth in global coal demand, and a peaking towards the end of the forecast period, coal will still be the largest source of CO_2 emissions, accounting for 15.7 bt of emissions in 2040. However, the largest increase in emissions, on an annual basis, is expected for natural gas (+3.3 bt) as demand for this energy source is set to increase significantly over the forecast period. At the same time, it is important to note that the overall increase in annual emissions of 6.3 bt between 2015 and 2040 represents a growth of around 19%, which is significantly lower than the overall increase in energy demand of more than 33%. This is a clear sign of the trend towards less emitting energy sources, not only through the increased share of renewable energy, but also through the substitution of coal by cleaner fossil fuels.

Figure 2.12 highlights emissions on a per capita basis. It shows the staggering difference between the very low values in Developing countries of slightly above 3 tonnes per capita and much higher values of 8 to almost 10 tonnes per capita in developed regions.

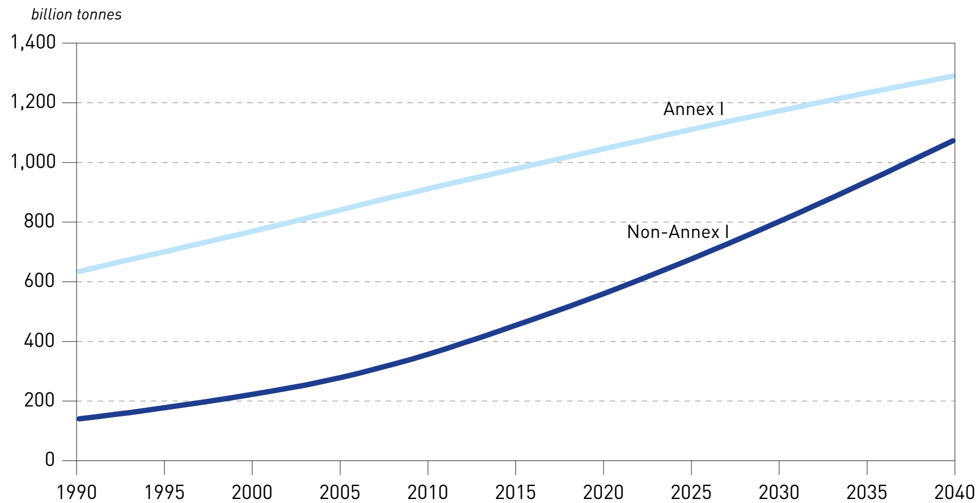
Figure 2.12
Per capita CO_2 emissions by major region, 2015 and 2040



The gap between Developing countries and the OECD is expected to gradually narrow over time. However, even by 2040, under the Reference Case, per capita emissions in the OECD are projected to be more than twice that of Developing countries. Compared to Eurasia, primarily due to its marginally declining population, the gap by 2040 is even wider than the one seen in 2015.

Regional differences in emissions are also reflected in historical cumulative emissions. Estimates of cumulative CO_2 emissions since 1900, as presented in Figure 2.13, show a significant gap in cumulative emissions between Annex I and non-Annex I countries. This has developed throughout the past century. Moreover, despite growing energy demand in developing countries, this gap is expected to remain in place throughout the Reference Case projection period. Even by 2040, historical cumulative emissions by non-Annex I countries are estimated to be more than 200 billion tonnes of CO_2 lower than those generated by Annex I countries since 1900.

Figure 2.13
Cumulative CO_2 emissions since 1900, 1990–2040

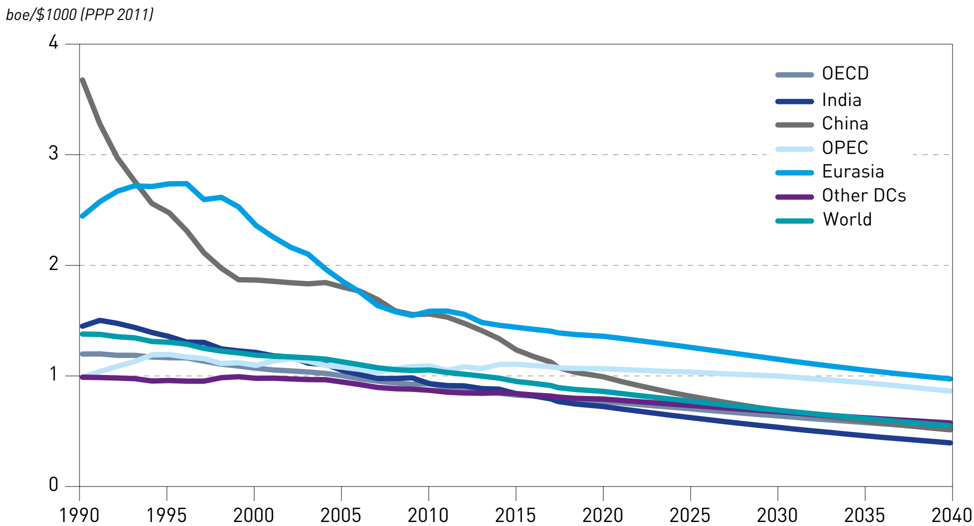


2.5 Energy intensity and consumption per capita

Energy intensity is typically defined as the ratio of energy used per unit of GDP. The inverse of energy intensity is often used as a proxy to measure energy efficiency. This implies that as energy efficiency increases, energy intensity declines; leading to a higher economic value out of every unit of energy used. However, energy intensity comparisons across countries and regions need to be handled with caution as there are often many other factors entering into the equation. These include the economic structure of an economy, the level of economic development of a nation, demographics of the population, climate of the region and urbanization levels, to name a few.

Figure 2.14 indicates that in most regions, and at the global level, the amount of energy required to produce one unit of GDP is falling. This effect is evident in developed countries, where GDP typically grows faster than energy consumption. In this context, technological progress and the increasing number of energy efficiency policies that are being implemented in the world are fostering a decoupling between economic growth and energy use.

Figure 2.14
Global and regional energy intensity, 1990–2040



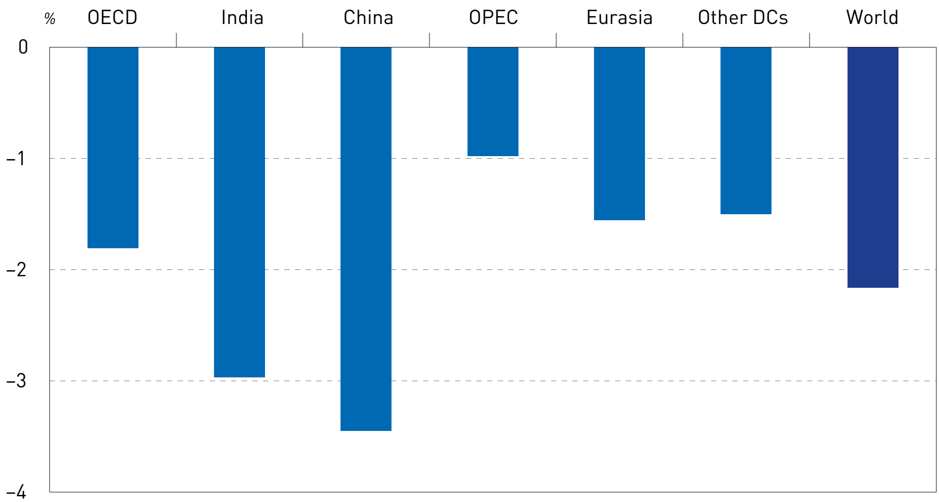
Currently, the global economy is around 2.5 times larger than in 1990, yet energy efficiency improvements achieved thus far mean that energy demand in 2018 will only be 1.6 times that in 1990. It is noteworthy that increasing energy efficiency is clearly evident in developing countries too. For example, energy intensity in China declined on average by more than 4% p.a. between 1990 and 2017. Significant improvements were also achieved in India, Eurasia, and Other DCs with intensities declining at 2.2%, 2% and 0.7% p.a., respectively.

Figure 2.14 also illustrates an expectation that energy intensities across major regions move towards convergence. Clearly, relative wide gaps in energy intensities that existed in the past will gradually be eliminated and intensities will move in a much narrower range around the global average.

The rate of energy efficiency improvements across major regions is summarized in Figure 2.15. As already mentioned, it emphasizes that energy efficiency improvements will continue in both OECD and non-OECD regions. Moreover, in most regions these improvements will accelerate compared to those achieved in the past 25 years. The fastest reduction in energy intensity is expected to be achieved in China and India, both in the range of 3% p.a. on average between 2015 and 2040. Other regions will see this reduction generally in the range of 1% to 2% p.a. whereas the global average is projected at 2.2% p.a. Needless to say that technology developments and policies will play a decisive role in lowering future energy intensities.

Another important trend in the energy landscape is that the world has increasingly become less energy poor. In 1970, the gap between energy consumption per capita in the OECD

Figure 2.15
Average annual rate of improvement in global and regional energy intensity, 2015–2040

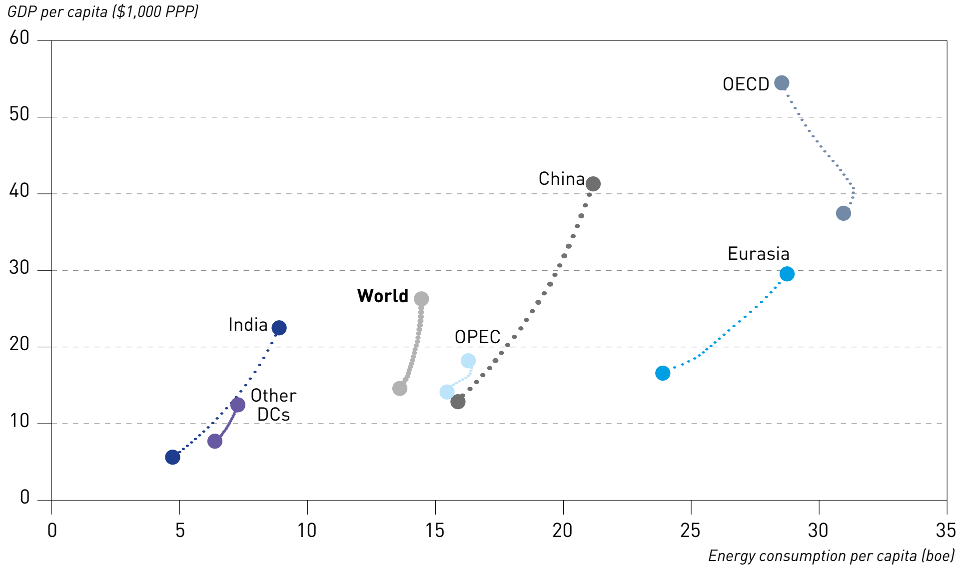


region and in the Developing countries was wide. While in the OECD region the average energy consumption was almost 27 boe per capita, in the Developing countries it was only 3 boe per capita. In some specific countries such as China and India, the average consumption was even below 1.5 boe per capita.

By 1990, the gap had not narrowed significantly and average consumption in the OECD region was still more than six times higher than in the Developing countries. However, since then, rapid economic expansion in the developing world, particularly in developing Asia, has lifted millions of people out of poverty and enlarged the middle class base, prompting an increase in access to energy. In 2015, the average energy consumption in the Developing countries had almost tripled with respect to 1970 and the gap with the OECD had narrowed. Nevertheless, the gap still remains wide and energy poverty remains an extremely important issue. Therefore, this year's Outlook pays special attention to the problem of energy poverty and the lack of access to modern energy types for hundreds of millions of people. Accordingly, a separate Chapter (Chapter 9) is devoted to sustainable development.

From the perspective of energy demand, Figure 2.16 shows that differences in average per capita energy consumption (in a very broad sense, a proxy to energy poverty/wealth) can be linked to differences in the level of development and, therefore, in average income levels. This Outlook anticipates that energy consumption in the non-OECD region will increase coupled with rapid economic growth. This will bring increasing electrification, rising income levels, increasing urbanization and an expanding middle class.

Figure 2.16
Energy consumption per capita vs. GDP at PPP per capita, 2015–2040



This is clearly seen in two cases: China and India. In the former, average per capita energy consumption is expected to increase significantly from almost 16 boe in 2015 to more than 21 boe in 2040. In the latter, average consumption is anticipated to double, reaching 9 boe at the end of the forecast period.

Contrary to these cases, a diverging trend is foreseen in the OECD region. Despite anticipated modest economic growth, energy consumption per capita is set to continue to decline, a tendency that began in 2004. This is a result of technology and policy driven energy efficiency gains.

Box 2.1

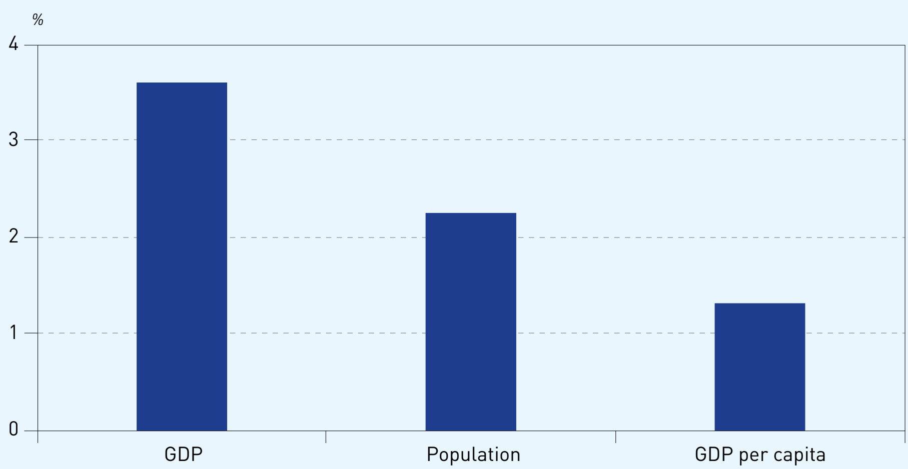
Focus on Africa

In the standard grouping of countries used in OPEC's WOO, African countries are included either under OPEC or in the group of countries called Middle East & Africa. However, because of the growing importance of the African continent on the global economic and energy scene, this year's publication looks in more detail and provides some insights on possible future developments related to the economy and energy demand of this region.

In the Reference Case, Africa is assumed to grow at an average 3.6% p.a. between 2017 and 2040 (Figure 1). As presented in Figure 3, the average economic growth between 2015 and 2020 is expected at 3% p.a. This accelerates gradually to 3.4% from 2020–2025, then 3.8% p.a. between 2030 and 2035 and reaches an average 3.9% p.a. over the last five years of the forecast period. As a result, the size of the African economy is estimated to more than double during the forecast period, from around $5.2 trillion in 2017, measured on a PPP basis, to $11.9 trillion in 2040.

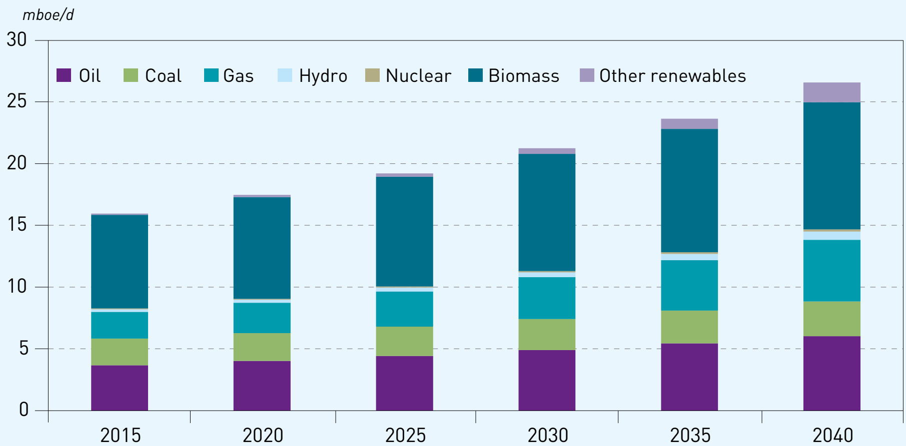
A large part of this growth is linked to an expanding population, which, according to the UN, will increase by more than 840 million between 2017 and 2040 to reach 2.1 billion. However, the standard of living in Africa is expected to progress much slower than its economic expansion. In fact, if measured on a GDP per capita basis, the standard of living is estimated to improve on average at only 1.4% p.a.

Figure 1
Average annual GDP, GDP per capita and population growth in Africa, 2017–2040



Reflecting the expected growth in population, economic activity and related energy policies, Figure 2 shows the projected growth in Africa's primary energy demand for major energy sources in the Reference Case. In 2015, total energy demand in Africa stood at 16 mboe/d. However, the use of biomass accounted for almost half of this, at around 47%. This clearly demonstrates the high dependency of the continent on the use of traditional fuels, mostly wood. The second largest energy source is oil, accounting for around 23% of the energy mix, followed by gas and coal, the shares of which are in the range of 13-to-14%. Other energy sources, including hydropower, nuclear and 'other renewables', contributed only a combined 2% to the energy mix in 2015.

Figure 2
Africa energy demand, 2015–2040



The Reference Case for Africa, however, projects some important changes taking place over the forecast period. While all energy sources are forecast to grow in absolute terms, totalling 26.6 mboe/d by 2040, the largest increase is seen in natural gas (+2.8 mboe/d) and biomass (+2.7 mboe/d).

Demand for oil is also anticipated to grow significantly (+2.4 mboe/d). In relative terms, however, the corresponding growth rate for oil is broadly in line with the rate of growth for total energy. Hence, oil is forecast to retain its share in Africa's energy mix at around 23% for the entire forecast period. Contrary to oil, the share of gas is anticipated to increase by around 5 percentage points between 2015 and 2040. A similar increase is witnessed in 'other renewables', which is expected to rise from less than 1% in 2015 to around 6% by 2040.

It is to be noted that the share of biomass, despite its increase in absolute terms, will drop by almost 9% as the use of modern energy sources, especially 'other renewables', gas, hydropower and nuclear, by far outpace the growth in the use of traditional biomass.

While the Reference Case for Africa assumes a relatively healthy average GDP growth of 3.6% p.a. across the forecast period, it is clear that this is well below the region's potential. The bulk of the region's population growth is characterized as working age population by 2040 (between the ages of 15–64), at over 60%, which compares to 56% in 2015. An increasingly youthful population provides the potential to create a thriving labour force, provided that job opportunities are created and sustained over time.

Urbanization is also taking place in Africa at a rapid pace, driven by population growth. By 2040, over half of the continent's population is projected to live in urban areas, expanding from around 40% in 2015. This presents vast opportunities for economic development, poverty alleviation and energy demand growth.

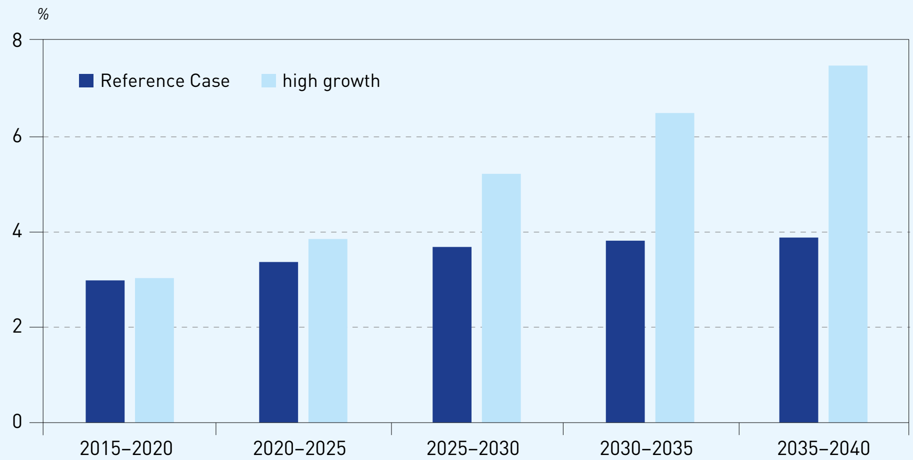
Africa is also home to countries with rich resource endowments, including oil, gas, cobalt, uranium, copper, bauxite and diamonds, among many other resources. This provides great opportunities to expedite future resource developments. It is also home to a large potential to expand its agriculture sector, as currently only a fraction of its area is used as arable land. Another prospective area relates to the development of infrastructure, such as road, rail, power grids and IT infrastructure. In this respect, 'leapfrogging' could provide a unique opportunity for African economic development, through technological advancement and access to capital investment.

Policymakers have already taken note of Africa's economic growth opportunities, as well as the challenges related to poverty, and have set out a series of plans to pave the way for meeting the continent's potential, all subject to improved political stability and creating conditions that are conducive to investment and business development that lead to inclusive and sustainable growth.

Recognizing the growth potential for Africa, an alternative high growth sensitivity was developed. Assuming further increases in labour productivity, participation rate, employment rate and the inflow of investment to the region, Africa's GDP growth would significantly accelerate under this sensitivity compared to the Reference Case. As shown in Figure 3, GDP acceleration in the high growth sensitivity takes place after 2025 and continues for the rest of the forecast period. During the 2025–2030 period, the average GDP growth in Africa under this sensitivity is assumed at 5.2% p.a., while growth reaches 7.5% p.a. during the last five years, significantly higher than the 3.9% p.a. assumed in the Reference Case over the same period.

Faster economic growth will have significant implications on the future energy demand in Africa too. Related energy demand for Africa and its energy mix is presented in Figure 4, while Figures 5 and 6 detail the changes in the high growth sensitivity compared to the Reference Case projections. To start with, total energy demand in Africa under the high growth sensitivity reaches 33.6 mboe/d by 2040. This is 7 mboe/d higher than in the Reference Case and almost 18 mboe/d higher that energy demand in 2015. It is important to note, however, that a large part of incremental demand will materialize during the last ten years of the forecast period, at the time when GDP growth picks up and the size of African economy is significantly larger than compared to the Refer-

Figure 3
Average annual GDP growth in Africa



ence Case. In relative terms, this represents an increase of more than 26% compared to the Reference Case.

Similar to the Reference Case, all major energy sources are expected to grow in this alternative sensitivity, but the proportion of growth between energy sources changes

Figure 4
Africa energy demand in the high growth sensitivity, 2015–2040

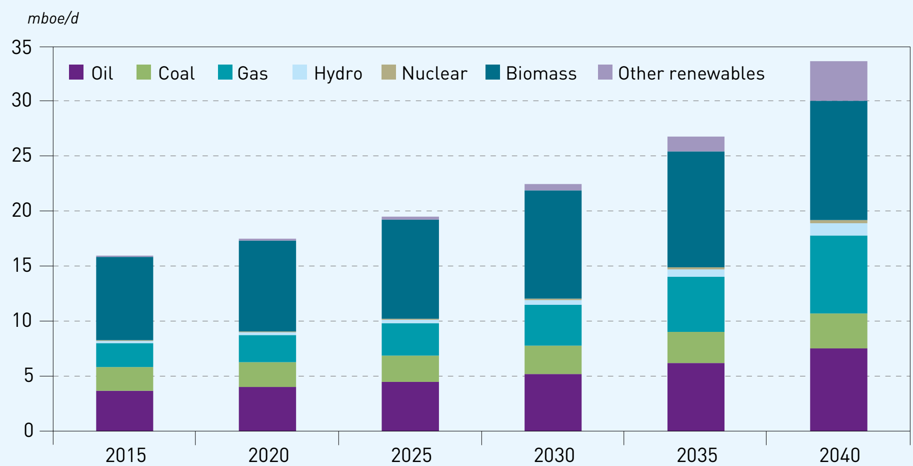


Figure 5
Additional energy demand in Africa in the high growth sensitivity, 2015–2040

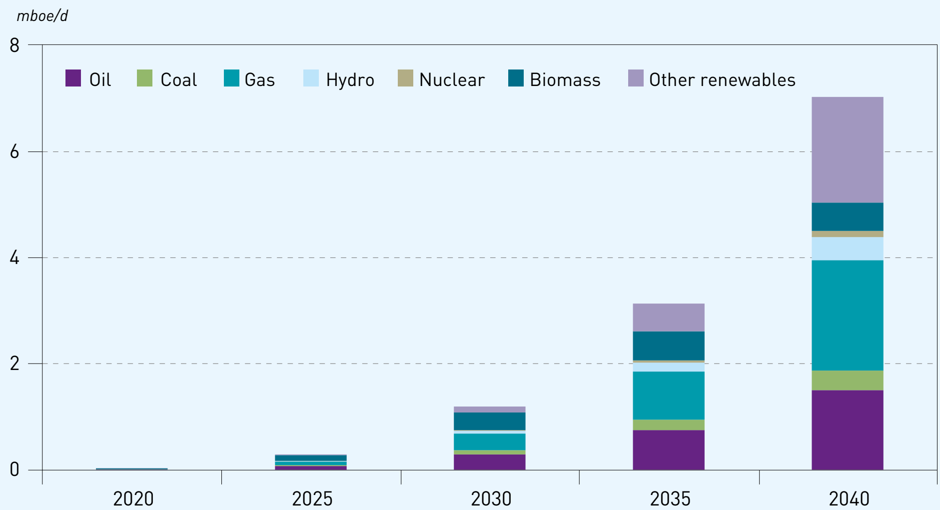
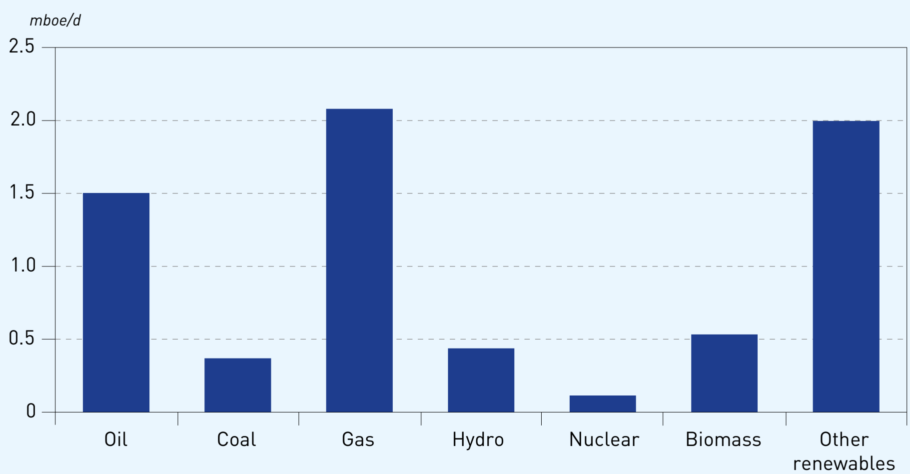


Figure 6
Additional energy demand in Africa in the high growth sensitivity, 2040



somewhat. The largest demand increase between 2015 and 2040 is expected for natural gas (+4.9 mboe/d), oil (+3.9 mboe/d) and 'other renewables' (+3.5 mboe/d). Assuming faster economic growth, technology leapfrogging and policies supporting improved access to electricity, 'other renewables' particularly, are expected to grow at very high rates, albeit from a very low base.

As a result, these energy sources (wind, PV, solar) will likely reach a share of more than 10% by 2040. High increase is also projected for the share of natural gas, gaining more than 7 percentage points over the forecast period. Rising shares of gas, 'other renewables', nuclear and hydropower (though the latter two energy sources will remain marginal in the energy mix of Africa) will be on the back of falling shares of biomass, coal and marginally for oil. The share of biomass is expected to lose more than 15 percentage points, hence, making the future energy mix in Africa in this high growth sensitivity much more diversified and dominated by modern energy sources.

Oil demand

Key takeaways

- Oil demand at the global level is expected to continue growing at healthy rates over the medium-term to reach a level of 104.5 mb/d by 2023.
- Implementation of the IMO regulations will challenge refiners and likely affect global demand levels.
- Long-term oil demand is set to increase by 14.5 mb/d to reach 111.7 mb/d in 2040.
- Global oil demand growth is forecast to slow from a level of 1.6 mb/d p.a. during the initial years to 2020 to just 0.2 mb/d during the last five years of the forecast period.
- India is projected to be the country with the fastest demand growth and see the largest additional demand in the period to 2040.
- More than half of the incremental oil demand over the forecast period is expected to be satisfied by light products.
- Within the light products, demand for ethane/LPG is set to increase by 3.3 mb/d between 2017 and 2040; this is the largest increase among all major products.
- Among all transport modes, the largest demand for oil comes from road transportation. In 2017, this sector represented 45% of global demand at 43.6 mb/d. Significant long-term growth is expected with an additional 4.1 mb/d to reach 47.8 mb/d by 2040.
- The increase in vehicle stock is the key driver that contributes to the rise in oil consumption in the road transportation sector. The total vehicle stock is estimated to grow by around 1.1 billion between 2017 and 2040 to reach 2.4 billion vehicles.
- Passenger cars are estimated to grow by around 877 million, with 768 million additional cars in Developing countries.
- The total commercial vehicle fleet is forecast to more than double during the period 2017–2040, rising from 230 million vehicles in 2017 to 462 million by 2040.
- Electric vehicles are set to experience a significant growth in numbers. It is forecast to reach around 320 million units in 2040. Out of this, passenger electric vehicles will account for more than 300 million, representing the second largest part of the passenger car fleet in 2040.
- Sensitivity cases assuming alternative developments in the expansion of electric vehicles indicate that these have the potential to shift global oil demand. The implication of all considered sensitivities are fairly limited during the next ten years, within the range of 1 mb/d, but start widening during the last decade of the forecast period. The range of uncertainty is more than 3 mb/d by 2035 and increases to above 4 mb/d by 2040.
- Strong growth is expected in the petrochemical sector where demand is forecast to increase by 4.5 mb/d over the forecast period.

Oil prices have generally been on a rising path, with the OPEC Reference Basket (ORB) increasing from levels around $60/b during the last two months of 2017 to above $77/b in the second half of May 2018, before moderating to levels close to $70/b during the summer months of 2018. It is to be noted, however, that the sharp price rises during April and May 2018 was primarily driven by increasing geopolitical tensions, rather than being a reflection of market fundamentals.

At the same time, global economic activity has also been on an upward trend over the past year. For example, the OPEC Secretariat's assessment of global GDP growth for 2018 reported in last year's WOO was 3.5%. This was gradually revised upward to 3.7% in the December 2017 Monthly Oil Market Report (MOMR) and then 3.8% in April 2018 MOMR. Higher than expected growth was observed mainly in the US and Europe, supported by solid growth in China and India, as well as an improving situation in Russia and Brazil.

Broadly reflecting the improving economic developments, oil demand also surprised analysts in a positive way. While initial assessments for oil demand growth in 2018 were around 1.3 mb/d, the estimate adopted in this Outlook is for 1.6 mb/d. Upwards demand revisions are mainly for the US, Europe and China. In these countries, besides strong economic performance, oil demand has also been supported by robust sales of sport utility vehicles (SUVs) over the past two years. At the same time, however, driven by declining battery costs and government support, BEVs and PHEVs continue to penetrate the market, particularly in China and the OECD region. Moreover, an increasing number of hybrid models at competitive prices are adding more efficient cars to the pool, hence, partly offsetting the effect of SUVs on oil demand. Similarly, car sharing, carpooling and ride-hailing are expanding in urban areas, enabled by technology.

Besides road transportation, healthy oil demand growth is also evolving in the petrochemical and aviation sectors. While demand in aviation has been on a steady rise for several years, the petrochemical sector is emerging as a front-runner in terms of future demand.

As already outlined in Chapter 1, several changes have also occurred on the energy policy side. The ones most relevant for future oil demand include, the deferral of the 'second phase' of CAFE standards for 2022–2025 model year cars produced in the US; the continuation of the 'diesel gate' scandal in Europe, including the ongoing discussion in European capitals to ban diesel vehicles in city centres; changes in Indian policy regarding electric vehicles; and the intensified discussion among policymakers, especially in Europe, on future support for electric vehicles.

Intensive ongoing negotiations are also focused on the implementation of the rules concerning the IMO regulations to limit bunker fuel sulphur content to 0.5%, effective January 2020. To enforce the implementation of the regulation, the IMO recently decided to ban vessels from carrying non-compliant fuel (fuel oil with sulphur content above 0.5%) unless they have a scrubbing facility on-board.

Obviously, this list of recently adopted policy measures is not exhaustive. It is, however, rather indicative of existing, probably even growing, uncertainties that surround developments in the oil market and which make future projections challenging. Nevertheless, this Chapter tries to capture the highlighted factors and provide the most likely outlook for oil demand in the medium- and long-term.

This Chapter starts with a dedicated regional analysis for the medium-term outlook (up to 2023), with special attention placed on the impact of the IMO MARPOL Annex VI Global Sulphur Cap. Then, the Chapter presents the long-term demand outlook with a particular emphasis on product demand and prospects up to 2040. Finally, an extended analysis of the sectoral demand is presented, specifically focusing on sectors that have the largest potential for incremental oil demand over the forecast period.

3.1 Medium-term oil demand

Reflecting assumed developments in regional economic activity, policy measures and price levels, as well as considering the structural changes taking place in oil markets, oil demand at the global level is expected to continue growing at healthy rates over the medium-term to reach a level of 104.5 mb/d by 2023. This represents an average annual increase of 1.2 mb/d over the forecast period, with a total incremental demand of 7.3 mb/d compared to 2017 (Table 3.1).

Table 3.1
Medium-term oil demand

mb/d

	2017	2018	2019	2020	2021	2022	2023	Growth 2017–2023
OECD America	25.0	25.3	25.5	25.7	25.8	25.7	25.6	0.6
OECD Europe	14.3	14.4	14.4	14.5	14.4	14.3	14.2	–0.1
OECD Asia Oceania	8.1	8.1	8.0	8.0	8.0	7.9	7.8	–0.3
OECD	**47.3**	**47.8**	**48.0**	**48.3**	**48.1**	**47.9**	**47.6**	**0.2**
Latin America	5.7	5.8	5.9	6.0	6.1	6.2	6.3	0.5
Middle East & Africa	3.8	3.9	4.0	4.1	4.2	4.3	4.4	0.6
India	4.5	4.7	5.0	5.2	5.4	5.6	5.9	1.3
China	12.3	12.7	13.1	13.4	13.7	14.0	14.3	1.9
Other Asia	8.7	8.9	9.1	9.4	9.6	9.7	9.9	1.2
OPEC	9.3	9.4	9.5	9.8	9.9	10.1	10.3	1.0
Developing countries	**44.4**	**45.5**	**46.6**	**47.9**	**48.9**	**49.9**	**51.0**	**6.5**
Russia	3.5	3.5	3.6	3.7	3.7	3.8	3.8	0.3
Other Eurasia	1.9	2.0	2.0	2.1	2.1	2.2	2.2	0.2
Eurasia	**5.4**	**5.6**	**5.7**	**5.8**	**5.9**	**5.9**	**6.0**	**0.6**
World	**97.2**	**98.8**	**100.3**	**101.9**	**102.9**	**103.7**	**104.5**	**7.3**

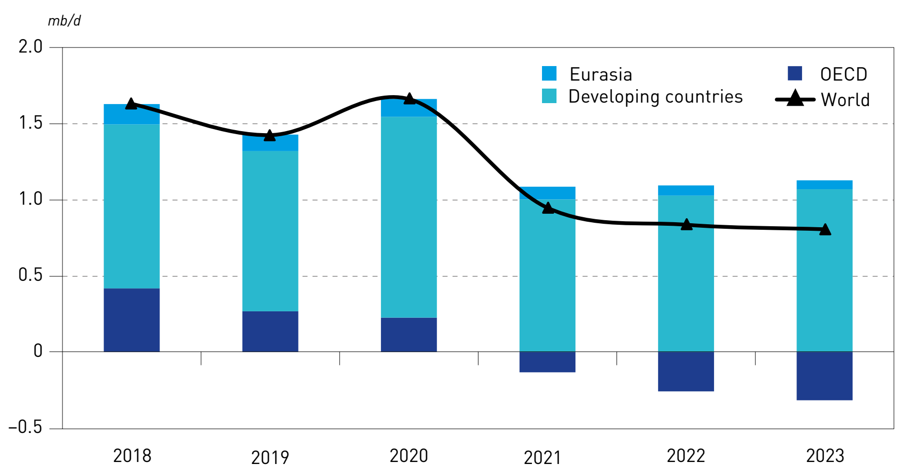
These solid growth numbers at the global level, however, mask significant variations, as well as diverging trends, at the regional, sectoral and product level. In fact, even at the global level, oil demand growth is anticipated to decelerate from around 1.5–1.7 mb/d in the 2018–2020 period to below 1 mb/d towards the end of the medium-term as slower economic growth, higher oil prices, efficiency improvements, the increased penetration of alternative vehicles, and lower population growth rates in the OECD and China limit growth potential.

Typically, it is a combination of these factors that has a measurable effect on oil demand in a given region. For example, the assumption of slowing economic growth in the OECD Americas, in combination with higher oil prices then those seen in the period 2015–2017, will likely lead to declining mileage driven in the region, and hence, decelerating oil demand growth.

This is likely to be further exacerbated by the increasing penetration of alternative vehicles, which will likely gradually displace oil with other energy sources. In the second part of the medium-term period, the combined effect of the increasing number of electric and natural gas vehicles at a global level is estimated to be in the range of 100 tb/d p.a., with OECD countries and China likely to be most impacted.

The net effect of these trends, in terms of incremental annual oil demand by region, is presented in Figure 3.1. It shows that the bulk of incremental demand is coming, and will continue to come, from Developing countries. Oil demand in this group of countries is projected to grow at a relatively steady rate of around 1.1 mb/d each year over the medium-term, except for 2020, when the implementation of IMO regulations on lower sulphur limits will likely provide a one-off impetus to oil demand. (The reasons for this sudden increase are discussed in detail in the latter part of this Chapter.)

Figure 3.1
Annual oil demand increments by region, 2018–2023



In broad terms, the future demand patterns for Developing countries are the result of the counter-balancing effects of continued GDP and population growth, with the knock-on expansion of the middle class supporting higher oil demand growth, which is partly offset by ssumed higher oil prices (compared to the past several years) and efficiency improvements stemming from both technology developments and the implementation of policy measures. Similar arguments are also applicable to the demand path for Eurasia.

Contrary to these regions, incremental oil demand in the OECD is projected to flip from the positive territory observed in the past few years, and expected to last until 2020, to negative growth thereafter. Besides the reasons already outlined, advancing efficiency improvements and fuel substitution – especially in the residential sector, industry, as well as in electricity generation – will more than offset the potential oil demand increase related to this region's economic growth.

As already noted, the implementation of the IMO regulations to limit the global sulphur content in all bunker fuels to 0.5%, effective January 2020, will not only pose a challenge to the refining industry, but will also likely affect overall demand levels, especially in the years during and after its implementation. In the Reference Case, oil demand is expected to decelerate from 1.6 mb/d in 2018 to 1.4 mb/d in 2019. However, instead of a continued growth deceleration in 2020, incremental oil demand in this year is expected to bounce back to 1.7 mb/d driven by specific market circumstances as a result of the IMO regulations.

Nevertheless, this extraordinary growth in 2020 will largely be compensated by lower incremental growth during the remaining part of the medium-term period. Indeed, oil demand growth is estimated to be below 1 mb/d in each year between 2021 and 2023.

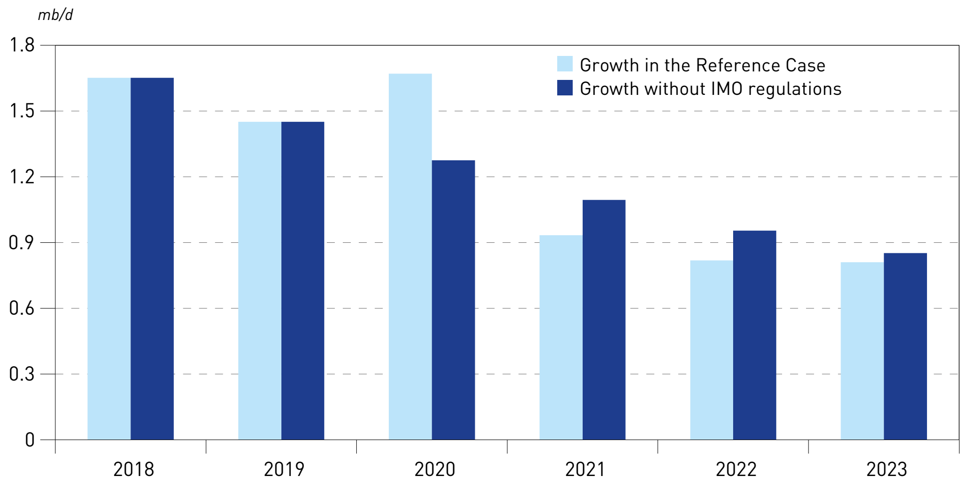
Figure 3.2 compares this growth pattern to the most likely path if the IMO regulations did not take place. In this case, the growth pattern for oil demand would be much smoother. It would decelerate from 1.6 mb/d in 2018 to 0.8 mb/d in 2023. The oil demand increase in 2020, as a result of the IMO regulation, is a direct consequence of two related issues.

First, given the lack of clarity on how this regulation will be implemented, the refining industry is reluctant to provide the necessary investment to expand capacity (especially secondary desulphurization and conversion capacity) that would be necessary to meet required fuels standards.

Therefore, additional refinery runs will be necessary to increase the production of low sulphur diesel, which will be used as a blending component to lower the sulphur content of heavy fuel oil. This, however, will also lead to a surplus of high-sulphur fuel oil (HSFO) volumes priced at a discount, which, it is assumed, will be absorbed by the power generation and industry sector. Most of the resulting additional demand will be located in regions with major bunkering ports, such as Other Asia, OPEC, OECD America and OECD Europe.

The second issue to be considered is the volumetric processing gain from switching from fuel oil to diesel. In 2020, when the need for additional diesel demand is largest, the resulting increase in processing gains is more than 0.1 mb/d. The effect of higher processing gains will cease over time, however, since the increasing number of scrubbers and the availability of low

Figure 3.2
Impact of IMO regulations on global oil demand growth



sulphur fuel oil (LSFO) will gradually eliminate required diesel demand additions. Further details on these issues are highlighted in section 3.1.3 – Impact of the IMO regulations.

3.1.1 Regional oil demand

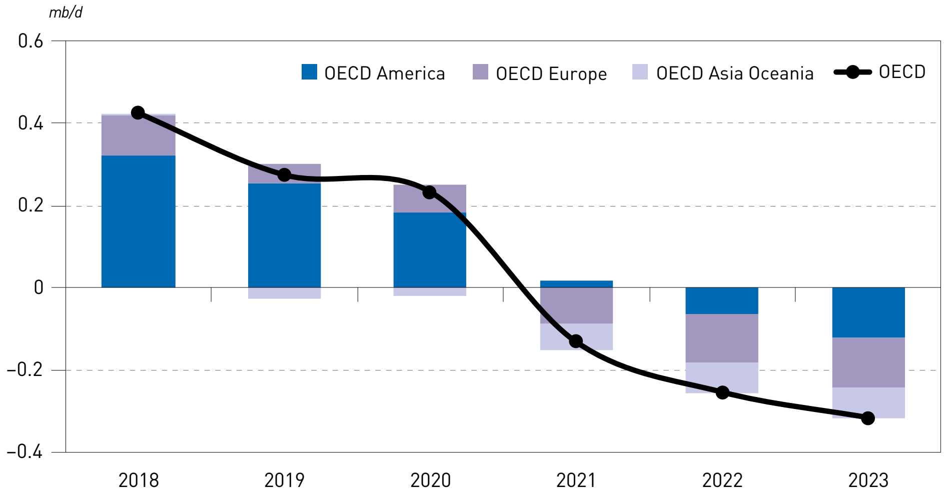
OECD

Historically, after peaking in 2005, oil demand in OECD countries was on a declining trend, until a combination of the collapse in oil prices and relatively high GDP growth rates (2.5% in both OECD America and Europe in 2015) stimulated a reversal of the trend so that OECD demand recorded significant growth of more than 0.7 mb/d in 2015. This positive oil demand growth has continued since, although the rate of growth decelerated to 0.4 mb/d in 2017. It is projected to decelerate further in 2019 to below 0.3 mb/d and revert to a declining path after 2020 (Figure 3.3).

This trend is already clearly emerging in OECD Asia Oceania, where almost no growth is projected for 2018 and with expectations for it to hit negative territory in 2019. In OECD Europe, the surprisingly strong demand growth seen in the period 2015–2017 (in the range of 0.2–0.3 mb/d p.a.) is not expected to continue. Most recent projections for 2018 indicate only marginal growth of around 0.1 mb/d driven by a slower expansion in the road transportation sector, in particular, followed by oil use in the industry and residential/agriculture sectors.

Some growth will likely be maintained during 2019, while IMO regulations are expected to boost it further during 2020, but for the rest of the medium-term, demand in OECD Europe

Figure 3.3
Annual oil demand growth in the OECD, 2018–2023



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is projected to revert to a declining trend as assumed higher prices (than those in the period 2015–2017) and a slowing growth in economic activity pressure the region's oil demand. Nonetheless, by 2023, oil demand in OECD Europe will be at 14.2 mb/d, only slightly below the observed level in the base year of 2017. While oil demand trends in OECD Europe and OECD Asia Oceania are easier to anticipate, a greater level of uncertainty relates to OECD America. This includes the assessment of the region's medium-term economic performance, the impact of higher prices on consumer behaviour and the implications of policy measures, such as the recent debate concerning future US CAFE standards. Moreover, the fast expansion of the petrochemical sector in the US (more details are provided in section 3.1.2 – Demand by sector and product) in the next two-to-three years raises questions about the sustainability of this trend over a longer period.

Taking into consideration these uncertainties, oil demand in OECD America is projected to grow until 2021, albeit with an annual decelerating growth rate. It is then anticipated to start declining marginally thereafter. The net effect is that oil demand goes from 25 mb/d in 2017 to 25.7 mb/d in 2021, before declining to 25.4 mb/d in 2023, still a higher level than in 2017. At the sectoral level, most of the growth is expected to take place in the petrochemical sector, followed by aviation and other industry, while gains in these sectors will likely be partly offset by declines in road transportation.

Non-OECD

Oil demand in Developing countries is projected to remain robust over the medium-term, growing on average by 1.1 mb/d p.a. (Figure 3.4). Demand growth in these countries is primarily driven by solid GDP growth, at an average 5% p.a. Moreover, GDP growth in

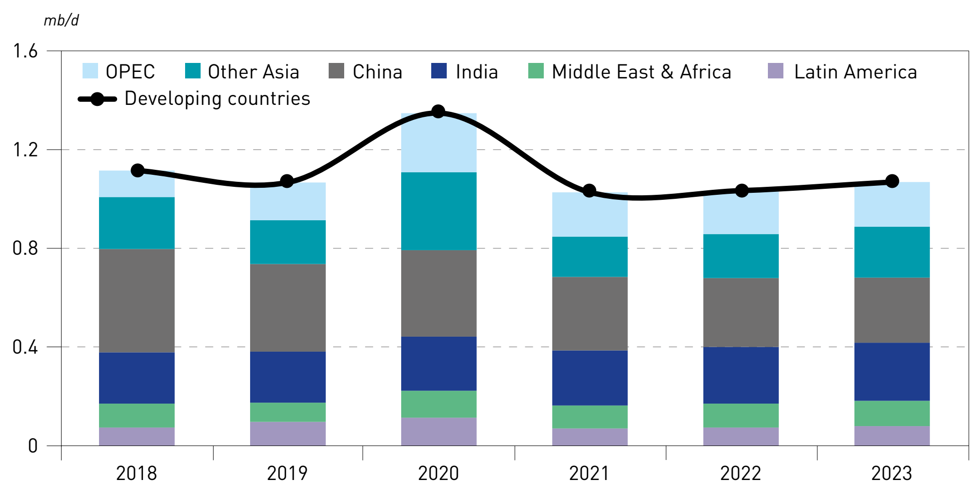
Developing countries (as a group) shows only a minor deceleration, falling from 5.1% in 2018 to 4.8% in 2023. In addition to economic growth, the largest part of incremental demand related to the implementation of the IMO sulphur regulations and the expected strong expansion in the global petrochemical industry will likely be felt in Developing countries. These come on top of the continued demand expansion in road, aviation and residential sectors, providing a solid basis for steady oil products demand growth, which is projected to increase from 44.4 mb/d in 2017 to 51 mb/d in 2023.

In Latin America, improving economic conditions, following sluggish to negative growth in the period 2015–2017, particularly in Brazil and Argentina, is expected to support demand growth, which reaches 6.3 mb/d by the end of the forecast period. In a similar vein, the outlook for faster economic growth and strong demographic developments in the Middle East & Africa (excluding OPEC Member Countries) is forecast to lead to this region's medium-term oil demand increasing by 0.6 mb/d, to reach 4.4 mb/d by 2023.

The largest part of incremental demand in Developing countries will come from China and India. The outlook for India shows moderately accelerating demand growth, increasing from 4.5 mb/d in 2017 to 5.9 mb/d in 2023. Although the overall incremental demand in India is only 1.3 mb/d (2017–2023), which is significantly lower than the estimated 1.9 mb/d demand increase for China, the figure for India sees it as the fastest demand growing region, expanding by 4.4% p.a. on average.

Most of India's incremental demand will come from a robust expansion of its transport system (combined 0.8 mb/d), in particular road transportation. Additional expansion over the

Figure 3.4
Annual oil demand growth in Developing countries, 2018–2023



medium-term is also projected in the residential/agriculture sector (0.2 mb/d), for the industrial use of oil (0.1 mb/d) and for petrochemicals (0.1 mb/d).

Contrary to India, oil demand growth in China is already on a decelerating growth path. On the back of decelerating economic growth and a profound restructuring of its economy, China's medium-term oil demand is anticipated to increase on average by 0.3 mb/d p.a. to a projected level of 14.3 mb/d by 2023.

Ongoing structural changes in China's economy have noticeable implications for medium-term oil demand. For example, while oil demand in China's industry sector increased by more than 0.7 mb/d during the first decade of this century, it is projected to grow by just 0.1 mb/d over the next five years. Moreover, no growth for oil demand in electricity generation is projected over the medium-term.

On the other hand, strong oil demand growth is set to continue in the road transportation and aviation sectors as China's expanding middle class give rise to mobility needs, despite the fact that sales of alternative vehicles are expected to grow at high rates. Of special importance for future oil demand is China's petrochemical industry, which is projected to grow by 0.3 mb/d over the medium-term, the second largest expansion in this sector worldwide, behind only the US.

The demand outlook for Other Asia shows strong growth, with an additional 1.2 mb/d from 2017–2023, to total 9.9 mb/d by 2023, supported by solid economic growth and an expansion in the region's petrochemical sector.

For OPEC, oil revenue contributes to economic growth, hence, it also partly affects domestic oil demand. In fact, in 2016, oil demand in OPEC Member Countries dropped for the first time since 1999, as in this year the annual oil price reached its lowest level during the recent downturn, and with only a moderate demand recovery during 2017. Looking to the future, assumed sustained higher oil prices will have a positive impact on the economy which, in turn, will support oil demand. By 2023, demand is projected to reach 10.3 mb/d, an increase of 1 mb/d compared to 2017.

In the period to 2023, the road transportation sector is expected to be the largest contributor to demand growth in OPEC Member Countries (Figure 3.5), adding around 0.4 mb/d to the level of 3.3 mb/d in 2017. A significant demand increase is also projected in the petrochemical industry (0.2 mb/d), while other sectors, such as residential, agriculture, non-petrochemical industry and commerce, are estimated to grow by a combined 0.3 mb/d. Additional demand in non-road transport is largely driven by expanding aviation traffic. Oil demand in the electricity sector is projected to remain stagnant over the medium-term as rising demand for electricity in OPEC Member Countries is mostly covered by a combination of renewable, nuclear and natural gas powered plants.

Figure 3.6 shows the annual demand increments in Eurasia. It should be noted that this region's annual incremental demand is in the range of just 0.1 mb/d; hence, its contribution to overall demand growth is marginal. In Eurasia, medium-term oil demand is estimated to increase gradually from 5.4 mb/d in 2017 to 6 mb/d in 2023. As presented in Figure 3.6, demand

Figure 3.5
Oil demand in OPEC Member Countries by sector, 2018–2023

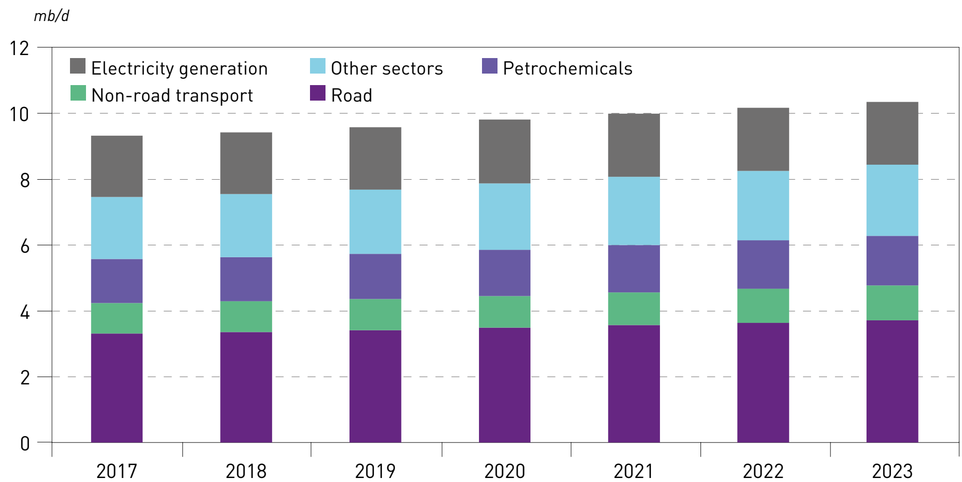
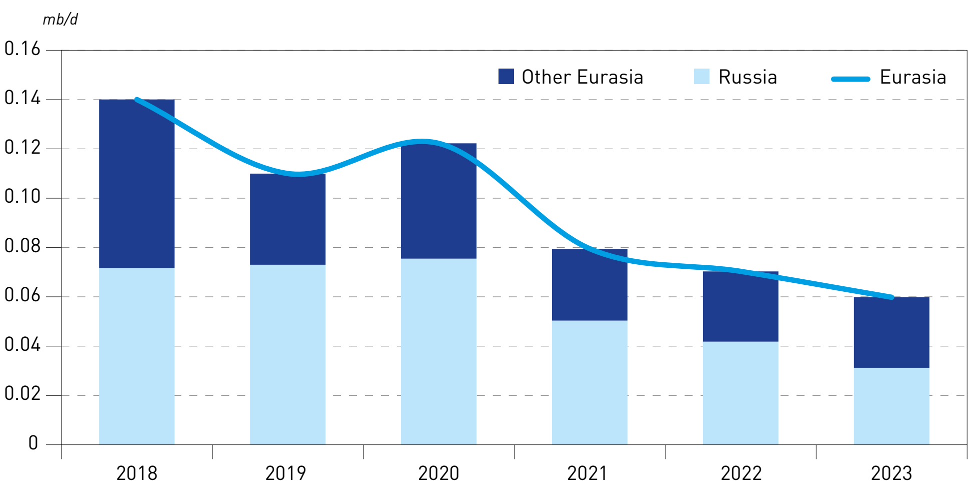


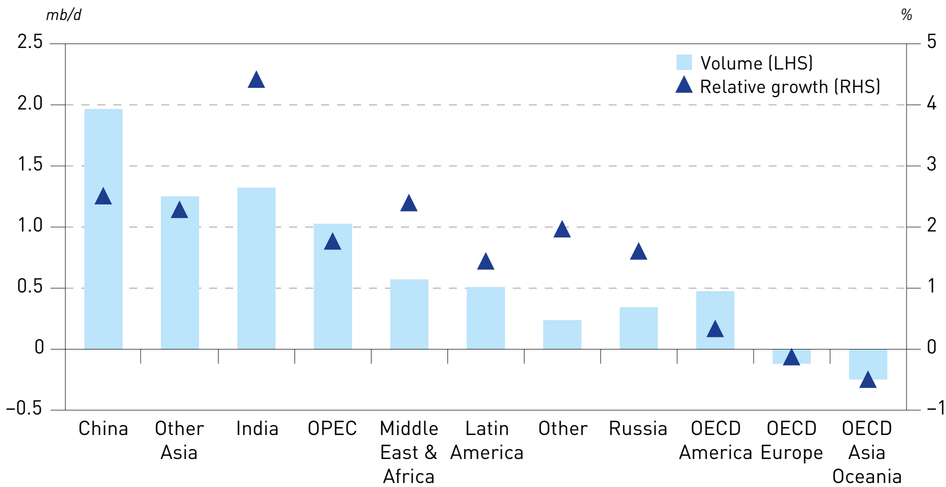
Figure 3.6
Annual oil demand growth in Eurasia, 2018–2023



growth in this region is more front-loaded as the recovery from the recent recession in Russia is set to accelerate, and current healthy GDP growth rates in other countries in the region are anticipated to decelerate as the medium-term progresses.

Russia's oil demand is expected to increase by 0.3 mb/d to reach 3.8 mb/d in 2023. Out of this, however, 0.2 mb/d is likely to be achieved by 2020, leaving little room for demand growth in the second part of the medium-term period. It is worth mentioning that demand growth in Russia's petrochemical sector during the medium-term is almost at parity with the road transportation sector. This is yet another sign of the strong global expansion in the petrochemical sector, as well as its growing importance to Russia. In the case of Other Eurasia, relatively strong demand growth of almost 2% p.a. is foreseen, with demand expected to rise from 1.9 mb/d in 2017 to 2.2 mb/d in 2023.

Figure 3.7
Regional oil demand growth between 2017 and 2023



To round-up the trends in regional oil demand, Figure 3.7 shows how this growth is distributed between regions alongside the corresponding average annual demand growth rate.

3.1.2 Medium-term oil demand by sector and product

Bearing in mind the regional differences in sectoral demand, often with divergent developments, especially when comparing the OECD and Developing countries, this section summarizes the major trends in sectoral demand at the global level. It also highlights the key observations in the resulting demand for the major groups of refined products over the medium-term.

Table 3.2
Global oil demand by sector, 2017–2023

mb/d

	2017	2018	2019	2020	2021	2022	2023	2017–2023
Road	43.6	44.3	44.8	45.3	45.8	46.2	46.6	3.0
Aviation	6.3	6.5	6.6	6.8	6.9	7.1	7.2	0.9
Rail/dom. waterways	1.8	1.9	1.9	1.9	1.9	2.0	2.0	0.1
Marine bunkers	4.0	4.1	4.2	4.2	4.3	4.4	4.4	0.4
Petrochemicals	13.0	13.3	13.6	13.9	14.2	14.4	14.5	1.5
Other industry	12.7	12.9	13.0	13.3	13.3	13.3	13.3	0.6
Resid./Comm./Agr.	10.6	10.8	11.0	11.1	11.3	11.3	11.4	0.8
Electricity generation	5.1	5.1	5.1	5.4	5.2	5.1	5.0	0.0
World	**97.2**	**98.8**	**100.3**	**102.0**	**102.9**	**103.7**	**104.5**	**7.3**

In respect to sectoral demand, Table 3.2 presents the breakdown of global oil demand and its growth in major consumption sectors. In volumetric terms, two sectors stand out over the medium-term: road transportation and petrochemicals.

Because of its high share in overall oil demand, the road transportation sector is traditionally the largest contributor to future demand. Therefore, it is no surprise that this remains the case for the period 2017–2023. It is important to note, however, that besides electricity generation, which has been on a declining trend for some time, road transportation is actually the second slowest growing sector (after Other industry), averaging 1.1% p.a., and the one where annual growth deceleration is most obvious.

The opposite is witnessed in the petrochemical sector, which keeps surprising analysts to the upside. The medium-term outlook for the petrochemical sector is largely driven by the growing availability of relatively cheap feedstock in North America, combined with growing protectionism, although this is partly offset by concerns about the long-term sustainability of the fast expansion. The industry is challenged by the need to bring world-scale capacities to market in a business where cycles and long-lead construction times are the rule, not the exception.

The US shale revolution has provided local petrochemical plants with a feedstock advantage leading to a number of new projects, with several of them already at an advanced construction stage. The first wave of new US ethane-based crackers, (such as Sasol and Shintech projects in Louisiana, and ExxonMobil, Chevron Phillips, Formosa Plastics and Dupont projects in Texas, is expected to add up to 10 million tons (mt) of additional capacity from 2018 to 2020. A less certain second wave (by 2023) includes projects such as PTTGC America in Ohio, Badlands in North Dakota and the Appalachian Shale Cracker Enterprise in West Virginia. These could potentially add another 5 mt.

These additions may represent as much as 10% of the global capacity and are likely to increase competition in the ethylene market. This is due to the fact that US domestic polymer demand is unlikely to increase at the same pace over the medium-term, so most of this new capacity will be aimed at export markets.

The US propylene market offers a slightly different picture than ethylene as liquefied petroleum gas (LPG) feedstock has competing uses for heating, cooking and industrial consumption. Therefore, capacity additions for propane dehydrogenation (PDH) are smaller, but still significant. The US propane supply surge is forecast to drive around 4 mt of new on-purpose PDH capacity. The major projects in this area are Enterprise Products' in Mont Belvieu, Texas, and the Formosa Plastics project in Point Comfort, Texas. Similar projects also exist in Alberta, Canada, planned by Inter Pipeline and Pembina Pipeline in cooperation with Kuwait's Petrochemical Industries Company.

A significant expansion in China's petrochemical industry is also projected, with medium-term capacity additions in the range of 5–7 mt. Contrary to those in the US, these additions are primarily configured to use naphtha as a feedstock, while only one project currently on the list (SP Chemicals in Jiangsu province) targets ethane imported from the US.

Naphtha as a primary feedstock is also considered in other petrochemical projects in Asia. Malaysia, South Korea, Thailand and India are the main candidates for new projects, which includes a huge refining and petrochemical complex proposed in Ratnagiri, India. This is a joint venture between Saudi Aramco, the Abu Dhabi National Oil Company (ADNOC) and a consortium of three Indian oil companies. Once materialized, it will be the single largest refinery worldwide, combined with a petrochemical capacity of 18 mt/year.

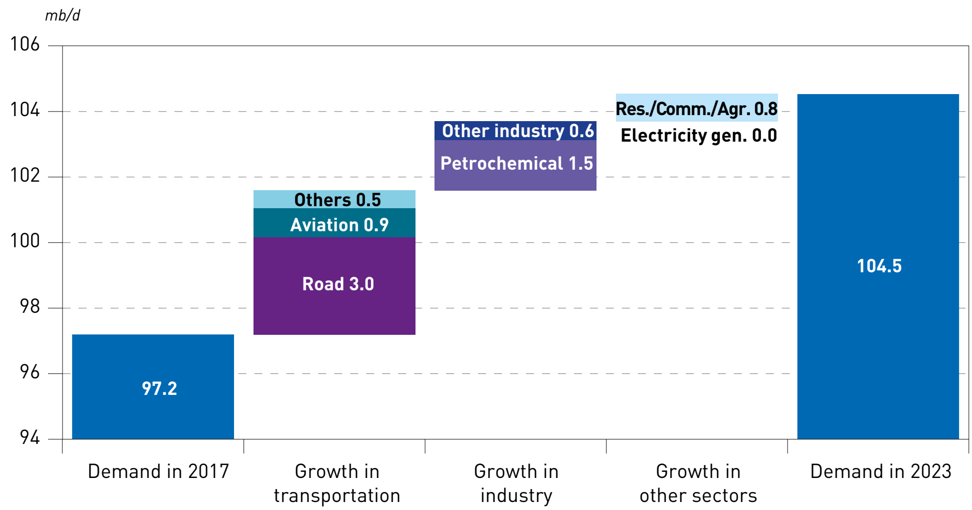
The other two regions with noticeable medium-term expansions are Russia and the Middle East. In the case of Russia, proposed projects total almost 5 mt of additional capacity, but it is unlikely that all of them will be completed within the 2023 horizon. From the feedstock perspective, they are expected to use a combination of ethane and naphtha, supplemented by LPG.

In the Middle East, the Crude Oil to Chemicals Complex (COTC) project in Saudi Arabia, between Saudi Aramco and Sabic, is expected to produce 9 mt per year of chemicals and base oils, bringing a new business model to the industry. Additional projects in the region exist in IR Iran and Oman.

In summary, as presented in Figure 3.8, incremental oil demand in the petrochemical sector, primarily associated with these projects, will be in the range of 1.5 mb/d over the medium-term. Of this, around 0.4 mb/d is estimated to take place in OECD America, 0.3 mb/d in China, around 0.2 mb/d in each of Other Asia and OPEC, and some 0.1 mb/d in each of India, Russia and OECD Europe.

Besides road transportation and petrochemicals, the rest of incremental medium-term demand is spread fairly equally across aviation, residential/commercial/agriculture and industry sectors, with some increases also in marine bunkers and rail and domestic waterways. For most of them, there is no major departure from recent trends.

Figure 3.8
Growth in global oil demand by sector between 2017 and 2023



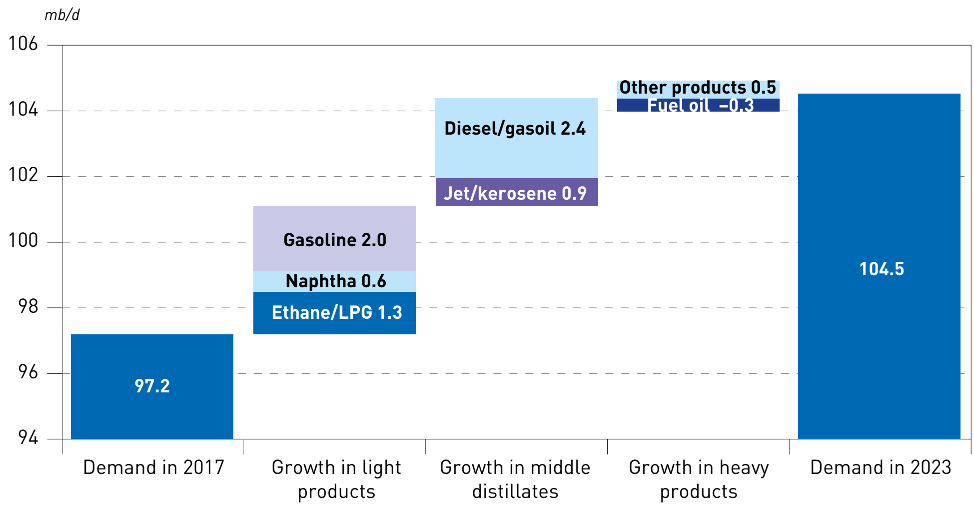
In terms of relative growth, the aviation sector is worth noting. This is projected to be the fastest growing sector at 2.2% p.a. on average. At the other end of the spectrum is electricity generation. Oil demand in this sector is projected to oscillate around 5.1 mb/d, with a temporary boost in 2020–2021 as a side effect of the IMO regulations (more details are provided in section 3.1.3 – Impact of the IMO regulations in the medium-term).

Figure 3.9 translates regional and sectoral oil demand trends into demand for specific refined products. The largest increase is projected for diesel/gasoil (+2.4 mb/d). There are several reasons for this. Firstly, the base consumption (2017) of diesel/gasoil is the highest among all major products. Secondly, this product is also the most widely used across various consuming sectors, including road transportation, rail, waterways, agriculture, industry, residential and marine sectors. Thirdly, the relatively large switch from fuel oil to diesel in the marine sector due to the IMO regulations as of 2020 contributes to the rise of diesel/gasoil during the forecast period.

Besides diesel/gasoil, gasoline and ethane/LPG are also projected to record significant growth. These products are primarily driven by developments in the road transportation and petrochemical sector, respectively. Moreover, growth in LPG will also be supported by the residential and industry sectors.

The increase in jet/kerosene (+0.9 mb/d) broadly corresponds to the expected expansion in the aviation sector as the domestic use of kerosene is anticipated to remain relatively stable over the medium-term. Higher demand for naphtha (+0.6 mb/d) is mainly driven by new naphtha crackers in Asia, as highlighted earlier.

Figure 3.9
Growth in global oil demand by product between 2017 and 2023



For the heavy products, demand for the group of 'Other products' (including asphalt, bitumen, petcoke, still gas, lubes, waxes etc.) is also widely spread across several sectors. From the growth perspective, the largest part of incremental demand is for bitumen – mainly road construction in developing countries – and lubricants. Finally, fuel oil demand is set to decline over the medium-term, mainly as the result of stagnant demand in electricity generation and some displacement of its demand by diesel in the marine sector.

3.1.3 Impact of the IMO regulations in the medium-term

Following the decision of the IMO to lower the maximum allowed sulphur content for marine bunkers from 3.5% to 0.5% (on a weight basis) as of 1 January 2020,[14] the prevailing view among market participants is that this development will be disruptive to both the shipping and refining sectors. Moreover, there are several key uncertainties surrounding the implementation of the IMO regulations, including the compliance rate, the future marine bunker fuel mix, the response of the refining and shipping industry, as well as potential price implications.

The uncertainty is partly the result of the variety of available options to comply with the IMO regulations. In principle, shipping companies have three options:

- A switch to 0.5% compliant fuel from 2020 onwards (LSFO, middle distillates or a compliant blend);
- Continuation of HSFO consumption in combination with an on-board scrubber facility; and
- A switch to an alternative fuel, such as LNG or biofuels.

While there have been some announcements in favour of LNG from shipping companies,[15] LNG bunkering is not expected to play a major short-term role, in terms of helping companies comply with IMO targets in 2020. This is mostly due to the relatively slow fleet turnover, as well as a lack of appropriate infrastructure, but LNG could play a more important role in the bunker fuel mix in the longer-term. In other words, ship owners will be left to choose between the first two options – a switch to compliant fuel or the installation of a scrubber.

According to recent announcements made by shipping companies, both options will be exploited. Global shipping companies such as Maersk and Hapag Lloyd have reportedly chosen 0.5% compliant bunker fuel. At the same time, other large players, such as commodity traders Trafigura and Cargill, will reportedly install scrubbers on a portion of their fleets. However, many ship owners have still not committed themselves to a specific pathway. This reflects the uncertainty regarding the composition of the marine bunker fuel mix in the medium- to long-term.

The uncertainty related to the composition of the bunker fuel mix, alongside the insufficient time to adjust, are the major reasons why the global refining system is not likely to engage in any significant additional investments on top of the ones that are already on track. Nonetheless, it should be noted that there has been some small-scale refurbishments and debottlenecking geared toward IMO regulations.

In line with revamps, the existing refining system – including the expected additions in the medium-term – does have a certain level of flexibility to change yields in order to ensure sufficient supplies of compliant fuel. The flexible mode of operation will help the global refining system to maximize the output of middle distillates and LSFO in 2020. In addition, some limited volumes of LSFO, currently used in other sectors, will likely be rerouted to the marine bunkers sector. Some relief will also likely come from the changing global crude slate, with increasing volumes of US light tight oil coming onstream. This should help to produce additional volumes of LSFO.

Nevertheless, the flexibility of the global refining sector is limited and assessed as insufficient to meet required demand. Therefore, similar to last year, the OPEC Reference Case projects an increase in global refining runs in 2020 as the most likely way to produce sufficient volumes of compliant fuel. The most obvious path is the maximization of middle distillate output, which would be blended with HSFO in order to produce compliant 0.5% blend fuel.

The unintended consequence of the increase in refinery runs will be an oversupply of HSFO, which could be used in industry and even for power generation, with possible heavy discounts during 2020. Needless to say, the assumed heavy HSFO discounts will likely stimulate the installation of scrubber facilities in the shipping industry, hence, reverting back to higher demand for HSFO in the years thereafter. Another unwanted consequence of higher crude runs will be an excess of light distillates, although it is expected to be kept at a necessary minimum. These will likely be put into stocks during 2020.

Considering all the challenges for shippers, as well as refiners, the problem of compliance with the IMO regulations should not be underestimated, especially in 2020. Recognizing this challenge, and in order to enforce the implementation of the regulation from 2020, the IMO decided to ban vessels from carrying non-compliant fuel – fuel oil with a sulphur content above 0.5% – unless they have a scrubbing facility on-board. The regulation addressing non-compliance will come into effect in March 2020. Moreover, the IMO has introduced new fuel database rules, which request flag states to collect data on bunker fuel use by type of fuel. This should allow for a better understanding of the global bunker fuel mix and track potential non-compliance.

However, despite the efforts to enforce the regulation, there is still a high probability of non-compliance, especially in the early implementation years. This is due to various reasons, such as the relatively low number of scrubbers installed and a potential lack of compliant fuel. Therefore, the Reference Case does not assume full compliance with the IMO regulation within the medium-term period. It is more likely that the compliance rate during the first year of implementation will be about 75%, with an expected gradual increase towards levels around 90% in 2023, in line with the increasing number of vessels with on-board scrubbing facilities.

In terms of the progress to scrubber installation in the shipping industry, in early 2018 it was estimated that less than 500 vessels had installed or ordered a scrubbing facility. Subdued interest for scrubbing facilities can be explained by the lack of financial incentives as the regulation goes into effect only from January 2020.

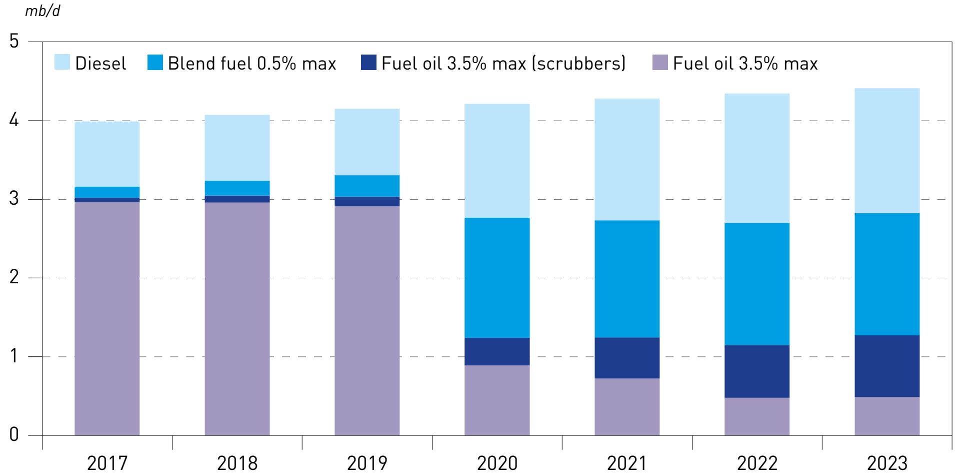
Therefore, OPEC's Reference Case assumes that installing scrubbing facilities will take off only from 2019, shortly before the IMO decision comes into force and once the financial incentive – in the form of a widening HSFO discount to compliant LSFO and gasoil – materializes. In 2020, it is estimated that there will be around 2,000 vessels with installed scrubbers. This is anticipated to be followed by a strong increase in the number to the end of the medium-term, with an estimated level between 4,500 and 5,000 scrubbers.[16]

Vessels without a scrubber facility on-board are required to burn compliant fuel with a sulphur content of less than 0.5%. As already noted, the IMO regulations do not specify the type of fuel, but only the sulphur content. This means that compliant fuel, in principle, can be anything between LSFO to diesel, including blends of high sulphur with low sulphur barrels, to arrive at compliant specifications. Nonetheless, the limiting factor in making blends is compatibility with existing vessel engines.

Accounting for these issues, it is projected that demand for both diesel and compliant 0.5% fuel in the marine sector will increase strongly in 2020 (Figure 3.10). Diesel demand in 2020 is estimated at around 1.4 mb/d, an increase of 0.6 mb/d from 2019. At the same time, demand for compliant LSFO is estimated at more than 1.5 mb/d, up from around 0.3 mb/d in 2019. For HSFO, its demand is projected to decrease from around 3 mb/d in 2019 to some 1.2 mb/d in 2020, based on the estimated non-compliance, as well as the use of scrubbing facilities.

In order to produce sufficient volumes of middle distillates, the global refining system is expected to increase runs by around 0.4 mb/d in 2020 (additional to the case if no IMO regulations were adopted), of which more than 0.2 mb/d will be surplus HSFO that will create pressure on its price and possibly lead to a heavy discount.[17] As the refining industry is set to adapt in the years after, this effect is expected to fade with estimated surplus HSFO volumes of some 0.1 mb/d in 2021 and then no surplus in 2022. Furthermore, the surplus of light products in 2020

Figure 3.10
Marine bunker demand by fuel type



is projected at slightly above 0.1 mb/d, although this is expected to be absorbed by stocks and without a significant impact on the products market.

Finally, the IMO regulations are expected to have a significant price impact on marine fuels and especially HSFO, considering the projected oversupply in the early years of its implementation. At the same time, LSFO and middle distillate cracks are expected to improve substantially, due to increasing demand. This projection is also supported by trends in the forward market, with diesel forward cracks showing continuous improvements for the year 2020, while at the same time HSFO forward cracks are seen to be under strong pressure in early 2020.

This trend was especially noticeable after an IMO announcement was made to ban vessels from carrying non-compliant fuel, which should increase the rate of compliance. Therefore, refining economics are expected to be dominated by the IMO regulation in 2020, with complex refineries – those with deep conversion units and geared towards distillate fuels – expecting to profit most in 2020. Simple refiners may experience a differentiated picture, with some upward tendency in margins for those with sweet crude intake, as they would be able to produce LSFO, but less benefits or even declining margins for those running sour and heavy streams.

Another effect that should not be overlooked relates to crude differentials, with medium- and heavy-sour grades expected to experience stronger discounts during the early years of the IMO regulations due to their high yield of HSFO. On the upside, medium-sweet grades should see improving spreads versus their benchmarks due to their low sulphur content and high middle distillate yield.

Overall, the IMO regulation is expected to have a significant impact on both the shipping and refining industries, with a large degree of uncertainty regarding the implementation path, including the compliance rate. Due to a sudden switch in the fuel mix, potential shortages of compliant fuel are possible, especially middle distillates, which could spread to other sectors too. It is hoped that that there will be sufficient flexibility in the refining system in order to avoid any extreme events in the years to come.

3.2 Long-term oil demand by region

In several respects, long-term oil demand will broadly follow the trends outlined in the medium-term, although some additional factors and drivers will increasingly play a role. These primarily relate to energy policy issues and technology developments that may impact future cost structures and enable options that were either previously uncompetitive or unavailable. At a global level, long-term oil demand is expected to increase by 14.5 mb/d, rising from 97.2 mb/d in 2017 to 111.7 mb/d in 2040. The regional breakdown of future oil demand is provided in Table 3.3.

Table 3.3
Long-term oil demand by region

mb/d

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	25.0	25.7	25.2	23.9	22.5	20.9	–4.1
OECD Europe	14.3	14.5	13.9	13.1	12.4	11.6	–2.7
OECD Asia Oceania	8.1	8.0	7.6	7.2	6.7	6.2	–1.9
OECD	**47.3**	**48.3**	**46.8**	**44.2**	**41.5**	**38.7**	**–8.7**
Latin America	5.7	6.0	6.4	6.8	7.1	7.3	1.5
Middle East & Africa	3.8	4.1	4.6	5.1	5.7	6.3	2.5
India	4.5	5.2	6.4	7.6	9.0	10.4	5.8
China	12.3	13.4	14.7	15.8	16.6	17.4	5.1
Other Asia	8.7	9.4	10.3	11.3	12.2	12.9	4.2
OPEC	9.3	9.8	10.7	11.5	12.0	12.3	3.0
Developing countries	**44.4**	**47.9**	**53.1**	**58.1**	**62.6**	**66.6**	**22.2**
Russia	3.5	3.7	3.9	3.9	3.9	3.9	0.4
Other Eurasia	1.9	2.1	2.2	2.3	2.4	2.5	0.6
Eurasia	**5.4**	**5.8**	**6.1**	**6.3**	**6.4**	**6.4**	**1.0**
World	**97.2**	**101.9**	**106.0**	**108.6**	**110.5**	**111.7**	**14.5**

OPEC Reference Case projections to 2040 show a contrasting picture between the three major regions considered in Table 3.3: declining long-term demand in the OECD stands in stark contrast to growing demand in Developing countries and a moderately rising to flattening oil demand pattern in Eurasia.

Driven by an expanding middle class, high population growth rates and stronger economic growth potential, oil demand in Developing countries is expected to increase by more than 22 mb/d between 2017 and 2040. It rises from 44.4 mb/d in 2017 to 66.6 mb/d in 2040.

In terms of incremental demand over the forecast period, India is projected to be the country with the fastest demand growth (3.7% p.a. on average), as well as the largest additional demand (5.8 mb/d). With this fast demand growth, India will likely pass the 10 mb/d mark sometime towards the end of the forecast period. Despite this impressive growth, its total demand will still be far below the level of China, the main consumer within the Developing countries region.

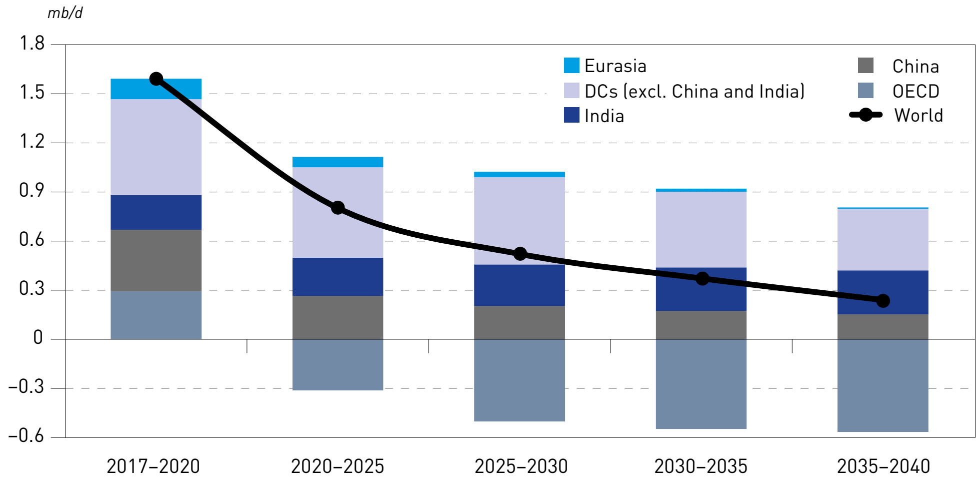
Oil demand in China is forecast to increase by more than 5 mb/d to reach 17.4 mb/d by 2040. This demand level is around 0.4 mb/d lower than projected in last year's WOO, primarily due to the expected faster penetration of alternative vehicles in the country, with part of its oil demand displaced by other energy sources. Part of the reduction is also due to lower long-term GDP growth compared to last year. Significant demand increases will also be achieved in Other Asia, with an additional 4.2 mb/d. This represents the third largest incremental demand increase among all considered regions, behind only India and China.

After India, the second fastest growth level in future oil demand, percentage wise, is expected in the Middle East & Africa (2.2% p.a.). However, due to the region's relatively small base demand, this translates to just 2.6 mb/d of incremental demand between 2017 and 2040. Relatively moderate demand growth is also forecast in Latin America, with an average 1.0% p.a. A slightly higher growth rate is projected for OPEC countries, at 1.2 % p.a., which translates into an overall demand increase of some 3 mb/d. In Eurasia, oil demand is forecast to increase by less than 1 mb/d to reach 6.4 mb/d in 2040. In fact, demand in this region is anticipated to plateau around 2035, at 6.4 mb/d.

On the flip side of this long-term demand growth is the OECD region, which is anticipated to show a significant decline of 8.7 mb/d over the forecast period. There are several reasons for this. One of them is the rather low population growth in the OECD, which is expected at 0.3% p.a. on average for the period 2017–2040. Another one is decelerating economic growth, which is forecast to stabilize at around 1.8% p.a. in the second half of the forecast period. This is significantly lower than the 2.4%–2.5% estimated during 2017 and 2018. Furthermore, in the OECD, a stronger tightening of energy policies that target energy efficiency and emission reductions is anticipated. Part of these efforts will be a significant penetration of alternative fuel vehicles in the transportation sector, as well as some fuel substitution from oil (and coal) to gas and renewable energy in other sectors.

The importance of Developing countries as the primary source for long-term oil demand growth is shown in Figure 3.11. Over the forecast period, oil demand in the region is expected

Figure 3.11
Average annual oil demand growth



3

to increase on average by 1 mb/d p.a., with China and India accounting for half of that growth. However, the picture is rather different at the end of the forecast period, compared to the beginning, as oil demand growth decelerates and the regional demand growth gravity centre shifts from China to India.

For reasons outlined earlier in this Chapter, oil demand decline in the OECD region is set to accelerate over the next decade, and in the last ten years of the forecast period, its oil demand is expected to drop on average by almost 0.6 mb/d p.a. The primary reason for this declining trend relates to expected developments in the road transportation sector. By the end of the forecast period, the car fleet is expected to be close to saturation with little room for increasing the number of vehicles. At the same time, the regional car fleet will become ever more efficient and with significant, and rising, levels of penetration by alternative vehicles.

Another important observation demonstrated in Figure 3.11 is the steadily decelerating oil demand growth at the global level. Global growth is forecast to slow from a level of 1.6 mb/d p.a. during the initial years to 2020 to just 0.2 mb/d during the last five years of the forecast period.

A contributing factor to this trend is the underlying assumption of moderately rising oil prices over the long-term. Another factor at play is an expectation that the global economy will see a growth deceleration as a result of lower employment growth coupled with lower labour productivity growth once the economy reaches a more advanced stage of development.

These factors are expected to curtail demand growth, but three further structural factors expected to limit the growth potential are of particular interest.

Firstly, the global economy, particularly that of developing countries, is anticipated to increasingly shift away from heavy industry, which tends to be more oil intensive, to a more service-oriented structure. A good example of this is China, where the weight of the service sector in the national economy has increased steadily over the past decade. According to the World Bank, in 2006 it represented 42% of the economy, while in 2017 its share had increased to 51.6%. Over the same timeframe, the weight of the industry sector dropped from 48% to 40%.

Secondly, further efficiency improvements will likely curb future oil demand growth. Whether this comes from a tightening of energy efficiency policies, technological improvements, or both, the use of energy (and oil) is expected to become ever more efficient. For example, cars will consume less fuel per kilometre, airplanes will burn less fuel per passenger kilometre and less energy will be needed to heat the same house in the future.

Finally, oil demand will likely continue to be limited by fuel switching. This trend has been visible in the electricity generation for a number of years. It is also particularly true in the road transportation sector, where increasingly more electric vehicles are estimated to penetrate the market, thus, displacing barrels of oil. In the marine bunkers sector, as already noted, the use of LNG could also displace some oil demand in the long-term. Similarly, in the residential, commercial and agriculture sector, a certain degree of substitution by gas and renewables can be expected to limit oil's sectoral demand growth.

It is interesting to observe, though, that oil demand growth will decelerate steadily in every region except two: India and the Middle East & Africa. These two regions share common features. Both of them have a young and dynamic population. And it is expected that future economic developments will lift millions out of poverty and help alleviate the challenge of energy access and energy poverty.

3.3 Long-term oil demand by product

Turning to oil demand for refined products, the key long-term trends are summarized in Table 3.4. At the global level, recent updates emphasize the continued shift in growing demand for light products. These contribute most to the demand increase over the forecast period.

In total, light products (ethane/LPG, naphtha and gasoline, including ethanol) are projected to increase by 7.8 mb/d between 2017 and 2040, followed by middle distillates (jet kerosene, domestic kerosene, diesel and biodiesel) with an increase of 5.5 mb/d. Heavy products (residual fuel and 'other products' such as bitumen, lubricants, waxes, still gas, coke, sulphur and direct use of crude oil) are estimated to see the smallest growth, increasing by 1.2 mb/d.

Compared to last year, Table 3.4 outlines some shifts in product demand. There are three primary reasons that have slightly altered the growth prospects for specific products.

The first one is the faster expansion of the petrochemicals sector compared to last year. This has pushed up demand, mostly ethane, in North America, the Middle East and Europe, as well as slightly increasing naphtha demand in the Asian region, Russia and Europe.

Table 3.4
Long-term oil demand by product

mb/d

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
Ethane/LPG	11.2	12.0	12.7	13.5	14.1	14.4	3.3
Naphtha	6.3	6.7	7.1	7.6	8.1	8.6	2.2
Gasoline	25.5	26.6	27.9	28.0	27.9	27.8	2.3
Light products	**43.0**	**45.2**	**47.7**	**49.1**	**50.0**	**50.8**	**7.8**
Jet/kero	7.2	7.7	8.4	8.8	9.4	9.8	2.5
Gasoil/diesel	28.6	30.8	31.2	31.6	31.7	31.6	2.9
Middle distillates	**35.9**	**38.5**	**39.6**	**40.4**	**41.1**	**41.3**	**5.5**
Residual fuel	7.1	6.6	6.8	7.1	7.3	7.4	0.3
Other products	11.2	11.6	11.8	12.0	12.1	12.2	1.0
Heavy products	**18.4**	**18.2**	**18.7**	**19.1**	**19.4**	**19.6**	**1.2**
World	**97.2**	**101.9**	**106.0**	**108.6**	**110.5**	**111.7**	**14.5**

The second important factor is the anticipated faster penetration of electric vehicles. The knock-on impact is slower demand growth for gasoline, and this partly affects diesel use in the road transportation sector.

The third reason relates to less long-term diesel consumption in the marine sector with more LSFO. Therefore, diesel demand growth is lower this year, compared to last year's Outlook, while demand for fuel oil shows some, albeit marginal, increases between 2017 and 2040. This product was projected to decline marginally a year ago.

Within the light products, demand for ethane/LPG is set to increase by 3.3 mb/d between 2017 and 2040. It should be noted that this is the largest increase among all major products. Significant growth for these two products is linked to the petrochemical, industry and residential sectors. Most of the ethane demand growth is expected to take place in the petrochemical sector, especially in OECD America and in OPEC Member Countries.

Contrary to ethane, the largest part of incremental LPG demand is expected to come from the residential sector in Developing countries as a result of the adoption of energy poverty alleviation measures. Around 10% of global LPG consumption is used in road transportation (concentrated in OECD Europe and OECD Asia Oceania), as well as 10% in the industry sector. However, LPG demand in these two sectors is anticipated to remain relatively stagnant in the next 10–15 years, before it witnesses a marginal decline during the remainder of the forecast period.

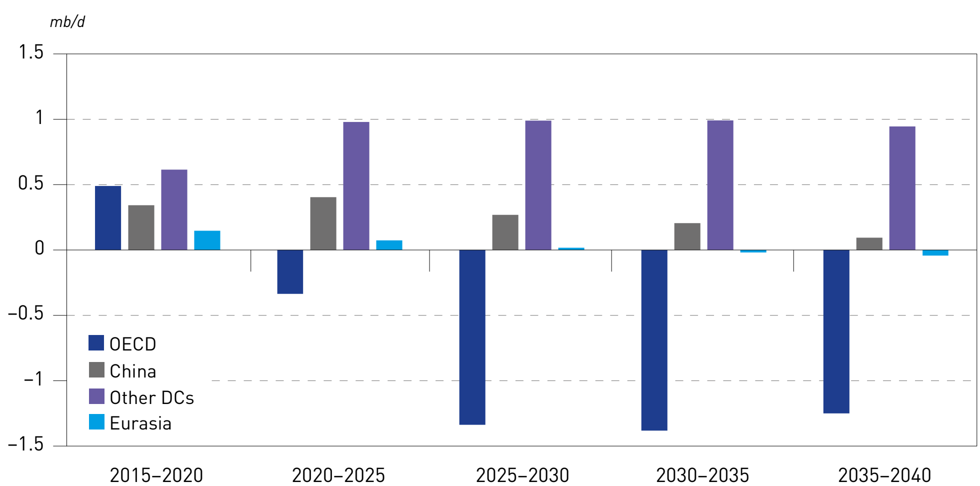
Driven by rapid growth in the petrochemical industry, naphtha is estimated to be the fastest growing product over the forecast period. The average demand growth rate for this product is forecast at 1.3% p.a. This represents 2.2 mb/d of additional demand by the end of the forecast period, when total demand reaches 8.6 mb/d. A large portion of the growth will likely materialize in China (+0.8 mb/d) and Other Asia (+0.6 mb/d). The rest of the incremental demand will be spread between India, OECD Asia Oceania, Russia, OPEC and Middle East & Africa.

