Oil

2020

Analysis and forecast to 2025

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Table of contents

List of figures

List of boxes

List of tables

Executive summary

Coronavirus clouds oil outlook

The outbreak of the new coronavirus (COVID-19) has added a major layer of uncertainty to the oil market outlook at the start of the forecast period covered by this report. In 2020, global oil demand is expected to contract for the first time since the global recession of 2009. The situation remains very fluid, however, making it extremely difficult to assess the full impact of the virus.

To construct a base case for oil demand in 2020, this report draws on a wide range of data sources, including initial data for transport fuel demand, the most affected sector, and recently revised global GDP estimates by the Organisation for Economic Co-operation and Development (OECD). In this base case, we assume that although the virus is brought under control in China by the end of the first quarter, the number of cases rises in many other countries. Containment measures imposed in North America, Europe and elsewhere are expected to have a smaller impact on oil demand than those in China. However, demand from the aviation sector will continue to suffer from the contraction in global air travel.

In this case, oil demand in China suffers the most in the first quarter, with a year-on-year fall of 1.8 million barrels per day (mb/d). Global demand drops by 2.5 mb/d. In the second quarter, an improving situation in China offsets deteriorating demand elsewhere. A progressive recovery takes place through the second half of 2020. For 2020 as a whole, the magnitude of the drop in the first half leads to a decline in global oil demand of around 90,000 barrels a day compared with 2019.

Ultimately, the outlook for the oil market will depend on how quickly governments move to contain the coronavirus outbreak, how successful their efforts are, and what lingering impact the global health crisis has on economic activity. At the time of publication, the high uncertainty over the course of the global epidemic has led us to propose two alternatives to our base case for demand in 2020: a more pessimistic one in which global measures are less successful in containing the virus, and an optimistic case in which it is contained quickly.

These alternatives are outlined in the March edition of the IEA's monthly *Oil Market Report*, which is released in tandem with this medium-term report.

Markets face major challenges

The arrival of the coronavirus is rattling a global oil market that was already facing challenges. On the demand side, growth in 2019 was significantly weaker than expected and new vehicle efficiency measures have started to weigh on transport fuels. Refining capacity additions in recent years have outstripped demand growth, bringing tough competition for an industry already challenged by tightening product specifications, most notably the new International Maritime Organisation (IMO) bunker rules introduced at the beginning of 2020.

On the supply side, geopolitics remain a wild card. Production losses from Iran, Libya and Venezuela have reached a combined 3.5 mb/d since the start of 2018. Even before the coronavirus, markets had been over-supplied, leading OPEC+ producers to cut output. Looking beyond the short term, the oil market looks comfortably supplied through 2025.

Following a contraction in 2020 and an expected sharp rebound in 2021, global oil demand growth is set to weaken as consumption of transport fuels increases more slowly. Between 2019 and 2025, global oil demand is forecast to grow at an average annual rate of just below 1 mb/d. Petrochemicals become an ever more important driver, with naphtha, liquefied petroleum gas (LPG) and ethane responsible for half of all growth. Efforts to improve the sustainability of the plastics industry will run up against the steady increase in demand from consumers in developing countries. Bans imposed on single-use plastics and recycling, even if fully implemented, will displace only a very modest amount of oil demand. Through 2025, global oil demand rises by a total of 5.7 mb/d, with China and India accounting for about half of growth.

At the same time, the world's oil production capacity is expected to rise by 5.9 mb/d. Non-OPEC supply will rise by 4.5 mb/d while OPEC builds another 1.4 mb/d of crude and natural gas liquids capacity. This assumes that there is no change to sanctions on Iran or Venezuela. The United States leads the way as the largest source of new supply. Given its huge resource potential, it could produce even more if prices end up higher than assumed in this report. Brazil, Guyana, Iraq and the United Arab Emirates also deliver impressive gains.

Strong growth in Asian oil demand is creating major opportunities for oil producing countries that can boost exports. But growth in non-OPEC production is set to lose momentum after a few years, indicating a greater role for OPEC+ countries. The pace of expansion in the United States is slowing as independent producers cut spending and scale back drilling activity in response to pressure from investors. The deceleration in US and other non-OPEC growth from 2022 will allow OPEC producers from the Middle East to turn up the taps to help keep the oil market in balance, thereby increasing their importance for oil consuming countries.

Oil and clean energy transitions

Global attention is increasingly focused on the need to accelerate clean energy transitions in order to mitigate the risks of climate change. With its major emissions footprint, the energy sector – including the oil and gas industry – is at the heart of the matter. Demand growth for gasoline and diesel between 2019 and 2025 is set to weaken as countries around the world implement policies to improve efficiency and cut carbon dioxide (CO_2) emissions, and as electric vehicles increase in popularity. Refiners, nevertheless, continue to build much more capacity than what is needed to meet product demand.

The impact of clean energy transitions on oil supply remains unclear, with many companies prioritising short-cycle projects for the coming years. To date, announcements by major oil companies on reducing their CO_2 emissions have tended to focus on long-term objectives. Nevertheless, investors continue to ratchet up pressure on the industry to sharpen its focus on sustainability issues while activists, especially in Europe and North America, seek to hinder new oil developments.

With uncertainties over demand, supply, investment strategies and business models, the global oil industry faces major challenges. While ensuring it is able to continue to meet growing demand, it must also address the need to curb emissions and improve sustainability.

1. Demand

Highlights

- Global oil demand will grow by 5.7 mb/d over the 2019-25 period at an average annual rate of 950 kb/d. This is a sharp reduction on the 1.5 mb/d annual pace seen in the previous 10-year period. Following a difficult start in 2020 (-90 kb/d) due to the coronavirus, growth rebounds to 2.1 mb/d in 2021 and decelerates to 800 kb/d by 2025 as transport fuels demand growth stagnates.
- Gasoline demand will grow the least over the forecast period, by just 90 kb/d per year. Consumption growth is expected to slow to 50 kb/d at the end of the forecast period, due to improved car efficiency standards and the increased penetration of electric vehicles.
- Diesel consumption will grow by 110 kb/d on average and growth will decelerate to a very limited level by 2025. All in all, progress in vehicle efficiency will be the main factor impacting diesel demand in the medium term.
- Petrochemical feedstocks naphtha, liquefied petroleum gas (LPG) and ethane will be responsible for half of oil products demand growth, or roughly 0.5 mb/d per year as demand for other fuels stagnates. Feedstock demand grows in line with the consumption of plastics, supported by cheap natural gas liquids (NGL) prices.
- Single use plastic bans and mechanical recycling have a small impact on oil demand. Government targets implemented over the last few years would help reduce oil demand by 700 kb/d by 2025, up from 380 kb/d in 2019; a net incremental impact of 315 kb/d in six years. This is equivalent to shedding about 5% of the increase in oil demand.
- The International Maritime Organisation's (IMO) rules on sulphur in bunker fuels were implemented on 1 January 2020. Based on the situation to date, we revised higher our estimate for very low sulphur fuel oil (VLSFO) demand to 1.3 mb/d in 2020 and 2.1 mb/d in 2025. High sulphur fuel oil (HSFO) consumption decreases by 1.8 mb/d year-on-year in 2020, but will stabilise thereafter, supported by vessels equipped with scrubbers.
- A common feature impacting all segments of the oil market is the acceleration of the energy transition in recent years. In this report, we look at the impact of transportation policies.

Global oil demand by product

Oil demand will grow on average by 950 kb/d each year between 2019 and 2025 (5.7 mb/d in total), a one-third reduction from the rate seen in the previous ten years. This is mainly due to demand for diesel and gasoline approaching a plateau, as new efficiency standards are applied to internal combustion engine vehicles and electric vehicles hit the market. Petrochemical feedstocks LPG/ethane and naphtha will drive around half of all oil products demand growth, helped by continued growth in plastics demand and cheap NGLs in North America. Meanwhile, demand for residual fuel will increase by a modest 0.4% per year. However, this hides an important shift where VLSFO surges in 2020, becoming the fastest growing oil product over 2019-25, while HSFO demand falls 60% in 2020, before stabilising.

As we publish this report, COVID-19 looks likely to have a significant impact on oil demand, triggering the first annual decline in consumption since 2009. The virus shut extensive parts of the People's Republic of China's (hereafter "China") transport and economic systems in 1Q20 and had spread to the rest of Asia, Europe, North America and other parts of the world. Our base case is for an 90 kb/d annual decline in oil demand in 2020. This assumes that the virus comes under control in China from the end of March, and that more limited containment measures in Korea, Japan, the Middle East and Europe affect oil demand further. The OECD's economic outlook of 2 March 2020, which assumes global growth of 2.4% (down from 2.9% previously) underpins our projections. Finally, we have assumed one-off impacts for the global transport industry (and therefore jet fuel, diesel and gasoline deliveries) in 1Q and 2Q20. The general assumption is that the virus does not spread further and that economic growth returns to normal in the second half of 2020.

After a difficult 2020, oil demand growth rebounds to 2.1 mb/d in 2021, the most in seven years. Our analysis is that the world's transport and manufacturing systems will remain intact and that usual consumer behaviour will resume, hence the return to a "normal" oil consumption volume in that year and the strong year-on-year growth this implies. From 2022 onwards, oil demand growth comes down to 1.1 mb/d and then falls below the 1 mb/d threshold in 2023 and subsequent years, as fuel savings in the transport sector begin to have a meaningful impact.

Table 1.1 Global oil demand by product (mb/d)

Product	2019	2020	2021	2022	2023	2024	2025	Annual % Growth	Annual Growth
LPG/Ethane	12.6	13.0	13.3	13.6	13.9	14.1	14.4	2.2%	0.3
Naphtha	6.5	6.6	6.8	7.0	7.3	7.5	7.6	2.8%	0.2
Gasoline	26.4	26.2	26.6	26.7	26.8	26.9	26.9	0.3%	0.1
Jet/Kerosene	8.0	7.9	8.1	8.3	8.4	8.4	8.5	1.1%	0.1
Gasoil/Diesel	28.9	29.2	29.5	29.6	29.8	29.9	30.0	0.6%	0.2
Residual fuel	6.3	5.7	6.2	6.4	6.4	6.4	6.4	0.3%	0.0
Other products	11.3	11.4	11.4	11.5	11.6	11.6	11.7	0.7%	0.1
Total products	100.0	99.9	102.0	103.1	104.0	104.9	105.7	0.9%	1.0

Petrochemicals reign over demand growth

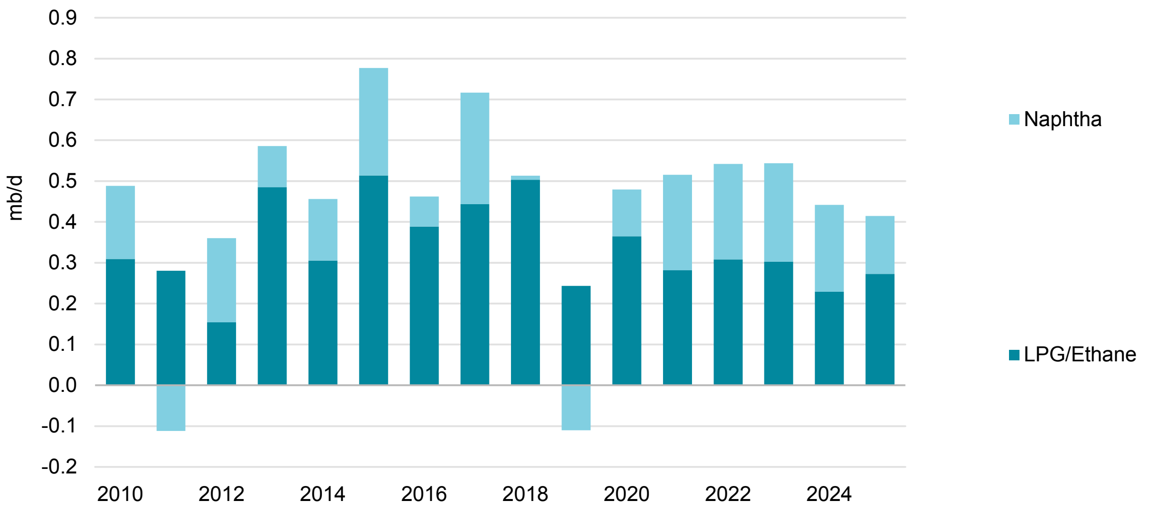
Petrochemical fuels naphtha, LPG and ethane will be responsible for half of all oil products demand growth over 2019-25, or 490 kb/d per year on average. In volumetric terms, this is only slightly more than in 2010-19 (470 kb/d). This is a larger contribution (in relative terms) than in the previous 10-year period, when they were responsible for one third of all growth, as demand for other products is stagnating or falling.

LPG, ethane and naphtha consumption will grow in line with higher feedstock requirements in the petrochemical industry, the result of rising plastic demand, which will increase by 2.6% per year on average during 2019-25 (See *Plastic demand falls short of GDP*), and with higher demand for petrochemicals in other sectors (e.g. electronics, detergents, pharmaceuticals, and paints).

Plentiful LPG and ethane supplies linked to the oil and gas production boom in the United States will continue to play an important role by reducing the cost of feedstocks for US crackers.

We expect naphtha demand to increase by 200 kb/d per year during the period to 2025, nearly double the 2010-19 average, with planned cracker investments in Asia fuelling growth (See *Petrochemical capacity grows rapidly*). LPG/ethane deliveries, by contrast, are likely to slow marginally, from growth of 360 kb/d during 2010-19 to 290 kb/d over the forecast period, as the boom in ethane cracker investments seen in North America progressively comes to an end. That being said, LPG and ethane will together remain the fastest growing fuels by volume, despite representing only 13% of oil products consumption at the time of writing.

Figure 1.1 LPG/ethane, naphtha demand growth (y-o-y)



LPG, ethane and naphtha contribute half of all oil products demand growth to 2025.

In 2019 we saw much lower combined LPG/ethane and naphtha demand growth than expected (only 130 kb/d), as reduced naphtha crackers utilisation in Europe and Asia offset new build capacity expansions. Also, several ethane crackers in the United States saw unscheduled stoppages, while the commissioning of several new units were delayed. Lower global economic growth, partly due to trade tensions between China and the United States, also played a role. A total of 300 kb/d of new ethane and naphtha cracker capacity is likely to be commissioned in 2020, with a further 2.2 mb/d planned over the 2021-25 period (see *Demand Appendix*).

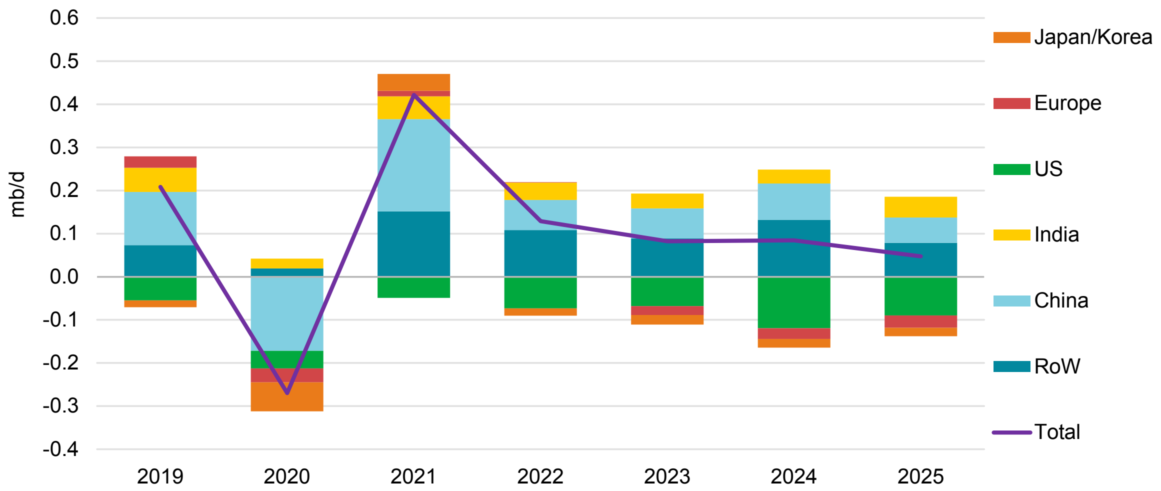
Gasoline demand slowing

Demand for gasoline, the second biggest oil products market, will grow the least over the forecast period, with demand up by just 90 kb/d per year. The United States, its biggest market, as well as much of the OECD, will decline, and gains in China, India and other non-OECD countries just about compensate this decrease. We expect gasoline demand to almost reach a plateau at the end of the forecast period.

Improved car efficiency standards implemented in the last few years are the main reason (see *Transport in transition*). For example, the average gasoline car is expected to be 7% more efficient in the United States and nearly 11% more efficient in Europe by 2025, compared with 2019, taking into account efficiency standards as well as fleet turnover. In addition, sales of electric vehicles are expected to increase sharply. In the developing world, gains in efficiency are likely to be even more substantial, given that the average car currently on the road is older. However, rates of car ownership are far lower and rising sales will boost gasoline demand.

Gasoline consumption growth reached 900 kb/d in 2015, after the collapse in oil prices, and has been decelerating ever since. In 2019, the 26 mb/d market grew by only 210 kb/d, supported mainly by gains China, India and Indonesia.

Figure 1.2 Gasoline demand growth by country (y-o-y)



Global gasoline consumption plateaus after 2024.