In volumetric terms, however, gasoline is, and is projected to remain, by far the most important light product. In 2017, 25.5 mb/d of gasoline (crude based gasoline, combined with ethanol) was consumed, with OECD America accounting for more than 40%. Looking ahead, gasoline demand is forecast to reach 27.8 mb/d in 2040. At the same time, gasoline is the product that shows the largest variation between regions. Moreover, its demand faces the largest uncertainties over the forecast period and beyond.

Since a large majority of OECD America consumption is in the road transportation sector and projections for ethanol supply (and demand) indicate fairly steady, albeit minor growth, it is important to look at demand for crude based gasoline in this sector, as presented in Figure 3.12.

Obviously, a large potential for gasoline growth still exists in Developing countries where the size of the car fleet is set to expand and the penetration of alternative vehicles is expected to increase relatively slowly. On the other hand, China represents the case where the car fleet is still growing significantly over the forecast period, but alternative vehicles, especially electric ones, are expanding fast, hence limiting the potential for gasoline demand growth. Contrary to these two cases, the potential for the overall fleet expansion in OECD countries is quite limited, while sales of electric vehicles are rising. This, combined with a faster

Figure 3.12
Incremental demand for crude based gasoline by region



car turnover and ever-increasing car efficiency, results in declining gasoline demand in the OECD after 2020.

Figure 3.12 also indicates another important observation: gasoline growth not only decelerates over the next decade, it also starts to decline after 2030. The overall drop between 2030 and 2040 is marginal, but it indicates a potential changing trend for one of the key refined products.

In the second major product group, current demand for gasoil/diesel is almost four times higher than that for jet/kerosene. However, jet/kerosene demand grows more than four times faster than diesel/gasoil so that by the end of the forecast period the ratio, in terms of volume, changes to almost 1:3.

In the long-term, demand for diesel/gasoil is expected to increase by close to 3 mb/d to reach 31.6 mb/d in 2040. The growth expectation is driven by a number of factors. On the positive side, growing requirements for transportation services in Developing countries leads to an expanding fleet of trucks and buses, as well as primarily diesel-driven light-duty vehicles. Some demand growth is also projected in the rail and domestic navigation sectors. This is further supported by the industry, commercial, residential and agriculture sectors, while the marine sector provides only a temporary boost to diesel demand (from 2020–2030), which is mostly eliminated thereafter.

On the negative side, diesel demand growth is partially offset by the expected demand reduction in the road transportation sector in the OECD region. New sales of diesel cars in Europe continue to be affected by the ongoing 'dieselgate' saga, as well as through policy measures such as banning diesel cars in several European capitals. Moreover, consumer behaviour is also being partly affected by announcements from several carmakers that they will phase-out the production of diesel-based models. There is also limited scope for further expansion in the trucking industry, as well as in the bus fleet, with both becoming increasingly more efficient. Finally, the continued declining use of oil in the electricity generation sector is also anticipated to curtail the use of gasoil/diesel in this sector.

Sluggish growth in gasoil/diesel will partly be compensated by strong growth in jet/kerosene. The growth in this product group is comparable to naphtha, averaging 1.3% p.a. between 2017 and 2040. In volume terms, this represents some 2.5 mb/d of additional demand by 2040. The growth comes almost exclusively from the fast-growing aviation industry, with its reliance on jet kerosene. Some growth is also projected in domestic kerosene used mostly for lighting, heating and cooking in developing countries. However, at the global level, the demand for domestic kerosene is forecast to decline due to a switch to alternative fuels in most regions, which more than compensates for growth in some developing countries, such as India and African countries.

Demand for residual fuel oil is anticipated to move within a relatively narrow range of around 0.8 mb/d over the forecast period. As discussed earlier, its demand is forecast to drop sharply through to 2020 due to IMO regulations limiting sulphur content, if residual fuel is used in marine bunkers. Thereafter, a smooth recovery is foreseen as the shipping industry increases its use of scrubbers (further details on the marine bunkers sector and the impact of the IMO regulations can be found later in this Chapter). This recovery, however, is subdued by expected developments in other sectors, such as electricity generation, refining, rail and domestic waterways. Demand for residual fuel oil in these sectors is expected to decline smoothly over the forecast period as a result of substitution with other energy sources, such as natural gas, renewables and diesel.

The last group of refined products considered in this analysis, called 'other products', consists of a wide range of mostly heavy products. The largest constituents are petroleum coke, bitumen, various lubricants and crude oil used for direct burning. It also includes, however, the extra light part of unseparated gaseous fractions from refining processes, known as still gas. Accordingly, there are diverging trends in the use of these products, ranging from an expected decline in the direct use of crude to produce electricity to an expanding market for lubricants. In 2017, demand for 'other products' totalled 11.2 mb/d, with most of the demand concentrated in the industry sector, particularly bitumen/asphalt for road construction and petcoke and still gas in refineries.

The product outlook shows that demand for 'other products' is anticipated to increase at modest rates in the next few years before plateauing in the 2030s. By then, demand for bitumen will still be growing, driven mainly by the expansion of road transport infrastructure in Developing countries, particularly in China and India. This will more than offset demand declines in the OECD region, which has a more developed road network. On the other hand, demand for 'other products' in the electricity generation and petrochemical sectors is expected to drop steadily over the forecast period as substitution by other fuels and energy sources progresses.

The major demand trends for specific products outlined in this sub-section are summarized in Figure 3.13. It shows that more than half of the incremental oil demand over the forecast period is expected to be satisfied by light products, which account for 7.8 mb/d out of a total demand growth of 14.5 mb/d. The demand for middle distillates is expected to increase by 5.4 mb/d, which will be almost equally shared between gasoil/diesel and jet/kerosene. Some growth (+1.2 mb/d) is also projected for heavy products.

Figure 3.14 summarizes trends in product demand from the sectoral perspective. There are a number of important aspects worth highlighting.

The use of naphtha is almost exclusively linked to the petrochemical sector. This was the case in 2017 and no change is expected until 2040. The same is to be concluded for gasoline and its use in the road transportation sector. No significant changes in sectoral shares are also expected for gasoil/diesel. Road transportation is set to continue to account for around 62% of gasoil/diesel demand, while changes for other sectors are generally in the range of 1%.

Ethane/LPG is mainly used in the petrochemical sector and in the residential/commercial/agriculture sectors. This is expected to remain the case in the long-term, but the share of ethane/LPG use in the petrochemical sector is anticipated to increase by almost 5% over the forecast period, mainly at the expense of road transportation and 'other industry'. In the jet/kerosene product category, demand for domestic kerosene – used mainly in the residential/commercial/agriculture sector – is anticipated to decline, while demand for jet kerosene grows steadily.

Figure 3.13
Demand growth by product category in the long-term

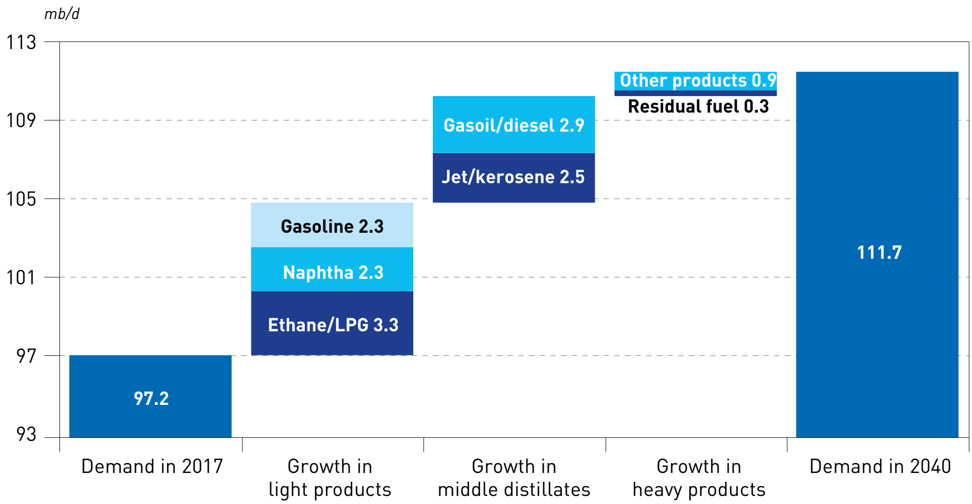
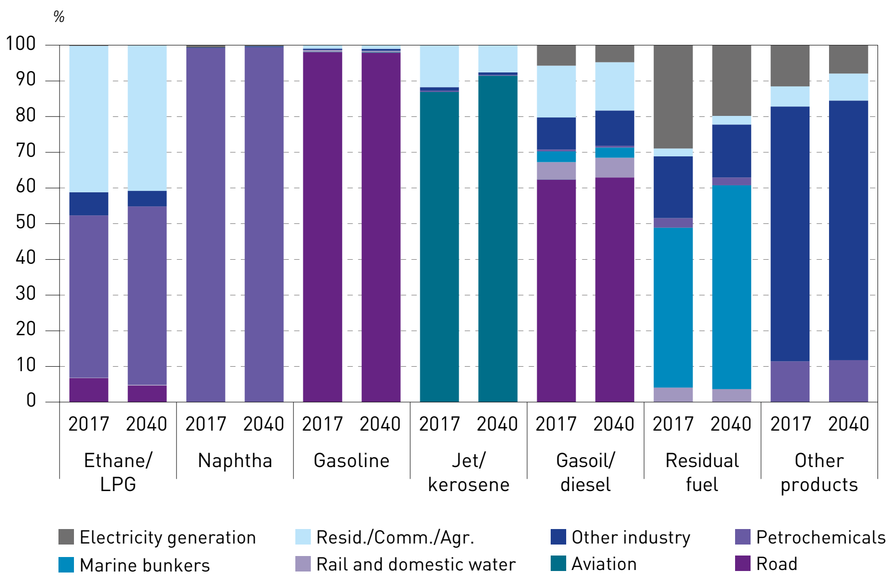


Figure 3.14
Share of the different sectors in demand by product, 2017 and 2040



That is why the weight of the aviation sector in this product's demand increases from 87% in 2017 to almost 92% in 2040.

The largest shift in sectoral use is projected for residual fuel oil, as the weight of the electricity generation sector is forecast to drop by almost 10%. At the same time, marine bunkers are expected to gain weight in demand for residual fuel as scrubbers allow for HSFO consumption, while LSFO is increasingly used too.

For 'other products', the weight of the 'other industry' sector is anticipated to increase from 71% to 73% as the expansion of road transportation infrastructure in developing countries supports the use of bitumen. Simultaneously, demand for 'other products' in the electricity generation is set to drop steadily, with an overall decline of more than 3% forecast between 2017 and 2040.

3.4 Long-term oil demand by sector

This section presents the sectoral oil demand breakdown in the Reference Case and an overview of long-term sectoral demand trends. The analysis covers the transportation sector, which includes road transportation, aviation, rail and domestic and marine bunkers; the industry sector, which comprises petrochemicals and 'other industry'; and other uses of oil such as in the residential/commercial/agriculture sector and in the electricity generation sector. Given the particular importance of the road transportation, aviation, marine bunkers and petrochemicals sectors, in terms of oil demand, and the significant structural shifts occurring, a more detailed analysis of these is presented.

Trends in sectoral oil demand outlined in the medium-term will broadly continue in the long-term too, although the longer time span will make these trends increrasingly visible. As shown in Table 3.5, a large portion of oil demand in the Reference Case is used for transportation. Together with the electricity generation sector, however, it is also the sector where oil faces strong competition from alternative fuels. Moreover, a number of policy measures that specifically target the transport sector, which, combined with technology advances, make it a battle field between mobility and transport needs, costs, technology, infrastructure development and environmental protection.

The transportation sector will evidently be a major source of additional oil demand. Between 2017 and 2040, the transportation sector is estimated to account for 56% of the additional barrels consumed. At the same time, demand growth in this sector is foreseen to decelerate on the back of efficiency improvements driven by technological developments, the tightening of energy policies and the increasing penetration of transport means that leverage natural gas and electricity as an energy source.

Among all transport modes, the largest demand for oil comes from road transportation. In 2017, this sector represented 45% of global demand, or 43.6 mb/d. Significant growth is expected in the long-term with an additional 4.1 mb/d to reach 47.8 mb/d by 2040 (Figure 3.15).

This is followed by aviation, which represents the fastest growing sector, with average oil demand growth at 1.5% p.a. This growth is driven by a rapidly expanding middle class,

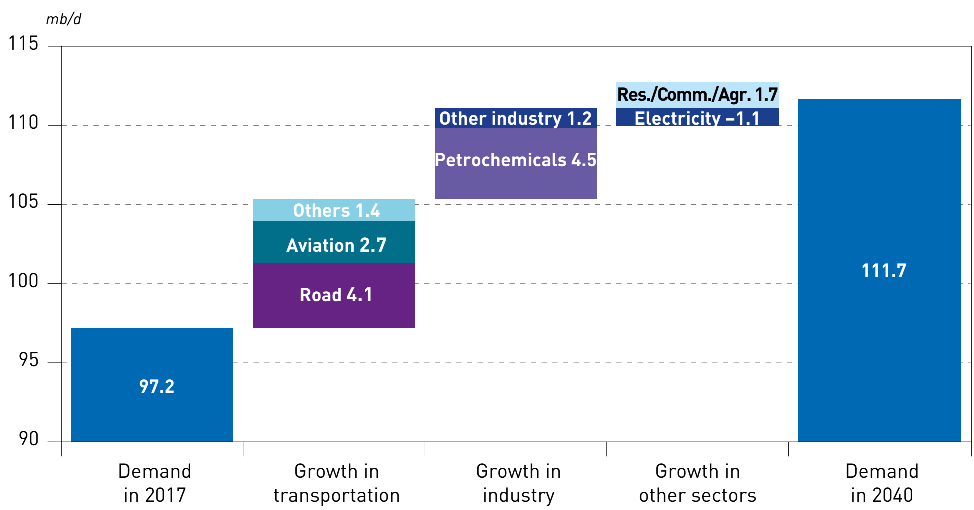
Table 3.5
Sectoral oil demand, 2017–2040

mb/d

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
Road	43.6	45.3	47.2	47.7	47.8	47.8	4.1
Aviation	6.3	6.7	7.5	7.9	8.6	9.0	2.7
Rail & dom. waterways	1.8	1.9	2.0	2.1	2.1	2.1	0.3
Marine bunkers	4.0	4.2	4.6	4.8	4.9	5.1	1.1
Transportation	**55.8**	**58.2**	**61.3**	**62.5**	**63.4**	**64.0**	**8.2**
Petrochemicals	13.0	13.9	14.8	15.9	16.8	17.5	4.5
Other industry	12.7	13.3	13.3	13.6	13.8	14.0	1.2
Industry	**25.7**	**27.2**	**28.1**	**29.4**	**30.5**	**31.5**	**5.7**
Resid./Comm./Agr.	10.6	11.1	11.6	12.0	12.2	12.3	1.7
Electricity generation	5.1	5.4	5.0	4.7	4.3	4.0	–1.1
Other uses	**15.6**	**16.5**	**16.6**	**16.7**	**16.5**	**16.2**	**0.6**
World	**97.2**	**101.9**	**106.0**	**108.6**	**110.5**	**111.7**	**14.5**

3

Figure 3.15
Sectoral oil demand growth



particularly in developing countries and an increasing penetration of low-cost carriers. Translated to incremental barrels, oil demand in the aviation sector is forecast to increase by 2.7 mb/d, rising from 6.3 mb/d in 2017 to 9 mb/d in 2040. Some growth is also projected in the marine sector, as well as in rail and domestic waterways. The average rate of growth, however, is much slower than in aviation, at 1% p.a. and 0.7% p.a., respectively.

The industrial use of oil accounts for around half of that in the transportation sector. Demand growth in industry is driven mainly by the petrochemical sector, while oil demand in the rest of industry – comprising primarily iron and steel, glass and cement production, construction and mining – is anticipated to continue to face strong competition from alternative fuels. This is especially the case in OECD regions where oil demand in 'other industry' is set to follow a declining path. However, a strong expansion in the economic activity of Developing countries will lead to the growing use of oil in 'other industry', which more than offsets declines in the OECD. However, growth is expected to decelerate even in Developing countries, as the structure of economies gradually moves from an industry-oriented one, towards a more service-oriented one. The global demand increase in 'other industry' is 1.2 mb/d between 2017 and 2040, representing an average growth rate of 0.4% p.a. Much stronger growth is expected in the petrochemical sector where demand is estimated to increase by 4.5 mb/d over the forecast period (for more details see 3.4.4 Petrochemicals).

Oil demand in the remaining two sectors of consumption – residential/commercial/agriculture and electricity generation – is expected to expand at almost the same rate as total demand, 0.6% p.a. on average. However, there is a distinct difference between the two sectors.

Indeed, electricity generation is the only sector where declining demand is forecast at a global level. This is a result of increasing competition from natural gas, as well as from renewables. A similar argument is also applicable to developments in the residential/commercial/agriculture sector in OECD countries, where almost 1 mb/d of oil demand is forecast to be lost between 2017 and 2040. However, this loss will be more than compensated by gains in Developing countries as LPG and kerosene replace traditional fuels in the residential sector and diesel demand expands, driven by expanding agriculture and commercial sectors.

Figures 3.16 and 3.17 present sectoral demand changes from the perspective of major regions between 2017 and 2040. As expected, this comparison provides a contrasting picture between OECD and Developing countries. In the case of the OECD, oil demand is projected to grow in only two sectors: aviation and petrochemicals. All other sectors are set to decline, with the largest drop projected for road transportation (–7.5 mb/d).

In the Developing countries region, the picture is rather different. Driven by healthy economic growth rates, rapidly growing populations and a significant expansion of the middle class, demand increases are expected in every sector, except electricity generation. Growth is particularly strong in the road transportation sector where demand is expected to increase by 11.2 mb/d driven by an expected massive expansion of the car fleet.

Significant demand increases are also projected in the petrochemical sector (3.8 mb/d) and in the residential/commercial/agriculture sector (2.6 mb/d). These are followed by the

Figure 3.16
Sectoral oil demand in the OECD, 2017 and 2040

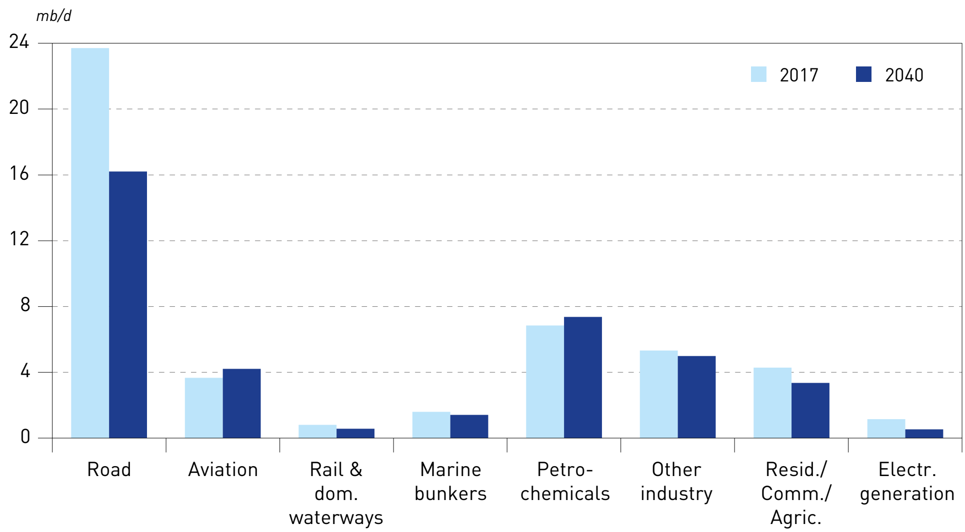
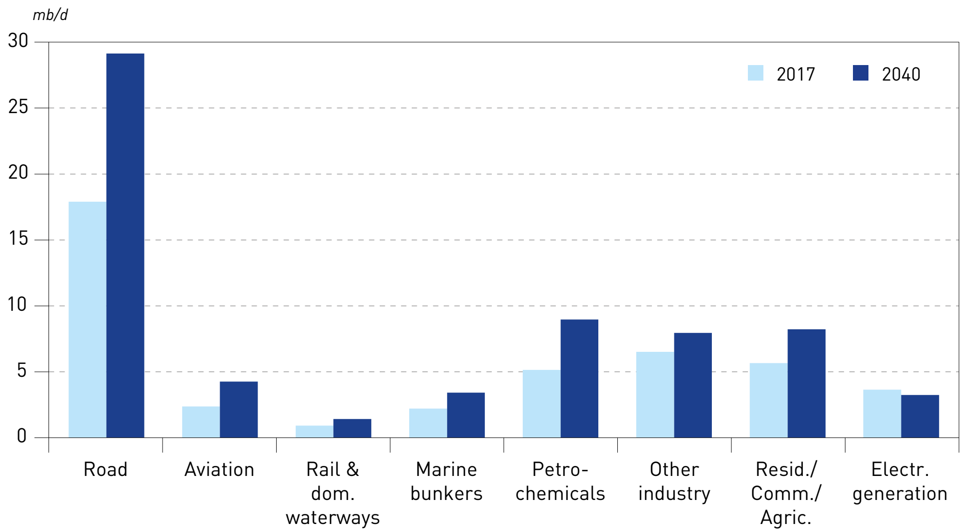


Figure 3.17
Sectoral oil demand in Developing countries, 2017 and 2040



aviation sector, where oil demand is forecast to almost double as rising income levels and economic activity foster demand for air travel. Similar to Developing countries, oil demand in Eurasia is also expected to grow in every sector, except electricity generation. However, the range of demand increases is much lower than in Developing countries. The largest increases are projected in road transportation (0.4 mb/d), petrochemicals (0.2 mb/d) and aviation (0.2 mb/d).

3.4.1 Road transportation

For more than a century, road transport developments were tightly linked to oil. The rise of the car as a primary means of transport was enabled by the unique properties of oil. Until now, all attempts to replace the dominant role of oil products in this sector either failed, or have remained a niche market. Recently, however, new dynamics have emerged in the form of electrification of road transportation, with many facets and accompanying challenges. This starts with electrification of the powertrain. Most manufacturers nowadays offer a wide range of powertrains with varied levels of electrification, from mild hybrids through hybrids, plug-in-hybrids to pure electric cars.

Moreover, electrification and digitalization are gradually penetrating all major components and control systems of modern vehicles, including trends towards autonomous cars. This goes even beyond the vehicle itself. Car sharing, ride hailing and carpooling, typically termed 'mobility as a service' are shifting the behaviour of consumers and are challenging policymakers to catch up with adequate regulation. Policymakers are also challenged to find the right balance between the huge investment needs, especially to develop the required infrastructure, the implications on budgets and the as yet uncertain benefits, especially as technology is also driving substantial efficiency improvements and environmental acceptance of modern combustion engines.

In short, road transportation nowadays is at a crossroads, with its long-term direction still very uncertain. Analysis provided in this sub-section does not aim to answer all related questions, but it will try to shed some light on several critical issues that are expected to drive future developments in this sector. This includes such issues as the development of the global vehicle fleet, both in terms of the total number of vehicles and its composition, the penetration of alternative fuels, changes in the oil use per vehicle (OPV), changes in average vehicle miles travelled (VMT) and overall improvements in fuel efficiency. Needless to say, all these factors are closely linked to technology developments and energy policies that are described in more detail in Chapters 7 and 8.

Vehicle stock

The increase in the vehicle stock is the key driver that contributes to the rise in oil consumption in the road transportation sector. To date, the expansion in the number of vehicles, at the global level, has always more than compensated for the effects of fuel efficiency improvements on oil demand. This, however, may not necessarily be the case at the regional or country level.

In the OECD, where vehicle stocks are approaching saturation levels, the expected increase in the number of vehicles will not be enough to compensate for fuel efficiency improvements and the penetration of alternative vehicles, with the sector's oil demand falling. In other regions, the opposite will be true. The net effect of these trends is a rise in world stock levels and it is anticipated to result in higher future oil consumption, although demand growth in this sector will likely plateau during the last decade of the forecast period.

This year's WOO sees higher GDP growth in the short-term, but lower growth in the longer term compared to last year's publication. This revision has led to a slightly higher projection for the number of additional cars over the coming years, but lower stock levels toward the end of the projection period, particularly in OECD America. Historically, OECD countries have accounted for the largest growth in vehicle stock, but this pattern changed some years ago and future growth will primarily take place in Developing countries.

As presented in Table 3.6, the total passenger vehicle stock is estimated to grow by around 877 million over the period 2017–2040, with 768 million cars in Developing countries. China is set for the highest increase in additional vehicles over the forecast period, at 291 million, followed by Other Asia with an increase of around 167 million cars. Global stock levels are anticipated to see an average growth rate of 2.1% p.a., while the rate in China will be around 4.3% p.a. The

Table 3.6
Number of passenger cars

millions

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	280	289	303	317	328	338	58
OECD Europe	254	258	261	264	266	268	13
OECD Asia Oceania	94	94	95	95	95	95	1
OECD	**628**	**641**	**660**	**676**	**690**	**700**	**73**
Latin America	77	82	90	98	106	112	36
Middle East & Africa	31	36	47	59	74	92	61
India	24	32	51	77	111	152	128
China	147	184	253	325	389	438	291
Other Asia	64	79	109	145	187	232	167
OPEC	51	60	77	95	115	135	85
Developing countries	**394**	**473**	**626**	**799**	**982**	**1,162**	**768**
Russia	35	37	41	44	47	50	15
Other Eurasia	46	50	55	60	64	68	22
Eurasia	**81**	**87**	**97**	**105**	**112**	**117**	**37**
World	**1,102**	**1,201**	**1,383**	**1,580**	**1,783**	**1,980**	**877**

highest growth rate, however, is projected for India, at 8.2% p.a. This is due to the relatively low base of existing stock levels and the projected high GDP growth. In absolute numbers, this translates to 128 million additional cars in India by 2040.

The passenger car fleet in the OECD is foreseen to increase marginally. This region, in total, is expected to add only 73 million additional cars over the forecast period. A large part of this increase will take place in OECD America (58 million). This is primarily due to the less developed public transport system and the different lifestyles in the region, compared to OECD Europe and OECD Asia Oceania. Generally, saturation levels in the OECD are the key factor for the lower increase in the number of vehicles. In addition to this, shared mobility (discussed in detail in last year's WOO, pages 141–146) contributes to this lower growth.

The commercial vehicle segment foresees a higher growth rate compared to passenger cars. This is the result of a more direct linkage between stock levels and economic activity. The absence of saturation levels, alongside very limited opportunity for vehicle sharing, creates more potential for high growth in this segment. Similar to the passenger cars segment, however, this year's WOO sees somewhat lower commercial stock levels as a result of lower overall GDP growth.

Table 3.7
Number of commercial vehicles

millions

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	39	41	45	49	53	58	20
OECD Europe	40	43	47	52	58	64	24
OECD Asia Oceania	26	26	26	26	26	27	1
OECD	**104**	**109**	**118**	**128**	**138**	**148**	**44**
Latin America	20	22	26	31	36	42	22
Middle East & Africa	14	16	20	25	32	39	25
India	14	18	25	34	46	59	45
China	26	29	37	45	55	66	40
Other Asia	26	29	36	44	52	60	34
OPEC	15	17	20	24	28	32	17
Developing countries	**115**	**132**	**165**	**204**	**248**	**298**	**183**
Russia	6	6	6	6	7	7	1
Other Eurasia	5	5	6	7	8	9	4
Eurasia	**11**	**11**	**12**	**13**	**14**	**15**	**5**
World	**230**	**252**	**295**	**344**	**400**	**462**	**232**

Table 3.7 summarizes global and regional developments for commercial vehicles, in terms of the number of vehicles. The total commercial stock is forecast to more than double during the period 2017–2040, rising from 230 million vehicles in 2017 to 462 million by 2040. The majority of the increase comes from Developing countries, particularly from China, Other Asia, and India. The total amount of additional vehicles in Developing countries is estimated to be around 183 million, which represents almost 80% of the total growth. A significant increase in commercial vehicles is also projected in OECD America and Europe. Contrary to these regions, OECD Asia Oceania and Russia are expected to witness a very small increase, as low as 1 million.

Vehicle fleet composition

As mentioned earlier, car markets around the world have seen quite limited change in the composition of the vehicle fleet in recent decades, especially when considering the total fleet. Some countries have experienced a growth in natural gas vehicles (NGVs) on the back of abundant gas resources, government support, and relatively lower gas prices. Nevertheless, the dominance of ICEs has remained untouched and has not been impacted by the emergence of any new technology.

With the advancement of battery technology and electric vehicles, however, the future picture is anticipated to be somewhat different from the past. Along with technological advancements, stringent government policies around the world, specifically addressing climate change issues, are supporting and facilitating the penetration of electric vehicles. In addition, falling battery costs are expected to pave the way for a faster rate of sales growth in the near future. These ongoing developments will impact the future composition of sales and, in the longer term, the composition of the vehicle fleet too.

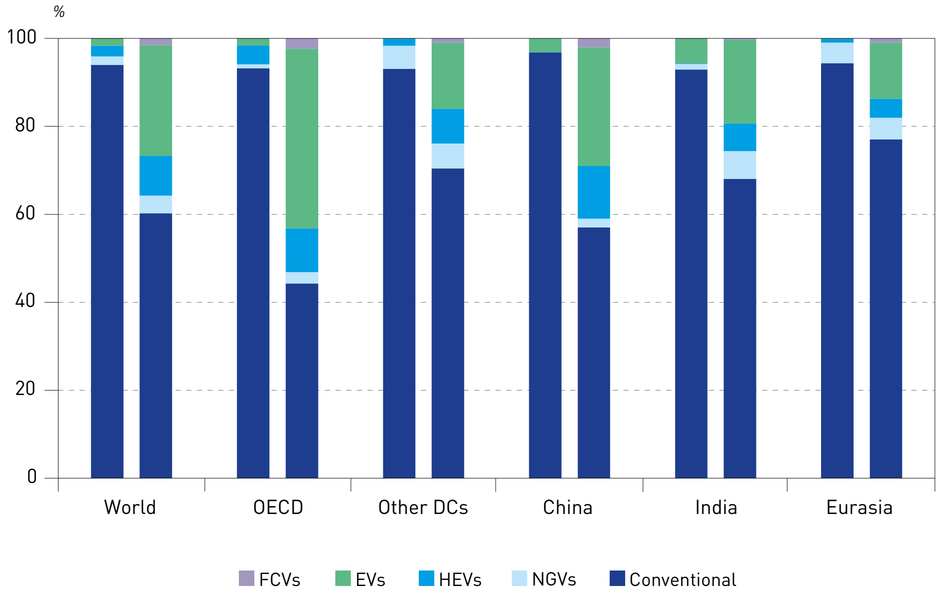
Passenger cars

There are a wide range of governmental policies around the globe supporting electric vehicles, which coupled with a significant reduction in battery costs, have led to an increased uptake of electric vehicles in the past few years. It should be noted, however, that although the growth rate for new sales of electric vehicles is very high, the share in both total stock and in total vehicle sales is still very low. In 2017, the figures were around 0.3% and 1.3% at the global level, respectively.

Norway is the only country where these figures are substantially different. Driven by governmental support, relatively lower electricity prices and the fast development of charging infrastructure, the share of electric vehicle sales in Norway reached around 39% in 2017. Other countries have also seen an expansion, but they remain far below Norway's level. For example, the share of electric vehicles sales in Canada and Netherlands are around 6%, and for other leading countries and regions, such as China, the US, and the EU, the number is less than 3%. In 2017, however, it is interesting to note that China experienced the highest number of electric vehicle sales in the world, expanding at a staggering 72%, compared to 2016.

Looking ahead, under the Reference Case, the WOO's analysis of passenger car sales shows that ICE vehicles (conventional and hybrid electric vehicles) are still estimated to constitute almost 70% of new sales in 2040, hence, they retain the dominant role at the global level (Figure 3.18). The share of electric vehicle sales is projected to increase to around 25% in 2040.

Figure 3.18
Shares of new passenger car sales by powertrain, 2017 and 2040

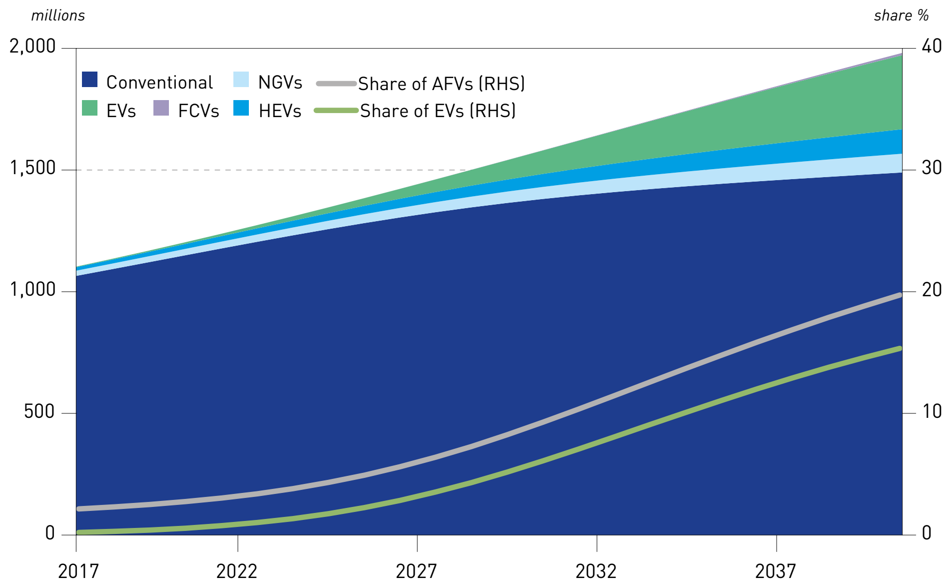


The OECD region is forecast to see the highest share of electric vehicle sales in 2040, at more than 40%, followed by China at 27%. The projected relatively faster adoption of electric vehicles in OECD countries is due to government policy and targets, advanced capital markets, extensive research and development plans, an increasing number of charging places, and investment plans by original equipment manufacturers (OEMs). China and India also have plans to support the penetration of electric vehicles. Other regions are electrifying passenger transport far less quickly. In Other Developing countries (excluding China and India) the share is expected be around 15%, and for Eurasia, the figure is about 13%.

With the promising perspective for electric vehicles, and to some extent for HEVs, NGVs are not expected to experience such significant growth. Moreover, growth will likely be limited to countries that already benefit from a high rate of NGV penetration. However, India should be viewed as an exception. This country is undertaking policies that will increase the uptake of NGVs and is projected to have high sales rates in the years to come. NGVs in OECD America, despite its abundant gas resources, are not expected to appeal to customers in the passenger car segment. In the other two OECD regions, Europe and Asia Oceania, the share of NGVs in new sales are also anticipated to remain relatively low, at around 2% in 2040.

Reflecting the trends in the composition of future new sales and accounting for the scrappage of older vehicles, electric vehicles are set to experience a significant growth in numbers. They are forecast to reach around 304 million units in 2040 (Figure 3.19).

Figure 3.19
Passenger car fleet composition, 2017–2040



It is worth noting that this figure is higher than last year's projection of around 235 million, mainly due to a more positive outlook for the expansion of PHEVs. These are expected to represent the second largest part of fleet in 2040, with around 160 million units on the road, second only to conventional vehicles. Currently, CNG vehicles are the largest alternative category after conventional cars. This category, however, is not expected to witness the same growth as electric vehicles, as there are only expected to be 77 million of additional units on the road in 2040. An even slower expansion is projected for fuel cells vehicles (FCVs), which are forecast to remain a niche market over the forecast period, particularly in OECD Asia Oceania.

In relative terms, the share of electric vehicles in the passenger car fleet is projected to increase to as high as 15% in 2040. This compares to a level well below 1% in 2017. The major take-off is expected to begin at some point after 2025, when the share of electric vehicles reaches around 2%. Thereafter, the market is anticipated to see around a 1% increase in its share annually. Adding CNG vehicles and FCVs will not dramatically change the overall pattern for alternative vehicles, as the increase in the share of CNG is rather limited, and this category will account for around 4% of the total fleet in 2040.

Commercial vehicles

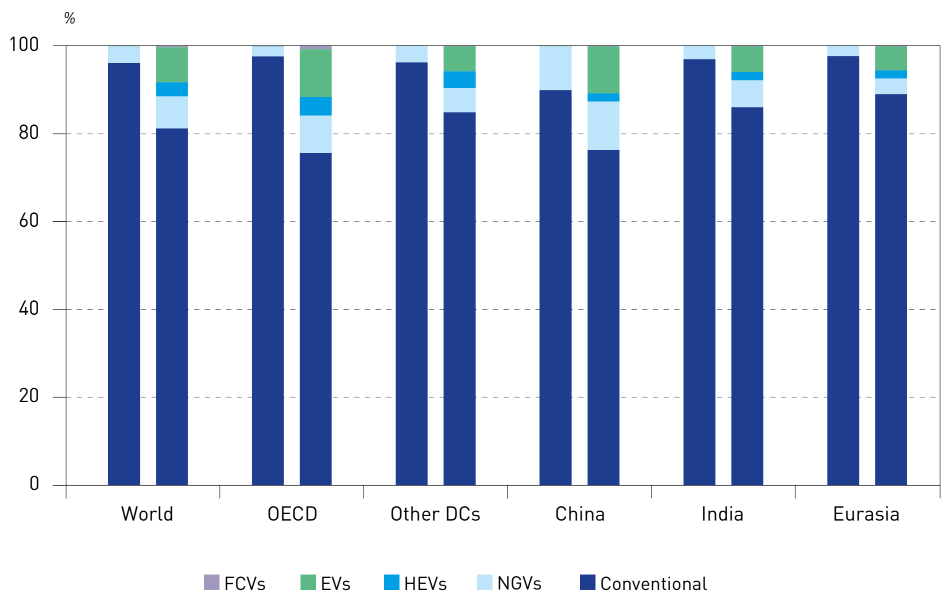
The dynamics of the fleet composition in the commercial segment is much lower than that for passenger cars and this is expected to also be the case over the forecast period as heavy-duty diesel engines tend to be the most efficient ones for commercial vehicles. So far, only NGVs have been able to capture a noticeable share of new sales at the global level, around 4% in 2017. However, demand for LNG trucks is soaring in China, which suggests that natural gas may play a larger future role in commercial vehicles.

Some room for alternative powertrains also exists in the segment of light-duty commercial vehicles, where electrification will increasingly play a role. Similarly, the use of electric buses, especially on fixed public transport routes in city centres, will increasingly penetrate this segment. To what extent electric powertrains also penetrate heavy-duty vehicles strongly depends on advancements in battery technology. It should be noted that two major distinctions related to commercial vehicles make their nature very different from passenger cars: they are much heavier and travel long distances. These two factors will limit the penetration of electric vehicles in this segment, compared to passenger cars.

Figure 3.20 shows that conventional ICE vehicles are expected to maintain their dominant sales share over the forecast period. Nevertheless, the share decreases from 96% in 2017 to 81% by 2040. This drop is mainly the result of rising electric vehicles and HEVs in the commercial segment by 2040, to nearly 8% and 3%, respectively. Another reason is attributed to the rise of NGVs, which are anticipated to increase from around 4% in 2017 to more than 7% in 2040.

In the OECD, the share of alternative vehicles in future new sales is expected to be higher compared to those at the global level. In fact, the share of electric vehicles in this segment in

Figure 3.20
Shares of new commercial vehicle sales by powertrain, 2017 and 2040

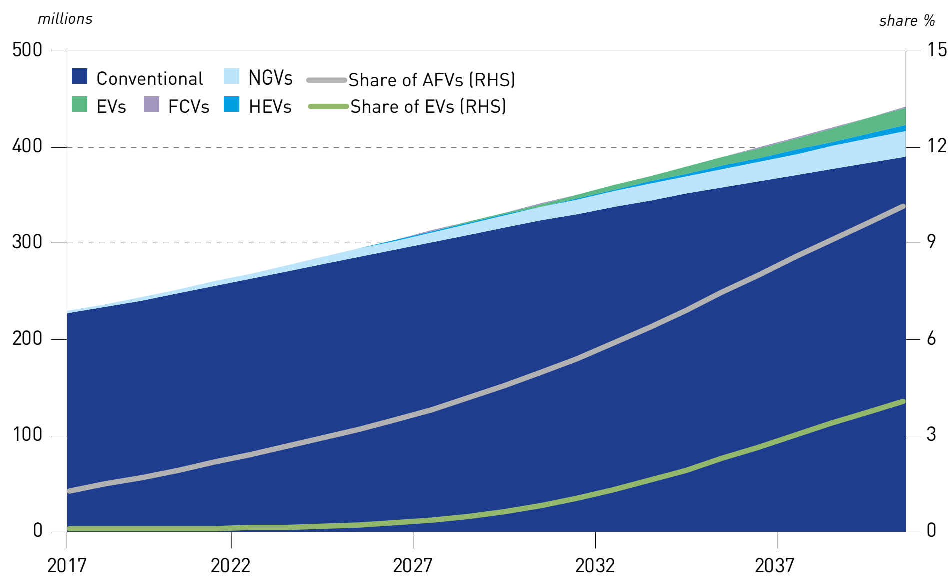


the OECD is expected be close to 11% by 2040. This will lead to a significant decline in the use of conventional vehicles, dropping from almost 98% in 2017 to less than 76% in 2040. HEVs will also gain momentum to account for a share of more than 4% by 2040. NGVs are seen to increase from 2% to close to 9% between 2017 and 2040. Finally, the share of FCVs is expected to stay at a very low level; less than 1% over the entire forecast period.

China is projected to experience the largest new sales share of electric vehicles and NGVs, both around 11% at the end of the forecast period. Despite this, conventional vehicles will remain dominant in the Chinese market, with a share of 76%. The sales share of alternative fuel vehicles in India will not be as large as in China, but still on a growth trajectory and reaching around 6% for both electric vehicles and NGVs. Almost the same figures are also projected for the group of Other Developing countries. Eurasia is anticipated to see the lowest alternative fuel vehicles sales share. The share of electric vehicle sales in the region is estimated to be around 6% by 2040, while NGVs are projected at less than 4%.

Naturally, the relatively lower opportunities for further diversification of the sales composition in the commercial segment will lead to a more stable global fleet composition over the forecast period. This is demonstrated in Figure 3.21. Out of 442 million commercial vehicles by 2040, a large majority (370 million) will remain conventional. NGVs, which currently have the second largest share, are forecast to maintain this position up to 2040, accounting for 6% of the fleet. Electric vehicles are forecast to gradually increase their share

Figure 3.21
Commercial vehicle fleet composition, 2017–2040



to as high as 4% in 2040. Combined together, the penetration of alternative fuel vehicles will accelerate somewhat after 2030, as more electric vehicles enter the market. It is expected to hit 10% by 2040.

Oil demand in road transportation

As presented in Table 3.8, oil demand in the road transportation sector is forecast to increase by around 4.1 mb/d between 2017 and 2040, from 43.6 mb/d to 47.8 mb/d. This increase comes mainly from Developing countries (11.2 mb/d) and marginally from Eurasia (0.4 mb/d). This more than compensates for the decline in the OECD region (–7.5 mb/d). The highest demand decline is foreseen to occur in OECD Americas, which is forecast to drop by as much as 4 mb/d over the forecast period. In Developing countries, demand is foreseen to increase rapidly, rising from 17.9 mb/d to 29.1 mb/d, an increase of almost 63%.

It is evident that with a strong growth in the vehicle stock, oil demand will continue to grow in spite of improvements in fuel efficiency and the increased penetration of alternative fuel vehicles. Approaching the end of the forecast period, however, the faster penetration of alternative fuel vehicles is anticipated to lead to decelerating demand growth even in Developing

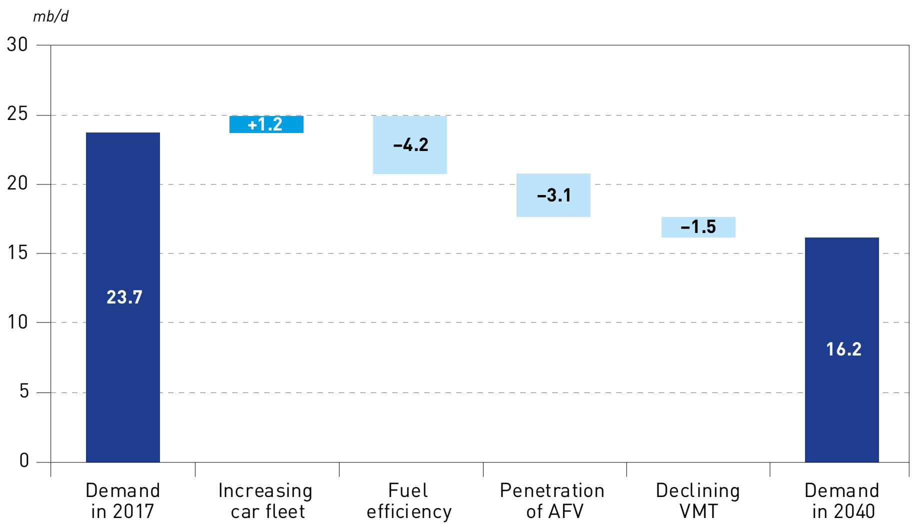
Table 3.8
Oil demand in the road transportation sector by region, 2017–2040 *mb/d*

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	14.2	14.5	13.9	12.7	11.4	10.2	–4.0
OECD Europe	6.7	6.7	6.4	5.8	5.1	4.5	–2.2
OECD Asia Oceania	2.8	2.7	2.6	2.2	1.9	1.6	–1.2
OECD	**23.7**	**23.8**	**22.8**	**20.7**	**18.4**	**16.2**	**–7.5**
Latin America	2.8	2.9	3.1	3.2	3.2	3.3	0.5
Middle East & Africa	1.7	1.9	2.1	2.4	2.7	3.0	1.3
India	1.7	2.1	2.7	3.5	4.3	5.2	3.5
China	5.1	5.5	6.3	6.8	7.3	7.5	2.4
Other Asia	3.2	3.5	4.1	4.6	5.0	5.4	2.2
OPEC	3.3	3.5	3.8	4.2	4.5	4.7	1.4
Developing countries	**17.9**	**19.4**	**22.1**	**24.6**	**27.0**	**29.1**	**11.2**
Russia	1.1	1.2	1.2	1.2	1.2	1.1	0.0
Other Eurasia	0.9	1.0	1.1	1.2	1.2	1.3	0.3
Eurasia	**2.0**	**2.2**	**2.3**	**2.4**	**2.4**	**2.4**	**0.4**
World	**43.6**	**45.3**	**47.2**	**47.7**	**47.8**	**47.8**	**4.1**

countries, although increases will still be at healthy rates. India and the Middle East & Africa are the exceptions. The incremental demand in these two regions is expected to continue at almost the same rate throughout the forecast period as a result of the still significantly expanding car stock.

To better demonstrate this sector's demand dynamics, Figures 3.22 and 3.23 present the effect of various factors impacting sectoral demand in the OECD and in Developing countries, respectively. For this purpose, the total change in oil demand between 2017 and 2040 is attributed to the major market elements comprising changes in stock, fuel efficiency, the penetration of alternative fuel vehicles and VMT. The OECD region and Developing countries are treated separately, as expansion patterns differ, particularly in terms of stock growth.

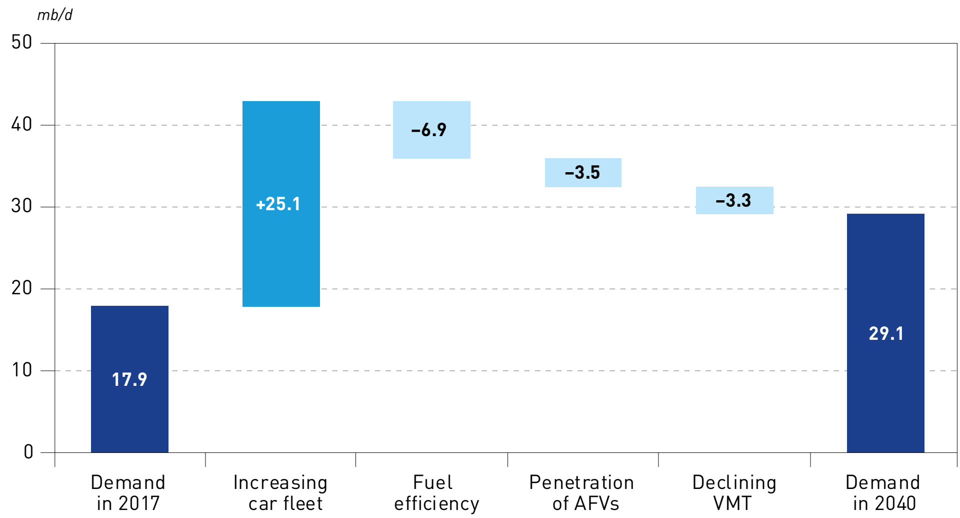
Figure 3.22
Demand in road transportation in the OECD, 2017 and 2040



As expected, development in the OECD stock levels is not expected to contribute significantly to an increase in oil consumption. It is estimated to add only 1.1 mb/d. The major downward impact relates to improvements in fuel efficiency, which is estimated to reduce oil demand by around 4.1 mb/d over the forecast period. This is the result of fuel efficiency improvements in newly sold cars and the scrappage of old cars with much lower efficiency.

The second major contributor to declining sectoral oil demand in the OECD is the penetration of alternative fuel vehicles. This reduces future oil demand by 3.1 mb/d. Moreover, declining VMT is expected to result in a further demand reduction of 1.1 mb/d by 2040. This is due to

Figure 3.23
Demand in road transportation in Developing countries, 2017 and 2040



several factors, such as approaching saturation levels, changes in the population age structure, the further development of public transport systems, and the expansion of car sharing. Overall, OECD sectoral oil demand sees a reduction of 7.5 mb/d, dropping from 23.6 mb/d in 2017 to reach 16.2 mb/d in 2040.

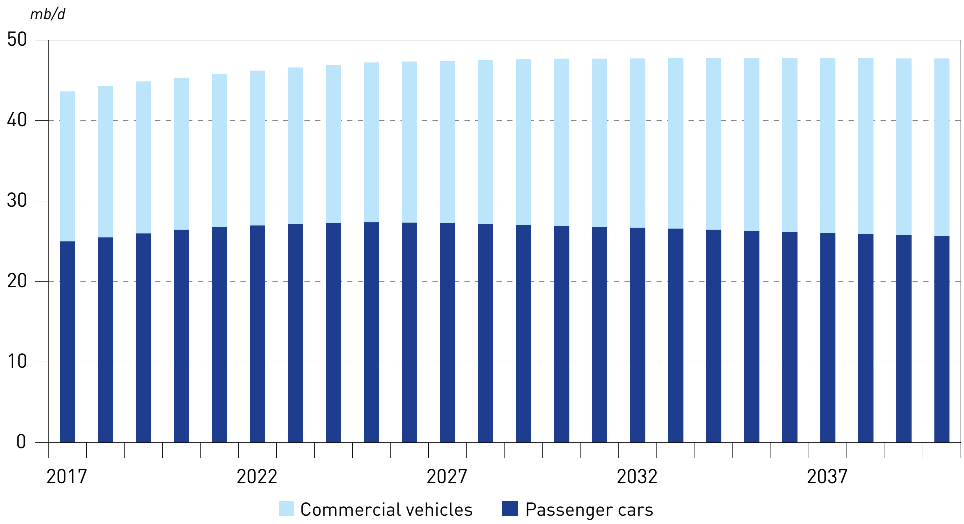
Looking at Developing countries (Figure 3.23), the major difference compared to the OECD region is in the car stock development. There are several reasons behind this. In the passenger car segment, Developing countries are far from saturation level, which is expected to result in a rapid increase in the number of cars. In addition, the majority of the global population increase, especially in terms of the middle class, is anticipated to come from developing countries, which will further accelerate demand for cars.

In the commercial vehicle segment, higher GDP growth means greater transport requirements to support economic activity, and thus, a higher number of commercial vehicles compared to the OECD.

Assuming there was no change in fuel efficiency, the penetration of alternative fuel vehicles and VMT, the increase in the road transportation fleet in Developing countries would add around 25.1 mb/d of incremental demand over the forecast period. This underscores the huge difference compared to the OECD. Of this amount, however, some 6.9 mb/d is expected to be lost as fuel economies gradually improve and old vehicles are scrapped.

On top of this, the penetration of alternative fuel vehicles is anticipated to further reduce sectoral oil demand in Developing countries by 3.5 mb/d, a large part of which is expected to come

Figure 3.24
Oil demand in the road transportation sector by segment



from China and India. Similar to the OECD, VMT also contributes to a drop in oil demand, by a further 1.5 mb/d. At the end of the forecast period, in contrary to the OECD region, the overall effect is that oil demand is expected to increase from 17.9 mb/d in 2017 to 29.1 mb/d in 2040.

Figure 3.24 adds another dimension to future developments in the road transportation sector by segregating oil demand by vehicle segment. It emphasizes that out of total growth of 4.1 mb/d between 2017 and 2040, commercial vehicles account for more than 80% of the demand increase, or 3.4 mb/d. In the case of passenger cars, demand growth in Developing countries and Eurasia is largely offset by losses in the OECD. Moreover, demand in this segment peaks at some point after 2025, and is then assumed to be on a declining path during the last decade of the forecast period.

The commercial vehicle segment differs from that of passenger cars. The effect of better fuel efficiency in this segment is much lower as diesel engines remain dominant and the prospect for more substantial efficiency improvements are limited. VMT follows economic growth closely, in an almost linear fashion. Moreover, the concept of saturation level and car sharing are not applicable for the commercial segment.

These factors result in a relatively lower oil demand reduction in the OECD region and a higher increase in Developing countries. Therefore, most of the incremental demand is foreseen to come from commercial vehicles so that, by the end of the forecast period, demand in this segment will be almost at parity with passenger car demand.

Box 3.1

Sensitivity cases: Electric vehicles penetration

While the Reference Case represents OPEC's best-informed forecast, it is obvious that future oil demand in the road transportation sector is sensitive to alternative paths, particularly in terms of the penetration of electric vehicles. While the potential for alternative developments are skewed toward a faster penetration than that assumed in the Reference Case, a downside scenario should also not be discounted.

In terms of the upside potential, consumer preferences could change rapidly and technological development, economies of scale and competition could drive battery costs down faster than anticipated. For example, Li-air batteries have the potential to reduce specific battery costs to values of US$60 to $80 kWh, and even possibly below these levels. There have also been moves to replace lithium with aluminium, but the uptake of this development is not expected soon. Moreover, range anxiety could be diminished due to a more expanded recharging infrastructure, and shared mobility could further accelerate the penetration of electric vehicles.

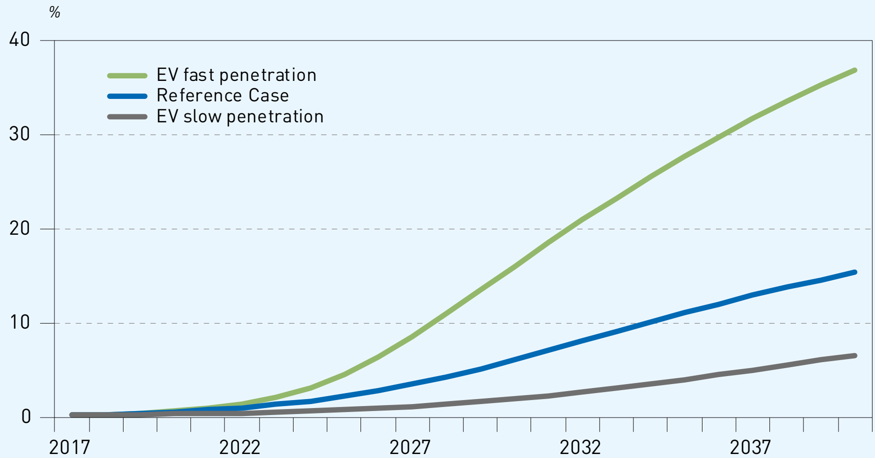
On the flip side, the expected progress in terms of battery costs and in the provision of the necessary charging infrastructure may prove to be disappointing. At the same time, potential also exists to improve the efficiency of ICE vehicles. This could delay the penetration of electric and alternative fuel vehicles for a substantial period of time and, depending on the extent of improvements, it may form the base for a long-term coexistence between conventional and electrified powertrains.

To account for this uncertainty, two alternative sensitivities have been developed. The first one, 'Electric vehicles fast penetration', assumes that annual sales of electric vehicles reach around 79 million by 2040. That is more than double the rate projected in the Reference Case. In absolute terms, there would be more than 720 million electric vehicles on the road at the end of the forecast period accounting for around 37% of passenger cars (Figure 1). This could only be achieved if the share of EVs in new sales in the OECD jumps to the level of 70–80% towards the end of the forecast period, and corresponding rates in other regions are also significantly higher than in the Reference Case. China, for example, would also approach 80%, India 50%, while other regions would need to be in the range of 30% to 40% in terms of new sales.

Moreover, the tipping point for the 'take-off' time would need to be achieved much earlier than in the Reference Case. It is important to note, however, that around half of these vehicles are assumed to be plug-in-hybrids that will continue to partly use oil as an energy source. To arrive at these higher sales numbers, the automotive industry would initially need to achieve faster cost reductions (battery and overall costs) than considered in the Reference Case to improve the competitiveness of electric vehicles and to extend their range. At the same time, this has to be accompanied by the faster development of the necessary recharging infrastructure, as well as an expansion in electricity generation capacity. The critical part of this is the management of peak charging times as the electricity grid could be exposed to higher variations compared to the Reference Case.

Moreover, this alternative sensitivity would also require strong support from policy-makers as it broadly reflects the publicly stated intentions of several countries to target 100% of new sales from electric vehicles over various time horizons. This is especially the case in Europe, with the UK, France, Germany, the Netherlands and Austria, among others, announcing targets. Similar initiatives also exist in other countries, such as China (20% of new sales by 2025) and India (targeting 30% of new electric vehicle sales by 2030).

Figure 1
Electric vehicle penetration in the car fleet in the different sensitivities



The second sensitivity, 'Electric vehicles slow penetration', has been developed to reflect downside concerns for electric vehicles and the potential for ICE improvements. In this case, the penetration of electric vehicles progresses at a much slower rate than in the Reference Case. The net effect under this sensitivity is that electric vehicles account for less than 7% of the global passenger fleet by 2040. This would be equivalent to around 130 million cars. The slower expansion of electric vehicles in this sensitivity is also likely to affect the segment of commercial vehicles, which will also marginally contribute to higher oil demand.

Figure 2 presents the resulting oil demand in the passenger car segment under the Reference Case and the two sensitivities. It shows that the implication of these sensitivities are fairly limited over the next ten years, within the range of 1 mb/d, but the gap starts widening over the last decade of the forecast period. The range of uncertainty is more than 3 mb/d by 2035 and then increases to above 4 mb/d by 2040.

Sectoral oil demand in the 'Electric vehicles fast penetration' sensitivity is estimated at 22.8 mb/d in 2040, which is 2.9 mb/d lower than in the Reference Case. On the other hand, if electric vehicles penetrate markets at a slower pace, in line with what is assumed under the 'Electric vehicles slow penetration' sensitivity, oil demand in the road transportation sector is assumed to be 27 mb/d by 2040. This is around 1.3 mb/d higher that the level projected in the Reference Case.

Figure 2
Oil demand in the passenger car segment in the different sensitivities

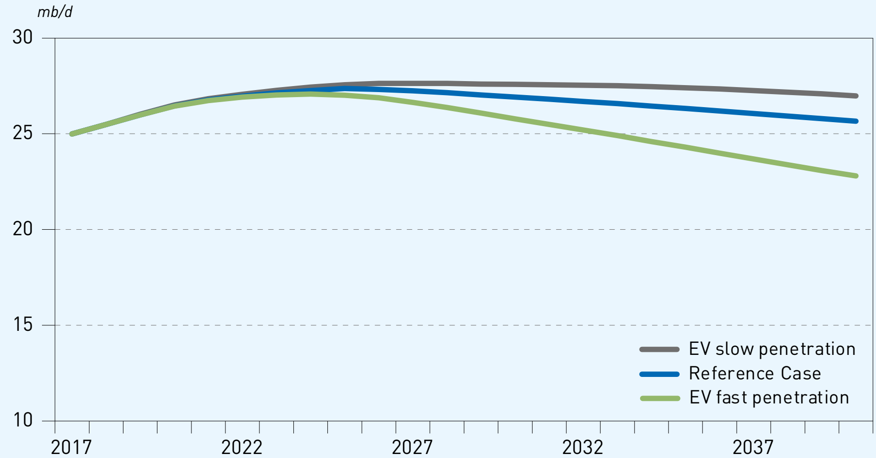
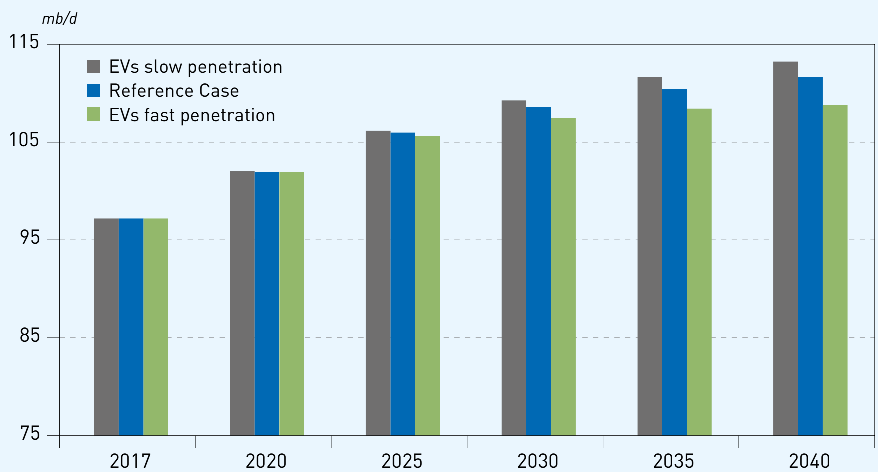


Figure 3 puts these sensitivities in the broader global oil demand picture. It shows that alternative developments regarding the expansion of electric vehicles, everything else being equal, have the potential to shift global oil demand from a high level of more than 113 mb/d ('Electric vehicles slow penetration') to below 109 mb/d ('Electric vehicles fast penetration') by 2040. In the 'Electric vehicles fast penetration' sensitivity, oil demand growth rapidly decelerates during the last decade of the forecast period and plateaus towards the end of the period.

Figure 3
Oil demand in the different sensitivities



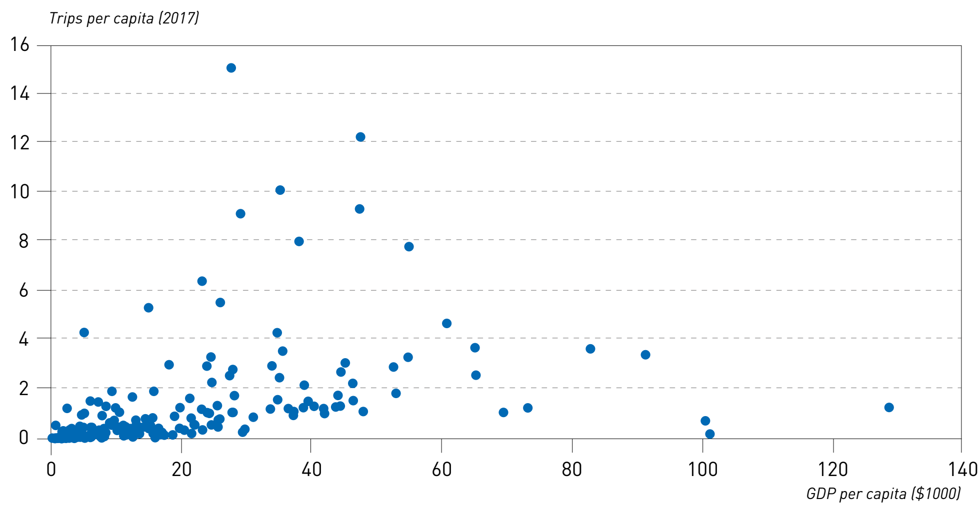
3.4.2 Aviation

The aviation sector represents one of the most dynamic industries today. According to World Bank statistics, the number of passengers carried has increased from around 0.3 billion in 1970 to 1.3 billion in 1995. It has since tripled to reach almost 4 billion in 2017. Average growth in the 1970–1995 period stood at 6% p.a., which moderated to 5.2% p.a. during the latter period. Equally impressive growth has also been achieved in air freight transport, which has increased from 83 billion ton-km in 1995 to almost 214 billion ton-km in 2017.

The growth in air traffic is expected to decelerate in the coming years, but it is still forecast to remain at high levels. For example, Airbus, in its '2018 Global Market Forecast' publication, projects that air passenger traffic will continue to grow at an average 4.4% p.a. in the period to 2037. The main reason for this forecast is the expected growth in the propensity to travel, especially in developing countries. As illustrated in Figure 3.25, in 2017 the overwhelming majority of countries were still in the category of countries with the number of flights per person below one. Moreover, out of almost 140 countries with a per capita GDP of less than $20,000 in 2017, there were only 28 countries with more than 0.3 trips per capita.

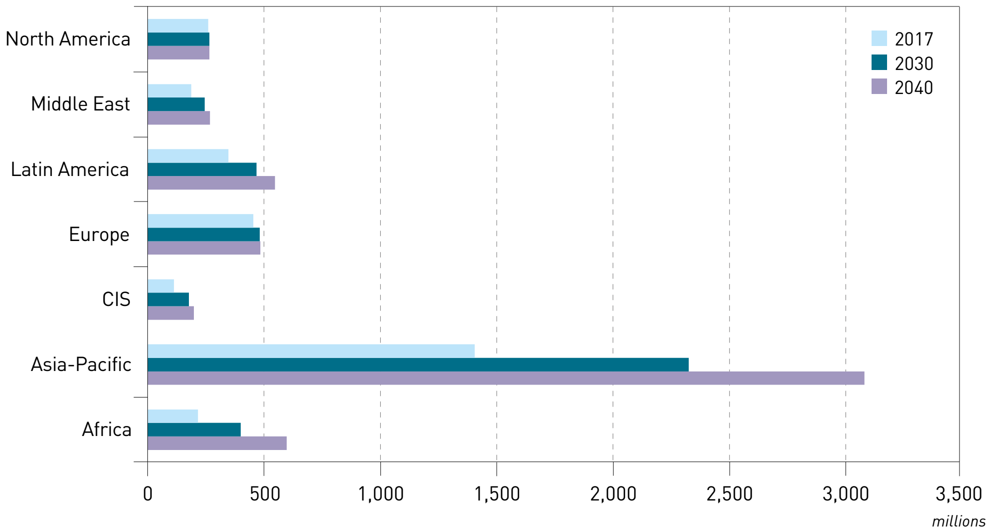
This indicates the huge potential for an increase in passenger traffic in the years to come, especially in developing countries, as rising income levels allow millions of people to rise out of poverty, join the middle class and increase their propensity to use air travel. As shown in Figure 3.26, this is especially relevant in the case of Asian countries where the number of people joining the middle class is forecast to more than double over the forecast period.

Figure 3.25
Propensity to travel, 2017



Source: Sabre, IHS, Airbus, OPEC.

Figure 3.26
Rise of the global middle class*



** Households with annual income between $20,000 and $150,000, in constant 2017 PPP prices.*

Source: Oxford Economics, Airbus, OPEC.

At the same time, it is not expected that oil demand in the aviation sector will grow proportionally to the increase in passenger traffic and freight transport. Higher load factors, better navigation equipment and, more importantly, improving fuel economies, will offset part of the potential growth in the sector. Indeed, besides security, fuel efficiency has always been the target of technical innovations in the aviation sector. In recent years, several innovations have contributed to lower specific fuel consumption, such as aerodynamic properties of airplane wings, the extended use of carbon fibre reinforced compounds and new lightweight, but resistant metal alloys, that will substantially reduce the weight of airplanes in the future.

Electrification is also underway in the air transportation sector, although at a substantially slower pace than in the road transportation sector. There are evidently electrification measures that can make airlines more efficient, but how much this impacts oil demand remains to be seen.

This sector is also increasingly being impacted by energy policies that target decarbonization. The International Air Transport Association (IATA) aims for an average improvement in fuel efficiency of 1.5% per year from 2009–2020, a cap on net aviation CO_2 emissions (carbon-neutral growth) from 2020 and a reduction in net aviation CO_2 emissions of 50% by 2050 (compared to 2005 levels).

Table 3.9 presents oil demand levels in the aviation sector after assessing the most likely implications of the mentioned factors. Projections indicate that this sector's demand will grow by 2.7 mb/d, from 6.3 mb/d in 2017 to 9 mb/d in 2040, driven by a massive increase in air traffic.

Reflecting the expected growth in per capita income levels, as well as the regional growth in air traffic, most of the incremental oil demand in this sector is expected to come from Developing countries. This is estimated at 1.9 mb/d between 2017 and 2040. Out of this, around 1.3 mb/d is associated with air traffic in Other Asia, India and China. It is interesting to note that additional long term oil demand in both Other Asia and India are higher than that of China in this year's Outlook.

The potential demand growth in the OECD region is much lower, at 0.5 mb/d over the forecast period, as the OECD represents a mature market where growth is somewhat constrained by infrastructure capacity. Nevertheless, demand growth is tangible, especially considering the fact that aviation and petrochemicals are forecast to be the only two expanding sectors in the OECD. Finally, strong growth in this sector is also projected for Russia, which is expected to

Table 3.9
Oil demand in the aviation sector by region, 2017–2040 *mb/d*

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	1.9	1.9	2.0	2.0	2.1	2.0	0.2
OECD Europe	1.3	1.3	1.4	1.4	1.5	1.5	0.2
OECD Asia Oceania	0.5	0.6	0.6	0.6	0.7	0.7	0.2
OECD	**3.7**	**3.8**	**4.0**	**4.0**	**4.2**	**4.2**	**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	0.4	0.2
India	0.2	0.2	0.3	0.4	0.5	0.5	0.4
China	0.6	0.7	0.8	0.9	0.9	1.0	0.4
Other Asia	0.8	0.8	0.9	1.0	1.1	1.2	0.5
OPEC	0.4	0.4	0.5	0.6	0.6	0.7	0.3
Developing countries	**2.4**	**2.6**	**3.1**	**3.5**	**3.9**	**4.3**	**1.9**
Russia	0.2	0.3	0.3	0.3	0.4	0.4	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Eurasia	**0.3**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.2**
World	**6.3**	**6.7**	**7.5**	**7.9**	**8.6**	**9.0**	**2.7**

almost double its oil demand over the forecast period. However, Russia's base demand, as well as Other Eurasia, is relatively low, hence, the overall demand increase in volumetric terms is limited, at 0.2 mb/d between 2017 and 2040.

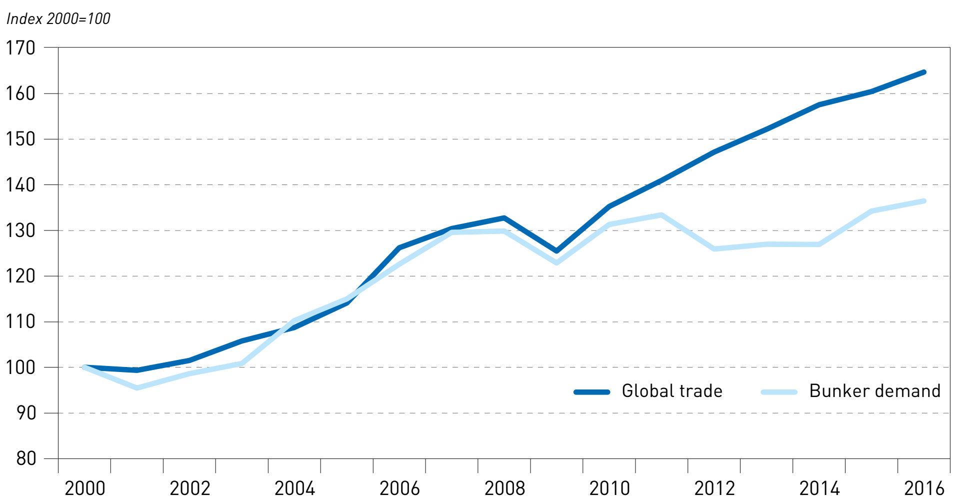
3.4.3 Marine bunkers

Having discussed critical issues for the marine bunkers sector during the medium-term period in section 3.1.3, this section will focus on the major long-term trends and factors affecting oil demand in this sector.

Oil demand in the marine bunkers sector is primarily driven by international seaborne trade, which, in turn, is closely linked to the level of global economic activity. Obviously, solid economic growth, such as that assumed in this Outlook, increases inter-regional trade and, therefore, oil demand. There are, however, several factors that weaken this link over time and partly offset potential oil demand growth. The critical one relates to efficiency improvements in seaborne transportation.

The IMO, in efforts to reduce emissions in the marine sector, adopted mandatory energy-efficiency measures in 2011, effective as of 1 January 2013. The target is to achieve a 30% efficiency improvement by 2025, for all new ships, compared to those built in 2014. The main tools to enforce the regulation are the Energy Efficiency Design Index, mandatory for new ships, and the Ship Energy Efficiency Management Plan, mandatory for all ships.

Figure 3.27
International seaborne trade and oil demand in marine sector, 2000–2016



Source: UNCTAD Statistics and OPEC.

Of course, regulation is not the only force that drives efficiency improvements. This is evidently demonstrated in Figure 3.27, which compares the growth in international seaborne trade with oil demand in the marine sector. The figure shows the strong correlation between changes in global seaborne trade and related oil demand during the first decade of the century and the then gradual decoupling of the link after 2010. One of the reasons contributing to this trend was higher oil prices, as well as the availability of spare shipping capacity that allowed (and forced) slow steaming. This begs the question: to what extent will slow steaming limit future oil demand growth?

Another factor affecting future shipping efficiency emerges from industry digitalization. New vessels are increasingly equipped with complex software-based control systems that allow the optimization of various processes, including dynamic positioning, propulsion management systems and the optimized use of power trains. It is clear that digitalization will penetrate all segments and operations of the industry and will help to improve efficiencies.

Critical to future oil demand in the marine sector will also be the speed of expansion in LNG vessels. Despite the fact that there are not many LNG-driven vessels currently operating and, existing infrastructure is still insufficient for the widespread adoption of LNG in this industry, there are some interesting policy moves to promote LNG as a shipping fuel.

The United Arab Emirates (UAE) is reportedly working on plans to install LNG storage facilities at the Port of Fujairah, which is the world's second-largest fuel oil bunkering hub. South Korea launched a project to develop LNG bunkering technology in 2018, given expectations for rising demand. Additionally, the EU has approved the European Commission's Trans-European Transport Network (TEN-T) proposal to fund an LNG pipeline for marine fuel use. The TEN-T fund consists of €22.1 million, a portion of which is allotted to the development of an LNG pipeline from Italy to Malta for marine transportation fuel.

Finally, the potential for LNG bunkering has also gained traction internationally, as an international focus group formed in 2014 to cooperate on LNG bunkering – initially consisting of the ports of Singapore, Rotterdam, Antwerp and Zeebrugge – was expanded in October 2016 to include the Port of Jacksonville (Florida, US); the Norwegian Maritime Authority (Norway); the Ministry of Land, Infrastructure, Transport and Tourism (Japan); and the Ulsan Port Authority (South Korea). Recent additions to the group are the ports of Ningbo-Zhoushan (China), Marseille (France) and Vancouver (Canada). In July 2018, the Copenhagen Malmö Port also started providing LNG bunkering services.

An additional element of uncertainty stems from recent trends toward increased trade protectionism. This could impact the sector, not only due to additional barriers to international trade, but also by limiting GDP growth, thus having a 'double barrelled' effect on oil demand.

Taking into account the mentioned factors, Table 3.10 presents oil demand in the marine bunkers sector up to 2040. At the global level, oil demand is anticipated to increase by 1.1 mb/d during the forecast period, from 4 mb/d in 2017 to 5.1 mb/d in 2040. This is somewhat lower than projected last year under an assumption of a higher switch to LNG than anticipated a year ago. Accordingly, growth will decelerate in the long-term as efficiency improvements and the penetration of LNG curtails growth potential.

Table 3.10
Oil demand in the marine bunkers sector by region, 2017–2040 *mb/d*

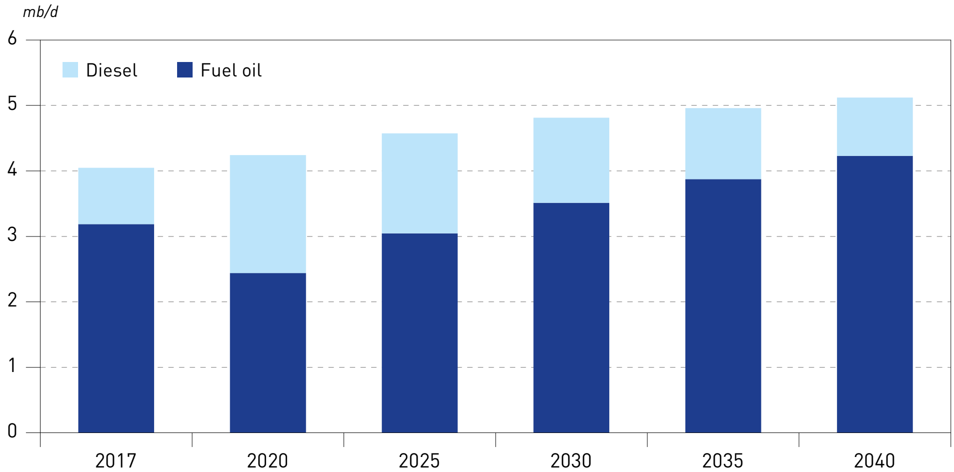
	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	0.5	0.5	0.5	0.6	0.5	0.5	0.0
OECD Europe	0.8	0.8	0.8	0.8	0.8	0.7	–0.1
OECD Asia Oceania	0.3	0.3	0.3	0.2	0.2	0.2	–0.1
OECD	**1.6**	**1.6**	**1.6**	**1.6**	**1.5**	**1.4**	**–0.2**
Latin America	0.2	0.3	0.3	0.4	0.4	0.5	0.2
Middle East & Africa	0.1	0.1	0.2	0.2	0.2	0.2	0.1
India	0.0	0.0	0.0	0.0	0.1	0.1	0.0
China	0.2	0.2	0.3	0.3	0.3	0.4	0.2
Other Asia	1.1	1.2	1.3	1.4	1.6	1.7	0.5
OPEC	0.5	0.5	0.5	0.6	0.6	0.7	0.2
Developing countries	**2.2**	**2.3**	**2.7**	**3.0**	**3.2**	**3.4**	**1.2**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.1	0.1	0.1	0.1	0.2	0.2	0.0
Eurasia	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.0**
World	**4.0**	**4.2**	**4.6**	**4.8**	**4.9**	**5.1**	**1.1**

It should be noted that this sector's entire demand growth is forecast to come from Developing countries, especially from Asia, as the centre of trade growth increasingly shifts to the region. A large portion of incremental demand is projected in Other Asia and OPEC; regions with major bunkering ports, such as Singapore and Fujairah.

Contrary to this, marine bunkers oil demand in Eurasia is projected to remain stagnant throughout the forecast period. Similarly, the OECD region is expected to remain flat throughout the next decade, before declining marginally towards the end of the forecast period. Demand losses in the OECD are not large, just 0.2 mb/d between 2017 and 2040, but are an indication of the strong competition in this sector.

The demand structure in the marine sector in terms of refined products is summarized in Figure 3.28. Currently, almost 80% of demand in this sector is for fuel oil. For the reasons explained earlier, the introduction of the IMO regulations in 2020 will change this proportion significantly in favour of diesel, which is expected to account for more than 40% of demand by then. However, the anticipated growing penetration of scrubbing technology and the increased availability of LSFO over time will likely support the use of fuel oil, which is forecast to regain its current share at some point after 2030. By the end of the forecast period, fuel oil is projected to account for 83%, or 4.2 mb/d, of product demand in the marine sector. It should be noted,

Figure 3.28
Product demand in the marine bunkers sector, 2017–2040



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however, that this pattern is sensitive to the advancement of scrubbers, which adds yet another facet to this sector's uncertainties.

3.4.4 Petrochemicals

Oil demand in the petrochemicals sector is expected to grow at a solid 1.3% p.a. on average over the entire forecast period. This is the second fastest growth rate at the sectoral level, second only to aviation. Table 3.11 presents the details of oil demand in this sector at both the global and regional level.

It underlines that global demand is set to increase by 4.5 mb/d, from 13 mb/d observed in 2017 to a forecasted level of 17.5 mb/d in 2040. It is worth emphasizing that, in terms of volume, this is the largest increase among all sectors, even more than witnessed in the road transportation sector, which has traditionally been the sector with highest incremental demand. However, another downward demand revision to the road transportation sector, primarily due to the expected increased penetration of electric vehicles, combined with an upward revision to the petrochemical sector this year, has pushed petrochemicals to the top of the list of sectors in terms of volume.

Moreover, similar to aviation, the petrochemicals sector is one of two sectors where oil demand is set to grow in all regions, albeit at varying paces. Among the three major regions, both the fastest growth (2.4% p.a. on average) and the largest increase (3.8 mb/d) are projected for Developing countries, most notably Asian countries and OPEC. Significant demand increases are also expected in OECD America. In fact, these three regions, Asia, OPEC and OECD America, are anticipated to account for around 90% of incremental demand and close to 70% of oil demand in the petrochemicals sector by 2040.

Table 3.11
Oil demand in the petrochemicals sector by region, 2017–2040 *mb/d*

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	3.0	3.3	3.4	3.5	3.5	3.4	0.4
OECD Europe	1.8	1.9	1.9	1.8	1.8	1.8	0.0
OECD Asia Oceania	2.1	2.1	2.1	2.1	2.2	2.2	0.1
OECD	**6.8**	**7.2**	**7.4**	**7.4**	**7.4**	**7.4**	**0.5**
Latin America	0.3	0.3	0.3	0.4	0.4	0.4	0.1
Middle East & Africa	0.0	0.1	0.1	0.1	0.1	0.1	0.1
India	0.4	0.5	0.6	0.8	0.9	1.0	0.6
China	1.8	2.0	2.2	2.4	2.6	2.7	0.9
Other Asia	1.3	1.4	1.6	1.7	1.9	2.0	0.8
OPEC	1.3	1.4	1.6	1.9	2.3	2.7	1.4
Developing countries	**5.1**	**5.6**	**6.3**	**7.2**	**8.2**	**9.0**	**3.8**
Russia	1.0	1.0	1.1	1.1	1.1	1.1	0.1
Other Eurasia	0.0	0.0	0.0	0.0	0.1	0.1	0.0
Eurasia	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**	**0.2**
World	**13.0**	**13.9**	**14.8**	**15.9**	**16.8**	**17.5**	**4.5**

The concentration of the petrochemicals industry in these regions is driven by two major factors – demand for petrochemical products, mostly as an intermediate material for production of finished products and the availability of feedstock. To better understand the future trends in this sector, its complexity and the competition between regions, it is important to recall the major processes to produce basic petrochemicals. These are steam cracking, catalytic reforming and fluid catalytic cracking (FCC).

Steam cracking produces olefins and aromatics from a wide range of petrochemical feedstocks. Depending on the feedstock used, steam cracking can produce only ethylene (when using ethane as feedstock) or the full range of basic petrochemicals (when using naphtha as feedstock). Catalytic reforming of naphtha is a refinery process for producing gasoline components that gives rise to about 65% of the benzene, toluene and xylenes used in the chemical industry.

Fluid catalytic cracking is also a refinery process for gasoline components that produces propylene, butenes, and in some cases ethylene as a by-product. The FCC process accounts for significant quantities of propylene in major gasoline producing regions, such as North America, Asia and Western Europe. There are also some other processes such as propane dehydrogenation (PDH), steam methane reforming, methanol-to-olefins (MTO) and coal-to-olefins (CTO) producing smaller quantities of petrochemicals.

Given the large refining base in Asia, most crackers in this region are naphtha-based, but can also be fed with LPG. Demand growth in the region is expected to be led by projects in China and India, supplemented by several other countries especially in Southeast Asia. Both China and India are boosting their production of petrochemical products to meet increasing demand.

As discussed in detail in sub-section 3.1.2 (Medium-term oil demand by sector and product), incremental capacity stemming from existing petrochemical projects in China is estimated in the range of 5–7 mt. This is the second largest regional capacity increase over the medium-term, behind only the US. Unlike the US, China has the most diversified feedstock slate, focusing mainly on naphtha, but also using LPG and, to a lesser extent, methanol and coal.

In the years to come, however, ethane and ethylene from the US are also expected to move to China to feed crackers and derivatives plants. Moreover, two on purpose PDH plants are also expected to add 600,000 tons p.a. of propylene by 2019 and Shandong Petrochemicals is adding 100,000 tons p.a. of propylene sourced from its FCC unit. Despite a slowdown in projects using MTO/CTO technology in China, some 880,000 tons p.a. of olefins and derivatives production, namely propylene, are also to be put online from MTO and CTO projects by 2019.

The use of MTO and CTO technology poses an uncertainty to future oil demand in China's petrochemical sector, considering the country's large coal resource base. Quantitative analysis shows that CTO projects have a slight cost advantage over oil-based ethylene production if the crude oil price is above $70/b.[18] On the other hand, using coal as a primary source has much higher environmental implications for local pollution, as well as CO_2 emissions. Hence, the use of CTO may bear other costs in the future and might not be consistent with sustainable development, unless combined with counterbalancing measures such as carbon capture utilization and storage (CCUS).

To sum up, China's oil demand in the petrochemicals sector is projected to receive a boost of around 0.4 mb/d by 2025. Thereafter, the demand growth rate will decelerate, especially towards the end of the forecast period, while the overall demand increase is projected at 0.9 mb/d between 2017 and 2040.

Other countries in the Asian region are also benefiting from the growing demand for petrochemical products, as well as an expansion of its domestic refining sector. India, for example, is taking take full advantage of the off-gas production at the mega-refineries in Jamnagar. Reliance Industries recently commissioned a 1.5 million tons/year capacity refinery off-gases cracker, along with downstream units and utilities. Looking ahead, India recently signed an agreement to explore a strategic partnership and co-investment in building a huge refining and petrochemicals complex at Ratnagiri, in a joint venture with Saudi Aramco and ADNOC. This should result in about 18 million tons/year of additional capacity.

Projects in South Korea (Lotte Chemical and LG Chemical), Malaysia (Rapid refinery and petrochemical plant at Pengerang), Thailand (PTT Global Chemical) and Indonesia (Cilacap refinery) are also expected to result in a substantial capacity increase to produce petrochemicals. This trend is also seen to continue over the long-term. Accordingly, long-term oil demand for petrochemicals in India and Other Asia is forecast to increase by 0.6 mb/d and 0.8 mb/d, respectively.

In the Middle East, petrochemical sector investment is expected to be in the range of $60 to $80 billion in the next few years. Saudi Arabia is leading the investment wave for the Gulf region's petrochemical capacity additions. Other countries currently expanding their petrochemical sector are Kuwait, Oman and the IR Iran. While most of the plants in the region use ethane as a feedstock, Saudi Arabia is also developing a crude-to-chemicals complex as a joint venture between Saudi Aramco and Sabic. The complex, which could potentially change the economics of petrochemicals, is expected to produce 9 million tons per year of chemicals and base oils.

In Africa, Egypt is investing more than $7.5 billion on the construction of two naphtha crackers, in Ain Sokhna and Port Said. In Nigeria, the Dangote integrated refinery mega project in the Lekki Free Zone has secured financing and is planning to add polypropylene and ethylene capacity too. Algeria is also planning to implement a PDH unit with Total.

In Latin America, the Etileno greenfield petrochemical complex is being built near Coatzacoalcos, Veracruz, Mexico. The project consists of a 1 million ton per year ethylene cracker, two high-density polyethylene plants and a low-density polyethylene plant. In Brazil, where petrochemical potential is substantial, domestic demand recovery will likely yield new petrochemicals projects. Similarly, the development of shale gas reserves in Argentina may bring petrochemicals capacity to the country in the future.

Turning to OECD regions, the US petrochemical sector will likely continue to benefit from its low-cost ethane feedstock, as well from tax reforms and solid global economic growth. As discussed earlier in this Chapter, existing projects for ethane crackers in the US are expected to add up to 10 million tons of additional capacity between 2018 and 2020.

This new capacity will be further expanded by additional projects that are planned beyond this period, although these projects will face greater competition and may prove to be more difficult to implement. This is because the US petrochemicals market is mature and ethane and ethane derivatives need to be oriented toward capturing exports opportunities, in addition to satisfying the domestic market. However, additional tariff and trade disputes may hinder developments in the US. Nevertheless, the Reference Case projections assume continued oil demand growth in the OECD America petrochemicals sector for most of the forecast period, resulting in additional demand of 0.4 mb/d from 2017–2040.

Developments in other two OECD regions will be somewhat different. Oil demand for petrochemicals in OECD Europe is anticipated to be stagnant, and Europe does not benefit from cheap feedstock. Moreover, part of any potential increase will likely be offset by plans to create a circular economy. The EU is aiming to further advance its recycling rate for plastics used in packaging by 2030. This will have a downward effect on plastics demand, in general, and in Europe, in particular.

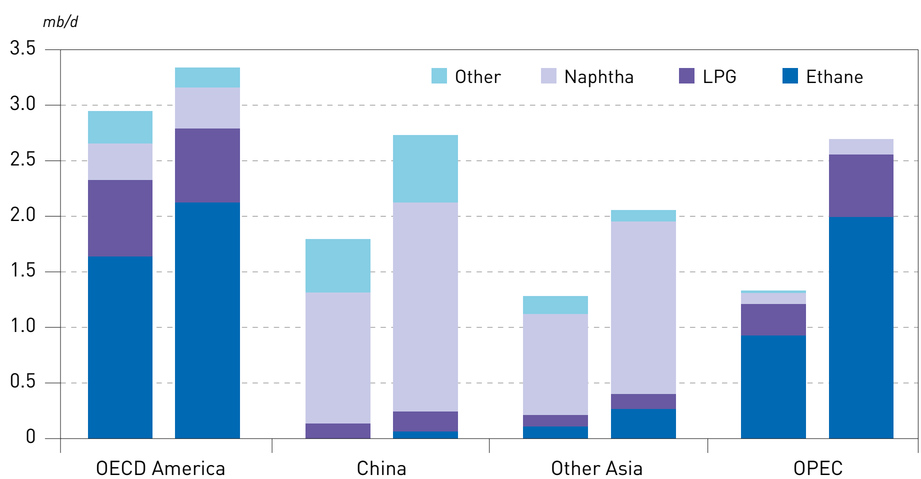
Europe's basic petrochemical plants rely on liquid feedstock, essentially naphtha. However, industry is considering increasing the share of light feedstock by taking advantage of the availability of ethane and propane from the US. This is especially true for coastal crackers. In the future, economics will dictate European petrochemical choices as mature demand may trigger a rationalization in the sector. The same issues are also relevant for OECD Asia Oceania, with the exception of South Korea, where some growth in its petrochemical sector is very likely.