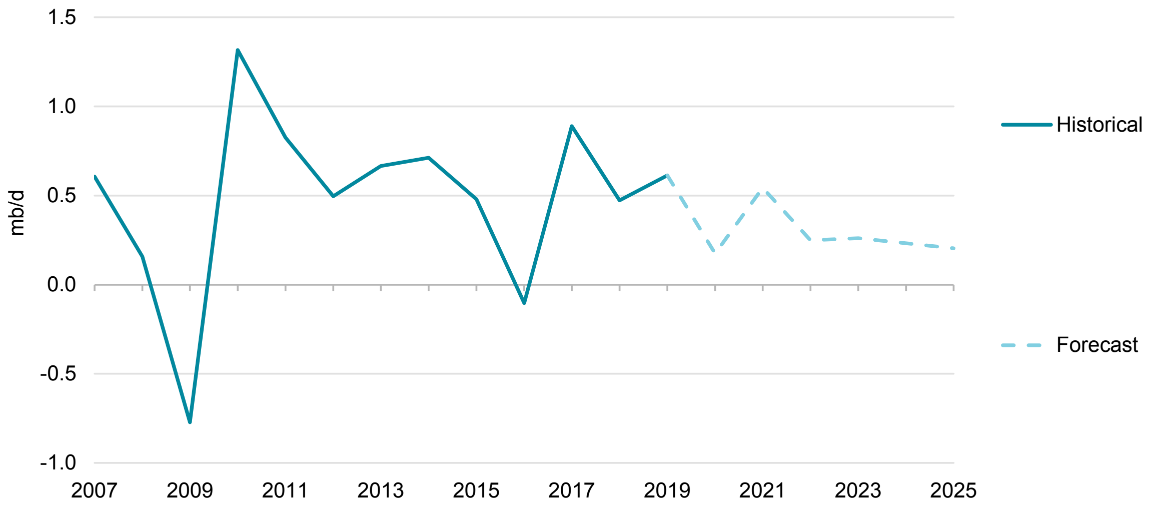
Middle distillates see mixed picture

Diesel, gasoil, jet fuel and kerosene demand will increase by 280 kb/d each year on average during the forecast period, a much slower rate of growth than the 640 kb/d registered over the previous 10 years. Jet fuel and kerosene demand will grow by 90 kb/d on average, down from 180 kb/d, while combined gasoil and diesel demand will grow by just 190 kb/d, less than half its ten year average of 460 kb/d.

Diesel consumption will continue to increase (+110 kb/d on average); however, just like gasoline, growth will decelerate progressively to only 30 kb/d in 2025. Improved fuel efficiency standards in Europe will pressure demand from diesel vehicles. Compared with 2019, we expect the average diesel vehicle (both cars and trucks) to be 4% more efficient in the United States and 7% more efficient in Europe by 2025. In non-OECD countries, efficiency gains are likely to be substantial too (e.g. 8% in China, India and the Russian Federation [hereafter "Russia"]).

Jet fuel and kerosene consumption growth will be 90 kb/d per year over the forecast period, the most for any oil product other than for petrochemicals and VLSFO. It represents nevertheless a significant slowdown compared to recent growth rates, as fast growing markets become more mature and energy efficiency improves. Chinese and Indian passenger traffic, for example, slowed significantly in 2019 after strong growth in 2018. Chinese air passenger traffic growth declined from 13% in 2017 to 11% in 2018 and 8% in 2019. India domestic traffic growth dropped from 19% in 2018 to 4% in 2019. All of the growth will be driven by rising demand for air travel, while kerosene demand, mainly for cooking and heating, will stagnate. The largest contributors to growth will be China (+30 kb/d), Europe (+10 kb/d), the United States (+10 kb/d) and India (+10 kb/d). We have included an average improvement in fuel efficiency for aircraft of 6% by 2025, compared with 2019, taking into account the commissioning of new, more modern planes and continuous improvements in flight routing technology.

Figure 1.3 Middle distillates demand growth



Diesel, gasoil and jet fuel demand will grow far less quickly than in the 2010-19 period.

Finally, the IMO bunker fuel standards have driven a change in the bunker fuel product mix for the coming decade. We estimate that marine gasoil demand will jump by 490 kb/d in 2020 as the fuel is readily available in most ports globally and provides a straightforward compliance option for shippers. It will then decline by an average 70 kb/d per year in 2021-24 displaced by VLSFO and HSFO burning by ships equipped with scrubbers.

Fuel oil navigates shifting standards

Residual fuel demand will be more or less stable over the forecast period, rising by just 20 kb/d on average. However, this hides significant year-on-year differences as well as intra-fuel changes. In 2020, as the new IMO rules are introduced, HSFO consumption is forecast to decrease by 1.8 mb/d, or more than 50%, to 1.2 mb/d, as ship operators switch to marine gasoil and VLSFO to comply. It will stabilise thereafter due to the growing number of vessels equipped with scrubbers. We expect non-compliance with IMO rules of around 12% in 2020, down from 15% in last year's report, owing to the larger consumption of VLSFO.

Our forecast of 2 500 scrubbers in place by end-2019 has been more or less realised, and we have left unchanged from last year's report our forecasts for 2020 (4 000 scrubbers), 2021 (4 700), 2022 (4 900), 2023 (5 000) and 2024 (5 200). Altogether, 700 kb/d of HSFO in 2020 will be used in ships fitted with scrubbers, growing to 1.1 mb/d by 2025.

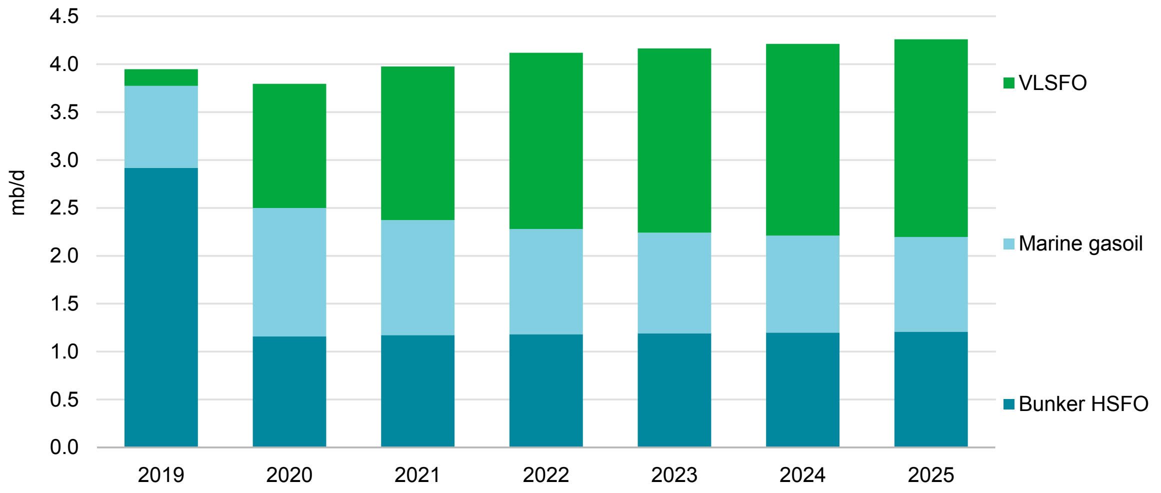
The major area of uncertainty is VLSFO, given that the product is relatively new. We expect consumption to increase by a sharp 1.1 mb/d in 2020, as evidenced by the rapid take-up in major bunkering hubs such as Rotterdam and Singapore and the relative ease with which oil refiners have been able to produce it. Demand will then increase by a steady 150 kb/d per year in 2021-25 to reach 2.1 mb/d by the end of the forecast period. VLSFO will be the fastest growing product in the whole oil barrel. In Singapore, deliveries of VLSFO rose from 40 kb/d in September 2019 to 550 kb/d in December, while HSFO bunker deliveries declined from 720 kb/d to 270 kb/d in over the same period. In early 2020, VLSFO accounted for 60% of bunker sales in Singapore.

Table 1.2 Bunker fuel demand (mb/d)

Product	2019	2020	2021	2022	2023	2024	2025	Annual % Growth	Annual Growth
Marine gasoil	0.9	1.3	1.2	1.1	1.1	1.0	1.0	2.5%	2.3%
VLSFO	0.2	1.3	1.6	1.8	1.9	2.0	2.1	51.0%	31.5%
Marine HSFO	2.9	1.2	1.2	1.2	1.2	1.2	1.2	-13.7%	-28.5%
Total bunker	**3.9**	**3.8**	**4.0**	**4.1**	**4.2**	**4.2**	**4.3**	**1.3%**	**5.2%**

Finally, inland demand for fuel oil (largely burned to produce electricity in the Middle East and some remote locations) is expected to go up by around 50 kb/d in 2020 and a further 220 kb/d in 2021, as the price of HSFO falls. It will then decline by 80 kb/d per year, in line with the pattern of steady declines seen over the last decade.

Figure 1.4 Bunker demand growth



VLSFO takes on a progressively larger share of the bunker fuel mix.

Economic outlook: Weak and uncertain

The International Monetary Fund's (IMF) *World Economic Outlook Update*, published in January 2020, and the OECD's *Interim Economic Outlook*, published in March 2020, form the basis of our medium-term oil demand forecasts. For major economies, we use the latest OECD growth figures for the years 2020-21, as they reflect the organisation's latest view on the impact of the COVID-19 crisis on the economy.

COVID-19 will have a substantial impact on economic activity in 2020. We assume global growth of 2.4%, down from 2.9% in 2019 and around 3% for 2020 before the virus hit. Growth is likely to rebound to 3.3% in 2021 and to 3.6% on average in 2022-25.

Table 1.3 Economic growth projections used in our demand model

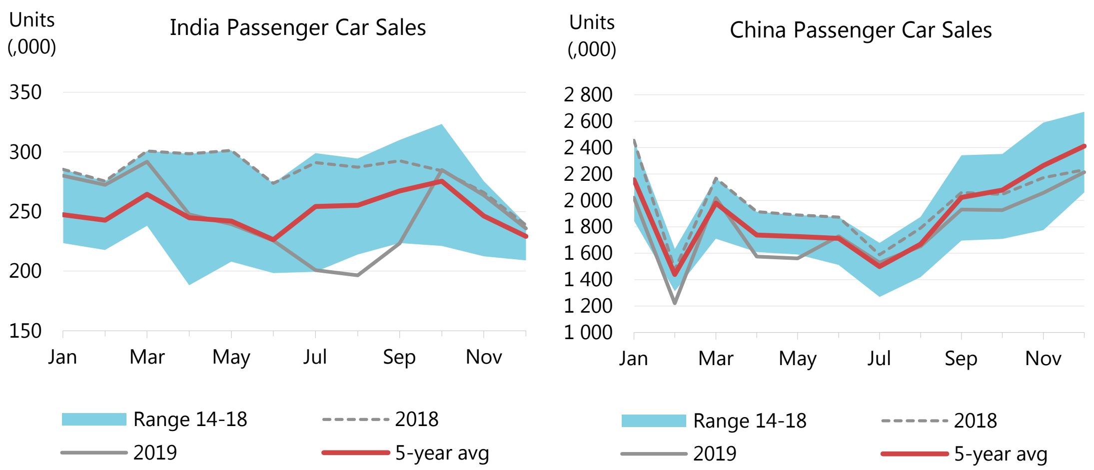
Country	2018	2019	2020	2021	2022	2023	2024	2025
United States	2.9%	2.3%	1.7%	2.1%	1.6%	1.6%	1.6%	1.7%
Japan	0.8%	1.0%	0.2%	0.7%	0.5%	0.5%	0.5%	0.5%
China	6.6%	6.1%	4.9%	6.4%	5.7%	5.6%	5.5%	5.4%
India	6.8%	4.8%	5.1%	5.6%	7.4%	7.4%	7.3%	7.2%
Germany	1.5%	0.5%	0.3%	0.9%	1.3%	1.2%	1.2%	1.1%
Russia	2.3%	1.1%	1.2%	1.5%	2.0%	1.9%	1.8%	1.8%
Brazil	1.1%	1.2%	1.7%	1.8%	2.4%	2.4%	2.3%	2.1%
South Africa	0.8%	0.4%	0.6%	1.0%	1.8%	1.8%	1.8%	1.8%
World	**3.6%**	**2.9%**	**2.4%**	**3.3%**	**3.6%**	**3.6%**	**3.6%**	**3.6%**

Sources: International Monetary Fund, OECD, IEA.

We assume that the direct effect of the coronavirus on the global economy will be largely limited to the first half of 2020. However, given the stellar rise of the Chinese economy since the SARS epidemic in 2003 and the growth in trade, the impact will be felt widely. Other economies most exposed to China, or which have developed cases of COVID-19 of their own, will also see a slowdown in GDP growth.

In 2019, the global economy saw a significant deterioration in world trade and industrial activity. World industrial production growth has also posted a spectacular decline since mid-2018. However, while recent prompt economic indicators remain mixed, trade tensions have eased. Trade agreements between the United States and Japan, or the United States, Canada, and Mexico and the phase one deal between the United States and China could alleviate trade tensions.

Figure 1.5 India, China car sales



China, India car sales showed recovery at the end of 2019.

Car manufacturing has been particularly impacted by the tough economic conditions in recent quarters. Credit restrictions in China and India, taxation changes and new environmental tests in Europe significantly reduced sales in 2018 and a large part of 2019. However, the car market started to recover in 4Q19. For the whole of 2019, new vehicle sales fell by 1.3% in the United States, 2.4% in the United Kingdom, 4.8% in Spain, 3.3% in Thailand, 10.5% in Indonesia, 2.3% in Russia, 23.3% in Turkey, 42.8% in Argentina, 8.2% in China and 12.7% in India. Some countries performed better, such as Brazil where vehicle sales rose by 8.6%. In addition, thanks to a strong rebound at the end of 2019, German car sales ended the year 5% above 2018 levels and French car sales were up 1.9%. In December, European Union car sales rose by 21.7%.

US economic growth will slow from 2.3% in 2019 to 1.7% in 2020 and be 1.6%-1.7% thereafter, as the effects of tax cuts and fiscal expansion fade away. Investment activity has been subdued in recent months, due to policy uncertainty in relation to the trade tensions with China. US unemployment remains low, however, and this is supporting consumption.

Growth in Europe has deteriorated significantly in recent quarters. In particular, the German industrial sector has been impacted by problems in the motor industry and lower Asian demand for its products. The economic environment should improve in the coming years however, on better external demand. UK growth should accelerate in 2021, assuming an orderly Brexit.

China's GDP growth fell to 6.1% in 2019 and is expected to slow further to 4.9% in 2020. However, at the time of writing this report there is considerable uncertainty due to the coronavirus. Our forecast assumes a return to normal levels of activity in the second half of 2020. The phase one trade agreement with the United States could support growth when activity picks up.

Indian growth was disappointing in 2019, slowing to 4.8% from 6.8% in 2018. Poor weather conditions and a decline in credit growth explain the slowdown. However, recent data appear relatively supportive. Growth is expected to accelerate slightly to 5.1% in 2020 and 5.6% in 2021, supported by monetary and fiscal policies.

Global oil demand by region

Table 1.4 Global oil demand by region (mb/d)

Product	2019	2020	2021	2022	2023	2024	2025	Annual % Growth	Annual Growth
North America	25.2	25.3	25.4	25.4	25.5	25.4	25.4	0.1%	0.0
Latin America	6.7	6.7	6.7	6.8	6.9	7.0	7.0	0.8%	0.1
Europe	15.6	15.4	15.5	15.6	15.6	15.6	15.6	0.0%	0.0
Africa	4.3	4.3	4.4	4.5	4.7	4.8	4.8	2.0%	0.1
Middle East	8.4	8.4	8.6	8.6	8.6	8.6	8.7	0.6%	0.0
Eurasia	4.3	4.4	4.5	4.5	4.5	4.5	4.6	0.9%	0.0
Asia Pacific	35.6	35.4	36.8	37.7	38.4	39.1	39.8	1.9%	0.7
World	**100.0**	**99.9**	**102.0**	**103.1**	**104.0**	**104.9**	**105.7**	**0.9%**	**1.0**

As the pace of global oil demand growth falls from 1.5 mb/d in 2010-19 to 950 kb/d in our forecast period, the Asia Pacific region takes on a more prominent role in relative terms. Its share of world oil demand growth rises from two-thirds to just under three-quarters. In volumetric terms, the region's consumption growth will slow to around 700 kb/d, largely as a result of the coronavirus in 2020 as well as improving road fleet efficiencies and the increased penetration of electric vehicles. Africa will see rapid growth of around 2% per year, but from a small base. So, by 2025 oil demand on the continent will still be only 4.8 mb/d, equivalent to a third of China's level. Demand is likely to stagnate in both Europe and North America, meaning OECD consumption has plateaued.

Non-OECD

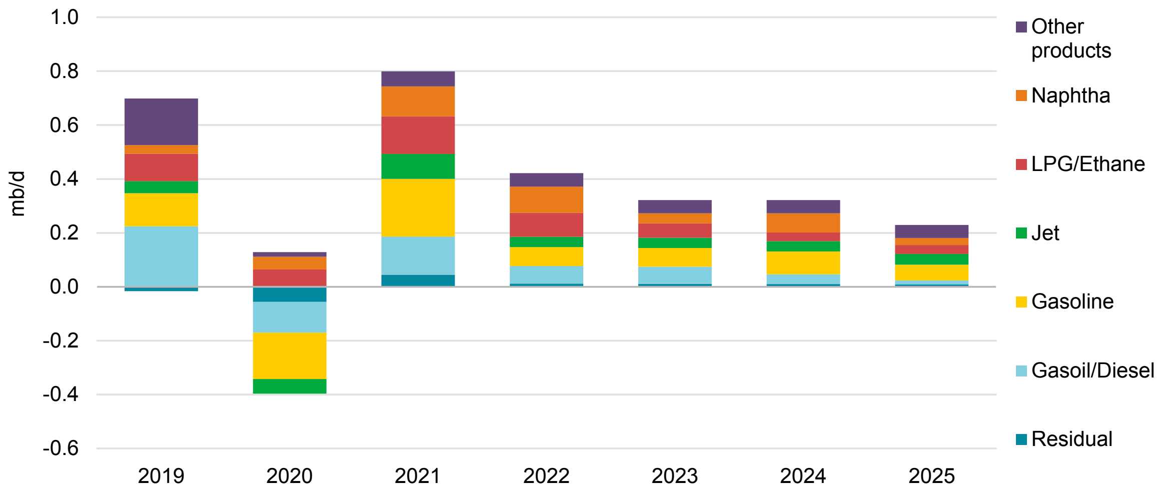
Non-OECD oil consumption will grow by 940 kb/d over the forecast period, down from 1.3 mb/d over the previous 10 years. The slowdown is largely attributable to China, where growth will halve by 2025 compared with the 2010-19 average. Demand from the Middle East will grow by just 50 kb/d per year during 2019-25, down from 120 kb/d, as a result of slowing economic growth and rising competition from natural gas in the power sector. Finally, oil demand growth will remain robust in Africa and Latin America.

China

Oil demand will grow by 300 kb/d on average over the forecast period, down from 570 kb/d over the previous 10 years. We expect growth to fall sharply in 2020, by 270 kb/d, due to the COVID-19 epidemic. This is the largest fall since our data begins in 1971. It will bounce back in 2021 as the economy recovers, before slowing progressively to just 230 kb/d in 2025.

The number of cars on the road will increase, but gasoline demand growth will slow markedly, to only 60 kb/d in 2025, as a result of improving fuel efficiencies, stringent car ownership limits in large cities and higher electric vehicle sales. Combined gasoil and diesel consumption will rise by 30 kb/d per year. This is a slower rate of growth than in 2010-19 (+80 kb/d), and is largely related to the development of alternative fuels for trucks and buses. Gasoil demand has been impacted in recent years by the gradual transformation of China from a manufacturing economy into a service economy and by local regulations to limit air pollution.

Figure 1.6 Chinese oil demand growth by product (y-o-y)



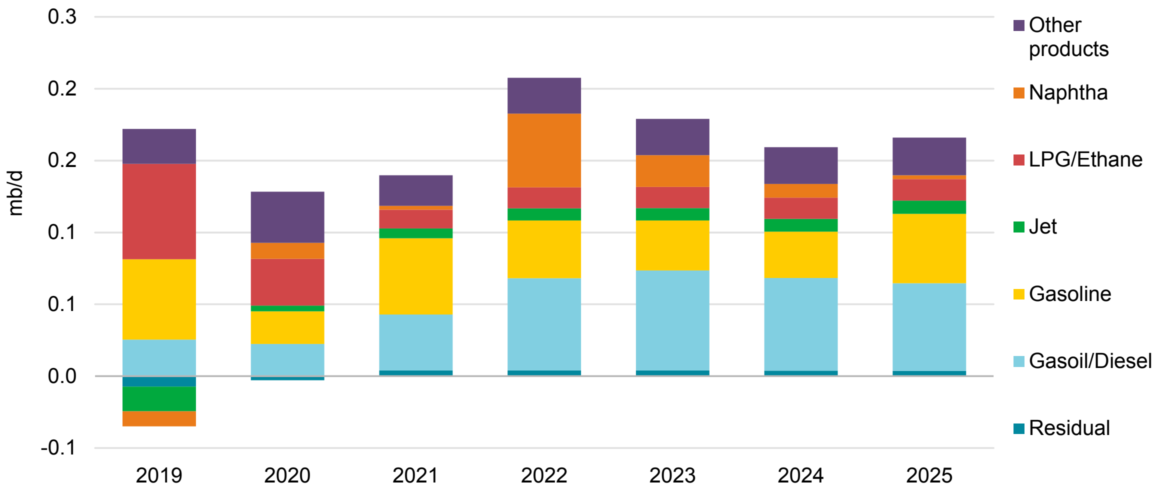
Chinese oil demand growth, after falling sharply in 2020, recovers in 2021-25.

India

Oil demand will rise at an annual average rate of 160 kb/d to 2025, slightly below its ten-year average of 180 kb/d, supported by strong growth in transport fuels and higher economic activity. Gasoil and diesel deliveries will grow in line with the ten-year average, by 50 kb/d, thanks to increased car ownership as well as expansions in construction and manufacturing. Gasoil demand growth will accelerate from 2021, supported by significantly stronger economic growth. Gasoline demand will increase by 40 kb/d, confirming its dynamism, with solid growth in demand for both two-wheelers and passenger cars.

Indian economic activity decelerated sharply in 2019 with GDP growth of only 4.8%, the slowest pace since the financial crisis in 2008-09. The economy was affected by tight credit conditions and an exceptional monsoon, which hampered the transport, agriculture and construction sectors. Therefore demand growth was only 140 kb/d versus 200 kb/d in 2018.

Figure 1.7 Indian oil demand growth by product



Indian oil demand grows solidly between 2019 and 2025.

Other non-OECD

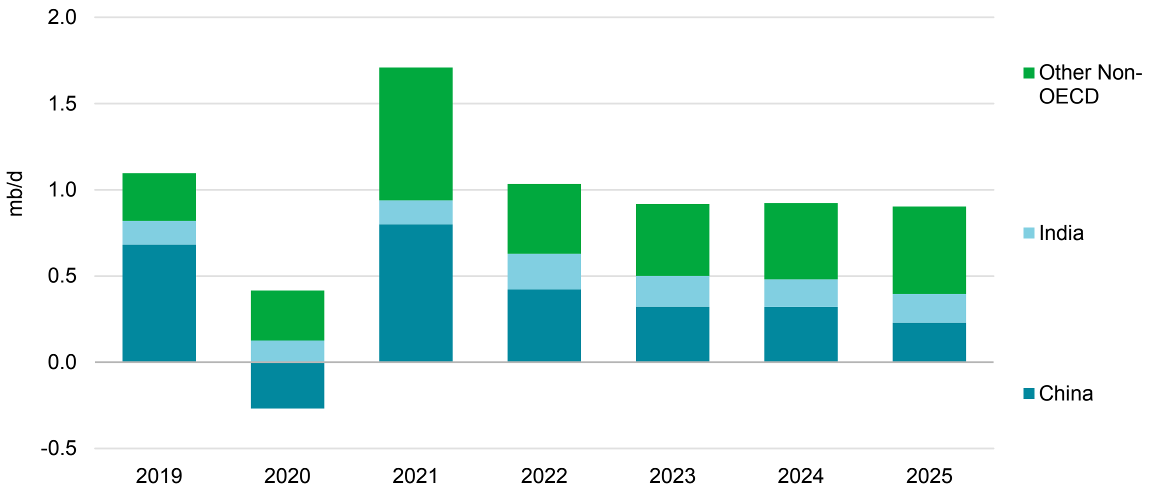
Saudi Arabia's fuel oil demand will likely be boosted by the implementation of the IMO marine fuel regulations in 2020, assuming a decline in HSFO prices. Projects are underway to increase fuel oil generating capacity by 8.5 gigawatt (GW). These include the 2.5 GW Jazan project, associated with the new 400 kb/d refinery, using HSFO as a feedstock to produce synthetic gas for electricity generation. We expect a further 5.6 GW of large steam turbines using HSFO as a feedstock to be commissioned. In addition, Saudi Arabia has 18.3 GW of oil-fired capacity currently using an estimated 400 kb/d of crude oil. Some of these plants could switch to fuel oil. Overall, Saudi Arabia's power sector is projected to increase its use of fuel oil by 70 kb/d in 2021 and to reduce it thereafter. By contrast, direct crude use will decline, displaced by natural gas and fuel oil.

Iraq is another Middle Eastern country set to use more natural gas in the power sector at the expense of crude oil. It has developed its domestic resources and is also importing gas from Iran for electricity generation. Some increase in fuel oil demand from 2021 is also expected, if HSFO prices fall following the implementation of the IMO regulations. Overall, we expect the country's oil demand to increase moderately over the forecast period.

Iran's demand should remain largely unchanged, as higher fuel oil use in the power sector offsets falling deliveries in other sectors due to the tough economic situation. Since 2014, Iran has seen a very large decline in gasoil and fuel oil use in the power sector and higher use of natural gas. According to some reports, this decline may have been reversed recently due to lower oil and gas output as the result of US sanctions. We assume in our forecast that Iran will use additional fuel oil to replace this gas and take advantage of lower fuel prices. Some 32.4 GW of capacity, mainly using natural gas, can switch to fuel oil.

Pakistan's oil demand is forecast to fall slightly over 2019-25, as growing competition from coal and gas in the power sector offsets growth in transport fuels. Demand dropped sharply in 2018 as more coal and gas were used at the expense of fuel oil. In 2015, Pakistan built a liquefied natural gas (LNG) floating storage and regasification unit (FSRU), initially receiving 1 million tonnes (Mt), rising to 3.4 Mt in 2016, and 6 Mt in 2017. A second FSRU started operations in 2018 and a third in 2019. By 2022, seven FSRUs will allow the import of 30 Mt/y of LNG. At the same time, Pakistan is developing 8 GW of coal-fired power generation capacity.

Figure 1.8 **Non-OECD oil demand growth**



China and India remain significant contributors to non-OECD oil demand growth to 2025.

Brazilian oil demand should grow by 20 kb/d on average over the forecast period. After two years of steady decline, demand returned to growth in 2017 as the economy emerged from recession. It then stagnated in 2018 and grew by 70 kb/d in 2019. **Argentina**'s oil demand collapsed in 2018 as GDP fell by 2.5% and declined again in 2019. A return to economic growth should see demand rise by 10 kb/d per year to 2025.

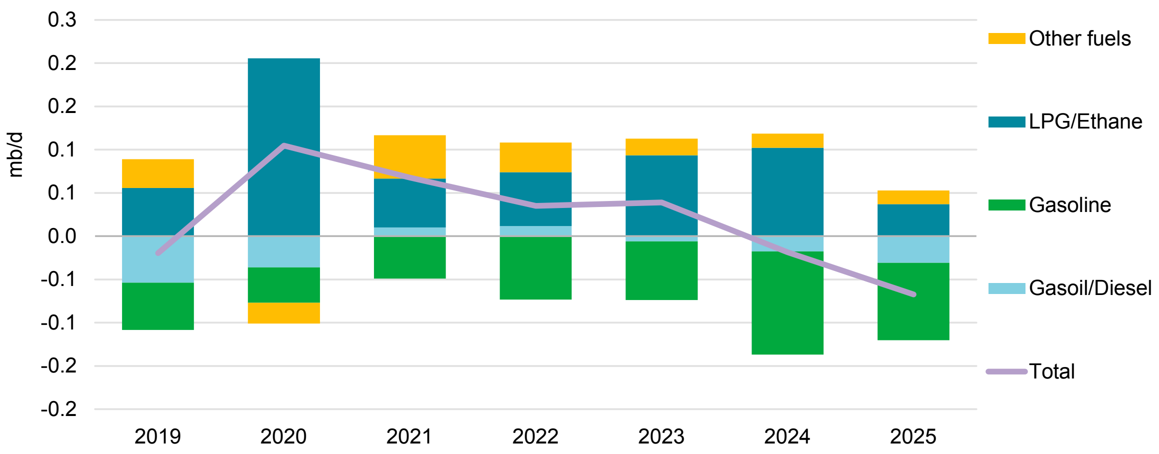
Russian fuel oil demand will temporarily increase in 2021-22 as excess HSFO is expected to be used in the power and district heating sectors. Russia has the world's largest district heating network, mostly fuelled by coal and natural gas. Alternatively, HSFO could replace some coal or gas used as fuel in cement factories or other heavy industries. Some HSFO could also be used as a fuel for domestic river transport. Russian demand will also be supported by petrochemical projects, with LPG and ethane growing at an average of 10 kb/d per year in 2019-25.

OECD

OECD demand is expected to grow by only 10 kb/d per year to reach 47.7 mb/d by 2025. Growth in petrochemical feedstock demand, with LPG/ethane and naphtha up by a combined 170 kb/d, will offset falling transport fuel demand. The last few years saw significant differences between OECD regions, with petrochemical-led growth in the Americas contrasting declines in Europe and relative stability in Asia (where growing petrochemical feedstock demand also offsets transport fuel demand). This will change, as tighter vehicle fuel efficiency standards and electric vehicles curb transport fuel demand everywhere and as the expansion of the US petrochemical industry slows. Demand will grow by 30 kb/d per year in the Americas, by 10 kb/d in Asia Oceania, and decline by 30 kb/d in Europe.

US oil demand is expected to increase on average by only 30 kb/d to 2025, down from 170 kb/d during 2010-19. LPG/ethane and naphtha consumption will grow strongly in 2020 (+210 kb/d) as a result of the delayed opening of several crackers and with other projects being commissioned. However, growth will come down thereafter, to around 70 kb/d. Diesel and gasoline deliveries will decline by 10 kb/d and 70 kb/d per year, respectively.

Figure 1.9 US oil demand growth by product



Growth in US LPG and ethane deliveries offset decline in transport fuels.

Canada and **Mexico** will post minor changes, and demand will largely stagnate.

OECD European demand will decline by 30 kb/d per year on average between 2019 and 25. Gasoline demand will fall 20 kb/d per year and diesel demand will decline even faster, by 50 kb/d. This is largely a consequence of Europe's disaffection for diesel, which has benefitted gasoline-fuelled car sales and electric vehicles. Concerns about air pollution and city restrictions have considerably reduced the share of diesel vehicles in new sales from a peak of 55% in the European Union in 2011-12 to only 31% in 2019. In addition, early 2020 data point to a sharp increase in EV sales in some countries driven by 2020 European Union (EU) CO_2 standards.

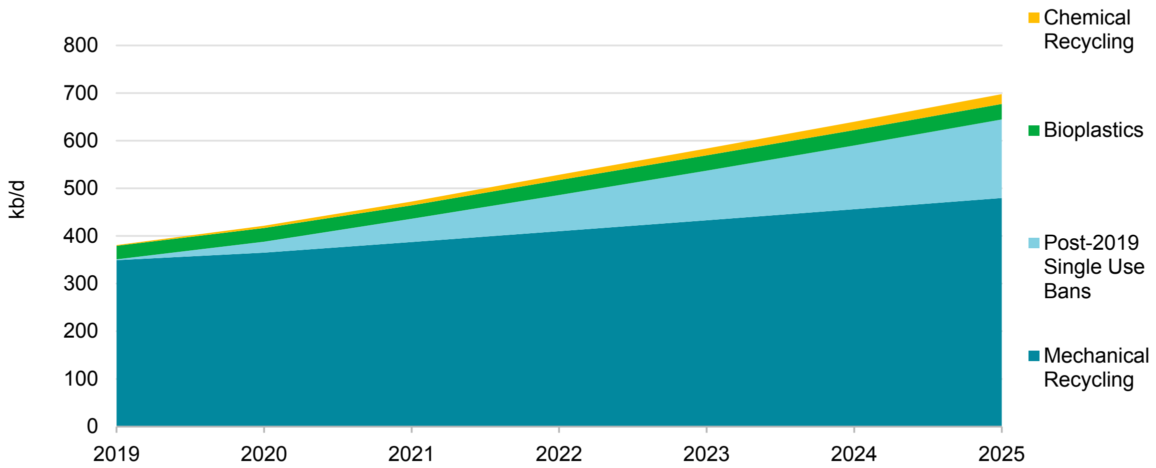
Korean oil demand should remain supported by petrochemical feedstocks over the forecast period, and grow by 40 kb/d on average. While the country recently experienced economic difficulties and was affected by the coronavirus in early 2020, lower trade tensions and accommodative fiscal policy should help in 2020 and provide a solid base for growth to 2025.

Japanese oil demand will continue to fall at a moderate rate (-30 kb/d per year), on continued improvements in energy efficiency. Gasoline will experience most of the fall.

Plastics' impact on oil demand

Single use plastic bans, recycling targets and other innovative plastic technologies, if they are implemented fully, will only have a moderate impact on overall plastics consumption and thus feedstock oil demand over the forecast period. We estimate that they will help reduce oil demand by 700 kb/d by 2025, up from 380 kb/d in 2019; a net incremental impact of 315 kb/d in six years. In relative terms, this is equivalent to shedding about 5% of the increase in oil demand (+5.8 mb/d) that we forecast between 2019 and 2025. This assumes that major consuming countries meet their ambitious targets for recycling and that single use plastic bans drive a meaningful reduction in plastic use (-1.3% by 2025), based on the share of these items in overall plastic consumption. However, poor data on plastic demand worldwide and the behaviour of consumers regarding plastic packaging are major uncertainties.

Figure 1.10 Oil demand replaced by recycling, single use bans and bioplastics



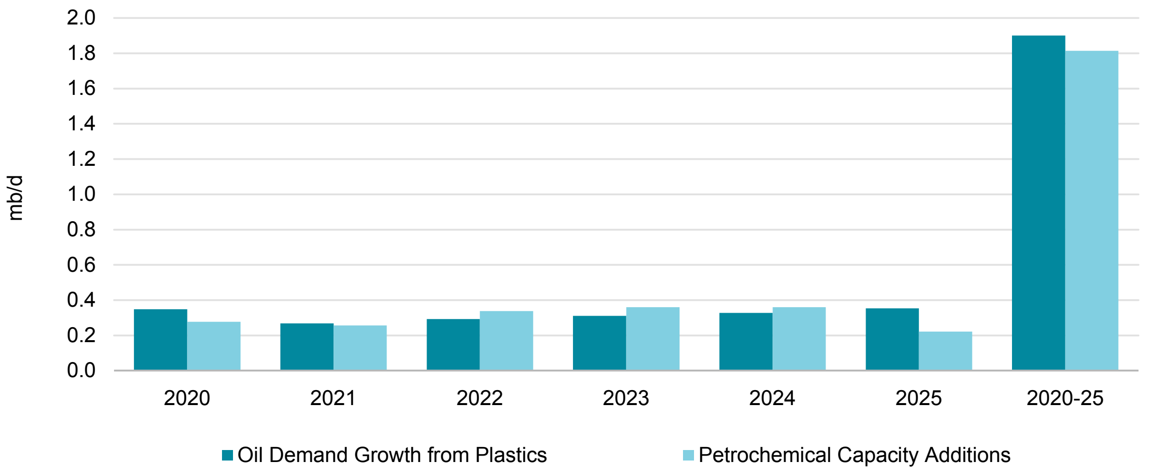
Single use plastic bans and recycling, if applied fully, would reduce 2025 oil demand by 700 kb/d.