In Russia, the petrochemical landscape is mostly ethane-based. Russian companies are expected to bring online new ethane cracking capacity in the range of 5 million tons in the next few years. Infrastructure for exports will also be part of the region's petrochemical development. Azerbaijan (SOCAR) is investing $17 billion in the expansion of its oil and gas processing and petrochemical complex. Combined together, prospects for an oil demand increase for the petrochemicals sector in Eurasia are limited. Growth is estimated at around 0.2 mb/d over the forecast period.

Figure 3.29 summarizes the trends discussed in this sub-chapter by presenting the expected changes in regional petrochemical product demand (mainly for feedstock purposes, but also for energy use) between 2017 and 2040.

In OECD America, all of the additional sectoral demand is anticipated to be satisfied by ethane, which accounts for almost 64% of demand by 2040, up from around 55% in 2017. The use of 'Other products' is even anticipated to decline as oil-based products used as an energy source are substituted by cheaper natural gas. A similar trend is also expected in OPEC countries where the relative weight of ethane is expected to increase. Out of a total sectoral growth of 1.4 mb/d between 2017 and 2040, ethane is forecast to increase by more than 1 mb/d. OPEC is also expected to see some growth in the use of LPG, as new petrochemical projects in OPEC's African Member Countries evolve.

Figure 3.29
Regional demand in the petrochemicals sector by products in 2017 and 2040



Contrary to these two regions, petrochemical growth in China will be dominated by naphtha. In 2017, demand for naphtha in China stood at 1.2 mb/d. This is expected to change to 1.9 mb/d by 2040, an increase of 0.7 mb/d, which represents a 4% increase in its share. Moreover, part of the demand increase in China's petrochemical sector will also likely be captured by ethane. While the increase is not large, an expected 0.1 mb/d by 2040, it does represent a new element in the country's feedstock slate. A similar picture is expected in Other Asia. However, the increase in ethane demand here is almost 0.2 mb/d, while naphtha growth is slightly less pronounced than in China.

3.4.5 Other sectors

Starting with oil use in rail and domestic waterways, demand in this sector is the lowest among all sectors considered in this Outlook. Moreover, more than half of it is concentrated in only two regions, OECD America and China (Table 3.12).

In OECD America, the majority of sectoral demand comes from the rail sub-sector, particularly due to the low levels electrification on US railways. For example, less than 1,000 km of railways are electrified in the US, and this number is less in Canada, with only around 130 km of electrified railways. Moreover, part of the regin's oil demand is linked to moving crude oil

Table 3.12
Oil demand in rail and domestic waterways sector by region, 2017–2040 *mb/d*

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	0.5	0.5	0.5	0.5	0.4	0.4	–0.2
OECD Europe	0.2	0.2	0.2	0.1	0.1	0.1	0.0
OECD Asia Oceania	0.1	0.1	0.1	0.1	0.1	0.1	0.0
OECD	**0.8**	**0.8**	**0.8**	**0.7**	**0.6**	**0.6**	**–0.2**
Latin America	0.1	0.1	0.1	0.1	0.1	0.2	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
India	0.1	0.1	0.1	0.1	0.1	0.1	0.0
China	0.6	0.6	0.7	0.7	0.8	0.9	0.3
Other Asia	0.1	0.1	0.2	0.2	0.2	0.2	0.1
OPEC	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Developing countries	**0.9**	**1.0**	**1.1**	**1.2**	**1.3**	**1.4**	**0.5**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
World	**1.8**	**1.9**	**2.0**	**2.1**	**2.1**	**2.1**	**0.3**

from remote producing areas to refineries that are closer to consumers or export ports. In the future, however, this is expected to change to some extent as the expanding electrification of railways and the increased pipeline infrastructure will likely limit the use of oil in this region over the forecast period.

Contrary to OECD America, most of China's oil demand in this sector comes from domestic waterways, since the country has a large network of waterways and the longest navigable rivers and canals in the world. According to the Asian Development Bank,[19] China has a coastline of 18,000 km and a navigable inland waterway system totalling 126,300 km. Despite this huge infrastructure system that has been developed over centuries, it has still not achieved its full potential in respect to both its size and its utilization. Therefore, the expectation is that an expansion in domestic waterway traffic in China, both for passengers and freight, will support oil demand growth over the forecast period. However, compared to other transport sectors, the incremental demand volume in rail and domestic waterways is relatively low. By 2040, total sectoral demand is forecast at 2.1 mb/d, just 0.3 mb/d higher than in 2017.

Much higher consumption levels and incremental demand is expected in the 'other industry' sector. Demand projections for this sector are presented in Table 3.13. Oil use in this sector is closely linked to the stage of development and economic structure of a given country. Typically, countries initially tend to have a high share of agriculture in their GDP. However, as countries grow and income levels rise, the agriculture sector increasingly becomes displaced by the industrial sector. Eventually further economic growth translates into a growing weight for the service sector. It is, therefore, not surprising that sectoral demand growth will come from Developing countries, particularly India, OPEC and African countries.

The growth in Developing countries is 1.4 mb/d over the forecast period, although part of the increase is offset by declining demand in China as it continues its shift towards a more service-oriented economy.

In the OECD region, oil demand in 'other industry' sector is expected to revert to a declining path, following a temporary boost observed in the past few years as industry benefited from lower oil prices. Looking ahead, however, the shrinking weight of the industry sector, technology and policy-driven efficiency improvements, as well as fuel switching towards natural gas, will likely result in a demand reduction of around 0.4 mb/d over the forecast period.

Driven by Developing countries, total oil demand in the 'other industry' sector is set to increase by 1.1 mb/d, compared to 2017.

A broadly similar pattern for oil demand is also expected in the residential/commercial/agriculture sector. Oil demand in this sector totalled 10.6 mb/d in 2017 and is projected to reach 12.3 mb/d by 2040 (Table 3.14).

However, demand in the OECD is expected to continue to decline, driven by energy policies targeting efficiency improvements and a switch towards natural gas and renewables, such as the use of solar and heat pumps by households. As a result, OECD oil demand in this sector is anticipated to decline by 0.9 mb/d between 2017 and 2040.

Table 3.13
Oil demand in 'other industry' sector by region, 2017–2040

mb/d

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	2.9	3.0	2.9	2.9	2.8	2.8	–0.1
OECD Europe	1.5	1.5	1.4	1.4	1.4	1.4	–0.1
OECD Asia Oceania	0.9	0.9	0.8	0.8	0.7	0.7	–0.2
OECD	**5.3**	**5.4**	**5.2**	**5.1**	**5.0**	**4.9**	**–0.4**
Latin America	0.9	0.9	0.9	1.0	1.0	1.0	0.2
Middle East & Africa	0.6	0.6	0.6	0.7	0.7	0.8	0.3
India	1.0	1.0	1.1	1.2	1.3	1.4	0.5
China	1.9	2.0	2.0	1.8	1.8	1.9	0.0
Other Asia	0.9	1.0	1.0	1.1	1.1	1.1	0.2
OPEC	1.3	1.4	1.6	1.7	1.7	1.7	0.3
Developing countries	**6.5**	**6.9**	**7.2**	**7.5**	**7.7**	**8.0**	**1.4**
Russia	0.5	0.5	0.5	0.5	0.5	0.5	0.0
Other Eurasia	0.4	0.4	0.5	0.5	0.5	0.5	0.1
Eurasia	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.0**	**0.1**
World	**12.7**	**13.3**	**13.4**	**13.6**	**13.7**	**13.9**	**1.1**

It is important to note that the residential sub-sector accounts for close to half of the oil consumption in this sector. Therefore, the focus of OECD policymakers is on improving efficiency standards in both existing buildings and new construction. Several OECD countries provide incentives to increase the use of renewable energy in residential and commercial buildings, enforce stringent standards for household appliances and have tightened building codes for new construction. Examples of such policy measures are the 'Energy Performance of Buildings Directive' of the European Commission targeting nearly zero energy buildings' by the end of 2020 and a zero-carbon standard (including offsetting actual emissions through cash-in-lieu contributions) to new residential developments (of ten or more units) in London, UK.

Clearly, improvements in new building codes are not limited to OECD countries. The same trend is also present in developing countries. This is especially important in regions/countries with high population growth and fast-growing cities. In China, for example, the push for energy efficient buildings is an integral part of plans issued by the Ministry of Housing and Urban-Rural Development. In a similar vein, India also issued an update of its National Building Code in 2017. It should be noted, however, that these policy measures in developing countries will not result in declining oil demand in the residential/commercial/agriculture sector as the

Table 3.14
Oil demand in the residential/commercial/agriculture sector by region, 2017–2040

mb/d

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	1.7	1.7	1.7	1.6	1.5	1.4	–0.4
OECD Europe	1.7	1.7	1.6	1.5	1.5	1.4	–0.3
OECD Asia Oceania	0.9	0.9	0.8	0.8	0.7	0.6	–0.3
OECD	**4.3**	**4.3**	**4.1**	**3.9**	**3.7**	**3.4**	**–0.9**
Latin America	0.7	0.7	0.8	0.9	1.0	1.0	0.3
Middle East & Africa	0.6	0.6	0.7	0.8	0.9	1.0	0.4
India	1.0	1.1	1.4	1.5	1.6	1.8	0.7
China	2.0	2.2	2.4	2.6	2.8	2.9	0.9
Other Asia	0.8	0.8	0.8	0.9	0.9	0.9	0.1
OPEC	0.6	0.6	0.7	0.7	0.7	0.6	0.1
Developing countries	**5.7**	**6.1**	**6.8**	**7.3**	**7.8**	**8.2**	**2.6**
Russia	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Other Eurasia	0.3	0.3	0.3	0.4	0.4	0.4	0.1
Eurasia	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.0**
World	**10.6**	**11.1**	**11.6**	**12.0**	**12.2**	**12.3**	**1.7**

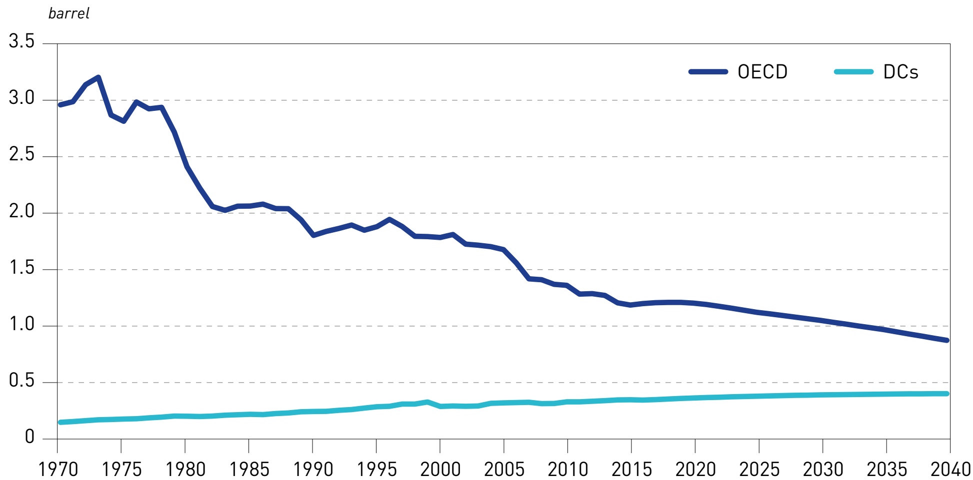
expansion in the number of new houses more than offsets efficiency improvements. Nevertheless, they reduce the use of energy in this sector.

Other factors to be considered in the case of the Developing countries region are rising incomes and increasing urbanization levels, which will continue to stimulate a switch away from traditional fuels for cooking and heating to commercial fuels, including oil products. Better access to modern energy will certainly improve the living conditions of many people. However, per capita use continues to be markedly different to that of the OECD.

As illustrated in Figure 3.30, OECD per capita consumption in this sector was more than four times higher than in Developing countries in 2010. This ratio will be closer to three by 2020 and is still expected to be above two by 2040. This underscores the underlying energy poverty issue in Developing countries.

Oil demand in Developing countries in this sector is projected to increase to 8.2 mb/d in 2040 from 5.7 mb/d in 2017. The largest demand increases in this sector will likely materialize in China, India and the Middle East & Africa.

Figure 3.30
Per capita oil consumption in the residential/commercial/agriculture sector, 1970–2040



Finally, oil use in electricity generation will continue to play a marginal role. The share of electricity generation in total oil demand has been on a downward trend for the last three decades, mainly due to its substitution by nuclear, coal, natural gas and lately renewables. In 1990, the electricity sector accounted for more than 11% of total oil demand. This share has decreased constantly, reaching 5% in 2015 and this trend is expected to continue over the forecast period, except for a few years after 2020 when an anticipated surplus production of HSFO at discounted prices will provide a window of opportunity for temporary increase. As already discussed, this is the side effect of the IMO regulations on marine bunker fuels.

At the global level, oil consumption for electricity generation stood at 5.1 mb/d in 2017, with a large portion of this demand observed in OPEC Member Countries, at 1.9 mb/d (Table 3.15). Looking ahead, sectoral oil demand is expected to decline by 1.1 mb/d to reach 4 mb/d in 2040. This is as a result of strong competition from alternative sources and a policy of several OPEC countries to benefit from the value-added use of available oil resources. Therefore, the largest demand decline in this sector is expected in OPEC countries.

On the other hand, some growth is expected in the Middle East & Africa and India on the back of improving access to electricity and energy poverty alleviation policies. The adoption of these policies on a larger scale could potentially provide some opportunities for the use of oil to generate electricity. Oil-based decentralized power generation does not need to establish extensive grid networks and is suitable for integrating a variety of alternative technologies, such as wind, solar, water, hydropower, or stationary fuel cells.

Table 3.15
Oil demand in the electricity generation sector by region, 2017–2040 *mb/d*

	2017	2020	2025	2030	2035	2040	Growth 2017–2040
OECD America	0.3	0.3	0.2	0.2	0.2	0.1	–0.2
OECD Europe	0.3	0.4	0.3	0.2	0.2	0.2	–0.2
OECD Asia Oceania	0.5	0.5	0.4	0.3	0.3	0.2	–0.3
OECD	**1.1**	**1.2**	**0.9**	**0.8**	**0.7**	**0.5**	**–0.6**
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	0.8	0.8	0.3
India	0.2	0.2	0.2	0.2	0.2	0.2	0.1
China	0.1	0.2	0.2	0.2	0.2	0.2	0.0
Other Asia	0.5	0.5	0.4	0.4	0.3	0.3	–0.2
OPEC	1.9	1.9	1.9	1.7	1.5	1.3	–0.6
Developing countries	**3.7**	**3.9**	**3.8**	**3.7**	**3.5**	**3.2**	**–0.4**
Russia	0.2	0.2	0.2	0.2	0.2	0.1	0.0
Other Eurasia	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Eurasia	**0.2**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**–0.1**
World	**5.1**	**5.4**	**5.0**	**4.7**	**4.3**	**4.0**	**–1.1**

Moreover, oil could play an increasing role in enhancing grid stability or providing back-up capacities for regions where natural gas logistics are difficult, or where the supply of other sources of energy is intermittent in nature. Additional room for oil-based power generation could be offered in countries with high oil refining and conversion capacities. The combination of power generation, for example, from petcoke gasification, with either the production of petrochemicals or cogeneration (or both), is interesting from the viewpoint of very low feedstock costs. Moreover, this could also be applicable to other low-value products resulting from refining processes.

Liquids supply

Key takeaways

- Non-OPEC supply estimates for 2017–2019 have been revised up significantly from last year's report, largely as a result of stronger-than-expected growth in US tight oil and as a result of the 'Declaration of Cooperation' accelerating the return of stability to the market. In addition, from this higher base of 57.5 mb/d in 2017, liquids supply is now projected to experience stronger growth, rising to 66.1 mb/d by 2023, or by 1.4 mb/d p.a., thus outstripping average medium-term demand growth of around 1.2 mb/d.
- The US remains by far the most important source of medium-term supply growth, contributing 5.6 mb/d, or two-thirds of new supply, driven by surging tight oil output. US tight oil is projected to grow very strongly in the period 2018–2020, albeit slowing a bit thereafter, and to peak at 14.1 mb/d in the latter half of the 2020s.
- Given the large number of variables underpinning US tight oil growth, and its short-cycle nature, two sensitivity exercises are examined in this WOO, giving an indication of the range, pattern and timing of alternative production outcomes. These suggest that by the time of its peak in 2027, US tight oil supply could be some 1–2 mb/d higher or lower versus the Reference Case peak, a range which widens to $^{+}/_{-}$ 3–4 mb/d by 2040 – and thus has a significant potential bearing on oil market balances.
- Other major sources of medium-term non-OPEC supply are Brazil, Canada, and to a lesser extent, Kazakhstan, which are expected to collectively add another 2.6 mb/d by 2023.
- The long-term picture for non-OPEC supply is a different one, with US tight oil peaking in the late 2020s, and with fewer sources of other growth. Viewed over the entire 2017–2040 period, crude oil (including tight crude) actually declines by 1.1 mb/d. Meanwhile, natural gas liquids (NGLs), biofuels and 'other liquids' grow by 2.1 mb/d, 1.4 mb/d and 2 mb/d, respectively. Refinery processing gains increase by 0.8 mb/d.
- The demand for OPEC crude declines to 31.6 mb/d by 2023 and only reaches current levels again in the late 2020s, when US tight oil peaks. Thereafter, it should rise steadily, reaching nearly 40 mb/d by 2040.
- Global upstream investment grew by 5% in 2017, after declining sharply in 2015 and 2016. Spending is expected to continue to rise in the medium-term, with an emphasis on US tight oil. However, successful cost cutting, efficient tie-backs to existing fields, and expectations of supportive prices should sustain continued non-OPEC supply growth, even while the major international oil companies (IOCs) echo each other in maintaining strong capital discipline and a general \$50/b guidance price.
- Meanwhile, circumstantial evidence suggests decline rates are being kept in check, amid the revival of some mature producing areas, such as US offshore, Mexico and parts of the North Sea. The past year has also seen some major greenfields sanctioned, including Liza in Guyana, Libra in Brazil and Johan Castberg in Norway.

This Chapter describes the findings of the Reference Case outlook for liquids supply from 2017–2040. As in previous Outlooks, the medium-term projections for 2017–2023 and the longer-term outlook are discussed separately, due to the different methodologies employed. The medium-term relies upon a bottom-up approach, identifying upstream project start-ups, their progress and the underlying decline in mature fields, while the long-term outlook is rather constructed upon an assessment of the available resource base. US tight oil is modelled and discussed separately.

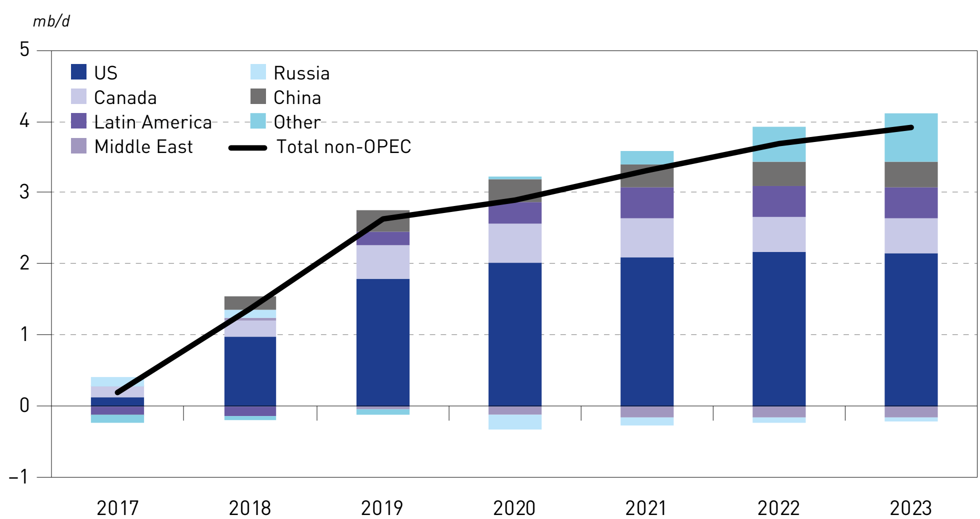
It is important to note that all supply figures quoted in this report reflect the fact that the Republic of the Congo joined OPEC as a Member on 22 June 2018. Naturally, this has led to a revision of the baseline OPEC and non-OPEC oil production assessments, as well as forecasts, which should not be confused with actual changes to the outlook.

4.1 Medium-term outlook for liquids supply

4.1.1 Revisions compared to WOO 2017

Revisions compared to the WOO 2017 are substantial, and are due to a combination of faster-than-expected US tight liquids growth, the 'Declaration of Cooperation' accelerating the return of stability to the market, a healthy demand outlook, and expectations of supportive oil prices. Non-OPEC supply in 2017 is now assessed to be 0.2 mb/d higher at 57.5 mb/d, compared to the previous publication. For 2018, the short-term assessments, which are in line with the Secretariat's MOMR, have resulted in total non-OPEC being revised up by a full 1.4 mb/d since the publication of the WOO 2017, of which some 1.0 mb/d are as a result of higher US supply (Figure 4.1). Moreover, non-OPEC supply, in general, and US tight oil, in particular, is now seen to grow at a faster pace in the medium-term. In addition to upward-revised Canadian supply, as well as other

Figure 4.1
Revisions to total non-OPEC supply vs. WOO 2017

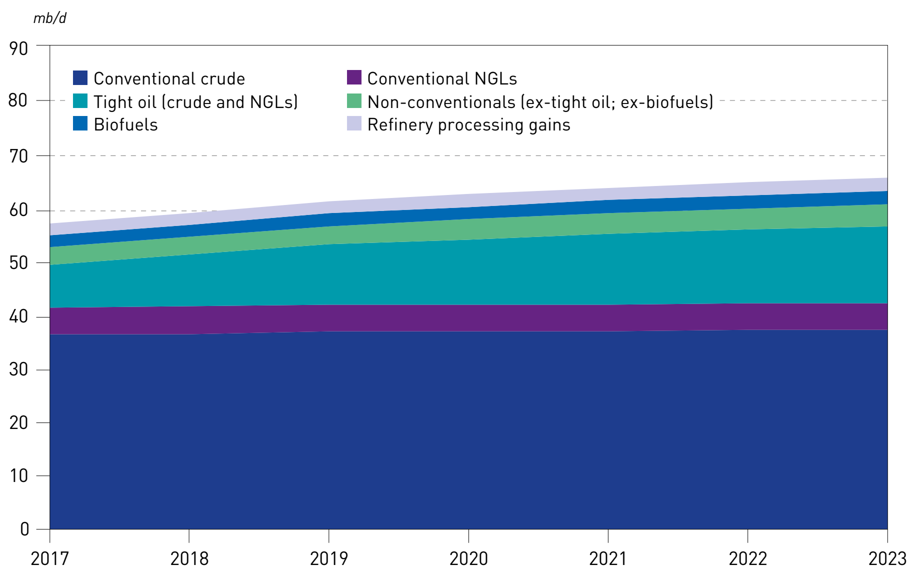


adjustments, the tail-end of the 2017–2023 period sees total non-OPEC supply adjusted up by nearly 4 mb/d, to 66.1 mb/d. Notable downward revisions include modestly lower-adjusted Russian supply, as well as anticipated slower recovery of oil production in Syria and Yemen.

4.1.2 Non-OPEC supply growth

Total non-OPEC supply is expected to grow from 57.5 mb/d in 2017 to 66.1 mb/d in 2023, an increase of 8.6 mb/d, or an average annual increment of 1.4 mb/d (Figure 4.2). As such, non-OPEC supply exceeds the rise in demand in this period, which averages an annual 1.2 mb/d. The overwhelming majority of additional oil supply (nearly 80%) comes from OECD countries, and two-thirds stems from the US. The US alone sees total liquids supply growth of 5.6 mb/d, almost exclusively from tight oil. Regionally, the most important contributors to non-OPEC supply growth remain OECD America and Latin America, which add some

Figure 4.2
Medium-term non-OPEC liquids supply by stream



6.3 mb/d and 1.5 mb/d, or 74% and 17% respectively, thus making up 91% of incremental medium-term supply. Eurasia is expected to grow by 0.3 mb/d in the period 2017–2023, while OECD Europe makes a smaller contribution of around 0.2 mb/d, and 'Other Asia' declines by 0.1 mb/d (Table 4.1 and Figure 4.3). In terms of individual countries' contributions to non-OPEC supply growth, the picture is dominated by three, which account for most of the new barrels in the 2017–2023 period. The US, Brazil and Canada are estimated to collectively add 7.9 mb/d of the total medium-term non-OPEC supply growth of 8.6 mb/d.

Table 4.1
Medium-term liquids supply outlook

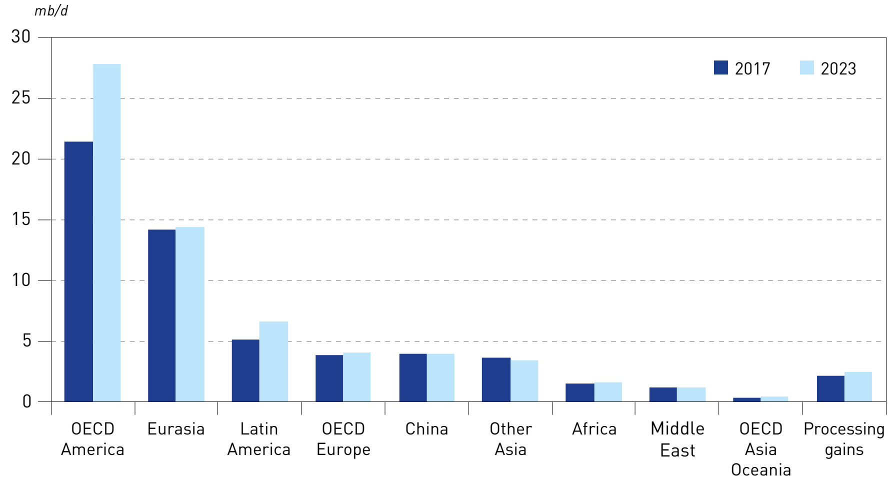
mb/d

	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
US	14.4	16.1	17.4	18.4	19.1	19.6	20.0	5.6
of which: tight liquids	*7.4*	*9.1*	*10.4*	*11.5*	*12.4*	*13.0*	*13.4*	*6.0*
Canada	4.9	5.1	5.4	5.5	5.6	5.6	5.7	0.8
of which: oil sands	*2.7*	*2.8*	*3.0*	*3.1*	*3.1*	*3.2*	*3.2*	*0.5*
Mexico & Chile	2.2	2.1	2.0	2.0	2.1	2.1	2.1	–0.1
OECD Europe	3.8	3.8	3.9	3.8	3.8	4.0	4.0	0.2
OECD Asia Oceania	0.4	0.4	0.5	0.4	0.5	0.5	0.5	0.1
OECD	**25.7**	**27.6**	**29.1**	**30.2**	**31.0**	**31.7**	**32.3**	**6.6**
Latin America	5.1	5.3	5.6	5.9	6.3	6.4	6.6	1.5
Middle East	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.0
Africa	1.5	1.5	1.6	1.6	1.6	1.6	1.6	0.1
China	4.0	4.0	4.0	4.0	4.0	4.0	4.0	0.0
Other Asia	3.6	3.6	3.6	3.5	3.5	3.5	3.5	–0.1
DCs, excl. OPEC	**15.5**	**15.6**	**16.1**	**16.3**	**16.5**	**16.7**	**16.9**	**1.4**
Russia	11.2	11.1	11.2	11.2	11.2	11.2	11.2	0.1
Other Eurasia	3.0	3.1	3.1	3.1	3.1	3.1	3.2	0.2
Eurasia	**14.2**	**14.2**	**14.3**	**14.3**	**14.3**	**14.4**	**14.4**	**0.3**
Processing gains	**2.2**	**2.2**	**2.3**	**2.4**	**2.4**	**2.4**	**2.5**	**0.2**
Non-OPEC	**57.5**	**59.6**	**61.8**	**63.1**	**64.3**	**65.3**	**66.1**	**8.6**
Crude	41.8	43.1	44.5	45.3	46.1	46.8	47.4	5.5
of which: tight crude	*5.0*	*6.3*	*7.3*	*8.1*	*8.8*	*9.3*	*9.6*	*4.6*
NGLs	8.0	8.6	9.0	9.2	9.4	9.5	9.7	1.7
of which: unconv. NGLs	*3.0*	*3.5*	*3.8*	*4.2*	*4.5*	*4.6*	*4.8*	*1.8*
Global biofuels	2.2	2.3	2.4	2.4	2.5	2.6	2.6	0.4
of which: fuel ethanol	*1.6*	*1.7*	*1.8*	*1.8*	*1.8*	*1.8*	*1.9*	*0.2*
of which: biodiesel	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.8*	*0.2*
Other liquids	3.2	3.4	3.5	3.7	3.8	3.9	4.0	0.8
of which: GTLs	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*
of which: CTLs	*0.2*	*0.2*	*0.2*	*0.3*	*0.3*	*0.4*	*0.4*	*0.2*
of which: others incl. Canadian oil sands	*3.0*	*3.1*	*3.3*	*3.4*	*3.4*	*3.5*	*3.5*	*0.6*
Total OPEC supply	**38.9**	**38.8**	**39.0**	**39.3**	**38.9**	**38.7**	**38.6**	**–0.2**
OPEC NGLs	6.0	6.1	6.2	6.3	6.4	6.5	6.6	0.6
OPEC Other liquids*	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.2
Demand for OPEC crude	32.6	32.5	32.5	32.7	32.2	31.9	31.6	–1.1
Stock change**	**–0.8**	**–0.4**	**0.5**	**0.5**	**0.3**	**0.2**	**0.2**	
World	**96.4**	**98.4**	**100.8**	**102.4**	**103.2**	**104.0**	**104.7**	**8.3**

* *This item includes other non-crude streams, such as GTL, methyl tetra-butyl ether (MTBE) and biofuels.*

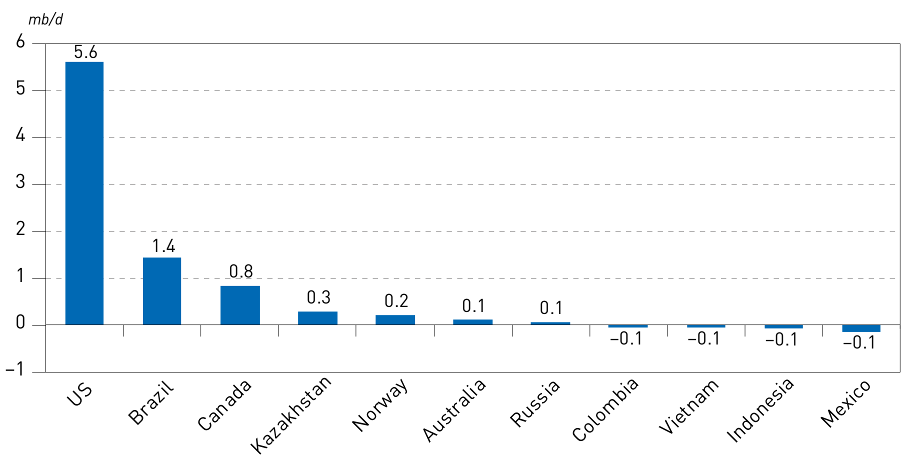
** *Stock change assumptions reflect commercial stock inventories, development of Strategic Petroleum Reserves (SPR), and the rising need for stocks as refinery capacity expands.*

Figure 4.3
Medium-term non-OPEC total liquids supply by region



Brazilian oil supply is expected to grow by 1.4 mb/d, much of which stems from deepwater pre-salt fields coming online, but also from higher fuel ethanol production (Figure 4.4). Canada is forecast to increase production by 0.8 mb/d due to higher oil sands and tight oil production, while Kazakhstan and Norway see more modest supply growth of 0.3 mb/d and 0.2 mb/d, respectively. The only pronounced supply declines by 2023 are in Colombia, Vietnam, Indonesia and Mexico, with supply each projected lower by 0.1 mb/d, respectively. All of these countries suffer from very mature fields, though Mexico is expected to soon see production declines bottom out, due to foreign investment flowing in following the country's energy reforms.

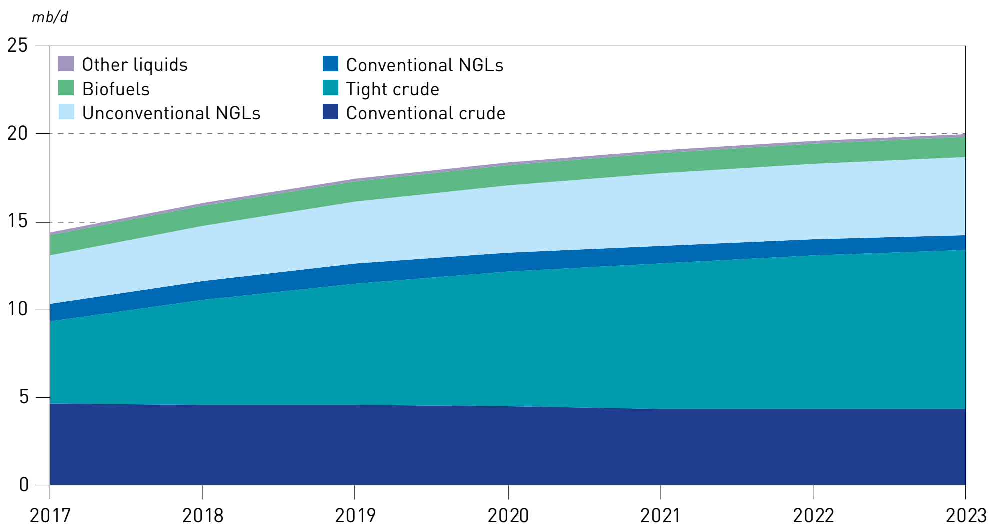
Figure 4.4
Select contributors to non-OPEC total liquids change 2017–2023



US

US oil supply growth makes up the largest share of incremental non-OPEC production in the 2017–2023 period, growing from 14.4 mb/d in 2017 (total liquids, including crude, NGLs, tight oil, biofuels and other unconventional barrels) to 20 mb/d in 2023 (Figure 4.5).

Figure 4.5
US medium-term total liquids supply

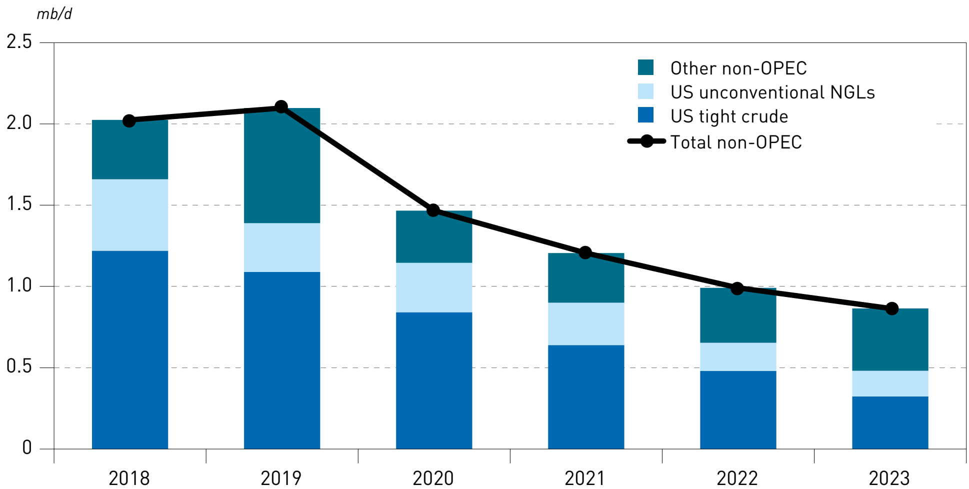


Following a decline of 0.4 mb/d in 2016, after oil prices fell, and investment and activity in the tight oil sector declined sharply, 2017 saw a rapid recovery, with total supply increasing by 0.8 mb/d. For 2018, production is expected to increase by a healthy 1.7 mb/d, thus nearly returning to the exceptional growth seen in 2014.

Most of this incremental supply is tight oil, both tight crude and unconventional NGLs, but other pockets of growth remain, including a number of fields starting up in the offshore Gulf of Mexico in the coming years. Overall, however, conventional crude and NGLs supplies decline (by around 0.3 mb/d and 0.1 mb/d, respectively), even as tight oil increases (+6 mb/d). Biofuels and other liquids both grow marginally.

In turn, US supply growth is the key driver in increasing medium-term non-OPEC supply (Figure 4.6). A more in-depth discussion of tight oil developments in the US (and elsewhere) can be found in section 4.3.

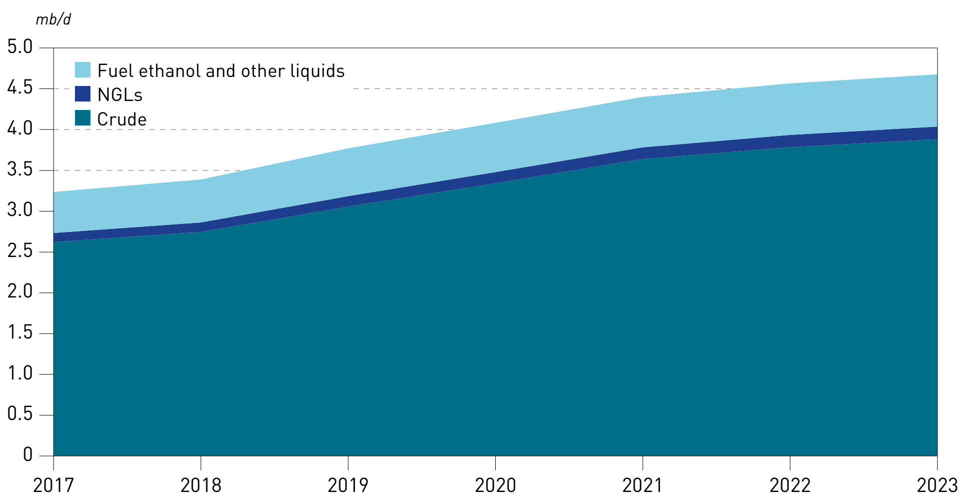
Figure 4.6
US tight oil supply growth (y-o-y change)



Brazil

Brazil is projected to be the second-largest single country source of non-OPEC medium-term supply growth, with total liquids increasing from 3.2 mb/d in 2017 to 4.7 mb/d in 2023. Much of this is due to new pre-salt fields coming online in the country's deepwater areas, thus boosting medium-term crude production by around 1.3 mb/d (Figure 4.7).

Figure 4.7
Brazil medium-term total liquids supply

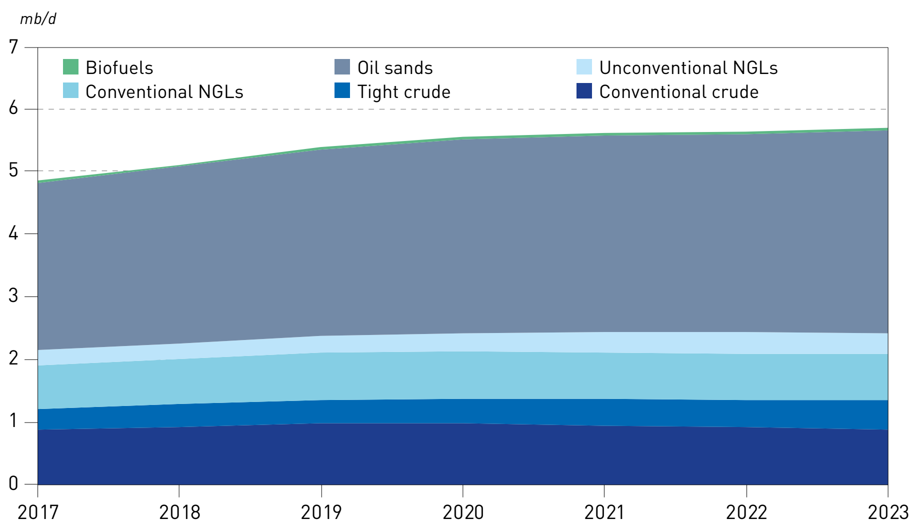


A steady stream of these large projects is due to come online in the coming years, ensuring continued growth. Indeed, since opening up operatorship of pre-salt fields to international partners, and relaxing some other regulations, including for local content, the government has made foreign investment in the country's upstream more attractive, as seen in the interest in recent bidding rounds for new acreage. Important new oil fields include the Buzios cluster, Sepia, the further development of the Lula complex, Itapu and Libra.

Canada

Canadian total liquids supply is projected to grow from 4.9 mb/d in 2017 to 5.7 mb/d in 2023, the third-largest single country source of growth (Figure 4.8). More than half of this growth (0.5 mb/d) is down to increased production from oil sands projects, which despite being relatively high cost, continue to grow, albeit at a slower pace than envisioned prior to the emergence of US tight oil. However, virtually non-existent geological risk, a continued thirst for relatively heavy barrels from the US midcontinent and Gulf Coast refining sector, and smaller, more modular incremental project stages are helping to continue to draw investment into this sector.

Figure 4.8
Canada medium-term total liquids supply



Infrastructural constraints remain a concern with regard to further long-term oil production capacity expansion, after the effective cancellation of yet another major export route project, and while the Keystone XL route is being re-evaluated. The Energy East project, which would have combined existing and new build pipeline routes to create an outlet for Canadian oil sands to the East Coast, was cancelled in late 2017. Meanwhile, the federal government has intervened to effectively nationalize the Trans Mountain crude pipeline, thereby supporting its further expansion from currently 300 kb/d to a planned 890 kb/d, and thus enabling more barrels to be exported from the West Coast. Previously, environmental and other protests had threatened to prevent the expansion, though new legal challenges may cause further delays.

Lastly, combined tight liquids growth adds another 0.2 mb/d, while conventional crude and NGLs, as well as biofuels volumes, remain relatively flat.

Russia

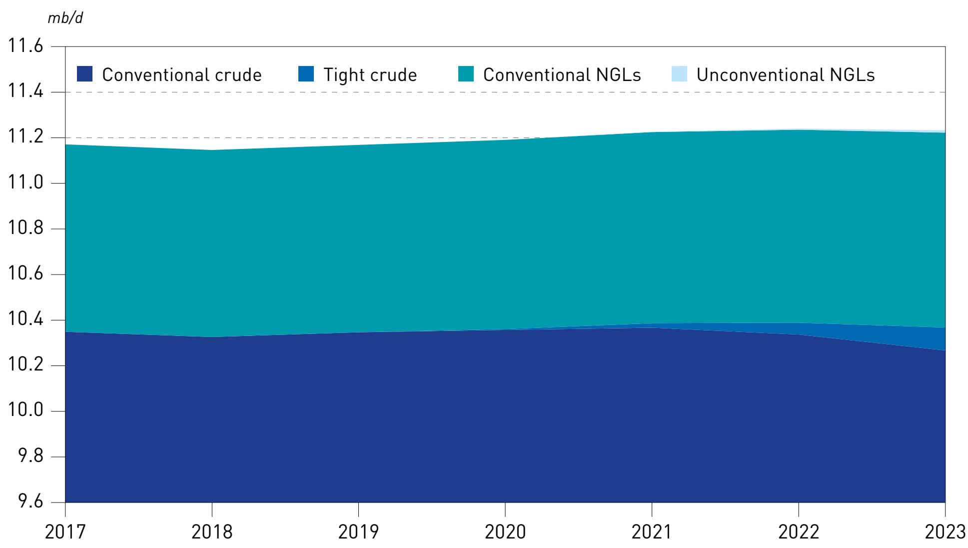
Russia's total liquids production is expected to stay relatively flat around 11.2 mb/d in the 2017–2023 forecast period (Figure 4.9). Even while some small volumes of tight crude and unconventional NGLs emerge towards the latter part of the forecast period (around 0.1 mb/d by 2023), it is assumed that any upstream investments will mainly serve to offset declines at Russia's extensive base of mature producing fields.

Moreover, as international sanctions remain in place, limiting foreign investment and technology with regard to shale oil, deepwater and Arctic upstream developments, the assumption is that this will curtail substantial volumes of new oil emerging from these frontier areas.

In the longer term, upstream production could get a boost from a change in the fiscal regime, as the Russian government continues to shift the tax burden from exports to wellhead production. Currently, the system is based on differentiated export duties on crude and oil products, which creates implied incentives for refining within Russia.

The proposed changes could be in place by the mid-2020s, though the exact variables of the new tax regime (e.g. tax levies for difficult-to-produce plays) have yet to be determined by the country's legislative body. While policymakers would need to address several issues of this new regime, including how to measure the exact production volumes from different plays of a field, the proposed changes could lend some support to production growth.

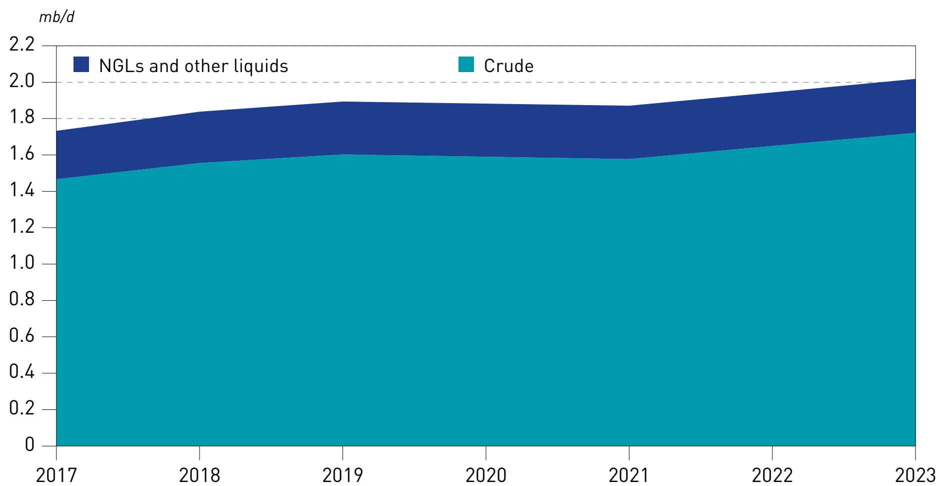
Figure 4.9
Russia medium-term total liquids supply



Kazakhstan

Kazakhstan is on track to see its liquids supply grow significantly in the medium-term, from 1.7 mb/d in 2017, to just over 2 mb/d by 2023 (Figure 4.10). This is largely down to a steady increase in crude production, as the Kashagan field reaches a capacity of 370 kb/d in its initial stage, and later, as expansion of the large Tengiz field adds another 260 kb/d of oil.

Figure 4.10
Kazakhstan medium-term total liquids supply



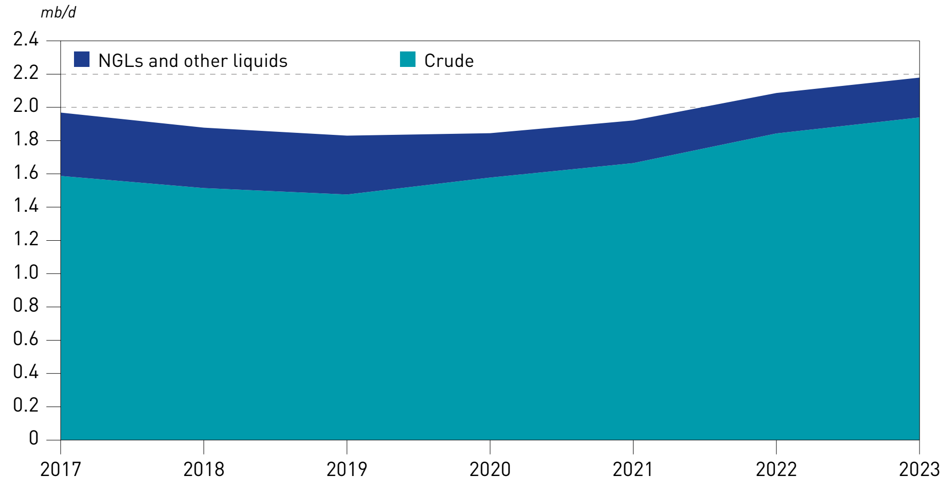
Norway

Norway is projected to see its total liquids production increase from 2 mb/d in 2017 to 2.2 mb/d in 2023, as it experiences a supply resurgence, following the discovery and development of several major new fields (Figure 4.11). Among others, most notably the next couple of years will see initial production at the major Johan Sverdrup field, as well as the sizeable Johan Castberg project. Thereafter, production is expected to decline again gradually, even while renamed Equinor has proven highly successful at slashing costs and rapidly developing smaller tie-back projects to existing fields.

Mexico

Mexico is projected to see its oil production decline modestly in the medium-term, from 2.2 mb/d in 2017 to 2.1 mb/d by 2023 (Figure 4.12). However, this hides the fact that the pronounced decline in output seen in past years is expected to be halted within this period, as the energy reforms launched in 2013 begin to bear fruit and new capacity begins to come online. Several successful bidding rounds for various types of resources have been held, and a hefty $150 billion has been committed in terms of investment. However, given the long lead-times

Figure 4.11
Norway medium-term total liquids supply



for such upstream projects these new volumes will only begin to be felt towards and beyond this report's medium-term outlook period. In the meantime, after the election of a new president in July 2018, new auction rounds have been put on hold until the new administration takes office in December this year.

Figure 4.12
Mexico medium-term total liquids supply

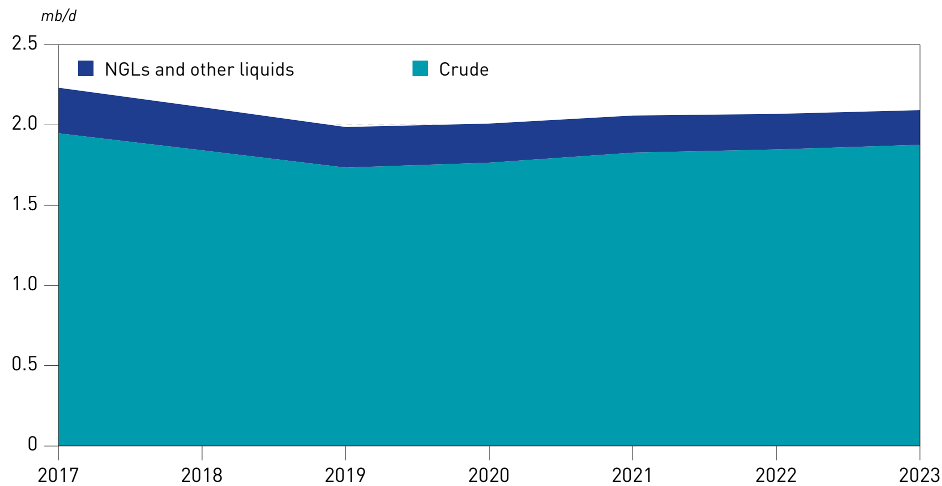


Table 4.2
Medium-term non-OPEC crude supply outlook

mb/d

	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
US	9.4	10.5	11.5	12.2	12.7	13.1	13.4	4.0
of which: tight crude	*4.7*	*5.9*	*6.9*	*7.7*	*8.3*	*8.7*	*9.0*	*4.3*
Canada	1.2	1.3	1.3	1.4	1.4	1.4	1.3	0.1
of which: tight crude	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.5*	*0.1*
Mexico	1.9	1.8	1.7	1.8	1.8	1.8	1.9	–0.1
OECD America	**12.5**	**13.7**	**14.6**	**15.3**	**15.9**	**16.3**	**16.6**	**4.1**
Norway	1.6	1.5	1.5	1.6	1.7	1.8	1.9	0.4
United Kingdom	0.9	1.0	1.0	1.0	0.9	0.9	0.9	0.0
Other OECD Europe	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0
OECD Europe	**2.9**	**2.9**	**2.9**	**2.9**	**3.0**	**3.1**	**3.2**	**0.3**
Australia	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0
OECD Asia Oceania	**0.3**	**0.3**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.0**
OECD	**15.7**	**16.9**	**17.8**	**18.5**	**19.1**	**19.7**	**20.1**	**4.4**
Brazil	2.6	2.7	3.1	3.3	3.6	3.8	3.9	1.3
Argentina	0.5	0.5	0.5	0.5	0.4	0.4	0.4	–0.1
Colombia	0.9	0.8	0.8	0.8	0.8	0.8	0.8	–0.1
Other Latin America	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.1
Latin America	**4.2**	**4.3**	**4.6**	**4.9**	**5.1**	**5.3**	**5.4**	**1.2**
Brunei	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
India	0.7	0.7	0.7	0.7	0.7	0.6	0.6	–0.1
Indonesia	0.7	0.7	0.7	0.6	0.6	0.6	0.6	–0.1
Malaysia	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.0
Thailand	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Vietnam	0.3	0.2	0.2	0.2	0.2	0.2	0.2	–0.1
Other	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0
Other Asia	**2.8**	**2.8**	**2.8**	**2.7**	**2.6**	**2.6**	**2.6**	**–0.2**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.0
Oman	0.9	0.9	0.9	0.9	0.8	0.8	0.8	–0.1
Syrian Arab Rep.	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Yemen	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0
Middle East	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**0.0**
Chad	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Egypt	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
Sudan/South Sudan	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.1
Other Africa	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1
Africa	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**	**1.4**	**1.4**	**0.1**
China	3.8	3.8	3.9	3.8	3.8	3.7	3.7	–0.1
DCs, excl. OPEC	**13.2**	**13.3**	**13.7**	**13.8**	**14.0**	**14.1**	**14.2**	**1.0**
Russia	10.3	10.3	10.3	10.4	10.4	10.4	10.4	0.0
Kazakhstan	1.5	1.6	1.6	1.6	1.6	1.6	1.7	0.3
Azerbaijan	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0
Other Eurasia	0.4	0.4	0.3	0.3	0.3	0.3	0.3	–0.1
Eurasia	**12.9**	**13.0**	**13.0**	**13.0**	**13.0**	**13.1**	**13.1**	**0.2**
Total non-OPEC	**41.8**	**43.1**	**44.5**	**45.3**	**46.1**	**46.8**	**47.4**	**5.5**

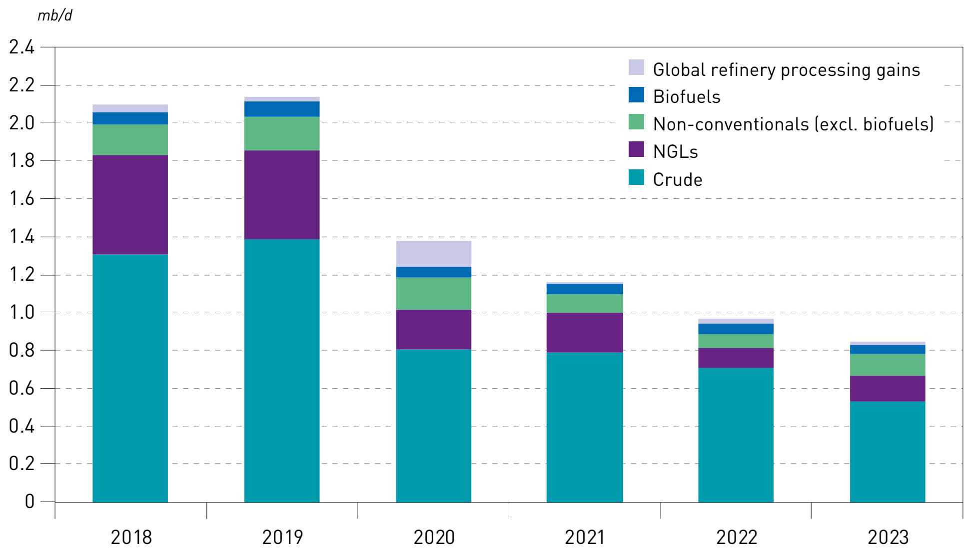
Table 4.3
Medium-term non-OPEC NGLs supply outlook *mb/d*

	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
US	3.7	4.2	4.7	4.9	5.1	5.2	5.3	1.6
of which: unconv. NGLs	*2.7*	*3.2*	*3.5*	*3.8*	*4.1*	*4.3*	*4.4*	*1.7*
Canada	0.9	1.0	1.0	1.0	1.1	1.1	1.1	0.1
of which: unconv. NGLs	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.1*
Mexico	0.3	0.3	0.2	0.2	0.2	0.2	0.2	–0.1
OECD America	**4.9**	**5.5**	**5.9**	**6.2**	**6.4**	**6.5**	**6.6**	**1.6**
Norway	0.4	0.4	0.4	0.3	0.3	0.2	0.2	–0.1
United Kingdom	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
OECD Europe	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.3**	**–0.2**
Australia	0.1	0.1	0.1	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**	**0.1**	**0.1**
OECD	**5.5**	**6.1**	**6.5**	**6.7**	**6.9**	**7.0**	**7.0**	**1.5**
Brazil	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.0
Argentina	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Latin America	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Latin America	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.1**
India	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Indonesia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Malaysia	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0
Thailand	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Other Asia	**0.7**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.0**
Oman	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Middle East	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
Egypt	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Africa	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
DCs, excl. OPEC	**1.3**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**0.1**
Russia	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.0
Kazakhstan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Azerbaijan	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Eurasia	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**0.0**
Total non-OPEC	**8.0**	**8.6**	**9.0**	**9.2**	**9.4**	**9.5**	**9.7**	**1.7**

4.1.3 Non-OPEC supply growth by type of liquid

Broken down into liquid type, total non-OPEC crude oil production (including tight crude) increases by 5.5 mb/d (or around two-thirds of total medium-term growth), while NGLs (including those derived from tight formations) make up 1.7 mb/d or around 20% (Figure 4.13). Other liquids, consisting largely of Canadian oil sands, but also including GTLs and CTLs, as well as

Figure 4.13
Annual non-OPEC total liquids growth by source



other unconventional barrels, are expected to make up another 0.8 mb/d, or 10%, while global biofuels grow a modest 0.4 mb/d, or 4%, by 2023. Global refinery processing gains add 0.2 mb/d, or 3%, over the medium term, (results may not add up to 100% due to rounding).

4.1.4 Other liquids supply (excluding biofuels)

Global unconventional supply, excluding biofuels and tight oil (this report includes the latter in the crude and NGL categories, respectively), are expected to see modest medium-term growth of 0.8 mb/d, rising from 3.2 mb/d in 2017 to 4 mb/d in 2023 (Table 4.4). The bulk of this is due to an increase in Canadian oil sands production, which is projected to rise by 0.5 mb/d.

While medium-term GTL volumes stay steady at 0.1 mb/d, CTL production is projected to double from 0.2 mb/d to 0.4 mb/d, largely due to increased volumes from China. 'Other' unconventional supply, which includes extra-heavy crude, oil shale (kerogen, not to be confused with tight oil from shale formations), MTBE and other liquids, is forecast to remain at around 0.3 mb/d throughout the forecast period.

Table 4.4
Medium-term non-OPEC other liquids supply outlook, excluding biofuels *mb/d*

	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
OECD America	2.8	3.0	3.1	3.2	3.3	3.3	3.4	0.6
OECD Europe	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0
OECD	**3.0**	**3.2**	**3.3**	**3.4**	**3.5**	**3.6**	**3.6**	**0.6**
Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
China	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1
Other Asia	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0
Developing countries, excl. OPEC	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.4**	**0.2**
Eurasia	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Non-OPEC	**3.2**	**3.4**	**3.5**	**3.7**	**3.8**	**3.9**	**4.0**	**0.8**
of which: Canadian oil sands	*2.7*	*2.8*	*3.0*	*3.1*	*3.1*	*3.2*	*3.2*	*0.5*
of which: GTLs	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*
of which: CTLs	*0.2*	*0.2*	*0.2*	*0.3*	*0.3*	*0.4*	*0.4*	*0.2*
of which: other non-conventional liquids	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.0*

4.1.5 Global biofuels supply

Non-OPEC biofuel volumes are modestly adjusted compared with the WOO 2017. While US fuel ethanol volumes have been revised lower, due to increased uncertainty regarding future mandated volumes, the opposite is true in China. There, the goal is to reach a 10% share of fuel ethanol in gasoline in the coming years, similar to what has already been achieved in the US. While it is not assumed that this will be fully realized in the required timeframe, nonetheless, the fuel ethanol outlook for China was adjusted up, albeit more in the years beyond 2023. In sum, global biofuels are expected to expand from 2.2 mb/d in 2017 to 2.6 mb/d in 2023, with growth spread globally, but weighted towards fuel ethanol over biodiesel (Table 4.5).

Table 4.5
Medium-term non-OPEC biofuels supply outlook *mb/d*

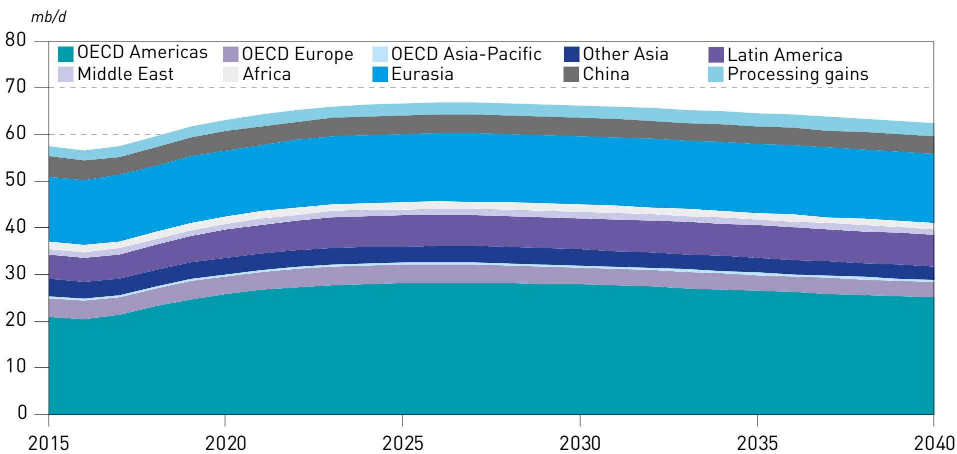
	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
OECD America	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.0
of which: US fuel ethanol	*1.0*	*1.0*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*0.0*
OECD Europe	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1
OECD	**1.4**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.6**	**0.1**
Latin America	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.1
of which: Brazilian fuel ethanol	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.1*
China	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Asia	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1
Developing countries, excl. OPEC	**0.8**	**0.8**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**0.2**
Non-OPEC	**2.2**	**2.3**	**2.4**	**2.4**	**2.5**	**2.6**	**2.6**	**0.4**
of which: fuel ethanol	*1.6*	*1.7*	*1.8*	*1.8*	*1.8*	*1.8*	*1.9*	*0.2*
of which: biodiesel	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.8*	*0.2*

4.2 Long-term outlook for liquids supply

The picture for non-OPEC supply beyond the medium-term (2017–2023) period is an entirely different one. From 2023–2040, total non-OPEC liquids are projected to shrink by 3.5 mb/d, of which 3.1 mb/d is expected to occur in the US, as tight oil production declines from the late 2020s (Figure 4.14).

Other medium-term sources of growth, such as Kazakhstan (+0.8 mb/d), Canada (+0.7 mb/d) and Brazil (+0.4 mb/d), see production continuing to rise, but this is more than offset by lower US supply and declines elsewhere, mainly mature producing countries such as Norway (–0.7 mb/d), Colombia (–0.4 mb/d), China (–0.4 mb/d), Malaysia (–0.2 mb/d) and the UK (–0.2 mb/d), among others.

Figure 4.14
Long-term non-OPEC total liquids supply growth by region



Nevertheless, given the strong growth in several countries in the short- and medium-term, including most notably the US, when viewed over the entire 2017–2040 period, non-OPEC supply still grows by 5 mb/d, with half from the US (+2.5 mb/d) and again, strong growth in Brazil (+1.8 mb/d), Canada (+1.5 mb/d) and Kazakhstan (+1.0 mb/d).

Broken down by liquid type, what is striking is how much of an outlier crude oil production is. Total non-OPEC crude supply declines by 1.1 mb/d in the 2017–2040 period. By contrast, NGLs and other liquids (excluding biofuels, but including Canadian oil sands, GTLs and CTLs, among others) grow by 1 mb/d and 2 mb/d, respectively, global biofuels by 1.4 mb/d, and refinery processing gains by 0.8 mb/d.

4.2.1 Long-term outlook for crude

Following its strong medium-term growth, total non-OPEC crude production is projected to decline beyond 2023, as US tight oil peaks in the late 2020s, and as crude production

Table 4.6
Long-term liquids supply outlook

mb/d

	2017	2018	2019	2020	2025	2030	2035	2040	Change 2017–2040
US	14.4	16.1	17.4	18.4	20.2	19.6	18.2	16.9	2.5
of which: tight liquids	*7.4*	*9.1*	*10.4*	*11.5*	*13.9*	*13.9*	*13.0*	*12.1*	*4.7*
Canada	4.9	5.1	5.4	5.5	5.9	6.1	6.3	6.4	1.5
of which: oil sands	*2.7*	*2.8*	*3.0*	*3.1*	*3.4*	*3.6*	*3.9*	*4.1*	*1.5*
Mexico & Chile	2.2	2.1	2.0	2.0	2.2	2.1	2.1	2.0	–0.3
OECD Europe	3.8	3.8	3.9	3.8	3.9	3.7	3.4	3.2	–0.6
OECD Asia Oceania	0.4	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.2
OECD	**25.7**	**27.6**	**29.1**	**30.2**	**32.6**	**32.1**	**30.5**	**29.0**	**3.3**
Latin America	5.1	5.3	5.6	5.9	6.6	6.8	7.0	6.7	1.5
Middle East	1.2	1.2	1.2	1.2	1.3	1.4	1.3	1.2	0.0
Africa	1.5	1.5	1.6	1.6	1.6	1.5	1.4	1.3	–0.2
China	4.0	4.0	4.0	4.0	4.0	3.9	3.7	3.6	–0.4
Other Asia	3.6	3.6	3.6	3.5	3.5	3.3	3.1	2.9	–0.8
Developing countries, excl. OPEC	**15.5**	**15.6**	**16.1**	**16.3**	**17.0**	**16.9**	**16.5**	**15.7**	**0.2**
Russia	11.2	11.1	11.2	11.2	11.3	11.2	11.1	11.1	–0.1
Other Eurasia	3.0	3.1	3.1	3.1	3.3	3.5	3.7	3.9	0.8
Eurasia	**14.2**	**14.2**	**14.3**	**14.3**	**14.6**	**14.7**	**14.8**	**14.9**	**0.8**
Processing gains	**2.2**	**2.2**	**2.3**	**2.4**	**2.5**	**2.7**	**2.8**	**3.0**	**0.8**
Non-OPEC	**57.5**	**59.6**	**61.8**	**63.1**	**66.7**	**66.3**	**64.6**	**62.6**	**5.0**
Crude	41.8	43.1	44.5	45.3	47.3	45.9	43.5	40.7	–1.1
of which: tight crude	*5.0*	*6.3*	*7.3*	*8.1*	*10.1*	*10.2*	*9.4*	*8.5*	*3.4*
NGLs	8.0	8.6	9.0	9.2	9.9	10.2	10.1	10.1	2.1
of which: unconventional NGLs	*3.0*	*3.5*	*3.8*	*4.2*	*5.1*	*5.4*	*5.4*	*5.4*	*2.4*
Global biofuels	2.2	2.3	2.4	2.4	2.7	3.0	3.3	3.6	1.4
of which: fuel ethanol	*1.6*	*1.7*	*1.8*	*1.8*	*1.9*	*2.0*	*2.2*	*2.3*	*0.7*
of which: biodiesel	*0.6*	*0.6*	*0.6*	*0.7*	*0.8*	*1.0*	*1.1*	*1.3*	*0.7*
Other liquids	3.2	3.4	3.5	3.7	4.2	4.6	4.9	5.2	2.0
of which: GTLs	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*
of which: CTLs	*0.2*	*0.2*	*0.2*	*0.3*	*0.4*	*0.5*	*0.6*	*0.7*	*0.5*
of which: others incl. Canadian oil sands	*3.0*	*3.1*	*3.3*	*3.4*	*3.7*	*3.9*	*4.2*	*4.4*	*1.4*
Total OPEC supply	**38.9**	**38.8**	**39.0**	**39.3**	**39.5**	**42.5**	**46.0**	**49.3**	**10.5**
OPEC NGLs	6.0	6.1	6.2	6.3	6.9	7.6	8.3	8.9	2.9
OPEC other liquids*	0.2	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.3
Demand for OPEC crude	32.6	32.5	32.5	32.7	32.1	34.4	37.3	39.9	7.3
Stock change**	**–0.8**	**–0.4**	**0.5**	**0.5**	**0.2**	**0.2**	**0.2**	**0.2**	
World	**96.4**	**98.4**	**100.8**	**102.4**	**106.2**	**108.8**	**110.7**	**111.9**	**15.5**

* *This item includes other non-crude streams, such as GTL, methyl tetra-butyl ether (MTBE) and biofuels.*

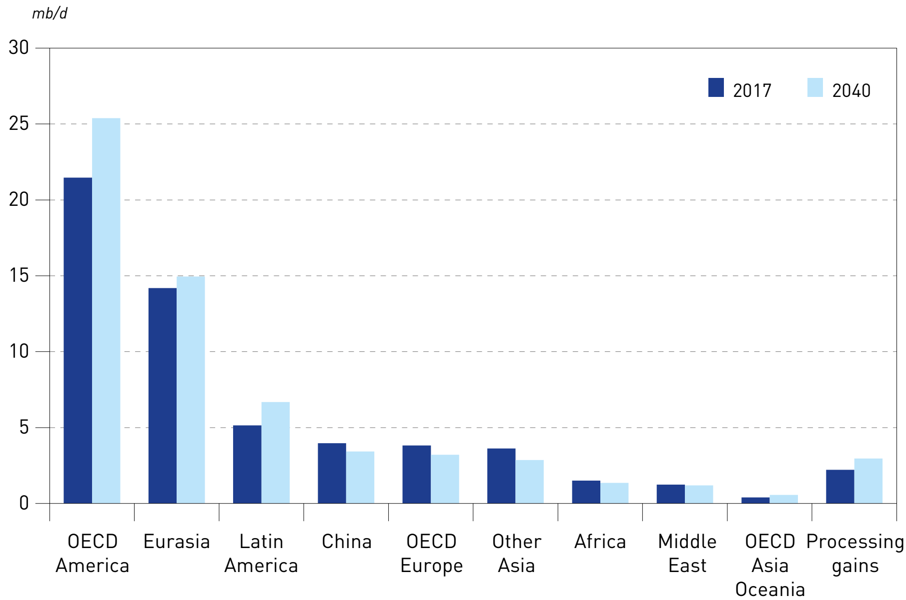
** *Stock change assumptions reflect commercial stock inventories, development of Strategic Petroleum Reserves (SPR), and the rising need for stocks as refinery capacity expands.*

Table 4.7
Long-term non-OPEC crude supply outlook

mb/d

	2017	2018	2019	2020	2025	2030	2035	2040	Change 2017–2040
US	9.4	10.5	11.5	12.2	13.4	12.8	11.4	10.1	0.7
of which: tight crude	*4.7*	*5.9*	*6.9*	*7.7*	*9.2*	*9.1*	*8.1*	*7.2*	*2.5*
Canada	1.2	1.3	1.3	1.4	1.4	1.4	1.3	1.3	0.1
of which: tight crude	*0.3*	*0.4*	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*	*0.2*
Mexico	1.9	1.8	1.7	1.8	1.9	1.9	1.9	1.8	–0.2
Chile	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OECD America	**12.5**	**13.7**	**14.6**	**15.3**	**16.7**	**16.0**	**14.6**	**13.1**	**0.6**
Norway	1.6	1.5	1.5	1.6	1.8	1.6	1.5	1.4	–0.2
United Kingdom	0.9	1.0	1.0	1.0	0.9	0.8	0.8	0.7	–0.2
Other OECD Europe	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	–0.1
OECD Europe	**2.9**	**2.9**	**2.9**	**2.9**	**3.0**	**2.8**	**2.5**	**2.3**	**–0.5**
Australia	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.0
OECD Asia Oceania	**0.3**	**0.3**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**–0.1**
OECD	**15.7**	**16.9**	**17.8**	**18.5**	**20.0**	**19.1**	**17.3**	**15.7**	**0.0**
Brazil	2.6	2.7	3.1	3.3	3.8	4.1	4.2	4.0	1.4
Argentina	0.5	0.5	0.5	0.5	0.4	0.3	0.4	0.3	–0.2
Colombia	0.9	0.8	0.8	0.8	0.7	0.6	0.5	0.4	–0.4
Other Latin America	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.2
Latin America	**4.2**	**4.3**	**4.6**	**4.9**	**5.4**	**5.5**	**5.5**	**5.1**	**0.9**
Brunei	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
India	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.4	–0.3
Indonesia	0.7	0.7	0.7	0.6	0.6	0.5	0.4	0.3	–0.4
Malaysia	0.6	0.7	0.7	0.7	0.7	0.6	0.5	0.4	–0.2
Thailand	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	–0.1
Vietnam	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	–0.1
Other	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	–0.2
Other Asia	**2.8**	**2.8**	**2.8**	**2.7**	**2.5**	**2.3**	**1.9**	**1.5**	**–1.3**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.0
Oman	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.7	–0.2
Syrian Arab Rep.	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Yemen	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Middle East	**1.1**	**1.1**	**1.1**	**1.1**	**1.2**	**1.2**	**1.1**	**1.0**	**–0.1**
Chad	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Egypt	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	–0.2
Sudan/South Sudan	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Other Africa	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0
Africa	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.2**	**1.1**	**–0.2**
China	3.8	3.8	3.9	3.8	3.6	3.4	3.1	2.8	–1.0
DCs, excl. OPEC	**13.2**	**13.3**	**13.7**	**13.8**	**14.1**	**13.6**	**12.8**	**11.6**	**–1.6**
Russia	10.3	10.3	10.3	10.4	10.4	10.3	10.2	10.1	–0.2
Kazakhstan	1.5	1.6	1.6	1.6	1.8	2.0	2.2	2.4	1.0
Azerbaijan	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	–0.1
Other Eurasia	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	–0.1
Eurasia	**12.9**	**13.0**	**13.0**	**13.0**	**13.2**	**13.2**	**13.3**	**13.4**	**0.5**
Total non-OPEC	**41.8**	**43.1**	**44.5**	**45.3**	**47.3**	**45.9**	**43.5**	**40.7**	**–1.1**

Figure 4.15
Long-term non-OPEC liquids supply outlook, 2017 and 2040



elsewhere experiences natural decline. From 2023–2040, non-OPEC crude supply is expected to decline by 6.7 mb/d, of which nearly half is due to lower US crude output. Other areas of notable decline in crude output in this period include OECD Europe, China and Other Asia. By contrast, Eurasia and Latin America are set to see crude production rise in this period (Table 4.7).

Given strong growth in the short- to medium-term, especially in the US, but also in countries such as Norway, which are expected to have a temporary output resurgence, this effect somewhat offsets the longer-term decline trend, and thus total non-OPEC crude, when viewed in the overall 2017–2040 period, declines only modestly, from 41.8 mb/d in 2017 to 40.7 mb/d in 2040.

Outliers here include Brazil, which is expected to witness sustained crude output growth, rising by 1.4 mb/d in the 2017–2040 period, and Kazakhstan, which sees an increase of 1 mb/d in the same timeframe. Meanwhile, China is projected to experience the most pronounced crude decline, shrinking from 3.8 mb/d in 2017 to 2.8 mb/d by 2040. Colombia and Indonesia are both forecast to see a decline of 0.4 mb/d in this period.

4.2.2 Long-term outlook for other liquids supply (including NGLs, biofuels, GTLs, CTLs and other)

Total non-OPEC NGLs supply is estimated to grow by 2.1 mb/d in the period 2017–2040, overwhelmingly driven by higher US output, which in turn is a side-effect of the expected continued

Table 4.8
Long-term non-OPEC NGLs supply outlook

mb/d

	2017	2018	2019	2020	2025	2030	2035	2040	Change 2017–2040
US	3.7	4.2	4.7	4.9	5.4	5.6	5.5	5.5	1.7
of which: unconventional NGLs	*2.7*	*3.2*	*3.5*	*3.8*	*4.6*	*4.9*	*4.9*	*4.9*	*2.1*
Canada	0.9	1.0	1.0	1.0	1.1	1.1	1.0	0.9	0.0
of which: unconventional NGLs	*0.2*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*0.3*	*0.1*
Mexico	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	–0.1
OECD America	**4.9**	**5.5**	**5.9**	**6.2**	**6.7**	**6.9**	**6.7**	**6.6**	**1.7**
Norway	0.4	0.4	0.4	0.3	0.2	0.2	0.1	0.1	–0.3
United Kingdom	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
OECD Europe	0.5	0.5	0.5	0.4	0.3	0.3	0.2	0.2	–0.3
Australia	0.1	0.1	0.1	0.1	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**	**0.1**	**0.1**	**0.1**
OECD	**5.5**	**6.1**	**6.5**	**6.7**	**7.2**	**7.3**	**7.1**	**6.9**	**1.4**
Brazil	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1
Argentina	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1
Other Latin America	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1
Latin America	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.6**	**0.2**
India	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Indonesia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Malaysia	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Thailand	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Other Asia	**0.7**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.0**
Oman	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Middle East	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.1**
Egypt	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Africa	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
China	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
DCs, excl. OPEC	**1.3**	**1.2**	**1.2**	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**0.4**
Russia	0.8	0.8	0.8	0.8	0.9	0.9	1.0	1.0	0.2
Kazakhstan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1
Azerbaijan	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Eurasia	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**	**1.5**	**1.5**	**0.3**
Total non-OPEC	**8.0**	**8.6**	**9.0**	**9.2**	**9.9**	**10.2**	**10.1**	**10.1**	**2.1**

tight oil and shale gas boom (Table 4.8). US NGLs output increases by 1.7 mb/d in this period, while other, more modest increments come from Russia (+0.2 mb/d), Australia, Kazakhstan, Brazil, Argentina and China (each +0.1 mb/d).

Other non-OPEC liquids, excluding biofuels, are also set to experience strong growth of 2 mb/d in the period 2017–2040 (Table 4.9). Here, the output of unconventional liquids from two countries is prominent. First, oil sands production in Canada, which is projected to increase by 1.5 mb/d in this period, from 2.7 mb/d in 2017 to 4.1 mb/d in 2040. Second, CTL output in China is expected to increase from 0.1 mb/d in 2017 to 0.4 mb/d in 2040, as the country continues its quest to diversify its energy supply sources.

Biofuels production in non-OPEC countries is also projected to see meaningful growth in the long-term, increasing from 2.2 mb/d in 2017 to 3.6 mb/d in 2040 (Table 4.10). Growth is split equally between fuel ethanol and biodiesel, though the latter retains its smaller share of the

Table 4.9
Long-term non-OPEC other liquids supply outlook, excluding biofuels *mb/d*

	2017	2018	2019	2020	2025	2030	2035	2040	Change 2017–2040
OECD America	2.8	3.0	3.1	3.2	3.5	3.8	4.0	4.2	1.4
OECD Europe	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0
OECD	**3.0**	**3.2**	**3.3**	**3.4**	**3.8**	**4.1**	**4.3**	**4.5**	**1.5**
Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
China	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.3
Other Asia	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
DCs, excl. OPEC	**0.2**	**0.2**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.5**
Eurasia	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Non-OPEC	**3.2**	**3.4**	**3.5**	**3.7**	**4.2**	**4.6**	**4.9**	**5.2**	**2.0**
of which: Canadian oil sands	*2.7*	*2.8*	*3.0*	*3.1*	*3.4*	*3.6*	*3.9*	*4.1*	*1.5*
of which: GTL	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*
of which: CTL	*0.2*	*0.2*	*0.2*	*0.3*	*0.4*	*0.5*	*0.6*	*0.7*	*0.5*
of which: other non-conventional liquids	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.0*

global biofuels pool. Major sources of growth include Brazil, which is expected to see fuel ethanol output increase by 0.3 mb/d from 2017–2040, China, Other Asia and OECD Europe. The outlook for Chinese fuel ethanol production has been lifted compared to the WOO 2017, following the planned introduction of a nationwide 10% target for ethanol in gasoline.

By contrast, US fuel ethanol output is expected to remain quite steady at 1.0–1.1 mb/d throughout the forecast period, as the debate over whether to further expand the Renewable Fuel Standard (RFS) mandate continues against the background of a generally sceptical current administration.

Table 4.10
Long-term non-OPEC biofuels supply outlook

mb/d

	2017	2018	2019	2020	2025	2030	2035	2040	Change 2017–2040
OECD America	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	0.1
of which: US fuel ethanol	*1.0*	*1.0*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*0.0*
OECD Europe	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.2
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.4**	**1.5**	**1.5**	**1.5**	**1.6**	**1.7**	**1.8**	**1.8**	**0.4**
Latin America	0.6	0.6	0.7	0.7	0.8	0.8	0.9	1.0	0.4
of which: Brazilian fuel ethanol	*0.4*	*0.4*	*0.5*	*0.5*	*0.6*	*0.6*	*0.7*	*0.7*	*0.3*
China	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Other Asia	0.1	0.1	0.1	0.1	0.2	0.3	0.4	0.5	0.4
DCs, excl. OPEC	**0.8**	**0.8**	**0.9**	**0.9**	**1.1**	**1.3**	**1.5**	**1.8**	**1.0**
Non-OPEC	**2.2**	**2.3**	**2.4**	**2.4**	**2.7**	**3.0**	**3.3**	**3.6**	**1.4**
of which: fuel ethanol	*1.6*	*1.7*	*1.8*	*1.8*	*1.9*	*2.0*	*2.2*	*2.3*	*0.7*
of which: biodiesel	*0.6*	*0.6*	*0.6*	*0.7*	*0.8*	*1.0*	*1.1*	*1.3*	*0.7*

4.3 Global outlook for tight oil supply

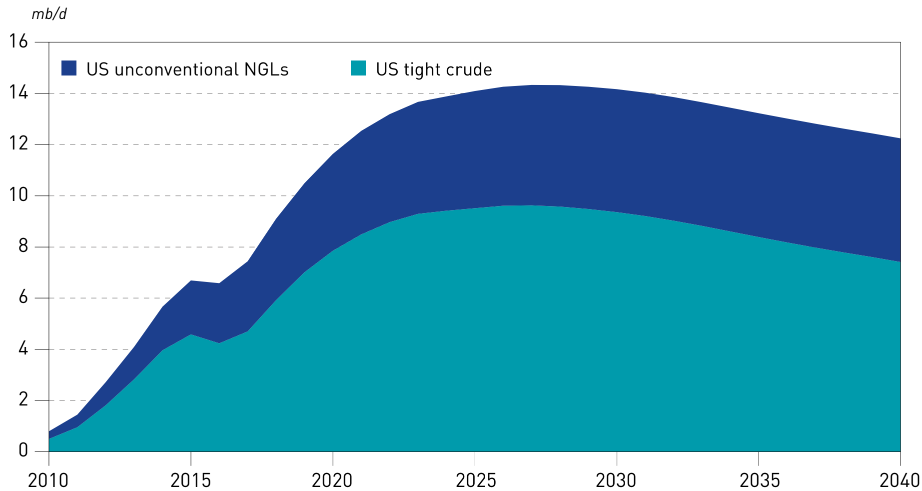
4.3.1 US tight oil developments

In the medium-term Reference Case outlook, US total tight oil production is expected to increase from 7.4 mb/d in 2017 to 13.3 mb/d in 2023, or by around 6 mb/d. Of this, 4.3 mb/d is incremental tight crude, while another 1.7 mb/d is unconventional NGLs derived from associated gas production (Figure 4.16).

The strongest annual increases are seen in the near-term (2018–2020), in which total US tight oil increases by an average 1.4 mb/d p.a. In the latter half of the medium-term period until 2023, growth slows to an average 0.6 mb/d p.a.

Thereafter, US tight oil growth is expected to slow significantly, but still achieves modest increases in the 2024–2027 period, reaching a peak of 14.3 mb/d in 2027/2028, before plateauing and gradually falling again. By 2040, US tight oil supply is expected to average 12.1 mb/d.

Figure 4.16
US tight oil supply outlook



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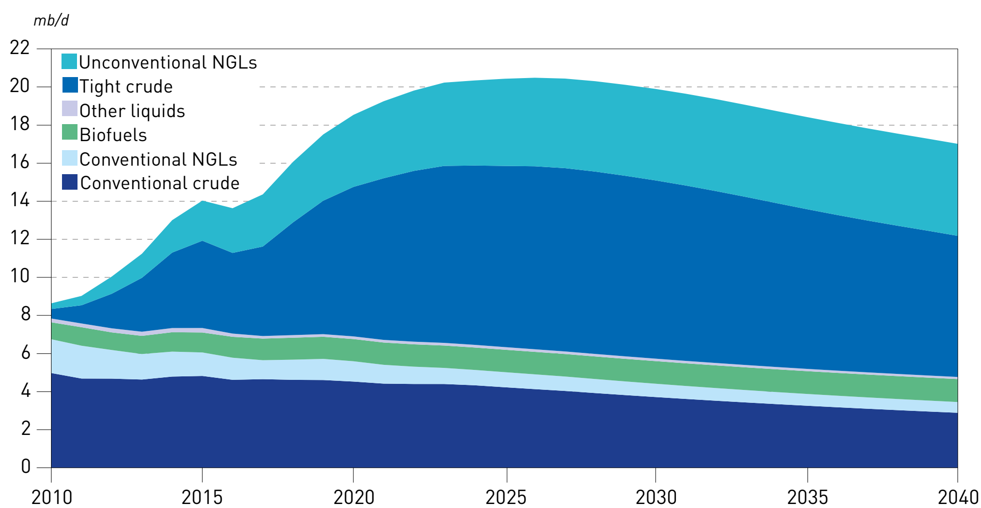
As can be seen in Figure 4.17, US tight oil already made up more than half of total US oil production in 2017, and is set to provide the vast majority of future liquids supply growth. Or to put it another way, in the absence of tight oil production (or any other new sources of oil), US supply would most likely continue to decline steadily, albeit with the country remaining one of the world's top ten oil producers.

Figure 4.17
US total liquids supply outlook



With a greater degree of detail, Table 4.11 below displays the breakdown of US total liquids supply in the medium-term, according to the Reference Case.

Table 4.11
US total liquids supply outlook

mb/d

	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
US tight oil	7.4	9.1	10.4	11.5	12.4	13.0	13.4	6.0
of which: tight crude	*4.7*	*5.9*	*6.9*	*7.7*	*8.3*	*8.7*	*9.0*	*4.3*
of which: unconventional NGLs	*2.7*	*3.2*	*3.5*	*3.8*	*4.1*	*4.3*	*4.4*	*1.7*
US other crude	4.7	4.6	4.6	4.5	4.4	4.4	4.4	–0.3
US other NGLs	1.0	1.1	1.1	1.1	1.0	0.9	0.9	–0.1
US biofuels	1.1	1.2	1.2	1.2	1.2	1.2	1.2	0.0
US other liquids	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Total US liquids production	**14.4**	**16.1**	**17.4**	**18.4**	**19.1**	**19.6**	**20.0**	**5.6**

US tight crude oil production by basin

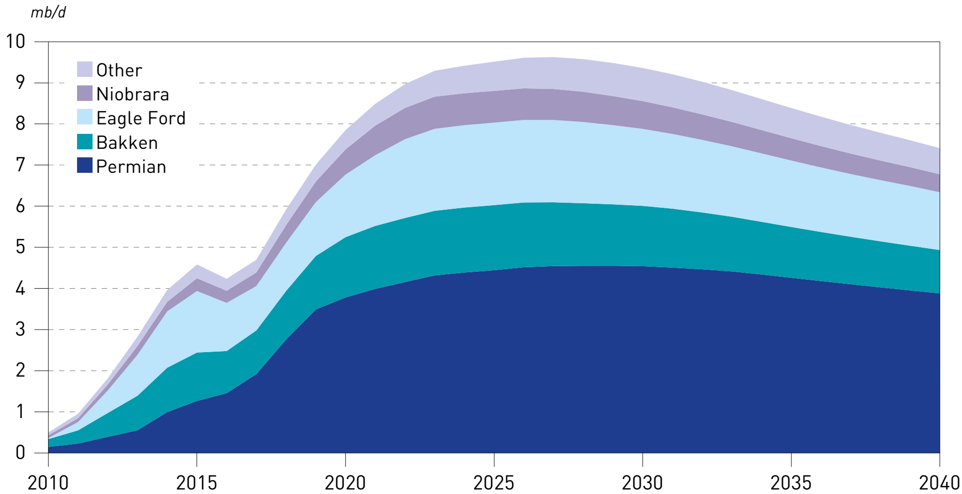
On a basin-by-basin level, developments are expected as follows (Figure 4.18).

1) The **Permian** basin, which straddles West Texas and Southeastern New Mexico, is already the most prolific source of US tight oil, and is projected to maintain that position throughout the forecast period. The basin is also a long-time source of conventional crude oil. The Permian Basin is expected to see tight crude production increase from 1.9 mb/d in 2017 to 4.1 mb/d by 2023. In the subsequent years, growth slows significantly, and peak production is expected at 4.3 mb/d in the late 2020s. Production is ultimately expected to decline modestly, to 3.7 mb/d by 2040, but due to its much larger resource base, the duration and the degree of decline are substantially more modest than in other basins.

2) The **Bakken** area, centred in North Dakota, but with some spill over into Montana and Canada, was in a sense the original tight oil producing region and, before the rise of Permian tight oil production, the most prolific. It is, however, also the most mature. Thus, from 1.1 mb/d of tight crude production in 2017, output in the Bakken is projected to rise to 1.6 mb/d in 2023. This represents the high point of expected output, which means it is anticipated slightly earlier than the Permian or Eagle Ford basins. By 2040, tight crude production in the Bakken area is estimated to average 1.1 mb/d.

3) The **Eagle Ford** basin, in southern Texas, has benefited from its relative proximity to the key refining hub on Texas's Gulf Coast, and was thus able to grow very rapidly

Figure 4.18
US tight crude supply by basin



in its initial stages. However, it also took a greater hit when oil prices slumped in 2014–2016, compared to more robust production in the Permian and Bakken. From 1.1 mb/d in 2017, tight crude oil supply in the Eagle Ford is projected to rise to 2.0 mb/d in 2023, thus overtaking the Bakken as the second-largest US tight oil producing basin. Thereafter, production is expected to plateau and then gradually decline, reaching 1.4 mb/d by 2040.

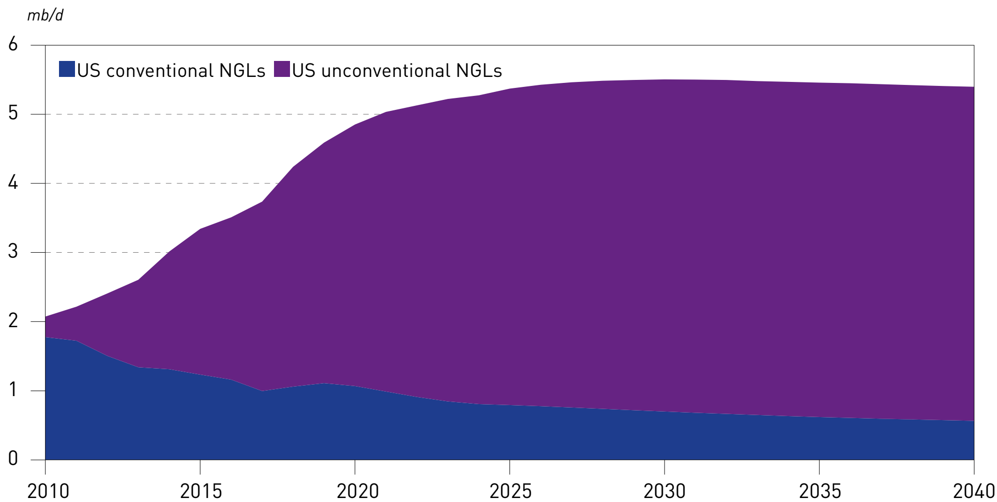
4) The **Niobrara** producing region is predominantly in northern Colorado and southern Wyoming and is expected to remain at a more modest level of tight crude output. From 0.3 mb/d in 2017, production is projected to grow to 0.8 mb/d in 2023, its peak, after which output steadily declines again. By 2040, tight crude production is projected to fall to 0.4 mb/d.

5) The '**other**' category encompasses a number of other tight oil-producing basins and regions, most of which have either only relatively small tight crude oil production levels, or are rather oriented towards tight and shale gas production (and associated NGLs). Production in this 'other' category averaged 0.3 mb/d in 2017 and is projected to rise to 0.6 mb/d in 2023. Output is expected to peak at 0.8 mb/d by around 2030 and then slowly decline to 0.6 mb/d by 2040.

US unconventional natural gas liquids

Unconventional NGLs produced from associated tight gas and shale gas assets, are a large, but less-discussed factor in overall US tight oil production. Having averaged 2.7 mb/d in 2017, they have far outstripped US conventional NGLs production, which stood at 1 mb/d in the same year. In the medium-term, unconventional NGLs supply is projected to grow to 4.4 mb/d. Unlike tight crude, output is expected to continue to grow for several years thereafter, in line with

Figure 4.19
US natural gas liquids production by type



unconventional gas, the resource base of which is basically much larger than for tight crude. As such, unconventional NGLs are set to plateau at 4.9 mb/d in the 2030s (Figure 4.19).

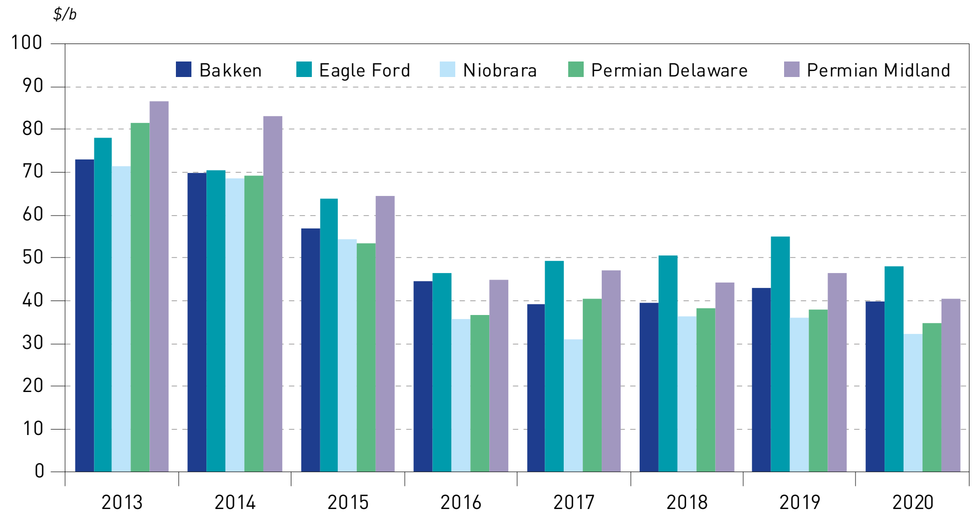
Economics of US tight oil production

The key driver of US tight oil production growth is the assumed oil price resilience in the medium- to long-term. The basic assumption is that while the price is supportive, and no other obstacles stand in its way, the US tight oil industry will ramp up production until resource constraints and natural decline levels intrinsic in tight oil production, force a peak, plateau and ultimately an output decline. Naturally, the Reference Case is subject to many assumptions and parameters, including economics, technology and regulation, which is why alternative sensitivity cases have been formulated later in this Chapter.

With oil prices having strengthened during the course of 2017 and the first half of 2018 (at the time of writing, NYMEX WTI front-month futures had averaged around $66/b in 2018 for the year-to-date), previously prohibitive average breakeven thresholds have been well surpassed, thus making continued investment in tight oil plays attractive. Importantly, this is not just true in the current price environment, but should also hold for the foreseeable future, based on the assessments by Rystad Energy, among others (Figure 4.20).

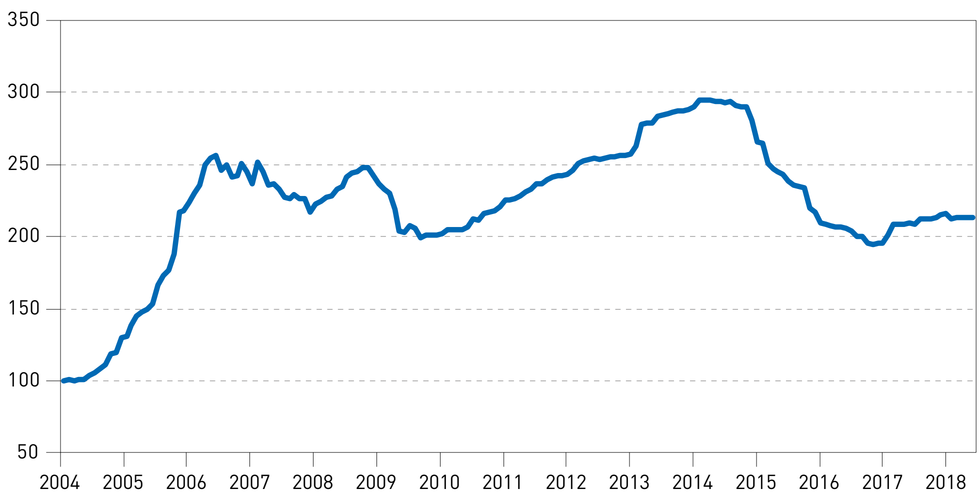
Furthermore, upstream development costs, which on average have fallen by around one-third since peaking in 2014, have so far remained contained (Figure 4.21), despite fears to the contrary. Expectations are still for service company costs to rise again eventually, but well-honed experience in drilling techniques, well spacing, multi-pad drilling, proppant choice and numerous other factors are currently holding costs in check. Interestingly, the number of active oil rigs in key US tight oil basins, after having recovered from a low reached in mid-2016, has only risen modestly since mid-2017, even while US crude oil production has surged

Figure 4.20
Evolution of wellhead breakeven prices by play



Source: Rystad Energy.

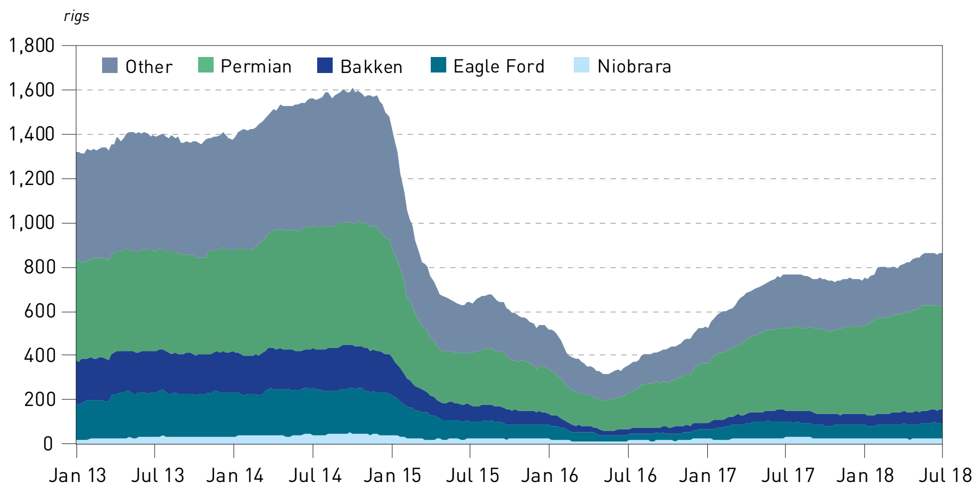
Figure 4.21
Cost of drilling oil & gas wells in US (Jan 2004 = 100)



Source: US Bureau of Labor Statistics.

(Figure 4.22). This highlights how much more efficient drilling and completion have become, as for example reflected in the US Energy Information Administration's (EIA) Drilling Productivity Report,[20] which shows production per rig in the three major basins up by around 25% on average since mid-2017.

Figure 4.22
US oil rig count by major basin



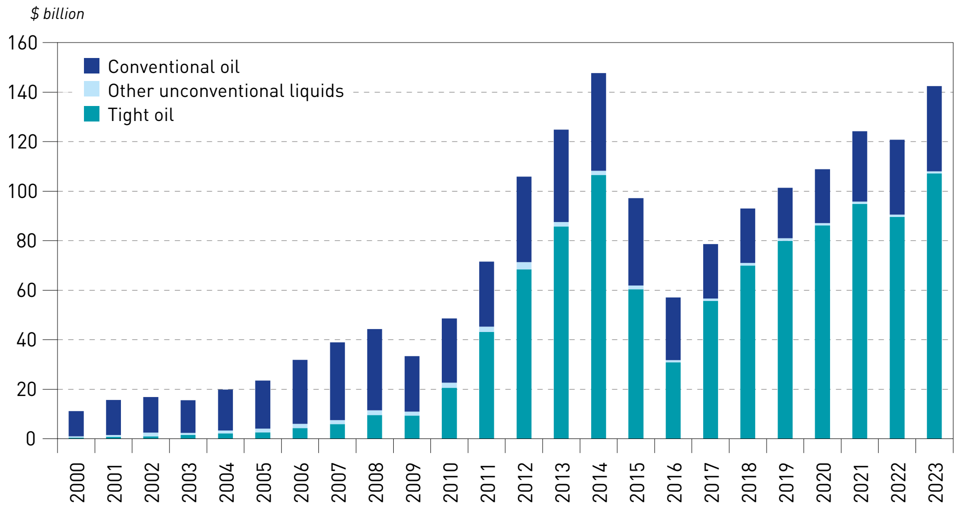
Source: Baker Hughes.

Specifically, it was assumed in the modelling that underpins this outlook, that while prices and breakeven rates remain supportive, rig counts would not increase to previous highs with the partial exception of the Permian Basin (in part because of rising productivity and a partial exhaustion of 'sweet spots' – the most attractive drilling areas). Due to significant legacy production, in the long-term, rig counts are expected to generally remain elevated, consistent with historical observations in the US upstream sector.

In line with expectations of continued improvement in production management, logistics, drilling techniques and technology advances, it was assumed that for defined, basin-specific periods, efficiency gains (in the range of 2–3% p.a.) would continue in the medium-term. Eventually this effect peaks and declines on a basin-specific basis. In a nutshell, efficiency gains peak first in the Bakken, as the most mature basin, and latest in the Permian, as the most proficient basin, but also as the one starting with the lowest productivity.

On the basis of this background, and given the assumption that prices will remain supportive, projections are for investment to continue while market conditions remain favourable. According to estimates by Rystad Energy, investment in developing US tight oil resources will rise from $56 billion in 2017 to $107 billion in 2023, or by an average of 12% p.a. (Figure 4.23).

Figure 4.23
US upstream investment by type of liquids



Source: Rystad Energy.

Importantly, this is set to happen despite a recent shift towards companies imposing 'capital discipline over growth', after many active in the US tight oil sector had long had a negative cash flow. However, this is to some extent balanced by new entrants to the sector, including cash-rich majors, and private equity investors. Moreover, at current and assumed price levels, existing players in the US tight oil sector have become increasingly profitable, allowing for further investment.

Resource base

Naturally, the resource base is also a factor in determining the future production profile for US tight oil, and others too. While the US EIA, in its most recent assessment, lists 32.7 billion barrels of proven reserves for the end-2016,[21] the more useful assessments are those for total recoverable resources, so a looser-defined estimation of technically recoverable barrels, yet not tied to specific technologies or price.

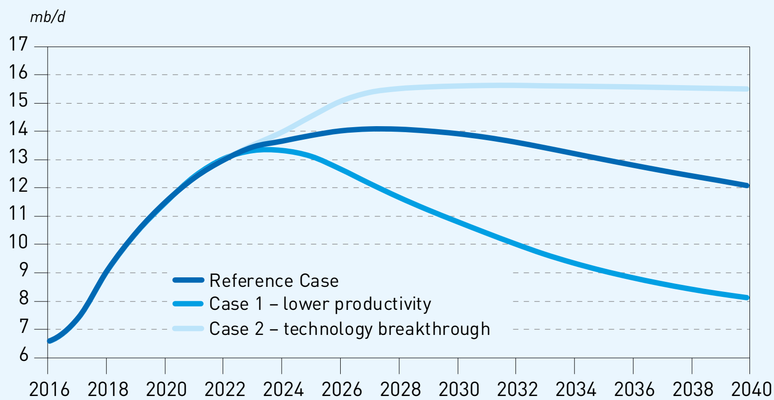
In its most recent assessment, Rystad Energy estimates that total US recoverable resources were some 323 billion barrels at the end of 2017, albeit including 79 billion barrels of 'prospective

Box 4.1

US tight oil production sensitivities

Given its rapid rise over the past ten years, and considering the speed at which tight oil production can be adjusted, due to its short-cycle nature, it is inevitable that there is a certain degree of uncertainty surrounding any US tight oil supply projections. Therefore, two sensitivity exercises have been developed, giving an indication of the range, pattern and timing of alternative production outcomes for US tight oil. The result is sharply different trajectories and outcomes for US tight oil production, with a range of around +/– 1–2 mb/d by its Reference Case peak in 2027, and as much as +/– 3–4 mb/d by 2040 (Figure 1).

Figure 1
US tight oil production – sensitivities *(mb/d)*



Case 1 – lower productivity

The first sensitivity is based upon the assumption that, in contrast with the Reference Case (and a widely-held consensus), projections of continued steady productivity gains in US tight oil production turn out to be erroneous. Despite a substantial overall resource base, in this sensitivity case companies soon begin to run out of the highest-quality drilling locations, often called 'sweet spots' or Tier-1 acreage.

To demonstrate this lower productivity sensitivity case, the assumption was made that productivity parameters in the underlying model plateau in the course of 2019, decline in the medium-term, and then gradually accelerate throughout the longer term outlook. While prices remain supportive, rig counts are increased modestly versus the Reference Case, as even while wells are no longer as productive, it is still economic to drill. However, rig counts remain flat in the latter half of the 2020s and decline in the long-term.

The result of this sensitivity is that overall US tight oil production peaks earlier, in 2023–2024, at a lower level of 13 mb/d, compared to the Reference Case peak of 14.1 mb/d in 2027–2028. Thereafter, the decline trajectory is steeper, with output hitting 8.1 mb/d by 2040, some 4 mb/d lower than the Reference Case.

Case 2 – technology breakthrough

This upward sensitivity assumes a significant and disruptive breakthrough in upstream technology related to tight oil production. This would by its nature be a medium- to longer term development. Thus, an accelerated increase in productivity is assumed from around 2023 and continues for some years, after which it remains high throughout the forecast period. Rig counts are assumed broadly unchanged *vis-à-vis* the Reference Case. However, decline rates are adjusted slightly higher.

The outcome of this sensitivity is a further rise in US tight oil production to top out at around 15.6 mb/d in the early 2030s, which is 1.5 mb/d higher than the Reference Case peak. Rather than much higher overall output, the more striking impact is on long-term production, which essentially stays flat throughout the remainder of the forecast period, rather than going into decline as in the Reference Case and the lower productivity sensitivity. Or to put it another way, the effect is to increase the volume of oil that can be ultimately recovered. This analysis suggests that recoverable resources would have to be some 30–40 billion barrels higher to ensure a sustainable production profile in the long-term, based upon the outcome of this 'technology breakthrough' sensitivity.

unawarded' volumes. Even without this, total recoverable resources amount to some 244 billion barrels, a significant volume. This report's projections take all this resource base into account.

Uncertainties & risks

In the short-term, possibly the most significant constraint to further strong growth in US tight oil production may be posed by pipeline and other offtake infrastructure, especially in the Permian Basin area. At the time of writing, any potential bottlenecks were not evident in data on physical flows, whether that is production, refining or exports, but a recent unusually wide discount for West Texas crude prices relative to Gulf Coast or international benchmarks is seen by many as a reflection of such a constraint.

However, at the same time, discounts of $10/b or more for Permian crude is enabling and increasing volume to be railed to refining hubs. In some instances, trucking may be an option to deal with short-term bottlenecks.

In theory, modest domestic demand growth, and a limit on how much light sweet crude from tight plays that US refiners may be willing to run, could also prove constraints on further production growth. Most projections assume that the bulk of new US tight oil will, therefore, be exported (as evident in rising crude export flows, which averaged 1.8 mb/d in the first half of 2018, up by 0.8 mb/d y-o-y). As a result, pipeline infrastructure, storage and loading facilities to facilitate higher exports from the US Gulf Coast are being developed.

But most consider that domestic infrastructure constraints will at most be a relatively short-term issue, given plans to build several new pipelines that are due to be commissioned in 2019. Consultancy IHS Markit for instance anticipates a brief period in 2019 in which offtake capacity will be full, after which new infrastructure takes off, including the new EPIC, Cactus 2 and Gray Oak pipelines.

Given the huge volumes of natural gas being produced in conjunction with oil in the US tight oil sector, a lack of gas offtake infrastructure may also be a temporary constraint. However, again, new lines to Mexico and to coastal LNG export terminals are being constructed, and the flaring of excess gas also remains a temporary stop gap.

In the longer term, any combination of lower prices, higher costs, significant changes to the fiscal or regulatory framework, or a strong economic downturn could negatively affect US tight oil production. As the sector grows ever-larger, questions are being raised again about possible constraints on skilled and semi-skilled labour, sourcing of sand and water, recycling/disposal of water and other waste liquids.

4.3.2 Tight oil developments outside of the US

Outside of the US, Canada remains the only country that currently has meaningful tight oil production. Its collective output of tight crude and unconventional NGLs is expected to rise from

Table 4.12
Global medium-term tight liquids supply *(mb/d)*

	2017	2018	2019	2020	2021	2022	2023	Change 2017–2023
US	4.68	5.92	6.91	7.67	8.27	8.72	9.02	4.34
Canada	0.33	0.35	0.38	0.40	0.43	0.45	0.46	0.13
Russia	0.00	0.00	0.00	0.00	0.02	0.05	0.10	0.10
Argentina	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.03
Total tight crude	**5.04**	**6.31**	**7.33**	**8.13**	**8.77**	**9.27**	**9.65**	**4.60**
US	2.74	3.18	3.53	3.83	4.10	4.27	4.43	1.69
Canada	0.24	0.26	0.28	0.30	0.32	0.33	0.34	0.10
Russia	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Argentina	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.01
China	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02
Total unconventional NGLs	**3.00**	**3.46**	**3.83**	**4.17**	**4.45**	**4.65**	**4.83**	**1.83**
Total tight liquids	**8.04**	**9.77**	**11.16**	**12.29**	**13.22**	**13.92**	**14.47**	**6.43**

0.6 mb/d in 2017 to 0.8 mb/d in 2023. Russia and Argentina will both see total medium-term tight liquids output rise to around 0.1 mb/d.

Thus, in the medium-term, global tight liquids is estimated to rise from 8 mb/d to 14.5 mb/d by 2023, up from 14% to a substantial 22% of total non-OPEC supply in the medium-term. Of this, tight crude will rise to 9.6 mb/d by 2023, and unconventional NGLs to 4.8 mb/d (Table 4.12).

In the long-term, and largely driven by the US, global tight oil supply is expected to peak in 2028 at 15.6 mb/d. It slowly declines thereafter, averaging a still-sizeable 13.8 mb/d in 2040. Besides the US, which provides the bulk of supply, Canada, Russia and, to a lesser extent, Argentina, emerge as meaningful producers (Table 4.13).

This report, meanwhile, now projects some small volumes of tight crude in Bahrain, after the discovery of large resources offshore – though development will largely take place from the mid-2020s. In China, meanwhile, it is assumed that the country sees the emergence of small unconventional NGL output, as tight and shale gas production is gradually developed.

Table 4.13
Global long-term tight liquids supply

(mb/d)

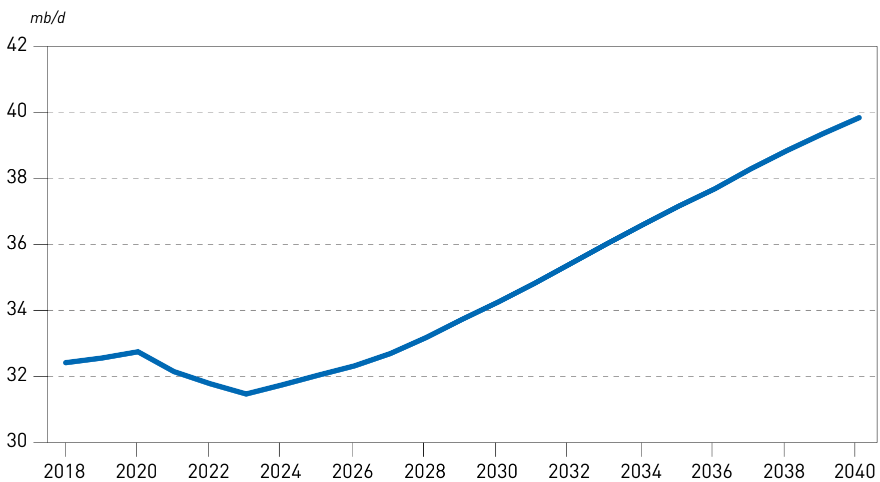
	2017	2018	2019	2020	2025	2030	2035	2040	Change 2017–2040
US	4.68	5.92	6.91	7.67	9.22	9.06	8.13	7.20	2.52
Canada	0.33	0.35	0.38	0.40	0.50	0.54	0.53	0.50	0.20
Russia	0.00	0.00	0.00	0.00	0.22	0.33	0.37	0.39	0.37
Argentina	0.03	0.04	0.04	0.05	0.07	0.13	0.25	0.27	0.22
Bahrain	0.00	0.00	0.00	0.00	0.04	0.10	0.10	0.10	0.10
Total tight crude	**5.04**	**6.31**	**7.33**	**8.13**	**10.06**	**10.17**	**9.37**	**8.46**	**3.40**
US	2.74	3.18	3.53	3.83	4.63	4.85	4.89	4.88	2.15
Canada	0.24	0.26	0.28	0.30	0.36	0.37	0.35	0.33	0.11
Russia	0.00	0.00	0.00	0.00	0.03	0.04	0.05	0.06	0.05
Argentina	0.02	0.02	0.02	0.02	0.03	0.04	0.05	0.05	0.03
China	0.00	0.00	0.00	0.01	0.03	0.06	0.06	0.06	0.06
Total unconventional NGLs	**3.00**	**3.46**	**3.83**	**4.17**	**5.07**	**5.37**	**5.39**	**5.37**	**2.40**
Total tight liquids	**8.04**	**9.77**	**11.16**	**12.29**	**15.13**	**15.53**	**14.77**	**13.83**	**5.80**

4.4 Demand for OPEC crude

The implied medium-term demand for OPEC crude[22] declines from 32.6 mb/d in 2017 to 31.6 mb/d in 2023 (Figure 4.24). From 2017–2018 levels of around 32.5 mb/d, demand rises marginally, to reach a peak of 32.7 mb/d in 2020, surging temporarily due to new IMO shipping regulations (and a short-lived run of more crude in the global refining system). But thereafter, declining demand for OPEC crude is a result of strong non-OPEC supply in the 2017–2023 period, most notably from US tight oil, in addition to some other sources.

Demand for OPEC crude only returns to 2017 levels by the late 2020s, when US tight oil peaks, and rises steadily thereafter. By the end of the forecast period in 2040, demand for OPEC crude is projected to average nearly 40 mb/d. The share of OPEC crude in the global oil supply is expected to increase from 34% in 2017 to 36% by 2040.

Figure 4.24
Long-term demand for OPEC crude oil

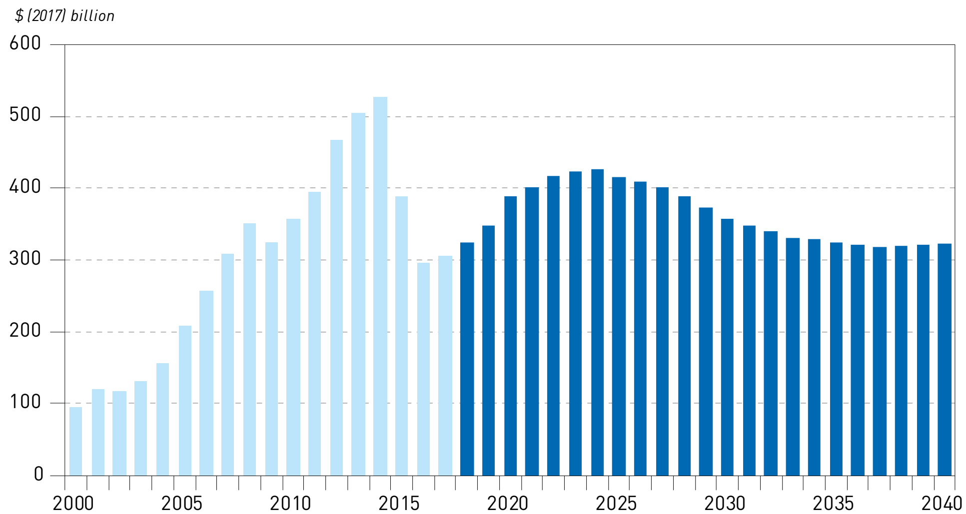


4.5 Upstream investment

Global upstream capital expenditures increased sharply in the early 2000s, as crude prices rose and global oil demand was robust. This upward trajectory continued in the subsequent years and according to Rystad Energy, reached a peak in 2014 with upstream investment at a level of $527 billion (in real terms). However, after crude oil prices fell sharply from mid-2014, upstream capital expenditure plummeted by 26% y-o-y in 2015. In 2016, it shrank by a further 24% y-o-y (Figure 4.25).

The current discussion around a perceived lack of global upstream investment is based upon the concern that this will inevitably – with a time lag – lead to a shortfall in new oil supply

Figure 4.25
Annual global upstream capital expenditure, historical and future requirements



Source: Rystad Energy (historical, adjusted for inflation), OPEC (projection).

coming online. The argument is often made that while US tight oil may provide all the new barrels needed to match rising short-term demand, a disproportionate focus on investing in this sector and so-called 'short-cycle' production will unavoidably lead to a shortfall in investments in 'long-cycle' projects to maintain non-OPEC supply.

To underpin this argument, it is often highlighted that natural decline rates in post-peak producing fields, which typically average from 3–7%, mean that several millions of barrels per day of production need to be replaced annually, in addition to barrels required to meet growing demand. Proponents of this view tend to warn of an impending supply 'shortfall' or 'crunch' sometime in the early 2020s. Moreover, headlines about divestment from fossil fuels by some pension funds, investment banks, as well as the World Bank, have in many cases been interpreted as confirmation of a more widespread trend.

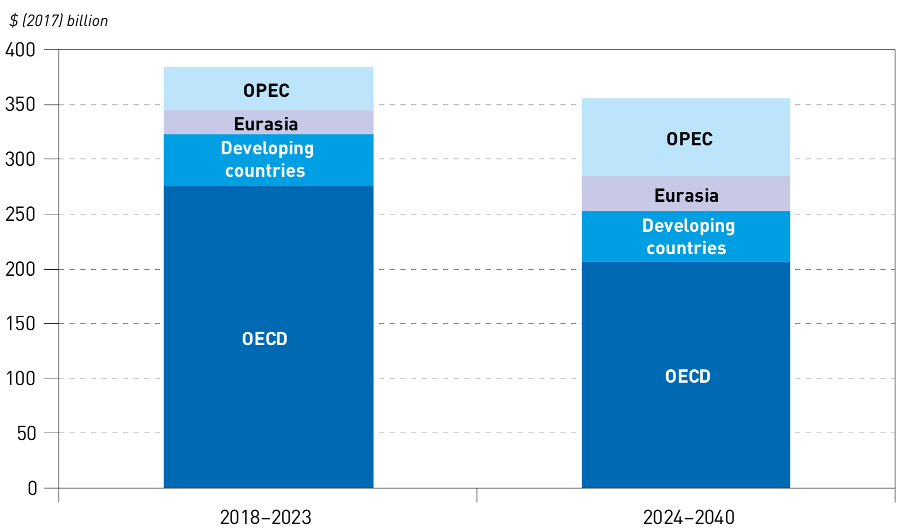
However, the counter argument to this is that global upstream investment rose again in 2017 (by 5%) and is forecast to continue to rise in the medium-term (6% p.a. on average in the period 2018–2023). Furthermore, it can be argued that absolute levels of upstream investment in 2012–2014, in particular, were abnormally high, and thus do not serve as an appropriate comparison baseline. After all, investment in 2017 is roughly similar to investment levels ten years earlier, and thus is much more than was invested in the years prior.

Furthermore, there is no direct one-to-one conversion of investment volumes into barrels of oil production. After all, non-OPEC production grew at a reasonable pace in the early 2000s when absolute levels of global upstream capital expenditure were far lower than in recent years (<$100 billion p.a.). Nor is there any sign so far of the 2015–2016 dip in upstream investment spending having an impact on current non-OPEC supply growth, barring a short-lived dip in output in 2016.

The required investment sums are a function of oil price, type of asset, cost, efficiency in the implementation of an upstream project, as well as many other factors. Due to the fact that, for instance, upstream costs have also come down sharply since 2014 – and more importantly, remained low – the cost of developing new barrels has effectively fallen. This report assumes that if prices are supportive, investments will follow, and will be sufficient to ensure that supply matches demand, at least in the medium-term.

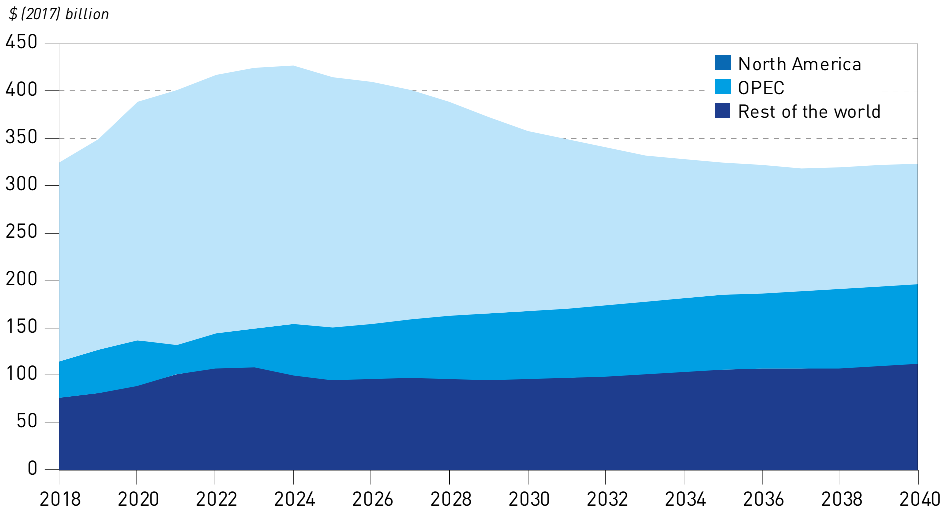
In the longer-term, upstream capital expenditure will need to be sustained in order to ensure steady growth in supply to meet the projected rise in demand, in addition to investment required to offset natural oil field declines. On average, this is projected to be around $384 billion p.a. in the medium-term period, and to decline modestly to an average $356 billion p.a. in the longer term (Figure 4.26).

Figure 4.26
Annual upstream investment requirements



Two trends are worth highlighting: First of all, the relative geographical shares of required investment, based upon the detailed projections underpinning this report, show that the overwhelming majority of investment will take place in OECD countries, at around 72% in the medium-term, although it declines to 58% in the long-term. In turn, this is skewed by the relative significance of North America in contributing supply capacity growth, especially in the medium-term, as well as the comparatively high cost of developing upstream US production (tight oil; deepwater) and Canada (oil sands). North America's share of required upstream medium-term investment is estimated to average 65% and a more modest 50% over the course of the longer term until 2040, albeit gradually tailing off towards the end of the forecast period (Figure 4.27).

Figure 4.27
Annual upstream investment requirements by major region



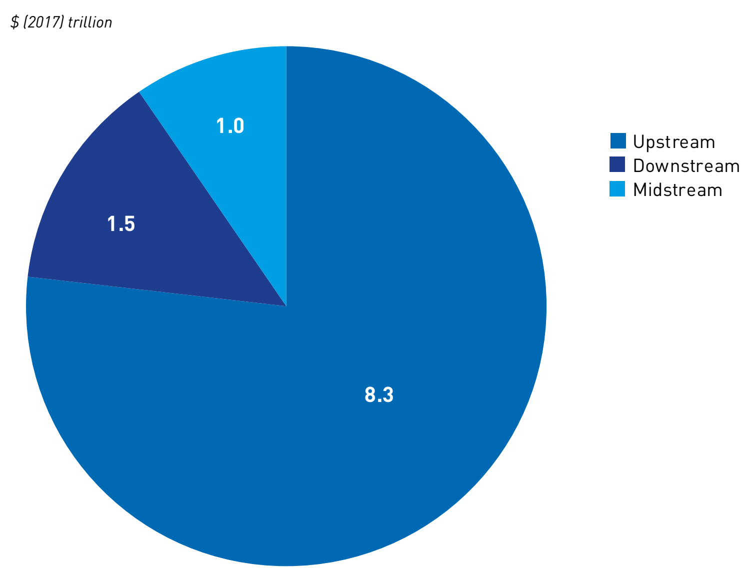
Secondly, overall volumes decline quite substantially over time, which is a function of OPEC Member Countries' growing role in ensuring future supply, and their relatively lower upstream development costs. By comparison with the OECD (including North America), OPEC's collective share of required upstream investment is much lower, at an average 10% in the medium-term, rising to just over 20% in the 2024-2040 period. Required upstream investment in the rest of the world, by comparison, is quite steady in absolute terms, at around $100 billion p.a., even while its share is estimated to rise from around 25% in the medium-term, to 30% in the long-term.

Given these numbers, there are some who ask the question: Will this upstream investment be forthcoming? Notably, these upstream investment requirements suggest that capital expenditure – despite the need to rise in the medium-term to support this period's high-cost surge in US tight oil – on average is quite substantially below the record-high investment levels seen in the 2012–2014 period. In fact, average upstream investment requirements for the entire

2018–2040 period are broadly on a par with spending in the late 2000s, before US tight oil growth began to really take off.

Cumulatively, total required upstream capital expenditure related to oil amounts to $8.3 trillion. In addition to this, it is projected that downstream capacity additions will require another $1.5 trillion (more details provided in Chapter 5.4), while midstream investments will necessitate another $1 trillion of investment globally. Therefore, global oil-related investment requirements for the entire 2018–2040 period are estimated to be nearly $11 trillion (Figure 4.28). This will require a supportive price environment, as well as the necessary regulatory and fiscal framework, to facilitate this necessary investment, in order to guarantee that future oil demand needs are met by sufficient supply.

Figure 4.28
Cumulative oil-related investment requirements by sector, 2018–2040



Refining outlook

Key takeaways

- Distillation capacity additions between 2018 and 2023 are projected at around 7.8 mb/d, located mostly in developing countries.
- More than 70% of the distillation capacity additions are expected in the Asia-Pacific and the Middle East. The Middle East is projected to add 2.3 mb/d in the medium-term, China, 1.6 mb/d and other Asia-Pacific, 1.7 mb/d.
- Potential incremental crude runs are estimated at around 7.4 mb/d (after consideration of availability and debottlenecking additions) in 2023, which is almost 2.5 mb/d higher relative to the demand increment of 4.9 mb/d.
- While refining capacity additions are in line with the demand increase between 2018 and 2020 (additionally due to IMO sulphur regulations), the gap opens from 2021 onwards.
- Largest excess builds seen in the US & Canada, Europe, due to decreasing demand post-2020, and the Middle East, due to strong medium-term capacity additions. At the same time, some deficits are projected for Latin America and the Asia-Pacific (excluding China) in the last year of the medium-term.
- Total distillation capacity additions in the period 2018–2040 are projected at 17.8 mb/d, again led by developing regions. Around 65% of the long-term additions are expected to occur in the Asia-Pacific and the Middle East. Africa will also likely have a significant share in terms of additions, accounting for around 16% globally.
- Refinery closures have slowed due to a number of closures that have occurred in the recent years. Estimated refinery closures for the period 2018-2023, based on announcements, is around 1 mb/d, predominantly in Europe and the US & Canada.
- In the long-term, further closures will be needed, especially in developed regions as refinery utilization drops in line with decreasing demand. A total of around 6 mb/d of refining capacity should be closed in the long-term in order to maintain the efficient overall level of refinery operations.
- Additions of secondary refining capacity in the medium-term are estimated at 3.3 mb/d for conversion units, 6.7 mb/d for desulphurization units and just under 2 mb/d for octane units. In the long-term, secondary capacity additions are projected at 10.5 mb/d for conversion, 20 mb/d for desulphurization and 5.5 mb/d for octane.
- In the medium-term, the IMO sulphur regulations will be the major challenge for the refining sector, including uncertainties regarding the bunker fuel mix from 2020 and the resulting impact on crude price spreads and product cracks. The potential restarts of some mothballed units could relax the projected market tightness to some extent.

Chapter 5 takes the Reference Case supply and demand projections and examines how various factors could impact the global refining sector over the medium- and longer term. It first presents the assessment of current 'base' capacity, projects, announced and further anticipated closures. Combining these three components leads to an assessment of net available capacity by year from 2018–2023, which is the medium-term period. The Chapter then compares the projected additions to capacity by year from 2018–2023 with the incremental 'call on refining' each year as driven by product demand growth, in order to assess the balance between incremental refining capability and the incremental refining required. In order to arrive at the net 'call on refining', this analysis takes into account the OPEC Reference Case output on non-crude supply – that is, NGLs, GTLs/CTLs and biofuels. Increases in these supply streams reduce the level of incremental refinery products needed. The resulting global and regional balances are presented and reviewed.

The Chapter also presents the long-term outlook based on the World Oil Refining Logistics and Demand (WORLD) modelling cases from 2020–2040. Compared to the medium-term assessment, this represents a somewhat different approach. In the long-term modelling, required capacity is added to accommodate changes in supply and demand (including crude and product quality), while also allowing for options to change crude and product trading patterns between regions.

This Chapter also assesses the medium- and long-term outlook for secondary capacity. The main emphasis is on conversion, desulphurization and octane units. The focus for the medium-term assessment (2018–2023) is on directly comparing secondary process unit capacity additions and potential yields with incremental demand by product at the regional level. The long-term assessment draws from the exact same WORLD model cases, but with the emphasis on the secondary unit additions and investments needed to meet incremental demand and product quality requirements given changes in the crude slate and non-crude supply. In addition, it also allows opportunities for trade – and shifting trade patterns – between regions.

This analysis serves to provide a Reference Case outlook for the global downstream and its 'strategic parameters' through 2040, as well as examining what factors could affect and alter the outlook.

As set out in Annex C, the WORLD model represents the world as 23 regions, which are aggregated into seven regions[23] for reporting purposes.

5.1 Existing refinery capacity

5.1.1 Overview

This section provides a detailed update to base capacity assessments (distillation and secondary capacity) by refinery worldwide. It includes additions to existing refineries, as well as new refineries that have come onstream and the closures that occurred in 2017.

Table 5.1 compares the January 2018 base capacity of 99.0 mb/d estimated in this Outlook with assessments from other organizations. In terms of the global total, the latest assessment of base capacity is very close to that of the IEA (98.7 mb/d) in its 'Oil 2018' medium-term outlook from February 2018. Appreciably lower, at 98.1 and 98.0 mb/d, respectively, are the latest assessments by BP and IHS Markit.

Table 5.1
Global refinery base capacity per different sources

mb/d

Source and date of assessment / publication	Reference date	mb/d[4]
Assessments made in 2018		
OPEC World Oil Outlook, 2018	Jan 2018	99.0
IEA Oil 2018, February 2018[1]	2017[2]	98.7
BP Statistical Review, June 2018	2017[3]	98.1
IHS, April 2018	Jan 2018	98.0

(1) Previously named the Medium-Term Oil Market Report (MTOMR).
(2) Not stated whether beginning or end of year; presumed end of year.
(3) Explicitly stated end of year.
(4) Per calendar day.

For the OPEC WOO 2018, the net additions versus January 2017 are at 1.6 mb/d. The main driver of this change is new capacity of close to 1 mb/d coming onstream during 2017, as well as upward revisions to the installed base capacity, plus some changes to partial and full refinery closures, based on a detailed refinery-by-refinery review.

A key takeaway is that the assessment of refinery base capacity is not a straightforward activity, hence the variability. Critically, no one data source can be relied upon entirely. Rigorous refinery-by-refinery research is necessary to increase the accuracy of any efforts to properly assess distillation and secondary capacity at the regional and global level. Since the accuracy and timeliness of capacity reporting varies by refinery, there is always an element of arriving at a 'best estimate' for base capacity, and for projects and closures. One important factor can be how temporarily shut-in refineries are treated. OPEC's approach is that, unless officially closed, refineries are included in the database of 'nameplate' capacity, though their effective availability may be identified in the WORLD modelling as being well below nameplate level, where appropriate.

5.1.2 Refinery capacity in 2018

This section summarizes the estimated 2018 base capacity as developed and applied in the WORLD model cases (Table 5.2). At the global level, today's refineries are increasingly 'complex' with expanding secondary processing capacity per barrel of primary distillation. This trend has been supported by two factors: firstly, the long-term shift toward incremental product demand, and, therefore, supply, comprising predominantly light clean products and an associated gradual decline in demand for residual fuel oil and, secondly, progressively more stringent regulations on fuel quality, notably the drive toward low and ultra low sulphur (ULS) standards for gasoline and diesel.

Together, these call for higher levels of upgrading, desulphurization, octane and related supporting capacity including hydrogen and sulphur recovery. Thus, base levels of secondary capacity are now substantial. As a percentage of crude (atmospheric) distillation capacity, vacuum distillation stands at an average of 38.5% globally, upgrading at just over 41%, gasoline octane units at 19% and desulphurization at 62%.

However, as Table 5.2 illustrates, regional differences on both distillation and secondary capacity are large. Global refining distillation capacity was estimated at 99.0 mb/d as of 1 January 2018. Of this, the US & Canada and Europe still comprise significant proportions, respectively at 20.5 mb/d and 16.6 mb/d of capacity, or 20.7% and 16.7% of the global total. In the US & Canada, total capacity has edged up in recent years, supported by increasing domestic oil supply, even though ongoing rationalization has reduced the total number of refineries in operation.

Table 5.2
Assessed available base capacity as of January 2018

mb/d

	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific	World
Distillation									
Crude oil (atmospheric)	20.5	8.1	4.2	16.6	7.1	9.1	14.8	18.7	99.0
Vacuum	9.4	3.6	1.1	6.6	2.9	2.8	6.1	5.7	38.1
Upgrading									
Coking	2.8	0.8	0.1	0.8	0.4	0.4	2.1	1.1	8.4
Catalytic Cracking	6.0	1.6	0.3	2.3	0.7	0.9	3.4	2.8	18.0
HydroCracking	2.4	0.2	0.2	2.1	0.5	0.9	1.6	1.5	9.4
Visbreaking	0.1	0.4	0.2	1.6	0.6	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
Gasoline									
Reforming	3.9	0.7	0.5	2.5	0.9	1.0	1.3	2.5	13.4
Isomerization	0.8	0.1	0.1	0.6	0.3	0.4	0.2	0.2	2.7
Alkylation	1.3	0.2	0.0	0.2	0.0	0.1	0.0	0.3	2.2
Polymerization	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1
MTBE/ETBE	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.3
Desulphurization									
Naphtha	4.8	0.9	0.6	3.3	1.1	1.6	1.3	3.1	16.5
Gasoline	2.9	0.5	0.1	0.6	0.2	0.3	0.8	1.0	6.5
Middle Distillates	6.7	2.1	0.8	5.8	1.9	2.4	3.4	5.8	28.9
Heavy Oil/Residual Fuel	3.0	0.4	0.0	1.8	0.2	0.5	0.5	2.5	9.0
Sulphur (short tons/day)	42,846	7,208	3,634	19,755	6,161	11,852	12,431	29,221	133,108
Hydrogen (million scf/d)	6,548	1,235	407	4,719	893	2,544	4,106	5,017	25,469

In Europe, rationalization has entailed reductions in both the total number of active refineries and the total operating capacity.

Meanwhile, capacity in the Asia-Pacific has been steadily increasing to the level of the US & Canada plus Europe, supported by the region's strong oil demand growth. Capacity for the region now totals 33.5 mb/d (33.9%), with China accounting for 14.8 mb/d (15%). The increase in total Asia-Pacific refining capacity occurred despite the fact that capacity in Japan and Australia has been declining due to extensive closures in those two countries. At the same time, Middle East capacity has witnessed a similar trend, rising from around 6.7 mb/d in 2000 to 9.1 mb/d as of January 2018. Taken together, these regions accounted for 43% of global capacity at the beginning of 2018.

Table 5.3 expresses the data from Table 5.2 as percentages of crude distillation capacity. The table highlights the variations in refinery configurations from region-to-region. On the three measures of upgrading, gasoline and desulphurization relative to distillation, the US & Canada represents the high end extreme and Africa is at the low end.

Within the upgrading category, the distribution by type of unit varies significantly. The US & Canada, Latin America and China account for the highest levels of coking and catalytic cracking, whereas the US & Canada, Europe and China have the highest levels of hydrocracking and Europe, the Russia & Caspian and the Middle East the highest proportions of relatively mild upgrading (i.e. visbreaking).

With regard to desulphurization and associated sulphur recovery, the regions that have fully implemented ULS gasoline and diesel standards have the highest levels relative to crude capacity. Notably, the proportions of desulphurization and sulphur recovery are also high in the Middle East with its advancing sophisticated capacity and the need to process primarily sour crudes.

5.2 Distillation capacity

5.2.1 Overview of additions and trends

The pace and the location of refinery investments continue to follow trends in oil demand growth. Consequently, the majority of investments are expected in developing countries, underpinned by local demand. The level of medium-term additions and investments are seen as continuing to recover from the effects of the 2014–2016 crude oil price drop. From levels of no more than 1 mb/d p.a. for 2016 through 2018, additions for 2019 through 2021 are projected to average 1.6 mb/d p.a. before reverting again to the 1 mb/d level in 2022 and 2023.

Over the whole six-year, medium-term period, total additions are projected at 7.8 mb/d. Overall, the industry is maintaining a 'typical' rate of additions of around 1.2–1.3 mb/d annually. This is occurring despite significant year-to-year variations. A detailed breakdown of the capacity additions projected for 2018–2023 is presented in Figure 5.1 and Table 5.4. These do not account for potential capacity closures or for the additional capacity achieved through minor 'creep' debottlenecking, which are taken into account and discussed separately.

Table 5.3
Secondary capacity relative to distillation capacity as of January 2018

	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific	World
					%				
Crude distillation (% of global capacity)	20.7	8.1	4.2	16.7	7.1	9.2	15.0	18.9	100.0
Vacuum % of crude distillation	45.7	44.5	25.4	40.1	41.3	30.7	41.0	30.3	38.5
Upgrading	**57.6**	**38.6**	**16.2**	**41.5**	**30.4**	**32.0**	**49.0**	**32.5**	**41.3**
Coking	13.8	10.0	2.0	4.6	5.5	3.9	13.9	5.8	8.4
Catalytic Cracking	29.2	20.2	6.1	13.9	10.3	10.1	22.7	15.2	18.2
HydroCracking	11.8	2.9	3.9	12.6	6.4	9.8	11.0	8.1	9.5
Visbreaking	0.7	4.7	4.1	9.5	7.8	6.2	1.0	2.9	4.1
Solvent Deasphalting	2.1	0.9	0.2	0.9	0.3	2.1	0.4	0.5	1.0
Gasoline	**29.2**	**13.4**	**14.2**	**21.3**	**18.1**	**18.0**	**10.5**	**16.5**	**18.9**
Reforming	18.8	8.4	11.8	15.3	13.3	11.4	8.7	13.6	13.5
Isomerization	3.8	1.7	1.4	3.8	4.3	4.8	1.1	1.1	2.8
Alkylation	6.1	2.8	0.8	1.4	0.3	1.4	0.3	1.5	2.2
Polymerization	0.3	0.1	0.1	0.3	0.0	0.1	0.0	0.1	0.1
MTBE/ETBE	0.1	0.5	0.0	0.4	0.2	0.3	0.4	0.2	0.3
Desulphurization	**85.2**	**47.5**	**36.7**	**69.6**	**48.1**	**52.9**	**40.3**	**66.3**	**61.6**
Naphtha	23.4	10.6	14.0	19.6	15.4	17.5	8.7	16.4	16.7
Gasoline	14.4	6.0	2.4	3.8	2.4	3.0	5.6	5.6	6.5
Middle Distillates	32.6	26.3	19.5	35.1	27.1	26.4	22.7	30.9	29.2
Heavy Oil/Residual fuel	14.8	4.6	0.8	11.1	3.2	6.0	3.3	13.4	9.1
					ratio				
Sulphur (short tons/day) ratio to crude	2,094	895	865	1,193	872	1,300	839	1,564	1,345
Hydrogen (million SCFD) ratio to crude	320	153	97	285	126	279	277	269	257

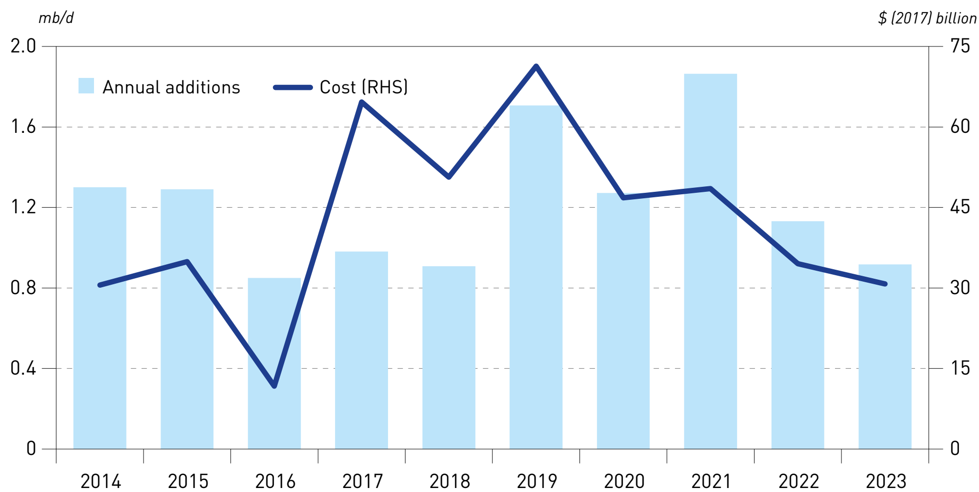
As emphasized in previous outlooks, a degree of circumspection is required when elaborating the medium-term outlook for capacity additions from known refining projects. The tendency is for refinery projects to 'slip', due to various reasons, including financing and technical problems. This is why the project evaluation process undertaken annually entails a 'risking' of both the probability of, and the timeframe for, completion. Some of the high-profile projects that had previously slipped beyond the medium-term periods of prior Outlooks are now slated for completion within the 2018–2023 timeframe. Overall, 7.8 mb/d[24] of refining capacity are considered 'firm' within the 2018–2023 timeframe, which compares to a much higher volume of announced projects of around 22 mb/d.

With regard to the circumstances surrounding the 2018–2023 period, it is possible, but relatively unlikely, that major new refinery projects will emerge that could be expected to be onstream by, or before 2023. Most likely any new, as yet unannounced, projects that could be onstream by, or before 2023, would be revamps and single unit additions, such as for a refinery debottleneck, coker or hydrocracker. Again, for any such new projects to be brought online by 2023, they would likely have to be in Asia where construction times can be relatively short. On the other side of the 'ledger', additional project cancellations or delays (to beyond 2023) could still be forthcoming, depending on oil price developments and demand levels.

Another factor that now looms large in the medium-term outlook is the decision by the IMO in October 2016 to proceed with the MARPOL Annex VI sulphur regulations in January 2020. The regulations have been cited as a justification for a small number of recent projects and could potentially lead to more. It is too late, though, for these projects to have much impact on new capacity that could be brought online by 2020.

However, the response to this regulation could materially impact the situation beyond 2020. One key factor will be whether or not the shipping industry decides to broadly adopt on-board

Figure 5.1
Annual distillation capacity additions and total projects investment

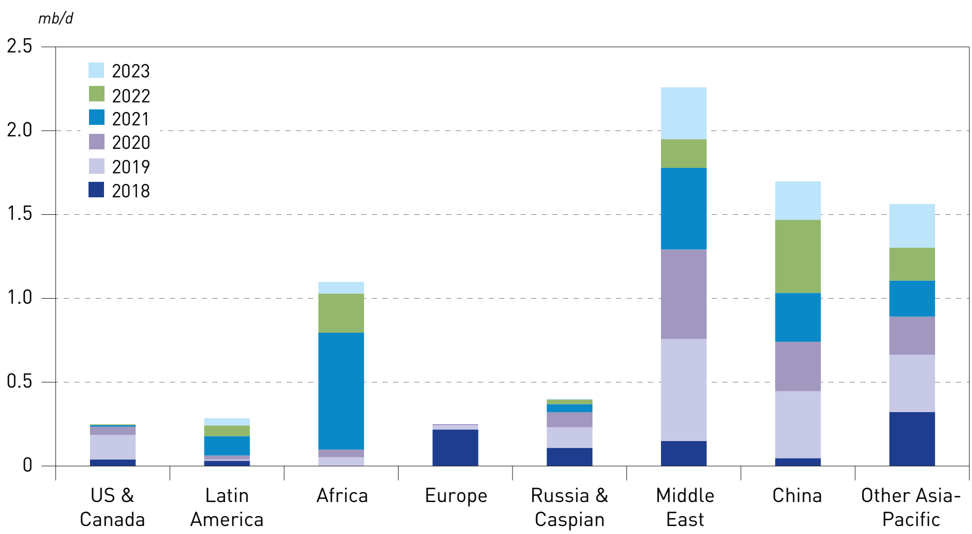


exhaust gas cleaning systems (scrubbers). To the extent it does, demand for high-sulphur marine fuel will be sustained, reducing the burden on the refining sector to produce 0.5% fuel – and vice versa. Arguably, the prospect that the shipping sector could widely adopt scrubbers

Table 5.4
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
2018	0.0	0.0	0.0	0.2	0.1	0.1	0.0	0.3	0.9
2019	0.1	0.0	0.1	0.0	0.1	0.6	0.4	0.3	1.7
2020	0.0	0.0	0.0	0.0	0.1	0.5	0.3	0.2	1.3
2021	0.0	0.1	0.7	0.0	0.0	0.5	0.3	0.2	1.9
2022	0.0	0.1	0.2	0.0	0.0	0.2	0.4	0.2	1.1
2023	0.0	0.0	0.1	0.0	0.0	0.3	0.2	0.3	0.9
2018–2023	**0.2**	**0.3**	**1.1**	**0.2**	**0.4**	**2.3**	**1.7**	**1.6**	**7.8**

Figure 5.2
Distillation capacity additions from existing projects, 2017–2023



acts as a deterrent to refiners to invest due to the regulations because of the risk that investments could be 'stranded' should scrubbers succeed.

One further caveat to this projection, which was also raised in previous WOOs, remains in place – namely that only 49% of the 7.8 mb/d of projects assessed as 'firm' through 2023 are currently under construction (1.6 mb/d) or nearing the construction stage (2.2 mb/d). The remaining 4.0 mb/d (over 50%), 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 to be accorded a high probability of going ahead and coming onstream by 2023.

As stated, there is little time remaining to build major projects that would be up and running during the medium-term (that is, through year-end 2023), and which would thus be able to add meaningfully to available capacity. The more likely risk is for reductions in projected capacity because of delays and cancellations due to various reasons.

5.2.2 Regional developments

The projects, as assessed, continue to show a pattern seen in previous Outlooks with most of them concentrated in developing regions, predominantly the Asia-Pacific and the Middle East. Indeed, the trend toward developing regions is increasing, in line with the concentration of demand growth. As shown in Table 5.4 and Figure 5.2, 88.5% of the distillation capacity projects assessed as viable for the period 2018–2023 are located in developing regions. The remaining 11.5% of projects are split a little over 3% each in the US & Canada and Europe and roughly 5% in the Russia & Caspian region.

The Asia-Pacific region is expected to account for 42% of new global capacity or 3.3 mb/d through 2023. For the first time in several years, this represents a slight easing off of the trend seen in previous WOOs in which new capacity is increasingly concentrated in the Asia-Pacific. The proportion of global additions grew from 40% between 2015 and 2020, as seen in the 2015 Outlook, to 45% in the WOO 2016 and then 49% in the WOO 2017. The reason for the reversal is a drop in the rate of additions in China, now at 1.7 mb/d, while the level for Other Asia-Pacific has held steady at 1.6 mb/d.

Offsetting the reduction in estimated medium-term expansions in the Asia-Pacific is an increase in the Middle East, with an anticipated 2.3 mb/d of new projects for the period 2018–2023. This comes on top of significant new recent refinery capacity in the region. Such sustained additions are being driven by a combination of expanding local demand, as well as policies in several countries that are designed to capture the value added through refining. At 0.9 mb/d, the region's demand increase over the period sees 40% of the investments taking place.

Part of the new capacity is expected to be used to reduce product imports, but the clear emphasis here is on an appreciable increase in the region's potential to market products internationally, as well as crude oil, in the near future. These and future 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.

Latin America's medium-term crude distillation capacity additions have been in steady decline in recent years. From over 1 mb/d for the medium-term period as projected in the 2013 and 2014 WOOs, the level in this year's Outlook for the period 2018–2023 is only 0.3 mb/d. This situation reflects a combination of factors across the region including less optimistic assumptions regarding economic growth in some Latin American countries and the adverse impacts on cash flow – and hence the ability to finance projects in regional crude exporting countries. Even with reduced medium-term economic growth – and, thus, reduced oil demand growth – the projected capacity additions are well below the projected demand growth of more than 0.5 mb/d for the same period. This implies yet further increases in the region's medium-term net product imports.

In the US & Canada region, projected medium-term additions have dropped back to 0.25 mb/d from around 0.5 mb/d that were estimated in the WOO 2017. This mainly reflects the cancellation of condensate splitter projects that were originally conceived largely as a means to circumvent the US crude oil exports ban. With the elimination of the crude export ban, which ended in December 2015, and the successful subsequent build-up in US crude oil and condensate exports, only minimal additional splitter capacity is being installed.

In Africa, there are some 50 listed refining projects, which, if all built, would add nearly 5 mb/d of new refining capacity to the continent. In recent WOOs, however, the proportion of projects considered firm has generally been low, for example, 0.4 mb/d for the 2017–2022 period in WOO 2017. This year, the outlook represents a significant reversal from recent history. For the first time in many years, projected firm additions at 1.1 mb/d exceed regional demand growth for 2018–2023 at 0.7 mb/d. This change relates primarily to one project in Nigeria now under construction. Recognizing that this one major project is in West Africa, the prospects for North and East/South Africa continues to be for further increases in regional net product imports.

The Russia & Caspian region is expected to add 0.4 mb/d of new medium-term capacity, which is closely in line with projected regional demand growth, implying little or no change in net product exports over the period. The main emphasis in Russia continues to be on product upgrading capacity – more so than distillation – as a result of the extensive rearrangement of crude oil and product export and excise duties, in combination with tightening domestic transport fuel standards.

This is encouraging refiners to make investments geared to overhauling and upgrading their refineries. One effect already evident is a reduction in residual fuel production and exports, offset by increases in clean product exports, notably ULS diesel, which can be expected to further increase over the medium-term. Additions in the Caspian in the medium-term are primarily centred on a handful of smaller projects, which together are estimated to add less than 0.1 mb/d of distillation capacity, plus a range of secondary process additions.

In Europe, approximately 18 projects are expected to be completed between 2018 and 2023. However, these are predominantly small- to mid-scale upgrading and quality improvement additions, primarily emphasizing diesel. This is not surprising given the environment of declining demand and high costs faced by European refiners, which has led to a string of closures in recent years. The only significant addition of distillation capacity is projected in Turkey, which is estimated to add 0.2 mb/d of capacity.

As previously noted in pervious WOOs, the overall trend is for a continuing shift of new refining capacity to new demand centres in developing countries, particularly in the Asia-Pacific and the Middle East. This, in turn, is leading to a shift in the patterns of international crude and products trade.

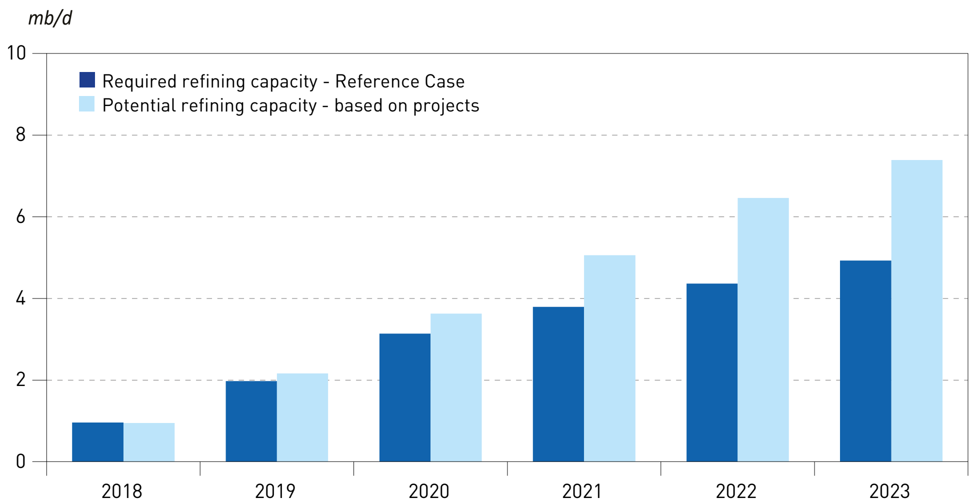
5.2.3 Medium-term outlook for distillation capacity

As previously described, global incremental distillation capacity resulting from existing projects is assessed at 7.8 mb/d for the six-year period from 2018–2023. Adding in an allowance for some limited additions to be achieved through 'capacity creep',[25] the total medium-term increment to crude distillation units is projected to be around 8.2 mb/d for the period 2018–2023.

These additions, broken down by year, are used to project potential annual incremental crude runs and associated refinery yields. These are then compared to projections for incremental refined-product 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.

Figure 5.3 provides a summary assessment of the cumulative medium-term potential for additional crude runs based on assessed refinery projects – including an allowance for 'capacity creep' – compared to the required incremental product supply from refineries based on global product demand growth. The potential crude runs also take into account the maximum annual

Figure 5.3
Additional cumulative refinery crude runs, required* and potential**



* *Required: based on projected demand increases.*
** *Potential: based on expected distillation capacity expansion; assuming no closures.*

utilizations that new projects could be expected to sustain. As per the methodology applied, refinery closures are not taken into consideration.

On this basis, potential incremental crude runs average approximately 1.2 mb/d annually (similar to last year's Outlook), leading to cumulative potential incremental runs of 7.4 mb/d (based on assumed utilization rate of 90%) in the period to 2023.

If there is no increase in non-crude supplies from 2018–2023 then the incremental refining potential of 7.4 mb/d would almost exactly match incremental demand, which is at 7.3 mb/d. However, non-crude supply streams are expected to grow by 2.4 mb/d over the period, leaving an incremental required refining output of only 4.9 mb/d. On an annual average basis, global demand growth in the six years from 2018–2023 is projected to average 1.2 mb/d whereas the requirement for incremental crude-based products, and hence crude runs, equates to 0.8 mb/d.

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 2019, but where a gap progressively opens up, especially from 2021 onward. By 2023, the cumulative 7.4 mb/d refinery production potential is 2.5 mb/d in excess of the requirement.

The standard caveats apply that this cumulative overhang would be lower should refinery projects slip, and higher, should demand growth prove less than expected. As the projection stands, it points to a period of rising international competition in product markets, as well as to the prospect for a resurgence in the need for refinery closures. In other words, if closures of 2.4 mb/d between 2018 and 2023 were to materialize, the danger from accumulating overcapacity would be averted.

It is important to point out that the advent of the IMO sulphur regulations in 2020 is expected to impact total global demand. Substantial y-o-y growth of 1.65 mb/d in 2018, dropping to 1.45 mb/d in 2019, would further decline in 2020 if there were no IMO regulations. Instead, this is expected to lead, *inter alia*, to a temporary boost in non-marine residual fuel demand such that global demand increases by almost 1.7 mb/d in 2020 versus 2019. As global supply and demand adapt to the regulations, and energy efficiency trends grow, annual demand increases post-2020 are expected to revert to a lower level, some 0.9 mb/d in 2021 and 0.8 mb/d in 2022 and 2023. Thus, the medium-term divides into two distinct periods with respect to demand growth: 2018–2020 when total growth is 4.7 mb/d, then 2021–2023 when total growth is almost halved at 2.6 mb/d. This disparity between the first three years and the second three years of the period has a marked impact on global and regional balances.

5.2.4 Medium-term regional balances

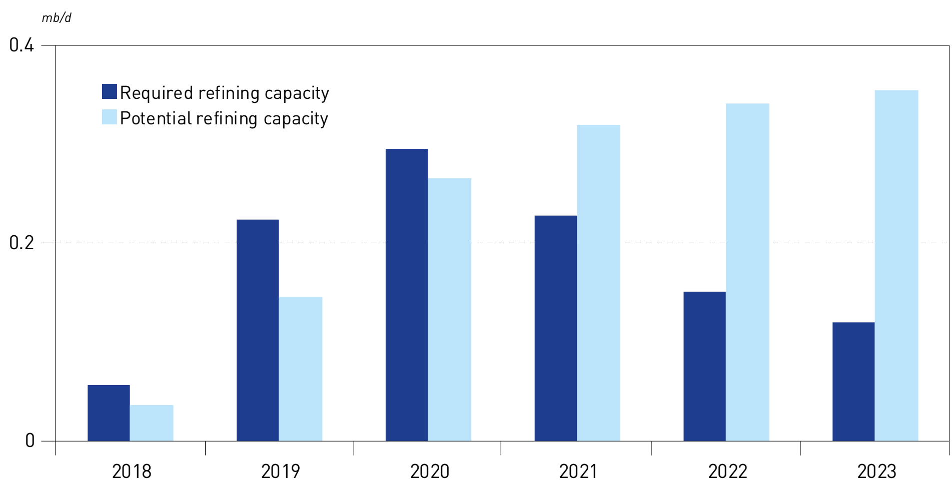
At the regional level, the contrasts in the refining supply/demand balances remain stark. Figures 5.4–5.7 present a comparison of data drawn from 2018–2023 for the four major world regions, namely: the US & Canada, Europe, China and the Asia-Pacific (excluding China).

Firstly, Figure 5.4 shows a widening gulf between added refinery production potential in the US & Canada and incremental requirements. Through a number of minor capacity expansions, new capacity potential is estimated to expand steadily to 0.35 mb/d by 2023. Against this, incremental requirements peak in 2020 at 0.3 mb/d, but then taper off to reach 0.1 mb/d in 2023, as regional demand shifts from growth to decline. Thus, incremental supply potential closely matches demand-based requirements through 2020, but, thereafter, a widening gap emerges. Key factors on the demand side are a peak and decline in the projected consumption of gasoline and diesel/heating oil, although this is partially offset by steady growth in ethane/LPG demand, driven by the petrochemical sector.

The potential versus required gap of over 0.2 mb/d by 2023 implies either a reduction in US & Canada refinery utilization, possibly resulting in closures, and/or further increases in product exports as the time horizon moves from 2018 to 2023. The indication from the WORLD Model cases for 2025 (used to calibrate required closures in the medium-term) and beyond, is that both factors may apply, with a risk of closures, but also some continuing increase in net product exports.

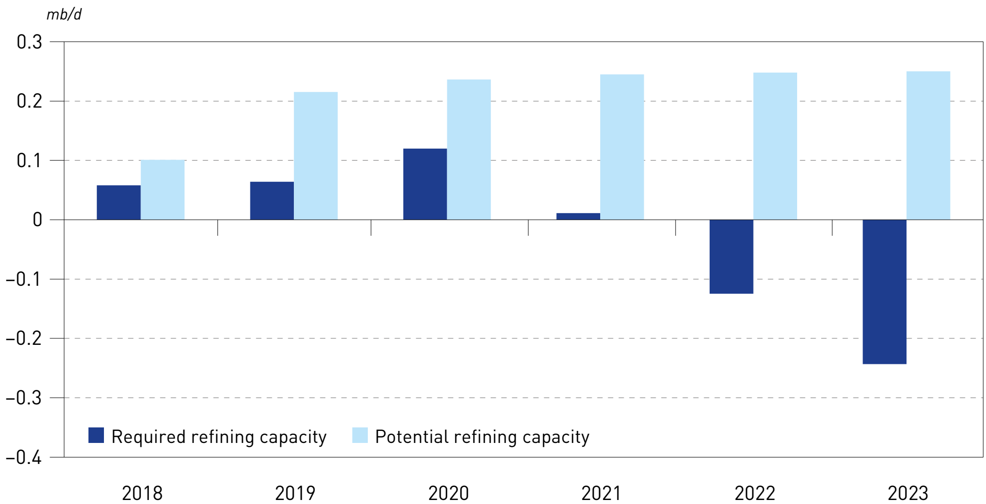
In Europe, a similar growing disparity is evident between incremental refinery potential and demand (Figure 5.5) in the medium-term. Increases in refinery potential remain minimal at under 0.3 mb/d over the medium-term. However, this year's Outlook, like the WOO 2017, embodies small demand increases at least through 2020. As a result, disparities between incremental refinery potential and incremental requirements remain around 0.1 mb/d to 2020, but then widen to 0.5 mb/d by 2023 as demand starts declining. As in previous Outlooks, this

Figure 5.4
Additional cumulative crude runs in US & Canada, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

Figure 5.5
Additional cumulative crude runs in Europe, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

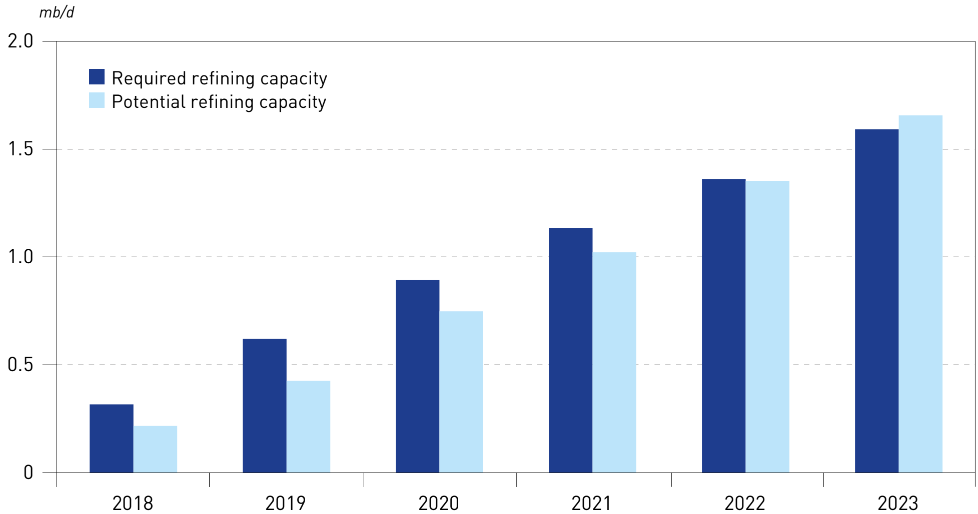
projection continues to signify a need for additional refinery closures in Europe, especially post-2020.

Figures 5.6–5.7 show the corresponding outlooks for the Asia-Pacific region – first, China alone, then Asia-Pacific (excluding China). At a scale of well over a cumulative 3 mb/d by 2023, 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 outlooks in the US & Canada and Europe.

China and other Asia-Pacific exhibit somewhat different outlooks in the first part of the medium-term period, but similar ones toward the end of the period. For China (Figure 5.6), incremental demand-based requirements are modestly lower for the six-year period than a year ago, but a drop in project additions has led to the prospect for incremental refinery potential to lag incremental requirements, at least through 2021. Thereafter, the two are closely in balance due to a pick-up in the pace of refinery additions. The deficit of potential versus demand reaches 0.2 mb/d in 2019, implying a reduction in China's short-term product export potential and/or an increased need for product imports. By 2022, both incremental required and potential are close to 1.35 mb/d and, by 2023, potential runs are slightly ahead of requirements of 1.6 mb/d.

In this year's Outlook, Asia-Pacific looks largely balanced as seen in Figure 5.7. By 2023, there is a small deficit projected of less than 0.1 mb/d. Throughout the outlook period, the

Figure 5.6
Additional cumulative crude runs in China, potential* and required**



* Potential: based on expected distillation capacity expansion; assuming no closures.
** Required: based on projected demand increases assuming no change in refined products trade pattern.

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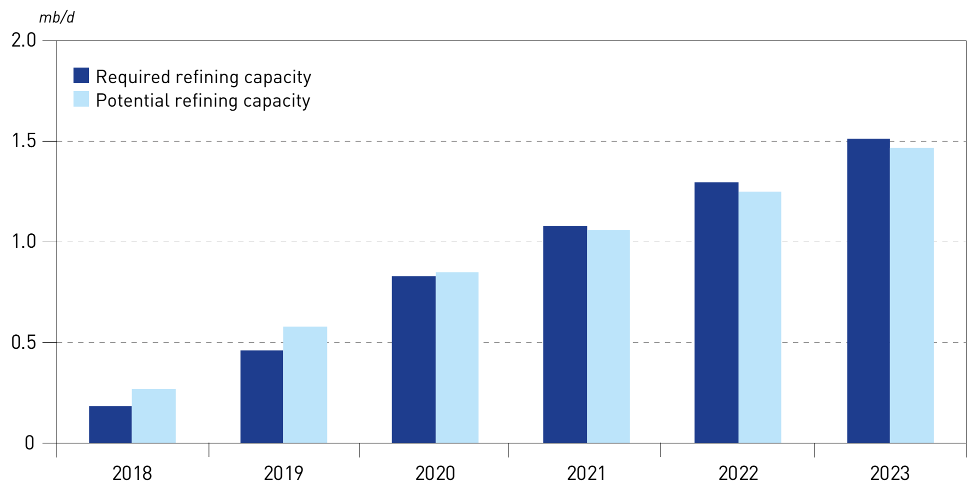
Figure 5.7
Additional cumulative crude runs in the Asia-Pacific (excl. China), potential* and required**



* Potential: based on expected distillation capacity expansion; assuming no closures.
** Required: based on projected demand increases assuming no change in refined products trade pattern.

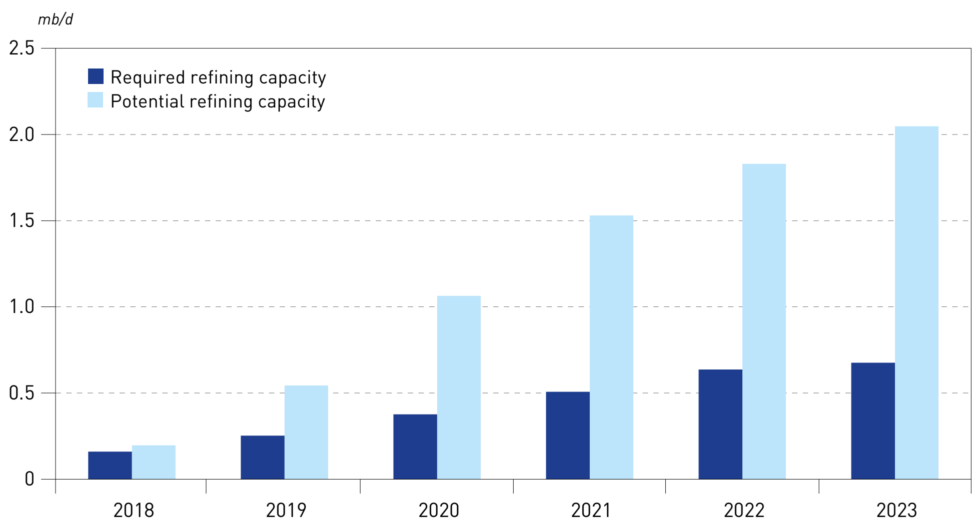
region is projected to progressively swing from moderate potential versus a demand excess of somewhat over 0.1 mb/d in 2018 and 2019, to a close balance in 2020 and 2021, before the deficit emerges in 2022/2023.

A clear implication is that the Asia-Pacific region as a whole looks to be more closely in balance over the medium-term in terms of incremental refining potential versus requirements. The relative balances in the two parts of the region imply possible product trade opportunities into China from Other Asia-Pacific in the short-term. In contrast, toward the end of the medium-term period, it appears the deficit in Other Asia-Pacific could be met by product supplies from China.

Figure 5.8 presents the outlook for the Middle East. This stands out as being the only region where demand growth is significant, but it is also far exceeded by refining supply potential. As such, the picture is the same as that from recent Outlooks. In other words, the region exhibits a growing potential for not only coping with domestic demand growth, but also for exporting increasing volumes of refined product (in place of crude oil).

Excess incremental refinery output potential, over and above incremental requirements, grows from around 0.1 mb/d in 2018 to almost 1.4 mb/d by 2023. Notably, the projected excess of refining potential over requirements is higher than projected a year ago when the WOO 2017 had it at 0.9 mb/d by 2022. The underlying reasons for this change comprise a moderation in the

Figure 5.8
Additional cumulative crude runs in the Middle East, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

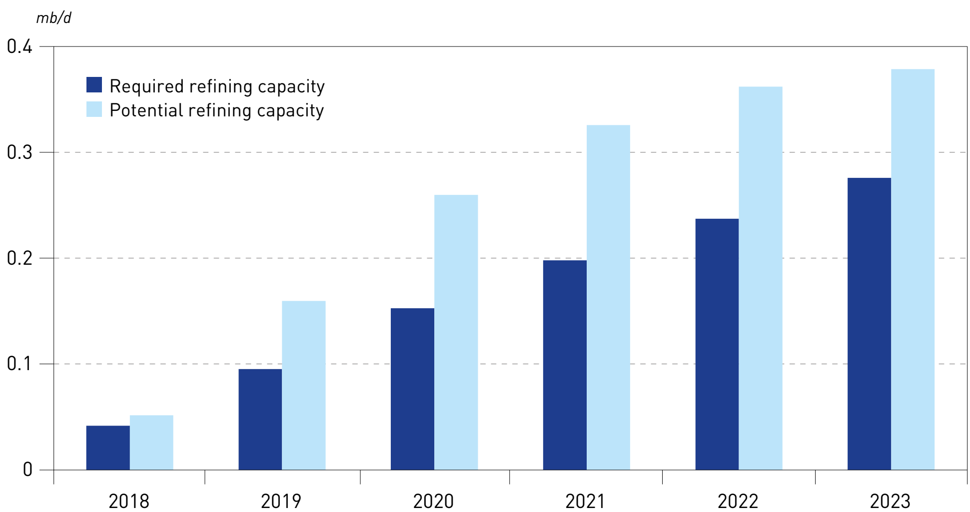
expected incremental requirements over the next six years (–0.1 mb/d), combined with an increase in refining potential (+0.4 mb/d) resulting from sustained major project additions. This outlook clearly has implications for changes in product export flows to deficit regions, notably the Asia-Pacific, but also Africa, as discussed later.

Figures 5.9, 5.10 and 5.11 present the outlooks for the Russia & Caspian, Africa and Latin America regions, respectively.

In the Russia sub-region (excluding the Caspian), the outlook continues to be a combination of very limited demand growth with appreciable refinery investments, prodded by recent tax and duty changes, which is leading to a situation where incremental refinery output exceeds incremental requirements. However, there is a small excess, averaging and not straying far from 0.1 mb/d over the period. From 2018–2023, the potential rises by 0.4 mb/d and requirements by 0.3 mb/d.

Since projected medium-term capacity additions in Russia are focused more on upgrading and quality improvement – and since the tax changes encourage production of clean products at the expense of residual fuel – what is more significant than these limited volume changes is the increasing ability of Russia to supply and export clean and ULS products, while reducing residual fuel output. These are products that will most likely move to Europe, increasing the

Figure 5.9
Additional cumulative crude runs in the Russia & Caspian, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

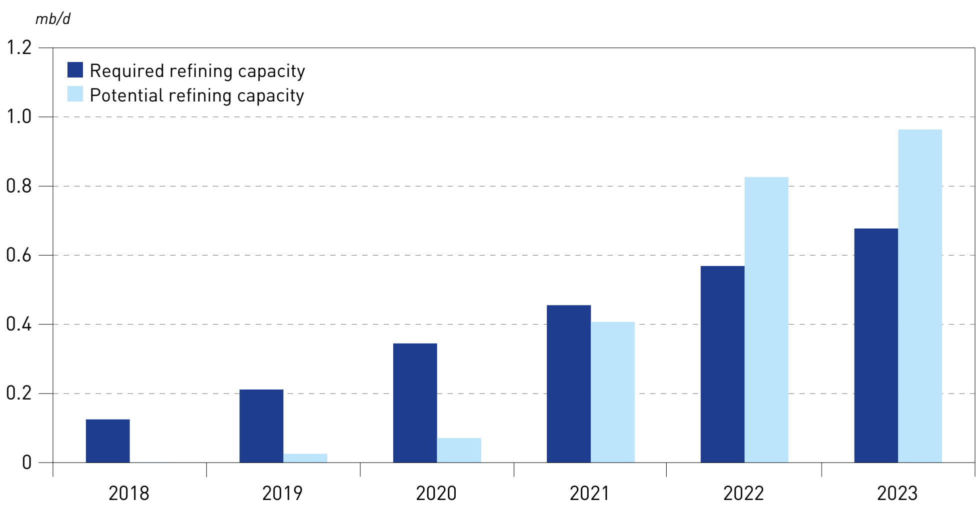
struggles that refiners face in that region. In line with this, there is already evidence of a shift away from heavy fuel oil exports.

This situation, however, applies only to Russia and not to the Caspian. In the latter sub-region, 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, the incremental refinery potential in the Caspian region is likely to be roughly in line with incremental requirements.

Last year's WOO hinted that, in Africa, "new projects could improve the situation somewhat toward the end of the period". This year, increasing confidence that the Dangote project in Nigeria will go ahead is indeed changing the picture. Allowing for some uncertainty in the project's start-up timetable, incremental potential in Africa is expected to continue to lag incremental demand-based requirements through 2020, after which the potential is for a balance or excess requirements. A deficit of around 0.2 mb/d in 2019–2020 is estimated to swing to an excess of around 0.3 mb/d by 2022–2023.

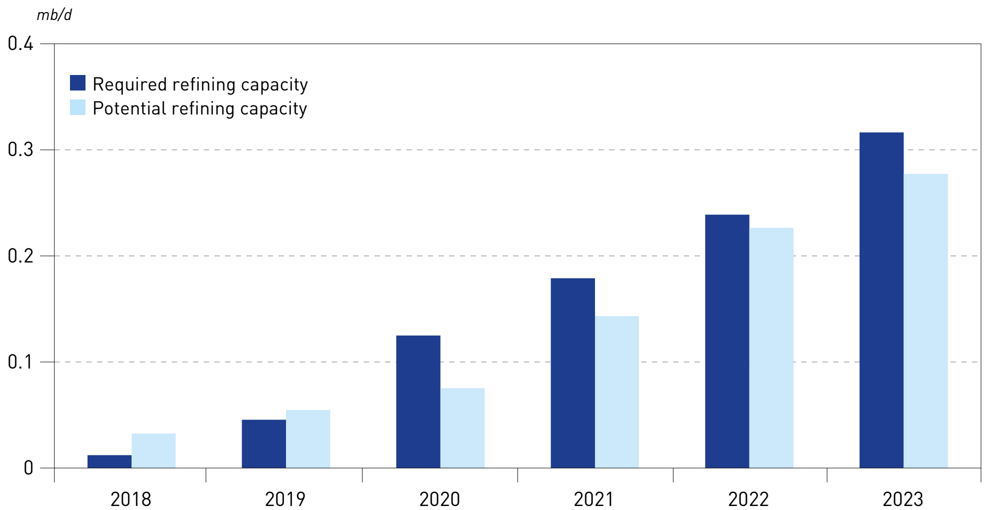
It must be borne in mind that this regional outlook is unusual in that it hinges largely on a single project. Moreover, since the project is in West Africa, its implementation does not necessarily alter the situations in North and East/South Africa. What should happen, especially in West Africa, is a reduction in the need and opportunity for product imports.

Figure 5.10
Additional cumulative crude runs in Africa, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

Figure 5.11
Additional cumulative crude runs in Latin America, potential* and required**



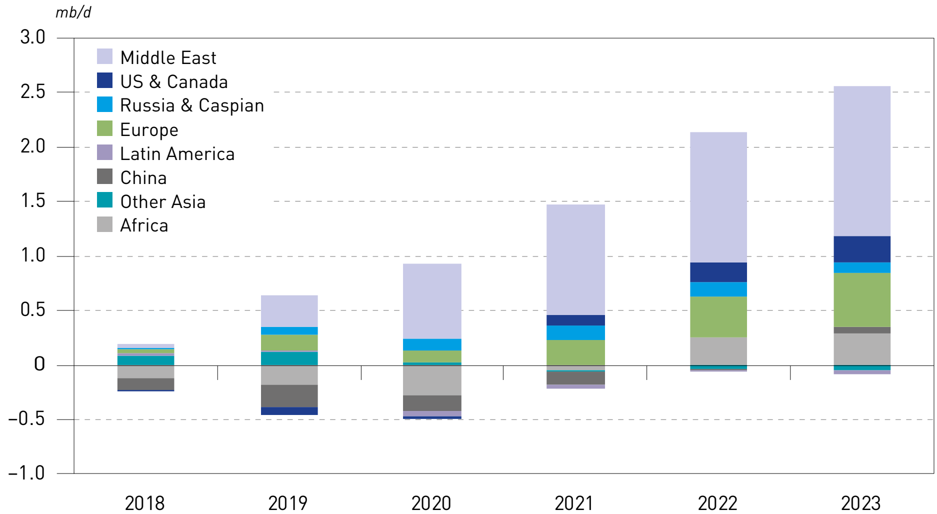
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

Latin America presents a picture where potential for increased product output consistently lags incremental demand requirements after 2018–2019, albeit with deficits that are small – generally less than 0.05 mb/d. The current outlook is for six-year growth in refining potential of slightly above 0.3 mb/d and incremental refining potential slightly below this figure. Previous outlooks for Latin America had significant levels of both incremental refinery potential from projects and incremental required refined products.

However, slowing economic growth rates in several countries in the region are the underlying causes for the changes in both demand growth and the pace of new projects and refining potential. The potential versus requirements balance in 2018 and 2019 should hold regional net product imports near current levels, but the subsequent deficit is expected to lead to a moderate increase from 2020.

Bringing these regional outlooks together, six regions have an excess of refined product potential compared to requirements. The most significant excess is that of the Middle East (1.4 mb/d by 2023), followed by Europe (0.5 mb/d), Africa (0.3 mb/d), US & Canada (0.25 mb/d), Russia & Caspian (0.1 mb/d) and China (0.1 mb/d), for a total of 2.6 mb/d by 2023. In contrast, the Asia-Pacific region (excluding China), as well as Latin America exhibit a deficit of less than 0.1 mb/d by 2023 each. As summarized in Figure 5.12, the net global outlook is for incremental refined product potential based on projects to exceed incremental refined product requirements by over 2.5 mb/d by 2023.

Figure 5.12
Net cumulative regional refining potential surplus/deficits vs. requirements



This outlook for increasing excess refining capacity implies reduced refinery utilizations and/or more closures, especially post-2020 as the excess builds. It is important to note, however, that this medium-term assessment does not take into account the effects of closures. As discussed later, additional (gross) closures of 1.2 mb/d were estimated for the period 2018–2023 and applied in the WORLD modelling cases. They are a combination of already announced closures, mainly early in the period, with estimated/possible closures later in the period that would likely result from anticipated demand declines, especially in Europe, but also in the US & Canada and potentially other regions. Based on this medium-term outlook, at least the highlighted level of closures would appear to be warranted.

As always, careful monitoring of refinery projects versus demand growth is called for to gauge whether this impending excess will 'evaporate' as the time draws nearer (via project slippage, further demand growth and/or plant closures) or whether it will in fact remain.

5.2.5 Long-term outlook for distillation capacity

Based on the assumptions already described, the Reference Case projections for distillation capacity additions from modelling results are summarized in Table 5.5. Figure 5.13 presents the corresponding projections by region and period. 'Assessed projects' in Table 5.5 refers to those refining projects that are considered firm – that is, ones that are expected to be constructed and onstream by the stated year. In this Outlook, this means 3.9 mb/d by 2020 and 7.8 mb/d by 2023. 'New units' represent the further additions – major new units plus debottlenecking – that are projected to be required 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 3.9 mb/d of assessed projects by 2020, the 2020 model case indicates a further 0.3 mb/d will be required (essentially representing assumed minor 'capacity creep') for total distillation capacity additions to 2020 of 4.2 mb/d. The 2025, 2030, 2035 and 2040 cases add an additional 1.3 mb/d, 3.7 mb/d, 3.1 mb/d and 1.7 mb/d, respectively, over and above the previous case (year) totals. When combined, the cumulative total additions – assessed projects plus total model additions – are projected to reach 17.8 mb/d by 2040.

Table 5.5 maintains the pattern evident in previous Outlooks – namely, that there is a steady reduction in the annual pace of refinery capacity additions required over time. The projections for refinery additions from 2025 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 5.5 shows, the pace of demand growth is projected to drop steadily over time, from 4.7 mb/d (1.6 mb/d p.a.) from 2017–2020 to an annual average of 0.5 mb/d in the period 2025–

Table 5.5
Global demand growth and refinery distillation capacity additions by period in the Reference Case

mb/d

	Global demand	Distillation capacity additions starting 2018			
	growth	Assessed projects*	New units	Total	Annualized
2017–2020	4.7	3.9	0.3	4.2	1.4
2020–2025	4.0	3.9	1.3	5.2	1.0
2025–2030	2.6	0.0	3.7	3.7	0.7
2030–2035	1.9	0.0	3.1	3.1	0.6
2035–2040	1.2	0.0	1.7	1.7	0.3
	Global demand	Cumulative distillation capacity additions			
	growth	Assessed projects*	New units	Total	Annualized
2017–2020	4.7	3.9	0.3	4.2	1.4
2017–2025	8.8	7.8	1.6	9.4	1.2
2017–2030	11.4	7.8	5.2	13.0	1.0
2017–2035	13.3	7.8	8.3	16.1	0.9
2017–2040	14.5	7.8	10.0	17.8	0.8

* *Firm projects exclude additions resulting from capacity creep. Total firm projects are split between 2018–2020 and 2021–2025.*

2030 and then only 0.25 mb/d from 2035–2040.[26] It is, therefore, not surprising that projected refinery capacity additions drop from an annualized 1.4 mb/d from 2017–2020 to 1.0 mb/d for 2020–2025, then to the 0.7 mb/d range by 2030 and to 0.35 mb/d by the late 2030s.