Petrochemical capacity grows rapidly

New steam crackers and propane dehydrogenation (PDH) plants will add 1.8 mb/d to worldwide petrochemical supply by 2025. Capacity expansion will be almost equally split between LPG/ethane (+910 kb/d) and naphtha (+900 kb/d), in contrast to the last few years which saw more focus on LPG/ethane. Countries showing the strongest increases are the United States and China, with Russia also a major player. All the petrochemical investments are concentrated in 12 countries. Growth of 1.8 mb/d in petrochemical supply capacity is largely comparable to the increase in naphtha and LPG/ethane feedstocks demand from the plastic sector (+1.8 mb/d), indicating the support for the investments made by petrochemical companies. Our global oil demand figures for LPG/ethane and naphtha are largely driven by these capacity additions, though not entirely. We have also assumed growth for LPG/ethane and naphtha coming from existing petrochemical plants (via higher utilisation), non-identified projects, and through non-petrochemical uses, such as heating, cooking or crop drying.

Petrochemical projects currently under construction or confirmed to be built are included in our analysis. It should be noted that there is still time for additional projects to be sanctioned to boost capacity in the years 2024-25. Such investment decisions would probably require further confidence in increased consumption.

Figure 1.11 Oil demand growth from the plastics sector, petrochemical capacity additions



Growth in plastic demand matches petrochemical capacity investments to 2025.

Continuous growth of shale oil and gas production has seen the **United States** rapidly add new ethane steam cracker capacity to take advantage of low feedstock prices. By 2025, ethylene production capacity will further increase by nearly 9.5 Mt/y, from 36 Mt/y in 2019. Several large scale ethylene plants are expected to be part of integrated petrochemical complexes, including polyethylene units. This wave of new projects will help the United States to not only meet growing domestic demand but supply export markets too. Overall, these projects will boost US LPG/ethane demand by 380 kb/d by 2025.

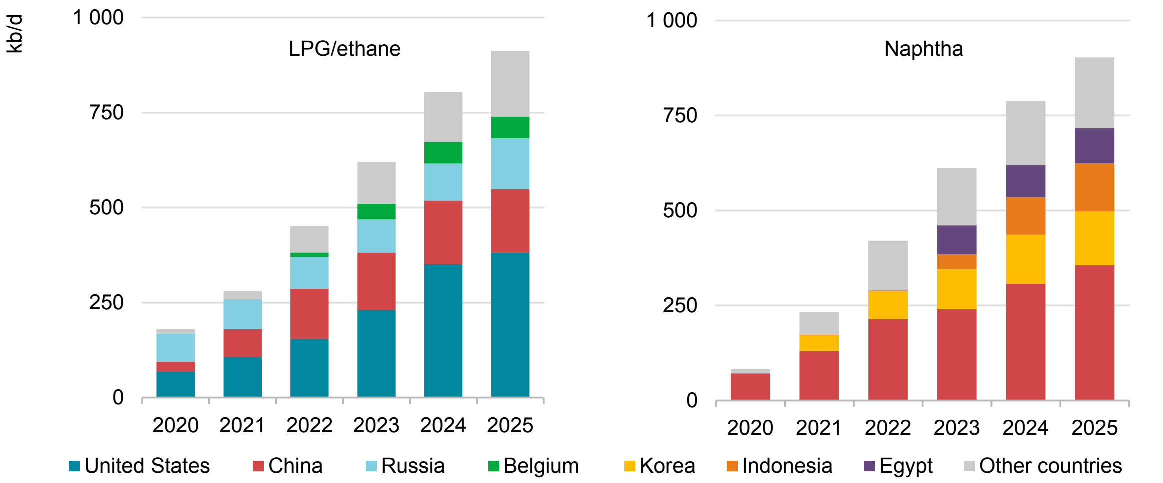
As the **Chinese** economy becomes increasingly consumer-focused and to supply plastic needed in manufacturing, 9.2 Mt/y of petrochemical capacity is due to come onstream by 2025, in addition to the 20 Mt/y existing in 2019. Unlike in the United States, Chinese capacity additions are mainly naphtha crackers. However, China is also planning to use LPG and ethane which could be imported from the United States, provided the United States/China trade dispute is resolved on a long-term basis. Zhejiang Satellite Petrochemical Co. Ltd., the country's largest acrylic acid and acrylates manufacturer, plans to commission two ethane crackers each with 1.25 Mt/y of capacity in 2021 and 2022. In total, Chinese LPG/ethane and naphtha demand grow by 170 kb/d and 355 kb/d, respectively by the end of the forecast period.

In other Asian countries, naphtha crackers dominate the capacity increase and push up feedstock demand. **Korea** could add 2.6 Mt/y of production capacity, resulting in extra demand for naphtha of 140 kb/d. In **Indonesia**, two naphtha plants (each with 1 Mt/y of capacity), will come onstream and increase naphtha demand by 130 kb/d. Among others, by 2025 **Viet Nam** sees an increase of 7.5 kb/d of LPG/ethane demand while **Thailand** sees increases of LPG/ethane and naphtha demand by 15 kb and 30 kb/d, respectively.

The **Middle East** and **North Africa** regions are likely to witness large capacity additions in the second half of the forecast period, led by **Egypt** and the **United Arab Emirates** (hereafter "UAE"). In Egypt, a 1.5 Mt/y naphtha cracker will start operations in 2023 and boost demand by 95 kb/d by 2025. Another 1.5 Mt/y capacity ethane cracker in the UAE will be onstream by 2025, adding 40 kb/d. **Iran** could commission a 20 kb/d PDH project in 2022, unless US sanctions prevent its completion.

In **Russia**, over 3.7 Mt/y of new production capacity is under construction. This will boost LPG/ethane demand by 135 kb/d and naphtha demand by 15 kb/d by 2025.

Figure 1.12 Feedstock demand increase from identified projects (cumulative, kb/d)



Source: IEA calculations based on industry press and company reports.

China and the United States are the focus of most petrochemical plant investments.

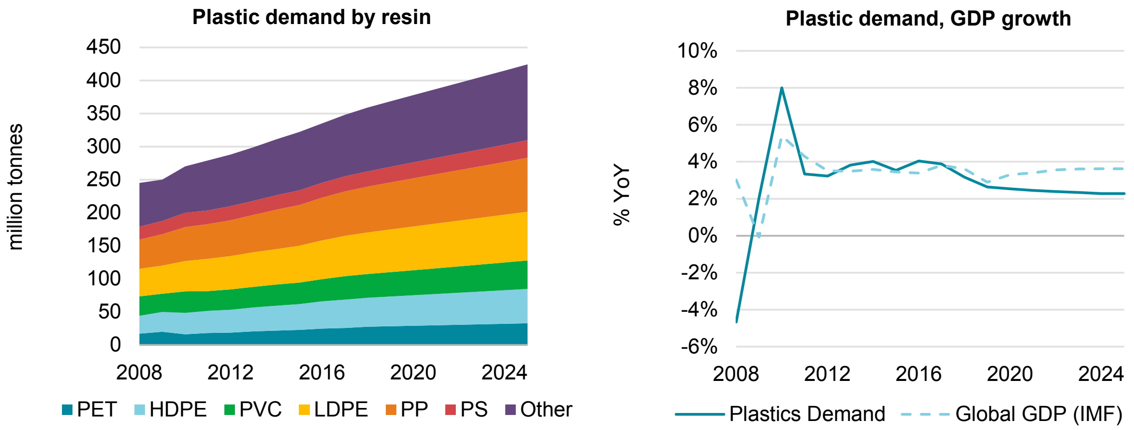
Plastic demand falls short of GDP growth

Global demand for plastics is forecast to grow by 2.6% per year on average during 2020-25, a slower rate than the 4% registered over the previous ten-year period. We also expect it to be lower than the annual average growth in GDP of 3.5%. This lag is due to the fact that developed economies are unlikely to see much growth, even if GDP and population numbers increase.

Plastic demand in those economies has reached saturation point and, if anything, could come under pressure from government regulations and plastic's increasingly bad reputation with consumers. As more countries reach advanced stages of development over the next few years, the elasticity of plastic demand falls thus capping total growth at the global level. By contrast, demand will grow robustly in China (+2.8% per year), India (+9.6%), Indonesia (+5.8%) and Viet Nam (+4.3%), as the consumption of goods increases. In those countries, it is assumed that plastic use continues to develop in line with historic patterns.

In our analysis, we use a Gompertz function where plastic consumption initially increases fast in relation to GDP and population, before slowing down materially. Each country has been classified according to its level of development (measured in terms of GDP per capita) along this curve. The underlying plastic demand data is from Japan's Ministry of Economy, Trade and Industry and Plastics Europe. We have also used GDP forecasts from the IMF and population figures from the United Nations (UN).

Figure 1.13 Historical and forecast plastic demand, GDP growth



Global plastic demand grows at steady 2.6% pace to 2025, though it is less than GDP growth.

Plastic backlash doesn't endanger demand growth

Plastic use has come under scrutiny in recent years due to mounting evidence about the pollution it creates both onland and at sea. A backlash has been widely relayed by the media and is starting to affect consumer behaviour in developed countries (mainly Europe, but also North America, Japan and Korea) and developing markets. Around 400 leading consumer goods companies have signed a pledge promoted by the *Ellen MacArthur Foundation* to reduce plastic content in their products and boost the use of recycled material. In 2019, 186 countries agreed a UN convention to reduce ocean plastic waste.

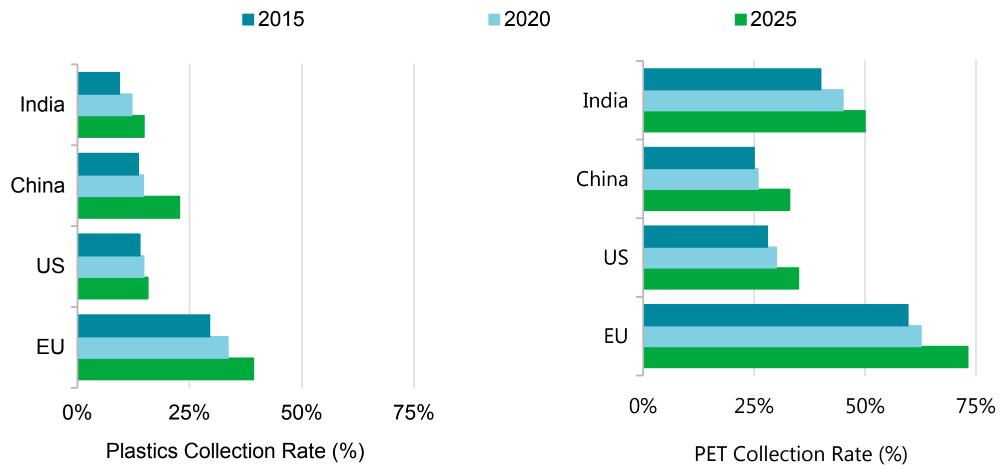
In addition, the UN estimates that 120 countries had introduced some form of ban on plastic bags in 2019 with a further 60 having implemented taxes on them. This flurry of initiatives is bound to reduce demand; however the question is: how much? Based on the information available, we take the view in this report that while single use bans and recycling will dent petrochemical fuel demand, this will not be enough to slow feedstock demand materially. We have not modelled specifically the impact of voluntary decisions by brands or consumers to reduce plastic use, however it is assumed to be part of the same trend.

Estimating the share of single use plastics (ie, in use for less than a year) in overall plastics demand is hard, given the lack of reliable data at the retail level in most countries. However, it is widely assumed to represent around 30-50% of the total plastics use, taking into account the known production of plastic resins such as low-density polyethylene (LDPE), polypropylene (PP) and polystyrene (PS). We estimate that only around 5% of single use volumes, representing about 1.3% of plastic demand, are threatened by government regulations in 2025. This is because the items targeted (plastic bags, straws, disposable cups, plates and cutlery, cotton buds, etc) weigh little and therefore do not represent a large volume of plastic. Regulations do not typically target food packaging or plastic used in the medical, construction, automotive, toy, consumer electronics and textile industries, which represent the bulk of volumes. In addition, bans are likely to be enforced progressively in most countries and in some cases, will result in higher demand for other types of plastic.

In total, bans cut 1 Mt (out of 379 Mt) from plastic demand in 2019 than would otherwise be the case, growing to 6 Mt (out of 435 Mt) by 2025. These volumes are based on the relatively simple assumption that 2% of volumes for certain plastic resins (PET, HDPE, LDPE, PP and PS) will be suppressed by 2025, growing in a linear progression from nearly zero in 2019. This percentage is based on various studies and the experience of the implementation of such policies by governments worldwide. In our model, we apply a multiplier to each plastic resin demand forecast, based on whether it is at risk or not from single use bans. Overall, this result in plastic demand destruction of 1.3% by 2025 compared with a no-ban scenario.

Plastic recycling will have a large impact over the forecast period, due to its already widespread use in many parts of the world and as a result of aggressive collection targets in some countries. We estimate that recycling will reduce demand for petrochemical fuels such as naphtha, ethane and LPG by 535 kb/d by 2025, versus 380 kb/d in 2019, resulting in a net incremental loss of oil demand of 155 kb/d by 2025. These volumes are based on announced government targets for plastic recycling and expectations about the rise of chemical recycling and bioplastics. This assumes broadly that government targets are met, as plastics have risen high on the public agenda and there is significant political momentum to increase recycling. However, achieving these targets will be difficult given the inertia built into the system and in many countries, the need for new investments. China's decision to ban imports of all but the highest purity plastics in 2018 has forced many countries to reconsider their approach to recycling and invest in recycling capacity at home. If we include the impact of single use bans announced in the last two years, the volume of oil displaced grows to 700 kb/d by 2025, or a net loss of oil demand of 315 kb/d compared with 2019.

Figure 1.14 Plastic, PET collection rate for mechanical recycling



Note: These figures do not include plastic collected and burned for electricity generation, and recycling yield losses.

PET collection for recycling will be the highest among plastic resins.

European countries are likely to boost collection rates by around 5-6 percentage points overall between 2019 and 2025, resulting in 7.5 Mt of additional volumes collected for recycling over the period. Collection rates for polyethylene terephthalate (PET), used in beverage bottles, will be the highest, at 73%, slightly less than the European Union's 75% objective. China will also see large increases in plastic collection over the period (+8.7 Mt), in line with targets to recycle around 35% of municipal waste in 46 major cities by 2020 and newly announced bans on single use plastic, as well as the decision to stop the bulk of plastic imports in 2018, which has left some domestic recycling capacity idle. India (+2.1 Mt) and Korea (+1 Mt) are also set to boost recycling in line with announced policy. By contrast, plastic collection in North America, Latin America, Africa and the rest of Asia is unlikely to progress much, due to a lack of government targets.

By 2025, we estimate that mechanical recycling will reach 80 Mt globally, from 58 Mt in 2019. This amounts to a collection rate of 18%, up from 16% in 2019. This volume does not cover plastic burned to generate electricity, which can be high in certain regions, as it does not displace virgin plastics and thus oil demand. In addition, we assume that only about one fourth of the total plastic collected, or 20 Mt, will effectively displace virgin material due to the typical yield loss at sorting and recycling facilities, as well as the widespread practice of 'down-cycling' (i.e., using recycled plastic as replacement for other materials). The majority of recycled plastics goes into creating new products or displaces other materials (e.g. low-quality waste plastics used to pave roads), and does not necessarily replace virgin plastic.

We have also taken into account the likely growth of the chemical recycling and bioplastic industries, which together will replace around 2.1 Mt of virgin plastic by 2025, up from 1 Mt in 2019. Plastic-to-plastic conversion facilities are still at the pilot stage at the time of writing; however several industrial plants are likely to be built over the next few years following announcements by companies such as Carbios (France), Fuenix Ecocy Group (the Netherlands) and Loop (Canada). Bio-based plastics, meanwhile, represent a small share of the plastic market, but are growing at a steady clip. Pyrolysis, the conversion of plastic waste to oil, was not taken into account in this analysis as it mostly produces gasoil (and does not replace virgin plastic). We have also excluded biodegradable plastics, as these come from fossil sources.

Transport in transition

Fuel standards, EVs and diesel bans are changing both the volume and the structure of transport fuel demand. Efficiency gains due to vehicle technology improvements and electrification underpin the slowdown in oil demand growth from an annual average rate of 1.5 mb/d in 2010-19 to 980 kb/d in 2020-25. We have modelled the likely efficiency improvements for both diesel and gasoline vehicles in each country based on historical fuel savings data, assumptions about car sales, and have taken into account fuel regulations adopted around the world (including, in the case of the United States, the recent rollback of CAFE standards). Efficiency gains in the vehicle fleet save an estimated 2.5 mb/d of gasoline and 1.3 mb/d of diesel by 2025, compared with a world where efficiency does not improve. Even if these figures are largely theoretical, this helps underscore their dampening effect on oil demand. The same regulations often drive electric vehicle development and are modelled as part of the same trend.

In addition, many cities have undertaken strong measures to reduce air pollution, in particular CO_2, sulphur dioxide and nitrogen oxide generated by international combustion engines, targeting in particular diesel engines. They have pushed for a higher share of electric cars, less polluting fossil-fuelled vehicles, the development of electric taxis and buses, as well as increasingly severe restrictions on private car use. These actions influence consumer behaviour and thus oil consumption patterns, and accelerate the impact of decisions taken at the global level.