Between 2017 and 2040, the supply of non-crudes (NGLs, biofuels, CTLs/GTLs and other supply streams) plus processing gains is projected to increase by more than 5.5 mb/d, which is more than one third of the overall liquids demand growth in the 2017–2040 period. Viewed at the global level, it thus eats heavily into the need for incremental refined products.

The resulting implied 'call' for incremental refining capacity would thus appear to be only 9 mb/d at the global level – yet additional capacity needs for 2017–2040 are projected at 17.8 mb/d. The reason for this difference is twofold. Firstly, global refinery utilizations average no more than 79–83% (there has been an average of 81% since 1990). This in itself increases the capacity that needs to be built to meet a given demand. Secondly, rational increases in needed refining capacity are well in excess of requirements when viewed purely at the global level because demand growth in the forecast period is predominantly in regions where new capacity is warranted (i.e. where there is demand growth).

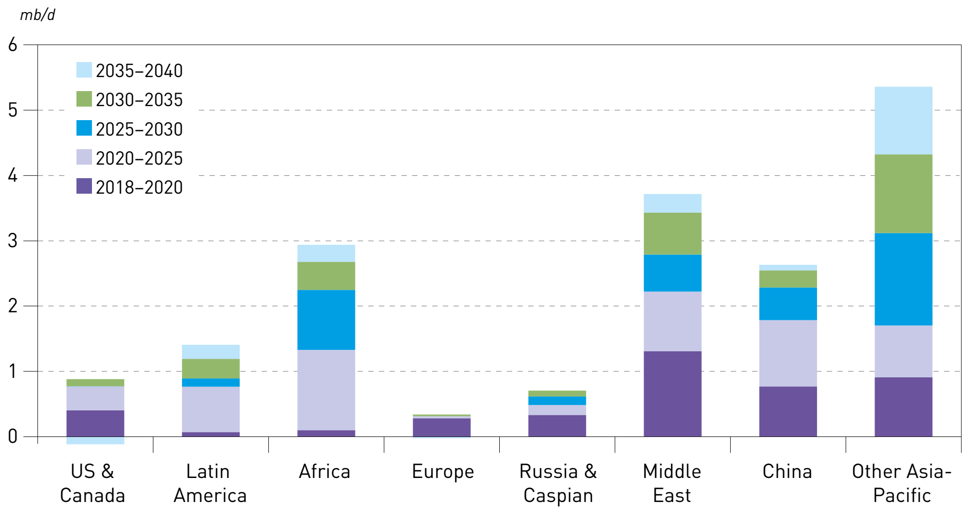
These new refineries, overwhelmingly in developing regions (Asia-Pacific and the Middle East, but also Latin America and Africa), will compete with existing facilities in the US & Canada, Europe and the Russia & Caspian, as demand in those regions becomes flat and starts to decline. The model results indicate that utilizations are expected to decline in the US & Canada, and especially Europe, long-term, with implications for continued closures.

As a result, the long-term potential for incremental product exports from the US & Canada, Europe and the Russia & Caspian is projected at around an additional 1.5 mb/d by 2040, above 2017 levels. In contrast, the total demand increase from 2017–2040, for the Asia-Pacific, the Middle East, Africa and Latin America combined, is projected at more than 19 mb/d and much of this is expected to be met by building additional capacity within the regions. Given refinery utilizations of around 80%, it is, therefore, consistent that projected additions to 2040 total 17.8 mb/d, which is overwhelmingly in developing regions.

In short, while continued competition for product export markets is expected and could put pressure on utilizations and margins, it does not look to be a key factor in determining where refineries are built over the long-term. Furthermore, the evident slowing in the pace of necessary long-term refinery capacity additions means that whoever invests first in new capacity may be in a better competitive position. 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 still be competition from existing, complex units (especially in the US) that have already partially depreciated.

As illustrated in Figure 5.13, 40% of the 2018–2020 capacity additions are projected for the Asia-Pacific region, over 31% for the Middle East and the US & Canada contributes 10%. The Russia & Caspian region and Europe contribute 8% and 7%, respectively, while the figure in both Latin America and Africa is around 2%.

Figure 5.13
Crude distillation capacity additions in the Reference Case, 2018–2040



For additions in the period 2020–2040, the share taken by the Asia-Pacific is estimated to rise further to 46%, driven by regional demand growth. The Middle East, Africa and Latin America have estimated respective shares of 18%, 21% and 10% in this period, with domestic regional growth again an important factor. The US & Canada and the Russia & Caspian regions account for less than 3% each, while additions in Europe are minimal.

Thus, in the Middle East, it is the wave of current major projects (1.3 mb/d out of a global total of 4.2 mb/d for the period 2018–2020) that raises its share of the short-term total, before settling back to around 18% over the longer term. The surge in the percentage share in Africa stems from a combination of a dearth of firm projects in the immediate short-term (2018–2020), followed by anticipated large projects additions in the 2020–2025 period. In the longer term, new additions are supported by the expectation of sustained longer term demand. A similar pattern applies to Latin America, where there is a lack of firm projects today, but significant longer term demand growth is driving the possibility of appreciable additions.

In contrast, the share for the Russia & Caspian region is projected to be the inverse: an appreciable share of shorter term additions, driven by the effects of recent tax changes, followed by a decline in its share as the result of flat to declining regional demand. For the US & Canada region, the pattern is similar: a short-term share at 10%, comprising a couple of new condensate splitters plus a number of minor debottlenecking projects, fades essentially to nil post-2025, due to a steady regional demand decline. For the same reason, almost 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 2025.

These projections for capacity additions maintain the view from prior Outlooks. In the longer term, local demand growth (in developing regions) 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 is expected to drop steadily. Post-2025, the rate of required new additions is anticipated to drop to the equivalent of one to two 300,000–400,000 b/d new refineries or expansions per year worldwide. In practice, this is likely to mean that almost no new refineries will be built. Rather, as has been evident for some time from the situation in the US, Europe, Japan and Australia, expansions (such as they are) will come from debottlenecking and the expansion of existing facilities. These will be partially offset by the retirement of older, less efficient units, or even whole refineries.

As already mentioned, the 7.8 mb/d of assessed (firm) medium-term projects was taken from a total 'inventory' of announced refinery distillation additions that continue to exceed 22 mb/d. This inventory is up 5 mb/d from that seen in the 2015 Outlook, shortly after crude oil prices dropped. This recovery indicates a degree of resilience or optimism in the refining sector. In the past year, however, the 'inventory' of projects has remained steady at somewhat over 22 mb/d, while the total additions needed by 2040 have declined from 19.6 mb/d to 17.8 mb/d. Of course, one year of projects has been added into the capacity base, but the fact is that the gap between 'projects inventory' and 'projects needed' has widened. Thus, either many of the projects currently listed will need to be modified, deferred or cancelled, or the risk of over-building will remain.

It is also important to recognize that the long-term additions projected, as required, are being driven more by the shift in global demand from industrialized regions to developing regions (mostly in the Asia-Pacific) 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. In effect, as demand declines in Europe, Japan and some other regions, existing refineries increasingly face declining demand, which means their utilization rates are likely to come under pressure. Consequently, a number of closures can be expected in the medium- and long-term.

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. Dirty freight rates remain at relatively low levels by historical standards. Clean freight rates on major routes have also been largely flat. The assumption in the modelling analysis is that freight rates for crude and product tanker movements will move upwards, at least in the medium-term, driven by the effects of the MARPOL Annex VI global sulphur regulations. Higher freight rates can impact trade patterns, and higher dollar per tonne differentials between crude and product movements tend to support curbing transport activity and raising refinery investments in demand growth centres.

Over the longer term, a high uptake of scrubbers on vessels – several analysts see this as likely and this has formed the basis of the underlying demand outlook in this report – would keep the cost of inter-regional movements at relatively low levels. How freight rates play out will thus affect the ability of refineries in regions and countries such as Europe, the US and even Japan, to compete for expanding markets in developing regions. In turn, this could either reduce or raise the level of capacity additions needed in developing regions versus those contained in the current analysis. Lower freight rates would also help to keep more refineries in industrialized regions open.

As already stated, the majority of future refining capacity expansions to 2040 are projected to be required in the Asia-Pacific region – 8 mb/d out of a global total of 17.8 mb/d. Expansions here continue to be dominated by China and India. Regional expansions are well below the 13.2 mb/d increase expected in Asia-Pacific demand to 2040. This figure itself is made up of a demand decline in Japan and Australasia of 1.5 mb/d, plus an increase in Asia's growth regions of 14.7 mb/d. This means that 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 3.7 mb/d of total additions from 2018–2040. This is well over 1 mb/d ahead of a projected regional demand increase of 2.5 mb/d. Driven by a series of major projects expected to come onstream by 2022, capacity additions in the Middle East are 'front-loaded', with 1.3 mb/d by 2020 and a further 0.9 mb/d by 2025, followed by increments of around 0.6 mb/d for each of the periods 2025–2030 and 2030–2035, before dropping to 0.3 mb/d in the period 2035–2040. While the longer term additions are more in line with regional product demand growth, one implication is that Middle East product exports can be expected to increase between now and 2025, and any product imports decline. Moreover, substantial refining capacity increases should lead to product exports partially displacing crude exports from the region.

In Latin America, projected capacity additions of 1.4 mb/d over the forecast period fit closely with the outlook for a demand increase of 1.8 mb/d and recognizing the almost 0.4 mb/d of expected growth in biofuels supply. Net product imports are projected to remain essentially flat between 2017 and 2040, partially offsetting the growth in biofuels supply and leading to an expansion in refinery crude runs essentially matching demand growth at 1.9 mb/d.

Total refinery distillation capacity in Africa is projected to rise by 2.9 mb/d by 2040, compared to the base capacity at the end of 2017. These additions comprise 0.1 mb/d of new capacity in the period to 2020 and a further 1.2 mb/d by 2025. The cumulative capacity additions by 2040 match the demand increase, of 2.8 mb/d, over the same period. On the basis that utilization rates will rise over the period, this, allied with the capacity expansions, should enable regional refinery throughputs to keep up with demand growth, leading to a stabilization in the region's net product imports over the long-term. Net product imports in 2040 are projected at around 2 mb/d. A key challenge for Africa remains exactly how to improve refinery utilization levels given that many of its refineries are old and small-scale, with relatively low complexity and low energy efficiency.

5.2.6 Refinery closures and utilization

Refinery closures and utilizations in the medium-term

This section reviews the recent history of refinery closures at a regional level, as well as the prospects for additional firm closures based on announcements and refinery capacity considered at risk of closure by virtue of a recent sale or other announcements. This leads to an updated assessment for total refinery closures from 2018–2023 and onward to 2025. The year

2025 was selected as the 'end date' for actively estimating closures since anything beyond that time horizon is considered too uncertain.

Table 5.6 and Figure 5.14 summarize closures since 2012, and projected closures through 2023 and 2025. A total closures level of 1.0 mb/d is shown for the medium-term, 2018–2023. This includes an assumed restart in 2020 of the 235,000 b/d Aruba refinery (i.e. gross closures equate to some 1.2 mb/d). This represents a continued reduction in projected medium-term closures versus recent Outlooks. In the WOO 2016, 2.6 mb/d was assumed for the period 2016–2021 and, in the WOO 2017, it was 1.6 mb/d for 2017–2022.

There are two reasons for this. The first, as is evident in Table 5.6 and Figure 5.14, is that total closures of around 5 mb/d for the period 2012–2017, notably in Europe, Japan and Australia, have gone a long way toward removing the worst regional capacity excesses.The second reason is that the global demand outlook continues to be revised upward based on strong growth in recent years.

The clear impact of these higher short- and medium-term demand outlooks is to diminish the need for refinery closures. In addition, the high level of actual closures recently achieved, also leads to a lower level of closures required in the immediate future. In contrast with a few years ago, research today on refinery closures yields little by way of announcements. In the immediate short-term, the only firm closures relate to two long-planned refinery rationalization projects in the Middle East. As a result, gross refinery closures through 2021 are expected to average only around 0.1 mb/d p.a. However, from 2022 through 2025, the closure rate is expected to pick up and to average around 0.3 mb/d each year.

Table 5.6
Net refinery closures, recent and projected, by region *mb/d*

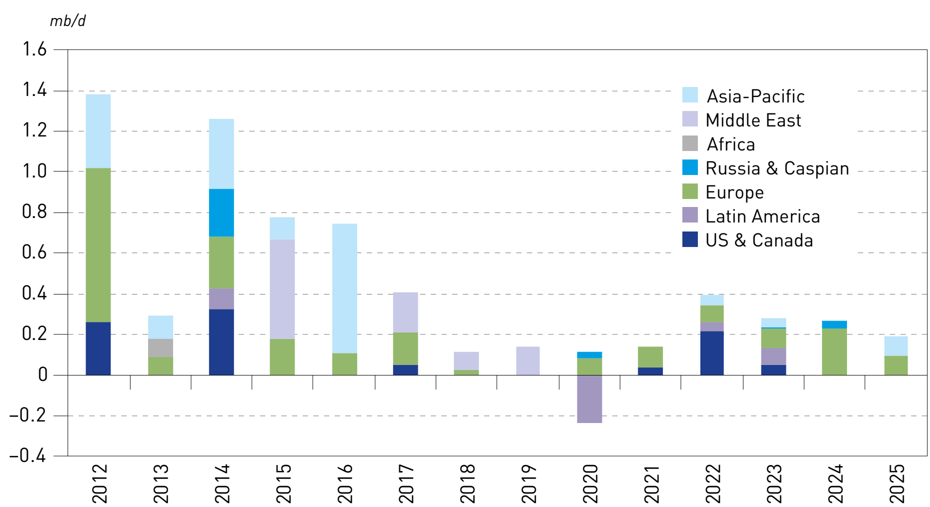
	Total 2012–2017	2018	2019	2020	2021	2022	2023	Total 2018–2023	Total 2018–2025
US & Canada	0.6	0.0	0.0	0.0	0.0	0.2	0.1	0.3	0.3
Latin America	0.1	0.0	0.0	–0.2	0.0	0.0	0.1	–0.1	–0.1
Europe	1.6	0.0	0.0	0.1	0.1	0.1	0.1	0.4	0.7
Russia & Caspian	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Africa	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Middle East	0.7	0.1	0.1	0.0	0.0	0.0	0.0	0.2	0.2
Asia-Pacific	1.6	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2
Total	**4.9**	**0.1**	**0.1**	**–0.1**	**0.1**	**0.4**	**0.3**	**1.0**	**1.4**

A first factor underlying this estimate is the trend toward demand declines in the US & Canada and Europe, as well as the fact that certain refineries in areas such as the US East Coast and in Europe are known to be vulnerable. (In recent years they have either narrowly escaped closure or have been put up for sale.) A second factor is that the fallout from the impacts of the IMO 2020 sulphur regulations could put stress on simpler refineries and thereby trigger closures. Overall, potential closures between 2018 and 2025 are estimated at 1.4 mb/d.

The fact that the projection for closures was not taken beyond 2025 does not mean that the era of refinery closures is over beyond then. As discussed later, a continuing long-term need for closures is projected, especially post-2025, as demand declines in industrialized regions and as smaller, less efficient, often ageing refineries in developed and developing regions struggle to compete with the larger, highly sophisticated, efficient refineries that are increasingly coming onstream, especially in the Middle East and Asia.

In addition, the number of refineries for sale, or where financial partnership is being sought, act as indicators of refineries 'at risk' and thus of possible future closures. Today, this scene remains active, notably in the Americas. In the US, the US Oil Tacoma Washington refinery was reported earlier this year to be up for sale, likewise in 2017 the Petrobras Pasadena Texas refinery. In January 2018, Philadelphia Energy Solutions LLC, operating the largest refinery complex on the US East Coast filed for bankruptcy. Mexico's Pemex has reportedly been seeking partnerships in its refineries – apparently with no takers – for over two years. Brazil's Petrobras has announced it is seeking divestiture of four of its refineries in Brazil. And the survival of the Petrotrin refinery in Trinidad is reportedly dependent on whether it can complete a project to produce

Figure 5.14
Net refinery closures, recent and projected, by region



ULS diesel. These announcements could portend appreciable changes in North and/or Latin America over time.

In Europe, Lukoil announced in 2017 that it was putting its ISAB refinery complex in Italy up for sale and, early this year, Shell reversed a plan to sell its Fredericia refinery in Denmark.

At the same time, one area where the 2020 IMO sulphur regulations may have an impact is in encouraging the restart of shuttered refinery facilities. Two announcements, which occurred too late to be embodied in the modelling analysis, are cases in point.

The current owners of the one-time HOVENSA refinery in the US Virgin Islands (USVI) has announced plans to effect a partial restart by end-2019 with a focus on processing heavy crude and producing 0.5% sulphur marine fuel. (The refinery has a coker and desulphurization units.) The plan requires a new operating agreement with the USVI government and will apparently cost $1 billion. It remains to be seen whether this project will indeed go ahead and, if so, by when it will be operational. The refinery would be run at potentially 200,000 b/d versus the 650,000 b/d 'nameplate' capacity when the facility closed in 2012. A second instance relates to the possible reopening of units to process feedstocks at a shuttered refinery in Wilhelmshaven, Germany, which ceased operation ten years ago. The vacuum distillation unit would be restarted, enabling processing of atmospheric residual fuel feedstock. Reactivation of other such facilities may occur as 2020 nears. Whether such projects will indeed go ahead is open to question, as is whether they would remain in operation for long given they were shut because they were unprofitable.

Looking at refinery runs, Figure 5.15 illustrates the history of utilization rates for the global refining system expressed as crude (and condensate) throughputs divided by 'nameplate' calendar day capacity. It is evident from this chart that utilization rates have only very rarely exceeded 82% – and often have been below that level. Moreover, global utilizations have only twice, in 2004 and 2005 approached 84% (respectively 83.6 and 83.8%). The implication from this is that, based on recent history, 84% appears to be the maximum for global utilization and thus effective capacity. (In 2004 and 2005, refining markets were extremely tight with references made to it being the 'golden age' of refining.)

Figure 5.16 illustrates both the history of distillation capacity, oil demand and crude runs since 1980 and estimates the effective spare refining capacity. Applying the 84% level based on past history points to extremely low effective spare capacity in 2004–2005, which is consistent with the tightness that then existed. As large capacity surpluses have gradually been whittled down since the 1980s, the levels of total liquid demand and nameplate refinery capacity have almost converged, such that installed capacity sits minimally above global liquids demand.

For example, in 2018 an installed base of 100 mb/d compares with global demand of 98.9 mb/d. However, as stated, refineries on average run well below their nameplate capacity and so crude runs in 2020 are projected at around 84 mb/d, with the gap between runs and demand met by a combination of non-crude supply and processing gains.

Figure 5.15
Historical and projected global refinery utilizations, 1980–2023

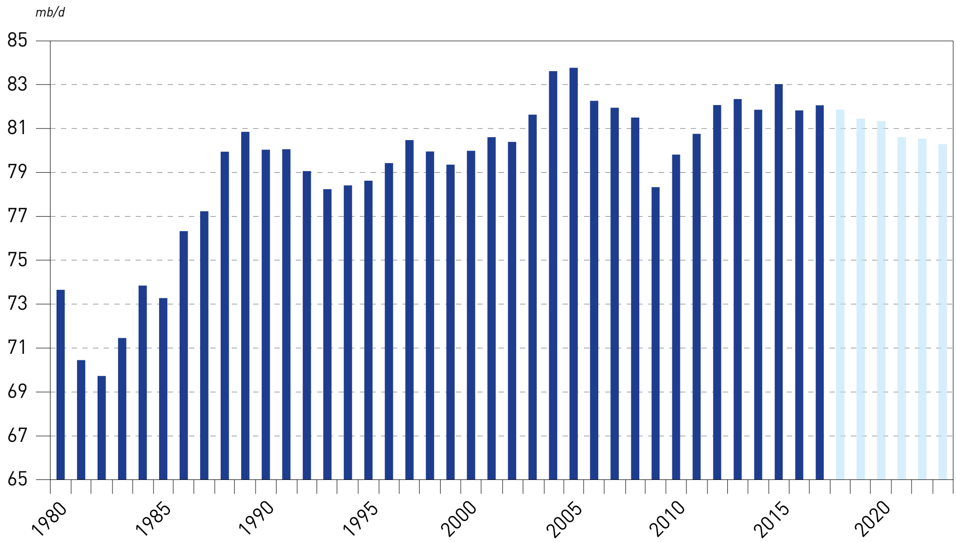
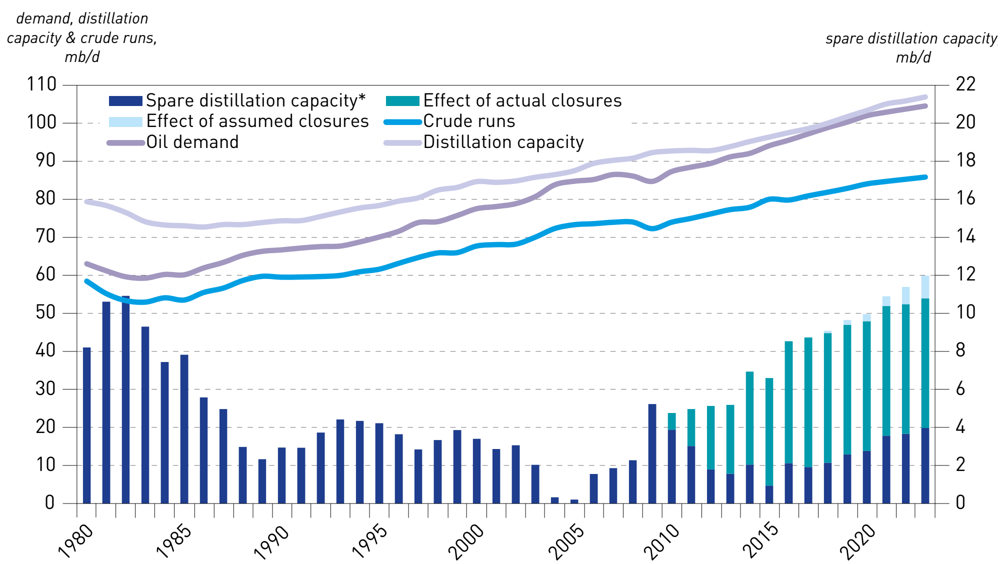


Figure 5.16
Global oil demand, refining capacity and crude runs, 1980–2023



*Effective 'spare' capacity estimated based on assumed 84% utilization rate: accounted for already closed capacity.

The right-hand axis in Figure 5.16 illustrates the effect of refinery closures. Close to 7 mb/d of closures occurred between 2010 and 2017 and, to this, an estimated 1.2 mb/d of additional closures by 2023 has been added for an aggregate total of 8 mb/d. The chart brings home the dramatic effect closures have had on containing surplus refining capacity. If none of the recent closures had occurred, current spare capacity (assuming 84% effective availability) would be in the order of 12 mb/d, a level not seen since the large excesses of the early 1980s. Instead, the current actual level is in the 2 mb/d range.

The estimated additional gross closures (1.2 mb/d) through 2023 have the effect of limiting spare capacity, but the combination of higher project additions than a year ago and of an increased NGLs supply offsetting higher demand, leads to an expansion in projected spare capacity to 2023 to a level approaching 4 mb/d. By way of comparison, the long-term average spare capacity from 2000–2015 was 3.2 mb/d, a period that encompassed the so-called 'golden age' of refining tightness, the recent major global economic recession and wide oil price variations.

It is clear that substantial recent closures have been effective in reducing overall global average spare capacity to a limited level that should be supportive of reasonable refining margins. It should also be recognized that significant regional differences 'buried' within the global trend must be accounted for. Figure 5.16 points to the importance of continuing closures in order to avoid a reversion back to higher excess levels that have the potential to force abrupt closures by lowering refining margins to unsustainable levels.

Refinery closures in the long-term

The WORLD Model results provide a cross-check on whether the assumed level of closures by 2025 is appropriate, or whether there is a need to indicate more (or fewer). As discussed, the Reference Case in 2025 projects global average utilizations at 80.6%. Embodied within this figure is an assumed level of closures for 2018–2025 of 1.4 mb/d (on top of the 0.4 mb/d of closures in 2017). This level of assumed closures appears reasonable, with the possible exception of Europe, where utilizations indicate possible further closures, beyond the assumed 0.7 mb/d by 2025 or so.

The WORLD model can 'back-calculate' the implied closures needed within a region to reach a user-input level of utilization. This parameter is currently set to 80%, representing the lowest utilization level considered viable. Thus, any region with a utilization level below 80% from the model results will have some level of implied long-term required closures. This feature is especially useful for assessing the potential need for additional long-term closures by region.

Beyond 2025, the outlook for long-term regional refinery utilizations demonstrates a need for continuing refinery closures, beyond those built in to the modelling, especially in industrialized regions where demand is projected to further decline. These are discussed in detail later. In summary, additional closures indicated by the modelling across the world's regions are close to 4 mb/d over the long-term to 2040. To these have to be added the 1.4 mb/d built into the modelling base outlook for 2018–2025, indicating that total closures somewhere in the range of 5–6 mb/d are required from 2018–2040.

This equates to an annual average rate of 0.25–0.3 mb/d for the period 2018–2040, a level that is moderately above the 0.2 mb/d average for 2018–2025, but well below the 1 mb/d average for 2012–2017. 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.

Crude runs and refinery utilizations in the long-term

The projected global and regional long-term refinery crude throughputs and related utilization rates are presented in Table 5.7. At the global level, throughputs rise from 80.8 mb/d in 2017 to 84.0 mb/d in 2020 and then to 90.0 mb/d in 2040. As already emphasized, 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 annual demand growth and steady increases in non-crude supplies.

The annual rate of increase through to 2020 is slightly above 1 mb/d. This rate slows to 0.5 mb/d during the period 2021–2025, to a little over 0.3 mb/d during 2026–2030 and then drops to 0.2 mb/d from 2031–2040. The reason for this is that the period to 2030 accounts for the bulk of total demand growth during the period 2017–2040. Demand growth for the period from 2031–2040 is only around 3 mb/d.

Put another way, crude runs are expected to rise by 7.2 mb/d in the period 2017–2030, but only 2 mb/d from 2031–2040. This changing growth profile 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 refinery utilizations is for a gradual decline over the forecast period, from 81.9% in 2017 to 77.8% in 2040. Global crude runs are estimated to rise by 3.2 mb/d between 2017 and 2020; the level in 2020 being driven upward partly by the expected spike in demand and refinery processing related to the January 2020 MARPOL Annex VI sulphur regulations. Based on the capacity additions to be online by 2020, utilization rates are projected at 81.3% for this year. It should be noted that how utilizations in fact evolve will depend on the actual realization of potential additions and closures, as well as demand.

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. This allows for realistic utilizations that tend to differ from region-to-region and over time. Secondly, the outlook has presumed no further closures after 2025, as any estimation beyond this timeframe was deemed too speculative.

Overall, slightly lower utilizations are projected globally compared to last year's WOO. As was the case in last year's Outlook, a key reason is that detailed research by refinery continues to identify small gaps in the refinery capacity base leading to upward revisions in base capacity. In addition, modestly higher global demand by 2040 is more than offset by increases in the projected supply of NGLs and other non-crudes, reducing the 'call' on refining.

Table 5.7 highlights the variation in outlooks between major regions. Consistent with recent projections, crude throughputs in the US & Canada are projected to rise in the medium-term to 2020 as the region benefits from limited capacity additions, growth in domestic crude supplies and slightly rising regional demand. The specific effects of the IMO sulphur regulations also act to boost US refinery throughputs in 2020. Thereafter, declining domestic demand is expected to result in a long gradual decline in crude throughputs. Thus, 2020 is seen to represent a peak. From 18.8 mb/d in 2020, throughputs drop to 17.2 mb/d in 2030 and to 15.9 mb/d by 2040.

Starting from record levels of just over 89% in 2017, and spiking to 90% in 2020, it takes until after 2030 before US & Canada utilizations drop below 80%. They are then estimated to reach 76% by 2040. This indicates a limited risk of shot-term closures in the region over and above the 0.3 mb/d assumed for 2018–2023, but significant risk thereafter. By 2040, the potential is

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
2017	80.8	18.2	4.8	2.4	12.8	6.8	7.3	11.5	16.9
2020	84.0	18.8	5.3	2.7	12.9	6.6	8.4	12.6	16.7
2025	86.5	18.0	6.7	3.5	12.4	6.5	9.1	13.3	17.0
2030	88.0	17.2	7.0	4.1	12.0	6.4	9.6	14.0	17.6
2035	89.3	16.6	7.4	4.5	11.8	6.3	10.2	14.1	18.5
2040	90.0	15.9	8.0	4.7	11.1	6.2	10.5	14.5	19.1
	Crude unit utilizations *% of calendar day capacity*								
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
2017	81.9	89.4	60.3	57.2	74.8	96.2	79.0	80.4	92.6
2020	81.3	90.1	64.0	61.9	76.9	90.0	80.0	81.1	85.0
2025	80.6	86.2	74.9	62.5	76.5	86.5	80.1	81.0	83.3
2030	79.3	82.0	77.7	64.0	74.3	84.4	80.5	82.4	80.9
2035	78.3	78.8	79.6	65.4	72.6	81.7	80.5	82.0	80.2
2040	77.8	76.1	83.3	65.9	68.5	81.2	81.3	83.8	79.6

for something in the order of 1 mb/d of closures, some or most of which could occur much earlier.

A key aspect of this projection is that while demand in the US & Canada is projected to decline by almost 5 mb/d from 2020–2040, the region's crude runs are forecast to drop by less than 3 mb/d over the same period. In other words, the competitive advantages of US refiners will enable them to at least partially compensate for domestic demand reductions with product export increases. As a result, net US product exports could still be well above 4 mb/d in 2040.

In Europe, crude runs are expected to peak in 2020, at slightly under 13 mb/d, and then to steadily drop in line with progressively declining regional demand. The magnitude of the decline, at 1.8 mb/d from 2020–2040, is less than that for the US & Canada. The 1.8 mb/d reduction in crude runs from 2020–2040 is somewhat lower relative to the reduction in European demand over the same period. This also implies a small reduction in net product imports to Europe over the long-term.

That said, the reductions in runs and utilizations, portend further closures in Europe. Between 2012 and 2017, some 1.6 mb/d of capacity has already closed. On top of this, a further 0.7 mb/d of closures has been projected by 2025. Even so, utilizations steadily decline post-2020 and, assuming no further closures beyond those allowed for, drop below 70% by 2040. The implication is, of course, that substantial additional closures (in the region of 2 mb/d) are potentially necessary for Europe by 2040, over and above the assumed 0.7 mb/d to 2025, as the region's refineries continue to lose throughput.

The primary driver of throughput reduction in both the US & Canada and Europe continues to be the expectation of progressively declining transport fuel consumption – and, to a much smaller degree, the rising supplies of biofuels and the use of alternative vehicles. Refiners in both regions continue to face a push toward higher transport fuel efficiency standards, although the US Administration's planned weakening of the CAFE standards is expected to delay a long-term decline in transport fuel demand. The decline projected for European demand for the same fuels is also significant. This is primarily driven by an assumption of the faster penetration of alternative vehicles, such as PHEVs and BEVs.

In the US, the current administration's position on the RFS remains uncertain, but any major biofuel supply increase appears unlikely. In the EU, ethanol by volume today constitutes 3.2% of the region's gasoline consumption and biodiesel 5% of the 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 allows for an increase in total European biofuels supply from below 0.3 mb/d in 2017 to 0.5 mb/d in 2040.

Globally, biofuels supply is projected to grow from around 2.2 mb/d in 2017 to 3.6 mb/d in 2040, shaving some 1.4 mb/d from demand for refinery products.

Japan and Australasia are also expected to experience a continued demand contraction, in the form of a relatively severe 29% combined drop from 5.2 mb/d in 2017 to 3.7 mb/d in 2040. This leads to the potential for further closures of around 0.4 mb/d across the period to 2040. In the tables and figures in this WOO, Japan and Australasia 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, Thailand, Indonesia and Vietnam – and the much higher growth in the Rest of Asia sub-region, which is dominated by India. In the former, demand grows by 2.2 mb/d from 2017–2040, a 21% increase. In contrast, in the Rest of Asia sub-region, demand of 5.6 mb/d in 2017 transforms into 13.0 mb/d by 2040. This is a 134% increase, driven by India's strong growth potential. All these significant differences between sub-regions within the Other Asia-Pacific, as well as their impacts on refinery throughputs and capacity additions, are captured in the model.

In the Russia & Caspian region, demand is expected to increase modestly, from 4.2 mb/d in 2017 to 4.9 mb/d by 2040. Conversely, refinery crude runs are projected to gradually decline throughout the period to 2040, by a total of around 0.6 mb/d. The reason for the decline in runs, despite the demand increase, is a projected appreciable drop in product exports over the period. This occurs in part because of the anticipated demand decline in Europe, which is the primary market for Russian products. In addition, the Russian government's 'tax manoeuvre', with its impacts on export duties, increases the attractiveness of producing clean products and/or of exporting crude versus exporting heavy fuel oil. Exports of the latter fuel have dropped as a result.

The effects are evident in the high proportion of upgrading and quality improvement projects in Russia, with little in the way of distillation capacity expansions. Noting the near absence of any assumed closures through 2025, Russia & Caspian utilizations are projected to slowly decline, with the implication that something in the order of 0.7 mb/d of closures may be justified, especially in the period post-2030.

It is developing regions, where significant demand increases are expected to occur, which sees considerable gains in refinery throughputs from 2017–2040; Latin America with 3.1 mb/d, Africa with 2.3 mb/d, the Middle East with 3.1 mb/d, China with 2.9 mb/d and Other Asia with 2.3 mb/d (this includes a mix of declines in Japan and Australasia, but increases elsewhere in the region). Overall, these gains total around 13.8 mb/d, which more than offsets the combined 4.6 mb/d of crude run declines in the US & Canada, Europe and the Russia & Caspian. Associated with the throughput gains, utilizations in developing regions are projected to gradually increase.

Returning to closures, the modelling cases point to a need for around 4 mb/d of further closures by 2040, over and above the 4.9 mb/d that occurred in the 2012–2017 period and the additional 1.4 mb/d (net) assumed for 2018–2025. Applying that level of closures would bring the currently projected capacity level of 115.7 mb/d in 2040 down to 111.7 mb/d and overall global refining utilizations up from an unsustainable 77.8% to a more tenable 80.6%.

5.3 Secondary capacity

5.3.1 Medium-term capacity additions

Substantial amounts of new secondary units will accompany new distillation capacity in wholly new refineries and major expansions. In addition, secondary capacity additions are occurring 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 the inclusion of significant proportions of secondary capacity. With few exceptions, the aim is to produce predominantly light, clean products to advanced standards. This goal is in line with, and derives from the fact that the vast majority of incremental product demand is for clean products, predominantly naphtha, gasoline, jet fuel and diesel, and that standards especially for transport fuels continue to be tightened.

Table 5.8 shows that the 7.8 mb/d of new distillation capacity from assessed projects by 2023 is expected to be accompanied by an additional 3.3 mb/d of conversion units, 6.7 mb/d of desulphurization capacity and 1.7 mb/d of octane units.

Table 5.8
Secondary capacity additions from exiting projects, 2018–2023

mb/d

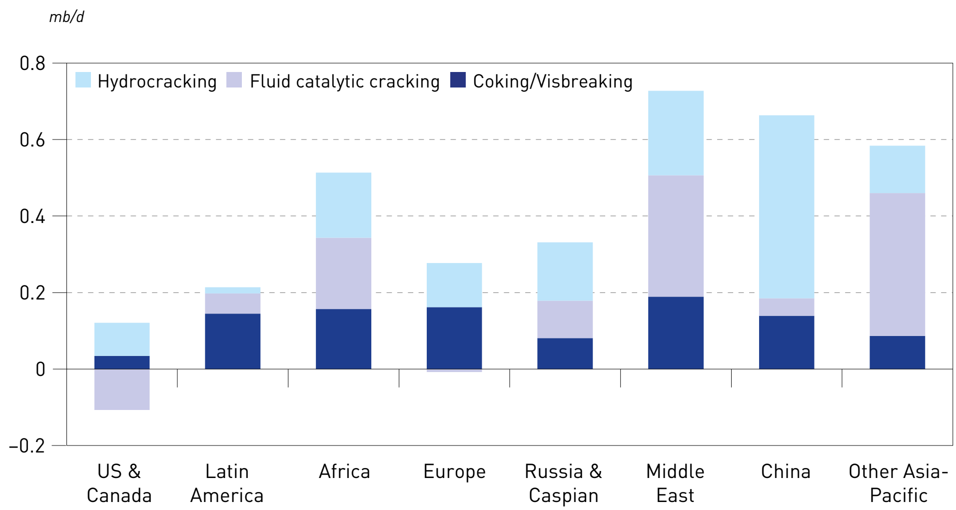
	By year		
	Conversion	Desulphurization	Octane units
2018	0.5	1.0	0.2
2019	0.7	1.3	0.3
2020	0.4	1.3	0.3
2021	0.7	1.4	0.4
2022	0.5	0.9	0.3
2023	0.5	0.8	0.2
	By region		
	Conversion	**Desulphurization**	**Octane units**
US & Canada	0.0	0.2	0.1
Latin America	0.2	0.5	0.1
Africa	0.5	0.6	0.3
Europe	0.3	0.2	0.0
Russia & Caspian	0.3	0.5	0.1
Middle East	0.7	2.8	0.6
China	0.7	0.8	0.4
Other Asia	0.6	1.2	0.2
World	**3.3**	**6.7**	**1.7**

As of early 2018, the total conversion capacity in place equated to just over 41% of global crude distillation capacity, desulphurization was at 62% and octane units at 19%. With respect to conversion, the make-up of current firm projects is similar at 42.5% of new distillation capacity and octane units at 22%. For desulphurization, there is evidently a distinct surge with new units equating to 86% of new distillation capacity. This is matched by rates of projected additions for hydrogen and sulphur recovery plants that are also well above their historical ratios relative to crude capacity.

Conversion units

Figure 5.17 highlights the geographic distribution of the conversion capacity additions by major unit category. The 3.3 mb/d of additions to global conversion units for the period 2018–2023 include substantial contributions from each of the three main unit categories. These are led by hydrocracking at approaching 1.4 mb/d (41%), followed by coking/visbreaking (essentially all coking) at just over 1.0 mb/d (30%) and FCC/residue fluid catalytic cracking (RFCC) at just under 1 mb/d (29%).

Figure 5.17
Conversion projects by region, 2018–2023



As shown in Figure 5.17, additions in each of the three conversion unit categories are expected in all regions except Europe, where there is a net small reduction in FCC additions because of unit closures, and the US & Canada, where FCC additions are net negative because of announced FCC unit closures in US refineries as components of project revamps. The US & Canada FCC closures (at 0.1 mb/d) offset hydrocracker additions at the same level. These developments are occurring despite a short-term surge that has pushed US gasoline demand to record levels. Over the medium- to long-term, however, the region's gasoline demand is expected to decline.

In addition, the growth in US light tight oil production has added to naphtha supplies. 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 volume. In Europe, the substantial regional gasoline surplus provides little incentive to add to the gasoline supply. In both regions, the emphasis continues to remain on raising distillate yields.

Overall, four regions display only limited medium-term conversion additions: the US & Canada, where net additions are minimal, then Latin America, Europe and the Russia & Caspian, where additions lie in the 0.2–0.3 mb/d range. Significant conversion additions are projected for the Middle East, China and Other Asia-Pacific, each in the 0.6–0.7 mb/d range, plus Africa where 0.5 mb/d of new capacity is expected. In the Middle East, the conversion additions (0.7 mb/d) are geared towards adding value and, in doing so, meeting expanding regional demand and supplying clean products for export. FCC additions lead the way at 0.3 mb/d with coking and hydrocracking each at 0.2 mb/d. In China (0.7 mb/d) and Other Asia-Pacific (0.6 mb/d), the conversion additions are geared more towards satisfying domestic demand.

The geographical distinctions are marked. At 0.5 mb/d, total Atlantic Basin additions – represented by the US & Canada, Latin America and Europe – compare with another 0.5 mb/d for Africa and 2 mb/d for the Pacific Basin (Middle East and Asia combined). Thus, the concentrations of conversion additions reflect that the preponderance of medium-term clean product growth is projected to take place in the Middle East and Asia (outside of Japan and Australasia).

5

With respect to coking, nearly all regions are expected to see some level of medium-term additions, generally in the 0.1–0.2 mb/d range. The exception, with only minimal additions, is the US & Canada. This reflects the region's already-high level of coking capacity, combined with domestic crude supply growth that is dominated by light tight oil. The current lightening of the global crude slate would, by itself, reduce coker throughputs.

However, one change expected to raise and even strain the throughput of cokers (and desulphurization units) is the introduction of the global marine fuel standard for 0.5% sulphur fuel in 2020. Given the expectation that on-board scrubber penetration will still be limited by 2020, and assuming shippers will generally try to achieve full compliance with the IMO Annex VI standard, the shift could result in a scramble to dispose of excess high sulphur intermediate fuel oil (IFO), which is mainly residual based. This would generally be achieved by additional upgrading and desulphurization, with their ability of cokers to process low quality residua arguably a key aspect.

Desulphurization units

Medium-term desulphurization unit additions equate to 86% of new distillation capacity. Of these additions, 1.7 mb/d is for naphtha processing, 0.9 mb/d for gasoline, 2.9 mb/d for distillates and nearly 1.1 mb/d for heavy streams (vacuum gasoil and resid). The naphtha desulphurization additions stem mainly from the 1.2 mb/d of new global catalytic reforming capacity, but also new condensate processing capacity in the Middle East.

The gasoline additions relate primarily to the processing of FCC naphtha to ULS standards. The distillate additions – 43% of the total – reflect the current drive, in developing regions especially, to implement low and ultra-low standards for diesel. The vacuum gasoil/resid additions reflect mainly a mixture of FCC and RFCC pre-treatment, and resid desulphurization in the Middle East, plus limited lube oils processing.

A review of individual projects indicates some of the high level of new desulphurization capacity can be attributed to the MARPOL Annex VI Global sulphur regulations now set for 2020. The IMO did not confirm until October 2016 that the regulations would be implemented in 2020. It would appear that a few refiners may have already taken strategic decisions to move ahead with desulphurization (and conversion) projects, which were justified in part by the perceived impacts of the regulations. However, the fact that it was not clear until October 2016 whether implementation would be in 2020, or five years later in 2025, suggests that many refiners may have held back from investments specifically because of the uncertainty of the timing of the regulations.

A few MARPOL-related projects have been announced since the IMO decision, but the prospect that scrubbers could be adopted in large numbers from 2020 is arguably also acting to deter many refiners from making major investment decisions to materially increase 0.5% marine fuel supply. Thus, the primary reason for the significant desulphurization additions would appear to be the number of low sulphur and ULS gasoline and diesel programmes that are now moving ahead.

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 means that the continuing shift of developing countries towards Euro 3/4/5/6 standards is the main force driving global hydrotreating capacity expansion.

Additions in the US & Canada are expected to total only 0.2 mb/d over the medium-term period, with a similar level in Europe. This reflects how nearly all gasoline and diesel production in those regions is already at ULS standards. In contrast, the Middle East is estimated at 2.8 mb/d and Asia at 2.0 mb/d, as an array of new refinery projects and upgrades come online with a major drive toward high refinery complexity and the ability to produce fuels generally to Euro V standards.

In the Russia & Caspian region, additions are anticipated at 0.5 mb/d and are driven, as with conversion additions, by the effects of the new Russian tax regime, as well as regulations to achieve ULS gasoline and diesel standards. New desulphurization capacity in Africa and Latin America is projected at 0.6 and 0.5 mb/d, respectively, and are spread across a range of projects. This indicates further progress on these continents towards tighter sulphur-content fuel standards.

The concentration of additions in mainly non-OECD countries partly reflects recent trends towards cleaner products within these regions. It also reflects the efforts of export-oriented refineries to provide low or ULS products that better comply with quality regulations in developed – and, increasingly, developing – countries.

Octane units

Octane unit additions are estimated at 22% of incremental distillation in the medium-term. This is moderately above the 19% level for base global refinery capacity as of early 2018. With the phase-out of lead essentially complete, this upward move reflects the fact that octane levels are being raised and/or total gasoline output is being increased essentially across all developing regions.

In line with this, additions are again predominantly in the Middle East and Asia (around 0.6 mb/d each), followed at lower levels by Africa and Latin America (0.3 mb/d and 0.1 mb/d, respectively). In the US & Canada, Europe and the Russia & Caspian, additions are at or below 0.1 mb/d in each case.

The nearly 1 mb/d of FCC additions by 2023 will serve to add an appreciable volume of higher octane blendstocks in the form of FCC gasoline (plus feedstock for alkylation units). However, these project additions again bring home the difference in trends between the Atlantic and Pacific Basins. In the former (the US & Canada, Latin America and Europe), medium-term octane additions are estimated to total less than 0.2 mb/d. In contrast, Pacific Basin additions (the Middle East plus Asia) total 1.2 mb/d.

The 1.7 mb/d of octane unit additions is comprised mainly of catalytic reforming at 1.2 mb/d, or 73% of the total. The remainder is split between isomerization (0.2 mb/d), alkylation (0.2 mb/d) and methyl tertiary butyl ether (MTBE) units (0.1 mb/d). In Europe, MTBE consumption levels are seen as flat. In the US, the use of MTBE was effectively banned in 2006, although some 80,000 b/d of MTBE and related oxygenates is still exported from merchant units on the US Gulf Coast. There also continues to be interest in expanding MTBE use in Asia as a means to meet rising gasoline pool octanes. Thus, the potential for an expanding role for MTBE, and whether this could represent an opportunity for exporters, should be monitored.

5.3.2 Medium-term implications for refined products supply/demand balances

In assessing the effects of capacity additions on regional product balances, it needs to be borne in mind that refiners have some flexibility to optimize their product slate depending on market circumstances and seasonality, either by altering feedstock composition and/or by adjusting process unit operating modes. Accepting the fact that refiners do have the flexibility to optimize their product slate, Table 5.9 presents an estimation of the cumulative potential incremental output of refined products resulting from announced projects. As already discussed, the incremental medium-term potential for refining is projected at 7.4 mb/d.

What is seen is a predominance of light, clean products, led by distillates and no incremental supply of residual fuel oil. This, in turn, reflects a continuation of broadly similar proportions of new secondary processing, especially upgrading, relative to new distillation capacity. Close to half (44%) of the increase by 2023 is estimated for middle distillates (3.3 mb/d) and another 2.1 mb/d (29%) for light products, specifically naphtha and gasoline. The ability to produce 'other products' is projected to rise by 2 mb/d, or 27% of the total incremental output. [27]

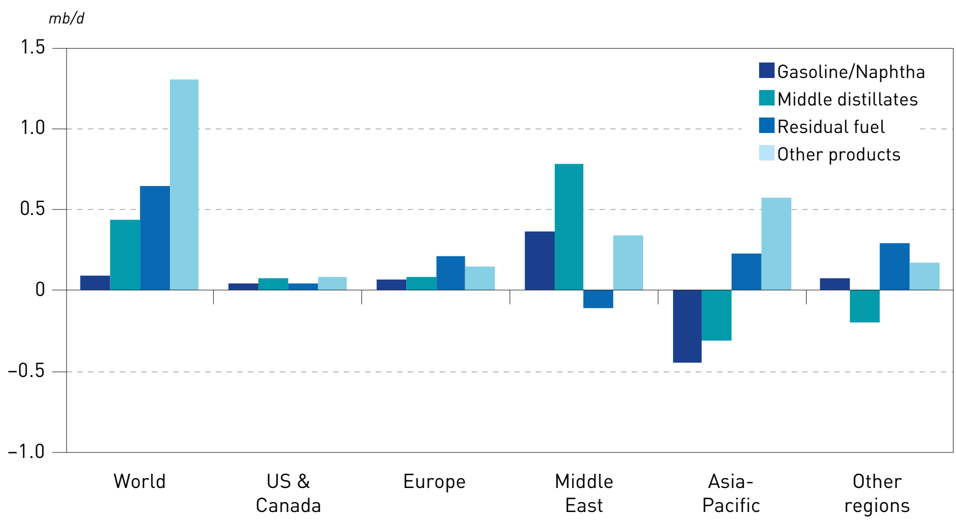
Figure 5.18 compares the potential additional regional outputs by major product group from the assessed projects (as detailed in Table 5.9) to projected incremental regional demand for the period 2018–2023. In assessing net incremental requirements by product, Figure 5.18 takes into account product supply coming from non-refinery streams, notably additional biofuels, CTLs, GTLs and NGLs.

Table 5.9
Global cumulative potential for incremental product output,* 2018–2023 *mb/d*

	Gasoline/Naphtha	Middle distillates	Fuel oil	Other products	Total
2018	0.3	0.4	–0.2	0.2	0.9
2019	0.9	1.2	–0.3	0.6	2.5
2020	1.2	1.8	–0.2	0.9	3.7
2021	1.6	2.4	–0.1	1.5	5.5
2022	1.9	2.9	0.0	1.8	6.5
2023	2.1	3.3	0.0	2.0	7.4

* *Based on assumed 90% utilization rates for the new units.*

Figure 5.18
Expected surplus/deficit* of incremental product output from existing refining projects, 2018–2023



* *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 too.*

The overall outlook is for incremental refining potential of 7.4 mb/d versus incremental requirements of 4.9 mb/d, which highlights a cumulative surplus of 2.5 mb/d by 2023. This trend towards a growing excess of refinery output potential compared to refined product requirements was previously described from the perspective of overall distillation capacity. The results here show the breakdown as net surpluses/deficits by product group, both globally and regionally, based on the same underlying figures.

At the global level, most striking is the projection for significant surpluses across all product groups, except gasoline/naphtha, which is roughly in balance. At the regional level, most prominent is the large excess in the availability of gasoline and middle distillates from the Middle East, which is offset, fully for gasoline and partially for distillate, by deficits in the Asia-Pacific. This has clear implications for product trade between the two regions.

Across the regions, gasoline/naphtha is broadly in balance and globally shows a small (0.1 mb/d) surplus. The US & Canada exhibits a surplus of 0.1 mb/d for middle distillates, but the primary driver today is the 0.8 mb/d excess projected for the Middle East as a result of the heavy emphasis on distillate production in the region's major projects. The global distillate surplus would be higher, but for the anticipated impacts of the IMO 2020 sulphur regulations in shifting marine demand toward distillates and away from residual fuel, at least for several years.

Arguably, the gradual elimination of the gasoline/naphtha surplus, combined with the sustained potential for surplus distillate, reflects a combination of refinery projects more heavily emphasizing distillate yield over gasoline while, at the same time, there has been a resurgence in gasoline demand growth, at least in the short-term, while the 'dieselgate' scandal has taken some of the edge off diesel growth.

The one product that is consistently in surplus across almost all regions is residual fuel; a global total of 0.6mb/d. A primary driver here is the IMO 2020 sulphur regulations that are expected, at least in the medium-term, to lead to a shift away from residual fuel for marine use.

Overall, across the period, the prospect is for a 1.4 mb/d surplus in the Middle East, while the US & Canada region has small surpluses in each of the four product groups that lead to an aggregate 0.25 mb/d excess supply potential. Europe is close to balance across the four product groups, with an aggregate surplus of 0.5 mb/d. The other regions are at a net surplus of 0.3 mb/d, with a small distillates deficit offset by surpluses in residual and 'other products'.

As noted, the regional imbalances have implications for product trade, particularly for increasing movements of gasoline/naphtha and middle distillates from the Middle East to Asia. The overall surplus of 2.5 mb/d points to increasing competition for product markets, especially with regards 'other products', notably NGLs, middle distillates and residual fuels.

What do the IMO sulphur regulations mean for refining?

Chapter 3 describes the Reference Case assumptions surrounding the implementation of the IMO sulphur regulations from 2020, including the rate of compliance and the possible bunker fuel mix. These regulations require reductions in marine sulphur oxide (SO_x) emissions;

specifically that, as from 1 January, 2020, all ships reduce their SO_x emissions by using either 0.5% sulphur fuel – outside the Emission Control Areas (ECAs) that are already at 0.1% – or an equivalent reduction mechanism. With regard to the equivalent options, there are two; namely, to continue to use high sulphur (3.5%) fuel in conjunction with an onboard exhaust gas cleaning system ('scrubber') or to use an alternative fuel, such as LNG or LPG, which achieves equivalent or superior emission reductions.

In the Reference Case (as described in Chapter 3), it was assumed that full compliance would not be achieved in 2020, rather that the implementation path of the regulations would lead to somewhat over 70% compliance in 2020. This equates to a sudden 'switch' from 3.5% to 0.5% fuel in 2020. However, over the long-term, the level of fuel scrubbed is projected to rise significantly, while the 0.5% fuel moves progressively to a lower proportion of marine diesel versus heavier product. The 'overnight' switch to 0.5% fuel in 2020 is projected to create several impacts on, and issues for, the downstream sector.

The first relates to crude run levels. The detailed modelling of the global refining system points to the mechanisms by which the refining industry will likely change its operations in 2020 in order to maximize the volume of marine fuel 'switched' from 3.5% to 0.5% sulphur standard (i.e., to decrease HSFO production, while at the same time raising that for marine diesel and LSFO).

The nature of the refinery processing changes that are needed is projected to lead to a requirement to process additional crude. Thus, firstly, to upgrade unwanted high sulphur residual streams, the refining sector will tend towards maximizing coker throughputs. Since a part of their liquid feed is 'rejected' as solid coke by-product, this alone necessitates running additional crude volumes. Secondly, shifting to the 0.5% fuel standard will tend to increase processing intensity (more severe upgrading and desulphurization). In turn, this raises hydrogen and refinery fuel consumption. Part of these increases will again likely come from crude oil.

According to the Reference Case, there is a need for additional refinery runs of at least 0.4 mb/d in 2020 – over and above a case without the IMO regulations – to meet the required (partial) move to the global fuel standard in 2020. Another factor considered, primarily in 2020, is the expectation that the market will react by enabling additional outlets for high sulphur heavy oil. Most discussed has been the potential for additional sales of high sulphur heavy oil (at relatively depressed prices) into the electric power sector. Partial displacement of direct crude-burn and short-term storage, including in tankers, have also been mentioned. This again tends to create a need for additional crude runs.

However, based on the Reference Case assumptions, the need to run extra crude is seen as a temporary phenomenon, which is expected to fade in the years following 2020. This projection is based on the assumption that the penetration of scrubbing technology will progress at scale from 2020 onward, leading to a partial reversion back to high sulphur heavy bunkers demand.

A second potential impact of the regulations is that it is expected to strain the refining system – to increase production of clean and lower sulphur products while cutting that for high sulphur residual fuel. This will tend to widen differentials between light clean and heavy dirty products. Raising diesel production will be a primary driver, hence diesel-HSFO differentials are expected to widen significantly in 2020. However, since the primary refining split is between light products and heavy products, and since the production and economics of the primary light clean products (diesel/gasoil, jet/kerosene and gasoline) are all inter-connected, strained differentials versus HSFO are also expected for jet/kerosene and gasoline.

Given the emphasis on sulphur reduction, spreads between low sulphur (0.5%) and high sulphur (3.5%) fuel oil are expected to widen sharply as the latter becomes unattractive and leans to a surplus. Alleviating the fuel oil oversupply could see HSFO competing against natural gas and ultimately coal in the power generation sector, which means that the price of HSFO could potentially collapse on a temporary basis around 2020. A widening spread between LSFO and HSFO should support the decision of ship owners to install scrubbers. After the initial shock, this spread could narrow somewhat, but still remain wide enough to continue to support scrubber installation.

A strained refining market would also inevitably bring impacts on crude oil, as well as product differentials. Low sulphur crudes can be expected to command a premium, while discounts for heavy sour grades would likely widen, potentially severely. The combination of the impacts on crude oil and product differentials is expected to affect refining margins. Arguably, complex refineries, especially those geared towards distillate fuels and which process heavy sour crude oils, would experience high margins. In part, this is because the prices for their crude intake would drop. Refineries with partial upgrading and desulphurization should also benefit, although not as much as highly complex, deep-upgrading facilities.

Margins for simple refineries (and marginal hydro-skimming refining modes) would depend on their crude and product mix. For simple refineries with sweet crude intake, margins should improve despite an increased premium for light sweet crudes, as they would be able to produce LSFO, as well as light clean products whose prices would spike.

US refiners are natural candidates for additional runs due to their high complexity and their ability to maximize distillate yields and process heavy sour resid streams. At the same time, the potential also exists in Europe, where the refining capacity is under-utilized. Further potential for additional production exists in the Middle East and parts of the Asia-Pacific (for example, India and China).

The prospect of scrubber success over the long-term has the potential to limit refinery investments to handle the IMO regulations. In the short-term, conversely, there is some evidence of shuttered capacity being restarted as already mentioned.

The direct strains resulting from the need to switch large volumes to 0.5% fuel are likely to be augmented by additional factors. Firstly, although not often mentioned, is the fact that a significant share of the global refining system is inland and not close to major ports (around 34% of global capacity of which around one third has no access to coastal markets). This constitutes an additional hurdle for the year 2020.

Another important issue is the quality of marine bunkers, which is expected to change. This is due to increasing blending activity and the use of new streams, in order to provide the volumes of 0.5% sulphur content fuel required for compliance with the regulations. 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 set of progressively heavier residual type grades (often referred to as IFO). Under ISO 8217, from 2012, four distillates and 11 residual grades are specified. A 2017 update modifies the standard, primarily with regard to the inclusion of biofuels in different blend grades. An ISO committee is working on further updates, expressly to accommodate the 0.5% sulphur standard.

Recent announcements point to a mixture of marine diesel and heavier (IFO-type) 0.5% grades being offered. From a refining perspective, there is a logic to producing heavier 0.5% grades, in order to take advantage of the quality 'giveaway' that is present in a 0.5% marine distillate. However, ship owners and operators tend to be conservative when it comes to testing and adopting new fuel formulations – and have expressed concerns about the potential for incompatibility between grades that could lead to on-board ship operating problems.

As 2020 approaches, announcements are beginning to emerge from refiners and bunker blenders regarding new 0.5% fuel formulations. As these constitute a range of formulations, there is no certainty as to how long it will take for newer fuels to be accepted in volume. Concerns over compatibility are likely to curb buyers' enthusiasm for new, heavier grades, raising, at least initially, the proportion of demand for 0.5% distillate, rather than IFO. Thereby, possibly crimping the effective available supply of 0.5% fuels.[28]

Finally, the advent of the regulations presents marine fuel logistics challenges. Fuel at 3.5% can be produced by refineries essentially everywhere. In contrast, the supply in 2020 of 0.5% fuel is expected to be far more geographically concentrated in the regions that have more sophisticated refining capacity. Yet some 800+ coastal ports around the world will have to be supplied with the 0.5% fuel. Achieving this will require adaptation and time. In addition, there are questions over whether bunker suppliers will have the separate tankage and bunker barges in each port necessary to supply both 0.5% fuel and – for ships with scrubbers – the 3.5% fuel. This is especially a concern for smaller ports and for ship owners who are installing scrubbers.

These uncertainties and challenges will continue to be monitored carefully, but the current Reference Case assumes that the adoption starting in 2020[29] will be progressive, rather than instant, and that scrubbers will be relatively successful over the long-term. The potentially sharp impacts on refining mean that the price implications of the IMO decision should not be overlooked. The change to marine fuels quality will impact not only fuel oil, but also all other products in all regions. Questions are still outstanding over potential regional differences in the enforcement and the consequences of ships using 3.5% fuel, when 0.5% fuel is not available where they need to bunker.

Despite the uncertainties, what seems certain is that shipping costs will increase, including, of course, those for all crude oils and products moved by sea; this is either through higher fuel costs or the costs of scrubbing facilities. However, this is not just a shipping fuel or shipping industry challenge, since the co-product nature of the refining industry means that tightness in marine fuels could also carry over into land diesel and other clean fuels. Therefore, it remains to be seen how demand, refining and enforcement parameters will play out, and to what extent these will precipitate or help avert extreme events, such as fuel shortages and price spikes.

5.3.3 Long-term secondary capacity additions

Refining capacity is measured first and foremost by distillation capacity. However, it is the supporting capacity for conversion and product quality improvement that plays the 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 for different product groups, these 'secondary' processes have become a key gauge of a refining sector's capability to meet demand.

Today, 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 meet 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 (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. More broadly, the number of large integrated refining plus petrochemicals 'mega-projects' continues to rise, especially in the Middle East and Asia. Smaller projects in existing refineries are generally directed towards the same goals of upgrading to reduce residual fuel output and achieving quality improvements for clean products.

Together, these factors are leading to greater proportions of secondary capacity per barrel of distillation. One exception to this trend is the high volume of new condensate splitter capacity that has recently, or is currently being built.

As shown in Table 5.9, existing projects to 2023 have conversion additions at 43% of new distillation capacity. Against this, from 2023–2030, the level surges to 89%, but then falls back to 52% from 2030–2040. (Table 5.10)

In the period 2030–2040, secondary additions per barrel of distillation are estimated to fall back for desulphurization units after surging in the 2023–2030 timeframe. This is based on the projection that by 2030, the world's regions will have largely completed the shift to ULS fuels and that additional desulphurization capacity post-2030 will be restricted only to regions with additional demand growth for clean products. 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, approaching the levels currently seen in more industrialized countries. Moreover, levels in industrialized countries themselves are expected to advance in order to achieve improved efficiencies in engine thermodynamics.

The Reference Case projections for future required secondary processing through 2040 are presented in Table 5.10 and Figures 5.19–5.23. Similar to those for crude distillation units,

Table 5.10
Global capacity requirements by process, 2018–2040

mb/d

	Existing projects	Additional requirements		Total additions
	to 2023*	2023–2030	2030–2040	to 2040
Crude distillation	**7.8**	**5.2**	**4.8**	**17.8**
Conversion	**3.3**	**3.9**	**3.2**	**10.4**
Coking/Visbreaking	1.0	0.7	0.5	2.2
Catalytic cracking	1.0	2.0	1.4	4.4
Hydrocracking	1.4	1.3	1.2	3.9
Desulphurization**	**4.9**	**12.2**	**3.0**	**20.2**
Gasoline	0.9	2.1	0.5	3.4
Distillate	2.9	9.5	1.1	13.5
VGO/Resid	1.1	0.7	1.5	3.3
Octane units***	**1.7**	**2.4**	**1.4**	**5.5**
Catalytic reforming	1.2	1.2	1.2	3.5
Alkylation	0.2	0.6	0.2	1.0
Isomerization	0.2	0.1	0.0	0.3
MTBE	0.1	0.5	0.1	0.7

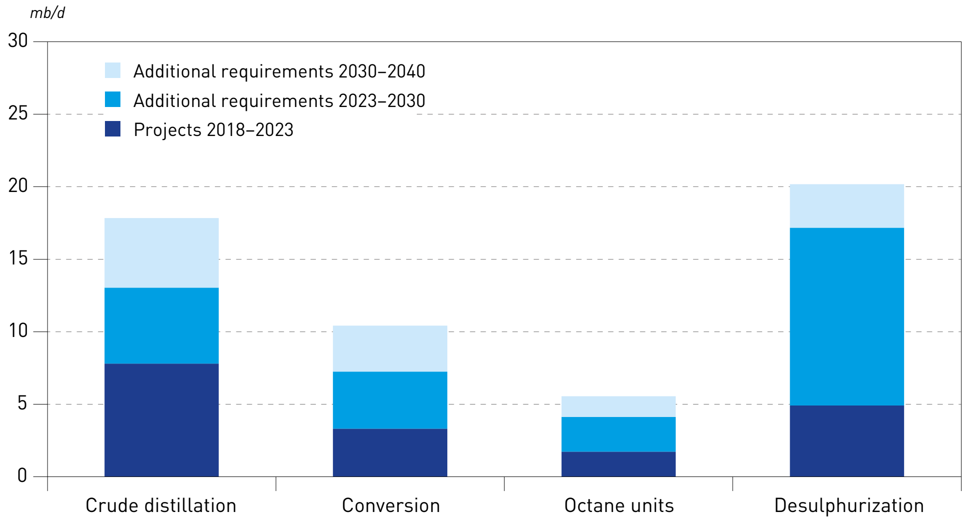
* *Existing projects exclude additions resulting from 'capacity creep'.*
** *Naphtha desulphurization not included.*
*** *New units only (excludes any revamping).*

projections for secondary process units take into account the estimated 1.4 mb/d of refinery net closures for the period 2018–2025. These not only remove 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 10.4 mb/d of conversion units, 20.2 mb/d of desulphurization capacity and 5.5 mb/d of octane units in the period to 2040.

Conversion units

The 2.2 mb/d of projected additions for coking/visbreaking, which comprises predominantly coking, is unchanged versus the previous two Outlooks. The level of coking/visbreaking additions drops from 1 mb/d in the six-year period 2018–2023 to 0.7 mb/d in 2023–2030 and 0.5 mb/d in 2030–2040. This fits with the outlook for a gradual, albeit small, recovery in residual fuel demand over time. That said, additions are expected to continue throughout the period because incremental demand is overwhelmingly for light clean products, while incremental supply includes significant proportions of medium and high sulphur crudes whose vacuum residues have to be upgraded.

Figure 5.19
Global capacity requirements by process type, 2018–2040



Catalytic cracking (FCC) additions are estimated to peak in the 2023–2030 period. This is because gasoline demand is expected to experience appreciable growth in the period to 2025, but then for growth to essentially halt thereafter. Hydrocracking additions are relatively more sustained from the medium-term through to the long-term, even though total distillate demand growth slows somewhat. Again, total required additions of conversion, or other units, are often higher than what would be justified by simply looking at the change in global total product demand. This is because certain regions have falling demand, while others have it continuing to rise, justifying new regional additions.

Future coking additions and utilizations will, of course, be sensitive to heavy crude developments in countries such as Canada, Venezuela, Brazil, Colombia and Mexico, as well as the Middle East, where production of heavy crude grades is increasing. The overall production volume of heavy grades is expected to increase in the long-term due to the rise in synthetic crudes (Canada and Venezuela). It should be noted that the refining capacity additions and investments reported in this Outlook exclude capacity in oil sands/extra heavy oil upgraders.

The varying outlooks across specific conversion units are also reflected in utilization rates indicated by the Outlook's model runs. Hydrocracking unit utilizations are projected to be consistently high – in the low 80% range – through the period to 2040. FCC unit utilizations are projected to be close to an average of 80% through the medium-term, spurred by short-term gasoline demand growth. They are then expected to gradually trend downwards to the 76–77% range post-2025. This trend is consistent with the anticipated reduction in long-term gasoline growth.

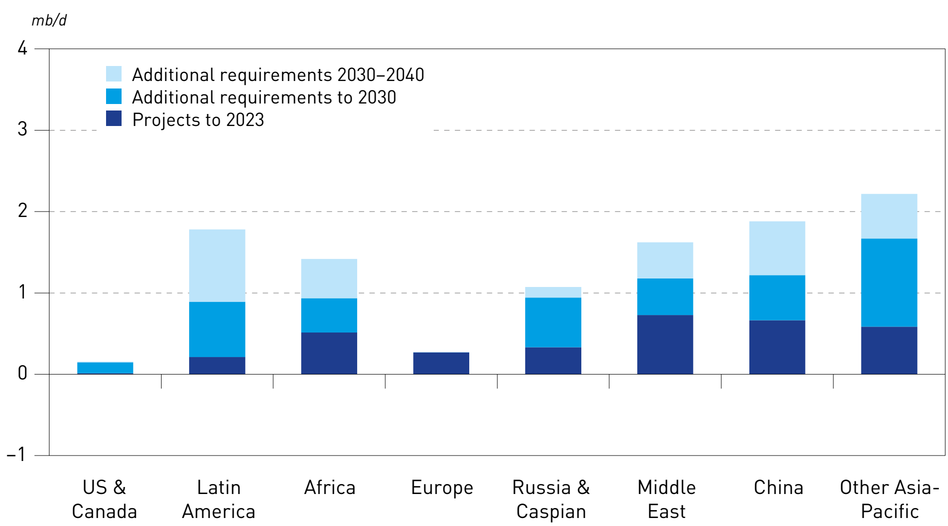
Utilizations on coking units are projected to follow a similar pattern to those for FCCs, trending down post-2025 to the 75–77% range. In the short-term, utilizations are projected to be above 80%. One factor here is the effect of the IMO sulphur regulations in driving refiners to maximize coker throughputs in the 2020–2023 period, in order to dispose of sudden levels of excessively high sulphur heavy residual streams. By 2025, utilizations are expected to have fallen below 80% as the uptake of on-board scrubbers (as assumed in the Reference Case) leads to a partial reversal in demand for high sulphur heavy marine fuel.

The regional distribution of total future conversion capacity additions is presented in Figure 5.20. Additions are minimal in Europe, with a total of 0.3 mb/d, and almost no activity beyond current projects. Similarly, only minor debottlenecking type additions are projected for the US & Canada, with some 0.15 mb/d. Requirements are expected to be led by the Asia-Pacific, at around 4.1 mb/d and the Middle East, at 1.6 mb/d.

Significant additions are also projected for Latin America and Africa, at around 1.8 and 1.5 mb/d, respectively. These are driven by sustained regional product demand growth with the bulk of the increases in the longer term. Additions in the Russia & Caspian region to 2040 are estimated at 1.1 mb/d. Overall, it is developing regions, with their continuing demand growth, that are expected to sustain conversion capacity growth over the period to 2040.

Significant coking additions, totalling 0.3 mb/d to 2040, are projected for Latin America as heavy crude production continues to expand there. Otherwise, minor additions are expected in most regions. Over 85% of FCC additions are projected to be in developing country regions,

Figure 5.20
Conversion capacity requirements by region, 2018–2040



with the largest, at 47%, in the Asia-Pacific. Beyond announced projects, FCC additions are minor (less 0.2 mb/d) for the Russia & Caspian, and minor for the US & Canada and Europe. The overall pattern is similar for hydrocracking. Appreciable additions are expected for all regions outside of the US & Canada and Europe, with the leaders being Other Asia-Pacific and China, the Middle East and Latin America.

As noted, the modelling results point to most FCC additions occurring before 2030 and then slowing thereafter. Thus, especially for FCCs, there is some risk of stranded investments because of the projected levelling off in global gasoline demand. Hydrocracking and coking additions also carry a specific risk that goes beyond the normal uncertainties associated with economic and oil demand growth – namely, the potential effects of the IMO sulphur regulations and the degree to which this drives a shift to distillates and away from high sulphur HFO.

The Reference Case demand profile assumes a jump in demand for 0.5% sulphur marine distillates in 2020. Research undertaken in the lead-up to this Outlook has highlighted few instances of marine fuels being cited as the primary basis for investments. What is evident is that a number of process technology developers are using the potential impacts of the IMO sulphur regulations to highlight the benefits of their technology. A handful of new processes – generally still at the pilot or demonstration stage – offer improved means to crack, desulphurize and even demetallize heavy crude oils, bitumen and heavy sour residual streams. Should one or more of these new technologies make it to the commercial scale, the timeframe will certainly be post-2020, but the impacts could be substantial, eating into additions for the conventional upgrading processes.

Desulphurization units

In addition to conversion, desulphurization capacity represents another important component of secondary units. Driven by the progressive move towards 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 increase among all process units over the 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 4.9 mb/d of desulphurization capacity (excluding naphtha desulphurization) that is included in assessed projects to 2023 (Table 5.10 and Figure 5.19), a further 12.2 mb/d is projected to be required by 2030, and an additional 3.0 mb/d between 2030 and 2040. This leads to additions totalling 20.2 mb/d by 2040, which compares to 17.8 mb/d of total crude distillation capacity additions by 2040.[30]

Two features stand out. Firstly, while major new refinery projects are designed with significant built-in desulphurization capacity, the high-level of total desulphurization additions, relative to distillation, points to substantial desulphurization additions occurring at existing refineries, as they adapt to meet progressively tighter fuel sulphur standards. Secondly, a considerable slowing in the pace of desulphurization capacity additions is apparent in the decade from 2030–2040, compared to 2023–2030. This follows from the projection that most regions will see gasoline/distillate fuel volumes reach ULS standards by 2030.

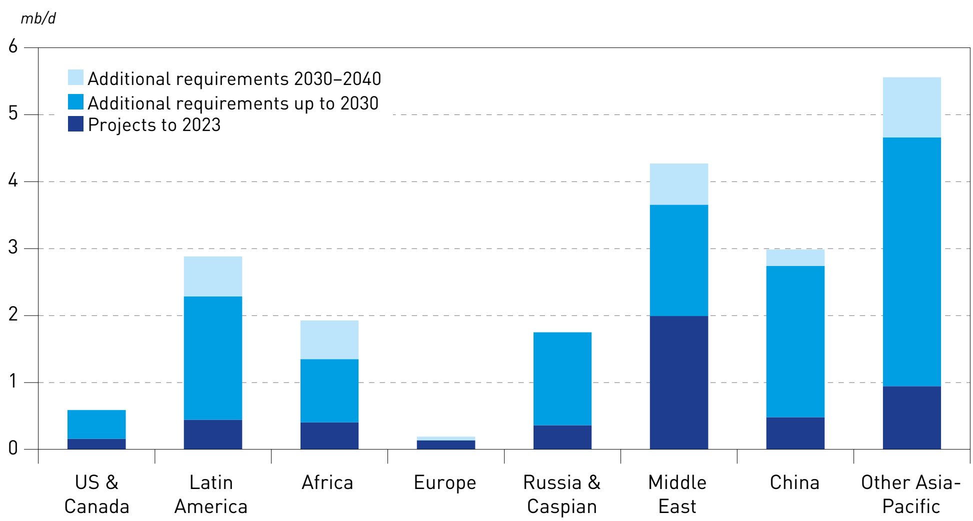
In terms of the regional breakdown (Figure 5.21), total additional global desulphurization capacity of 20.2 mb/d by 2040 is projected to be led by the Asia-Pacific at 8.6 mb/d, of which China comprises 3.0 mb/d. The Middle East follows with 4.3 mb/d and then Latin America with 2.9 mb/d, driven by demand, the expansion of the refining base and stricter quality specifications for domestic fuels.

Africa is projected to need some 1.9 mb/d of desulphurization additions as the region also moves towards tighter standards for transport fuels. Significant additions are also projected for the Russia & Caspian region (1.8 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.

The 0.6 mb/d requirement for the US & Canada comprises less than 0.2 mb/d from announced projects, plus minor long-term additions, in part to deal with high sulphur crude from oil sands. The lowest desulphurization capacity additions are projected for Europe, with a minimal 0.2 mb/d over the forecast period, where transport fuels are already at ULS standards, and both demand and refinery throughputs are projected to continue to decline.

In terms of timing, for Europe, only 30% of total additions to 2040 are over and above projects to 2023. For the Middle East, that figure is 53%, reflecting the impact of the current project wave in terms of front-loading the additions. For other regions, additions beyond announced projects in the medium-term are generally in the range of 75–85% of the total to 2040.

Figure 5.21
Desulphurization capacity requirements by region*, 2018–2040



** Projects and additions exclude naphtha desulphurization.*

In respect to the main product categories, of the 20.2 mb/d of global desulphurization capacity additions between 2018 and 2040 (excluding naphtha desulphurization), some 67%, or 13.5 mb/d, are estimated for distillate desulphurization, followed by 3.4 mb/d for gasoline sulphur reduction. The remaining 3.3 mb/d is for vacuum gas oil (VGO) resid processing (Figure 5.22).

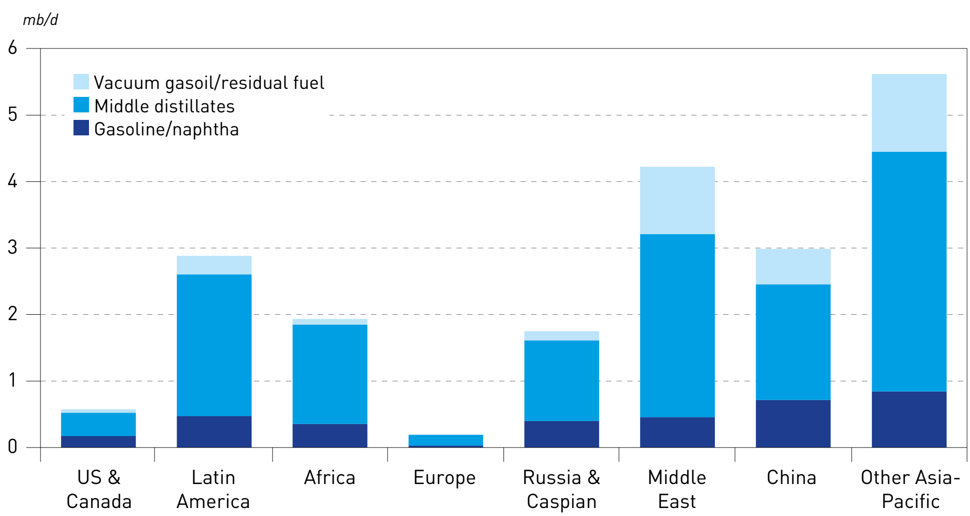
It is important to note that opportunities to revamp existing distillate desulphurization units could impact the required capacity addition levels indicated. The modelling incorporates relatively conservative assumptions regarding the ability of refiners worldwide to repurpose existing distillate desulphurization units into ULS services.

These opportunities are generally dependent on such issues as the age and configuration 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

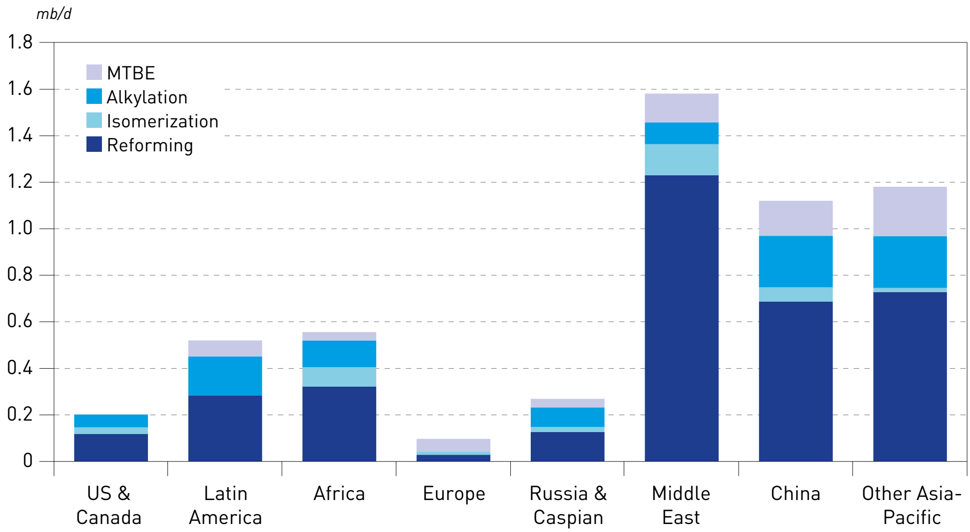
For octane units, future requirements are projected at 5.5 mb/d throughout the forecast period (Figure 5.23). The majority of these units are expected to be required in the form of catalytic reforming at 3.5 mb/d, with alkylation at 1 mb/d, isomerization at close to 0.4 mb/d and MTBE units at 0.7 mb/d. Reforming and isomerization raise naphtha octane and

Figure 5.22
Desulphurization capacity requirements by product and region*, 2018–2040



** Projects and additions exclude naphtha desulphurization.*

Figure 5.23
Octane capacity requirements by process and region, 2018–2040



thus enable additional naphtha – including that from condensates – to be blended into gasoline.

In line with other secondary processes, most of these additions are projected for the Asia-Pacific and the Middle East, the two regions with the largest gasoline demand increases, as well as expanding petrochemical industries. Together, these account for 70% of the total expected octane unit additions to 2040. Latin America and Africa are also projected to have significant octane unit additions as their gasoline standards rise, each accounting for around 10% of the total.

The US & Canada, Europe and the Russia & Caspian each account for 4%, 2% and 5%, respectively, of total additions. Of projected MTBE capacity additions totalling 0.7 mb/d to 2040, some 70% are in the Middle East and the Asia-Pacific, with the balance spread across all regions except for the US & Canada, where MTBE is not used. The US has the refinery and/or merchant feedstocks, but MTBE use was effectively banned in 2006. This means that all MTBE capacity there has been shut down except for about 80,000 b/d of Gulf Coast merchant MTBE and related ether units whose product is exported.

5.4 Investment requirements

Investment requirements in the downstream sector are shown in three different categories. The first category relates to identified projects that are expected to be commissioned in the medium-term (2018–2023). The second category is related to possible investments in new projects in the long-term. These are refining capacities estimated as needed and are in line with Reference Case assumptions. The third category focuses on maintenance of the global refining system and covers necessary capital replacements.

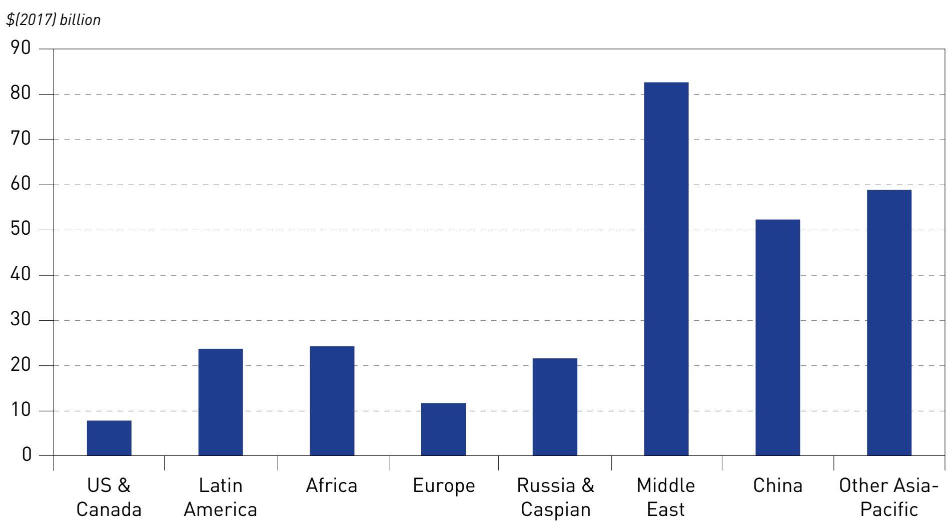
For the first category (shown in Figure 5.24), the total investment volume is estimated at around $283 billion.[31] The distribution of this amount is uneven and in line with the medium-term outlook on refining capacity expansion and demand development.

The largest share of investments in this category is projected to occur in the Asia-Pacific and the Middle East. Investment volume for the two regions combined is seen at almost $195 billion, which is almost 70% of the global total, almost unchanged compared to the previous WOO. The medium-term investment in the Asia-Pacific alone is estimated at just above $110 billion, of which $52 billion is located in China, while the rest is distributed across the rest of the Asia-Pacific region (notably projects in India, Vietnam, Malaysia and Indonesia).

The major driver for this expansion is increasing demand. Medium-term additions in the Middle East are expected to result in an investment volume of around $83 billion, with new projects across the region, including in Saudi Arabia, Kuwait, Iran, Iraq and the UAE. The increasing investment in the downstream sector is not only supported by the region's increasing demand, but also through efforts to expand product exports to other regions.

In Latin America, the volume of investments in the refining projects is estimated at around $24 billion in the medium-term, influenced by the overall slowdown in this region. Continuous deferrals and cancellations of projects in countries like Brazil and Mexico have led to

Figure 5.24
Cost of refinery projects by region, 2018–2023



lower investment activity than previously estimated. However there are still a number of projects under construction and in post-final investment decision (FID) phase, which are expected to be finalized within the medium-term, including projects in Brazil, Peru, Colombia and Argentina.

In Africa, an investment volume of around $24 billion is expected in the period 2018–2023, driven by healthy demand growth and a relatively high share of product imports, which stimulates downstream capacity additions. A large share of the medium-term investment volume in this region is accounted for by some large single projects in West Africa, as already mentioned.

Turning the focus to developed countries, the US & Canada region is projected to invest only around $8 billion in refinery projects in the medium-term. Recent years, including 2017, have already seen healthy investment activity in this region, predominantly based on the increase in domestic feedstock, with several new condensate splitters being commissioned. Several new condensate splitters are expected to come online in the medium-term in Texas, while other downstream investments are related to minor additions, mostly in PADD III.

In the Russia & Caspian region, the total medium-term investment volume is estimated at levels just above $20 billion, mostly in Russia. The refinery sector is dominated by smaller expansions and upgrades of secondary capacity, which will help to reduce the output of residue and increase the production of clean products.

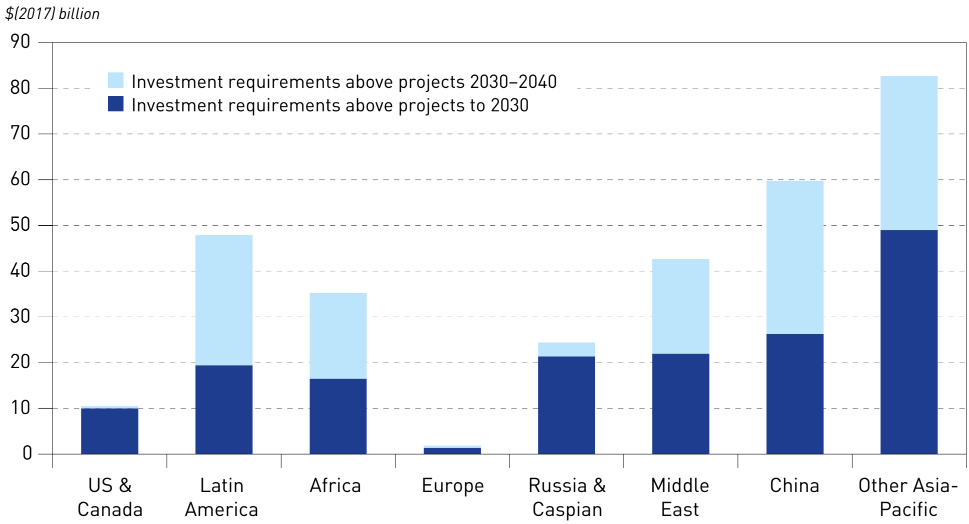
Finally, in Europe just under $12 billion of investment is expected until 2023. This investment volume includes one single new refinery, Aliaga in Turkey, starting in 2018, and several smaller upgrading and expansion projects in the Netherlands, Belgium, Poland and the UK.

Meanwhile, looking at the long-term capacity additions needed (after the medium-term period ending in 2023), there are significant assessed investments needed (for 2024–2040) in order to maintain sufficient refining capacity to balance demand on the global and regional level. All these further additions are the result of modelling based on the Reference Case supply and demand assumptions. According to the estimates, investments of around $305 billion will be needed in the period until 2040, as shown in Figure 5.25.

Similarly to the medium-term estimates, the majority of investments will be located in the Asia-Pacific (excluding OECD Asia-Pacific), driven by demand growth in the region's developing countries. While investments in China are projected at a level close to $60 billion, investments in other developing countries of the Asia-Pacific region are seen at just above $83 billion. Furthermore, investments in the Middle East are projected at around $43 billion, which is some 50% of the investment expected in the medium-term period. This reflects the anticipated slowdown in new builds in this region over the long-term.

Latin America is projected to see a strong increase in capacity additions after 2023, driven by healthy demand growth and insufficient domestic refining capacity. Consequently, the investment volume in Latin America between 2024 and 2040 is projected at almost $48 billion. Somewhat lower investment volumes are projected in Africa, around $35 billion, supported by expanding demand in Africa.

Figure 5.25
Projected refinery direct investments* above assessed projects



* *Investments related to required capacity expansion, excluding maintenance and capacity replacement costs.*

African domestic feedstock is mostly sweet, which keeps investment in secondary units, such as desulphurization, lower relative to other comparable regions, such as Latin America. New projects in both Latin America and Africa, will have to compete against exports from the US and Europe, which is expected to limit the number of new projects.

In the Russia & Caspian region, the level of investment between 2024 and 2040 is seen at around $24 billion, above firm projects. As a region with a surplus refining capacity, with only an expected minor growth in long-term product demand, there is no incentive to expand capacity significantly. In addition, oil demand in the traditional export market for Russian refiners, Europe, is seen to decline in the long-term, which is another reason for the relatively low investment volume. The largest share of investments is expected to occur in secondary capacity, in order to comply with stricter product specifications in the region's target export markets.

In the US & Canada, the refining sector is expected to see only minor long-term expansions, as demand is expected to peak and then decline towards the end of the forecast period. However, some investments can be expected, especially in secondary units, as the share of heavy and sulphur-rich crudes from Canada gradually increases. As a result, an investment volume totalling around $10 billion is expected in the long-term.

Finally, long-term investments in Europe relate only to minor expansions (debottlenecking and secondary capacity) due to declining long-term oil demand in combination with strong competition from other regions, such as the US, the Russia & Caspian and the Middle East. Consequently, the investment volume projected is only around $2 billion between 2024 and 2040.

In total, the first two categories (identified projects in the medium-term and generic investments in the long-term) make up just under $590 billion. This is the level necessary to accommodate the development of long-term oil demand, in terms of growth and regional distribution. Moreover, stricter environmental regulations regarding product quality are also driving investment into the downstream sector.

Driven by medium-term demand, almost 50% of the total estimated investment volume of $590 billion will occur in the medium-term (2018–2023), while the rest is estimated to be disbursed in the long-term. This becomes even clearer when taking the period until 2025 with projected investment of around $385 billion, which is 65% of the total investment volume. Long-term oil demand growth sees a slowdown in most regions, with developed countries facing negative growth.

Finally, maintenance and the replacement of installed refining capacity over the forecast period 2018–2040 is estimated to require associated investments of around $895 billion. The assessment of this investment category is based on the assumption that the annual capital needed for capacity maintenance and replacement is around 2% of the cost of the installed base. Based on this approach, the largest share of medium-term maintenance costs occurs in developed countries as these countries have the highest level of base capacity.

In the long-term, however, the share of maintenance and replacement costs will increase toward developing countries. This is the reason why long-term maintenance and replacement costs in the US & Canada are estimated at just above $200 billion. At the same time, Other Asia-Pacific (excluding China) stands at $210 billion. Other regions (except for Africa) show maintenance and replacements cost levels between $70 billion and $110 billion, resulting from capacity increases (Latin America, Middle East, China) or high base capacity (Europe, Russia & Caspian). Africa is the only region with low long-term maintenance and replacement costs, estimated at just below $25 billion, based on this region's relatively low base capacity.