Tight standards cap fuel use

Fuel standards have tightened in a number of prominent oil consuming countries, including Europe, Korea, China and India. We have assumed that these regulations are respected and that fuel savings accelerate over the next few years. As the vehicle fleet has a turnover of 12 to 16 years on average (depending on the car model and consumer preferences), efficiency improvements realised since 2005 continue to have an impact over the forecast period.

Table 1.5 Annual car efficiency gains in selected countries, 2019-25

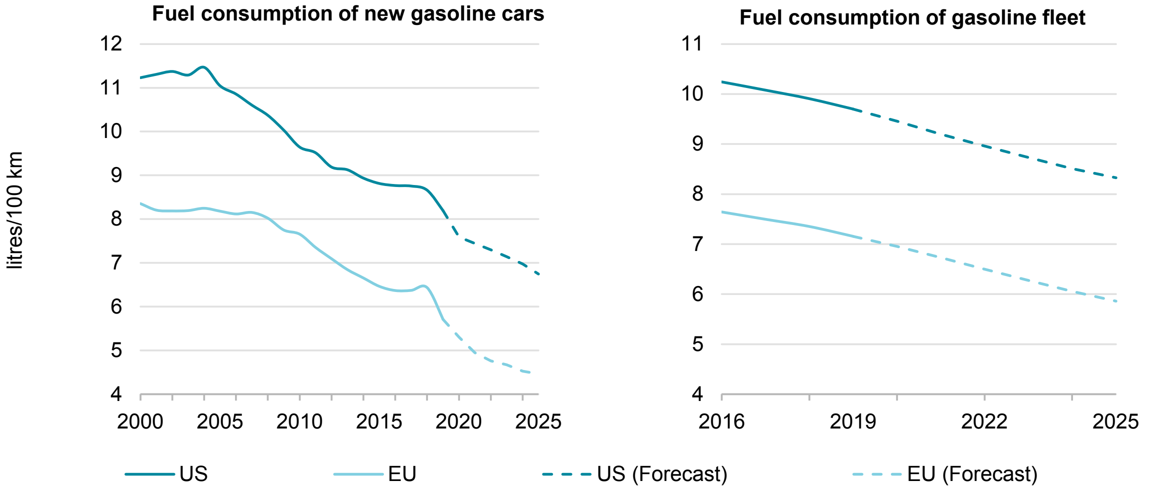
Country/Region	Gasoline	Diesel
United States	1.3%	0.7%
Canada	1.1%	0.5%
Mexico	1.7%	0.3%
Japan	1.9%	0.7%
Korea	1.7%	1.4%
Australia	1.6%	1.8%
EU17	1.8%	1.2%
EU7	1.8%	1.7%
Russia	1.0%	1.4%
China	1.7%	1.4%
India	1.8%	1.3%
Indonesia	1.0%	0.7%
Brazil	1.2%	1.5%

In our forecast, fuel efficiency progresses through 2025 as older vehicles come out of the fleet and are replaced by new ones. The largest and most visible impacts will be in the OECD, as several of its members (particularly Europe, Japan and Korea) have adopted tight standards. But vehicle efficiency will improve materially in non-OECD countries too, even if it is not enough to arrest oil demand gains given the big potential for fleet expansion. It should also be noted that gains are more marked for gasoline than for diesel, as there is comparatively less potential for technological improvements in diesel engines.

In the **United States**, fuel economy standards will bring about a contraction in gasoline demand in the medium-term. The CAFE standards introduced in 2012 mandated a strong improvement in fuel economy for passenger cars and light trucks. For cars, this corresponds to 2025 fuel consumption of 4.2 litres/100km, or 56.7 miles per gallon (mpg), and for light trucks 6 litres/100km. In 2018, the standards were frozen indefinitely by the US Administration. However, many states and cities (e.g. California and Northeastern states) representing around one third of the car fleet have decided to adhere to stricter rules and this will help improve the overall efficiency of the fleet. In the United States, the historical annual improvement in gasoline fuel efficiency was over 1% during 2015-19. We forecast this to reach 1.3% from 2019 to 2025.

Past efficiency gains continue to have an impact into the future. New car consumption is expected to decrease from 8.2 litres/100 km in 2019 to 6.7 litres/100 km in 2025. Even if we maintain new car consumption at 8.2 litres/100 km through the end of the forecast, total gasoline fleet efficiency gains would still be declining, but at a slightly lower rate. In addition, **Canada** has adopted similar regulations and will see continued improvements in efficiency of 1.1% per year for gasoline and 0.5% per year for diesel.

Figure 1.15 Fuel efficiency of gasoline cars in the United States and European Union



The average car gasoline consumption is expected to continue its long-term decline.

The **European Union** has implemented progressively tighter fuel economy standards since the 1990s. The 2020 targets, among the strictest in the world, set an almost 30% improvement on the 2015 levels. They aim to curb CO2 emissions below 95 g/km and improve average fuel consumption for new cars to 4.1 litres/100 km on average. In addition, in April 2019, the European Union adopted post-2020 CO2 standards stating that from 2025 new cars and new vans must emit 15% less CO2 on average compared with 2021. From 2030, cars and vans will be required to reduce CO2 emissions compared with 2021 by 37.5% and 31% respectively. In the case of non-compliance, car manufacturers are subject to substantial financial penalties. Low carbon vehicles (battery electric, plug-in hybrids, etc.) are expected to contribute to achieving these targets, but at the time of writing, EV sales are not sufficient and the probability that some automakers will exceed the targets is quite high. Car manufacturers offer a variety of hybrid electric vehicles (HEVs) and plug-in hybrid electric vehicles (PHEVs), which emit less CO2. These are expected to gain market share over the forecast period and help to boost efficiency.

In the European Union, the historical annual improvement in fuel efficiency for gasoline cars from 2015 to 2019 was less than 2% and we foresee this to reach 1.8% from 2019 to 2025. We estimate that the average petrol car fleet will improve its fuel efficiency by roughly 11% from 2020 to 2025, driven both by past ameliorations and the tighter standards.

Japan has a very efficient passenger car fleet partly due to the high penetration of hybrid vehicles. Its 2020 target of 122 g/km for passenger cars was reached in 2013. It has adopted an objective of 74 g/km for 2030, corresponding to a consumption of 3 litres/100km. Japan is also a leader for light, efficient commercial vehicles, with a target of 133 g/km of CO2 emissions by 2022. In **Korea**, fuel efficiency targets are also very strong, imposing gains of 5.5% per year from 2013 to 2020.

The standard for CO_2 emissions from new cars is 97 g/km, corresponding to a fuel economy of 4.2 litres/100 km of gasoline. We assume a continued improvement in total gasoline vehicle efficiency of 1.9% per year in Japan and 1.7% in Korea.

China has some of the strictest fuel economy standards in the world. The target for new car average fuel consumption fell from 8.2 litres/100km in 2010 to 5 litres/100 km in 2020 and will decrease to 4 litres/100km by 2025. We assume an improvement in gasoline fleet efficiency of 1.7% per year in 2019-25 and 1.4% per year for diesel.

The **Indian** government has required an improvement of 1.6% per year in fuel economy for new cars between 2012 and 2022. The passenger car CO_2 emissions target is 130 g/km until 2022 and will tighten to 113 g/km from 2022, which is equivalent to gasoline consumption of 4.9 l/100 km. In addition, in 2017, India introduced regulations to reduce the fuel consumption of heavy duty vehicles weighing more than 12 tonnes. This impacts roughly 60% of total fuel use from the haulage fleet. Between 2018 and 2021, new trucks must reduce their consumption by between 5% to 13%, tractors, trucks and trailers by between 7% to 10% and buses by 15%. For India, we see an improvement in total gasoline vehicle efficiency of 1.8% per year in 2019-25 and 1.3% per year for diesel.

Electric vehicle sales increasing in key regions

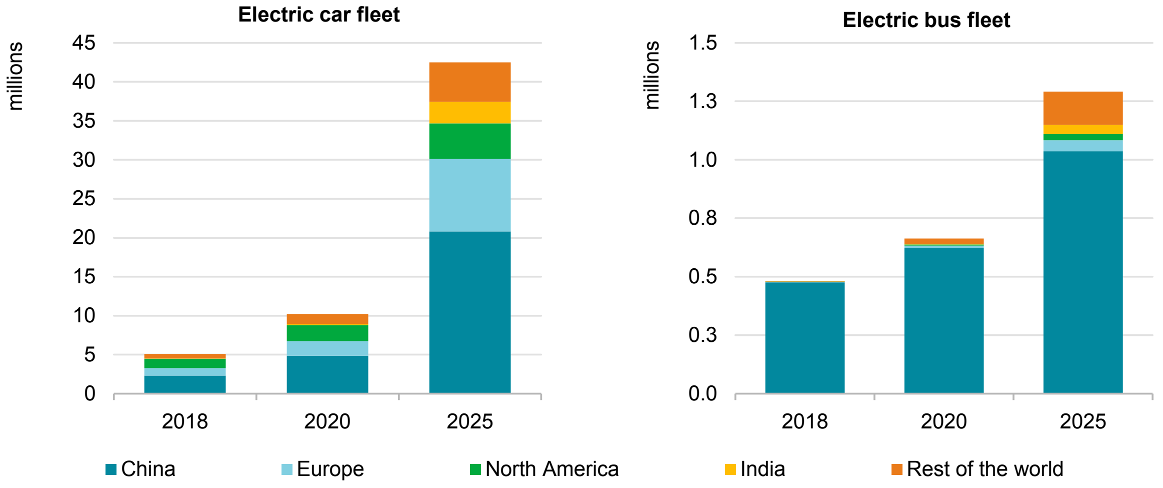
Electric vehicles will have a significant impact on demand to 2025. In our forecast, we assume that the electric vehicle fleet increases from 5 million units in 2018, the last year when historical data is available, to nearly 43 million units by 2025. These figures are based on announced policies and assume that, broadly speaking, countries hit their CO_2 reduction targets for the car sector. China accounts for the bulk of the increase, but there are substantial fleet increases in Europe, North America and India too.

There were an estimated 5.4 million electric light duty vehicles (LDVs) in circulation in 2018, of which the vast majority (5.1 million) were passenger cars and only 250 000 were light commercial vehicles (LCVs). Battery electric vehicles (BEVs) account for 65% of the world's EVs. The number of electric buses is also expected to increase significantly. Some electric buses will be deployed in India, Chile, Europe, the United States and the rest of the world but, until 2025, the development will remain mainly a Chinese story.

The **United States** had electric LDVs sales of 358 000 units in 2018. This was exceptional growth compared to 200 000 cars in 2017, and is attributable to the launch of the Tesla Model-3. In 2019, sales are estimated to have declined to 337 000, as consumers waited for new models to be introduced in 2020. In particular, new affordable electric SUV-crossovers should support sales.

China is the world's largest EV market, with 1.16 million cars and LCVs sold in 2018. After growing by 74% in 2017 and 80% in 2018, car sales remained roughly stagnant in 2019, according to preliminary estimates. The fleet of electric LDVs nevertheless reached 3.6 million, an increase of 44%. Chinese electric car sales declined sharply in July 2019, as subsidies were reduced by the government, and did not recover thereafter. The target of the Ministry of Industry was to reach the production of 2 million electric vehicles in 2020 but the COVID-19 crisis is likely to reduce this objective.

Figure 1.16 Historical and forecast electric vehicle fleet by country/region



Electric car fleet surpasses 40 million units by 2025, while bus fleet tops 1.3 million.

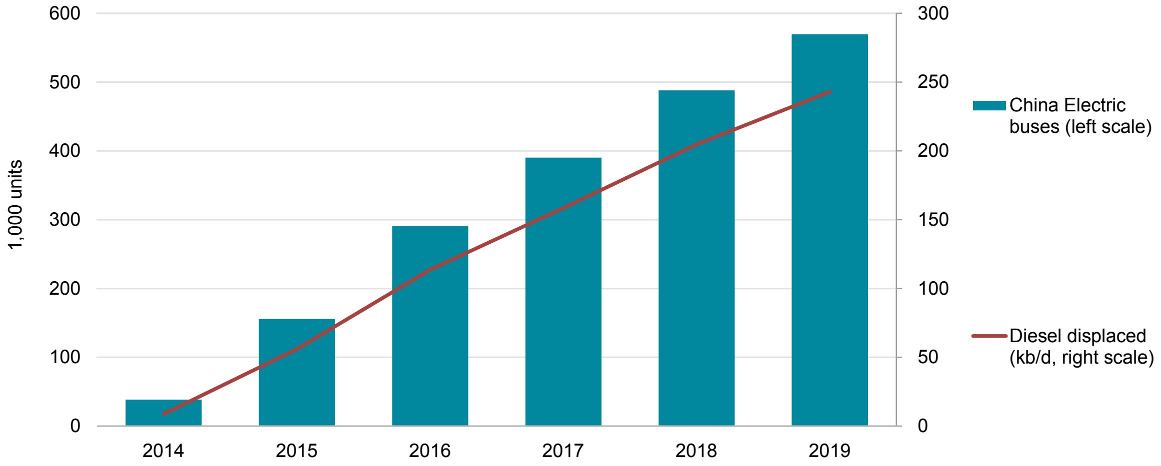
Seven big cities (Beijing, Shanghai, Guangzhou, Shenzhen, Hangzhou, Tianjin, and Guiyang) have set quotas for internal combustion engine vehicles. License plates are very difficult to obtain. In Beijing since 2011 plates for gasoline cars are awarded by lottery. The local government wanted to keep the total number of vehicles under 6 million by the end of 2017 and authorities allocated only 150 000 plates each year in 2014-17. In 2018, the annual allocation was reduced to 100 000, 60% of which was reserved for electric vehicles. In Shanghai, the cost of a plate at auction was close to USD 14 000 in 2018, equivalent to the price of a small car. Since 2012, Guangzhou uses both auctions and lotteries to limit the availability of plates.

Many Chinese cities have traffic restrictions based on plate numbers. Even so, congestion and the lack of parking space remain major problems. There are, however, no restrictions on electric vehicles, with the exception of Beijing which has small limitations in place. This explains why these cities have accounted for more than half of EV sales in China between 2015 and 2017. To support a struggling car industry amid a slowdown in sales, some cities (Guangzhou, Shenzhen and Guiyang) have recently temporarily increased the number of available plates.

A key priority for city authorities is often to electrify vehicles with high mileage such as taxis and buses. Shenzhen had electrified its total fleet of 22 000 taxis by the end of 2018. Beijing had 4 000 electric taxis in the middle of 2019 and planned to have 16 000 more by end-2020. Guangzhou had 3 000 electric taxis in 2019 and plans to electrify the whole fleet by 2023.

In addition, the city of Shenzhen had electrified 100% of its 16 500-strong bus fleet by 2018 and estimates that about 7 kb/d of diesel consumption has been replaced. Guangzhou has more than 11 000 electric buses in operation. Ten other large Chinese cities, Nanchang, Chongqing, Wuhan, Changsha, Zhengzhou, Qingdao, Tianjin, Hangzhou, Shanghai and Beijing should also have entirely electrified their bus fleet by 2025.

Figure 1.17 Evolution of Chinese electric bus fleet



Chinese electric bus fleet reached 500 000 units in 2019.

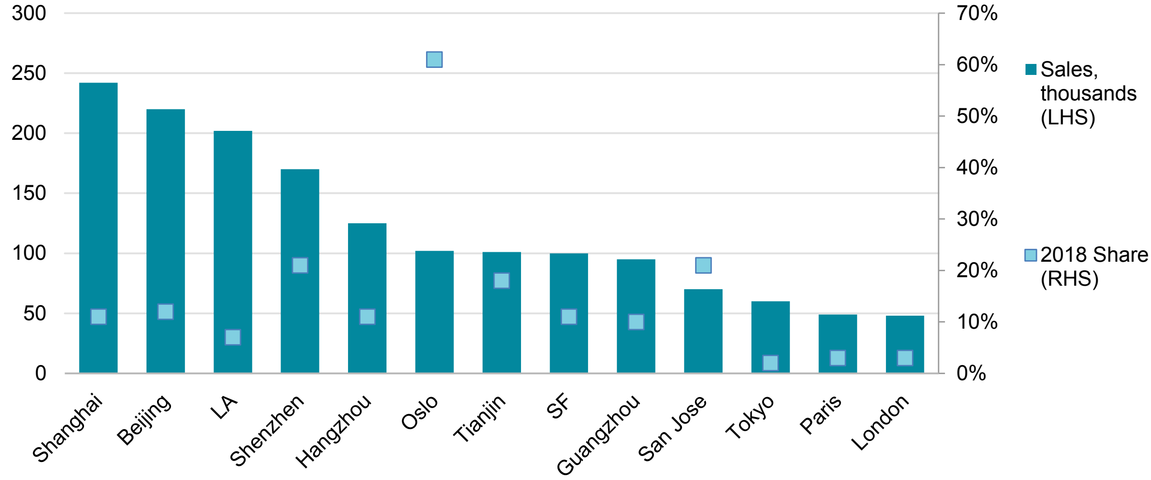
Europe is the second-largest electric car market with sales of 407 000 units (LDVs) in 2018. Sales rose strongly in the first three quarters of 2019, pointing to annual sales of 580 000 units. Car manufacturers may however have delayed sales beyond the end of 2019 to count them against 2020 CO_2 emission standards.

Many European cities have recently introduced low-emission areas, including Amsterdam, Athens, Barcelona, Brussels, Copenhagen, Hamburg, Liverpool, London, Madrid, Milan, Oslo, Paris and Rome. They belong to the *40 Cities Climate Leadership Group* (C40), a global coalition to tackle air pollution. At the group's 2015 conference, the mayors of Athens, Madrid, Mexico City and Paris announced their intention to ban diesel vehicles from their streets by 2025. In all, 34 cities representing 165 million inhabitants pledged to make a large part of their city centre's emissions-free by 2030 and to buy only zero-emissions buses from 2025.

Other large cities in Europe, Asia and the United States have started to seriously consider and to invest in the electric bus option. About 2 220 electric buses are in use in Europe and another 1 600 were on order in 2018, a sharp increase compared with 1 030 in 2017. The Netherlands, France, the United Kingdom, Poland, Germany and Italy account for the majority of orders.

London had a fleet of 240 electric buses by the end of 2019, the largest in Europe, and it aims for a zero emission bus fleet by 2037. Paris bought 75 electric buses in 2019. Local operator RATP currently has 950 hybrid powered buses, 140 biofuel buses and 83 electric buses. It will order 800 electric buses to replace existing diesel vehicles and fight pollution in the run-up to the 2024 Olympics. The city wants to have only clean buses by 2025 (4 700 vehicles) using both electricity and biofuels. In the Netherlands, Rotterdam ordered its first 55 electric buses in 2019. Amsterdam uses 100 electric buses and plans to have its whole fleet electrified by 2025. The Dutch provinces of Groningen and Drente have deployed 160 electric buses in 2019. The provinces of Overijssel, Flevoland and Gelderland have ordered 300 electric buses to be deployed from December 2020 to 2023.

Figure 1.18 Cumulative electric car sales (2011-18) and 2018 share in total car sales



Source: ICCT

Several Chinese cities feature prominently in the list of places with most EV sales.

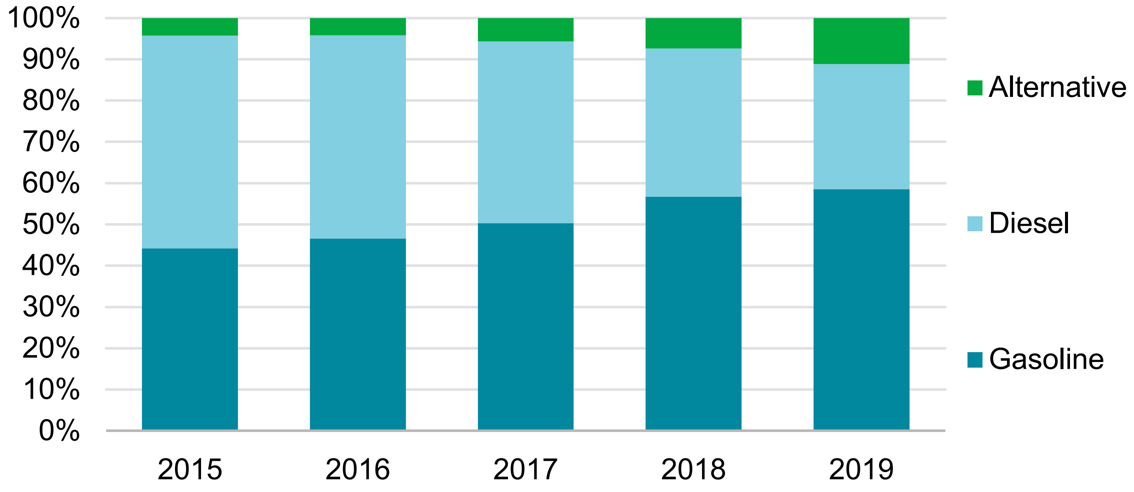
Diesel becomes the new pariah

Since the Volkswagen diesel engines emissions scandal erupted in 2015, the share of diesel vehicles in new car registrations in Europe has fallen from 52% in 2015 to 30% in 2019. Diesel's market share has been mainly captured by gasoline but also by alternative-fueled cars. While efforts to ban urban car use contributed to this decline, customers' perceptions and, in some cases, higher diesel tax, have been powerful factors.

In Paris, all cars made before 1997 are prohibited on weekdays and some streets will be reserved for electric cars starting 2020. In addition, the city intends to ban diesel from its streets by 2025. Together with the increase of taxes in 2015, the ban has contributed to push down the share of diesel in new car sales from more than 70% in 2012 to 34% today. Since 2017, cars must have an anti-pollution sticker (Euro classes 0 to 6) to circulate in certain large **French** cities. These stickers help the authorities to activate temporary restrictions during peaks in pollution. In 2019, for example, driving bans were imposed in Lyon, Marseille, Paris and Strasbourg except for the cleanest vehicles. In 2020, new permanent and temporary low emission zones will be created and it will become more difficult for diesel vehicles to obtain a "clean" sticker, thus restricting their access to city centres even further.

The share of diesel in new registrations has also fallen rapidly in **Germany**, the home of some of the world's largest car manufacturers, from almost 50% in 2012 to 32% in 2019. A blue badge identifies vehicles emitting low nitrogen oxide levels and is only awarded to Euro 6 diesel cars (manufactured after 2014). In August 2019, there were six diesel traffic restriction zones in four cities, and further zones will be established in 2020. In February 2018, a German court allowed cities to decide whether they wanted to ban diesel cars on their streets to improve air quality. In May 2018, Hamburg was the first city to do so for certain roads. And the ban impacted 215 000 vehicles, or two-thirds of diesel cars. Berlin banned diesel cars manufactured before 2015 from June 2019 onwards, with some 200 000 cars affected. Frankfurt was allowed by a federal court to ban all (but the most recent) diesel cars from February 2019, concerning 60 000 vehicles.

Figure 1.19 Car registrations in Europe, share by fuel



Source: ACEA.

In just five years, diesel car sales have been eclipsed by gasoline in Europe.

In **Spain**, the diesel share of new car registrations has fallen from 70% in 2012 to 28% today. Sales plunged after Madrid announced it would ban diesel cars by 2025 and, together with Barcelona, prohibit vehicles manufactured before 2006 and gasoline cars produced before 2000. In 2019, city authorities extended these bans to newer vehicles.

The share of diesel in new car sales has fallen in the **United Kingdom**, from 52% in 2012 to 25% currently. Several city initiatives contributed to discourage possible buyers. Liverpool has proposed a temporary ban on diesel starting in 2022. London introduced a toxicity charge for pre-Euro 4 cars in 2017 and launched an ultra-low emission zone in 2019. These standards will be widened to buses and coaches in 2020 and to a larger area in 2021. London also plans to ban vehicles from certain "pedestrian priority areas" and aims for a zero emissions area in central London by 2025.

In **Italy**, Milan limited in 2019 city access for cars and a low emissions zone on 70% of the city's territory. It affects 95% of residents. Euro 4 vehicles were banned from the streets during weekdays. The ban will be extended to all diesel vehicles by 2030. Rome also plans to ban diesel vehicles from the centre by 2024.

In the **Netherlands**, Rotterdam has already implemented a zero emissions zone for trucks and will create one for freight transport in 2025. Amsterdam plans to have its city centre accessible only to zero-emission vehicles by 2025.

In **Belgium,** Brussels has created a low emissions zone and plans to ban all diesel vehicles by 2030. **Mexico City** prevents drivers from using their cars once a week and, since 2008, on Saturdays. **Athens** bans diesel vehicles from entering the city on certain days, by restricting cars with license plates with odd or even numbers.

Box 1.1 Hybrid vehicles have room to increase their share in the fleet

Fuel efficiency targets will become stricter during the forecast period of this report. In turn, automakers offer various hybrid models and powertrains to meet consumer preference and to facilitate meeting regulations.

According to the *International Council on Clean Transportation*, new passenger cars sold in the European Union in 2018 emitted 121 g/km of CO_2 on average, 2 g/km higher than in 2017 and still 26 g/km above the 2021 target. The increase in 2018 is attributable to changes in consumer preference from small vehicles, which have comparatively low CO_2 emissions, to medium size cars and sports utility vehicles (SUVs), of which some are crossovers. So far, no major car manufacturer has achieved the 2021 target. The Toyota-Mazda fleet looks to be the closest with average CO_2 emissions of 110 g/km for the fleet sold in 2018, versus its target of 94 g/km in 2021. It has the largest share of HEVs, which represent 46% of its sales in Europe. Currently, Toyota (including Lexus) offers 14 models of HEVs covering all vehicle categories (small to large, including the fast growing SUV category which is difficult to fully electrify). A high share of HEVs helps automakers to reduce CO_2 emissions to achieve their regulatory targets.

In November 2019, Volkswagen, the world's largest carmaker, announced a plan to launch 60 new hybrid models by the end of 2029 and sell six million HEVs. Together with BEVs, the company will have 135 electric models on offer.

China, the world's largest automobile market, accounted for 40% of global electric car sales and half of the existing stock in 2018 thanks to the New Energy Vehicle (NEV) Mandate Policy. In June 2019, the government reduced subsidies for NEVs and sales saw significant year-on-year decreases as consumers are quite sensitive to the trade-off between vehicle performance and the up-front costs of owning vehicles (which are higher for EVs). In July 2019, The Ministry of Industry and Information Technology released a proposal for NEV Mandate Policy modification which stipulates that the sales of fuel-efficient vehicle (highly likely to include HEVs) could offset certain percentage of the manufacturer's NEV credit. This modification could effectively work to achieve manufacturers' fuel efficiency target. HEVs achieve the equivalent or more distance between refuelling stops compared with conventional diesel/gasoline vehicles and are competitively priced against BEVs or fuel cell vehicles. Therefore, they appeal to Chinese consumers who are keen to support the government push toward NEVs, but are not ready to shift to pure-electric vehicles.

For China, as for other major car markets, electrification of vehicles is the main manufacturer strategy to achieve regulated fuel efficiency or CO_2 emissions targets. However, it is important to get the right technology to achieve the desired evolution in car sales. HEVs - as a technology - have lower penetration barriers, a more affordable price, and are well adapted to the period of build-up in infrastructure (i.e. charging point). They may have more room to increase their market share.

Appendix

Table 1.6 Identified petrochemical capacity addition in the United States

Projects	Location	Capacity ('000 t/y)	Feedstock and maximum demand (kb/d)		Scheduled year
Indorama Ventures Olefins LLC	Westlake, LA	440	Ethane/Propane	27	Q1 2020
Dupont (Expansion)	Orange, TX	91	Ethane	5	Q1 2020
Formosa Plastics	Point Comfort, TX	1200	Ethane	67	Q1 2020
Total Petrochemicals and Refining USA	Port Arthur, TX	1000	Ethane	55	2021
Shell Chemical Appalachia	Monaca, PA	1500	Ethane	83	2022
Enterprise Phase-2	Mont Belvieu, TX	750	Propane (PDH)	27	Q2 2023
ExxonMobil SABIC	Corpus Christi, TX	1800	Ethane	100	2023
PTTGC-Daelim America	Belmont County, OH	1500	Ethane	83	2024
Formosa Petrochemicals	St. James, LA	1200	Ethane	67	2024

Source: Industry press and company reports.

Table 1.7 Identified petrochemical capacity addition in China

Projects	Location	Capacity ('000 t/y)	Feedstock and maximum demand (kb/d)		Scheduled year
Sinopec-Kuwait Petroleum Corporation	Zhanjiang, Guangdong	800	Naphtha	65	Q3 2020
Rongsheng Petrochemical Co., Ltd.	Zhoushan, Zhejiang	600	Propane (PDH)	21	2020
Sinopec SK Wuhan Petrochemical(Expansion)	Wuhan, Hubei	300	Naphtha	24	Q2 2021
Lianyungang Petrochemical Co. I	Lianyungang, Jiangsu	1250	Ethane	69	Q3 2021
Formosa Plastics	Ningbo, Zhejiang	600	Propane (PDH)	21	Q4 2021
Sinochem Quanzhou Petrochemical Co., Ltd	Quanzhou, Fujian	1000	Naphtha	81	2021
Liaoning Bora Petrochemicals	Panjin, Liaoning	1000	Naphtha	81	2022
Sinopec Gulei JV, Zhangzhou	Zhangzhou, Fujian	800	Naphtha	65	2022
Lianyungang Petrochemical Co. II	Lianyungang, Jiangsu	1250	Ethane	69	2022
CNPC Tarim Oil Field Branch	Korla, Xinjiang	600	Ethane	33	2022
Sinopec Hainan Refining & Chemical (HRCC)	Yangpu, Hainan	1000	Naphtha	81	2024

Source: Industry press and company reports.

Table 1.8 Identified petrochemical capacity addition in Russia

Projects	Location	Capacity ('000 t/y)	Feedstock and maximum demand (kb/d)		Scheduled year
Sibur ZapSibNeftekhim Ethylene	Tobolsk	1500	Ethane/ Propane/Butane	95	Q1 2020
Gazprom Cracker	Novy Urengoy	420	Ethane	23	2020
Nizhnekamskneftekhim (NKNC) Ethylene Complex	Tatarstan	600	Ethane/Naphtha	39	2022
Sibur-Amur	Svobodny	1200	Ethane/Propane	73	2025

Source: Industry press and company reports.

Table 1.9 Identified petrochemical capacity addition in selected countries

Projects	Location	Capacity ('000 t/y)	Feedstock and maximum demand (kb/d)		Scheduled year
Hyosung Chemicals	Cai Mep, Viet Nam	300	Propane (PDH)	11	Q4 2020
PTTGC Map Ta Phut Cracker 5	Map Ta Phut, Thailand	500	Naphtha/LPG	38	2020
PTTGC Chandra Asri Expansion	Java, Indonesia	40	Naphtha	3	Q1 2021
JG Summit (Expansion)	Batangas City, Philippines	160	Naphtha	13	2021
Yeochun NCC	Yeosu, Korea	335	Naphtha	27	2021
LG Chemicals (Expansion)	Yeosu, Korea	800	Naphtha	65	2021
SCG-Dow (MOC) Expansion	Map Ta Phut, Thailand	300	Naphtha/LPG	23	2021
Oman Oil Refineries and Petroleum Industries Co.	Liwa, Oman	900	Naphtha	73	2021
Grupa Azoty Police II	Police, Poland	429	Propane (PDH)	15	Q4 2022
HPCL-Mittal Energy Ltd.	Bhatinda, India	1200	Naphtha/Kerosene	97	2022
Lotte Chemical Hyundai	Daesan, Korea	750	Naphtha/LPG	57	2022
NOVA Chemicals, Canada (Expansion)	Corunna, ON, Canada	350	Ethane	19	2022
Borealis AG	Kallo, Belgium	740	Propane (PDH)	26	2022
Mehr Petrokimiya Co PDH	South Pars, Iran	450	Propane (PDH)	16	2022
Salman-e-Farsi PC PDH	Bandar Imam, Iran	450	Propane (PDH)	16	2022
Inter Pipeline Redwater PDH	Alberta, Canada	525	Propane (PDH)	19	2022
Carbon Holding Tahrir Petrochemicals	Ain Sokhna, Egypt	1500	Naphtha	121	Q1 2023
Lotte Chemical Titan Merak Banten Naphtha Cracker	Banten, Indonesia	1000	Naphtha	81	2023
GS Caltex	Yeosu, Korea	700	Naphtha	56	2023
INEOS Rafnes Cracker 2	Bamble, Norway	500	Ethane	28	2023
INEOS Cracker	Antwerp, Belgium	1000	Ethane	55	2023
Pembina PIC	Alberta, Canada	550	Propane (PDH)	20	2023
PTTGC Chandra Asri	Java, Indonesia	1000	Naphtha	81	2024
Borouge 4	Ruwais, UAE	1500	Ethane	83	2025

Source: Industry press and company reports.

2. Supply

Highlights

- Global oil production capacity is set to increase by 5.9 mb/d by 2025, which marginally outpaces growth in demand. Robust non-OPEC supply growth in the next few years suggests a likely role for continued OPEC+ market management.

- Growth in non-OPEC oil supply tapers off from 2022, allowing OPEC producers from the Middle East to ramp up output to maintain a balanced market. While expansion in the United States slows, it remains the largest source of growth. Significant gains from Brazil, Guyana and Canada contribute to a total non-OPEC increase of 4.5 mb/d through 2025.

- As for OPEC, solid growth in the Middle East more than makes up for declines in Africa and Venezuela to boost the group's crude oil capacity by 1.2 mb/d by 2025. Iraq and the United Arab Emirates (hereafter "UAE") lead the gains. If Iran were released from sanctions, a further 1.7 mb/d of capacity could be made available to the market in short order.

- The call on OPEC crude is expected to reach 30.6 mb/d by 2025, 2 mb/d more than the group produced in early 2020. However, spare capacity remains above 3 mb/d, even with Iran still under sanctions.

- Oil and gas producers are increasingly under pressure to embrace energy transitions. Many are looking to rise to the challenge by announcing ambitious targets to fight climate change. Clean energy investments are increasing but remain a small percentage of the industry's overall spending, and the announced targets are unlikely to make a visible impact on global oil supply in this six year forecast.

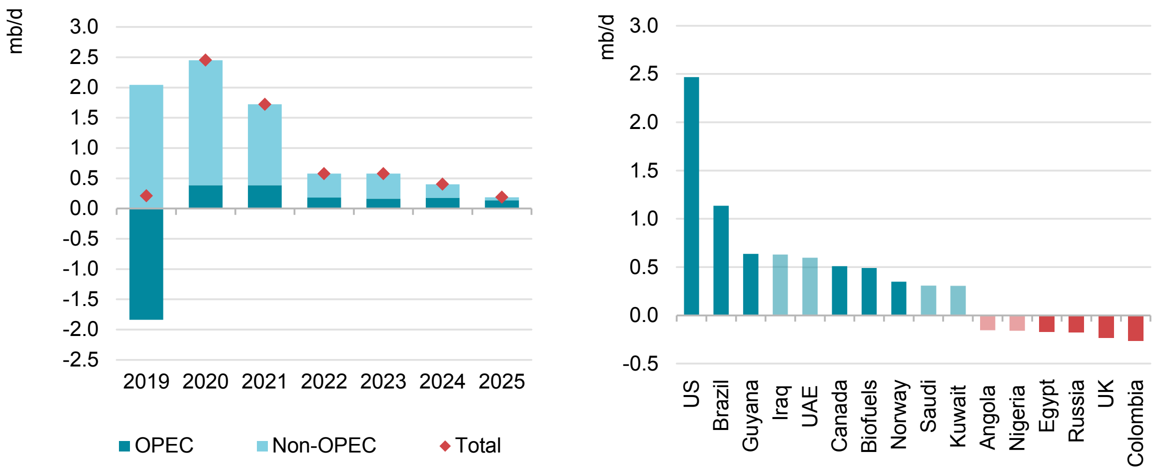
- Global upstream capital investments are expected to rise modestly to USD 491 bn (+1.5%) in 2020, as increased offshore activity offsets further declines in the shale sector. In the United States, heightened focus on capital discipline and investor returns by independent producers and the growing presence of the major oil companies has tempered the rush to growth seen in recent years.