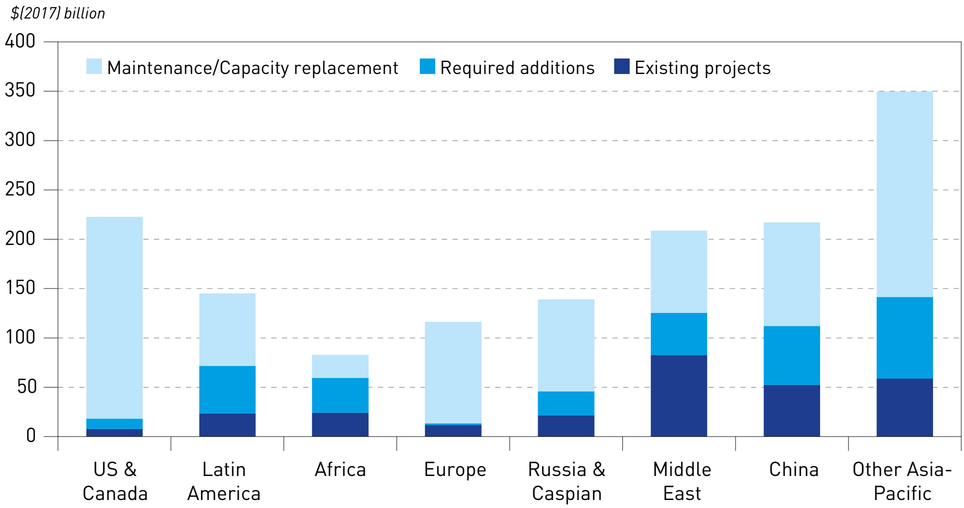
In summary, the total volume of the three categories in terms of downstream investments is estimated at just under $1.5 trillion for the period 2018–2040. Of this, $283 billion is expected to be invested in known medium-term projects, $306 billion into additions beyond known projects in the long-term, and around $895 billion for maintenance and replacement for the whole period 2018–2040. (Figure 5.26)

5.5 Refining 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 at the global level over the medium-term than incremental demand requirements would indicate as necessary.

Figure 5.26
Refinery investments, 2018–2040



The medium-term capacity 'overhang' now appears to be resurging with 2.5 mb/d projected for the end of the current medium-term period in 2023.

Second, at the regional level, stark contrasts emerge. Medium-term capacity excess is expected to build in the US & Canada and Europe, while Latin America is anticipated to experience sustained capacity/product deficits and Africa potentially swings from deficit to surplus. Minor deficits in the Asia-Pacific region, with its sustained demand growth, are projected to be more than offset by surpluses emanating from the Middle East. The latter maintains its position as one of the leading demand growth regions, but it is also expected to witness capacity additions in order to increase product export potential.

These factors and trends are projected to carry over into the long-term. Two major drivers are evident: a progressive slowdown in the rate of liquids demand growth – 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 at least 4 mb/d of closures are indicated as needed over the long-term, in addition to the projected closures of 1.4 mb/d projected for 2018–2025, in order to establish and maintain efficient utilization levels in all regions. A key question is whether, and when, 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 global refining margins if all projects are implemented and substantial closures are not made in the coming years.

Historically, pressures on margins have led to significant closures in industrialized countries, so the same could – or should – continue to happen in the future. 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 industrialized countries will be applied.

A potential related issue is whether the associated need to move to a smaller numbers of larger refineries can readily occur. This has been the long-term trend in, for instance, the huge US market. Nonetheless, can it be repeated elsewhere – in countries and regions with far smaller consumption levels? In many developing countries, existing refineries are relatively small and can be isolated. Moreover, many are run by state oil companies that can be more constrained in their options than their private sector counterparts. 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 areas of a given country, or in smaller countries, which may mean some end up with no refineries and rely 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 as to the degree to which they will be realized.

What appears certain is that the steady slowdown in capacity additions – from around 1 mb/d p.a. to 2025 to around 0.3 mb/d p.a. post-2035 – will require an adjustment to a low growth refining sector, reinforcing the emphasis on competitiveness and efficiency. At the global level, corresponding growth rates in refinery crude runs are expected to drop from 1.1 mb/d p.a. to 2020, to a low of 0.2 mb/d post-2030. (The rate of capacity additions is higher than the net global rate of crude run growth because the latter combines declines in some regions and growth in others that need new capacity.)

This steady drop-off in the rate of required additions points to the need for caution in considering any major expansion. Paradoxically, though, it creates an incentive for 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 worth noting that the projected need for long-term annual capacity additions gradually declines to a level which, at 0.3 mb/d post-2035, essentially converges with the 0.25–0.3 mb/d long-term annual average closure rate indicated as required. 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.

Oil movements

Key takeaways

- Global crude oil and condensate exports are expected to increase by around 5.5 mb/d between 2017 and 2040 and reach almost 44 mb/d in 2040, mostly driven by increasing demand in the Asia-Pacific and decreasing domestic supply.
- In 2025, the global crude export level is projected to drop to around 39 mb/d, mainly due to lower volumes coming from Latin America and Africa, as more volumes are refined in these regions. Furthermore, exports from the Middle East are also projected to fall somewhat, in line with declining production between 2020 and 2025.
- Post-2025, global crude exports are expected to increase gradually to levels below 44 mb/d in 2040, driven by increasing demand from the Asia-Pacific and rising exports from the Middle East and the Russia & Caspian. Middle East crude exports are estimated to rise by more than 6 mb/d between 2025 and 2040.
- The long-term outlook shows that given the evolution of regional demand, the importance of the Middle East-Asia Pacific trade route will gradually increase. Export volumes, estimated at almost 14.5 mb/d in 2017, are projected to rise to almost 21.5 mb/d in 2040.
- Already in 2020, crude exports from the US & Canada are at just under 3 mb/d. They are expected to further increase to almost 4 mb/d in 2025.
- Overall oil flows from Latin America are projected to decrease gradually from around 5 mb/d in 2017 to below 4 mb/d in 2040, in line with increasing domestic demand in Latin America and expanding refinery projects.
- Crude exports from Africa are anticipated to start declining from 2025, despite rising crude output levels. This is mainly due to increasing refining capacity in the region, supporting African domestic oil demand growth. African crude exports are estimated at 5.3 mb/d in 2040, down from around 6 mb/d in 2020.
- US refiners, which prefer low-quality crude and discounted grades, are likely to continue processing supplies from Latin America and the Middle East in the medium-term.
- Asia-Pacific remains the main crude importing region and is expected to offset declines in other importing regions, such as Europe and the US & Canada. Crude oil imports are anticipated to increase from 22 mb/d in 2017 to just below 30 mb/d in 2040.
- Asia-Pacific is set to increase refined product net imports, in line with increasing oil demand. Other net importing regions are expected to remain mostly stable in the period 2020–2040.
- The majority of the additional product net imports will be covered by the Middle East and the US & Canada. In the Middle East, incremental product supply will come from new refinery projects, while in the US & Canada declining domestic oil demand leaves space for additional product exports.

Trade movements of crude oil, finished and intermediate products are crucial elements of the global oil market and are responsible for the integration of different regions into the overall global system. This Chapter will describe projected crude and product flows based on the OPEC Reference Case assumptions.

6.1 Logistics developments

Development in logistics infrastructure is crucial for maintaining oil exporting capabilities and the availability of products to major markets. Crude oil and product movements tend to vary with the type of infrastructure developments. This applies mainly to pipelines for crude oil movements that can move important volumes and provide economies of scale and, to a lesser extent, to railway systems. Thus, developing infrastructure from pipeline, coastal terminals and berthing capacities for moving crude and oil products including liquid hydrocarbons is key to accessing new international markets and providing exports flexibility. Some specific regions require a continuous focus of attention because of their potential to alter inter-regional crude trade. This applies especially to China, the Russia & Caspian and North America regions with important hydrocarbons resources and strategic locations.

6.1.1 US & Canada

Logistics developments in the region continue to resemble a race between crude oil production and takeaway capacity. The recent years of growth for Canadian oil sands and North American tight oil have led to a massive build-out and re-orientation of the crude oil logistics system.

In the US, this has been primarily to take large new production volumes to the coast – instead of bringing imported crudes inland. Pipeline capacity within western Canada, cross-border from western Canada into the US and east to Sarnia and Montreal has also been expanded. In parallel, substantial crude-by-rail capacity has been developed, especially from the Bakken and other US producing regions to the coast, and also to carry western Canadian production to eastern Canada and to US destinations. In some instances, this array of developments has led to excess capacity, notably total pipeline-plus-rail take-away capacity from the Bakken region.

The drop in oil prices from 2014–2016 had the effect of slowing tight oil growth, providing somewhat of a 'breather' for takeaway capacity in the US. However, that was short-lived. The resurgence of US crude oil and condensate production in the past couple of years, especially in the Permian, has led to bottlenecks that have depressed WTI prices relative to Brent.

These constraints, however, should also be short-lived. Currently, there is approximately 3 mb/d of pipeline capacity from the Permian to the US Gulf Coast. A series of projects should add 1.4 mb/d by the third quarter of 2019 and a further 1.75 mb/d by 2020–2021. This capacity will, in part, also bring Eagle Ford crude and condensate to the coast. Direct capacity from the Eagle Ford, mainly to Corpus Christi and to Houston in Texas, totals 2 mb/d, with a further 1 mb/d on the way. Together, these additions should ensure that continued growth in supply from these basins is not constrained from late 2019 onwards.

Cross-border pipeline flows from western Canada into the US have also hit limits. The 'nameplate capacity' of cross-border pipelines today is estimated close to 4.2 mb/d, but their effective maximum utilization appears to be around 89%. As a result, they are full. Consequently, crude-by-rail movements are rising again and this looks set to continue until additional pipeline capacity is forthcoming. Bringing new pipeline capacity onstream from western Canada is not proving to be easy. Despite the higher costs of crude-by-rail, and the associated widening in Canadian heavy crude discounts, data indicates that Canadian exports to the US continue to rise, albeit slowly.

The current big 'exports' story arguably relates to the US. Until 2016, recorded increases related overwhelmingly to product exports, although these have been relatively stable for the past two years at around 5 mb/d. This category includes finished products, intermediate streams, blendstocks and NGLs. Growth in US natural gas production is continuing to boost NGLs supply and exports.

The end of the US crude oil export ban in December 2015 has led to the largest change in the export picture. After a slow start as foreign refiners test-ran US crudes, exports have accelerated to the 2.5–3 mb/d level earlier this year in certain weeks. Predominantly, this comprises very light crude oils that do not fit well with the grades most US refineries run. (Most light tight oil production is in the 40–55° API range, whereas average US refinery crude slates are in the 32–34° range and heavier on the West Coast.) The implication is this additional production could primarily be exported – just as the majority of the very light Eagle Ford crude and condensates are today.

Presuming US refinery throughputs and crude oil imports do not change greatly over the next few years, the medium-term prospect is for additional exports, primarily from the Gulf Coast. It begs the question: can/will the infrastructure be there to handle this? The answer would appear to be almost certainly, yes. Current Gulf Coast export capacity for crude oil has been assessed at 4–5 mb/d, which leaves a good margin versus current export volumes. Moreover, a series of projects continues to add to storage and dock capacity across the Gulf Coast.

These, together with channel dredging, are also seeing a shift to larger tankers, firstly SUEZMAX over AFRAMAX, but already test loadings and partial loadings, plus reverse lightering, for very large crude carriers (VLCCs). The single current VLCC facility on the Gulf Coast, namely LOOP offshore Louisiana, which was designed to handle crude oil imports, has already test-loaded VLCC cargoes. The potential reversal of Capline (capacity of 1.2 mb/d) to bring crudes from Illinois to the US Gulf Coast could add to the incentive to make LOOP a regular VLCC export port. Aided by pipeline capacity that now takes crude oils across the Gulf, the potential exists for rising exports at several hubs from Corpus Christi in the west to St. James and LOOP in the east.

In Canada, the pipeline project story has continued over the last year. Recent WOOs have reported on the status of pipeline projects to increase takeaway capacity from the Western Canadian Sedimentary Basin (WCSB). Today, it is clear that additional capacity is needed. Continued WCSB supply growth has hit the limit of current pipelines, meaning that marginal, albeit growing, export flows to the US now need to be via rail. These have been slow to pick up, despite over 700,000 b/d of nameplate crude-by-rail loading capacity in Western Canada, leading to wide discounts for heavy WCSB grades. (The Western Canadian Select (WCS) discount to WTI widened to as much as $30/b in June 2018.)

However, rail companies and producers negotiate unit-train term contracts for crude-by-rail. On this basis, the recent severe WCSB crude discounts should narrow somewhat and crude-by-rail volumes should rise. It should be noted that export movements by rail recently rose to nearly 200,000 b/d earlier this year. This is now essential to avoid shutting in WCSB production since progress toward getting major new pipeline capacity onstream continues to be a case of 'one step forward, one step back'.

For five major export pipeline projects, the scoreboard currently reads: lost two, won one (nearly), struggling to finish two. After last year's cancellation of the Northern Gateway and Energy East pipelines, three projects remain: Trans Mountain to the British Columbia Coast, Keystone XL to the US Gulf Coast, and the cross-border Line 3 Replacement Program. Together, these three projects would increase pipeline capacity by 1.8 mb/d – more than enough to absorb WCSB supply growth for the next ten years. However, question marks remain over whether they will go ahead.

Enbridge's project to replace its cross-border Line 3 pipeline and thus restore its original capacity, effectively an increase of about 370,000 b/d, looks closest to proceeding. Construction has begun and, in June, Minnesota regulators gave their approval. The project is intended go online in November 2019 provided it does not encounter further hurdles.

After having secured approximately 500,000 b/d of firm commitment, construction for the $8 billion Keystone XL project is expected to start in earnest in 2019, ten years on from the initial application. TransCanada's 1,200-mile proposed pipeline would carry 830,000 b/d of crude from the oil sands region of Alberta to Steel City, Nebraska, where it will connect to other pipelines and send crude to US Gulf Coast refineries. Nonetheless, despite having received a Presidential Permit and approvals from the US State Department, the project is still facing court battles from environmental groups and Native American tribes that could lead to further delays.

In a somewhat unusual move, the Canadian Government has said it will purchase Kinder Morgan's Trans Mountain pipeline and its expansion project for $3.5 billion (US), a figure that apparently excludes the project construction cost that has been listed at close to $6 billion. This action came after the expansion project received pushback from environmental groups and British Columbia's provincial government. The intent is to ensure that the expansion's construction will continue while Kinder Morgan and the government seek a third-party buyer or buyers. Furthermore, in August 2018 a Canadian court rejected approvals for expansion plans that could delay the project by further 12 months.

It is still early days to know whether this approach will ensure the project goes ahead. The Trans Mountain pipeline expansion would increase the system's throughput capacity from 300,000 b/d to 890,000 b/d and carry oil sands, as well as conventional crudes and products, from Alberta to a port near Vancouver, British Columbia. The expansion would serve the growing Asia-Pacific market and the US West Coast. The targeted in-service date for the project is now December 2020, a year later than originally expected. The project creates the opportunity for Western Canadian crude to reach markets beyond the US, which is currently Canada's almost sole buyer.

If all three projects are successfully completed, they will clearly diversify WCSB crude oil markets and help ensure takeaway capacity is not a constraint on increasing crude production from the region.

6.1.2 Russia & Caspian

From the perspective of the Russia & Caspian region, which has significant influence on future crude oil flows, there are a number of pipeline expansion projects worth noting. Currently, a large share of oil exports is exported via pipeline systems such as the Druzhba pipeline system to Eastern Europe and the Eastern Siberia–Pacific Ocean (ESPO) pipeline to China and the Pacific Ocean. Russia is continuously developing its pipeline network and increasingly turning to rising demand centres such as Asia and especially China.

In Asia, Russia continues its efforts to expand the ESPO pipeline system to China and the Pacific Coast. The ESPO pipeline was inaugurated in 2009 and is now an outlet for volumes of the ESPO blend to the Asia-Pacific market, which is now a well-established source of supply for the region's refiners. The estimated capacity of the pipeline from East Siberia (Taishet) to Skovorodino is 1.16 mb/d, while the initial capacity of the branch to China was estimated at around 0.3 mb/d (according to some sources this is even 0.45 mb/d with additional pumping stations). In early 2018, Russia finalized the expansion of the pipeline connection to China. From an existing 0.3 mb/d, the capacity was doubled to 0.6 mb/d, which will gradually pull additional volumes of Russian crude to China. The increase in ESPO pipeline deliveries to China could in the medium-term lead to the lower availability of this crude at the Pacific Coast at Kozmino Bay, which would be expected to be replaced with similar grades from other destinations, such as Africa and the Middle East, or even the US & Canada.

The capacity of the branch from Skovorodino to the Pacific Coast is estimated at 0.6 mb/d. A further connection branch of the ESPO pipeline to the Khabarovsk refinery was completed in 2015 (120,000 b/d), while an expansion to the Kosmomolsk refinery was completed in 2018 (160,000 b/d).

The final stage of the overall ESPO expansion is under construction and scheduled for completion by 2020. In total, the ESPO pipeline capacity to Skovorodino (main line) should be increased to 1.6 mb/d and from Skovorodino to the Pacific Coast to 1 mb/d by 2020. The WOO assumes further expansions of the ESPO pipeline system to China and the Pacific Coast, with the overall capacity increasing to 2 mb/d in 2030 and 2.4 mb/d in 2040.

6.2 Oil movements

The integrated global downstream sector is built on the capacity to move large parcels of oil liquids (crude or products) 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. The ability to move crude oil and products also helps to avoid short-term shortages of fuels. For example, shortages caused by weather-related issues could lead to the shutdown of crude oil and product supply in specific regions, but at the same time these are offset through corresponding price signals.

Various factors can 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; 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 that 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 result in a preference for locating refining capacity in consuming regions due to the lower transport costs for crude oil compared to oil products, but there are also strategic reasons. This leads to the majority of trade – especially over long distances – involving crude oil. However, when costs or other hurdles exist to build the required refining capacity, or where there are substantial regional supply/demand imbalances, the result can be significant trade in products.

For producing and consuming countries alike, there is an emphasis on securing supplies of refined products through local refining rather than imports, regardless of 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 at times result 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 and term contracts, and a modelling approach that looks longer term, with few restrictions on movements and which operates by minimizing global cost, 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 ten 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.

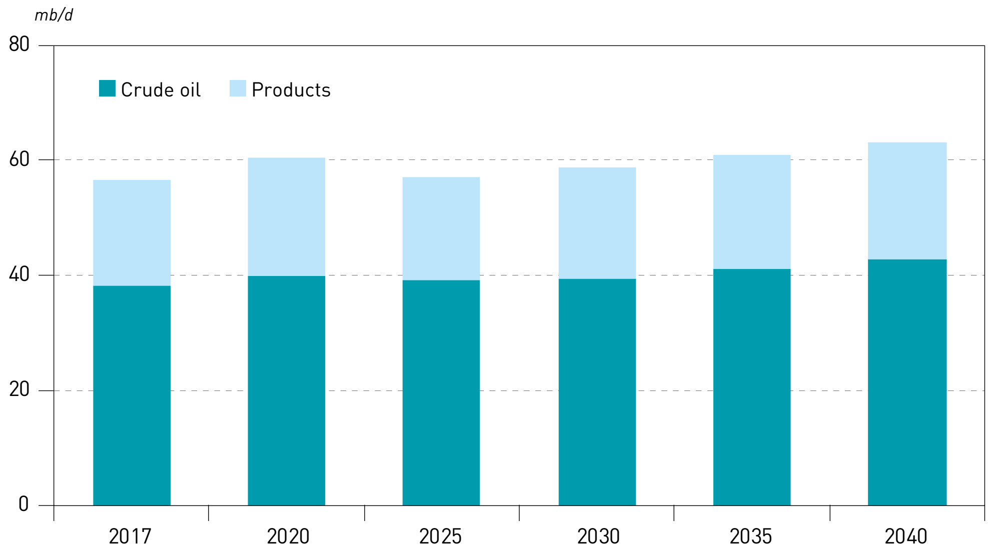
Key elements in this are the volumes and qualities of both crudes produced and the products consumed by region, and how these change over time. Another element is the location and capability of refining capacity. Over the longer term, the relative economics of building new refinery capacity in different 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. 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.

Figure 6.1 provides an overview of projected global oil trade to 2040 as reported on a seven-region basis. Crude trade volume is projected to increase slightly from around 38.5 mb/d in 2017 to 40 mb/d in 2020. Although the total volume increase of around 1.5 mb/d sounds small, there are significant shifts at the regional level. While the US & Canada region emerges as a significant exporter of crude and condensate to the world's markets with average volumes close to 3 mb/d in 2020, some other regions such as Latin America and the Middle East see a slight drop in export volumes due to higher domestic refinery throughputs and the respective increase in domestic demand.

The IMO sulphur regulations are expected to give support to trade flows of crude and condensates in 2020. The regulations will put pressure on maximizing the processing and upgrading of heavy sour crudes to deal with the surplus high sulphur heavy fuel oil. As a result, both exports from, and imports to, the US & Canada are expected to rise significantly around 2020. Consequently, the US & Canada region is estimated to increase imports of sour crudes from Latin America and the Middle East, as price differentials of those barrels should come under pressure in 2020. The US & Canada is equipped with a highly complex refining system able to process cheaper medium and heavy sour crudes, which at the same time creates a surplus of light, sweet crude for exports.

Figure 6.1
Inter-regional crude oil and products exports, 2017–2040



In 2025, the global crude and condensate trade is expected to witness a slight slowdown with an increase in domestic consumption the main reason. Several major exporting regions are anticipated to see an increase in domestic refining capacity, such as Latin America, the Middle East and Africa, which lowers the volume of crude available for export to other regions. The global trade in crude and condensate is consequently expected to drop around 1 mb/d between 2020 and 2025 to a level around 39 mb/d.

In the long-term, the trade of crude and condensates is projected to increase gradually to levels just below 43 mb/d in 2040. The major driver is the demand increase in the Asia-Pacific with more volumes being shifted from the Middle East to the Asia-Pacific, while at the same time the exports from other regions such as Latin America, the US & Canada and Africa are forecast to decline in this period.

Product movements were estimated at levels around 18.5 mb/d in 2017 and are expected to increase to around 20 mb/d in 2020. Refinery new build in importing regions such as Africa, Latin America and the Asia-Pacific is estimated to not be sufficient to cover demand growth in the same period, which supports additional product flows.

In addition, the IMO regulation, effective as of 1 January 2020, is another reason supporting the movements of refined products. The IMO regulation is expected to result in the extra production of HSFO which, most probably, will find its final outlet in the power generation sector. At the same time, regions with a simple refining set-up will have to increase imports of cleaner fuels (LSFO or diesel), while exporting HSFO. The shift to the 0.5% sulphur standard is expected to concentrate low-sulphur marine fuels production – versus the traditional 3.5% fuel – yet still require distribution to essentially all world ports.

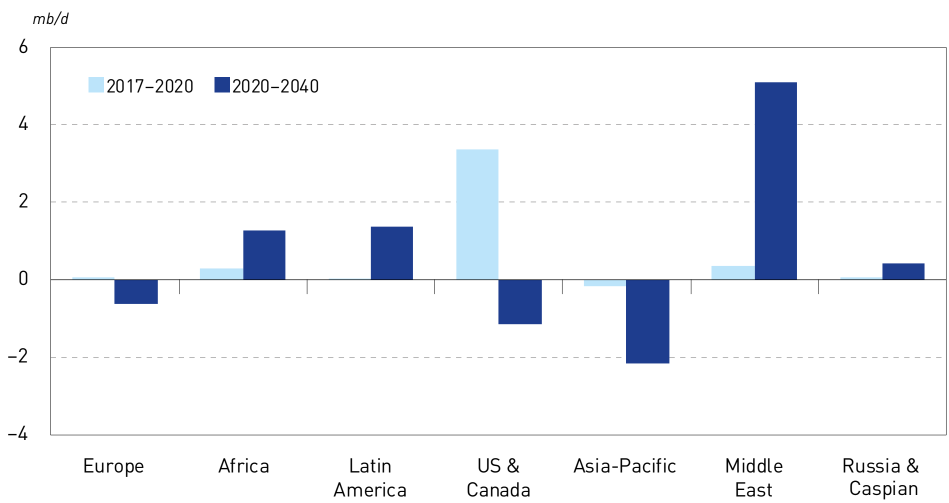
However, as the system in the post-IMO regulation stabilizes and the refining system in product importing regions expands, total product movements are projected to decrease significantly in 2025 to around 18 mb/d. Another reason for this drop is the declining demand in the US & Canada, which leads to lower product imports in 2025. From this level, product movements are then seen to gradually increase to almost 20.5 mb/d by 2040, following the overall demand growth trend.

6.3 Crude oil movements

All projections for crude oil trade flows between major model regions are based on the OPEC Reference Case projections on regional demand and supply patterns (Chapters 3 and 4), as well as the outlook on developments in the regional refining capacity (Chapter 5), the installed base capacity, and the complexity of the regional refining system. In addition, assumptions on the logistics and infrastructure development, for example, pipeline developments, also play an important role in crude oil movements in the medium- and long-term.

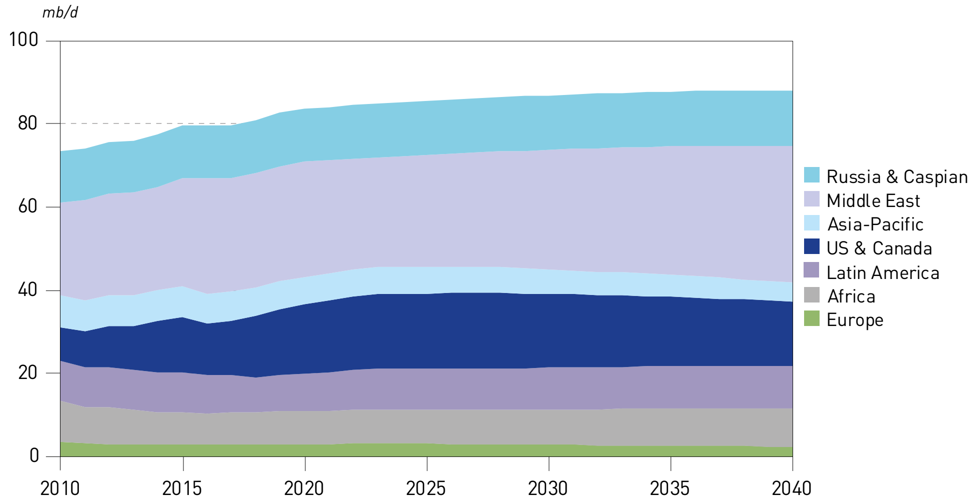
The regional crude supply outlook is shown in Figures 6.2 and 6.3. Figure 6.2 shows the incremental regional crude oil production in the two outlook periods: 2017–2020 and 2020–2040.

Figure 6.2
Crude oil* supply outlook to 2040



* *Includes condensate crudes and synthetic crudes.*

Figure 6.3
Change in crude oil* supply to 2040



* *Includes condensate crudes and synthetic crudes.*

In the period until 2020, crude supply is expected to increase by just over 4 mb/d. The US & Canada show the largest increase of below 3.5 mb/d, mostly driven by growth in the output of US tight oil, but also an increase in Canadian oil sands. Furthermore, Africa is expected to increase output by some 0.3 mb/d, driven by developments mostly in West Africa. Production in the Middle East, dominated by OPEC Member Countries is seen increasing by some 0.4 mb/d between 2017 and 2020. A small increase is projected for Latin America. This is the result of expected declines, predominantly in Mexico, but also to a lesser extent in other countries, such as Colombia and Argentina, which are offset by output gains in Brazil over the same period. Smaller increases (less than 0.1 mb/d) are estimated for Europe in the period 2017–2020, with several new developments in the North Sea that are expected to offset declines from ageing fields.

Similarly, in the Russia & Caspian region, supply is forecast to increase marginally between 2017 and 2020, driven by gains in Kazakhstan, which more than offsets depletion in other countries, such as Azerbaijan. On the negative side, the Asia-Pacific region is likely to see a decline of almost 0.2 mb/d as production is seen to drop relatively quickly in several countries of the region, including China.

In the period 2020–2040, the supply picture is dominated by expected increases in the Middle East (mostly OPEC Member Countries) of just above 5 mb/d. The majority of the increase comes after 2025. With this addition, the Middle East is expected to reach crude output levels around 33 mb/d by 2040, which is estimated to be 37% of the global oil production (without NGLs).

In the long-term, Latin America and Africa are large contributors to supply growth. In Latin America, the increase between 2020 and 2040 is estimated at around 1.4 mb/d with expected further expansion in Brazil and Venezuela (mostly heavy oil). This should more than offset depletion in other countries of the region, such as Colombia and Argentina. In Africa, long-term growth in crude and condensate output is estimated around 1.3 mb/d, driven by a recovery in Libyan output and further gains in West Africa.

Furthermore, the Russia & Caspian region is expected to increase long-term output by around 0.4 mb/d, attributed to production increases in Kazakhstan, while other countries are seen either stable, or slightly declining, over the same period.

However, several regions are expected to see declines in crude and condensate output between 2020 and 2040, totalling just under 4 mb/d. The largest share is accounted for by the Asia-Pacific, with a loss of around 2.2 mb/d, mostly due to declines in China, but also in countries such as Indonesia, Malaysia and India. Furthermore, the US & Canada region is projected to decline around 1.1 mb/d in the 2020–2040 period. This is the result of a decline in the US of around 2.1 mb/d, which is partly offset by an increase of almost 1 mb/d in Canada (mostly synthetic oil). In Europe, long-term production growth is expected to flip into negative territory. Around 600,000 b/d is projected to be lost in Europe between 2020 and 2040, as North Sea production is estimated to decline due to natural depletion.

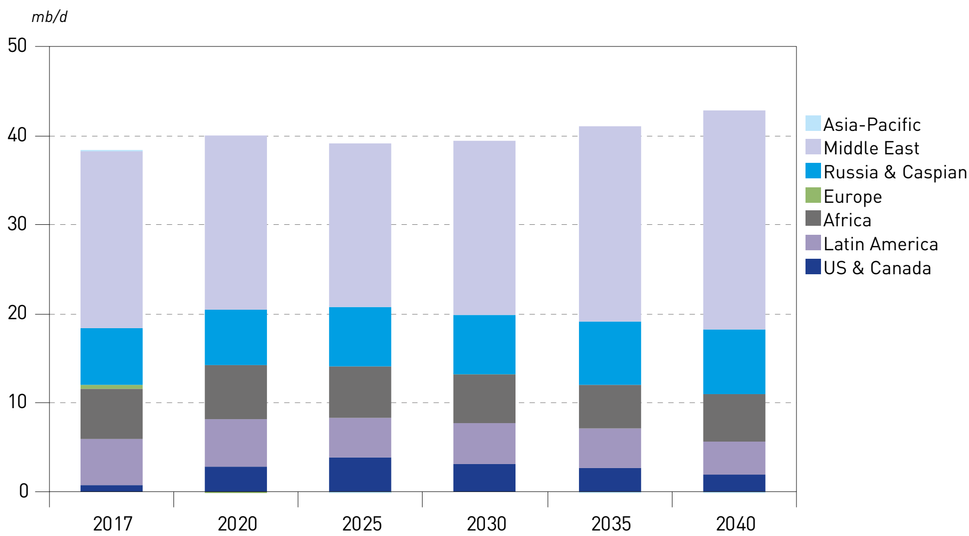
In total, global crude oil production is expected to increase by 4 mb/d between 2017 and 2020, followed by an increase of 4.3 mb/d between 2020 and 2040. This is an increase of around 8.3 mb/d for the 2017–2040 forecast period, with the Middle East covering the majority of this growth, especially in the longer term. Consequently, global crude and condensate supply reaches levels around 88.1 mb/d in 2040, up from just below 80 mb/d in 2017, as show in Figure 6.3.

Figure 6.4 shows global crude exports in the period 2017–2040. These are expected to increase by around 4.5 mb/d, mostly driven by increasing Asia-Pacific demand and decreasing domestic regional supply. In the short-term, global crude exports are likely to increase to around 40 mb/d by 2020, up from 38.5 mb/d in 2017. This is driven by increasing export volumes from the US & Canada, which are forecast to jump more than 2 mb/d between 2017 and 2020. At the same time, imports to the US & Canada remain strong with heavy and medium sour barrels finding their way to complex US refiners.

In 2025, the global crude export level is projected to drop to around 39 mb/d, mainly due to lower volumes coming from Latin America and Africa, as more volumes are refined in these regions. Furthermore, exports from the Middle East are also projected to decline somewhat, in line with the region's expected declining production between 2020 and 2025. At the same time, US & Canada crude exports are expected to peak at just under 4 mb/d in 2025.

Post-2025, global crude exports are expected to increase gradually to levels just below 43 mb/d, driven by increasing demand from the Asia-Pacific and increasing exports from the Middle East. Middle East crude exports are seen to rise by more than 6 mb/d between 2025 and 2040. Another region contributing to the increase in global crude exports is the Russia &

Figure 6.4
Global crude oil exports by origin,* 2017–2040



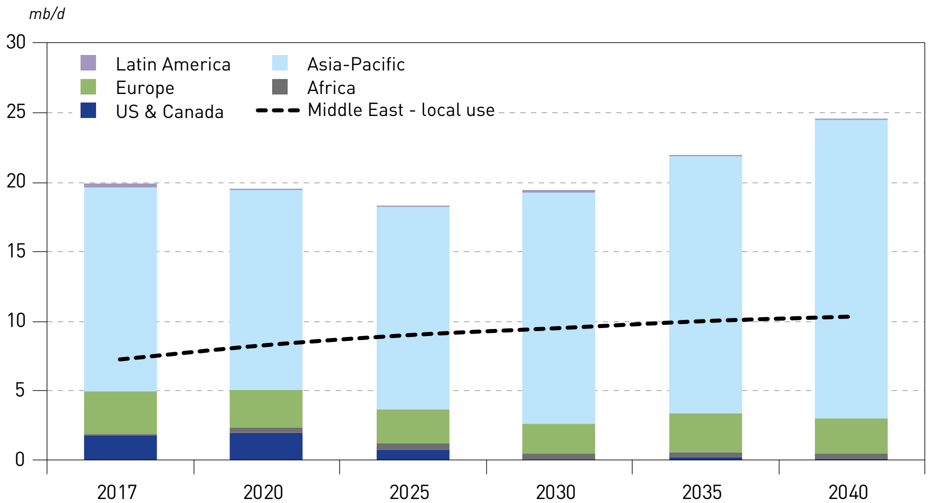
* *Only trade between major regions is considered.*

Caspian, with volumes rising to above 7 mb/d, mainly due to output increases in Kazakhstan. Traditional exporting regions such as Latin America and Africa are expected to see lower crude exports to global markets, as increasing domestic demand results in additional refinery runs in those regions. Crude exports from the US & Canada are expected to decline to just below 2 mb/d in 2040, which is 50% of the exports expected in 2025. The major reason is the anticipated longer term decline in US tight oil production.

In Figures 6.5–6.9, the regional outlooks for crude exports (including condensates and synthetic crudes) are shown, focusing on traditional exporting regions (Middle East, Russia & Caspian, Latin America and Africa), as well as for the US & Canada, which is set to become a major exporting region in the global crude oil market. In Figures 6.10–6.12 major importing regions are shown; the US & Canada, Europe and the Asia-Pacific. Finally, Figure 6.13 shows long-term regional net crude oil imports for all seven WORLD regions. As already mentioned, the figures shown are the result of the Reference Case assumptions on the regional crude oil supply and demand, as well as on the expansion of refining capacity and infrastructure.

At the global level, the Middle East is, and will remain, the region with the highest long-term crude oil exports (Figure 6.5). Although the Middle East exports crude oil to all the world's regions, it is by far the most important supplier of crude to the Asia-Pacific region, including large consumers, such as China and India. The long-term outlook shows that with the evolution of regional demand, the importance of the Middle East-Asia Pacific trade will gradually

Figure 6.5
Crude oil exports from the Middle East by major destinations, 2017–2040

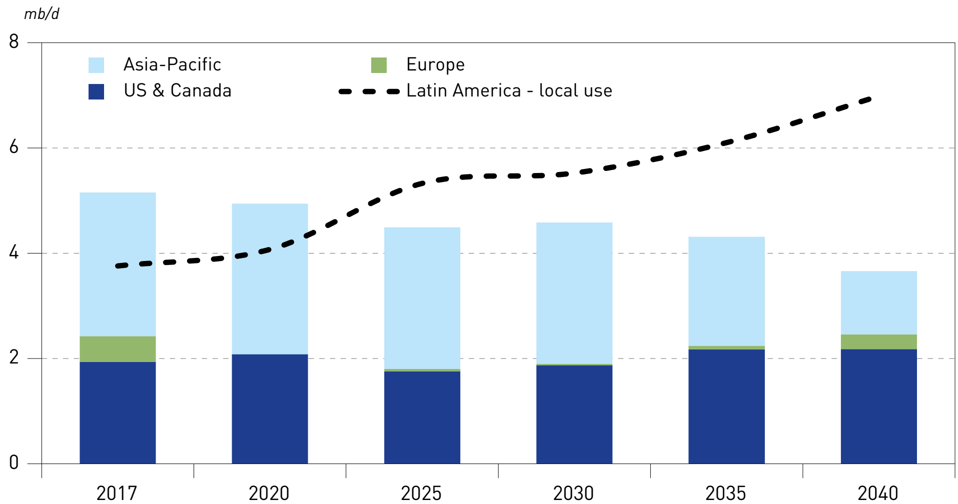


increase. Export volumes, estimated at almost 20 mb/d in 2017, are projected to increase to almost 24.5 mb/d in 2040. Compared with last year's WOO, however. Middle East export volumes are around 1 mb/d lower in 2040, which is due to the lower demand outlook for refinery-based fuels.

As already noted, the largest share of Middle East exports is expected to flow to the Asia-Pacific, increasing from around 14.5 mb/d in 2017 to about 21.5 mb/d in 2040. The share of the Asia-Pacific in overall Middle East exports is seen to increase from below 75% in 2017 to above 85% in the year 2040, thus illustrating the importance of this trade route. Exports to the US & Canada region (mostly the US) are forecast to remain strong in the medium-term, with volumes even slightly increasing in 2020 to around 2 mb/d, from 1.8 mb/d in 2017. This can be explained by the increasing exports of light tight oil from the US & Canada, with US refiners, at the same time, importing heavier and sourer barrels, which normally trade at a discount to light-sweet crude.

The upcoming implementation of the IMO rule in 2020 is expected to further weaken sour grades versus light barrels, creating an additional initiative to purchase US sour grades. Nevertheless, after a peak around 2020, Middle East exports to the US & Canada region are projected to gradually decline to just below 1 mb/d in 2025, and then further to below 0.5 mb/d by 2040 as the US & Canada refinery throughputs decline by over 2 mb/d from 2020–2040. In addition, the increase in output of heavy crudes in Canada, suitable for US refiners, reduces the need for barrels from the Middle East in the long-term.

Figure 6.6
Crude oil exports from Latin America by major destinations, 2017–2040

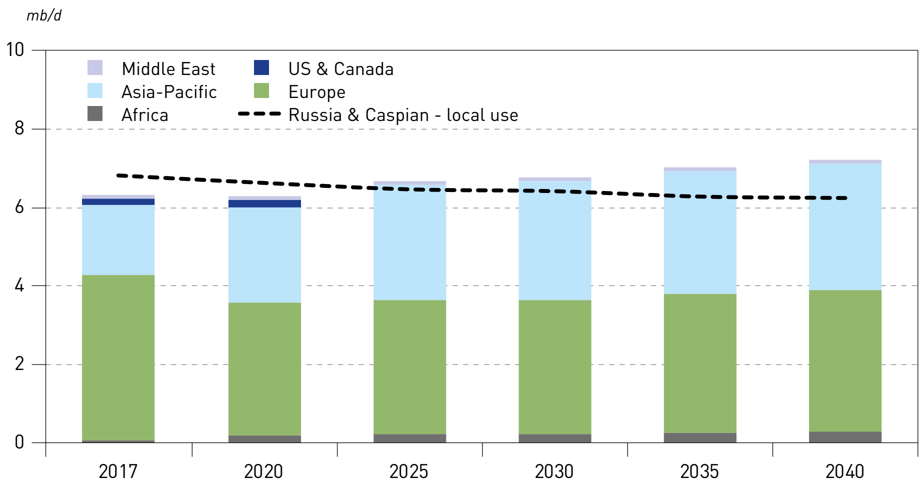


Crude exports from the Middle East to Europe are expected to decline gradually from levels around 3 mb/d in 2017 towards 2.5 mb/d in 2040. It should be noted that a temporary increase to above 2.5 mb/d in 2035 stems from the interplay between declining US & Canada production and exports to Europe and the timing of increases into the region of supply from the Russia & Caspian. Due to the similarity in crude quality, the main uncertainties related to Middle East exports to Europe are flows from the Russia & Caspian region, which increasingly focus on the Asia-Pacific.

Finally, Middle East exports to Africa are forecast to increase to just below 0.4 mb/d in 2020 and remain stable thereafter, which reflects increasing demand in Africa and expected declining supply in some countries (for example, Egypt). The local use of oil in the Middle East is anticipated to rise from 7.2 mb/d in 2017 to almost 10.5 mb/d in 2040, which mirrors not only the increase in local demand, but also demand from export-oriented refining projects in the Middle East.

Overall oil flows from Latin America shown in Figure 6.6 are projected to decrease gradually, in line with rising domestic demand in Latin America and expanding refinery projects. Flows are seen at around 5.2 mb/d in 2017 and are expected to drop to around 3.8 mb/d in 2040. The effects of the energy reform in support of projected Mexican output, at least through to the mid-2020s, plus progressively rising output from Brazil, before declines post-2030, contribute to the expectation that total regional supply peaks in the late 2020s. In turn, this supports a peak in crude oil exports around 2030, followed by a decline. A large share of crude flows from Latin America are seen to continue to head to the US, as the majority of US refiners are configured for low-quality oil supplies, which are discounted compared to US light sweet crude.

Figure 6.7
Crude oil exports from Russia & Caspian by major destinations, 2017–2040



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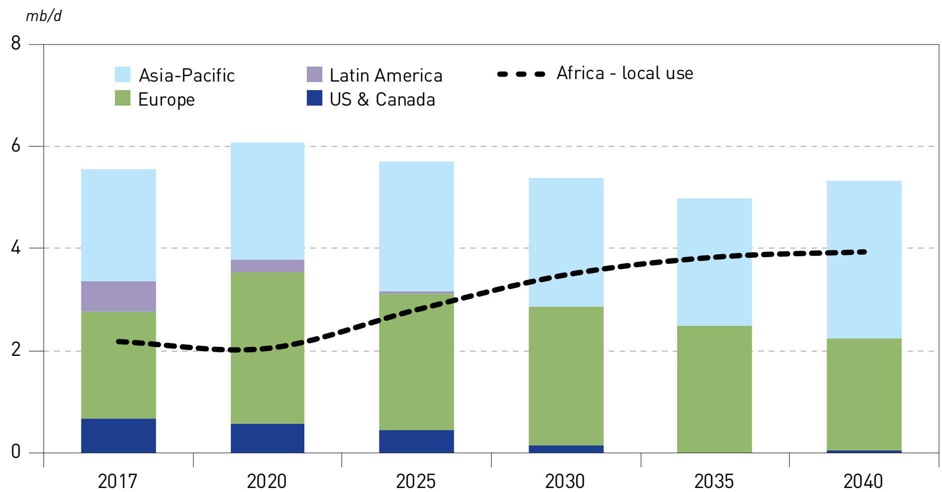
Crude flows from Latin America to the US & Canada are seen hovering around 2 mb/d throughout the period. The Asia-Pacific is another important outlet for Latin American oil, but flows are expected to be around 1.2 mb/d in 2040, from 2.7 mb/d in 2017. The clear disadvantage of the trade route is the distance, and thus cost, which explains the crude flows to the Asia-Pacific being the marginal flows versus the more stable flows to the relatively close region of the US & Canada. While exports to Europe are still significant in 2017 at around 0.5 mb/d, they are projected to disappear in the medium-term, with limited volumes seen towards the end of the period (around 0.3 mb/d in 2040). Domestic use of Latin American crude is expected to increase gradually from 3.8 mb/d in 2017 to levels around 7 mb/d in 2040, which is in line with growing demand and increasing refinery capacity.

Oil exports from the Russia & Caspian region are projected to rise from around 6.4 mb/d in 2017 to a level around 7.2 mb/d in 2040 (Figure 5.5), supported by increasing crude oil output, predominantly from Kazakhstan. Europe remains the most important outlet for oil from the Russia & Caspian region, although volumes decline somewhat in the medium-term (around 2020) as supplies from the US & Canada kick-in, together with expansions in the ESPO system that take additional crude to the Asia-Pacific. Trade flows from the Russia & Caspian to Europe are estimated at around 3.5 mb/d in 2020, and are then expected to hover around this level until the end of the forecast period. Compared to last year's WOO, these volumes are slightly lower, which can be explained by more optimistic estimates on domestic crude output in Europe.

The second most important outlet for volumes from the Russia & Caspian is the Asia-Pacific, where exports are projected to increase strongly from around 1.8 mb/d in 2017 to above

Figure 6.8
Crude oil exports from Africa by major destinations, 2017–2040



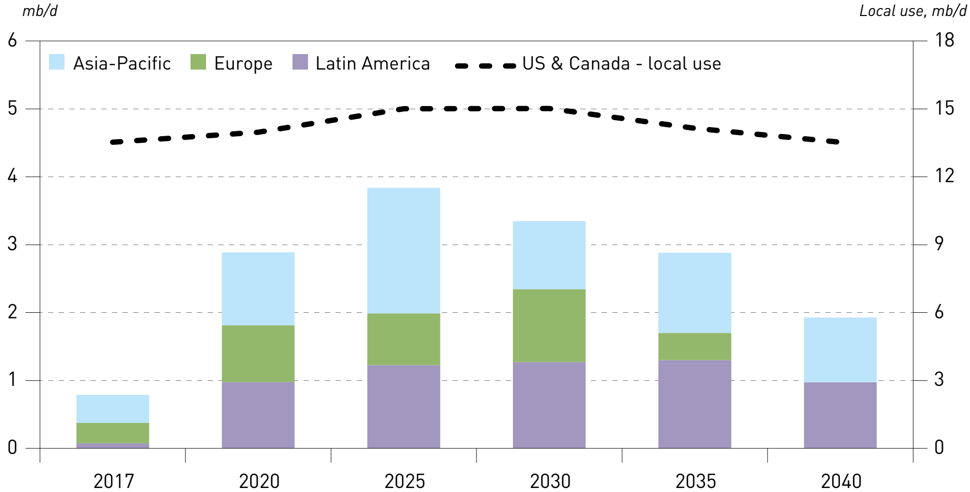
3.2 mb/d in 2040. The increase in oil shipping to the Asia-Pacific is partly accounted for by the expansion of pipeline capacity from Russia-to-China and the Pacific Coast, but also seaborne flows. Movements to the Asia-Pacific remain subject to the dynamics of export infrastructure development in the medium- and long-term. Exports to the US & Canada, starting at 0.2 mb/d in 2017, are seen to disappear in the long-term as North American domestic supplies increase. The local use of oil is projected to decline from 6.8 mb/d in 2017 to just above 6.2 mb/d in 2040, which reflects increasing competition in the product export markets from the Middle East and North America, as well as less demand in traditional importing regions, such as Europe.

As shown in Figure 6.8, Africa's exports to world markets are forecast to increase from around 5.6 mb/d in 2017 to 6.1 mb/d in 2020, supported by rising crude output and limited expansion of refining capacity in this period. However, crude exports from Africa to the global crude market are expected to start declining from 2025, despite rising output levels. This is mainly due to increasing refining capacity in the region, supporting domestic African oil demand growth.

African refinery throughputs are anticipated to almost double between 2017 and 2040. Regarding the regional distribution of crude exports, Africa is projected to increasingly focus on the Asia-Pacific, the primary demand growth region, with volumes gradually rising from around 2.2 mb/d in 2017 to 3.1 mb/d in 2040. Europe remains an important outlet for African crude (especially North Africa) with volumes increasing in the medium-term, somewhat replacing declines in flows from the Middle East and the Russia & Caspian to Europe.

Crude flows from Africa to Europe are expected to increase to almost 3 mb/d in 2020, up by more than 0.5 mb/d, relative to 2017. Nevertheless, lower refinery throughputs in Europe

Figure 6.9
Crude oil exports from the US & Canada by major destinations, 2017–2040

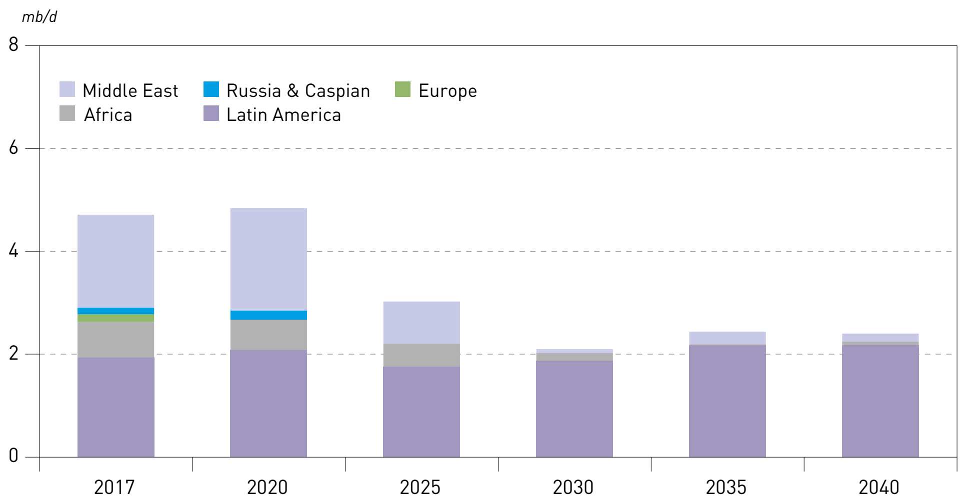


caused by declining domestic demand, are expected to lead to a drop in African crude movements to Europe to around 2.2 by the end of the forecast period. Africa has been a traditional crude oil supplier to the US & Canada region, but with increasing US sweet crude output, African flows are projected to decline from some 0.7 mb/d in 2017 to negligible volumes around 0.1 mb/d as soon as 2030.

US & Canada crude exports to global oil markets were estimated at just under 0.8 mb/d in 2017, increasing by around 0.5 mb/d from 2016, driven by increasing tight oil output. Given the rising crude oil output trend in the US & Canada, medium-term crude exports from this region are projected to increase significantly as shown in Figure 6.9. US & Canada crude output is expected to rise by around 5 mb/d between 2017 and 2025, most of it being light tight oil. Already in 2020, crude exports from the US & Canada are seen at just under 3 mb/d, and are expected to further increase to almost 4 mb/d by 2025. The barrels exported are mostly light-sweet, while domestic sour production, for example, Canadian heavy sour output, is expected to be processed mainly in the US. This is why crude oil exports are expected to drop in line with the decline in tight oil production, with total volumes estimated at 1.9 mb/d in 2040. The US & Canada is expected to export crude to three regions: Latin America, Europe and the Asia-Pacific.

Movements to the Latin America are pojected to increase to some 1 mb/d in 2020, and then hover between 1 mb/d and 1.5 mb/d until 2040. The flow of light-sweet crude to Latin America is mirroring Latin American flows of sour crudes to the US, as complex US refiners prefer discounted barrels to light-sweet crude, while short-distance flows to destinations in Latin America tend to reduce needed refinery investments in the region while supporting moves toward low and ultra-low fuel sulphur standards.

Figure 6.10
Crude oil imports to the US & Canada by origin, 2017–2040

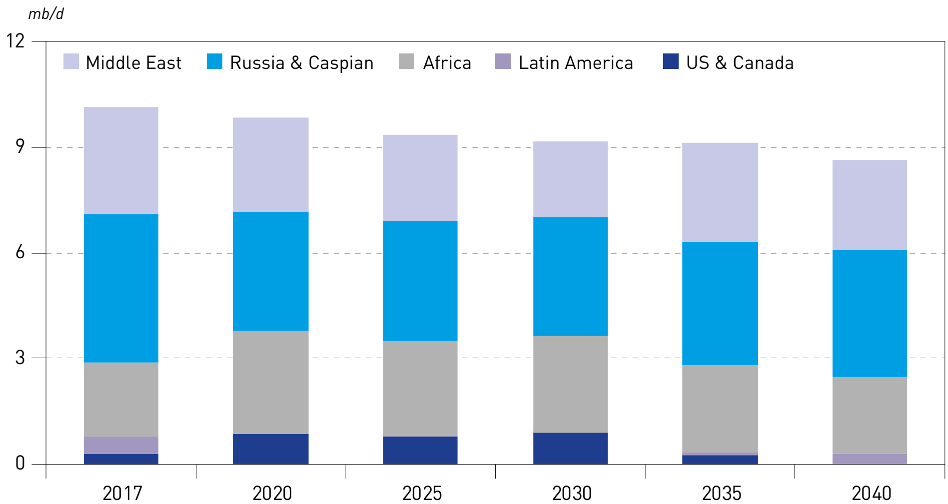


US & Canada exports to Europe are seen to increase gradually towards 1 mb/d in 2030, up from 0.3 mb/d in 2017, supported by decreasing light-sweet North Sea output and declining Middle East exports. Nevertheless, crude flows to Europe are projected to decline by 2040, due to falling refining throughputs in this region and declines in US production, especially in the longer term.

Finally, the largest share of US & Canada crude flows is estimated to be accounted for by the Asia-Pacific. Movements of around 0.4 mb/d in 2017 are set to increase to almost 2 mb/d in 2025, the year when US & Canada exports are expected to peak. Between 2025 and 2040, crude movements are expected to halve to 1 mb/d in 2040. (This comprises a combination of US and Canadian crudes.) The local use of oil in the US & Canada is projected to increase between 2017 and 2025, supported by the expansion of Canadian heavy sour crude output. Then a decline in own use is projected post-2030, in line with falling refinery throughputs.

At the same time, crude oil imports into the US & Canada (Figure 6.10) are expected to increase slightly around 2020. This is the result of anticipated short-term changes in crude flows from the onset of the IMO sulphur regulations in that year. In essence, the refining sector is expected to respond by maximizing throughputs on cokers, hydrocrackers, desulphurization and related units, with an associated shift in sour crude grades to the regions that have the most upgrading and sulphur removal capability, in this case the US. Hence, the projected increase in crude runs and imports from Latin America and the Middle East in 2020, mainly driven by the relative economics of the different crude grades and despite increasing domestic output over the same period. US refiners, which prefer low-quality and discounted grades, are likely to continue processing supplies from Latin America and the Middle East in the medium-term.

Figure 6.11
Crude oil imports to Europe by origin, 2017–2040



Imports of Middle East volumes are expected to increase to around 2 mb/d in 2020, up from 1.8 mb/d in 2017. At the same time, Latin America imports are projected to climb to about 2.1 mb/d, up by some 0.2 mb/d from 2017. Oil imports from the Middle East are projected to decline gradually in the long-term, partly due to lower declining oil demand in the US, but also rising volumes of heavy supplies in Canada.

Middle East flows to the US & Canada are seen declining to below 1 mb/d in 2025 and further to under 0.5 mb/d in 2040. Latin American imports are relatively stable in the longer term (due to the proximity of the region), hovering around 2 mb/d.

Imports from Africa are seen to gradually decline throughout the outlook period, from 0.7 mb/d in 2017 to almost zero in 2040. This is mainly due to the increase in US domestic supplies of sweet grades, which in terms of quality are similar to African supplies.

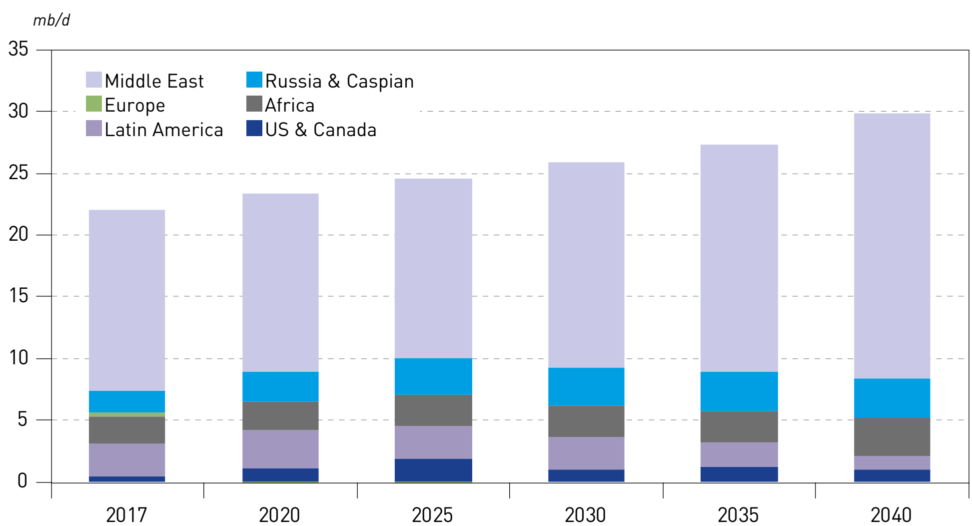
Figure 6.11 portrays European oil imports in the long-term, which are expected to witness a gradual decline from around 10 mb/d in 2017 to 8.6 mb/d by 2040. An important factor in the overall balance is Europe's crude oil output, which after an increase to around 3.2 mb/d in 2025 (from approximately 3 mb/d in 2017), is estimated to decline to 2.4 mb/d in 2040. Another important factor is European oil demand and the expected refinery throughputs, which are forecast to decline by around 1.7 mb/d between 2017 and 2040. This means that expected reductions in refinery throughputs, especially in the long-term, are likely to more than offset Europe's declining indigenous production, leading to lower crude imports, as already highlighted.

The most important European oil supplier will remain the Russia & Caspian region, although volumes are estimated to drop from just above 4 mb/d to around 3.5 mb/d in 2020, before stabilizing around this level in the long-term. Oil from the Russia & Caspian region is supplied through the Druzhba oil pipeline system, as well as through the ports in the Baltics and the Black Sea. Some seaborne volumes also come from the Turkish port of Ceyhan (Azeri crudes). It should also be recalled that with the expansion of pipeline infrastructure to the Asia-Pacific, exports from the Russia & Caspian are increasingly moving to this region.

Although at lower levels, Middle East volumes have a significant share in total European imports at around 2.5 mb/d until 2025, and they then move in a projected range between 2.1 mb/d and 2.8 mb/d until 2040. Crude flows from Africa are expected to increase in the medium-term from around 2.1 mb/d in 2017 to just below 3 mb/d in 2020, as flows from African producers look for additional outlets in Europe due to the loss of US market share. Nevertheless, African exports are expected to decline gradually thereafter, reaching 2.2 mb/d in 2040, as Africa uses more of its crude domestically. Finally, Latin American imports are projected to decline from around 0.5 mb/d in 2017 to levels close to 0.3 mb/d in 2040.

Due to its continuous oil demand growth and declines in domestic supply, the Asia-Pacific remains the main crude importing region and is expected to offset declines in other importing regions, such as Europe and the US & Canada. Crude oil imports are expected to increase from 22 mb/d in 2017 to just below 30 mb/d in 2040 (Figure 6.12). This reflects not only the increase in demand, but also a production decline of almost 2.5 mb/d in the period 2017–2040. The

Figure 6.12
Crude oil imports to the Asia-Pacific by origin, 2017–2040



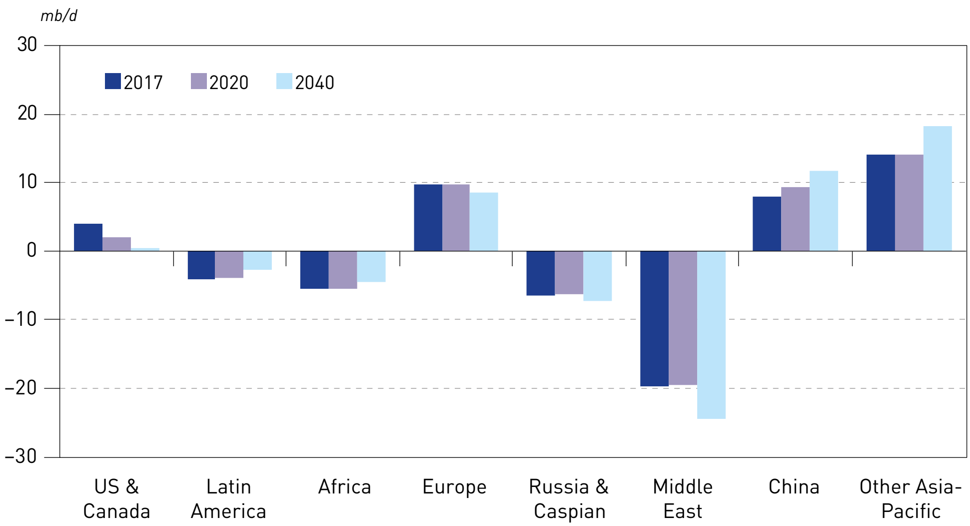
Middle East remains the most important supplier of crude and condensate to the Asia-Pacific, with expectations of an increase from about 14.5 mb/d in 2017 to almost 21.5 mb/d in 2040. Consequently, the share of Middle East flows to the Asia-Pacific equates to more than 70% of the total crude flows to this region in 2040, up from around 65% in 2017.

Furthermore, imports from the Russia & Caspian are estimated to increase from 1.8 mb/d in 2017 to above 3 mb/d in 2040, which is partly the expected result of long-term pipeline expansions (for example, ESPO), but also increasing seaborne flows. With this expansion, the Russia & Caspian region becomes the second most important supplier of oil to the Asia-Pacific in the long-term.

As the model results suggests, crude oil movements from Africa to the Asia-Pacific are expected to gradually increase from around 2.2 mb/d in 2017 to a level around 3 mb/d in 2040. This is due to the rise of supply in Africa and decreasing demand for African oil in other regions, such as the US & Canada and Europe. After an initial increase to around 3 mb/d in 2020, Latin America flows to the Asia-Pacific are expected to decline to 1.2 mb/d in 2040. This trend is the result of declining overall exports from Latin America due to the increasing usage of oil domestically, and more focus on the US market given its proximity.

Finally, barrels from the US & Canada should see an increased medium-term market share in the Asia-Pacific, rising from 0.4 mb/d in 2017 to about 1.8 mb/d in 2025. Nevertheless, US & Canada flows to the Asia-Pacific are expected to decline gradually towards 1 mb/d in 2040, as US oil output comes to a peak and then declines after 2030. Figure 6.13 shows the net

Figure 6.13
Regional net crude oil imports, 2017, 2020 and 2040



effects of all inter-regional crude oil trade (i.e. imports versus exports). The patterns summarize the regional trade projections already discussed. The US & Canada's net imports of crude are expected to decline from around 4 mb/d to almost zero in 2040, thanks to increasing domestic supply and declining long-term demand, which reduces the need to import foreign barrels.

Net exports from both Latin America and Africa are seen as stable in the medium-term, while declining in the long-term, predominantly due to their higher own use of crude oil and in line with increasing domestic demand. Net exports from Latin America and Africa in 2040 are estimated at 2.8 mb/d and 4.6 mb/d, respectively.

Europe's net imports are the result of its own crude supply and domestic demand, with the latter having the larger impact in the long-term. Consequently, crude net imports in 2040 are seen at 8.6 mb/d, down by more than 1 mb/d relative to the 2017–2020 period.

Net crude exports from the Middle East are projected to remain stable in the medium-term, in line with supply projections over the same period. However, net exports are likely to expand by around 5 mb/d between 2020 and 2040, reaching levels around 24.5 mb/d in 2040.

The Russia & Caspian region is also projected to expand its crude net exports based mostly on increasing supply from Kazakhstan. Total crude net exports in 2040 are projected at 7.2 mb/d, up from a range around 6.4 mb/d seen between 2017 and 2020.

Finally, crude net imports to China and the Asia-Pacific are expected to expand strongly in the long-term. Cumulatively, net imports are seen to rise by around 8 mb/d, to reach levels close to 30 mb/d in 2040.

6.4 Product movements

In comparison to crude movements, refined product movements between the seven major WORLD regions are significantly lower, as refined products are mostly produced and consumed within the regions. Transportation costs for clean products are normally higher relative to crude, which is another reason for lower product movements between the seven regions.

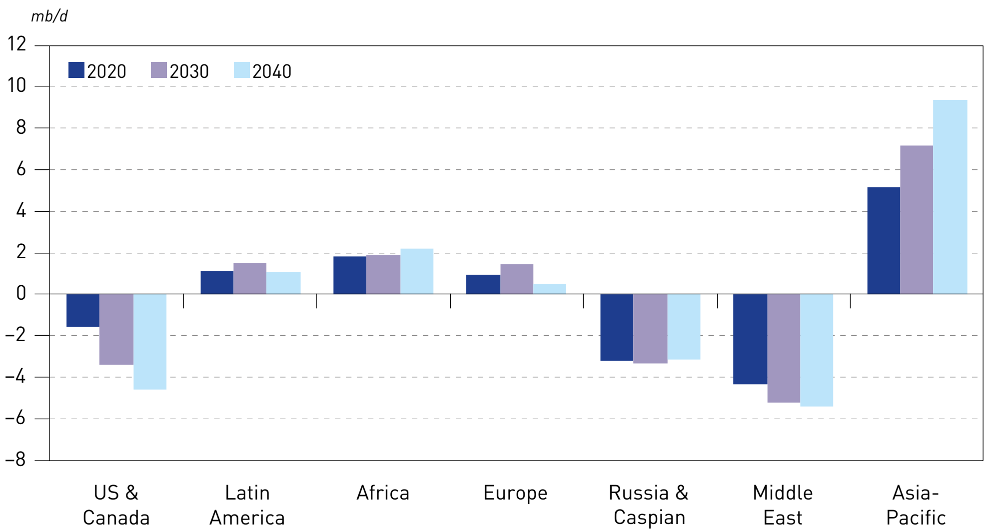
As already described, overall product trade is seen to increase from around 18.5 mb/d in 2017 to almost 20.5 mb/d in 2040. However, the expansion of refining capacity does not fit entirely with the medium-term demand growth pattern in several major consuming regions.

This, combined with the impact of the IMO regulations, is expected to lead to higher product trade at around 20 mb/d in 2020. In the years after, product movements are projected to decline as several developing regions such as Latin America, Africa and the Asia-Pacific expand domestic refining capacity, which reduces the need for imported products. In addition, regions such as the US & Canada and Europe see declining demand in this period, which consequently leads to lower product imports. This results in product trade of around 18 mb/d in 2025. For the rest of the forecast period, the expansion of product movements is expected to follow the overall demand growth trend, increasing gradually between 2025 and 2040, from 18 mb/d to almost 20.5 mb/d.

In order to show a simple and understandable picture of the general trends in the global product trade, this Chapter focuses on net flows only. Figure 6.14 presents product net imports for the major WORLD regions. Three regions show significant change in the long-term: the Asia-Pacific, with a significant increase in net imports, and the Middle East and the US & Canada, with rising net exports.

Product net imports to the Asia-Pacific are projected to rise from around 5 mb/d in 2020 to 9.5 mb/d in 2040. Increasing refining capacity in the Asia-Pacific is not sufficient to satisfy the entire extra demand, which calls for additional imports from the Middle East and the US & Canada, as well as the Russia & Caspian region. High-quality clean products, such as LPG and naphtha, as well as middle distillates, represent the majority of the increase.

Figure 6.14
Regional net product imports, 2020, 2030 and 2040



Latin America and Africa are set to remain product net importers throughout the period, with refining capacity additions in these regions not being sufficient to reduce import flows. Latin America product net imports are seen increasing from around 1 mb/d in 2020 to 1.5 mb/d in 2030, as demand picks up faster than projected refinery throughputs. By the end of the period, product net imports are seen to decline to levels around 1 mb/d.

Similarly, in Africa product net imports are expected to increase gradually from 1.8 mb/d in 2020 to 2.2 mb/d in 2040. Meanwhile, refiners in Europe will have to compete with imports from the US & Canada, as well as from the Middle East and the Russia & Caspian. This leads to an increase in net imports to Europe, from around 0.9 mb/d in 2020 to 1.4 mb/d in 2030. Nevertheless, decreasing long-term demand is expected to lead to lower net imports of around 0.5 mb/d in 2040.

On the net export side, the Middle East and the US & Canada are estimated to increase their volumes significantly, while the Russia & Caspian is expected to decline somewhat. The focus of some Middle East oil producers on product exports leads to additional long-term product net exports from around 4.3 mb/d in 2020 to around 5.5 mb/d in 2040. The Middle East has the clear advantage of its proximity to major consuming regions, such as the Asia-Pacific, Europe and Africa, combined with ample crude supplies in the region. The majority of additional net exports are destined for markets in the Asia-Pacific.

The US & Canada region also sees a significant increase in product net imports driven by three factors – ample crude oil supplies, declining domestic demand and highly complex and competitive refining systems. Product net exports from the US & Canada are anticipated to increase from around 1.5 mb/d in 2020 to 4.5 mb/d in 2040.

Finally, product net exports from the Russia & Caspian region are anticipated to decrease from 3.2 mb/d in 2020 to around 3 mb/d in 2040. This can be explained by declining demand in Europe, which is the main market for products from this region.

Energy and technology

Key takeaways

- ICEs still have substantial development potential beyond the current emission standards.
- The issue of polluting emissions from ICEs, mainly nitrogen oxide (NO_x), can be resolved by using amply dimensioned catalysts and filters, together with appropriate temperature management.
- Battery technology is expected to evolve continuously and will lead to solid-state batteries in the course of the next decade.
- Conventional and electric powertrains will co-exist in the coming decades.
- Recycling will play a very important role in the case of electric vehicles.
- Gas turbines remain the main engines for commercial airplanes.
- Electrification may become an interesting complement in air transportation in view of adding to the operational security, as well as peak power development mainly upon take-off.
- The record-high efficiency of large marine diesel engines limits their potential for further improvements; air lubrication and hybridization may offer better solutions.
- The use of LNG as a sulphur-free fuel offers several advantages, including for WHR, but it will be impacted by a shortage of bunkering facilities in the short- and medium-term.
- Combined cycle gas turbines (CCGT) provide, by far, the lowest specific CO_2 emissions of all fossil fuel technologies used in the power generation sector.
- Renewable power generation is expected to come mainly from wind and solar in the future, with storage increasingly playing a key role.
- Power storage may be a key element for renewables; battery electric storage systems are making progress in parallel to the development of electric vehicles.
- Tight oil will continue to play an important supply role, especially in the medium-term horizon, due to the substantial technological advances in this area.
- The crude oil-to-chemicals (COTC) concept may substantially improve processing facility output and bring 'Industry 4.0' principles to the petrochemicals sector.
- Data collection, data processing and AI are becoming omnipresent in the energy business, from exploring and exploiting resources through to oil refining for final consumption.
- Technological developments may not only contribute to new forms of energy, but also to strengthening the role of conventional energy sources.

Scientific discovery and technical innovation have often had a disruptive impact on the global oil industry. In recent years, the velocity of such technological change has accelerated in many areas, often due to the ongoing IT revolution. Technological development has, therefore, the potential to substantially impact future oil and energy markets. This publication considers current and potential future trends in technological development. For example, energy intensity will likely be reduced by efficiency improvements and the energy base may be broadened by the increasing use of additional energy sources.

Some developments may be evolutionary – as is typically the case for mature technologies already in use for a substantial period of time. Some, however, may turn out to be revolutionary. Examples of the latter are wind and solar for renewable power generation, but also fracking technology that has enabled the rise of tight oil production. Moreover, the variety of available energy technologies has increased in recent years and is expected to expand further.

There are anticipated to be evolutionary concepts in transportation that will likely further improve existing engine technology, but revolutionary technological advances are also possible. For example, these may occur in electric mobility, as well as in ICE technology, which may allow so-called conventional vehicles to continue to be a firm component of the vehicle fleet in the long-term.

The chemical sector, and in particular, petrochemicals, seems to be more stable and faces fewer threats than that of transportation, although it does face the trend of renewable sources potentially replacing oil and gas. Nevertheless, concepts such as COTC will also rely on advanced technology levels, not least by integrating modern concepts such as 'Industry 4.0'.

The energy industry, as a whole, and the oil industry, in particular, is already incorporating modern IT to improve efficiency at all levels – from exploration through to production and to refining.

7.1 Transportation

7.1.1 Road transportation

Transportation, particularly road transportation, accounted for the majority of oil product consumption in 2017, with demand at 55.8 mb/d, representing a share of 57%. It is, therefore, not a surprise that road transportation receives a lot of public attention in the context of emissions. However, one should distinguish between GHG emissions – mainly CO_2, but also methane (CH_4) that may escape as unburnt fuel from combustion engines – and polluting emissions, for example, NO_x gases or particulates that may be a threat to people's health. While the first type is directly linked to fuel consumption and can be reduced by improving fuel efficiency, or to a certain extent, by switching fuel type, the latter is mainly a technical issue that can be solved with sufficiently dimensioned catalysts (NO_x) or filters (particulates).

After more than a century of ICE-based mobility, technological innovations, mainly in the field of battery technology have opened a path to electric mobility. In conjunction with internet-based fleet management – car and ride sharing, or advanced hire car services – new means of urban transport are emerging, integrating or complementing not only personally owned vehicles, but public transport too.

IT innovation is not restricted to the engine and stability control of a vehicle, including fuel injection and antiblock systems. Moreover it may also allow for complete autonomous future operations. Such technological advancements may completely reshape the personal transportation experience, from an active driving task for one occupant towards a mainly service-oriented event where all occupants are moved around autonomously. Nevertheless, the vehicle still requires an engine for propulsion, which will consume energy – whether as fuel or as electric power; this engine technology can also be expected to advance considerably in the upcoming decades.

Technology advances for ICEs
Traditionally ICEs have dominated all road transport segments, whether passenger or commercial vehicles. An important advantage over competing technologies – mainly battery electric operation and fuel cells – is their capability to burn a broad range of fuels, in addition to well-known gasoline and diesel fuels. They may run also on LPG, CNG or LNG, and even hydrogen, alcohols or biodiesel. Only two different combustion principles are required to make use of this broad range of fuels: spark-ignited or self-ignited, with the latter usually referred to as 'diesel combustion'. This flexibility allows alternative fuels to quickly play an important role by using the long-established technology of ICEs. Electric vehicles, on the other hand, require a parallel upgrade of vehicle and charging infrastructure.

Efficiency improvements for ICEs
Concerns about energy intensity in the transportation sector have driven efficiency improvements in the past. In previous decades, engineers have increased the efficiency of ICEs for passenger vehicles from below 20% to around 35% on average today for gasoline engines and from around 30% to even above 40% in the case of diesel engines. This corresponds to a specific fuel consumption of around 248 g/kilowatt hour (kWh) in the case of gasoline and 215 g/kWh for diesel. Heavy duty diesel engines for commercial vehicles can even reach 45% efficiency, meaning they consume only approximately 192 g/kWh of power generated.

However, lower fuel consumption is not the only reason for the dominance of diesel engines in commercial vehicles. Favourable taxing on a per-volume base is equally important. Liquids like gasoline and diesel are typically measured per volume, not mass, and the higher density of diesel (typically 0.820–0.845 kg/dm^3) compared to gasoline (0.720–0.775 kg/dm^3) gives an advantage of around 10%, in terms of energy per volume for diesel fuel.

Nevertheless, there is still a substantial difference between today's engine efficiency, especially for road transportation, and the actual physical limits imposed by thermodynamic laws. In the case of large combined cycle gas turbines (CCGTs) – combining a gas turbine and a steam bottoming cycle for waste heat recovery – this difference has reduced to around 10%, while for gasoline engines for passenger cars the difference remains over 30%. It is worth noting that today's racing car engines have the highest efficiency of all vehicle engines at approximately 50% – a value which is achieved mainly due to their very high degree of hybridization.

This means there is a substantial potential for future improvements in ICEs. Emphasizing this long-proven technology will, on the one hand, guarantee a substantial share of future sales, but on the other hand, reduce the specific vehicle fuel consumption. It is estimated that values as low as 150 g/kWh are possible in the long-term. Such technological advances will allow ICEs to retain their dominance as the most economical transportation technology in the long-term, especially in developing countries.

Important advances towards less energy intense transportation have been made in the recent past, particularly by downsizing – often termed 'rightsizing' – piston engines. The piston engine has become smaller, i.e. both, bore and stroke and as a consequence, displacement has been reduced, often in conjunction with reducing the cylinder number. Super-charging is mandatory to maintain maximum power. The average load of the engine increases and, correspondingly, the part load fuel consumption drops.

Additionally required components like the expansion turbine, compressor turbine and inter-cooler, limit the total size, weight and cost decline of the engine. Downsizing is, therefore, primarily a strategy to reduce gasoline consumption, not the cost of the engine. Nevertheless, it is an important advance towards PHEVs that need to carry an additional electric powertrain with a battery and electric motor.

Competing concepts such as, for example, controlled auto ignition (CAI), often called the homogenous charge compression ignition (HCCI), highlight the current dynamics of technology and manufacturers have become far more open in terms of multi-faceted technology concepts. For CAI or HCCI, fuel is dispersed in an even, but sub-stoichiometric manner. The charge is compressed until well-controlled and intentional auto-ignition occurs. The effects are reduced fuel consumption comparable to diesel engines, especially in part load, and lower emissions. It is mainly NO_x that is reduced and the engine requires a far less sophisticated exhaust gas cleaning sub-system, which may provide an economic advantage.

To achieve the highest efficiency, cooling or wall and exhaust losses must be reduced substantially in the future. How important such wall losses are can be observed by comparing small engines for passenger vehicles and the very large two-stroke engines of merchant vessels. The surface-to-displacement value is far lower in the latter case and far more of the hot flue gas is enclosed in a large engine per surface of the combustion space. The relative wall losses drop to a negligible 3% of the value for passenger engines. The record-high efficiency of these large two-stroke engines of up to 53% – equivalent to specific fuel consumption of 164g/kWh – is nearly exclusively a consequence of the negligible cooling losses. Future technology development may find a similar way and reduce fuel consumption towards far more efficient ICEs.

WHR units have been developed and tested for commercial vehicles, but mainly for heavy-duty long-distance trucks. Thermocouples are able to convert the heat of the exhaust gases directly into electric power and may be a solution for smaller passenger vehicle engines. Intense research is underway on an inexpensive option for converting heat to power. Such a technological breakthrough would substantially extend the base for WHR applications into industrial and even residential sectors.

The prototype for efficient WHR is the CCGT with a bottoming cycle. It captures the thermal energy of the hot exhaust gases from the gas turbine to generate hot and highly pressurized steam which, in turn, is used to power steam turbines. By doing so, efficiency could be increased to a level beyond 62%. This example impressively indicates the remaining efficiency potential of modern ICEs; technology may make this potential available to the transportation sector. This Outlook takes their future development potential into consideration, as well as alternative powertrains, mainly electric.

Pollution and exhaust gas cleaning

Technological advances are not restricted to raising the engine efficiency or increasing its power development. When comparing the air quality in urban areas today over the course of several decades, it becomes clear that exhaust gas cleaning has improved significantly. Today, the gaseous pollution – mainly NO_x, but also unburnt hydrocarbons – from a gasoline engine is virtually zero.

Unfortunately, and mainly because of sub-dimensioned catalysts and additive tanks, this had not been achieved in the case of diesel engines earlier. Selective catalytic reduction (SCR) is the most appropriate technology in the foreseeable future. Here, a catalyst combination that first converts an injected aqueous urea solution into ammonia (NH_3) and CO_2 is used. A second catalyst transforms NO and NO_2 by means of the produced ammonia into ordinary nitrogen (N_2) and water. If the catalysts are sufficiently dimensioned, and an appropriate amount of the urea solution is injected and the temperature of the cleaning system is maintained above 250°C, then combustion engines – whether gas, gasoline or diesel – would not emit any significant amount of NO_x and can be considered 'clean'.

Particulate emissions from gasoline direct injection engines can be eliminated by employing a filter that is already used for diesel engines. As a consequence, there appears to be no reason to ban modern conventional vehicles from entering urban centres or expect electric-only mobility in these areas.

From an economic point of view, the co-existence of conventional and electric mobility may be interesting in the long-term. Investments into batteries are expected to remain substantially above the combined costs of even a more sophisticated ICE and the fuel tank. It is unlikely that any other technology will be able to provide such a long driving range at comparable costs in the near future.

Technological advances for electric mobility

A major example of how quickly technological advances may radically affect industry is the advent of fully electric vehicles. Substantial battery research and the development of lithium-ion (Li-ion) technology have made this possible. Passenger vehicles are already taking advantage of powertrain electrification, encompassing HEVs, PHEVs and BEVs. Li-ion technology dominates all these vehicle types.

Nevertheless, current batteries are far too big, heavy, and expensive to compete with diesel engines for long-distance trucks. However, several manufacturers of commercial vehicles have announced medium heavy delivery trucks with a range of up to 200 km. The amount of oil displaced by electric power in the case of commercial vehicles will, therefore, be limited for the foreseeable future.

The physical capacity limit of a lithium-cobalt battery, for example, is around 1.23 kWh/kg. The actual weight of an electrical power pack – including electrolyte, electrodes, casing – is today typically at least six times higher than the actual chemicals. The corresponding energy density of Li-ion batteries drops to substantially less than 10% of conventional fuel – even when considering the limited efficiency of ICEs. A state-of-the-art ICE efficiency of 40% means that fuel reaches 4.6 kWh/kg. In the future, more efficient ICEs may increase that value substantially beyond 6 kWh/kg.

Intense research and development is currently underway to move battery technology to the next level – so-called solid state batteries – that typically employ a ceramic or glass-like solid material to separate the electrodes instead of a liquid electrolyte. Once developed, they could be approximately 50% more compact and lighter than conventional Li-ion batteries and costs would decrease significantly. Such solid-state batteries could potentially be an important step towards achieving specific battery costs of $100/kWh or even less. Apart from the cost advantage, they can be charged in a short time – if the grid connection allows such charging power in the MW range for a 100 kWh battery. The charging time is an important aspect affecting consumer uptake. However, solid-state batteries are not expected before 2025, and it is unlikely that electric mobility will take-off at a large scale before then.

Despite all these technological advances, it should be noted that large batteries (80 kWh and more) will still be quite heavy. Battery costs will still be significant even at $100/kWh. An 80 kWh battery would cost $8,000 in this scenario – an additional premium that customers would never accept for conventionally powered vehicles.

The difference between batteries and fuel tanks will remain as long as batteries – even solid-state batteries – carry the oxidizer within the battery. Combustion engines do not have this disadvantage because they are taking the oxidizer – oxygen in this case – from the surrounding air and releasing the reaction product into the environment.

From a conceptual point of view, the final step for battery technology is the development of so-called air-breathing batteries. They take the oxidizer from air when it is needed – specifically, when the battery is discharged – and release it again into the environment when it is not required – upon charging. A value of around 11 kWh/kg is often cited as the physical limit for such lithium-air batteries. Combined with future high-speed charging at rates of up to several MW and reducing the charge time even for large batteries to what customers are accustomed to in terms of refuelling at a gas station, then such technological advances are expected to finally address the difference between electric and ICE-powered vehicles.

However, this potential game changing battery technology is currently only in the laboratory phase, with more substantial development work required than is the case for solid-state batteries. Hence, air-breathing batteries cannot be expected before the middle or end of the 2030s. Nevertheless, a substantial price difference may persist because of the initial battery investment.

Apart from batteries, electric motors are the second essential component of an electric vehicle. Induction – often called asynchronous – motors running on alternate current (AC) have the advantage that all required elements (iron, copper, aluminium) are readily available in abundant quantities and no supply shortcut can be expected in the future. This makes this motor type interesting, despite the greater weight and modest efficiency (between 85% and 97% for traditional motors). However, for use in electric vehicles, weight, efficiency and size had been optimized and could be reduced to 1 kg per kW of sustained power. The typical value of 3–5 kg per kW in the case of ordinary AC motors indicates the substantial and fast advance of technology in this area.

As a consequence, most electric vehicle models today employ brushless direct current (DC) motors with permanent magnets. Compared to asynchronous motors, their magnetic field cannot be increased by external currents, but is set according to the material characteristics. Science has provided strong permanent magnets by adding rare earths – mainly neodymium – to an iron-boron mixture forming $Nd_2Fe_{14}B$, which is one of the most powerful permanent magnets.

Electric motors based on these magnets may have a specific weight as low as 0.2 kg/kW of sustained power. This is around twice the value for gas turbines, but at a fraction of the average value for a combustion engine with auxiliary devices (super-charger and coolers) that is typically between 1 kg/kW and 2 kg/kW. They have been developed for electric or hybrid airplanes because weight is of an even higher importance and reach an efficiency of between 95% and close to 99%. Such high-density electric motors, together with air-breathing batteries, may have a system weight equal to, or even lower than, that of an ICE-fuel tank system in the distant future.

The expression 'rare earths', for neodymium and other elements, point towards the fact that these elements are not abundantly available. However, they are far less scarce than gold or platinum. In fact, neodymium is a more common part of the Earth's crust than copper or lead.

Box 7.1

Electric vehicles: Emissions and recycling

For conventional vehicles, most energy is consumed when driving from a 'cradle to grave' point of view. Cradle-to-grave is a holistic approach, which includes mining the required ores and other materials; their transformation into appropriate components (iron ore to steel sheets, for example); the development, manufacturing and assembly of the vehicle; the operation (including fuel, lubricants and other consumables, such as tyres and block pads) and scrapping. As the requirement for valuable minerals increases, especially aluminium, neodymium, lithium or cobalt, recycling will become more important than has been in the case of conventional vehicles, which still largely rely on steel.

In countries with a low share of renewables, electric vehicles typically emit a substantial amount of CO_2. This emission occurs in an indirect way from remote power plants. Electric vehicles with low specific CO_2 emissions only occur in countries with a very high share of renewables or nuclear power, or both. Medium levels of specific emissions are achieved by using natural gas in conjunction with CCGTs for power generation, or by combining fossil fuels with high CO_2 emissions (basically coal) with an increased share of renewables, for example, as has been observed in Germany in recent years.

The International Renewable Energy Agency (IRENA) expects that renewables will expand significantly in the near and mid-future. Accordingly, in countries with low carbon power generation resources, specific CO_2 emissions of electric vehicles are expected to drop in the future.[32] IRENA envisages China with a renewable share of around 40% in 2030 (including hydropower) in power generation, compared to a current level of 25%. If this is the case, specific emissions are set to decrease from 140g CO_2/km to around 115g CO_2/km for an average electric vehicle.

It is interesting to view today's specific CO_2 emissions of electric vehicles with the current or upcoming advanced fuel efficiency standards for ICE-powered vehicles. As these standards have already existed for some time, car manufacturers have been working to implement them. Even if the current US administration loosens certain regulations, the industry is already prepared for these standards and the new generation of vehicles will comply with these advanced standards that may regularly cause lower net emmission than electric vehicles given the current power mix in many regions.

A major component of electric vehicle manufacturing is battery production. The battery adds significant weight and energy consumption to the manufacturing process as no comparable component is present in conventional vehicles. GHG emissions involve not only CO_2 emissions, but also nitrous gases and/or methane, for example. Different structures of power generation may cause significantly different specific CO_2 emissions depending on the region where batteries and their components are produced, or where elements such as lithium, cobalt or manganese, are mined and refined. Battery production can easily add another 10g to 30g of CO_2 per driven kilometre over the vehicle and battery's lifetime. The larger the battery, the greater the GHG emissions share of battery manufacturing becomes.

Recycling is expected to play an important future role, not only in view of the availability of materials, but also in terms of limiting emissions during the manufacturing process. However, recycling will not significantly reduce additional requirements for lithium, cobalt and neodymium, for example, prior to 2030, because the fleet of electric vehicles and the associated number of batteries needs to expand before recycling can affect scrapped material, namely consumed batteries.

A 'second life' for older batteries as stationary battery storage, where round-trip efficiency is more important than maintained capacity, may even move recycling further into the future. This would shift substantial amounts of recyclable capacity to the end of the 2030s by extending the actual lifetime and delaying the availability of batteries to be recycled.

However, it is dispersed and does not form concentrated ores as is typically the case for iron or aluminium.

Fuel cells, hydrogen and natural gas

Fuel cells have been, and are being promoted, as a solution for the range issue of BEVs, as they produce only water as exhaust. However, producing and handling large quantities of hydrogen is a substantial challenge. Fuel cells currently achieve a fuel-to-power efficiency of around 60% for hydrogen and 40% for methanol fuel cells. Technology developments are expected to increase these numbers over time, but, in general, the overall efficiency of the whole supply chain must be considered; from carbon-free hydrogen generation through compression or liquefaction for transport purposes to the generation of electric power in the on-board fuel cell.

This efficiency may be around 50%, even considering the full chain from hydrogen production through transport and distribution until the power appears at the vehicle's wheels. If hydrogen is produced from renewables, for example, then only half of the initially generated power is finally available for propulsion. Batteries are doing far better, at more than 80%, including power distribution, as well as battery charging and discharging.

Despite the expression 'cold combustion', which is typically associated with fuel cells, the fuel cell stack requires a powerful cooling system that is comparable to conventional ICEs and substantially beyond that of BEVs. Even at higher fuel cell efficiencies of 60–70%, the difference, around 30–40% of the fuel power, is converted into heat and must be removed quickly to avoid overheating and the destruction of the fuel cell components.

Mainly in context with fuel cells, hydrogen is regularly presented as the fuel and energy carrier of the future. However, as a gas at ambient temperature, hydrogen must be compressed or liquefied to achieve an acceptable density. Typical pressure values for compressed hydrogen and CNG are 700 bar and 300 bar, respectively.

For hydrogen, both compression and liquefaction (to produce liquefied hydrogen) require far more power than natural gas. Even when considering the substantially higher heating value of hydrogen (approximately 120 MJ/kg for hydrogen versus 50 MJ/kg for methane), the difference remains impressive. Compressing and liquefying hydrogen consumes more than four times the share of the energy content, when compared to natural gas. The recuperation of the initially invested energy is necessary to improve the overall balance. Highly compressed, or liquefied gases, form an energy reserve that can be back-converted by appropriate devices.

7.1.2 Aviation

Aviation is not only the fastest growing transport segment, but it is also the focus of much attention, mainly due to the fact that airplanes cause emissions in the upper atmosphere. However, airplanes and especially gas turbine technology, have witnessed important advances in recent decades. Travelling by plane has become a very efficient – and considering the often long distances – a generally comfortable way to travel. It can be expected that the experience offered by airline companies will improve further in the future, with passengers in 2040 looking back on 2018 in the same way that many do today when looking back to the early 1970s. Technology advances have substantially reduced fuel consumption, increased comfort and improved the environmental friendliness of air traffic. A major aspect is the now far lower noise levels – essential for the acceptance of high flight frequencies, as well as airport night operations.

Impulsion

Flight gas turbines are ICEs that are comparable to piston engines for road transportation, albeit usually with a far higher power development. Therefore, many of the same principles for road transport apply in this segment too. From reciprocating piston engines, it is known that the engine efficiency and, hence, the fuel consumption, strongly depends on the compression ratio. It is, therefore, no surprise that turbine engineers have attempted to increase such a ratio – and have evidently succeeded in doing so.

Today, modern flight gas turbines have reached an astounding 50:1 compression ratio, which means that after leaving the multi-stage compressor the aspired air has a 50-times higher pressure than upon intake from the environment. This number suggests that the concept of further increasing the compression ratio and, as a consequence, reducing fuel consumption, is nearing the end. It is expected that the future compression ratio may be increased further, but at a slow pace. It is the optimization of the turbine's components that is more promising.