Global overview

Global oil supply looks comfortable through the forecast period. The world's oil production capacity is expected to rise by 5.9 mb/d by 2025, which more than covers growth in demand. Gains in supply are heavily front-loaded, however, and robust non-OPEC growth through 2021 suggests that there is likely to be a role for OPEC+ market management during the first part of the period. From 2022, the United States loses steam allowing OPEC producers from the Middle East to turn up the taps to help keep the oil market in balance.

The United States leads the way as the largest source of new supply, and given its huge resource potential it could produce still more if prices were higher than assumed in the futures curve used for our analysis. Brazil, Guyana, Iraq, the UAE and Canada also deliver impressive gains. Colombia, the United Kingdom, the Russian Federation (hereafter, "Russia"), Egypt, Nigeria and Angola post the biggest declines. Total non-OPEC oil supply rises by 4.5 mb/d to reach 69.5 mb/d by 2025. As for OPEC, even though sanctions and economic distress have wiped out 2.5 mb/d of production from Iran and Venezuela since 2017, effective crude oil capacity rises by 1.2 mb/d to 34.1 mb/d.

Figure 2.1 Global oil capacity growth (2019-25)



Note: Assumes Iran remains under sanctions.

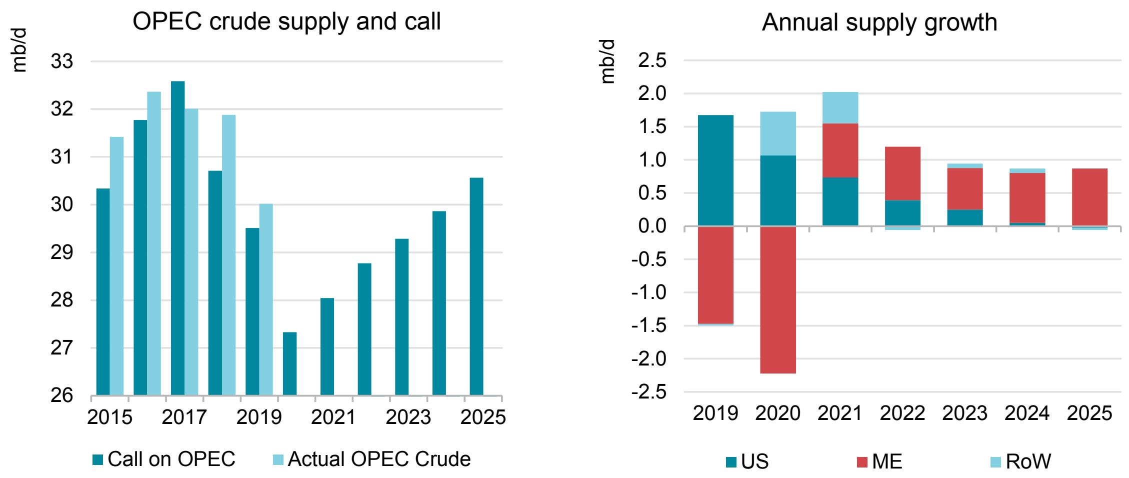
Global oil capacity to rise by 5.9 mb/d by 2025. United States leads supply gains.

In this forecast, we have assumed that Iran remains under sanctions. If sanctions were to be eased, OPEC's effective crude oil capacity could rise by an additional 1.7 mb/d in short order.

As the pace of non-OPEC growth slows and the call on OPEC rises, Middle East producers – with their relatively low cost reserves – take over from the United States as the leading source of supply growth from 2022 to 2025 (see *Figure 2.2*). Iraq and the UAE are poised to build capacity to fresh record highs and Saudi Arabia and Kuwait will benefit from the resumption of flows from the Neutral Zone. Qatari condensate and NGL production will gain from further development of its massive gas resources in the North Field. By 2025, the call on OPEC crude is expected to reach 30.6 mb/d, 2 mb/d more than the group produced in early 2020.

However, in the early part of the forecast, market management by producers is likely to play a role. For three years, Saudi Arabia and Russia have led a group of producers accounting for nearly half of global supply in a series of cuts that amounted to 2.1 mb/d in early 2020. That makes for ample spare capacity in OPEC. In 2025, spare capacity remains above 3 mb/d even with Iran remaining under sanctions.

Figure 2.2 Rising demand for OPEC crude allows higher Middle East production



Note: Right-hand graph assumes global oil supply equals demand.

Box 2.1 Bold clean energy targets unlikely to hit medium-term oil supply

From the majors to national oil companies (NOCs), the oil and gas industry is under pressure to play a bigger role in energy transitions. Many are looking to rise to the challenge by announcing bold strategies to reduce the carbon intensity of their operations, albeit with targets that are usually long term and light on detail.

Large international oil companies (IOCs), especially in Europe, have taken the lead in embracing clean energy and are increasing investments in renewables such as biofuels, solar and wind. BP has laid out the boldest climate goals yet stating that it will achieve net zero emissions from its operations and from the oil and gas that it produces (including emissions from customer use of its products, known as scope 3 emissions) by 2050 or sooner. Repsol has made a comparable commitment by pledging to reach net zero emissions before 2050. Peers such as Royal Dutch Shell, Total and Equinor have announced targets for curbs, but none has promised net zero emissions from their overall activity. Several US majors also have targets, but these tend to be less ambitious.

Public pressure is often directed at the seven integrated oil and gas majors due to their relative transparency and activitist shareholders. But the industry is much larger: the majors account for 15% of global oil and gas production, 12% of reserves and 10% of estimated emissions from industry operations (*The Oil and Gas Industry in Energy Transitions* [IEA, 2020]).

However, NOCs – fully or majority-owned by national governments – account for well over half of global production and an even larger share of reserves and need to play their part. Since the oil price collapse in 2014-16, many of their governments have renewed commitments to reform and diversify their economies to decrease reliance on oil.

Some are progressing better than others. For example, Saudi Arabia and the UAE have plans to stimulate other parts of the economy. They intend to invest in the generation of electricity from natural gas, renewables and nuclear to reduce carbon emissions. In Russia, Rosneft has pledged to invest around USD 5 billion in "green" projects over the next five years. Petrobras, which claims to have one of the world's lowest emissions intensities of oil production, plans to spend USD 100 million a year over the next five years to further decarbonise production and an additional USD 70 million a year on research and development for decarbonisation and renewables.

Clean energy investments by oil and gas companies are increasing, albeit from a small percentage of the industry's current overall spending. From a global oil supply perspective, the announced targets are unlikely to make a visible impact in this six year forecast. Demand for oil grows over the medium term (even though efficiency improvements and electric vehicles are causing the pace to slow) and producers are prepared to meet that increased requirement. Further ahead, the prospect of peak demand may in fact drive some in the industry to build up capacity and production as swiftly as possible while consumption is still expanding.

Recognising that oil and gas production will be needed for decades to come, BP's new CEO, Bernard Looney, echoed a wider industry sentiment when stating BP will remain in the oil and gas business "for a very long time". What is clear, is that with oil and gas still dominating the energy mix, carbon capture, storage and utilisation, and efforts to reduce emissions from operations need to be part of the clean energy solution. But that may not be easy while at the same time ensuring affordable energy and rewarding shareholders.

Emissions reduction targets by selected international oil and gas companies

Company	Targets
BP	Net zero greenhouse gas (GHG) emissions from operations and upstream production by 2050. Applies to scope 1, 2 and 3 emissions.* Cut carbon intensity of all products sold by 50% by 2050. Reduce operated methane intensity by 50%.
Chevron	Cut upstream net GHG emission intensity for oil (by 5-10%) and gas (by 2-5%) by 2023 vs 2016. Applies to scope 1 emissions. Reduce methane intensity by 20-25% by 2023 vs 2016.
ConocoPhillips	Cut GHG emissions intensity by up to 15% by 2030 vs 2017. Applies to scope 1 and 2 emissions.
Eni	Cut net emissions by 80% by 2050. Applies to scope 1, 2 and 3 emissions. Cut emissions intensity by 55% by 2050 vs 2018. Net zero upstream carbon footprint by 2030, net zero for group by 2040. Applies to scope 1 and 2 emissions. Cut upstream methane emissions by 80% by 2025 vs 2014.
Equinor	Cut net carbon emissions intensity by at least 50% by 2050 vs 2020. Applies to scope 1, 2 and 3 emissions. Cut GHG emissions of Norwegian operations to near zero by 2050. Applies to scope 1 and 2 emissions and includes methane. Maintain methane intensity of near zero.
ExxonMobil	Cut methane emissions by 15% by 2020 vs 2016.
Repsol	Net zero emissions by 2050 vs 2018. Applies to scope 1, 2 and 3 emissions (of own production). Cut carbon intensity by 40% by 2040 vs 2016. Cut methane emissions by 25% by 2025 vs 2016.
Shell	Halve net carbon emissions intensity by 2050 vs 2016. Applies to scope 1, 2 and 3 emissions. Maintain methane emissions intensity for operated assets below 0.2% by 2025.
Total	Cut carbon emissions at operated production facilities to under 40 Mt by 2025 (-15% vs 2015). Applies to scope 1 and 2 emissions. Cut carbon intensity of energy products sold by 15% by 2030 and 25-40% by 2040 vs 2015. Applies to scope 1, 2 and 3 emissions. Cut methane emissions intensity to below 0.2% to 2025.

*Scope 1 emissions are direct emissions from operations. Scope 2 emissions are from the power used for operations. Scope 3 emissions occur during combustion of fuel by end users.
Source: Reuters, company reports.

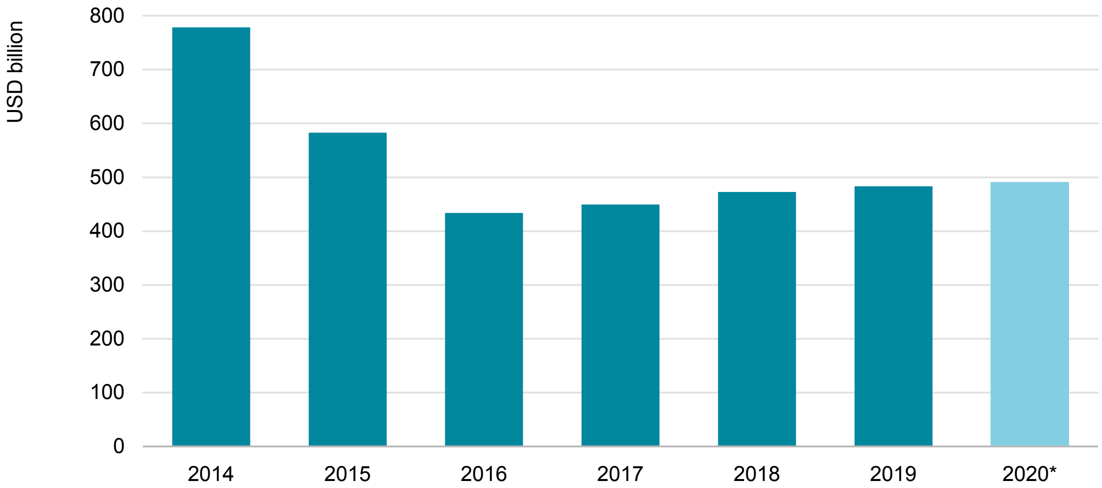
Upstream investment

Global upstream capital investments are expected to rise modestly to USD 491 bn (+1.5%) in 2020, based on preliminary company announcements. Higher conventional offshore investments will offset a further easing in shale activity.

During 2019, spending on onshore projects, which accounted for over 70% of total upstream expenditure, fell for the first time in two years, according to Rystad Energy. Investment in US shale resources slipped 4%, a dramatic change to the trend that saw it more than double between 2016 and 2018. With subdued oil prices, the focus on capital discipline and investor returns intensified, leading independent operators to spend below the levels anticipated in their earlier outlooks.

The IEA US Shale Upstream Cost Index rose 2.9% in 2019, reflecting, amongst other factors, a shortage of skilled personnel and some equipment and supplies. Global upstream costs remained flat, at around 25% below the levels seen in 2014.

Figure 2.3 Global oil and gas upstream capital spending



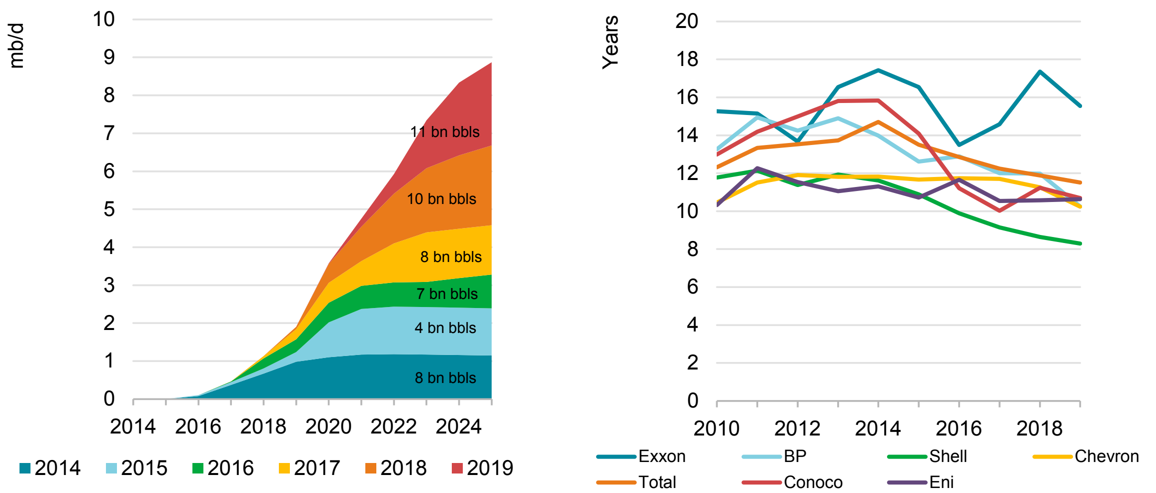
*Preliminary, based on company reports.

Easing investment in unconventional plays is just offset by a rebound offshore.

The offshore oil sector in 2019 saw increased spending (+3%) and more project approvals. According to Rystad Energy, USD 105 bn of offshore investment was approved, double the level in 2017 and 2018, with the majority of it to be spent on greenfield developments. Expenditure is focused in the Middle East and Latin America; particularly in Saudi Arabia and Brazil (see *Table 2.1*). Including the onshore, the volume of conventional oil resouces approved rose to 11 billion barrels. These new projects will add 2.2 mb/d to global production capacity to 2025.

There are clear signs that access to capital is becoming more difficult as investors, conscious of the challenges to the industry from the energy transition, raise their return requirements for oil projects. Access to financing and regulatory change was a reason for the delay of several final investment decisions (FID) in 2019, in particular for projects operated by smaller independent companies who are more vulnerable to capital market sentiment.

Figure 2.4 Production volumes by FID year — Majors' reserves life



Notes: Majors include ExxonMobil, Shell, Chevron, BP, Total, Eni and ConocoPhillips.
Source: IEA analysis based on company reports and Rystad data (2020).

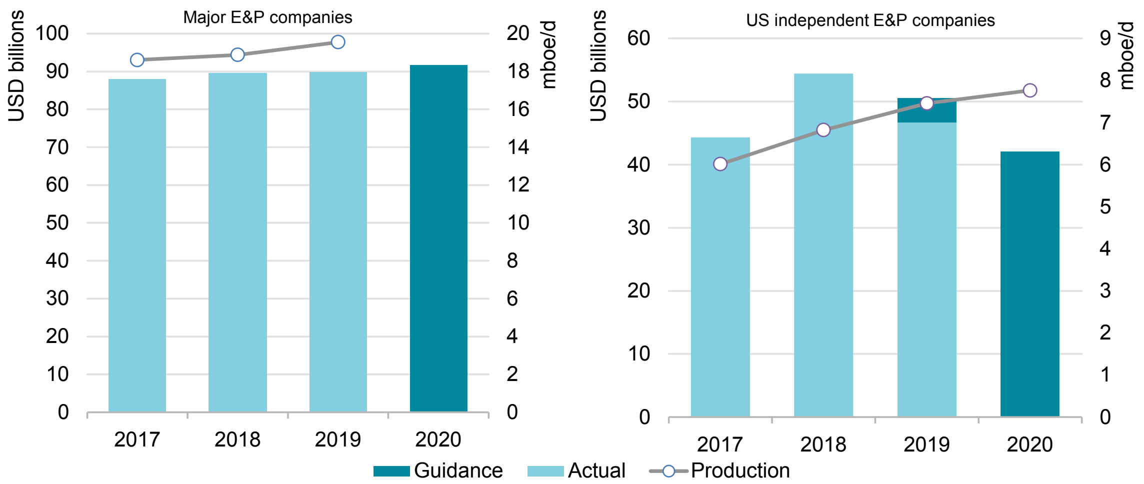
More conventional resources approved in 2019. Long-term growth at risk from depressed exploration.