Apart from the gas turbine efficiency itself, the associated conversion of turbine power into thrust to propel an aircraft plays an important role. The power fostered by a turbine is the kinetic energy of the accelerated air jet emitted by the turbine. From an efficiency perspective, it is advantageous to increase the mass of the accelerated jet while making its velocity difference – compared to the airplane's speed – as low as possible. According to these principles, the so-called bypass ratio has a far better impact on thrust and, therefore, fuel consumption, than when increasing the compressor pressure ratio. The fan of modern flight gas turbines moves most of the aspired air around the actual power producing gas turbine and accelerates it to produce the thrust. They have steadily gained in diameter so that today's largest turbines show an outer diameter of more than three metres.

Although the number of passenger-km is set to increase substantially in the forecast period to 2040, overall fuel consumption is not forecast to increase at the same pace. The high bypass ratio is the most important reason, combined with lighter materials and improved wing profiles, why modern airplanes consume as few as three litres of fuel per 100 passenger-km and future airplanes are expected to lower this number considerably. This Outlook considers the counteracting effects of increasing air transportation demand and improved efficiency.

Electrification is also an increasing element in air transportation. Today, there are small airplanes that run entirely on battery-electric power. Moreover, Siemens and Airbus, as well as several other companies, have plans to extend the concept to commercial airliners, albeit for short-distance flights. Norway claims to be a forerunner in this area. Considering auxiliary devices (air conditioning, pressurization, etc.) electrification is evidently starting to become a reality.

While for some smaller aircrafts, a combination of an electric motor and a battery may be sufficient for short-haul flights (a few hundred km or so); the larger projected experimental airplanes employ a gas turbine to generate power for the electric motor. Apart from weight issues related to the complete gas turbine-generator-electric motor chain – with the generator typically a comparable weight to the electric motor – this cannot really be considered an electric airplane; it is far more a serial-hybrid.

The original hybrid electric vehicle might be a perfect analogy as a combustion engine was the only power source. In the end, a well-designed combination of a combustion engine – here, the gas turbine – and a battery-electric motor sub-system may not only have the advantage of providing additional power upon take-off, but it may also reduce the whole system's average fuel consumption in terms of the gas turbine and the electric sub-system. Additionally, it may add a significant security level by providing a second power source in case of a main engine problem – a substantial improvement from the passenger's point of view towards a zero-accident operation.

Hull and wings

The use of light carbon fibre compounds has had a substantial impact on fuel efficiency per passenger-km (or ton-km in the case of freight). Every single kg of saved weight leads to a directly corresponding reduction to in-flight fuel consumption as proportionally the wings need to generate less lift. Part of the reduced weight can be spent to improve the comfort of passengers, as evidenced by modern wide-body aircrafts.

The introduction of so-called supercritical wing profiles has increased the lift-to-thrust ratio for airplanes. In general, however, they add substantial instability to the airplane's flight characteristics. Nonetheless, technology development, mainly in the IT sector, provides the necessary sophisticated avionic systems that are required for the stable and secure operation of such fuel-efficient wings and airplanes.

However, technology advances are not only limited to the plane's operation. In the course of the development of a new plane, extensive aerodynamic calculations are carried out rather than the previous repeated aerodynamic model experiments in wind tunnels, for example. Technology has already reached such a high level that pilots can use a flight simulator to replicate the use of a new plane before it has even taken off.

Alternative fuels

A complementary path to reduce GHG emissions in air transportation could be the use of biofuels, experimental fuels based on natural gas, or even hydrogen. In the case of biofuels, several successful demonstrations have been conducted (e.g. KLM). LNG and liquid hydrogen remain at an early planning stage.

Passengers' concerns regarding reliability play an important psychological role, in this regard, which prohibits the use of gaseous fuels and especially hydrogen in airplanes due to the notion that these fuels will explode instantaneously in the case of an accident. Such concerns are an important example that the breakthrough success of such fuels rely not only on the technology, but also on acceptance from the general public. Although LNG does not present a higher risk than liquid fuels because its very low temperature prohibits its evaporation to form an ignitable gas-air mixture, passengers still need to be convinced.

Looking ahead, it will be challenging to replace the current main engines – efficient and powerful combustion engines – or the currently used jet fuel, with alternative technology concepts or propellants. Hence, aviation represents a sector with expanding oil demand, as reflected in Chapter 3.

7.1.3 Rail transportation

The continuous trend towards the electrification of railways continues to advance, with the full electrification of the world's longest railroad line, the Trans-Siberian Railway, being the most impressive success. It should also be noted that China is advancing quickly in this respect, mainly in connection with the strong expansion of its high-speed rail network.

Non-electrified railroad lines are today nearly exclusively serviced by locomotives running on diesel engines. However, stricter pollution regulations, as well as the low price of natural gas in North America, have given rise to the use of LNG as an alternative fuel.

The efficiency of these new LNG railroad engines is at the level of medium- and large-sized stationary engines, as they employ the same technology. Specific fuel consumption may be below 200 g/kWh. It is expected that considered improvements will broadly take place at the same pace as seen in the case of heavy-duty commercial or stationary engines. In general, however, the trend in rail transportation is towards more electrification.

Nevertheless, any potential oil demand decline due to fuel substitution in this sector will likely be more than compensated by the expanding railway network and increased traffic, especially in developing countries.

7.1.4 Marine transportation

Large merchant vessels (bulk, container and tanker) are commonly propelled by large and slow running two-stroke engines, which are directly coupled to the propeller. They are the most efficient reciprocating piston engines currently being built, consuming only 164 g of fuel per kWh of power at the optimum operating point. The simple layout, comprising typically only one large and hydraulically actuated exhaust valve makes them very reliable – an important asset. The basic structure has been proven for many decades and apart from modernized sensing and control devices, the most important mechanical innovation has been the adoption of common rail injection systems, long used in road transport vehicles.

It is estimated that there is only a very limited potential for further efficiency improvements as long as WHR is not used. Friction is comparably low because no valve train needs to be driven. Moreover, wall heat losses are almost negligible. However, even increasing the efficiency level by 1% (absolute) will create a considerable fuel saving, because these large engines consume such a large amount of fuel per day. With WHR, an overall efficiency of 60% may be reached in the long-term, and without WHR it is expected that some 55% may be possible.

Faster running four-stroke marine engines are now at an efficiency level of up to 48%, even without WHR. Only a decade ago the difference between two-stroke and four-stroke engines was more pronounced. Such four-stroke engines – the largest with a power development of up to 25 MW – are typically used for smaller vessels, but also for the large cruise ships. They have a softer power development and, as a consequence, produce fewer vibrations – an important advantage for passenger ships. In this case, a major efficiency improvement is anticipated to only be possible by adding a WHR unit.

On 13 April 2018, the IMO Marine Environment Protection Committee (MEPC) announced a target to cut the shipping sector's overall CO_2 output by 50% by 2050. Already by 2025, the intention is to see all new ships 30% more energy efficient compared to those built in 2014. In the past, ships became more efficient in terms of fuel consumption per ton-kilometre of freight, mainly by improving the hull and advanced propeller design and through manufacturing. However, these strategies have advanced in a more asymptotic manner in recent years, as this type of ship technology is already mature.

Both two-stroke and four-stroke marine engines are today regularly offered as dual-fuel engines, capable of running on liquid fuel and natural gas. The substantially lower specific CO_2 emissions of methane compared to liquid fuel offers a possibility to reduce GHG emissions in the marine sector. Switching between the fuel types occurs continuously, (i.e. without interrupting the engine's operation). Although switching the fuel type from HFO to LNG would make compliance with reducing GHG emissions easier, the lack of LNG bunkering facilities, even by 2025, makes it unlikely that a major amount of HFO will be replaced by LNG in the short- and medium-term.

The recent tightening of IMO regulations in view of sulphur emissions (see Chapter 3) has increased the importance of scrubbers. This is because they may be more readily available than LNG bunkering facilities and their operation may be cheaper than using LSFO. Two different scrubber types can be distinguished: dry and wet scrubbers. Dry scrubbers use granular carbonate (typically calcium carbonate or lime) with a very large internal surface to which the emitted SO_2 is chemically bound. The alternative wet scrubbers use sweet or sea water with caustic soda that is typically sprayed into the exhaust gas stream. Caustic soda captures the sulphur and sulphuric acid from the exhaust gas and is separated. It should be noted that the large amount of potentially harmful chemicals that are produced may present a substantial future challenge.

LNG would also help to solve the emissions problem too, but due to the reasons already mentioned, in terms of a lacking bunkering infrastructure, it remains unlikely that LNG will play a decisive role in providing a major alternative to scrubbers in the short- and medium-term. This Outlook, therefore, assumes that from a technical point of view, scrubbers will be the preferred choice for ship owners to comply with sulphur regulations, though some increased penetration of LNG vessels is likely.

In the longer term, however, an important aspect to consider in conjunction with the use of natural gas is the potentially lower exhaust temperature and the associated increased WHR efficiency. Today, high-sulphur fuel requires a minimum exhaust temperature of around 160°C to avoid the condensation of sulphur and sulphuric acid from the exhaust. The deposition of these acids onto the inner surfaces of all components in the exhaust path – from the exhaust valves of the main engine through to the turbine of the supercharger and the exhaust piping including a heat exchanger for WHR – would cause serious corrosion and later destruction of these components. The corresponding elevated temperature level currently forbids decreasing the exhaust temperature to a desired lower level in a WHR engine.

As a consequence, engine efficiency may not be as high as its potential and fuel consumption may be higher than necessary. Using LNG as fuel does not present this problem because no acidic products are generated. As soon as a satisfactory LNG bunkering infrastructure becomes available, expected in the long-term, using LNG instead of HSFO may not only make scrubbers obsolete, but also improve fuel efficiency. However, it remains to be seen how fast the penetration of LNG vessels will progress.

7.2 Power generation

Power generation is an important consumer of primary energy. Today, electricity is mainly generated based on coal and natural gas; oil has almost completely lost its importance in this sector, particularly when compared to the early 1970s. Coal has been, and generally remains, substantially cheaper at the global level. In the US, nevertheless, with the shale gas boom delivering an enormous amount of inexpensive natural gas, coal has been displaced to a large degree, without the need for regulations or incentives.

Power generation shows how technology development over the past two centuries has shaped the global energy business. This has happened, for example, by improving and upscaling existing technology from steam engines of a few kW of power to large steam turbines of more than 1 GW – a scaling factor of nearly 1 million. Moreover, conversion technology has made possible the use of new forms of energy with oil as an important example of the mutual dependency: oil-based fuel needs ICEs, and ICEs need fuel.

The scientific discovery of nuclear forces and their use in nuclear power plants marked the access to a new energy, and the most powerful energy source in history. Today, more technology development has turned towards renewables, making wind and solar energy available at large scale, not only from a technical, but also from a commercial point of view. However, fossil fuels remain the most important aspect in power generation, and technology advances are occurring here too.

7.2.1 Fossil fuel power generation

Fossil fuel power generation continues to occupy by far the largest portion of the electricity sector, not least because of the enormous build-up in Chinese capacity over the last two decades or so. As already noted, coal and natural gas play the most important roles in this sector.

Coal and steam power plants

Most modern coal-fired power plants are so-called supercritical ones where the steam pressure is beyond the critical pressure of water at 220.6 bar; conventional steam power plants are typically running at pressures around 100 bar. The phase boundary between liquid water and steam vanishes upon heating the working fluid (water). The result is a better match in the cooling line of flue gases from the coal-combusting chamber and the heating line of the highly pressurized water. Thermodynamic irreversibility is minimized and, finally, more power may appear at the steam turbine's shaft.

Nevertheless, all these steam and vapour-based power plants are approaching a limit imposed by natural laws. The already achieved 48% efficiency of supercritical steam power plants may rise to values close to 55%, but no future game-changing breakthrough can be expected. A major limiting factor is the maximum temperature of the heat exchangers that transfer thermal energy from the flue gases to the steam generator and superheater.

However, it should be recognized that most of the globally existing plants do not even achieve 40%. This Outlook considers such existing and future coal-fired power plants as important sources of electricity generation. Nonetheless, despite technology advances, coal remains by far the most adverse power source in view of GHG emissions. In fact, if this is the power source for electric vehicles, it will cause them to emit more CO_2 in the end than conventional vehicles.

In principle, any other fluid that is condensable at ambient temperature can be employed for such a power plant with a condenser. Organic substances, for example, hydrocarbons, partially fluorinated hydrocarbon (FHCs), or silicon-based oils are employed in so-called organic Rankine cycle (ORC) power plants. They have achieved certain importance when using geothermal energy, or for WHR, as by choosing the appropriate fluid nearly all temperature ranges between 100°C and 300°C can be matched. The future development potential is important; power generation can be increased up to 20% in the future. This is because a lot of waste heat – up to 20% of the whole energy consumption of a country – may be available at low- and medium temperatures, thus, ORC devices may play an increasingly important role in reducing the energy intensity of industrial consumers, for example.

Natural gas and CCGTs

Today, large CCGTs, or combined cycle power (CCP) plants, are the most efficient internal combustion engines. The current global record of 62.22% is coming close to the thermodynamic limit of perhaps 73% to 75%, even when considering any further increase in the combustion temperature or multi-staged combustion chambers. While such further improvements may somewhat decrease power generation costs, no disruptive development can be expected from the gas turbine technology itself. Nevertheless, CCGTs form an impressive example of how technology advances can get close to physical limits, as well as stimulate engineering developments in other areas.

The more flexible operation of gas turbines and a combination of heat and power generation – or CHP for short – has generally pushed the use of gas turbines in the power range of between 5 MW and 50 MW. Several countries offer incentives for CHP – although this is quite uneven from country-to-country – where power is supplied to the grid and the exhaust heat is used for industrial processes or district heating. The combined efficiency can be as high as 90%, or even more in some cases. While typically around 30–40% of the thermal fuel power is converted into electricity, the remaining 50–60% is captured as heat for further use. This Outlook considers such attempts to improve the combined efficiency while reducing GHG emissions.

7.2.2 Renewable power generation

Support for renewable power generation is driven by many issues and concerns. They range from environmental challenges related to GHG emissions, to the desire for a nationally or regionally controlled domestic power source, which is evidently the case in the EU. Renewable power generation and renewable energy, in general, has, therefore, witnessed increasing support from many sides. For example, besides the objectives of governments, industry may look for additional power sources, while environmentalists are putting the reduced carbon footprint to the fore. Technology development has advanced faster than what was envisaged 20 years ago, especially in the case of PV cells; their price per kW of peak power has dropped by around 90% since the 1990s. Moreover, in many instances, power generated at home has become cheaper than power purchased from the grid.

Hydropower

An important renewable power source with a more than century-long history is hydropower. The regional focus today is on developing countries in Asia, mainly China, with some additions also in Africa and Latin America. Most OECD countries, on the other hand, have already exploited their hydropower potential and only minor additions can be expected.

This Outlook assumes that hydropower will be among the most reliable future renewable sources, considering a levelized cost of energy (LCOE) of typically between $35/MWh in developing Asia, with a still substantial potential, and $100/MWh in Japan. From a technology point of view, hydropower can be considered a mature technology because water turbines have reached an efficiency of 95–98% – comparable to DC electric motors – and only a very limited further potential is possible.

Wind

Wind has emerged as one of the most promising renewable global energy sources. Today, wind is the cheapest renewable energy source with an LCOE of between $60/MWh and $110/MWh. These values are coming close to, or are already competitive with conventional sources. Important technology advances have substantially improved the usability of low-speed, as well as high-speed wind, increasing the capacity factor – actually average generated power versus nameplate power– to 40%, and in some regions, even beyond 50%.

Nevertheless, the technology is now mature and further improvements are basically only expected by scaling and through the experience gained in the case of the deployment of offshore wind turbines. Currently, offshore wind is limited to shallow shelf regions as, for example, the North Sea. The turbines are mounted on a rigid platform that is positioned on the solid sea floor, similar to the first offshore oil platforms. However, this construction principle limits the regions where such offshore wind farms can be built because in most cases the sea depth quickly exceeds 30–50m, which is currently the limit for such platforms.

A promising new concept is to deploy wind turbines in a floating manner in deeper sea regions. By forming semi-submerged wind turbines, the appropriate areas can be extended; examples include the north-east coast of Brazil, the coast lines of important sections of the North and Latin American continents, but also large parts of the coast of China and Japan, among others. Technology advances do not only improve efficiency or decrease costs, but substantially enlarge the usable geographic base. In the end, the global wind energy potential will be increased considerably.

It is possible that, by the 2030s, offshore wind power costs will approach that of onshore wind power and, hence, conventional power production. Currently, it is typically one of the most expensive renewable source with an LCOE of between $120/MWh and $135/MWh. An important question is how fast and, to what extent, the grid can be expanded to the level required for an efficient and large-scale redistribution of the generated power. Apart from a few exceptions – Northwest Europe is an important one – most windy regions are far away from consumer regions and grid limitations are an important factor. Nevertheless, this Outlook considers wind as an important additional source of power going forward.

Solar

Solar energy also has huge potential, with PV the leader with an overall installed capacity of 385.7 GW in 2017 and a LCOE of typically between $60/MWh and $140/MWh, in the case of large PV plants (at least 10MW at their peak). Improved multi-layer solar cells may increase the sunlight-to-power conversion efficiency beyond 30% in the case of PV. An important side-effect is that the area covered by such PV cells is reduced.

Concentrated Solar Power (CSP) has lost some relevance because PV modules have become economical far quicker, although the upscaling of CSP could decrease the LCOE, which is currently between $120/MWh and $180/MWh. However, CSP relies on proven steam power plant technology with solar absorbers replacing the furnace, so the potential of new technologies is limited.

The substantial advantage of CSP over PV is the possibility of incorporating storage already at the CSP site. It may generate electric power for an extended time period (typically two-to-six hours) when the sun is not shining. These are thermal energy storages (TES) based on molten salt (mostly a mixture of sodium and potassium nitrates). They do not store the electric power directly, but thermal energy produced by the concentrating mirrors. The thermal energy is then fed to the steam generator of the CSP plant to generate steam for the turbine.

It should also be noted that solar energy requires vast areas because the average energy density is low; favoured locations may receive up to 3,000 kWh of solar radiation per square metre annually. A coal or uranium mine, or an oil well, is capable of providing a million times more energy over the same time period. Thus, areas with low population densities, and obviously significant hours of sun, are favoured.

Recognizing the important build-up of solar power plants on all levels from a few kW to multi MW, this Outlook considers an important expansion of this renewable energy source. Nevertheless, it also considers that a 1 GW peak in the case of solar usually corresponds to 150 MW of continuous power generation at a conventional plant as, for example, coal, gas or nuclear.

An interesting application of solar energy, which is currently under intense scientific research, is the so-called solar-chemical cell. It attempts to produce fuel, mainly hydrogen, but also simple hydrocarbons, for example, methanol directly from abundant chemicals – basically from CO_2, water – and solar radiation. This cell can be also considered to carry out artificial photosynthesis. Although it is too early to judge the potential of this technology, it clearly indicates the dynamics of ongoing scientific research and technology development in the energy sector.

7.2.3 Power storage

The principal stumbling block for renewables – apart from hydropower and biomass – is their intermittent availability, which requires reliable back-up plants or a very large storage capacity to avoid blackouts. The most feared situations are so-called 'dark doldrums' when neither the sun is shining nor the wind is blowing. All required power must then be provided by back-up plants or storage. Although this is a rare situation, sufficient back-up capacity must be available and this can substantially impair investment performance. Large-scale grids, spanning entire continents, may be a partial solution, but are seen as extremely costly. Therefore, renewables have the potential for a substantially higher increase in their share in the power sector if storage technology can be extensively improved in the long-term.

Pumped hydropower

Pumped hydropower is a proven technology, but requires certain topographic characteristics with a large upper and a large lower water reserve. Given that the water levels of the upper and lower reserve can fluctuate by 10m or more (between fully charged and fully discharged), such reservoirs can present a serious environment conundrum, contradicting the ambient-friendly argument in favour of pumped hydropower. The required topographic characteristics can only be found in mountainous regions with abundant water resources that form a natural limit. Nevertheless, pumped hydropower is currently the leading storage technology in view of power and efficiency, with 80% or more of the supplied power able to be reproduced.

Traditionally, pumped hydropower storage plants have been used to balance peak and off-peak power generation. However, mainly through solar power usage – which is generally mostly available around noon when peak power demand occurs – this peak demand is now substantially covered. As a consequence, pumped hydropower is technically feasible, but increasingly lacks appropriate locations and attractive economics. Developing countries with favourable topography nevertheless plan to expand their pumped hydro capacity, headed by China with an expected capacity of around 20 GW by 2030.

Thermal energy storage

Today, the most well-known TES is formed by the molten salt storage of CSP plants where the thermal energy produced by the concentrating mirrors is stored as hot molten salt in large tanks. The advantage is that such CSP plants may produce power even when the sun is not shining, mainly after sunset. A major disadvantage is that the used salts are chemically very aggressive and can cause serious incidents, both in terms of the impact on people and the environment. Nevertheless, the possibility to pump the molten salt at atmospheric pressure – the salt has a vapour pressure substantially below atmospheric pressure – is an important asset.

For several years, solid-state TES systems have been proposed that use concrete or rocks as the storage medium. The advantage of abundant and cheap storage materials is contrasted by the slow charge and discharge rate because the applied or extracted thermal energy must propagate through the solid material. This limits the charge/discharge power and causes significant temperature gradients. However, scalability is an asset and the virtually unlimited and readily available storage materials avoid any supply constraints.

Such TES systems do not store or re-generate power directly, but produce thermal energy, which must be converted later to power through thermal engines, typically steam or ORC turbines. Their contribution to the global storage capacity is very low, at below 1%, and costs are very high ($200/MWh and above). Technology development is focused on elevating the round trip efficiency by improving the employed vapour engines.

Battery electric storage

On 2 December, 2017, the world's largest BES with a capacity of 129 MWh and a rated power of 100 MW was switched on in South Australia. Far more appealing than the capacity – a typical nuclear reactor produces this amount in five-to-six minutes – is the speed of installation: less than five months between the construction order and putting it into service. The investment costs are around $400/kWh.

The very opposite of this large BES – in terms of distributed power – are systems that have storage capacity in the multi-kWh range, which are often used to store power produced by a PV panel throughout a sunny day for later (night) usage. Due to economies of scale, overall BES investment costs – including inverters, control units etc. in addition to the actual battery cells – are in the range of $800 to $1,000/kWh. Such small battery storages can be financed by many small investors and connected instantaneously to the grid. In energy markets where small investors have immediate access to capital markets – a situation typical for OECD countries – PV has been mainly driven by them.

The scalable and distributed nature of battery storages may follow the success path of small PV once competitive battery solutions become available with prices below $500/kWh. Such BES obviously benefits from the overall battery technology advances, as described in section 7.1.2. Module costs of $200/kWh may make sustained 24/7 local power generation possible at least in sunny regions. Given that such small storages are typically located close to consumers and where power processes are higher, even higher storage costs may lead to competitive costing if the power is reproduced from storage.

Additionally, intelligent battery storages may play an important role in the build-up of smart grids. Even batteries in BEVs that are not in motion may be used as power storage. The roundtrip efficiency of battery storages can be as high as 90%, and even surpass the levels for pumped hydropower. It can be expected, therefore, that power from battery storage will become competitive with grid power in the 2020s and play an important role especially in local microgrids. This Outlook pays attention to this development, in view of the anticipated further deployment of renewables.

7.2.4 Nuclear power

Nuclear power is attracting attention again specifically in view of reducing GHG emissions. The close-to-zero emissions, in comparison to other fossil sources, together with decades-long experience and recent technology development towards inherently safer reactors, the so-called fourth generation, are considered an asset. However, the impact of the Fukushima disaster continues to cast a shadow over the sector, and the important question of nuclear waste remains unresolved.

Transmutation reactors are an interesting concept in this sense, but would require an industry covering the full-nuclear cycle. These reactors convert the long-term radioactive actinides into short-living fission products. They become harmless within less than a thousand years – a very short time scale when dealing with nuclear waste. These trans-uranium actinides, for example, Americium (Am), Curium (Cm) and others, are produced in commercial reactors by breeding reactions from uranium or thorium and form together with non-recycled plutonium, most of the long-term radioactivity from nuclear waste.

Apart from waste and security issues, overall power generation costs are an issue for nuclear energy. In many OECD countries, the power produced may become more expensive than wind, for example, an LCOE of around $105/MWh compared to $60/MWh to $80/MWh. However, nuclear is typically used for baseload; in the case of fluctuating renewable energy, so storage costs should also be included to provide a real comparison.

As discussed in more detail in Chapter 2, this Outlook takes into account the announced plans of several nations to make nuclear power an important component of their national electricity generation in the upcoming decades.

7.3 Carbon capture, storage and utilization

Carbon capture and storage (CCS) focusses on the separation and capture of CO_2 out of an exhaust gas stream (so-called after-combustion CCS). The exhaust stream may originate from carbon or hydrocarbon combustion (coal, oil, or gas-fired power plant), steel and aluminium plants, refineries and petrochemical plants, among others. Another strategy is to capture the CO_2 before combustion. This may be carried out by converting the hydrocarbon, for example, into CO_2 and a CO_2-free fuel. Steam reforming of natural gas is an example; the produced CO_2 is captured, and the hydrogen is burnt without GHG emissions.

After capturing the CO_2, it is compressed or liquefied according to requirements and then injected into appropriate geological formations. Typical examples are aquifers or depleted gas and oil wells. The latter can already be considered the logical next step: carbon capture and utilization (CCU) because the injected CO_2 typically increases the well pressure and raises the yield of the well – a strategy for enhanced oil recovery (EOR). Other proposed CCU applications comprise the production of hydrocarbons in conjunction with renewables that deliver hydrogen as the other component. Through well-known chemical paths, for example, methanol can be produced.

Two major non-financial issues accompany the current discussion around CCS and CCU. These are the lack of large reservoirs close to the use (i.e. combustion) of hydrocarbons or coal, and the limited acceptance of these projects in densely populated areas. They are for obvious reasons the principal locations where CO_2 is generated. Most hydrocarbon sources – oil and gas wells –

are not only adequate for storing CO_2, but may additionally benefit from an extended oil and gas production – or EOR – when CO_2 is re-injected into the wells. It would be a 'win-win' situation to return the produced CO_2 back to the original hydrocarbon source. This strategy requires the need to consider not only the hydrocarbons, but also the produced CO_2 as a commodity.

While with the notable exception of the US, coal is the cheapest power source with an LCOE typically between $50/MWh and $85/MWh, and CCS increases costs substantially. Currently, LCOE for coal with CCS would rise to values beyond $100/MWh and may even surpass the power generation costs of offshore wind, which is currently one of the most expensive large-scale renewable source.

7.4 Tight oil

Tight oil reserves are characterized not only by a low permeability of the enclosing plays (typically below 100μDarcy), but also by a fine distribution of oil in tiny pores (typical sizes are in the order of μm^3). Surface or adhesion forces are far larger than the gravitational gradient that separates gas and oil phases in the conventional case.

To access the substantial tight oil resources and make wells drilled into the corresponding plays productive, a combination of horizontal, or directional drilling, and fracking is required. Nevertheless, the current tight oil boom is also an effect of a steep learning curve in terms of how to access and exploit these new sources, accompanied by considerable advances in seismic, sensing and data processing.

Directional drilling

Horizontal or directional drilling has been employed for many decades before the tight oil boom. After being identified as one of the most important technologies – apart from fracking – to drive tight oil production, it has received a substantial boost. By making the downhole motor steerable it allows the drill head to continuously change orientation. Equipped with multiple sensors, it may follow entirely along the path of a comparably thin layer, even one that changes direction frequently. Such advanced technology is now also used on conventional wells.

The important advancement is that information to the drilling crew is available in real-time, which allows them to monitor and act immediately upon the data. Initially, the achievable horizontal displacements were a mere 400 feet or so, but with experience and learning, as well as continuous improvement in the drilling equipment itself, this has now moved to over 8,000 feet (2.5 km).

Fracking

To obtain access to the tiny portions of oil in the pores of a given formation, an access path must be opened in the rock. This is commonly achieved along already existing defects in the rock, which act as rated break points.

Through the tubing, the so-called proppant is pressed into one or more of the clusters. Once the rupture strength of a rock defect is exceeded, the rock starts to crack and a laterally extending fracture gradually opens up. It is important to emphasize that the fracture tends to travel along the initial direction, even if the originally opened defect ends.

If the pores are very small, then the surface tension and wetting forces may exceed the pressure forces; as a result, the oil remains trapped in the pores and only the associated gas is released towards the well. Chemical agents to reduce surface tension and wettability can help to drive the oil out of the tiny pores so that they may travel along the fracks to the production well.

Despite substantial advances, the recovery rate from tight oil formations remains low, particularly in comparison with conventional resources. To increase the yield, fracks need to occur in a denser manner, which means lowering the average distance between two fracks. Moreover, the re-pressurization of already producing – and declining – tight oil wells has been carried out, but with limited success to date.

It is evident that increasing the pressure within a tight oil formation can have a substantial effect on well production and costs, both in the short- and the long-term. Given that tight oil is still a relatively new business segment, such learning and technology advances can be expected in the future too.

Advanced sensing and artificial intelligence (AI)
The conditions in a tight oil well can best be described as 'challenging', especially in view of pressures and temperatures.

Taking developments from other areas, specifically in terms of acoustic applications, optical fibres have been adapted successfully as highly innovative sensing equipment. Varying pressures and temperatures alter the optical characteristics of such fibres, which can then be detected by means of Raman scattering.

Sophisticated in-hole sensing produces an enormous amount of data streams that must be analyzed in real-time, but this has the potential to offer unprecedented details of the soil build-up and the ongoing fracking and extraction processes. Together with AI, it can be expected in the near future that technology will allow companies to virtually look down into the soil, to view drilling and fracking processes; the soil may become transparent. This will allow a far more detailed search-and-exploit real-time approach, particularly in view of locating valuable reservoirs on the spot.

The technology advances in the case of tight oil are based on a combination of several disjointed technologies (horizontal drilling, fracking), alongside advanced sensing and data processing. Moreover, IT is changing its role from a supportive technology to one that is far more a driver of technology than a decade ago. Technologies developed in conjunction with tight oil are increasingly also being applied to conventional resources to improve oil and gas production. Hence, supply projections included in Chapter 4 take into consideration the impact of these technologies.

7.5 Residential, commercial and industrial sector

Apart from electric power, the residential, commercial and industrial sector mainly consumes thermal energy. Electric power is discussed in section 7.5; hence, this section will focus on thermal energy for the mentioned sectors.

Heat is required for many purposes, for example, warming buildings, hot water, pasteurization for dairy products etc. Moreover, the industrial sector will often consume thermal energy in the course of a variety of production processes. Traditionally, such thermal energy has been provided by the simple combustion of fuel, mainly natural gas and fuel oil. A more advanced concept is CHP production where the thermal energy of hot exhaust gases from combustion engines – mainly gas turbines and reciprocating piston engines – is captured for further use. Most of these plants are heat-driven, with the power output fluctuating with the varying heat demand.

In the case of heating for buildings, as well as hot water production for residential consumers, heat pumps are increasingly employed. This mainly happens in regions where substantial amounts of renewable power are available, for example, Switzerland; most of the newly built, as well as renovated homes and condominiums there, are equipped with such devices.

Small temperature differences between the source of thermal energy, usually the surrounding air or soil and the intended consumer – low temperature space heating at 30ºC to 40ºC or hot water at 50ºC to 60ºC – allow multiples (up to five times) of the consumed electric power supplied as thermal energy to the consumer. Looking ahead, technology development could increase this factor still significantly.

The multiplication factor makes heat pumps increasingly interesting for use at higher temperature levels. Considering a source temperature of between 5ºC and 25ºC – a reasonable range in view of year-round seasons – and a pasteurization temperature of 100ºC to 130ºC, then a power factor of between 3.2 and 4.4 is the physical limit. This is enough for an achievable level of between 2.5 and 3.5; 1 kWh of electric power may generate 2.5 kWh to 3.5 kWh of thermal energy. For still higher temperature levels, the power factor drops to values that are not profitable when considering the required investment for the heat pump systems.

Nevertheless, a major asset for heat pumps, in conjunction with renewables, is that the power generated by remote wind turbines, for example, during the cold season, may be converted into valuable and required thermal energy. Simple resistance heaters that have been and are still employed to make use of surplus power during the night, often in conjunction with nuclear power, are inappropriate for low temperature levels because their power factor is as low as one; 1 kWh of electricity is converted into 1 kWh of heat only. They only make sense where high temperatures are required. An important example is an electric melting furnace to produce high-grade steel.

Advancing urbanization and the shift in economies from rural agriculture and low-level manufacturing towards service and high-level manufacturing industries constantly increases the demand for air conditioning (A/C). Moreover, the productivity of employees substantially improves if they work in a comfortable environment and, in this regard, temperature and humidity play an important role. It is, therefore, not surprising that the power demand from such A/C devices continues to rise y-o-y.

In view of the commercial importance of the A/C industry – by 2020 the size of the US market alone is expected to be $53 billion – considerable efforts are currently being undertaken to further improve these devices. Today, small window systems with 5,000 Btu can be purchased for around $200. However, they consume more than 1,000 kWh of power when utilized for 2,000 hours per year. In other words, power costs may be ten times more important than acquisition costs over the lifetime of such a device.

7.6 Refining and crude oil to chemicals

An interesting upcoming technology is the COTC concept that looks to integrate refining and petrochemicals. This focuses on final products being directly produced, not intermediate products that need further processing in dedicated petrochemical plants. The concept increases the range of products a plant can produce and in a far more flexible manner according to real-time requests. In this sense, COTC plants are another element of Industry 4.0 that pursues a seamless integration of all steps in the production and value chain. Such COTC plants typically integrate distillation units, heavy-oil crackers, continuous catalytic reforming (CCR), solvent de-asphalting, gasification, hydro-treatments, MTBE, and alkylation units.

COTC acknowledges the fact of the expected and sustained increase in demand for petrochemical products. In the fuel sector, renewables, natural gas and biofuels, as well as electric mobility, may put pressure on oil demand. Contrary to this, petrochemicals will unlikely face a comparable threat in the foreseeable future. Available alternatives based on biomass are either inappropriate – in most cases chemical or simple mechanical resistance is not met – and/or not available in the required quantities. From a general point of view, this Outlook monitors such developments in the refinery sector.

To complete the picture it should be noted that attempts are underway in petrochemical plants to further reduce emissions in the course of producing fertilizers – one of their most important products. However, most GHG emissions occur after the fertilizers have left the petrochemical plant and are used in the field, which is obviously outside the area of the plant's influence. Certain agricultural methods are causing elevated GHG emissions, including a substantial amount of methane. Because this gas is far more climate-adverse with a greenhouse warming potential of 27 for a 100-year period, optimizing agricultural processes towards lesser emissions is extremely important and may be substantially more efficient compared to making the petrochemical process less GHG-emitting.

7.7 IT, big data and blockchain

IT developments have driven change and substantially reshaped many parts of the oil business. Exploration has always been on the forefront of computing to obtain a clear picture of potential and actual hydrocarbon reserves below surface. The signals received by geophones in the course of seismology lack meaning without further data processing. This situation has become substantially more complex with in-hole sensing carried out by means of optical fibers and tunable lasers. Such state-of-the-art sensing produces an unprecedented stream of data. This must be recorded and analyzed by extremely powerful IT equipment to extract and leverage the valuable information.

The data streams are generated by a multitude of innovative sensors, with each one delivering constant high-resolution signals. For better real-time control of all the steps along a value chain, such sensors are now interconnected. For instance, in a refinery, sensors may continuously provide information about process parameters, such as pressure and temperature, as well as product characteristics on various levels of processing, energy consumption, and staff activities. The end result is a collection of a huge amount of data – or 'big data' as it is often called. Through IT, the information streams are put in order, analyzed and processed to provide the staff on all levels – from process supervision to management – with timely and reliable results as a basis for decision taking. Without advanced IT, such large amounts of data would be left unexploited, instead of being leveraged to find valuable conclusions.

One segment of business-oriented data processing that is becoming increasingly important is blockchain (it should be noted that this technology is far more than a cryptocurrency). The inherently forward-oriented structure – approved actions cannot be reverted at a later stage, but only compensated for by a future action – makes blockchain an interesting concept to accelerate international trade, among others.

The unique time stamping of individual transactions will also be helpful in many other time-critical areas, particularly those with a clear cause-effect structure. There is evidently significant potential in the energy industry. LNG trades have been already conducted over the blockchain platform managed by ING and Société Générale. It can be expected that such blockchain-based trading will increase substantially in the coming years as it reduces costs and accelerates the exchange of goods and payments in various currencies.

Energy and climate change

Key takeaways

- The Paris Agreement on climate change, combined with the cost competitiveness of natural gas, means that the coal industry is under increasing pressure, particularly in the power generation sector.
- Following the US announcement of its intention to withdraw from the Paris Agreement, the EU, China, and India have reaffirmed their commitments to the Agreement.
- The road transportation sector is increasingly under regulatory scrutiny, with the establishment of more stringent emissions targets across various regions.
- Diesel fuel faces tighter quality standards across several countries, particularly following the 'dieselgate' controversy.
- The popularity of electric vehicles among policymakers is evident across regions; however, all of the regions reviewed in this Chapter are undergoing an evaluation, in one form or another, of the fiscal burden of subsidies for electric vehicles.
- Policymakers across the world are re-examining the potential role of nuclear energy in power generation, chiefly as a means to achieve climate and energy security objectives.
- Renewables are poised to play a greater long-term role in power generation, as a result of government support and falling costs, particularly for wind and solar.
- US energy policy has experienced an evolution of goals over time, ranging from 'energy security', to 'energy independence', and culminating in the current aim for 'energy dominance'.
- While the US's federal regulatory regime is liberalizing tight oil resources on federal lands, economics and technology prevail when it comes to the commerciality of tight oil resources.
- By 2030, the EU plans to reduce GHG emissions by at least 40%, meet a minimum renewable energy level of 27% in the energy mix, and an increase in energy efficiency of at least 27%.
- In the EU, LNG features prominently as a means toward achieving diversification in energy supplies.
- China's policy developments reflect the endeavour to achieve the domestic goals of realizing a future with 'blue skies'.
- Renewable energy is intended to make up the bulk of India's power additions in the medium- to long-term, led by solar and wind.
- While policies can be powerful mechanisms driving long-term changes, market fundamentals, consumer preferences, and fiscal realities also have a significant impact on energy markets.

Across the world, policymakers utilize climate and energy policies as mechanisms to achieve various national priorities and objectives. These policies are often evolutionary in nature; adapting over time in accordance with technological advancements, social pressures, and geopolitical developments, among other factors. The manner through which these policies change over time can both directly and indirectly impact oil and energy markets.

The Reference Case takes into account the energy policies that are currently enacted, while recognizing that policies and regulations tend to be adapted over time. Each year, the WOO projections are revised to reflect recently enforced policies, and to evaluate the outcomes of previously imposed policy measures. As such, the WOO is also evolutionary; aiming to proactively reflect policy developments as they materialize over time, and anticipate their future development. This Chapter examines recent developments in climate and energy policies, and reflects on the potential impacts of the various policy measures employed by decision makers in major energy consuming countries and regions.

The climate and energy policies of various countries and regions are in constant motion. The ebb and flow of policy making is a function of the political, market-related, technological, and social dynamics at play during a given period. The US is an excellent example of the evolutionary nature of policies, as exemplified by the dramatic differences between the goals and objectives of one presidential administration and another.

The Paris Agreement sets the tone for the environmental agenda relating to emissions reductions across various sectors. Even the US, which aims to depart from the pact, is affected by the outcomes of the Agreement, as individual states and non-state actors establish their individual environmental positions, which may diverge from the federal stance.

As it relates to oil demand specifically, the transportation sector is increasingly under regulatory scrutiny. The emergence of lower emissions alternatives, combined with competitive technologies, has coincided with a public backlash and scrutiny of automotive emissions testing methodology, particularly following the 'dieselgate' controversy. This phenomenon is evidenced in the policy drive to tighten regulations on diesel fuelled vehicles, in particular, and the establishment of more stringent emissions targets across various countries and regions.

The popularity of electric vehicles among policymakers is also evident across regions; however, it should be noted that all of the regions reviewed in this Chapter are undergoing an evaluation, in one form or another, of the fiscal burden of subsidies. In fact, more and more regions are reducing, if not withdrawing, subsidies relating to zero emissions mobility, and waiting to see if technologies are competitive enough to survive.

In the power generation sector, various regions have different approaches to the coal industry; one that is often a critical source of energy and job security to their populations. While the relationship between policymakers and the coal industry varies from a protective one in the US and an increasingly critical one in China, the industry is under scrutiny in the age of the Paris Agreement. The same applies to the nuclear power industry, which remains a controversial one post-Fukushima.

Nonetheless, regardless of policy support for or against the coal industry, market dynamics have swayed favourably toward the natural gas industry. Particularly in light of the abundance of global natural gas supplies, teamed with emissions reductions targets set forth in environmental pacts like the Paris Agreement, the fuel has gained a competitive edge in the power sector, even while other fuels sometimes enjoy policy protection.

This dichotomy reflects the true impact of policies in an environmental and energy context. Policies are a mechanism utilized by regulators to facilitate change beyond purely market-driven dynamics. While these can be powerful mechanisms, they are still subject to market fundamentals, consumer preferences, and, ultimately, budgetary limits as evidenced by subsidy reversals.

Ultimately, policies are evolutionary and will continue to change and develop over time, across sectors, and from region-to-region. Therefore, it is important to continuously monitor their development and potential impacts, and revise any conclusions over time.

8.1 United States

US energy policy has experienced an evolution of goals over time, ranging from 'energy security', to 'energy independence', and culminating in the current aim for 'energy dominance'. Following the election of President Donald Trump in November 2016, the energy policy of the new administration is being reshaped under one master plan; the 'America First' energy policy. While a comprehensive energy plan with a clear framework and timeline is emerging over time, the current administration's energy policy objective is to 'unleash American energy'.

In order to achieve these goals, following President Trump's assumption of office, the administration swiftly activated the Congressional Review Act (CRA) in order to undo some previous policies. The CRA is a legal process enabling the US Congress to invalidate any recently finalized federal regulation by a simple majority vote in both chambers (subject to presidential endorsement).

Simultaneously, on 21 January 2017, the White House released the administration's 'America First Energy Plan', which pledges support for the tight oil and gas industry by way of eliminating the Climate Action Plan and the Waters of the US rule, deregulating the oil and gas industry overall, as well as opening federal and tribal lands for oil and gas leasing. Additionally, on 28 March 2017, President Trump issued an 'Executive Order on Promoting Energy Independence and Economic Growth'. Among its objectives, the Order directs federal agencies to identify and minimize all obstacles to the expansion of domestic natural resource production, including oil.

Against the backdrop of President Trump's 'America First' policy agenda, and following campaign promises to the same effect, on 1 June 2017, President Trump announced a public statement indicating the withdrawal of the US from the Paris Agreement. This statement was followed by the formal submission of communication to the UN that indicated the intentions of the US to withdraw as soon as it is eligible to do so under the terms of the agreement. While announcing the withdrawal, the president expressed the assertion that the climate accord undermines the US economy and its sovereignty, but left room for potential renegotiation of different terms in the future.

Although the intention to withdraw from the Agreement has been communicated officially to the UN, technically, the soonest that the withdrawal can take effect is November 2020; the same month and year, and just one day after, the next US presidential election. The reason for this timeframe is that, according to Article 28 of the Paris Agreement, a Party to the Agreement may only withdraw from the accord by submitting its intentions to do so in writing three years after the Agreement came into force. Once the formal communication is received, the withdrawal only becomes effective one year later (or even further if so indicated in writing by the Party to the Agreement).

It should, however, be noted that even within the federal government itself, there are some opposing views regarding the direction of climate policy, as exemplified by a US government report compiled by 13 federal agencies, the 'Climate Science Special Report' conducted by the US Global Change Research Program.[33] Although the opening statements of the report expressly prequalify its findings from "predicat[ing] regulatory action", its conclusions are arguably at odds with the current climate policy direction, and the statements and assumptions established by the federal government.

Furthermore, while the current US administration is catalyzing an environmental deregulation movement, some non-federal entities have declared their own climate policy objectives. The role of federalism in US government enables states to challenge and even defy federal legislation seen to be at odds with their own constitutions. In fact, state government officials are not required to enforce federal laws that are determined by the state to be unconstitutional.[34] This illustrates the level of autonomy that state legislators have and can observe as they relate to the climate policy sphere. Upon President Trump's assertion to withdraw the US from the Paris Agreement, several states, cities and non-state actors, holding opposing views to the federal government, have set out to establish their own positions on the issue.

Supply policy

On the supply front, the federal policy pronouncements of the Trump administration include declarations to "unleash American energy" in order to achieve "energy dominance". Along with these proclamations, the federal regulatory regime is liberalizing tight oil resources on federal lands, deregulating environmental rules, and paving the road for infrastructure facilities for the industry.

In essence, however, economics and technology prevail when it comes to the commerciality of tight oil resources. To illustrate, out of over 30 million acres that were offered for lease from 2009–2016, only 25% attracted interest.[35] As for the federal lands on offer for leasing in 2017, less than 7% of the leases were purchased.[36] Out of the leases that were sold by the US Bureau of Land Management, over 30% were sold for $10 per acre or less, which indicates that bidders are likely speculating with the aim to resell leases in the future, or use them as collateral to obtain bank loans, and have no intention to drill. What is more, the Congressional Budget Office (2016) reports that companies only drill about 8% of acres purchased for $10 per acre or less.

Moreover, the lack of available seismic data, combined with the geologically challenging characteristics, and limited (and often non-existing) infrastructure makes tight oil development on federal lands a long bet, and one that is anticipated to be less attractive in comparison to resources on non-federal lands. In the absence of a breakthrough in market dynamics, the federal regulatory environment is only one factor impacting the future of the US tight oil industry. This reality is evident in the fact that significant US tight oil supply emerged under the previous administration's regulatory environment, one that has been described as overly burdensome for the industry. However, that federal regulatory environment did not stop the emergence of the tight oil industry.

The nature of federalism in the US generally establishes states as the prime authorities over the regulatory environment within their territories, as long as the minimum federal standards are met. Given that federal regulations are not only being relaxed, but are already considered liberal toward the tight oil industry, the onus falls on state level regulators to govern the industry. Even then, energy companies have already voluntarily established standards that are stricter than those imposed by federal and state regulators,[37] indicating that such standards may result in efficiency and/or reputational gains.

At the state level, each state enjoys unique characteristics, thereby resulting in heterogeneity amongst various tight oil regulations. However, the regulatory environment as it relates to tight oil development and extraction is not remarkably different to that applicable to conventional resources within an individual state. States like Texas and North Dakota maintain relatively liberal regulations governing the industry, while some localities continue to challenge the state's decisions.

Even in liberal regulatory state regimes, the negative externalities relating to the emergence of the tight oil industry in some localities has resulted in pockets of resistance within individual states. In Texas, the city of Denton banned hydraulic fracturing within the city's limits in 2014. Oklahoma experienced similar local resistance in 2015. In both places, the state's authority prevailed over localities, thereby reinforcing the preemption of state regulations over those of localities. In Colorado, when tight oil extraction spread from farmland to suburbs, near schools and homes, a public debate on regulatory oversight was ignited, and its future is uncertain.[38]

Road transportation policies

In the transportation sector, in an effort to achieve energy independence and energy security, the former George W. Bush administration established the RFS. The RFS requires that transportation fuels in the US contain ever increasing levels of renewable fuels over time. The RFS programme stems from the Energy Policy Act of 2005 (EPAct), and the Energy Independence and Security Act of 2007 (EISA), both of which aimed to increase US energy security and independence from oil imports. Consequently, the application of EISA is intended to reduce GHG emissions by 9% by 2030. As an element toward achieving this goal, the EISA contains provisions to increase renewable fuel blending by way of the RFS programme, which mandates that the US must produce of a minimum of 36 billion gallons of renewable fuels annually by 2022.

The EPA sets the annual RFS, and the responsibility to fulfil the RFS requirements lies on US refiners, who must either abide by blending the mandated amounts of biofuels into gasoline and diesel sold in the US market, or rely on purchasing credits called Renewable Identification Numbers (RINs) to offset missing the targets. As such, the main stakeholders in this issue are US refiners and biofuel producers, as the survival of their respective industries is affected by the RFS in divergent ways.

Currently, an ongoing debate surrounding the application and future of the RFS is underway. At the start of the most recent US presidential campaign, President (then candidate) Trump advocated maintaining the standard, which earned particular support from ethanol producing states such as Iowa. However, oil refiners argued that the standards were too burdensome to meet, and the RINs too expensive, thereby resulting in financial losses.

Following much uncertainty regarding the RFS in the wake of the new US administration, on 30 November 2017, the EPA issued the final RFS mandate for 2018 at 19.29 billion gallons. The final level is a slight increase from the 2018 level planned by the previous Obama presidential administration; 19.24 billion gallons.

In fact, in January 2018, almost 30 refiners filed for waivers from the RFS program, claiming risks of potential bankruptcy. The EPA has the power to grant exceptions to refineries with less than 75,000 b/d of refining capacity if the companies establish that meeting the RFS (or purchasing RINs) would result in financial hardship. From 2012–2016, the EPA granted only 29 exemptions to the RFS – indicating that the January 2018 level of waiver applications is unprecedented. Additionally, in January 2018, the owner of the largest US East Coast Refinery, Philadelphia Energy Solutions, announced that it was filing for bankruptcy as a result of the RFS. This bankruptcy announcement has ignited the debate on the application of the RFS and its future implications. Therefore, the future of the RFS, and its application, remains an element of uncertainty.

Another element intended to achieve energy security and independence, while also meeting climate policy objectives, is the CAFE. This was enacted by the US Congress in 1975 (later amended by EISA in 2007) with the purpose of reducing energy consumption and GHG emissions by increasing the fuel economy of cars and light trucks.

On 2 April 2018, following a series of similar announcements in 2017, the US EPA officially announced its rejection of the Obama-era 'second phase' CAFE standards for 2022–2025 Model Year (MY) cars, which would require a fleet-wide average of 54.5 mpg. The EPA reviewed these standards and concluded they are "too high" and would freeze them at the 2020 level (41.7 mpg) through the year 2026. As these new standards are less stringent than previously determined by the Obama administration, they may potentially lend support for long-term oil demand growth in the US road transportation sector.

However, there are uncertainties affecting the potential fuel economy standards and their application in the US. The rule-making process to formally establish these new CAFE standards is anticipated to face legal objections from California. The state has traditionally been able to obtain a waiver from the EPA to set higher CAFE standards than the federal level, and other states are able to choose to follow California's lead. Consequently, in March 2017, California's Air Resource Board announced that it would follow the Obama-era (54.5 mpg) standards, and

13 other states comprising about 30% of new US vehicle sales, stated that they would follow suit. The EPA pledged it would challenge California's waiver to set its own standards, and complex legal obstacles are expected to ensue.

Electric vehicles

The US tax reform at the end of December 2017 and subsequent 2019 federal budget proposal floated by the White House in February 2018 did not manage to end speculation surrounding the potential elimination of federal electric vehicle tax credits and alternative fuel incentives programs. These incentives programs were slated to end on 31 December 2016, but, were eventually maintained retroactively covering the period up to 31 December 2017. However, their fate in 2018 is undetermined. While the tax credit does not yet exist for 2018, there is a chance that the credits could be extended retroactively for 2018, in a similar fashion to what transpired in 2017. The most notable of these incentives are the Plug-In Electric Drive Vehicle Credit, Fuel Cell Motor Vehicle Tax Credit, Alternative Fuel Excise Tax Credit, Alternative Fuel Vehicle Refuelling Property Credit, and the Biodiesel Income Tax Credit.

The uncertainty surrounding whether such incentives programs are eliminated or retroactively reinstated through budget negotiations, arguably lends to consumer hesitance regarding investing in such technologies. It has resulted in speculation regarding the potential cancelation of the incentives, and highlights the range of potential risks facing adopters of these new technologies.

While many states are compelled to achieve climate and energy policy objectives by way of the transition toward electric vehicles, this movement has created a dichotomy where state budgets are diminished through spending on incentives, while losing tax revenue usually generated by way of conventional fuels. As such, according to the US Department of Energy's (DOE) Alternative Fuels Data Centre (AFDC), states are facing declining revenues from gasoline and diesel taxes, combined with vehicle fuel efficiency improvements, the increased adoption of electric vehicles, and a reduction in miles travelled. Therefore, most state-wide electric vehicle incentives last only as long as the state budgets are not depleted.

This dichotomy has led states to consider other forms of tax revenue generation, in addition to the planned phasing out of incentives (either by a certain deadline or when the budget for incentives is depleted). Even California, traditionally the most ardent supporter of electric vehicle technology and with aggressive positions on low-emissions mobility, announced plans to begin charging electric vehicles a $100 annual registration fee beginning in 2020. The purpose of the fee is to make up for lost tax revenues previously generated by gasoline and diesel.

Some states, like Colorado, are already charging electric vehicle owners annual fees to cover lost tax revenues. Colorado charges an annual fee of $50 for using public electric charging equipment. Similarly, Nebraska charges $75 each year for any vehicle powered by a source that is not already subject to the state motor fuel tax. In North Carolina, the annual fee is $130 for electric vehicle license renewal, while Georgia charges $200–$300 for the same purpose.

Other states are exploring options for alternative road transportation tax generation. For example, in Oregon, the incentive programs have already expired, and state legislators have turned to replenishing their budgets by charging all vehicles a VMT fee. This is an option considered by some states including Indiana and Vermont, and charges drivers a fee based on the miles driven as opposed to the fuel that is consumed.

Power generation

Among the Obama-era policies that have been dismantled by the Trump administration is the Clean Power Plan (CPP). The CPP is a 2015 rule that was viewed as a critical element of the US's commitment to the Paris Agreement, and overall climate change objectives. The CPP aimed to decrease GHG emissions from existing fossil fuel power plants to 32% below 2005 levels by 2030. It also granted states the flexibility to meet this goal by limiting emissions from existing power plants either by way of switching from coal to natural gas or installing new renewable power generators.

Since its inception, the CPP has ignited controversy and resulted in a series of lawsuits from around 30 states, which led the Supreme Court to temporarily block the law from taking effect in 2016. Upon taking office, and through the Executive Order on Energy Independence (28 March 2017), President Trump ordered the EPA to review the CPP. The Trump administration credited the review of the plans as consistent with the 'America First' strategy, and aligned with job preservation and stimulation particularly among the coal mining community.[39]

Consequently, days after the issuance of the Executive Order, on 30 March 2017, the EPA sent a letter to all US state governors advising them that they have "no obligation to spend resources to comply with" the CPP. After that, on 25 October 2017, the EPA published a report[40] containing a much anticipated proposal to repeal the CPP. Before finalizing the repeal of the rule, the EPA must undertake a formal public comment period in accordance with the Administrative Procedure Act (APA 1946).

As such, the deadline for the public comment period was 26 April 2018, and after that, the EPA can review the public comments and may introduce any changes to the rule before finalizing and publishing it in the Federal Register. A proposal for a replacement for the CPP is yet to be made public.

Similarly, and in parallel to the CPP, the Carbon Pollution Standards for New, Modified and Reconstructed Power Plants was established in 2015. These standards enabled the EPA to regulate the emissions of all new power plants, or those slated for modification or reconstruction. However, soon after announcing the review of the CPP, the EPA launched a review of the emissions standards in April 2017. Following the review, the EPA may "suspend, revise or rescind" the rule.

In a further effort to support the US coal industry, and in fulfilment of President Trump's campaign pledges, in February 2018, the US Interior Secretary announced $300 million in grants for abandoned coal mines. The grants are to be distributed among 25 states and Native American tribes. The grant amount is higher than the previously allocated $180 million for the same purpose.

However, regardless of these federal initiatives, some power companies are already transitioning away from coal power generation for economic gains, as well due to stakeholder influence. To illustrate this, some of the largest power suppliers ranked in 2016 by the US Energy Information Administration (EIA) as the top five coal producing states[41] are beginning to shut down coal plants, and replace them with natural gas or renewables, citing economics and pressure from corporate consumers and investors. As such, regardless of the CPP's repeal, a 2017 analysis projects that the US may achieve an electricity emissions reductions of between 27–35% below 2005 levels by 2030, due to market dynamics.

The abundance of natural gas supplies in the US has enhanced its competitiveness as a power source. The transition away from coal has strengthened since 2015. According to the EIA, natural gas power generation overtook coal on a monthly basis in April 2015, and on an annual basis in 2016. In fact, according to the EIA, every state houses at least one natural gas plant, with the exception of Vermont. In fact, the largest clean coal power plant in the US, the 582 MW Kemper County Power Plant, announced in June 2017 that it would be retrofitted to a natural gas plant due to escalating costs.

According to analysis by the Brookings Institution, only 1.5% of new power generation capacity planned through 2024 is sourced from coal, with natural gas and renewables (especially wind) replacing the retired plants.

While economics have led the transition away from coal generated power, the climate agendas of states, corporations, and investors have also played vital role. For example, the US Climate Alliance, which is made up of 16 states, announced intentions to remain committed to the US Paris Agreement NDCs of reducing GHG emissions by at least 26–28% below 2005 levels by 2025.

In the US National Security Strategy, released by President Trump in December 2017, the administration aims to support all forms of energy in the US, including fossil fuels, nuclear, and renewable energy. Consequently, the US DOE activated its legislated authority in September 2017 by issuing a Notice of Proposed Rulemaking (NOPR) directing the power grid regulator, the Federal Energy Regulatory Commission (FERC), to ensure that the nation's "diverse mix of resources must include traditional base-load generation with onsite fuel storage that can withstand major fuel supply disruptions caused by natural and man-made disasters." The NOPR aimed to specifically support coal and nuclear power generation, including cost recovery for power plants that maintain 90 days of fuel onsite. However, the FERC rejected the NOPR in January 2018, stating that the directive may not attain "reasonable" results.

While the rejection of the NOPR was a setback for nuclear (and coal) power generation, the Bipartisan Budget Act of 2018 extended the $0.018 per kilowatt hour tax credit for power plants that enter into service after 2020. Additionally, the new law enables the US Secretary of Energy to allocate credits for up to 6 GW of new nuclear capacity, which enters service after 1 January 2021.

The tax credit is considered by the nuclear power industry to be an important element for the completion of plants already under construction, but it mainly benefits one project in particular; the Georgia Vogtle nuclear power plant. Vogtle's future was in limbo in 2017 following the bankruptcy of the reactor designer Westinghouse, and was not expected to be in service until 2022 at the earliest. As the tax credit's original language applied only to nuclear plants in operation by 2020, Vogtle would have been disqualified from reaping the benefits of the tax incentive.

Nonetheless, similar to coal power production, despite federal support for nuclear power generation, economics play the most decisive role in the future of the sector. Given the competitiveness of natural gas, combined with the relative affordability of renewable power sources stemming from federal incentives, nuclear power generation faces a challenging economic environment.

8.2 European Union

The EU's climate and energy policy agenda is founded on three main principles:

- Energy Security;
- Energy Affordability; and
- Energy Sustainability

Regarding the first objective, like other energy consumers around the world, the EU prioritizes the security of energy supplies and reliability of energy sources. As for the second objective, the diversity of energy supplies and sources is considered an important element to facilitate competitiveness and in achieving affordable energy. Finally, the third objective introduces an environmental component, which seeks to promote sustainable energy consumption by way of reducing GHG emissions and pollution, and diversifying away from fossil fuels.

In order to facilitate meeting these three main objectives, the EU has established targets for 2020, 2030, and 2050 (compared to 1990 levels). The major thrust of these goals is highlighted below.

By 2020, within the Climate & Energy Package, the EU aims to:

- Decrease GHGs by a minimum level of 20%;
- Increase the share of renewable energy in the energy mix to a minimum of 20% of consumption; and
- Increase energy efficiency by a minimum of 20% by 2020.

Subsequently, by 2030, the EU plans to:

- Reduce GHG emissions by at least 40%;
- A binding target of a minimum of 27% of renewable energy in the EU energy mix;
- An increase in energy efficiency by at least 27%, to be reviewed by 2020, with the potential to increase the target to 30% by 2030; and
- Establish an internal energy market with an electricity interconnection goal of 15% between EU countries.

Finally, the 2020 and 2030 goals are intended to culminate in a 2050 target, through which the EU aims to achieve a drop in GHG emissions of between 80 and 95%, compared to 1990 levels.

Following the US announcement of its intention to withdraw from the Paris Agreement, the EU has banded together with China to reconfirm both parties' commitments to the Agreement. The EU's firm commitment to the accord is illustrated by the fact that the EU was the first major economy to submit its INDC to the Agreement in March 2015. Within the INDC, which became the bloc's NDC, the EU member states collectively pledge to achieve a minimum reduction of 40% in GHG emissions compared to 1990 levels by 2030. According to the European Commission, the NDC commitments are realistically achievable as total EU emissions are already estimated to be 26% below 1990 levels, according to 2015 data.

Road transportation policies

According to the EU, the transportation sector in general represents 25% of emissions in the bloc, with road transportation making up the largest bulk (around 70%) within the sector. Therefore, the road transportation sector is specifically targeted by policymakers as they move forward with meeting climate policy objectives.

Regulatory positions on the road transportation sector are undergoing a period of transformation in the EU. Traditionally, diesel has been a favoured road transportation fuel, in comparison to gasoline. Now, the political preference for diesel is under scrutiny, particularly in light of environmental objectives and the emergence of lower-emission alternatives. In fact, the European Strategy for Low-Emission Mobility aims to reduce GHG emissions from the transportation sector by a minimum of 60% compared to 1990 levels, and "be firmly on the path towards zero" emissions.

The previously political preference of diesel fuel over gasoline in the EU can be observed in the average national tax applied to unleaded gasoline being over €100/1,000 litres higher than that applied to diesel. This is a distinct difference between US and EU fuel taxation policy; while the US taxes diesel more heavily than gasoline, the opposite holds true in the EU. History plays a large part in this phenomenon, as the 1974 oil crisis affected Europe more than the US, largely due to significantly lower oil production in Europe compared to the US, it resulted in a concerted policy focus on energy efficiency. Diesel engines, being more fuel-efficient on a volume basis than gasoline engines, therefore, gained a political preference, and were viewed as a key element of energy security strategy.

However, a public and regulatory backlash against diesel vehicles has emerged as a consequence of the 'dieselgate' controversy in September 2015, which involved inaccurate emissions test readings of diesel-powered vehicles manufactured by Volkswagen. As a consequence of this, studies on vehicle emissions have established that while diesel vehicles emit less CO_2 than their gasoline counterparts, NO_x emissions are drastically higher from diesel vehicles; yet, this was not previously taken into account by the EU policy community until recently.

The recognition of the NO_x emissions levels has led to a public backlash against diesel-powered vehicles and has resulted in pressure on EU legislators to take strong positions on the monitoring and testing of vehicles. This stance is evident in the European Parliament passing a proposal in April 2017, which requires EU member states to finance vehicle exhaust testing centres, and permits EU officials the right to conduct spontaneous checks and penalize offenders with levies.

On 31 August 2017, the European Commission announced that new vehicle models would be subject to more stringent on-road emissions tests starting from 1 September 2017. Moreover, while diesel may have previously enjoyed political preference by regulators compared to gasoline, in the EU, both fuels are at a policy disadvantage in the age of alternative fuel vehicles, as will be explored throughout this Chapter. Either by way of taxes against fossil-fuel powered vehicles, incentives for the purchase of zero emission alternatives, stringent environmental standards, or outright bans on diesel or ICE fuel vehicles, in general, regulation of the transportation sector is considered a vital means of achieving the EU's climate goals by 2030.

EU legislation establishes binding emission targets for new car and van fleets. The European Commission sets out emissions reduction targets of 20% by 2030, from 2008 levels, and 60% by 2050, from 1990 levels.[42] Additionally, the EU has set a target of a 40% reduction in emissions from new vehicles in 2021, compared to 2005 levels, and a 19% reduction for new vans in 2020, compared to 2012 levels.

Through mandatory labelling requirements, EU legislators are raising consumer awareness and attempting to introduce the elements of fuel efficiency and CO_2 emissions into the consumer purchasing process. EU member states are required to ensure that all new vehicle sales provide information regarding each model's fuel efficiency and CO_2 emissions levels.

Electric vehicles

In order to meet the EU-wide road transportation objectives and emissions reduction targets, individual EU member states are at liberty to set policies to achieve their national targets.

In October 2016, German policymakers discussed a potential resolution to ban the sale of new vehicles with ICEs by 2030. However, while this proposal illustrates some German policymakers' support for electric vehicles, it is considered to have 'no legislative effect' as the German resolution is from a lower house of government with limited legislative powers.

At the city level, Paris plans to ban diesel vehicles initially, and all ICE vehicles eventually, from the city by 2025 and 2030, respectively. Since July 2016, Paris bans both gasoline and diesel powered vehicles registered before 1997 from accessing the capital between the hours of 8 am and 8 pm. While London has not yet introduced an outright ban, the city of London is introducing penalties of £12.50 on polluting vehicles entering areas deemed 'Ultra-Low Emission Zones' in central London beginning from April 2019, with the intention to extend the ban on all vehicles by 2021. Rome, Madrid, and Athens are looking to target diesel-powered vehicles, in particular, with planned bans from the city centres between 2024 and 2025.

Most recently, in February 2018, the federal court in Germany permitted the cities of Stuttgart and Dusseldorf to ban older ICE vehicles, even if a similar federal policy does not exist. The ruling allows for such bans to take place if they are deemed by the cities to be crucial to reducing air pollution.

While all western European countries, and almost all EU member states,[43] offer incentives to promote the uptake of electric vehicles in some countries these incentives are being phased out.[44] This experience is similar to that taking place in the US, where states are phasing out tax incentives and introducing fees to address the loss of tax revenue previously generated from conventional transportation fuels.

Primarily, the main electric vehicle incentives are made up of tax discounts and exemptions, as is the case in Austria and Germany, and bonuses and premiums, such as in France and the UK. In the case of France, a 'bonus-malus' tax system is administered, which effectively serves as a carrot-and-stick approach; either an incentive (bonus) or disincentive (malus) is applied to vehicles based on their respective CO_2 emissions.

European countries that are exploring the phasing out of tax incentives for alternative vehicles include Denmark, the Netherlands, Norway[45] and Estonia. Denmark is transitioning away from tax incentives for alternative fuel vehicles by way of a five-year phase-out period, which began in 2016. The phasing out of incentives began gradually, with 20% of registration taxes applying in the first year, graduating to 40%, 65%, 90% and, eventually 100% on an annual basis between 2017 and 2020, respectively. The Netherlands also anticipates a removal of tax incentives for electric vehicles by 2020, which means that these would be subject to registration, motor vehicle and CO_2 taxes after 2020.

During negotiations on the country's 2018 budget, Norway[46] explored the potential to introduce a $10,500 electric vehicle tax, dubbed by the media as the 'Tesla Tax', on electric vehicles weighing over two tonnes. The purpose of the tax proposal, which failed to materialize in the final fiscal budget, was to compensate for the damage that heavy electric vehicles cause to highway infrastructure. The loss of tax revenues due to electric vehicle incentives and exemptions in Norway is estimated at $3.84 billion, which was proposed to be recovered by the tax. While the electric vehicle tax proposal was excluded from the 2018 budget, it reveals the budgetary pressures facing countries offering hefty financial incentives to alternative vehicles.

Subsidies in Estonia already expired in August 2014 and offer a glimpse into the potential impact of the lifting of electric vehicle subsidies on sales. Until then, the government subsidized up to half of an electric vehicle's price, up to a maximum of €17,000. Despite being the first country to set up a nationwide network of electric recharging stations, the expiry of the financial incentives program resulted in a dramatic fall in sales. While around 600 electric vehicles were sold in 2014, only 35 were sold in 2015 and 2016. The Estonian experience with phasing out financial incentives for electric vehicle uptake illustrates the dependency on government financial incentives, which may be the experience of other countries in the future.

Natural gas

The issue of power generation is intrinsically linked to that of energy security in the EU, particularly in Central and Eastern European countries. Natural gas features as the top national energy security element as it is mostly sourced from Russia (over 40%),[47] with Ukraine serving as the main supply route to the EU. The lack of supply diversification has left the region susceptible to supply disruptions and shortages.

Consequently, the diversification from gas pipelines by way of LNG has featured in EU policy, namely the European Commission's Strategy for LNG and Gas Storage of 2016. The strategy intends to increase LNG's competitiveness in the EU market in order to enhance the security of gas supplies and competitiveness. Part of the EU's strategy is to encourage floating storage regasification units (FSRUs), such as the Klaipeda FSRU terminal in Lithuania, which has supported the country in diversifying its supply and increasing its competitiveness. In order to accomplish its strategy, the European Commission defines three focus areas:

- Building the necessary infrastructure to ensure access of EU member states to international LNG markets (either directly or through neighbouring countries);
- Completing the internal gas market; and
- Cooperating with global partners to increase the international liquidity and transparency of LNG markets.

It is arguable, combined with the abundance of global LNG supplies, that the strategy is taking shape. In the majority of EU countries, reliance on Russian gas has been balanced by way of adequate access to supply substitutes from Norway (representing over 30% of EU gas pipeline imports), and LNG imports from Qatar (44%), Algeria (16%), Nigeria (16%), Norway (9%), and the US (6%).

In recent years, the EU's natural gas demand has increased due to relatively competitive pricing, an economic recovery, and its expanded use in power generation.[48] The emergence of the US as an LNG exporter has resulted in several EU countries' importing US LNG, with eight EU member states importing at the end of 2017.

While northern and western European countries, such as Germany and Denmark, have pushed for EU-wide decarbonization strategies targeting the power generation sector, countries such as Poland, Slovakia, Hungary, the Czech Republic, Romania and Bulgaria have opposed such positions on the grounds of national sovereignty over their respective national energy mix.

Coal

There are over 300 coal power plants in the EU, mainly located in Poland, Germany, Bulgaria, the Czech Republic and Romania. In fact, around half of the EU's coal capacity lies in Poland and Germany. Consequently, these countries are the most affected by EU policies regarding the decarbonization of the power generation sector. Given these countries' reliance on coal to meet their power generation needs, the sector is a matter of energy and national security.

The coal industry is under pressure in the EU due to climate policy objectives. For example, in April 2017, EURELECTRIC, a pan-European power sector association of over 3,500 corporations stated that it plans to stop investing in new coal power plants beyond 2020. Additionally, during the same month, the EU set emissions requirements that stated that coal-fired power generators must either comply by retrofitting existing plants or close operations by 17 August 2021.

These requirements are based on the 2011 Industrial Emissions Directive and strengthen the definitions within the 'Best Available Techniques Reference Document' (BREF), which sets out ranges for emissions including sulphur dioxides, nitrogen oxides, mercury, and particulate matter. According to the Institute for Energy Economics & Financial Analysis (IEEF), the revised

BREF will affect 108 coal plants, mainly in central and eastern Europe, which are 40% above the revised BREF and thus, would require substantial investment to conform to the rules.

Meanwhile, a number of EU countries including the UK, France, Finland, Netherlands, Portugal, and Italy have announced plans to phase out coal power generation within 10–15 years. France plans to phase out coal power plants by 2022, while the UK and Italy target 2025, and the Netherlands, Portugal and Finland aim for 2030. Germany, which houses newer coal plants than those in central and eastern European countries, is currently debating a potential phase-out from coal, but it is a highly sensitive political decision affecting jobs and energy security. The decision will only likely be made in 2019.

The cost competitiveness of natural gas, incentives for renewables, combined with government imposed taxes on coal emissions, has resulted in a rapid phase-out of coal plants in the UK. In fact, three coal plants closed in 2016, and one more is planned to close in 2018. Meanwhile, Spain's market and competition regulator Comisión Nacional de Mercados y la Competencia (CNMC) recently issued a ruling that abandoned a long history of Spanish policy support for domestic coal power generation. The CNMC, in January 2018, blocked a proposed government law that would have permitted the prevention of the closing down of older coal plants.

Nuclear

Another item on the energy security agenda in the EU is nuclear power. Following the second oil crisis in 1979, some EU member states invested significantly in nuclear energy. France, in particular, depends on nuclear for 75% of its power. However, the Fukushima disaster in 2011 "caused deep public anxiety throughout the world and damaged confidence in nuclear power".[49] This was true in the EU. Combined with abundant natural gas supplies and a policy push for renewables, Germany, France, Belgium and Sweden have all pledged to phase out their existing nuclear power plants.

According to the IAEA, in 2017 there were 58 nuclear reactors operating in France, with a combined net capacity of 63.1 GWe. A 2015 energy policy planned to decrease the country's share of nuclear power generation to 50% by 2025, but in November 2017, the French government postponed this target to between 2030 and 2035. It cited that the target was unrealistic, would increase the country's GHG emissions, endanger the security of energy supply, and risk jobs.

In Germany, seven nuclear power reactors are in operation, with a combined net capacity of 9.4 GWe. The country is planning to phase out nuclear generation by 2022, as part of the 'Energiewende' policy. The policy aims to transition into a low-carbon, nuclear-free economy. However, some climate policy observers anticipate that coal consumption would increase as a result of Germany's plans to phase-out nuclear, in the absence of policies to advance CCS and/or natural gas substitution.

Other EU member states, particularly those in central and eastern Europe, have a different position regarding nuclear power. Due to the lack of supply diversity, countries in this area depend highly on nuclear power reactors. For example, Slovakia, Ukraine and Hungary rely on nuclear power to meet over half of their electricity needs, while nuclear power supplies between 30–35% of the power requirements in Slovenia, Bulgaria and the Czech Republic.

Renewables

Renewables are championed by EU policymakers to achieve climate and energy objectives. These goals are highlighted in the Renewable Energy Road Map of 2007, which aims to achieve the "twin objectives of increasing security of energy supply and reducing greenhouse gas emissions". The Road Map sets a target of obtaining 20% of total EU energy consumption from renewable energy sources by 2020, and promoting the role of renewables in electricity, transportation and the heating/cooling sectors. EU member states have set their own binding renewable energy targets for 2020. By 2030, the Renewable Energy Directive sets a target for renewables to make up 35% of the total energy mix.

So far, the EU seems on the way to achieving its renewable energy target for 2020.[50] In fact, 30% of electricity in the EU was generated by renewable sources in 2017, up from 12% in 2000. Wind makes up the largest portion of all of the renewables in the EU's power mix at 11.2%, followed by hydropower (9.1%), biomass (6.0%), and solar (3.7%). While coal made up more than double the share of renewables in EU electricity generation five years ago, in 2017 it ceded its position to renewables.

8.3 China

China's policy developments reflect the endeavour to achieve the domestic goals of realizing a future with 'blue skies'. There is also an economic element in this policy agenda, as the country positions itself to take a competitive position in the technological and manufacturing sphere related to global emissions reductions.

The Chinese government has set out a series of medium- to long-term goals to achieve its climate goals. Within the 13th FYP for 2016–2020, the government set a series of targets including the following climate related goals:

- Limit carbon emissions per unit of GDP to 15% below 2015 levels;
- Reduce SO_2 and NO_x emissions by 15%;
- Reduce CO_2 emissions per unit of GDP (energy intensity) by 40–45% below 2005 levels; and
- Increase the share of non-fossil fuels in primary energy consumption to around 15%, from 9.4% in 2010.

Road transportation policies

In support of the Chinese government's 'blue skies' objectives, at the end of 2016, the Ministry of Environmental Protection (MEP) established the China 6 vehicle emissions standards for light-duty vehicles (LDVs) (up to 3,500 kg in weight). The China 6 vehicle emissions standards are planned to become effective as of 1 July 2020. In a departure from previous methodology for the establishment of vehicle emissions standards in China, which used to follow European standards, the China 6 standards merge best practices from the US and Europe. The China 6 vehicle emissions standards consist of two emission limits, China 6a and 6b, to address air pollutants such as carbon monoxide, nitrogen oxides, particulate matter, and nitrous oxide. There is also a requirement for the vehicle test cycle to shift from the New European Driving Cycle to the World Harmonized Light Vehicle Test Cycle, which is considered more stringent than previous standards.

Following a pilot programme in 2013, in January 2017 Chinese authorities established nationwide China V gasoline and diesel fuel quality standards. These standards are similar to Euro V standards. By July 2020, regulators hope to establish even more stringent fuel standards under the China VI guidelines. The fuel quality program is well underway, as Beijing began rolling out the China VI standards in January 2017.

The China V standards require gasoline to meet 92 octane levels and a maximum 10 ppm sulphur content, while the diesel standard requires a 51 cetane level and 10 ppm sulphur content. China VI standards were finalized at the end of 2016 and take the China V regulations a few steps further by limiting common air pollutant emission levels; the NO_x limit is reduced from 2.0 to 0.4 g/kWh, and the particulate matter limit is also lowered from 0.02 to 0.01 g/kWh.[51]

Vehicle registration in China is heavily regulated by way of a lottery system, where consumers are subjected to auctions and/or lotteries before being awarded vehicle registrations. Such programs are intended to limit the uptake of vehicles in major cities. In some cities, the lottery program favours electric vehicles, as opposed to ICE vehicles, by allotting them higher probabilities of vehicle registration.

For example, in the cities of Guangzhou, Hangzhou, Tianjin and Guiyang, owners of unconventional vehicles are permitted to receive license plates without going through the customary lottery/auction process. In Shenzhen and Beijing, a lottery programme applies to unconventional vehicles, however, unconventional vehicles have a higher probability of receiving licensing approval.

Chinese authorities in some cities like Beijing are also progressively decreasing the total number of vehicle registration quotas, while increasing the number of license registration quotas for electric vehicles specifically. For example, the total number of vehicle registrations in Beijing's quota system dwindled by around 40% between 2012 and 2018. ICE vehicle registration quotas fell by over 16% between 2012 and 2018, while the quota allowance for electric vehicle registration increased by over 30% during the same period.

Electric vehicles

In addition to tightening fuel standards and vehicle emissions levels, the Chinese government is incentivizing a consumer shift toward electric vehicles. The incentives are both tangible and intangible, as represented by tax credits and subsidies, as well as preferential treatment for electric vehicles during the country's tightly controlled vehicle registration process. The government has also deployed electric quotas for automobile manufacturers.

The Ministry of Industry and Information Technology set a target for electric vehicles to make up 20% of new vehicle sales by 2025. In order to move toward this target, the government has set milestones through 2025. As early as 2019, Chinese regulators endeavour for electric vehicles to represent 10% of total vehicle sales. By 2020, regulators plan for five million electric vehicles to be sold compared to the 440,714 electric vehicles sold in 2017.

In order to achieve these targets, the Ministry of Industry and Information Technology established a strategy dubbed by analysts as the 'cap-and-trade' electric vehicle policy. Within this strategy, automobile manufacturers that manufacture or import over 30,000 vehicles per year are required to obtain and maintain a minimum electric vehicle score, which is based on the production of different forms of zero and low emission vehicle models. The 'cap-and-trade' policy was originally planned to come into effect in 2018, but was postponed to 2019. This was presumably in response to international and local reactions from automobile manufacturers who petitioned the government for more time to prepare for compliance.

When the program takes effect in 2019, the cap is set at 10% and increases to 12% by 2020. Those manufacturers that do not meet the caps must either purchase credits from others who have earned them, or face hefty fines. This strategy creates a market around electric vehicle credits, thereby rewarding and incentivizing the production of electric vehicles while penalizing non-compliance.

Some industry analysts believe these targets to be challenging and too ambitious to achieve by 2025. The ability for battery prices to fall fast enough by the time that government subsidies are withdrawn is one element of uncertainty. Another factor is that quality issues have emerged as a result of automobile manufacturers' accelerating the manufacturing of electric vehicles in order to reap the subsidies available before they are phased out.[52]

Additionally, the strain of financial subsidy programs on the government's budget is evident. According to the Global Electric Vehicle Outlook 2017, national exemptions for electric vehicles from customs/excise charges are estimated between $5,000 and $8,500, and local authorities are permitted to complement these incentives by a further 50%. Some cities, such as Shanghai, offer benefits in addition to subsidies toward unconventional vehicle purchases, such as an exemption from anti-congestion rules, which prohibits driving gasoline/diesel powered vehicles once a week.

The government was reportedly planning to withdraw local electric vehicle subsidies from provinces in 2018. However, the central government decided to maintain local incentives for electric vehicle uptake in the 2018 budget. By 2020, a complete phase-out of incentives is planned, beginning with a 20% reduction of subsidies every two years between 2017 and 2020.[53]

The phase-out of incentives is somewhat influenced by the government's discovery of a cheating scandal in 2016. A fraud investigation revealed that automobile manufacturers were manipulating the system to reap the benefits of unconventional vehicle incentives, and publishing misleading data regarding their sales of the same vehicles. Although the total value of the subsidies is unknown, in March 2017, China's finance minister announced that the government had recovered the equivalent of $334 million from companies that had fraudulently received incentives from the government.

Coal

According to China's 13th FYP, coal's share of total energy consumption should drop to 58% by 2020, compared to 64% in 2015. Additionally, coal-fired power capacity is planned to be capped at 1,100 GW by 2020, which would require a reduction of 109 GW of current coal-fired capacity. In alignment with these goals, a moratorium on new coal mining capacity was established for the period between 2016 and 2019.

Out of 1,000 million tons of coal mining capacity that is planned to be reduced during the 13th FYP period, 500 million tons is expected to be closed due to age and inefficiency. The remaining 500 million tons is intended to be reduced by way of mergers between mining companies. Furthermore, plans to build coal plants larger than 150 GW will either be cancelled or delayed, thereby capping coal power capacity at 1,100 GW by 2020.

In progressing toward reaching these targets, in January 2017, China's National Energy Administration (NEA) cancelled 103 coal power plant projects. Eighty-five of the projects were in the planning phase, while 15 others were already under construction. This decision removed 120 GW of planned coal power capacity. By the end of 2017, 65 GW of existing power capacity had been eliminated.

While these decisions reflect the determination of Chinese regulators to wean the country's power generation off coal, it mainly addresses an issue of overcapacity in the power sector. According to some assessments, if not for the cancellation of these projects, China's power capacity would have reached between 1,250–1,300 GW; corresponding to a 150–200 GW surplus of the country's 2020 target.

By 2020, the 13th FYP envisages emissions of major pollutants in the power sector to be reduced by 60% and annual CO_2 emissions from coal-fired power plants to be lower by 180 million tons. Regulations require newly constructed power plants to emit less than 50 milligrams (mg) of NO_x per cubic metre. These emissions standards are much more stringent than those applied in the US and EU; 95 and 150 mg/cubic metres respectively. Consequently, ultra-supercritical coal power plant technology is being increasingly utilized by most new coal plants in order to meet tighter emissions standards.

In line with these emissions standards, in March 2018, China's Premier Li Keqiang announced that the country was aiming to cut coal capacity by 150 million metric tons in 2018. Additionally, inefficient coal power plants with a capacity under 300 MW will be closed in 2018.

The phasing out of carbon-intensive industries such as coal power generation is considered to be one of the biggest challenges for Chinese climate policy. According to Yin Weimin (February 2016), the Chinese minister for human resources and social security, almost two million (out of 12 million) coal and steel employees are expected to be laid off in the near term.[54] Consequently, the government has committed about $15.27 billion to a fund to cover any unemployment stemming from such policies.

Until recently, it was widely believed that total coal demand in China had peaked in 2013, particularly as it fell by around 1% in 2014, 2% in 2015, and 1% in 2016. However, in 2017, Chinese coal demand actually increased by 3%; the first uptick in coal consumption since China announced a 'war on pollution'.

The pick-up in coal consumption in 2017 was likely due to economic growth responding to stimulus ahead of the 19th National Congress in October 2017, signalling the political importance of the coal sector. As already noted, it is anticipated that China's climate policies will mitigate further growth in coal power plant additions, but coal will evidently remain an important part of China's power mix in the future.

Natural gas

According to China's National Action Plan on Climate Change, the country aims to increase the share of natural gas to 10% of total primary energy supply by 2020. In 2016, natural gas represented only 3% of the electricity mix. This policy decision has faced some obstacles including gas shortages in northern Chinese provinces during the winter of 2017. Additionally, the switch from coal to natural gas in the power sector resulted in a temporary policy reversal in some provinces in order to prevent further gas shortages.

However, these challenges are expected to be short-term. Thys should be resolved in the long-term, as China propels forward with its 'blue skies' agenda. China's determination to replace coal with gas is evident in the country replacing South Korea as the world's second largest LNG importer, second only to Japan. In fact, some analysts, including Wood Mackenzie, expect China to overtake Japan as the world's largest LNG importing country after 2028.

Consequently, the National Development and Reform Commission[55] (NDRC) expects China's LNG receiving capacity to increase by nearly 9% annually, and reach 100 million tonnes by 2025. Furthermore, natural gas storage capacity is anticipated to increase by 17% per year from 2015–2025, reaching 40 bcm by 2025. Additionally, the NDRC expects that natural gas import pipeline capacity will increase by about 8% per year between 2015 and 2025 and reach 150 bcm by the end of that period.

The issue of a shortfall in import capacity for LNG was evident at the end 2017, when LNG imports were 106% above the country's LNG import capacity. In order to resolve the issue of under capacity, in November 2017, the NDRC approved the first phase of the Zhangzhou LNG terminal in southern Fujian province. The 3 million ton p.a. project is the first LNG regasification facility to receive NDRC approval since 2014.

Additionally, in December 2017, the Asian Infrastructure Investment Bank (AIIB) approved a $250 million loan to Beijing Gas, a gas distributing company, for infrastructure development in fulfilment of the coal-to-gas switching policy. The project is expected to reduce China's coal consumption by around 650,000 tons per year by 2021, and replace it with around 12.6 bcf per day of gas for domestic consumption. Beijing Gas plans to utilize the funds for the construction of natural gas distribution networks, pipelines, and domestic connection facilities, with the aim of connecting Chinese rural households with gas for heating and cooking.

Nuclear

China's 'Energy Development Strategy Action Plan 2014–2020' sets a target for 58 GW of nuclear power capacity to be online by 2020, compared to approximately 36 GW[56] in 2017, with an additional 30 GW under construction in 2020. According to the IAEA, China currently has 38 nuclear power reactors in operation and 19 under construction. Since 2000, China has multiplied the number of nuclear reactors by over ten times, and brought five nuclear units online in 2017 alone. Therefore, the country is considered by the IAEA as topping the list of 'expanding countries', which are increasing nuclear power production worldwide.

Among the 19 nuclear reactors currently under construction in China are advanced, third-generation models. Consequently, the technological developments being explored by China in this field are considered a pilot program for the rest of the world. This also means that the technology will require additional testing lead-time during the construction process and trial test period.

To illustrate, two European Pressurised Reactors (EPRs), which were imported by a French multinational advanced nuclear power company, have faced years of delays. The units were first expected to be online in 2015, but their launch date has been postponed to the latter half of 2018. Considering the delays faced by EPR power plants in other countries, the 2018 timeline may also be postponed. For example, EPR plants in Finland and France were supposed to begin operations in 2009 and 2012, respectively, however, both have faced delays; the latest timeline revisions expect both to come online near the end of 2018, or early 2019.

Renewables

China's National Energy Development Strategy Action Plan sets the following targets for renewable power by 2020:

- 340 GW of hydropower (already achieved in 2017);
- 200 GW of wind power (about 164 GW online in 2017);
- 15 GW from biomass; and
- 190–200 GW of solar (new target as of July 2017, as China had already surpassed the original 13th FYP target of 120 GW in 2017).

In order to achieve these targets, between 2016 and 2020, the NEA plans to invest $364 billion into renewable power generation – or about $72 billion annually. According to the Brookings Institution, China's investment in renewables has grown 100 times compared to 2005, and represented one-third of global renewable investments in 2017. These plans indicate that the country is positioning itself as a global leader in renewable power technology, in parallel with its leadership role in the Paris Agreement.

China has already exceeded some of its renewable energy targets, especially solar power, and is expected to surpass its wind power target as early as 2018 or 2019. In 2017, solar power generation capacity increased by almost 50 GW, and exceeded the original 2020 target of 120 GW. Therefore, the NEA issued a new solar power target aiming for between 190–200 GW by 2020.

China's commitment to achieving these targets is reflected in its global status in the field of solar power. According to the IRENA, China took the lead in global capacity installations by adding nearly half of all new 2017 capacity (followed by India).

While China's commitment to renewable power generation capacity is clear, it is important to note that curtailment of renewable power generation remains a challenge. According to some analysis, curtailment in some provinces may be as high as about 40%.[57] Wind power curtailment wavered from 10% to over 15% from 2010–2016.

According to a report by the Brookings Institution, the causes for curtailment varied over time and between different Chinese provinces. Between 2010 and 2012, the main culprit was the speed of capacity installation growth, which outpaced the power grid's development. The issue was addressed between 2012 and 2014, with the construction of additional power grid connections. However, after 2014, economic deceleration resulted in lower power demand. Consequently, the slowdown in power consumption has resulted in overcapacity in the power sector, and competition between power sources. Faced with overcapacity, and in the absence of power sector reforms, grid operators tend to favour coal plants when dispatching power due to their reliability, as well as coal operators' political influence.

8.4 India

India's national circumstances are unique to the other regions covered within this study, and its characteristics are reflected in its national priorities. UN Sustainable Development Goals (SDGs) relating to poverty eradication, food security and nutrition, water sanitation, universal access to healthcare and education, and sustainable urbanization for its burgeoning population are high on the priorities of policymakers. These issues are critical to India's prosperity and development. Energy security and environmental conservation are also critical agenda items for the country, and are viewed within the lenses of its national priorities.

In 2022, India will celebrate its 75th year of independence. As such, several policy targets are planned to be achieved by that year. Among these goals, the country aims to attain 'Housing for All' and 'Electricity for All' by 2022.

Since around 240 million Indians are lacking access to electricity – a remarkably high number in spite of significant achievements in recent years – this is a critical policy agenda. In order to achieve this target, the government established the $2.5 billion 'Saubhagya' program, which first plans to provide electricity to 40 million households (300 million people) by the end of 2018.[58] As these plans materialize, urbanization also continues at a rapid pace in India. According to India's Minister of State for Housing and Urban Affairs, Hardeep Singh Puri, 50% of the country's population is expected to reside in urban areas by 2030.

The government wants to stimulate domestic manufacturing and invigorate its GDP. By 2022, the country aims for manufacturing to play a greater role in contributing to India's GDP, increasing from 16% in 2017 to 25% in 2022. Between 2017 and 2027, the government aims for its GDP to grow by 7–8% on an annual basis. The country also has ambitions to transform itself into a global manufacturing hub through the 'Made in India' initiative, which targets 25 economic sectors ranging from IT services to automobile manufacturing.

Similarly to China, India maintained its commitment to the Paris Agreement following the US announcement that it intends to withdraw. As the world's third largest CO_2 emitting country, behind the US and China, India's position *vis-à-vis* the Agreement is considered a critical element.

Road transportation policies

Considering that India houses the world's second largest population, and has observed rapid urbanization over the past years, the road transportation sector is an important focus for policy-makers. Urbanization, teamed with higher living standards, has given way to a consumer preference for personal mobility. To illustrate, the number of vehicle registrations in India has increased by over 200%[59] over the past decade and significant growth is anticipated in the future. Therefore, the road transportation sector is high on the government's agenda as the country sets policies to meet its national priorities, such as energy security, economic development, and environmental mitigation.

Similarly to the EU, diesel fuel is increasingly the target of policy reform. The fuel is often blamed by policymakers for being the source of air pollution in city centres, and, therefore, bears the brunt of emissions standards, and even outright bans.

This phenomenon is also taking place in India, despite findings by the Indian Institute of Technology Kanpur in 2016, in a study commissioned by the Indian government, that indicated that the majority (almost 60%) of particulate matter pollution in New Delhi comes from dust,[60] and that diesel vehicle emissions only contribute around 10% of emissions in city centres. Nonetheless, there is a focus on diesel fuel for policymakers aiming to improve air quality. Consequently, several policies regulating diesel fuel have been enacted in India, though many have been contradictory in nature and/or poorly enforced.

In October 2014, India, among other countries, lifted fuel subsidies amid a drop in global crude oil prices.[61] Prior to that period, diesel subsidies were considered politically sensitive; therefore, many policymakers avoided reform, due to concern over the potential negative impact on low-income households (later refuted by IMF research).[62] However, the fuel is no longer supported by subsidies and is also facing tightening regulation.

In fact, diesel-powered vehicles are facing bans in several Indian cities, although the process of banning such vehicles has been inconsistent over the years. In December 2015, the Supreme Court in New Delhi issued a ban on all new registrations of 'large' diesel engine vehicles (those with 2,000 cubic centimetre engine cylinder capacity). However, in the face of staunch opposition, the ban was lifted in August 2016 and replaced with a 1% 'green cess' ('levy' or 'tax') on large vehicle types.

The Supreme Court even agreed to consider increasing the tax to a range between 10–30% for all sizes of diesel-powered vehicles – a proposal by an independent opposing counsel, which was later not imposed, but indicates the court's stance toward diesel fuel.

Meanwhile, in July 2016, a court order was issued banning all diesel vehicles older than ten years from New Delhi's streets. However, while the vehicles would lose their registration from New Delhi, the same vehicles could be resold in other cities. Therefore, the related vehicle emissions would effectively be shifted from one city to another.

In combination with the lifting of subsidies and outright bans on diesel vehicles, Indian policymakers are also increasing fuel emissions standards and accelerating their evolution. After gradually imposing Bharat IV (equivalent to Euro 4) fuel quality standards since 2010, in April 2017, the government enacted a nationwide implementation of Bharat IV fuel quality standards. Bharat IV standards limit sulphur content of fuel to 50 ppm, from 350 ppm under the previously applicable BS III, and emissions of hydrocarbon, NO_x and particulate matter are also reduced.

The government ambitiously aims to 'leap-frog' to Bharat VI (Euro 6 equivalent) standards, skipping the Bharat V (corresponding to Euro 5) transition entirely, by 2020, which is four years ahead of the previous schedule. The Bharat VI standards limit sulphur levels to 10 ppm maximum and require an almost 70% reduction in NO_x emissions. In order to meet the more advanced fuel standards, Indian Road Transport Minister, Nitin Gadkari, estimated that the Indian downstream sector would need to invest $4.5 billion by 2020.

Electric vehicles

Meanwhile, electric vehicles are taking centre stage in future Indian transportation policy targets, albeit with some discrepancies. Electric vehicles have been supported by government policies since 2010, when the Ministry of New and Renewable Energy introduced a 20% subsidy for the vehicles by way of the Alternate Fuels for Surface Transportation Programme. This incentive programme was followed by the National Electric Mobility Mission Plan (NEMMP), which aims to achieve 6–7 million total electric vehicle sales (including two- and three-wheeler) by 2020 and establish Indian automobile manufacturers as industry leaders in related technologies.

To that effect, in April 2017, India's Minister of Power, Piyush Goyal, announced that "by 2030, not a single petrol or diesel car should be sold in the country". However, about one year later, at the launch of India's "national e-mobility program" in March 2018, the target was scaled down to 30% (instead of 100%) of new electric vehicle sales by 2030.

These developments highlight the uncertainty facing India's long-term electric vehicle policy. The lack of clarity with regard to the aims and objectives of India's long-term road transportation policy has resulted in ambiguity amongst automobile manufacturers and consumers. This uncertainty is demonstrated in recent developments in India's electric vehicle incentive program and vehicle taxation.

To facilitate achieving the NEMMP goal of 6–7 million total electric vehicle sales by 2020, the first phase of the Faster Adoption and Manufacturing of Hybrid and Electric Vehicles (FAME) programme was launched in 2015. The first phase of the programme was intended to run from 2015–2017, but it has since been extended on a number of occasions to September 2018. This program offers incentives as high as around $300, $930, and $2,000 for the adoption of eligible models of electric two-, three-, and four-wheel vehicles, respectively.

The first phase of the programme is being applied in 11 cities for passenger vehicles, and nationwide for two- and three-wheelers. The second phase of the FAME program is only expected to be implemented upon determining the success of the first phase.

The repeated extension of the first phase of the FAME programme demonstrates two things; the Indian government's determination for e-mobility to succeed, and its indecision regarding the ability of subsidies to pave the way for a competitive electric vehicle industry.

To date, the FAME programme is not considered a success; total electric vehicle sales between 2016 and 2017 totalled around 25,000, representing less than 1% of the three million passenger vehicles sold during the same period.[63] Consequently, the Indian National Institution for Transforming India (also called 'Niti Aayog'), a government think tank, proposed a plan to replace FAME. Among the study's recommendations is for the government to increase incentives for electric vehicles through 2025, at levels that are high enough to achieve equal cost parity with conventional vehicles. It is important to note that the 'Niti Aayog' study is only a proposal, and would require legislative approval and sufficient budget allocations if it were to be implemented.

India's plans for electrification in its transportation sector are considered ambitious, particularly in the wake of the many challenges currently facing electric vehicle uptake. According to the Society of Manufacturers of Electric Vehicles (SMEV), at the forefront of these challenges is the lack of infrastructure, such as charging stations, and the time needed to recharge batteries (between one to eight hours depending on the type of battery).

In the absence of a sophisticated charging infrastructure network, electric vehicle drivers risk being stranded on India's roads, a phenomenon termed 'range anxiety' by the Centre for Study of Science, Technology and Policy at Bengaluru. The Centre also contends that the national power grid would need to expand in order to achieve the NEMPP target of 6–7 million electric vehicles on Indian roads by 2020. The National Institute of Urban Affairs also highlights other barriers in the way of achieving the NEMPP goal. India does not have lithium ion reserves in order to support the production of the battery technology required for the proposed electric vehicle uptake in India.

Automobile manufacturers have lamented the lack of clear policy direction regarding India's long-term electric vehicle policy. Due to the size of the Indian automobile market and the high level of capital investments necessary for electrification, the industry requires consistent and clear plans in order to meet future targets.

This uncertainty is also evident in the recent tax reform; particularly an element that reflects a policy reversal from supporting the uptake of hybrids. In India's Goods and Services Tax (GST) reform, while electric vehicles are exempted from the GST and are taxed a lower additional levy, following the tax reform; almost all vehicles are taxed less as a result of the GST – with the exception of hybrid vehicles. Unlike their counterparts, hybrid vehicles have witnessed an increased tax rate of 13% compared to the previous regime. Industry analysts, including automobile manufacturers, were surprised by the uniform application of the GST of 28% and an additional levy of 15% across the board for middle, large, luxury, hybrid vehicles. Luxury cars and SUVs, by comparison, have reduced tax rates of 10% and 5%, respectively.

The decision to increase the tax rate for hybrids is seen as an indication of the Indian government's commitment to incentivize the exclusive uptake of electric vehicles over all other types of vehicles, including hybrids. Additionally, the decision implies an acquiescence, and even encouragement from the Indian government for the uptake of SUVs and other large vehicles, as well as electric vehicles.

This seems to resonate with the notion reflected in India's NDC of the government aiming to "provide a dignified life to its population and meet their rightful aspirations"; it may be argued that the emerging middle class seeks the opportunity to aspire to luxury and large vehicle types, as has been the experience of their counterparts in other parts of the world. It is also congruent with consumers' personal preferences, which have tended to favour SUVs over other vehicle types; sales of SUVs grew seven times faster than passenger cars during the period from March 2017–March 2018.[64]

Coal

Similarly to China, coal-fired power plants are targeted as a means to achieve India's environmental policy goals. While coal power capacity is anticipated to grow by 46 GW between 2017 and 2027, inefficient coal power plants are planned to be retired and replaced with more advanced technologies.

The National Electricity Plan 2018 establishes a timeline for the phase-out of 48.3 GW of older coal plant capacity by 2027, and a simultaneous deadline for the introduction of emissions controls systems within coal plants. The plant closures are expected to take place in two phases:

- 22.7 GW of coal capacity retirements by 2022; and
- A further 25.6 GW of closures by 2027.

It should be noted, however, that the deadline for the installation of emissions control technologies was postponed from 2017 to 2022. Meanwhile, 94.3 GW of new coal power plant capacity is expected to come online by 2027, thereby bringing India's total coal power capacity to 238 GW.

Considering that the National Electricity Plan foresees India's GDP to increase by between 7–8% on an annual basis between 2017 and 2027, power demand is anticipated to nearly double from around 300 GW to 600 GW over the same period. Renewables are expected to compensate for the surge in power demand, given the planned coal power plant retirements during the same timeframe. These plans put pressure on the Indian coal industry in India in the long-term; similar to what the industry is facing in the other regions covered in this Chapter.

The coal power industry is also facing challenges in the short-term. Recent data from the Central Electricity Authority indicates that the number of coal power capacity additions has decreased in 2017 to the lowest level since 2006. Bloomberg estimates that coal-fired power capacity increased by around 810 MW in 2017, which is the slowest growth since 680 MW was added in 2006. Meanwhile, the coal plant utilization rate has simultaneously fallen between 2006 and 2017; illustrating a paradox of unutilized power capacity in a country facing energy poverty.

The reason for the deteriorating coal power capacity additions is mainly due to weak demand from India's electricity retailers, as demonstrated by falling utilization rates. These retailers are currently facing financial constraints. Analysts attribute the financial difficulties of India's main power consumers (state-owned distributers) to their incurrence of large debts combined with financial losses through electricity theft, inadequate metering, and pricing electricity below its actual costs. The latter reflects the major challenge of electricity affordability in India.

Natural gas

The National Electricity Plan foresees natural gas playing a somewhat limited role in India's power mix, but one that is supportive to renewable power generation, in order to balance power demand during peak times. According to OPEC estimates,[65] in 2017 the share of natural gas in India's power mix was around 8%. Meanwhile, the Central Electricity Authority plans for the role of gas in India's power mix to decrease by nearly half between 2017 and 2027.

Between 2017 and 2022, the plan foresees 406 MW of natural gas power capacity additions. However, from 2022–2027, no additional natural gas power units are considered. This is due to a natural gas shortage facing the country, resulting in gas power plants running at low[66] utilization rates.

The Columbia Centre on Global Energy Policy (CGEP) notes that natural gas' modest position in India's power mix is mainly due to competition from cheaper resources, particularly coal, and limited domestic natural gas production. Traditionally, India's natural gas demand was met by domestic supply, but local production has been dwindling since 2010. Gujarat province is an exception, as local policymakers promoted the construction of gas-powered electricity and fertilizer plants, in addition to LNG receiving capacity in 2004.

Nuclear

The Central Electricity Authority expects nuclear power capacity additions to more than double between 2017–2022 and 2022–2027; from 3,300 MW to 6,800 MW, respectively. According to India's Department of Atomic Energy, as of March 2018, a total of 22 nuclear power reactors are currently operational with a combined capacity of 6,780 MW. Nine additional nuclear power reactors are under construction, which would bring total installed nuclear capacity in India to 13,480 MW by 2024.

As early as 2009, the Indian government had set a target for nuclear power to reach 63 GW by 2031–2032. However, in April 2018, this target was revised down by around two-thirds, to 22,480 MW of nuclear power by 2031–2032. While the government did not provide reasons for the downward revision, it is possible that financial and manpower hurdles hindered the ability to secure adequate project financing.

Renewables

Renewable energy is intended to make up the bulk of India's power additions in the medium- to long-term. By 2022, the country plans to produce 175 GW of renewable energy and this goal is increased to 275 GW by 2027. These numbers represent a 44% and 25% share of the nation's total power capacity and generation, respectively. According to the Ministry of New and Renewable Energy, almost 40% of the 2022 goal (65 MW) had been achieved by March 2018.

Out of the 2022 target, solar power is planned to make up 100 GW, while wind will make up 60 GW, up from 9 GW and 29 GW in 2017, respectively. Hydropower and biomass are planned to make up the remainder of the renewable power target. Meanwhile, although hydropower capacity additions are planned to increase to 6,823 MW and 12 GW by 2022 and 2027, respectively, overall, its share in the power mix is expected to decrease by about 30% by 2027.

Meanwhile, the Central Electricity Authority notes that the government is on track to meet its renewables target; since 2016, new capacity additions from renewable energy sources have more than doubled that of net new thermal capacity additions. The Institute for Energy Economics and Financial Analysis (IEEFA) contends that in addition to India's low-carbon goals for the future, falling prices of renewable power sources (especially wind and solar) have contributed to their competitiveness in the country.

According to the draft National Energy Policy prepared by 'Niti Aayog', the target of 175 GW of renewable power capacity by 2022 is an achievable one, but requires overcoming the technical challenges of grid integration. Among these hurdles are the redesigning of the national grid, introducing technology, and optimizing operations; all of which must be tackled by India in order to address electricity outages.

To that effect, the draft National Energy Storage Mission, established by the Ministry of New and Renewable Energy in January 2018, sets a target for 15–20 GWh of battery storage to be connected to the national power grid by 2022. This target is intended to address the challenges posed by intermittent power generated from renewable sources. According to media reports, several storage projects have been cancelled in recent years due to unattractive prices – including almost ten tenders that were cancelled in 2017 alone. Therefore, technology and market dynamics play a prominent role in achieving this goal.

Financial challenges are also evident in the high capital expenditure required for renewable projects to come to fruition. Researchers note that while renewable power plants are generally commercially economical, they require intensive capital investment during their early phases. In order to achieve its solar power target by 2022, $100 billion investment is estimated, compared to $10 billion invested in the renewable power sector in India in 2015. Attracting private investors is considered a major factor determining the achievement of these long-term goals.

8.5 Other regional developments

Australian policymakers continue to debate the future of the country's National Energy Guarantee (NEG), which was originally anticipated to be finalized in August 2018. However, political positions toward the NEG have shifted in recent months – with a change in Prime Minister at the end of August – and its future application may materialize somewhat differently than originally planned. The NEG is a climate and energy policy that aims to achieve both intermittent power access and emission reductions. The NEG aims to decrease CO_2 emissions levels in Australia by 26% by 2030 (compared to 2005 levels). However, the policy is nuanced in that it is 'fuel neutral' and enables all power sources to compete without government support.

Therefore, market spectators question how the NEG could coexist with Australia's Renewable Energy Target (RET). The RET is a federal policy that targets a minimum of 33,000 GWh of power to be derived by renewables in 2020, compared to 17,500 GWh in 2016. Advocates of the RET argue that renewables subsidies need to be maintained in order for renewables to compete with fossil fuels. As a result, the NEG is a controversial policy, as it levels the playing field among power sources, without government support.

Proponents of the NEG are aiming to resolve power issues such as intermittence and relatively high prices. Power interruptions are a serious issue in Australia, which analysts suggest relate to the challenges in switching from coal to renewables. While natural gas is intended to serve as a transitional power source, attractive international natural gas prices have incentivized the export of the fuel rather than for domestic use. Should the NEG go through, in practice, it may favour fossil fuels, such as coal and natural gas, as those are able to provide reliable electricity access.

Meanwhile, in a similar move to the US, although for different motivations, Japanese energy policy foresees coal playing a greater role in the country's energy future. In April 2018, Japan released its National Energy Plan (NEP), which expects 26% of the country's power to be derived from coal by 2030. This indicates a policy reversal from previous targets for coal to make up to 10% of the country's long-term electricity mix.

The policy reversal reflects a shift in the national consciousness following the 2011 Fukushima Daiichi nuclear power plant disaster, which resulted in a loss of public trust in nuclear power. The industry underwent a reassessment period after the crisis, and as a result over 50 nuclear power reactors in Japan were shut down (pending safety installations), although some have now reopened. Japan's NEP demonstrates the evolutionary nature of climate and energy policies; they shift and change over time according to events and experiences.

While other countries have shifted toward natural gas and renewables as future power sources, Japan is aiming to increase the role of coal due to its relative cost competitiveness. Opponents of the policy argue that the policy shift would make it challenging for Japan to meet is Paris Agreement NDC target of reducing GHG emissions by 26% by 2030 (compared to 2013 levels).

Conversely, at the end of December 2017, South Korea released an energy policy that would shift away from coal and nuclear power toward natural gas and renewables. As the world's second largest LNG importer and fourth largest coal importer, its policy changes could have a significant impact on future energy demand. As a result of the policy enactment, some analysts expect that the country's LNG imports could more than double by 2030, while its coal purchases could peak as soon as 2019.

The policy aims for 20% of its power generation to be met by renewables by 2030, compared to 6% in 2017. In order to meet this target, South Korea plans to increase its installed renewable power capacity to nearly 60 GW by 2030, compared to 11.3 GW in 2017. As a result of the policy, coal power generation would decrease to about 36% in 2030 and nuclear to around 25%, compared to 45% and 30% in 2017, respectively.

The country is now expected to switch two planned, and four existing, coal power plants to natural gas. This represents a shift from the original plan of switching four out of nine new coal power plants to natural gas. In order to meet growing demand, South Korea still expects to introduce two new nuclear power reactors by 2022. However, the long-term vision of the country is to decrease its dependence on nuclear power post-2025.

In June 2017, Mexico's Secretariat of Energy ('SENER') released the Development Program of the National Electric System for 2017–2031. This program consists of a plan for the national power grid, and expects that that over 57 GW of additional power capacity will be added to the national electricity system, about 40% of which will be from conventional sources (around 21.5 GW) and 62% from renewables (around 35.5 GW), by 2030. Of the latter, wind energy is expected to make up the majority (approximately 21%), while solar, hydropower, and geothermal will make up 12%, 8%, and 2%, respectively.

In the lead up to the 2030 goal, Mexico's policymakers aim for renewables to make up about 40% of its electricity mix by 2024. In April 2018, Mexico's Secretary of Energy announced that 65 new renewable power plants were under construction; 40 powered by solar energy, and 25 by wind power. The number of solar power plants in the country has expanded by over 100% in the two-year period between 2015 and 2017, increasing from nine to 23. By 2021, Mexico is expected to have nearly 70 solar power plants.

In the Middle East and North Africa (MENA) region, the power generation sector is undergoing reforms in the medium- to long- term in order to meet rising power demand, while also reducing carbon emissions. By 2020, OPEC Member Country Qatar and neighbouring Oman aim for renewable sources to make up 2% and 10% of their national power mix, respectively. Meanwhile, in the long-term, OPEC Member Countries Kuwait, Saudi Arabia, and the UAE have established targets to produce 15%, 10%, and 24%, respectively, of their power from renewables by 2030. Similarly, fellow OPEC Member Country, the IR Iran, has established a target to install 5 GW of renewable power capacity by 2020, corresponding to the capacity of almost five nuclear reactors. Meanwhile, both OPEC Member Country Algeria and Egypt aim to meet 20% of their countries' power demand through renewables by 2030.

Similarly to China and India, several West African nations have tightened fuel quality standards. As of 1 July 2017, Benin, Ghana, Ivory Coast, and Togo had introduced more stringent sulphur restrictions on diesel fuel that is marketed within their boundaries; limiting the sulphur content to 50 ppm. Meanwhile, in October 2018, OPEC Member Country, Nigeria, will begin to gradually improve fuel quality standards, moving sulphur content to 300 ppm from 1,000 ppm, with a target of reducing the sulphur content to 150 ppm by October 2019.

These plans reflect a shift away from high-sulphur diesel fuels that were previously sold in the region, some with sulphur content of around 3,000 ppm. Additionally, this development illustrates the 'leap-frogging' potential of African nations in relation to fuel quality and emissions standards.

Energy and sustainable development

Key takeaways

- A core feature of the UN 2030 Agenda for Sustainable Development, which was adopted on 25 September 2015 by Heads of State and Government at a special UN summit, is its 17 goals (SDGs) and their associated 169 targets, which offer a practical pathway to address challenges and create opportunities for sustainable development.
- Energy has a prominent place in the 2030 Agenda. SDG 7 seeks to ensure access to affordable, reliable, sustainable and modern energy for all. Achieving SDG 7 could catalyze actions to reach the other SDGs, including poverty eradication.
- At a global level, access to electricity has progressed steadily since 1990, and in 2016 stood at 87.4%. However, about 0.94 billion people still live without access to electricity, with electrification rates in Africa the lowest in the world. Around 3 billion people also lack access to clean fuels and efficient technologies for cooking.
- With regard to the realization of the other two targets of SDG 7; the share of renewable energy in total final energy consumption has increased modestly over the last few years, while progress in doubling the global rate of improvement in energy efficiency is still not sufficient to meet the target.
- The achievement of SDG 7 targets on increasing the use of renewables and energy efficiency improvements will have a significant impact on the future energy mix and levels.
- Demand for fossil fuels at the global level is projected to decline relative to the Reference Case, while the share of renewables, as well as nuclear energy, will increase.
- This Chapter undertakes sensitivity analysis (Sensitivity A and Sensitivity B). Under Sensitivity B, which assumes the achievement of the SDG 7 targets on renewables and energy efficiency, coal is projected to be the most affected fuel with a demand reduction of about 65%, compared to the Reference Case, alongside an almost 15% decline in oil demand and a 13% reduction in gas demand in 2040.
- Global energy-related CO_2 emissions are estimated at 25.8 $GtCO_2$ when achieving both the SDG 7 renewables and energy efficiency targets, so that they are reduced by about 34.5% in 2040 compared with the Reference Case.
- Petroleum exporting countries could face large adverse impacts arising from energy efficiency and renewable policies. The reduction of OPEC Member Countries' GDP is large under both sensitivities compared with the impact on the global economy.
- The interlinked and cross-cutting nature of the SDGs requires a holistic vision to achieve prosperity while increasing climate resilience. Synergies should be enhanced to alleviate trade-offs for achieving the different goals.
- Sufficient financial resources, technology development and effective policies designed to encourage investments are needed to achieve SDG 7. International cooperation is crucial to enhance actions of countries that aim to accelerate the energy transition.

The 2030 Agenda for Sustainable Development (2030 Agenda), adopted at the UN Sustainable Development Summit on 25 September 2015, is in its early years of implementation. As a plan of action for people, planet and prosperity, the 2030 Agenda recognises that "eradicating poverty in all its forms and dimensions, including extreme poverty, is the greatest global challenge and an indispensable requirement for sustainable development".

In this context, the multi-dimensional nature of poverty should be considered for the implementation of the 2030 Agenda. A holistic vision of society is required that aims to achieve economic well-being, social inclusion and environmental sustainability in an integrated manner. To this end, the 2030 Agenda comprises of a set of 17 SDGs which are to be achieved by 2030 in order to stimulate action and put the world on a sustainable and resilient path.

Covering a wide range of issues, the SDGs are designed to be universal, applicable to both developed and developing countries, as well as all segments of society. They are voluntary and country-led, taking into account different national realities, capacities and levels of development, while also respecting policy space and priorities.

Moreover, the SDGs set a number of global priorities and objectives that are fundamentally interdependent and require a coherent approach and international cooperation for their implementation. The goals call UN Member States to work towards ending poverty and hunger, reducing inequalities, addressing climate change, promoting peace and justice, and enhancing partnerships. The SDGs also promote access to basic quality services such as health care, education, water and sanitation, and sustainable energy.

The concept of addressing poverty in all its forms and dimensions has, therefore, become a prominent feature of policymaking and is considered to be a pervasive issue preventing sustainable development globally. A notable feature of the SDGs is the fact that they explicitly recognize the direct link between energy access and poverty eradication. Increasing energy use empowers the most vulnerable members of society and can eliminate energy deficits concentrated in the low-income and low-energy segment of global distribution. Hence, eradication of energy poverty for billions of people, particularly in developing countries, is seen as crucial to realizing inclusive and sustainable development by promoting economic growth and improving human well-being.

The High-Level Political Forum (HLPF) acts as the global structure responsible for assessing progress, achievements and challenges within the 2030 Agenda, in order for it to remain relevant and ambitious. Using a number of SDG indicators, the HLPF is tasked to conduct reviews on progress towards the achievement of the SDGs and their targets on an annual and thematic basis. Matters related to energy were reviewed under the theme of the 2018 HLPF session on 'Transformation towards sustainable and resilient societies'.

With these in mind, this Chapter aims to increase awareness about the potential opportunities and challenges associated with advancing the implementation of the SDGs, with a focus on matters related to energy. It addresses the link between energy and sustainable development, in particular by exploring issues related to achieving SDG 7 and its interactions with the remaining SDGs. Analysis shows that accelerated action in support of enhancing sustainable energy is a critical contribution to the delivery of all SDGs. In addition, two sensitivities are considered on potential future energy mix and levels, assuming the achievement of SDG 7 targets on increased use of renewable energy and energy efficiency improvement.

9.1 SDG 7 on energy

Energy has a prominent place in the 2030 Agenda, being fundamental to human development and a cross-cutting issue in socio-economic prosperity and environmental sustainability. As already mentioned, it is included explicitly as one of the SDGs, with goal number seven (SDG 7) calling for access to affordable, reliable, sustainable, and modern energy services.

To achieve this goal, actions are needed in the following areas: i) ensure universal access to energy services (target 7.1), ii) increase the share of renewables in the energy mix (target 7.2), and iii) double the rate of energy efficiency improvement (target 7.3). Moreover, the priorities for implementing SDG 7 are to enhance international cooperation and promote investment, as well as to expand infrastructure and upgrade technology in developing countries.

Three years into the implementation of the 2030 Agenda, progress has been made towards SDG 7, but it has not been at the pace required to achieve its targets. In addition, it has become apparent that achieving the targets of SDG 7 will affect, and be affected by, progress in all other 16 SDGs.

For instance, considering the food-water-energy nexus along with SDG 2, SDG 6 and SDG 15, which focus on zero hunger, clean water and life on land, respectively, it is likely that synergies prevail when implementing these goals. Water is required in the energy sector for cooling in thermal power plants and generating hydropower while energy is needed for residential and industrial water usage and pumping water for irrigation. At the same time, water is needed for food and bioenergy production. Potential trade-offs may also arise as a result of prioritization. For example, food production may compete with bioenergy production for the same land and/or water.

In general, energy access is a key element in food systems that aim to achieve the goal of zero hunger (SDG 2). Recent data shows that hunger is on the rise again for the first time in more than a decade. There were about 38 million more hungry people in the world in 2016 than 2015, rising from 777 million to 815 million. To address poverty and end hunger, agricultural productivity should improve as the majority of poor people work in agriculture. Energy is needed for agricultural machinery, irrigation systems and pumps, processing and conserving agricultural products, and transporting and storing them. More mechanised, modern farm practices and improved refrigeration facilities could have a significant impact on food security by increasing agricultural productivity and reducing food waste.

Access to modern energy is also essential for the provision of clean water and sanitation (SDG 6). In 2015, 4.5 billion people lacked access to safely managed sanitation services, and about 2.1 billion people lacked access to safely managed drinking water supplies. Considering access to safe drinking water remains elusive for many people, primarily in developing countries, modern energy is needed for residential and industrial water usage. It also allows for water desalination, as well as for enhancement of land-use management (SDG 15), given that reliance on traditional biomass encourages deforestation and land degradation. Forest areas are still shrinking, albeit at a slower pace, leaving just 30.7% of the world's total land area as forested in 2015. At the same time, about one fifth of the land surface covered by vegetation showed persistent and declining trends in terms of productivity.

SDG 7 also interacts with the remaining SDGs. For example, ensuring the world's poor have access to affordable, reliable and modern energy services enables the goal of poverty eradication (SDG 1). The energy services made possible by modern energy sources could provide a solid foundation for escaping the poverty trap by stimulating income-generating activities. Poverty is predominantly rural, and the poor consume less energy, but spend a higher proportion of their income on it. They also typically rely on the inefficient and unsustainable use of traditional biomass. Access to energy services through affordable, reliable, sustainable and modern energy is, therefore, essential to ending poverty.

Energy efficiency technologies could also encourage innovation, create jobs and support economic growth (SDG 8). A lack of access to electricity limits opportunities for people to improve their productivity and earn higher incomes. In Sub-Saharan Africa, about 70% of businesses consider unreliable electricity services to be a major constraint to economic growth. Unreliable electricity has been found to have a significant negative impact on productivity, with firms losing on average about 5% of their annual turnover.[67]

The transition towards clean, efficient and modern energy will further contribute to tackling climate change (SDG 13), improving air quality, extending human health (SDG 3) and decreasing ocean acidification (SDG 14).

More specifically, providing energy access in developing countries will not come at the expense of achieving environmental sustainability. For example, LPG could be used to replace traditional biomass in order to ensure access to clean fuels and technologies for cooking. Empirical evidence indicates that even if access to modern fuels for cooking and heating is achieved with fossil-fuel-based products, this would result in only a small increase in CO_2 emissions, largely compensated by reduced emissions from deforestation.[68]

In addition to improving indoor air quality and reducing the risks of respiratory diseases, modern energy access also supports the functioning of health care facilities. It is estimated that indoor air pollution, resulting from the lack of efficient use of clean fuels and technologies for cooking alone, is responsible for almost 4 million deaths a year worldwide. Women and children are the primary victims and almost half of those who die are children under the age of five. Moreover, about 58% of health care facilities in Sub-Saharan Africa do not have access to electricity and nearly 60% of refrigerators used in health care facilities have unreliable electricity, compromising the safe storage of vaccines and medicines.

Ensuring energy access in countries where access to reliable energy services are still lacking could further lead to increased educational attainment and, therefore, reinforce education goals (SDG 4). At a global level, more than 290 million children go to primary school without electricity. In Sub-Saharan Africa, only 37% of primary schools have access to electricity, thereby impeding the likelihood of children receiving adequate and quality education. The ratio of students completing lower secondary school has increased in recent years, but remains low compared with a global average of 75%. Moreover, the share of children out of primary school averages 21%. To enhance the quality of educational services, increase educational attainment, and allow children to study after nightfall, energy access is imperative.

Access to energy would also expand the number and range of opportunities for women, enabling them to work and thereby generate sources of income (SDG 5). In addition to the noted challenges, gender inequality continues to hold back human development in developing countries, depriving women of opportunities and basic rights. For instance, the current reliance on traditional biomass has social costs, such as the opportunity cost of retrieving firewood. Females spend hours collecting firewood and the time spent on fuel collection reduces the likelihood of school attendance, particularly for girls.

Access to modern energy could empower women by reducing fuel collection time and create income generation opportunities at home, while also improving safety through street lighting and allowing girls to attend schools. Concurrently, people located in both rural and urban areas could engage in more productive job opportunities with energy access, therefore, reducing inequality within countries as well (SDG 10). Universal access to energy is not only key to achieving gender equality, but also to reducing inequality within and among countries.

Building resilient infrastructure (SDG 9) has important energy related elements too. Upgrading and retrofitting infrastructure to make it more reliable and sustainable, providing financial and technical support to promote technological development and encouraging innovation could benefit countries' energy systems. Powering up income generating sectors, such as agriculture, could also contribute to productivity improvements and better developed rural infrastructure. Synergies also exist with both transport and telecommunications services. The ICT (Information and Communications Technology) sector (that is, fibre optic cables) could be developed in parallel with transmission lines, whereas the transport sector (including road, rail and ports) could benefit from investment in the energy sector, with rural areas gradually gaining access as well.

Access to modern energy is a prerequisite to creating the conditions needed for sustainable cities and communities in terms of transport, housing, urban planning and air quality, among other factors (SDG 11). At the same time, the more efficient use of natural resources could affect consumption and production patterns (SDG 12), therefore, reducing waste.

To achieve SDG 7, effective institutions are needed at local, national and international levels, particularly in developing countries (SDG 16). International cooperation, as well as the provision of means of implementation regarding financial support, technology transfer and capacity-building (SDG 17) are equally important to ensure energy access for all. In light of the above, synergies need to be enhanced when implementing the SDGs so that interactions within and between the different goals are mutually supportive and make progress in all areas. On the other hand, the potential trade-offs of achieving the different goals should be removed.

Implementing an integrated and coherent approach would offer new opportunities across different sectors of the economy. Therefore, the nature and dynamics of the interactions between the SDGs need to be clearly understood before the policy formulation phase so that a design for implementing 'win-win' strategies can occur.

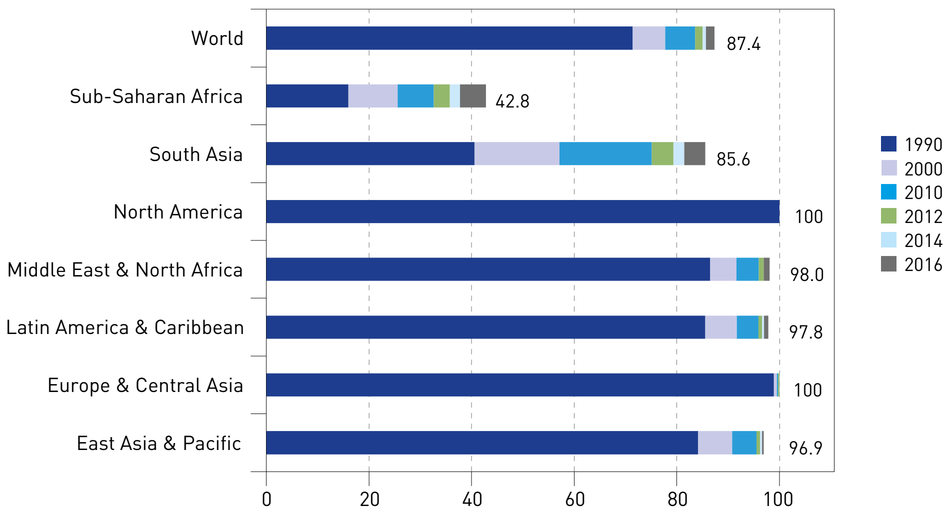
9.2 Energy access

9.2.1 Access to electricity

Billions of people around the world still do not have access to electricity, clean fuels or efficient technologies for cooking. With regard to the other two targets of SDG 7, the share of renewable energy in total final energy consumption increased modestly over the period 2010–2015, while progress in doubling the global rate of improvement in energy efficiency is still not sufficient to meet the target.[69]

Based on the latest available data, about 87.4% of the world population had access to electricity in 2016 (Figure 9.1). An increase of 3.8 percentage points is observed since 2010, amounting to approximately 118 million people annually gaining access to electricity for the first time. In the least developed countries, the proportion of the population with access to electricity has more than doubled between 2000 and 2016. However, about 0.94 billion people still function without electricity, and half of those people live in Sub-Saharan Africa. Even in 2016, this region had an access rate of only around 43%.

Figure 9.1
Access to electricity, % of population

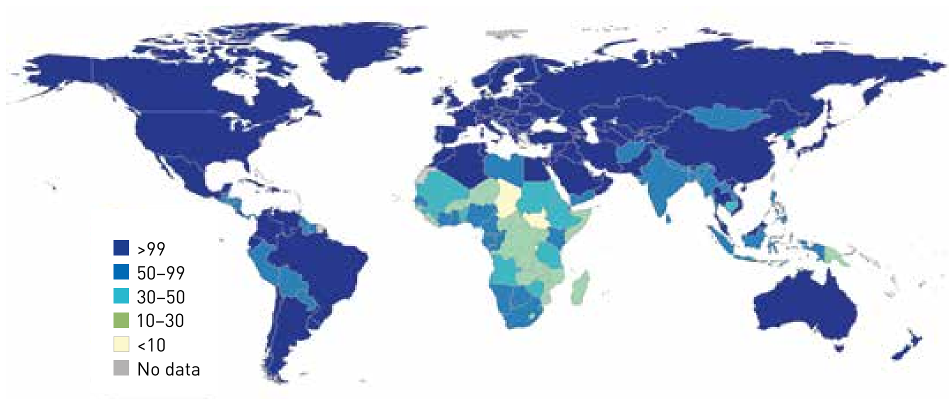


Source: World Bank, 2018, Sustainable Development Goals (SDGs).

In general, electrification has outpaced population growth in most regions, and countries in South Asia have increased their electrification by 28.5 percentage points in the course of the 2000–2016 period. The absolute access deficit in Sub-Saharan Africa peaked in 2015 at about 595 million people and began to fall by 28.5 million people in 2016. Nevertheless, about 20 African countries still have electricity access rates of 30% or less, accounting for the access deficit (Figures 9.2).

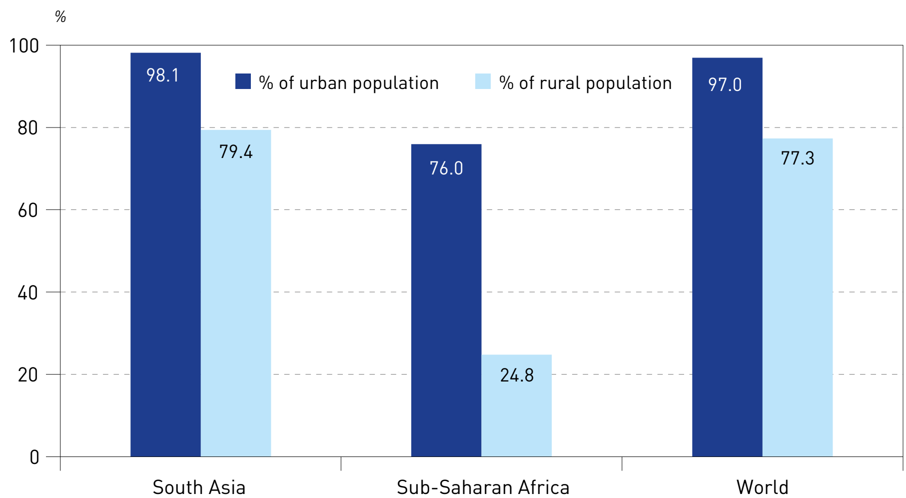
Even within these countries, significant differences are observed between urban and rural areas (Figure 9.3). Rural areas are gaining access at a much lower rate compared to urban areas and lag behind in access rates at just 77.3% compared to 97% in urban areas. Therefore, at a global level, 22.7% of people living in rural areas had no access to electricity in 2016. This rate

Figure 9.2
Share of population with access to electricity in 2016, (%)



Source: World Bank, 2018, Sustainable Development Goals (SDGs).

Figure 9.3
Access to electricity, % of population, 2016



Source: World Bank, 2018, Sustainable Development Goals (SDGs).

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increases to 75.2% in Sub-Saharan Africa, whereas rural residents made up 87% of the global deficit in electricity access.

It is estimated that if the current trends continue, there would still be about 674 million people living without electricity in 2030. To reach universal access by 2030, the rate of access to electricity needs to improve by 0.8% every year.[70] These figures underscore the need for enhanced and urgent action with the objective of closing the reported gap and ensure energy access for all in the coming years and up to 2030.

9.2.2 Access to clean fuels for cooking

At the same time, approximately 3 billion people (or 41% of the world's population), the majority of them living in Sub-Saharan Africa and Asia, are still cooking without clean fuels and efficient technologies. About 1.4 billion people gained access to clean cooking fuels and technologies over the years 2000–2016. However, this advancement was offset by population growth during this period. Figures 9.4 and 9.5 illustrate that as population and economies grow, electricity access has increased while access to clean cooking has lagged behind during this period.

In 2000, the global average for electrification was 77.7% of the world population and for clean cooking it was 49.4%. In 2016, the share of population with access to electricity reached the level of 87.4% and the respective figure for clean cooking was only 59.3%. This corresponds to an increase of only 10 percentage points between 2000 and 2016. As a result, the absolute number of people relying on solid fuels for cooking has increased. In urban areas, 82.6% of the world population has access to clean cooking, but only 31.7% of those living in rural areas.

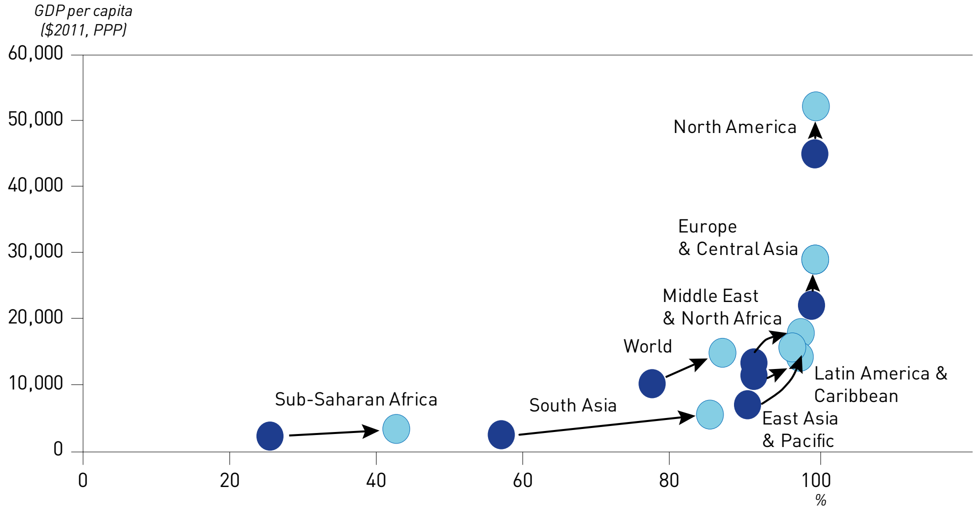
Overall, some countries – including Indonesia and South Africa – have made rapid progress in clean cooking, but for others there is room for improvement (for example, Ethiopia, Madagascar, Tanzania, and Uganda). Sub-Saharan Africa and many parts of Asia have the largest populations lacking access to clean cooking fuels and technologies. In 2016, approximately 2.8 billion people still used solid fuels with inefficient stoves, leading to high levels of indoor air pollution (Figure 9.6).

To reach universal access to clean cooking fuels and technologies by 2030, the annual rate of clean cooking access needs to accelerate to 3%. If the current trajectory continues, 2.3 billion of the global population would remain without access to clean cooking fuels and technologies in 2030.[71]

Access to affordable, reliable, sustainable and modern energy services

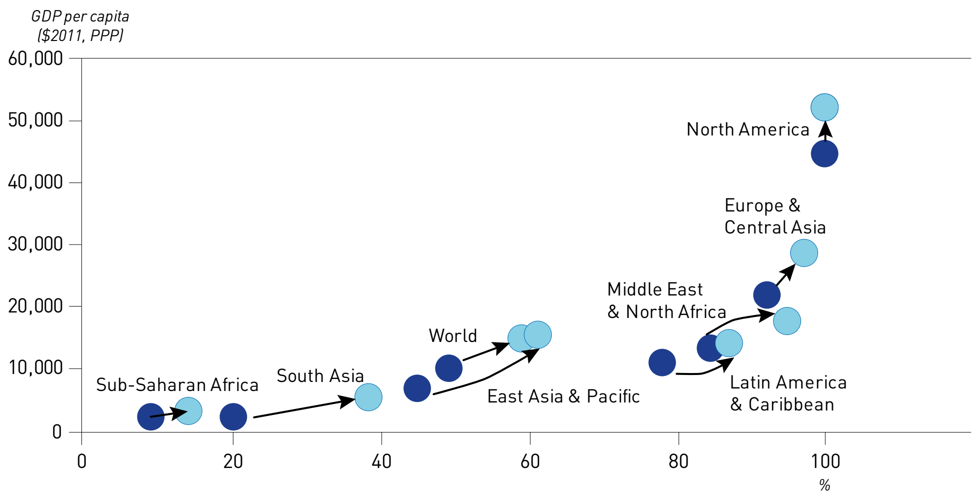
It should be highlighted that even those regions and countries that report (almost) universal electrification and access to clean cooking may also need to address energy access challenges. These relate mainly to remote, off-grid locations, on-grid access with limited or intermittent supply due to poor infrastructure or fuel supply problems, and affordability issues. The indicators noted to measure energy access may be at (or close to) 100% in terms of physical access; however, the energy services considered may not be accessible to the fuel poor, if they cannot afford their cost. In addition, ageing infrastructure, a lack of supply diversity, and interruptions or shortages in supply restrict access to energy, in particular regions and populations, can lead to energy poverty.

Figure 9.4
Access to electricity: GDP per capita vs. % of population with access to electricity, 2000 and 2016



Source: World Bank, 2017, Sustainable Development Goals (SDGs) and World Development Indicators.

Figure 9.5
Access to clean cooking: GDP per capita vs. % of population with access to clean cooking, 2000 and 2016



Source: World Bank, 2017, Sustainable Development Goals (SDGs) and World Development Indicators.

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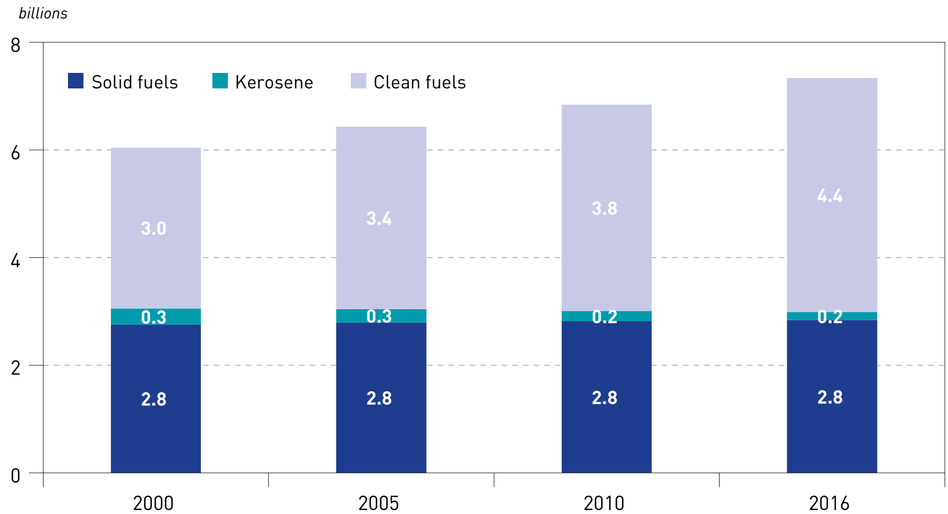
Figure 9.6
Number of people with primary reliance on clean fuels, kerosene and solid fuels



Note: Solid fuels include wood, coal, charcoal, dung and crop waste.
Source: UN Department of Economic and Social Affairs, 2018, The Sustainable Development Goals Report 2018.

Consequently, a lack of access to modern energy services could hinder the achievement of other SDGs. As elaborated earlier, the SDGs interact with one another. A modern energy system could support all sectors of the economy – from businesses, medicine and education to agriculture, infrastructure, communications and high-technology.

Access to modern energy could, therefore, reduce the share of population relying on wood, charcoal, dung and coal for cooking (and heating) resulting in fewer premature deaths due to indoor air pollution. Similarly, access to modern energy could empower women by creating income generation opportunities at home; girls could attend schools, children could do homework at night, hospitals could store vaccines and medication, and people could engage in more productive job opportunities.

In light of the mentioned, it becomes evident that sufficient financial resources, technology development and effective policies designed to encourage investments in modern energy sources are needed to ensure energy access at a global level. International cooperation on these aspects could enhance actions of countries that aim to accelerate the transition to an affordable, reliable, sustainable and modern energy system.

To meet the challenge of energy poverty, developing countries should also create markets for modern energy, considering the many aspects of the energy system, including source and capacity, the duration of access and reliability, the quality of the energy delivered, and the affordability of access. Ensuring energy access further requires a combination of national power grid expansion, off-grid systems and mini-grids.

Traditional grid expansion to rural areas, where the majority of people without access to electricity live, is often constrained by high operating costs and connection charges that lead to insufficient revenues and investments. Some developing countries have managed to further develop their electricity infrastructure, but insufficient, unreliable or inaccessible grid electricity has resulted in a greater focus on developing off-grid and mini-grid systems, considered to be more cost-effective electrification options than on-grid systems.

In particular, oil-fuelled generators are preferred by many households in Asia and Africa, even when connected to the grid. Such off-grid systems allow them to climb up the energy ladder, progressing from basic energy needs to productive uses. Mini-grids, which comprise a generator and a low-voltage distribution network, may also serve an entire community, even being integrated into a main grid, where technically possible. Off-grid systems and mini-grids not only provide electricity in rural (remote) areas, but also allow for flexibility in design and business models. Such electrification options are also used in developed countries to increase the resilience of the electricity supply, as they can continue to supply businesses and households when the main grid suffers interruptions.

The source of electricity for mini-grids may be diesel or oil-fuelled generators, solar PV systems, micro-hydro schemes or a combination (hybrid) of these sources. Those that use diesel or oil-fuelled generators have the advantage of low capital costs and the use of widespread technology that makes repairs and maintenance easy. Moreover, their capacity does not vary according to weather and season, as for renewable energy mini-grids. Existing mini-grids in Africa, for example, fall into the capacity range between 10–15 MW, and are mostly diesel or hydropower systems, albeit with the number of solar PV and hybrid systems growing. If their number is to be scaled up significantly, public support for the development of off-grid systems and mini-grids will be required.

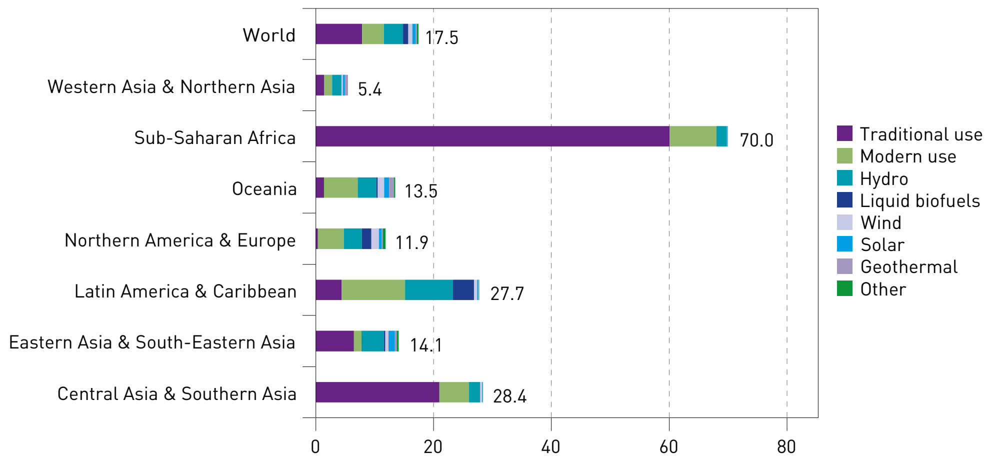
9.3 Renewable energy sources and energy efficiency

An uptake in new renewables (such as wind, solar and PV), the second target of SDG 7, would also ensue when moving away from traditional uses of biomass and towards modern energy sources. This progress is already taking off in the electricity sector, with wind and solar PV accounting for the majority of renewable electricity capacity added each year. Given that emissions from the electricity sector constitute a significant share of total emissions from the combustion of fossil fuels, electricity generation from renewable sources and fuel substitution away from coal to lower carbon content fuels could lead to a significant reduction in emissions.

In the period 2010–2015, the share of renewable energy (including biomass) in the total final energy consumption (TFEC) increased by 0.8 percentage points, reaching a share of 17.5%. During the same period, renewable energy consumption increased by 18%. However, regional and national differences should be highlighted. The high share reported for many developing countries reflect their reliance on the traditional use of biomass.

For instance, in Sub-Saharan African countries, renewable energy accounted for almost 70% of total final energy consumption in 2015. The share of traditional use of biomass was 60.1% and the remainder corresponds to modern renewable energy uses (Figure 9.7). As a result, the share of renewable energy in some developing countries is likely to decline as these economies accelerate their transition towards modern energy sources.

Figure 9.7
Share of renewable energy in total final energy consumption, 2015



Source: World Bank, 2018 & UN Department of Economic and Social Affairs, The Sustainable Development Goals Report 2018.

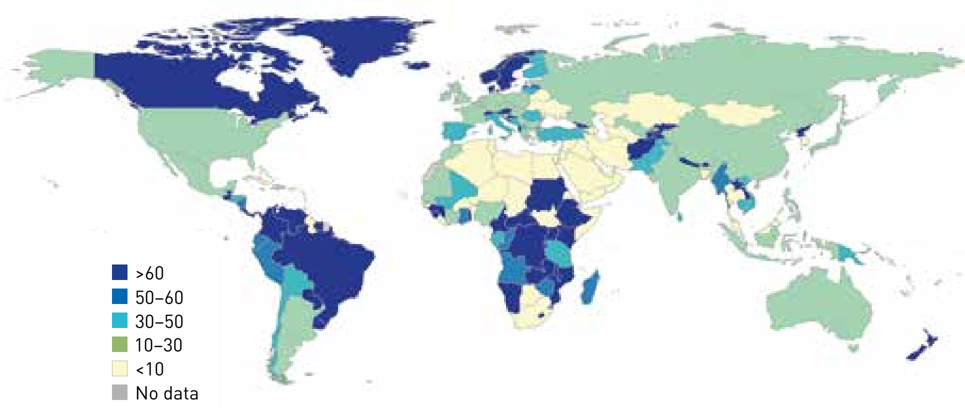
Moreover, the share of renewable energy in electricity has increased since 2010, reaching the level of 22.8% in 2015. Many developing countries are leading in renewable electricity production, particularly in terms of renewable electricity as a percentage of a country's total electricity output (Figure 9.8). The share of renewable energy in heat consumption has also increased but at a slower pace. Between 2010 and 2015, it increased by less than one percentage point, estimated at 24.8% at the end of 2015. However, renewable energy in this segment was dominated by traditional use of biomass, accounting for 65%. In the transport sector, renewable energy consumption has increased faster than either electricity or heat, albeit from a low base.

Turning to the third target of SDG 7, significant improvement in energy efficiency is also needed to achieve this target. A proxy used to measure energy efficiency is energy intensity – the ratio of energy used per unit of GDP. The progress in improving energy efficiency is described in detail in Chapter 2.

9.4 Sensitivity analysis of achieving SDG 7 targets

With the above trends and recent developments in mind, a sensitivity analysis is considered as a means to understand how the achievement of the energy efficiency and renewable targets under SDG 7 might impact the future energy mix and oil demand.

Figure 9.8
Renewable electricity (% of total electricity output), 2015



Source: World Bank, 2018, Sustainable Development Goals (SDGs).

As previously mentioned, the second target of the SDG 7 calls for a substantial increase in the share of renewable energy in the global energy mix by 2030, without indicating a quantitative target. This target is expected to be implemented by countries around the world based on their national circumstances, under which varying quantitative targets may be set.

At the same time, the third target calls to double the global rate of energy efficiency improvement by 2030. Such target settings are further reflected in the NDCs of countries under climate change negotiation processes that aim to achieve the long-term temperature target of the Paris Agreement.

Chapter 8 showed that the prominence of both energy efficiency and renewables in the policy agenda in developed and developing countries has risen. The introduction of energy efficiency policies and measures has been growing around the world in recent years, as well as the number of renewable energy policies. A similar future trend is expected owing to the ongoing implementation of the SDGs, as well as the expected enhanced mitigation action of countries in order to meet NDCs targets.

Using the Reference Case projections for energy demand outlined in Chapter 2, two sensitivities are analyzed in this Chapter focusing on the SDG 7 targets on renewable energy and energy efficiency improvement. To the extent possible, both sensitivities reflect the current concerns arising for the implementation of the SDGs and the policies already announced – including those presented in the NDCs. The policies considered are mainly those referring to changes in the power generation mix with increased renewable uptake, energy efficiency improvements in the residential and industry sectors, and transport-related policies.

In this context, the first sensitivity (Sensitivity A) focuses on the energy efficiency improvement target and assumes ambitious energy efficiency programs for buildings, energy saving measures in industries, and stringent fuel standards that apply in the transport sector, forcing higher rates of energy efficiency on the respective sectors around the world. Energy consumption, therefore, decreases in buildings and industries – principally in heating and cooling, but also for electricity used in appliances and lighting – due to regulatory measures on energy saving. In addition, the fuel efficiency of light-duty vehicles is assumed to increase substantially, with a roll-out of best practice across the world, while heavy-duty vehicles see some improvements in efficiency as well.

The aviation and freight sectors increase their fuel efficiency and rail becomes almost entirely electrified over the projected period. Therefore, consumption of liquid fuels in the transport sector is expected to decline, as is the case with the other two sectors mentioned earlier. Other sectors broadly follow the Reference Case trajectory; yet, the SDG 7 target on energy efficiency improvement is assumed to be met. In particular, the average rate of improvement in energy intensity is assumed to be of 2.8% for the period 2017–2030.

The second sensitivity also takes into consideration the renewable energy target of SDG 7 (Sensitivity B). It builds on the above sensitivity (i.e. the energy efficiency target of SDG 7 is met) and further assumes implementation of renewable energy policies to increase the share of renewables in the energy mix. The respective SDG 7 target is also met owing to policies – including feed-in-tariffs and subsidies – introduced to the power generation sector so that the share of renewables in the energy mix increases substantially.

The increased feed-in-tariffs and renewable subsidies encourage renewable uptake in the power generation sector, hence, they reduce the share of fossil fuels. This change is assumed to accelerate after 2030 due to a reduction in the cost of renewables resulting from economies of scale and learning effects. Under this sensitivity, compared to the Reference Case, hydropower and nuclear electricity generation are expected to increase the most, followed by wind generation – both onshore and offshore. Some additional increase in electricity generation (compared to the Reference Case) from solar and biomass (including biogas) is also considered.

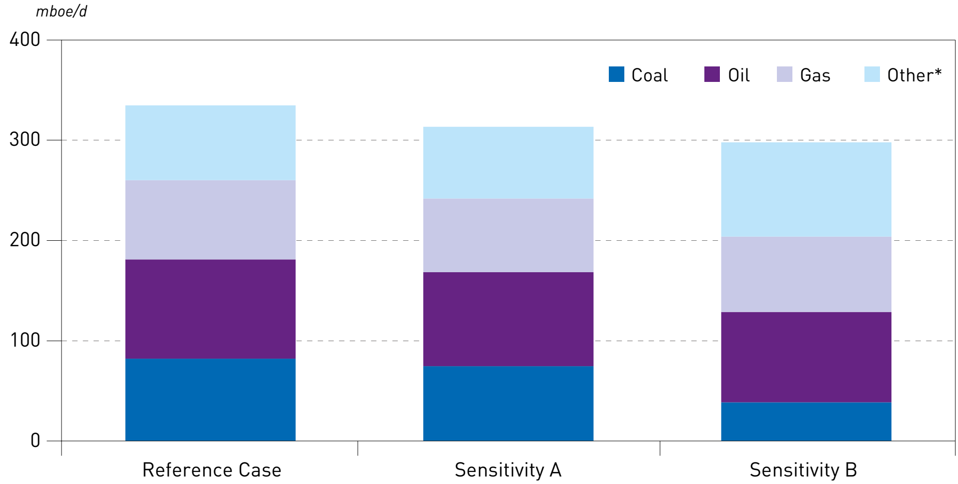
Implications on energy demand and the energy mix

Figures 9.9 and 9.10 show that climate and energy policies considered either for achieving the renewables target or the energy efficiency improvement would have a significant impact on primary energy demand. Under the first sensitivity (Sensitivity A), a 6.4% reduction of global primary energy demand is estimated in 2030 compared with the Reference Case, with demand falling to 313 mboe/d owing to energy efficiency improvements.

The respective figures in 2040 are at the level of a reduction of about 9%, with global energy demand at 330 mboe/d. The global energy demand would be further reduced when introducing additional renewable energy policies. In particular, global energy demand is expected to decline to 298 mboe/d in 2030 under Sensitivity B; then reaching the level of 310 mboe/d in 2040.

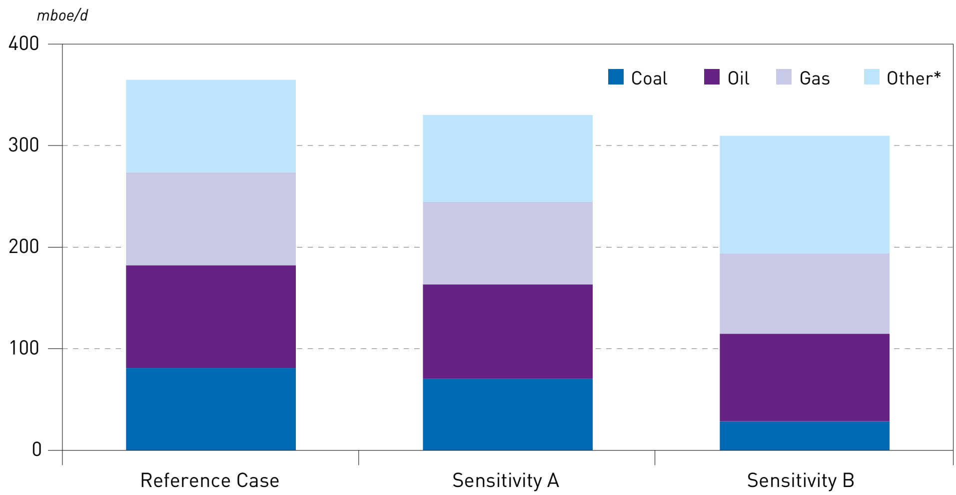
It is important to note, however, that the reduction in energy demand achieved under these two sensitivities still fall behind the levels required to achieve a below 2°C temperature target.

Figure 9.9
Global primary energy demand and the energy mix in 2030



** Including nuclear, hydro, biomass and other renewables such as wind, solar, PV, geothermal etc.*

Figure 9.10
Global primary energy demand and the energy mix in 2040



** Including nuclear, hydro, biomass and other renewables such as wind, solar, PV, geothermal etc.*

In this case, significant changes in the global energy sector are required compared with the trends expected in the Reference Case and in either of the two sensitivities.

Most scenarios consistent with the well below 2°C target suggest that global energy demand must be further reduced significantly and the reduction in energy from fossil fuels needs to start earlier in this case. In contrast to fossil fuel energy sources, the growth of renewable energy (including nuclear) would further accelerate.

The range of changes in global primary demand for major fuels for the different sensitivities relative to the Reference Case is summarized in Figures 9.11 and 9.12.

Reflecting the changes in the energy mix share over the forecast period under Sensitivity A, there is an estimated reduction of around six percentage points for coal in total primary energy demand in 2040 compared to 2016, alongside an estimated decline of almost three percentage points in the share of oil and about a three percentage point increase in the share of gas. However, oil continues to see growth to 2030 and then is expected to plateau for the rest of the forecast period.

Under Sensitivity B, the overall level for coal is estimated to drop by more than 60% by the end of the projection period, while growth in oil is significantly restricted so that its demand by 2040 is similar to the levels seen in 2016. There is an almost 32% increase in the level of gas demand and a more than 100% increase in demand for renewables/other energy sources.

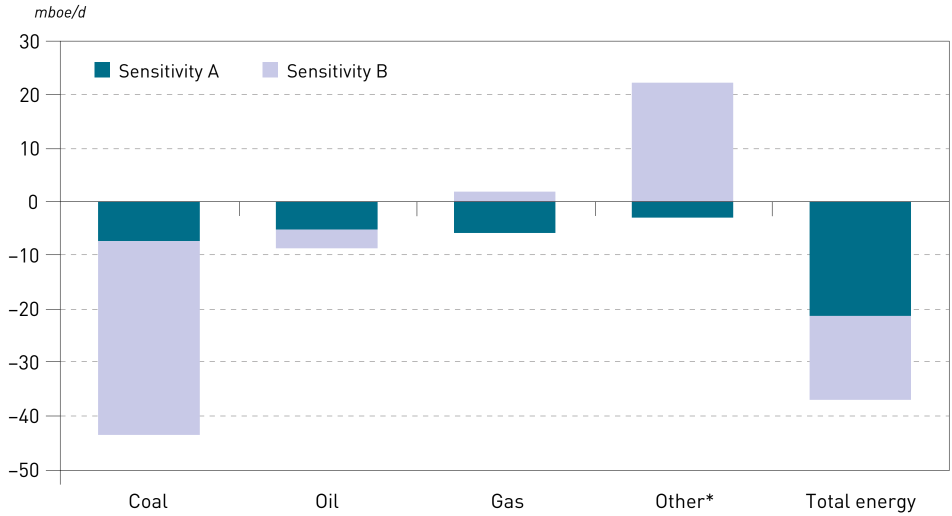
The higher penetration of renewables/other energy sources expected under Sensitivity B is evident. Combined, they would contribute almost 94 mboe/d to the global energy mix by 2030 and more than 115 mboe/d by 2040. In terms of the remaining fuel types, oil consumption is reduced in 2030 from about 99 mboe/d in the Reference Case to 93.7 mboe/d in Sensitivity A and further to 90.2 mboe/d under Sensitivity B. The respective figures in 2040 are from 101.3 mboe/d, to 93.1 mboe/d and then to 86.3 mboe/d.

Potential implications on CO_2 emissions and macroeconomic impacts

As discussed in Chapter 2, global CO_2 emissions are projected to increase over the Reference Case forecast period, reaching the estimated level of 39.4 $GtCO_2$ in 2040. Despite the climate and energy policies already in place, emissions continue to grow at a decelerated pace owing mainly to economic growth and increasing energy demand, without reaching a peak before 2040. Therefore, annual CO_2 emissions will be around 18% higher in 2040 than in 2016. CO_2 emissions in developed countries (Annex I) will represent 28.4% of the total in 2040, compared to about 39.1% in 2016. Moreover, the majority of cumulative CO_2 emissions over the forecast period are related to coal consumption. These will still account for almost 40% of the total emissions in 2040.

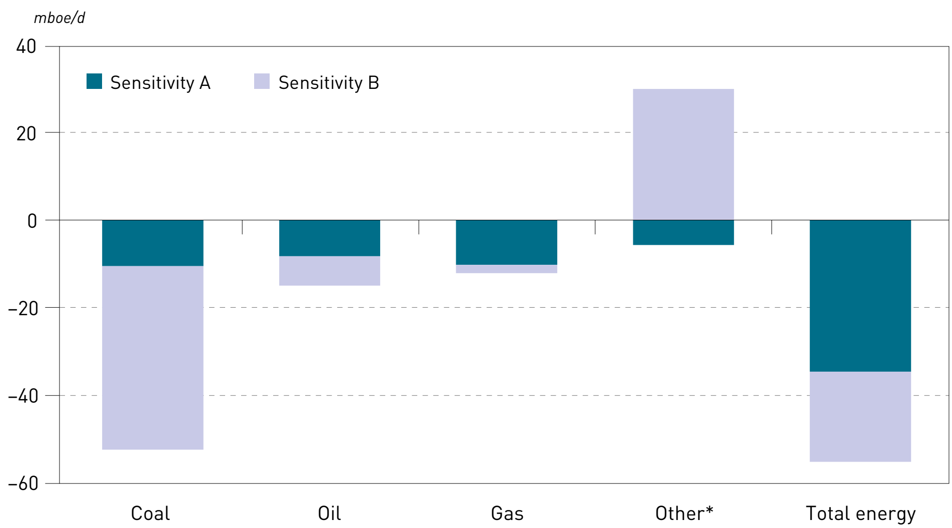
Figure 9.13 summarizes implications of the two alternative sensitivity paths in energy demand on future CO_2 emissions. In 2040, global energy-related CO_2 emissions are estimated at 34.9 $GtCO_2$ when the target of energy efficiency improvement is achieved. Therefore, global emissions could be reduced by 11.4% compared with the Reference Case. The CO_2 emission reductions expected to be achieved by implementing renewable energy policies as well could reach

Figure 9.11
Energy demand reduction relative to the Reference Case in 2030



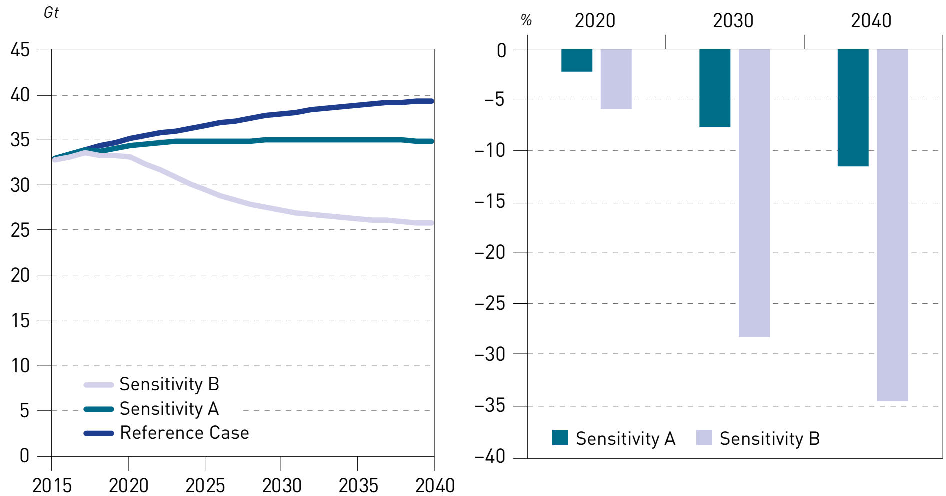
** Including nuclear, hydro, biomass and other renewables such as wind, solar, PV, geothermal etc.*

Figure 9.12
Energy demand reduction relative to the Reference Case in 2040



** Including nuclear, hydro, biomass and other renewables such as wind, solar, PV, geothermal etc.*

Figure 9.13
Impact on CO_2 emissions



the level of about 34.5% in 2040 under Sensitivity B, which corresponds to about 25.8 GtCO_2 of emissions by the end of the forecast period. It is worth mentioning, however, that achieving the SDG 7 targets on renewables and energy efficiency are not sufficient to put the world on a pathway consistent with a well below 2°C temperature target.

As mentioned earlier, energy efficiency improvements and an uptake in renewables could result in reductions global energy demand. The use of fossil fuels would drop in the sensitivity cases, compared to the Reference Case, with the decrease of coal demand between the Reference Case and the sensitivities being larger than the demand decrease for other fossil fuels. On the other hand, demand for renewable energy increases throughout the sensitivities.

In light of all this, petroleum exporting countries could face large adverse impacts arising from the implementation of energy efficiency and renewable policies. The reduction of OPEC Member Countries' GDP is large under both sensitivities compared with the overall effect for the global economy. Under Sensitivity A, the reduction of OPEC Member Countries' GDP could be 1.5% compared with a 0.5% decrease in global GDP for the year 2040. A slightly more negative effect would also result from Sensitivity B. However, analysis also showed that the path consistent with the well below 2°C target would reduce global GDP by 4.3% in 2040, whereas for OPEC Member Countries, GDP is expected to be reduced by more than 10%.

It is evident that the more stringent the policies, the worse the implications would be for petroleum exporting countries owing mainly to lower oil prices, reductions in oil demand and, thus, weakened terms of trade. Considering oil export revenues account for a significant share of

OPEC Member Countries' GDP, the estimated reductions would also have an impact on their economies. However, OPEC Member Countries' losses vary across the sensitivities. Economic diversification supported by increased foreign direct investment could help alleviate the potential adverse economic impacts. Nonetheless, such measures are usually not sufficient enough to fully mitigate the impacts of more stringent policies.

9.5 International initiatives on sustainable energy

The aim of implementing SDG 7 and achieving its targets on renewable energy and energy efficiency improvements is expected to have an impact on future investment needs. In order to achieve the targets of SDG 7, much of the existing capital stock would need to be replaced since related projects are often considered as capital-intensive. Scaling up the level of investment would, therefore, be vital to achieving both targets.

However, long-lived assets could lead to uncertainties in the investment environment. In addition to energy and climate policies, economic conditions and costs could also affect future investment decisions. Moreover, investments would not have a uniform pattern, since countries implement different policies and investment options according to their national circumstances.

In this context, current financing for SDG 7 is estimated at about $500 billion per year. This needs to increase to more than $1 trillion per year until 2030 in order to achieve the SDG 7 targets – including the one regarding energy access. The investment required in energy efficiency each year reaches about $560 billion. The power generation sector will also need to increase investment, despite the measures relating to energy efficiency. The increased requirement could be up to $650 billion each year.[72]

The additional investment requirements to ensure universal energy access are estimated at about $56 billion per year. Considering these financing needs could take resources from other sectors in the economy, the provision of means of implementation, including adequate financing, particularly in developing countries is of vital importance.

OPEC and its Member Countries have been strong advocates of sustainable development, recognizing eradication of energy poverty as a universal aspiration. The OPEC Fund for International Development (OFID) has recently inaugurated as a lead partner the Oil and Gas Industry's Energy Access Platform, together with major oil and gas companies and other stakeholders including business developers.

The objective of this platform is to contribute to the achievement of universal energy access, by leveraging industry capabilities to support access to energy, sharing best practices, fostering communication and contributing to the better integration of energy access in policies and projects at a country level.

The focus areas of this initiative includes the following: promoting the use of cleaner cooking technologies and fuels that can reduce household air pollution (for example biogas and LPG); promoting the integration of mini-grids that have as power source a diesel-powered generator, a renewable energy power plant or a hybrid power plant; and highlighting the oil and gas sector's technical knowhow to develop solutions that could have an important part to play in contributing to a sustainable energy future.

Finally, OFID is implementing an 'Energy for the Poor' Initiative, which is funded through a revolving endowment of $1 billion, a sum pledged by the institution's supreme body, the Ministerial Council, in its June 2012 Declaration on Energy Poverty. By the end of 2017, energy operations accounted for about $4.77 billion of OFID's total approvals. These resources have been distributed among 90 countries for projects ranging from infrastructure and equipment provision to research and capacity building.

Endnotes

1. Algeria, Ecuador, Republic of the Congo, Gabon, Kuwait, Nigeria, Qatar, Saudi Arabia, United Arab Emirates (UAE), and Venezuela.
2. The 'Declaration of Cooperation' was an outcome of the joint OPEC-non-OPEC Producing Countries' Ministerial Meeting held on 10 December 2016 in Vienna, Austria. The Declaration is made up of OPEC Member Countries: Algeria, Angola, Republic of the Congo (joined on 22 June 2018), Ecuador, Equatorial Guinea, Gabon, Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, UAE and Venezuela, and co-operating non-OPEC countries: Azerbaijan, Kingdom of Bahrain, Brunei Darussalam, Kazakhstan, Malaysia, Mexico, Sultanate of Oman, the Russian Federation, Republic of Sudan and the Republic of South Sudan.
3. Algeria, Ecuador, Republic of the Congo, Gabon, Kuwait, Nigeria, Qatar, Saudi Arabia, the UAE, and Venezuela.
4. A legal process enabling Congress to invalidate any recently finalized federal regulation by a simple majority vote in both chambers (subject to presidential endorsement).
5. Including two- and three-wheelers.
6. When the program takes effect in 2019, the cap is set at 10% and increases to 12% by 2020. Those manufacturers that do not meet the caps must either purchase credits from others who have earned them, or face hefty fines.
7. Smil, Vaclav (2015): Moore's Curse (https://spectrum.ieee.org/energy/renewables/moores-curse) and Smil, Vaclav (2008): Moore's Curse and the Great Energy Delusion (http://vaclavsmil.com/wp-content/uploads/docs/smil-article-20081119-the_American.pdf).
8. This Chapter uses energy equivalent units (mboe/d) to make the correct comparison between the different fuel types. It deals with the origin of energy and considers biofuels as biomass, coal-to-liquids (CTLs) as coal and gas-to-liquids (GTLs) as gas. In Chapters 3-6, however, oil is expressed in volumetric units (mb/d) and includes non-oil liquids (e.g. CTLs, GTLs and biofuels).
9. Other coal markers increased accordingly and in line with increases in Northwest Europe.
10. https://www.eia.gov/todayinenergy/detail.php?id=35412.
11. According to 2018 Hydropower Status report.
12. Official target of Chinese government is 190-200 GW of solar capacity in 2020. The initial target 120 GW of the 13th FYP was hit in 2017.
13. According to *2018 Global Wind Report* from Global Wind Energy Council.
14. This is for all areas outside Emissions Control Areas (ECAs), which already have a maximum 0.1% fuel sulphur limit.
15. Japanese Mitsui O.S.K. Lines and NYK have announced plans to start using LNG as a shipping fuel.
16. There is a perceived capacity limitation of up to 3,000 scrubber installations per year, taking into consideration the time required for the retrofit.
17. Surplus HSFO volumes will most probably be absorbed by the power generation and industry sectors.
18. Qun Zhang, Shanying Hu and Dingjiang Chen, A comparison between coal-to-olefins and oil-based ethylene in China: An economic and environmental prospective, *Journal of Cleaner Production*, Volume 165, 1 November 2017, pp. 1,351–1,360.
19. Promoting inland waterway transport in the People's Republic of China, Asian Development Bank.
20. Drilling Productivity Report, EIA, August 2018.

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21. https://www.eia.gov/dnav/pet/pet_crd_pres_dcu_NUS_a.htm, 'Crude Oil Proved Reserves'.
22. Calculated by subtracting non-OPEC and OPEC non-crude liquids supply from global demand and taking into account global stock change projections.
23. The seven regions that form the basis of crude and product trade reporting are: US & Canada, Latin America, Africa, Europe, Russia & Caspian, Middle East and Asia-Pacific.
24. Based on the throughout review of project announcements.
25. 'Capacity creep' most focuses on small expansions in the crude distillation and major upgrading units.
26. As discussed in Chapter 3, the demand increase from 2017–2020 is relatively high in part because of the increase in heavy fuel demand allowed for in 2020 as a result of the IMO sulphur regulations. This then also has the effect of reducing the annualized rate of demand growth from 2020–2025. (At 1.6 mb/d annually, the 2017–2020 demand growth is twice the 0.8 mb/d annually for 2020–2025.)
27. Assuming that new secondary units are fully used at the 90% level, the ability to produce and after consideration of creep capacity additions, the incremental medium-term potential for refining is projected at 7.4 mb/d.
28. Concerns over the effects of fuel stability and incompatibility have been a major theme at IMO meetings. The stability concern is over whether relatively untried fuel blends will become unstable over time and deposit out solids that could be damaging to engines. The incompatibility concern is that two 0.5% fuels made from different components, and each stable within themselves, could become incompatible when mixed in a ship's bunker tanks and deposit solids in the form of asphaltenes. The biggest risk is that engine stoppage could be an outcome with potentially disastrous consequences. One response has been that new forms of fuel testing are being developed.
29. The IMO has repeatedly said that there will be no delay beyond the January 2020 start date.
30. 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 are included in Table 5.8.
31. The 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 construction stage, part of the global cost has already been invested in recent years.
32. IRENA (2017), Electric vehicles: Technology brief, International Renewable Energy Agency, Abu Dhabi.
33. The program is a part of the congressionally mandated National Climate Assessment, established under the Global Change Research Act (1990).
34. Cato Institute 2013.
35. Centre for Western Priorities and Bureau of Land Management 2016.
36. Bureau of Land Management 2018.
37. Bureau of Land Management Factsheet 2016.
38. *Harvard Law 2016.*
39. In 2017, almost two-thirds of coal producing states in the US lost coal mining jobs. However, it may be argued that the policy has not had enough time to take shape.
40. 'Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783'.

41. Wyoming, West Virginia, Pennsylvania, Illinois and Kentucky.
42. White Paper on Transport 2011.
43. With the exception of Croatia, Lithuania, Malta and Poland.
44. European Automobile Manufacturer's Association 2017.
45. Not an EU member state, but referenced here to reflect the experience of a European nation.
46. Ibid.
47. European Commission 2017.
48. Ibid.
49. IAEA Director General, Yukiya Amano, September 2011.
50. Sandbag 2018.
51. ICCT, 2017.
52. Wood Mackenzie 2017.
53. ICCT, 2017.
54. An exact timeframe was not specified, but it is anticipated that the timeframe coincides with the 13th FYP targets for 2020.
55. Chinese government's planning arm.
56. China Energy Portal 2017 Electricity Statistics.
57. Paulson Institute 2016.
58. By July 2018, around 9 million Indian households gained access to electricity as a part of the program.
59. OPEC calculation based on Haver Analytics, SIAM.
60. Mainly from construction projects.
61. McKinsey, 2014.
62. See Adil, M., Anand, R., Coady, D., Thakoor, V., & Walsh, J. (29 May 2013) 'The Fiscal and Welfare Impacts of Reforming Fuel Subsidies in India', International Monetary Fund Working Papers.
63. Society of Manufacturers of Electric Vehicles 2017.
64. Ibid.
65. Based on 2017 data collected from the Ministry of Power (India), BP, Non-OECD Energy Balances, and JODI Oil & Natural Gas Databases.
66. According to the Central Electricity Authority's National Electricity Plan (January 2018), the plant load factor (PLF) of gas power plants is around 23%, with some gas-based power plants currently idle due to low supply of natural gas resources.
67. Overseas Development Institute (2014), How does electricity insecurity affect businesses in low and middle income countries?
68. PBL Netherlands Environmental Assessment Agency (2012), Roads from Rio+20. Pathways to achieve global sustainability goals by 2050.
69. Economic and Social Council, United Nations, (May 2018), Progress towards the Sustainable Development Goals: Report of the Secretary-General, High-level Segment, E/2018/64.
70. 2018 HLPF Review of SDG implementation: SDG 7 – Ensure access to affordable, reliable, sustainable and modern energy for all, Background note on the Status of Progress on SDG 7, available at: https://sustainabledevelopment.un.org/content/documents/20060195532018_background_notes_SDG_7Final1.pdf.
71. Ibid.
72. Ibid.

Annex A
Abbreviations

AC	Alternate current
A/C	Air conditioning
ADNOC	Abu Dhabi National Oil Company
AFV	Alternative Fuel Vehicle
AI	Artificial Intelligence
AIIB	Asian Infrastructure Investment Bank
Am	Americium
APA	Administrative Procedure Act (US)
API	American Petroleum Institute
bcm	Billion cubic metres
b/d	Barrels per day
BENM	Bears Ears National Monument
BEV	Battery electric vehicles
boe	Barrels of oil equivalent
BoJ	Bank of Japan
BREF	Best Available Techniques Reference
bt	Billion tonnes
CAFE	Corporate Average Fuel Economy
CAI	Controlled auto ignition
CAPEX	Capital expenditure
CCGT	Closed-cycle gas turbine
CCP	Combined cycle power
CCR	Continuous catalytic reforming
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CGEP	Columbia Centre on Global Energy Policy
CH_4	Methane
CHP	Combined heat and power
Cm	Curium
CNG	Compressed natural gas
CNMC	Comisión Nacional de Mercados y la Competencia
CO_2	Carbon dioxide
COTC	Crude oil to chemicals
CPP	Clean Power Plan
CRA	Congressional Review Act (US)
CTLs	Coal-to-liquids
CSP	Concentrated solar power
CTO	Coal-to-olefins
DC	Direct current
DOE	Department of Energy (US)
EC	European Commission
ECA	Emission Control Area

A

ECB	European Central Bank
EIA	Energy Information Administration (US)
EISA	Energy Independence and Security Act (US)
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency (US)
EPAct	Energy Policy Act (US)
EPRs	European Pressurised Reactors
ESPO	Eastern Siberia-Pacific Ocean
ETBE	Ethyl tertiary butyl ether
ETS	Emissions trading system
EU	European Union
EV	Electric vehicle
FAME	Faster Adoption and Manufacturing of Hybrid and Electric Vehicles
FCC	Fluid catalytic cracking
FCV	Fuel cell vehicles
FED	US Federal Reserve
FERC	Federal Energy Regulatory Commission
FHC	Fluorinated hydrocarbon
FID	Final investment decision
FSRU	Floating storage regasification units
FYP	Five Year Plan
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GHG	Greenhouse gas
GST	Goods and Services Tax
GTLs	Gas-to-liquids
GW	Gigawatt
HCCI	Homogenous charge compression ignition
HDV	Heavy-duty vehicle
HEV	Hybrid electric vehicle
HLPF	High-Level Political Forum
HSFO	High sulphur fuel oil
IAEA	International Atomic Energy Agency
IATA	International Air Transport Association
ICAO	International Civil Aviation Organization
ICE	Internal combustion engine
ICCT	International Council on Clean Transportation
IEA	International Energy Agency
IEEFA	Institute for Energy Economics & Financial Analysis
IFO	Intermediate fuel oil
IMO	International Maritime Organization
IMF	International Monetary Fund
INDCs	Intended Nationally Determined Contributions

IOC	International Oil Company
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
JODI	Joint Organisations Data Initiative
kg	Kilogramme
km	Kilometre
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelized cost of energy
LDVs	Light-duty vehicles
LGG	Lower GDP growth
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LSFO	Low sulphur fuel oil
MARPOL	International Convention for the Prevention of Pollution from Ships
mb/d	Million barrels per day
mboe/d	Million barrels of oil equivalent per day
mBtu	Million British thermal unit
MENA	Middle East and North Africa
MEP	Ministry of Environmental Protection
MEPC	Marine Environmental Protection Committee
mg	Milligrams
MJ/kg	Mega Joule per kilogram
MOMR	Monthly Oil Market Report (OPEC)
mpg	Miles per gallon
mt	Million tonnes
MTBE	Methyl tertiary butyl ether
MTO	Methanol-to-olefins
MTOMR	Medium-Term Oil Market Report (IEA)
MY	Model Year
MW	Megawatts
N_2	Nitrogen
NAFTA	North American Free Trade Agreement
NDCs	Nationally Determined Contributions
NDRC	National Development and Reform Commission
NEA	National Energy Administration (China)
NEG	National Energy Guarantee
NEP	National Energy Plan
NEMMP	National Electric Mobility Mission Plan
NGLs	Natural gas liquids
NGV	Natural gas vehicle
NH_3	Ammonia

NOCs	National Oil Companies
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
OFID	OPEC Fund for International Development
OPEC	Organization of the Petroleum Exporting Countries
OPV	Oil use per vehicle
ORB	OPEC Reference Basket (of crudes)
ORC	Organic Rankine Cycle
OWEM	OPEC World Energy Model
p.a.	Per annum
PDH	Propane dehydrogenation
PHEV	Plug-in hybrid electric vehicle
PLF	Plant load factor
ppm	Parts per million
PPP	Purchasing power parity
PV	Photovoltaic
R&D	Research & Development
RET	Renewable Energy Target
RFCC	Resid fluid catalytic cracking
RFS	Renewable Fuel Standard
RINs	Renewable Identification Numbers
SCR	Selective catalytic reduction
SDGs	Sustainable Development Goals
SENER	Secretariat of Energy (Mexico)
SMEV	Society of Manufacturers of Electric Vehicles
SO_2	Sulphur dioxide
SO_x	Sulphur oxides
SPR	Strategic Petroleum Reserve
SOCAR	State Oil Company of the Azerbaijan Republic
SUVs	Sport utility vehicles
TAN	Total acid number
tCO_2	Tonnes carbon dioxide
TEN-T	Trans-European Transport Network
TES	Thermal energy storages
TFEC	Total final energy consumption
UAE	United Arab Emirates
UK	United Kingdom
ULEZ	Ultra-Low Emission Zones
ULS	Ultra-low sulphur
UN	United Nations

UNFCCC	UN Framework Convention on Climate Change
US	United States
USVI	US Virgin Islands
VGO	Vacuum gasoil
VLCCs	Very large crude carriers
VMT	Vehicle miles travelled
WCS	Western Canadian Select
WCSB	Western Canadian Sedimentary Basin
WHR	Waste heat recovery
WOO	World Oil Outlook (OPEC)
WORLD	World Oil Refining Logistics Demand Model
WTI	West Texas Intermediate
WTO	World Trade Organization
y-o-y	Year-on-year

Annex B
OPEC World Energy: 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
Côte d'Ivoire
Democratic Republic of the Congo
Djibouti
Egypt
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
Indonesia
Kiribati
Lao People's Democratic Republic
Malaysia
Maldives
Micronesia (Federated States of)
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan
Papua New Guinea
Philippines
Samoa
Singapore
Solomon Islands
Sri Lanka
Thailand
Timor-Leste
Tonga
Vanuatu
Viet Nam

OPEC

Algeria
Angola
Republic of the Congo
Ecuador
Equatorial Guinea
Gabon
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

Annex C
World Oil Refining Logistics and Demand: definitions of regions

US & CANADA

United States of America
Canada

Turks And Caicos Islands
United States Virgin Islands
Venezuela

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
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

Mexico

Mexico

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
Côte d'Ivoire
Democratic Republic of Congo
Equatorial Guinea
Gabon

Ghana
Guinea
Guinea-Bissau
Liberia
Mali
Mauritania
Niger
Nigeria
Republic of the Congo
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

Pacific Industrialized
Australia
Japan
New Zealand

Pacific High Growth
Brunei Darussalam
Indonesia
Malaysia
Philippines
Republic of Korea
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

A

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

A

Annex D
Data sources

Accenture Consulting
Advanced Resources International Inc.
Africa Progress Panel
African Union
Airbus
American Chemical Society (ACS)
American Petroleum Institute (API)
Argus
Asia-Pacific Economic Cooperation (APEC)
Baker Hughes
Barclays Research
Bloomberg
Boeing
BP Statistical Review of World Energy
Brazil, Ministry of Mines and Energy
Brookings Institute
Bunkerworld
Cambridge Econometrics
Canada, National Energy Board
Canadian Association of Petroleum Producers
Canadian Energy Research Institute
Center for Strategic and International Studies (CSIS)
China National Petroleum Corporation (CNPC)
Citigroup
Climate Action Tracker
Consensus forecasts
Daily Caller
Deloitte
Deutsche Bank
E&P Magazine
East African Community
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
EUREL
European Automotive Manufacturers Association (ACEA)
European Commission (EC)
European Council
European Environment Agency
Eurostat
Evaluate Energy
Financial Times

A

Global Carbon Capture and Storage Institute (GCCSI)
Global Commission on the Economy and Climate
Global Wind Energy Council
Goldman Sachs
GSMA Intelligence
Harvard Business Review
Haver Analytics
HSBC
Hydrocarbon Processing
International Commodities Exchange
IEA Monthly Oil Data Service (MODS)
IEA Oil Market Report
IEA World Energy Outlook
IHS Markit
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 du Pétrole (IFP)
Interfax Global Energy
Intergovernmental Panel on Climate Change (IPCC)
International Air Transport Association (IATA)
International Association for Energy Economics (IAEE)
International Atomic Energy Agency (IAEA)
International Civil Aviation Organization (ICAO)
International Council on Clean Transportation (ICCT)
International Maritime Organization (IMO)
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)
Journal of Petroleum Technology
Kennedy School of Government, Harvard University
McKinsey Global Institute
National Development and Reform Commission (NDRC)
National Energy Administration of the People's Republic of China (NEA)
National Renewable Energy Laboratory
Natural Gas World Magazine
Nexant
Norton Rose Fulbright
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
Oil & Gas Journal
OPEC Annual Statistical Bulletin (ASB)
OPEC Fund for International Development (OFID)
OPEC Monthly Oil Market Report (MOMR)
Oxford Economics
Oxford Institute for Energy Studies
Petrobras
Petroleum Economist
Petroleum Intelligence Weekly
Platts
PricewaterhouseCoopers
REN21 – Global Status Report 2017
Reuters
Rystad Energy
Seatrade
Siemens AG
Society of Petroleum Engineers (SPE)
Stratas Advisors
Sustainable Energy for All
The Economic Times
Turner, Mason and Company
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 Bureau of Labor Statistics

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
Wood Mackenzie
World Economic Forum
World Nuclear Association
World Resources Institute
World Trade Organization (WTO), International Trade Statistics
Xinhua

A

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