Of the major IOCs, only ExxonMobil flagged a significant increase in its capital budget for 2020, although its CEO stated these plans could be adjusted if market developments were unsupportive. Exxon is making large investments in Guyana and continues to expand in the Permian. Chevron, Shell and BP have also ramped up output in the US shale patch, attracted by short-cycle developments and the low-risk operating environment. The growing preference for projects with less upfront capital expenditure and faster paybacks, for shale and also for the conventional sector, is not just a consequence of the 2014-16 price crash. These projects also make sense as they lower the risk that a shift in oil demand due to energy transitions could wipe out longer-term returns.

Due to the lower price outlook several IOCs wrote down the value of some of their assets in 2019. Chevron wrote down USD 10.4 bn of asset value while Repsol, Shell, BP and Equinor also took impairement charges in excess of USD 2 bn each. Repsol indicated the lower value of its portfolio was related to new carbon reduction targets, hinting at the impact of the energy transition. While the majors reject the notion that they might be left with stranded assets, weaker growth in demand for oil is likely to add further pressure in the coming years. This may also partly explain the continued decline in the majors' exploration expenditure, which has fallen for the last six years. While firms may be confident that they can monetise their current assets within the coming decades, the heightened uncertainty means that there is less incentive to increase their resource base. The majors' average reserve life (proved reserves divided by annual production) fell to 11 years in 2019, having been on the decline since the 2014-16 price crash. ExxonMobil had bucked the general trend as its discoveries in Guyana and increased US shale acreage gave a sizeable boost to proved reserves.

In 2019, the US independent shale producers pledged to rein in spending to satisfy investor demands for returns rather than maximise production growth. They exceeded their promises and cut back spending by 14%, while focus on cost control and efficiency allowed them to meet their production targets. Guidance for 2020 suggests a further reduction in spending. Although production is expected to grow, the pace is easing with fewer opportunities for efficiency gains and a larger base decline to offset. Ongoing concerns about the shale business model have severely impacted operator's ability to access funding and led to an increasing number of bankruptcies. According to law firm Hayes and Boone, 42 North American E&P companies filed for bankruptcy in 2019, a 50% annual increase. However, the majors' growing US shale footprint may mean investment is more stable as their large balance sheets allow them to better manage price volatility. Some majors indicated that their divestment programmes are partially to generate funds for expansion in the United States.

Figure 2.5 Selected company oil and gas upstream capital spending



Notes: Majors include ExxonMobil, Shell, Chevron, BP, Total, Eni and ConocoPhillips. US E&Ps include EOG, Occidental, Pioneer, Apache, Continental Resources, Chesapeake, Marathon, Nobel Energy, Concho, Devon Energy, Murphy Oil, Whiting, Diamondback, Parsley, Carrizo, Callon, Laredo, EQT Corp., Continental Resources, Antero Resources, Cimarex and SM Energy.

US independents display capital discipline, but the sector struggles with financing.

A rising number of institutional investors, asset managers, insurers and pension funds have pledged to divest assets deemed to be incompatible with meeting the targets of the 2015 Paris Agreement. In 2019, several high profile names committed to pull out of oil and gas and/or tighten their rules for making new investments in the sector. These include BlackRock, Goldman Sachs, the European Investment Bank, insurers Axa and Alliance and pension funds run by the Norwegian government and several American and European universities and cities. Overall, environmental campaign group 350.org reported that funds managing over USD 11 trillion have agreed to divest their fossil fuel holdings. While this is an impressive number, it is less clear what share of the total is related to oil and gas or the timeframe for withdrawing funds. In some cases, divestments relate specifically to certain assets, such as coal and Artic exploration, rather than the industry as a whole.

Reportedly, only half of the world's major banks have made sustainable finance commitments and, according to 2019's Banking on Climate Change report,[1] bank lending for oil and gas projects has increased since 2015 despite the growing pressure to do otherwise. In general, the divestment

[1] Rainforest Action Network (2019), *Banking on Climate Change – Fossil Fuel Finance Report Card 2019*.

movement doesn't have a material influence on the overall level of investment in the medium term but firms such as Shell, BP and Chevron have publicly recognised that it has the potential to impact the value of their business. Not least, activists have been successful in their demand for more disclosures of climate change risks and the need for these to be considered during investment decision-making.

Table 2.1 Selected 2019 upstream project sanctions

Country	Project	Peak Capacity (kb/d)	Start Year	Operator
Saudi Arabia	Marjan Expansion	300	Not specified	Saudi Aramco
Saudi Arabia	Berri Expansion	250	Not specified	Saudi Aramco
Guyana	Liza Phase 2	220	2022	ExxonMobil
Norway	Johan Sverdrup Phase 2	220	2022	Equinor
Brazil	Mero 2	180	2022	Total
Brazil	Marlim Redevelopment	150	2022	Petrobras
Brazil	Lula Oeste	150	2022	Petrobras
Brazil	Buzios V	150	2023	Petrobras
Mexico	Ichalkil	100	2020	Fieldwood Energy
Azerbaijan	Azeri Central East	100	2023	BP
United States	Kings Quay	80	2022	Murphy Petroleum
United States	Thunder Horse South Phase 2	50	2021	BP
United Kingdom	Seagull	50	2021	Neptune Energy
United States	Atlantis Phase 3	38	2020	BP
Norway	Duva	30	2020	Neptune Energy

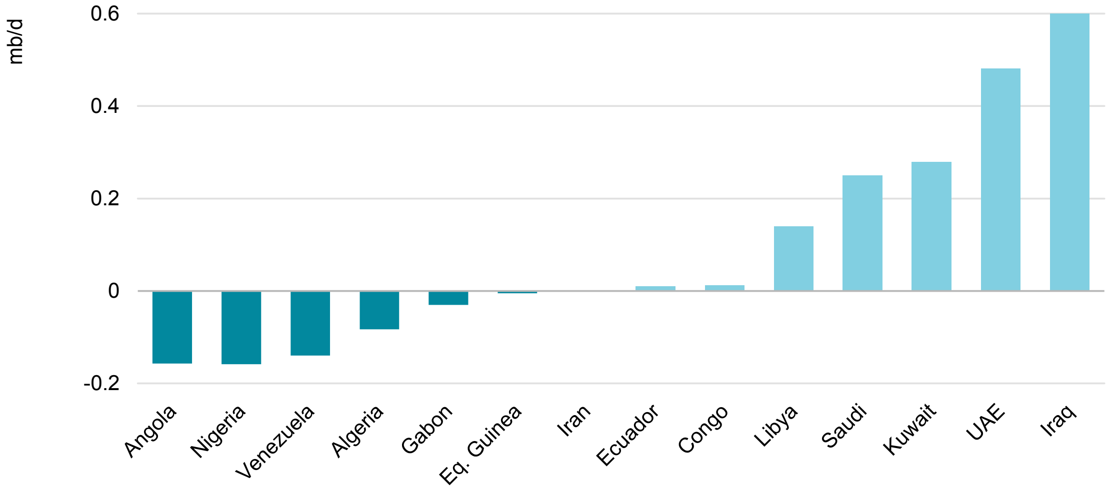
Note: Project capacity and start dates per company guidance.
Source: Company announcements.

OPEC crude oil capacity

A substantial expansion effort in the Middle East far offsets declines in Africa and stagnation in Venezuela to raise OPEC's crude oil capacity by 1.2 mb/d by 2025. OPEC's effective capacity returns to growth in 2020 after plunging 1.85 mb/d in 2019 when US sanctions slashed Iranian supply and Venezuela saw a further substantial production loss. We assume that US sanctions against Iran stay in place through the six-year period. The forecast includes the restart in 2020 of the Neutral Zone shared between Saudi Arabia and Kuwait whereas in previous oil market reports it was excluded. If Iran were released from sanctions, it could add a further 1.7 mb/d of capacity in short order.

Iraq, including the Kurdistan Regional Government (KRG), and the UAE continue to lead the gains in capacity and should remain comfortably in OPEC's number two and three slots, respectively, through 2025. Both pumped at annual record highs in 2019, with Iraq at 4.7 mb/d and the UAE at 3.2 mb/d. Angola and Nigeria post the biggest declines in capacity, as ageing oil fields lose steam and investor enthusiasm, especially in Nigeria, is on the wane. On the other hand, producers in the Middle East are willing to spend substantial amounts to boost capacity by 1.6 mb/d as they expect stronger demand for their crude. Our estimates show that the call on OPEC crude rises to 30.6 mb/d in 2025 from 27.3 mb/d in 2020.

Figure 2.6 **Change in effective OPEC crude capacity 2019-25**



Note: Assumes Iran remains under sanctions.

Middle East dominates OPEC expansion effort.

Iraq, UAE set to break capacity records

Despite the formidable security, financial and institutional challenges it faces, **Iraq** has managed to double production from 2.36 mb/d in 2010 to a record 4.7 mb/d in 2019. Exports have also doubled to nearly 4 mb/d. The People's Republic of China (hereafter, "China") and India both receive about 1 mb/d from Iraq, another 1 mb/d moves to Europe and the United States takes 0.4 mb/d. However, escalating tension between the United States and Iran spilled over into Iraq in early 2020, increasing its vulnerability as a supplier just as its strategic importance has grown.

In the medium term, heightened security concerns could make it more difficult for Iraq to build production capacity. Even so, its crude oil expansion is expected to be the largest within OPEC thanks to its vast reserves and strong economic incentives to boost output. Capacity is projected to grow by 600 kb/d to reach 5.5 mb/d in 2025.

While there are myriad above-ground hurdles that can complicate the delivery of projects, Iraq has some of the lowest-cost resources in the world. Even before the January 2020 clashes between Iran and the United States in Iraq, widespread protests had posed a threat to oil fields and terminals although there was no material impact on operations.The Basra oil heartland in the south, where IOCs are managing mega-projects, will dominate the capacity building effort. By contrast, the northern Kirkuk oil fields and the capacity that is controlled by the KRG are expected to deliver modest growth.

The southern oil fields of Rumaila, West Qurna, Zubair and Majnoon combined account for 60% of Iraq's oil production. Prospects for boosting their capacity would improve if the ministry were to press ahead with the long-delayed Common Seawater Supply Project (CSSP). The Basra Oil Co (BOC) has taken responsibility for the CSSP and put it out to tender. The first multi-billion dollar phase, expected to take at least three years to construct, aims to pipe 5 mb/d of treated seawater to fields across Basra and to Nassiriya.

The Ministry of Oil is also continuing its plans for the multi-billion dollar Southern Iraq Integrated Project (SIIP). This is expected to boost output from the Nahr Bin Umar and Ratawi oil fields from current combined levels of roughly 80 kb/d to 500 kb/d. The revenue generated would finance the upgrading of southern infrastructure, including the Gulf export terminals. The SIIP also includes a water injection project (at this point separate from the CSSP) that would treat water from the Gulf and distribute it to the oil fields in the South.

Water is not an urgent need at greenfields in the south such as Halfaya, which has fuelled much of the recent growth, and Majnoon, which is expected to pump more over the coming years. Halfaya is climbing towards its plateau output level of 400 kb/d and a third central processing facility is due to lift capacity to 450 kb/d at the field operated by China National Petroleum Corporation (CNPC). Majnoon, discovered by Petrobras in the 1970s, has been transformed from a battlefield into an oil field and now has the capacity to produce more than 200 kb/d. BOC operates the field following Shell's departure in mid-2018, and is looking to boost output to 400 kb/d. A substantial drilling effort is gathering pace to underpin this expansion.

Water is one of the biggest hurdles at Rumaila, Iraq's largest oil field, currently producing 1.5 mb/d. Increasing production requires additional water handling and separation facilities. The 70-year-old field has a natural annual decline rate of more than 20%, so production has to be increased by around 300 kb/d each year to compensate.

So-called "national effort" fields in the south such as the 80 kb/d Nassiriya are also set for higher output. Baghdad has signed a contract for a drilling programme to raise output by 40 kb/d over the next two years.

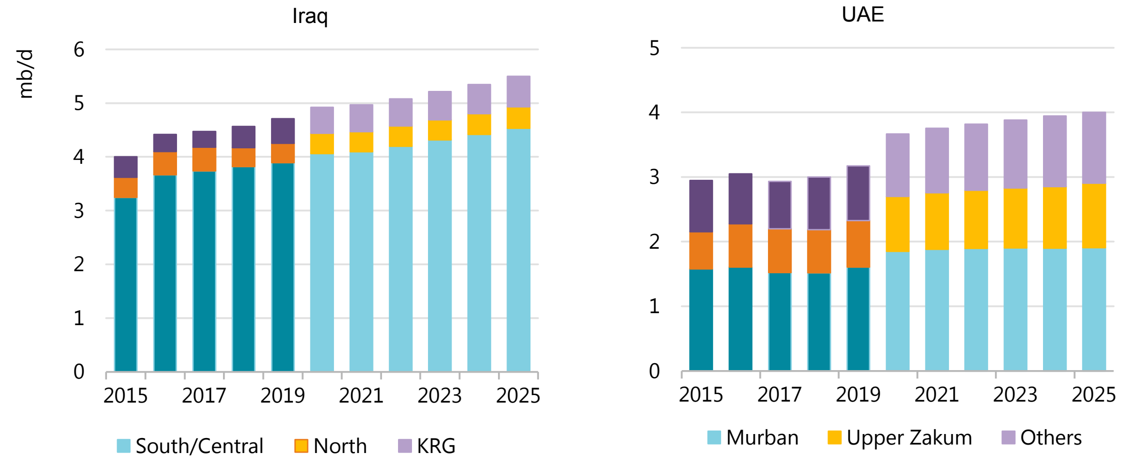
Export capacity in the south, due to rise from around 4 mb/d currently, should be enough to handle the anticipated production increase. To support its capacity-building efforts, Iraq has signed an initial agreement with Dutch company Boskalis to build an artificial island in the Gulf to raise export capacity by 3 mb/d and boost storage capacity by 6 mb from an existing 10 mb. In early 2020, shipments of Basra crude were running at around 3.3 mb/d.

Baghdad is also striving to boost output from the northern fields, which were responsible for just under a fifth of Iraq's production in 2019, primarily from the Kirkuk and Bai Hassan fields. Efforts have been frustrated by the 2014-17 battles with Islamic State as well as the dispute between the federal government and the KRG over the control of land and oil. Complicated geology has also hindered the development drive.

Production at Kirkuk slumped to around 500 kb/d in 2019 from 900 kb/d in 2001. The oil field, producing since the 1920s, is composed of three main geological formations, or domes: Khurmala, Baba and Avana. Khurmala straddles Erbil province and is administered by the KRG under a 2008 agreement with Baghdad. There are plans to raise Kirkuk's production capacity to 1 mb/d, comprised of an increase of 170 kb/d at the Khurmala dome and 330 kb/d from elsewhere. The nearby Qayara field, operated by Sonangol, has a near-term production target of 60 kb/d, double the current level.

As for Kurdistan, although the KRG is still burdened with debt that piled up during its financial crisis after the 2014-16 oil price drop, its production has recovered to 480 kb/d. Output has risen to 175 kb/d at the Khurmala dome, operated by the KAR group, and the swift development of the Peshkabir field, operated by DNO, has helped make up for natural declines at Tawke. Production at DNO's Taq Taq field has been in sharp decline, falling from 130 kb/d in 2014 to 10 kb/d in 2019. Output at the Gazprom Neft-operated Sarqala field has risen from 5 kb/d to 30 kb/d. Production at the heavy oil producing Shaikan field is relatively steady at 40 kb/d.

Figure 2.7 **Production, capacity in Iraq and the UAE**



Note: Actual production from 2015-19; sustainable capacity thereafter.

Iraq and the UAE drive OPEC gains.

The **UAE** is also expected to deliver a substantial production capacity increase thanks to its secure operating environment and relatively low-cost resource base. Growth of 480 kb/d is forecast by 2025, with capacity rising to 4 mb/d, higher than Iran's. In 2019, the UAE's crude supply rose to a record 3.2 mb/d, up 180 kb/d year-on-year (y-o-y), making it OPEC's third-largest producer after Saudi Arabia and Iraq. Recent growth was supported by spending on the offshore Umm Lulu and Satah al-Razboot (Sarb) fields, which are expected to produce 200 kb/d by 2023.

The climb towards 4 mb/d will require the expansion of the Exxon-operated Upper Zakum offshore field, one of the world's largest. Output is around 750 kb/d and is expected to reach 1 mb/d by 2024. ExxonMobil has invested around USD 6.5 billion in Upper Zakum since it took a share in 2006. More near-term supply will come from offshore oil fields Ghasha, Dalma and Hail. As for the onshore, the Haliba field started up in 3Q19 and output is expected to reach 40 kb/d. Located along the Abu Dhabi-Oman border, it is operated by Al-Dhafra Petroleum, a joint venture between the Abu Dhabi National Oil Co (ADNOC), Korea National Oil Corp and GS Energy.

Apart from Upper Zakum, ADNOC split its 700 kb/d offshore oil concession into three separate ventures: Lower Zakum, Umm Shaif and Nasr, and Sarb and Umm Lulu. Total secured a 5% stake in Lower Zakum and 20% in Umm Shaif/Nasr; while OMV acquired the final 20% stake in Sarb and Umm Lulu. ADNOC will retain a 60% stake in each.

For its onshore sector, which pumps around 1.8 mb/d of flagship Murban crude, ADNOC has secured foreign partners for a 40% share of the concession. The official aim is to boost Murban output beyond 1.8 mb/d and, to that end, ADNOC plans to lift production from the Bab field to 485 kb/d from around 420 kb/d currently. Total and BP both hold 10% of ADNOC Onshore, with GS, Inpex, CNPC and Zhenhua Oil securing minority stakes.

Iran stymied by sanctions

Iran's expansion ambitions will be thwarted by US sanctions that are assumed to stay in place throughout the forecast. Iran was expected to rank as one of the world's leading sources of supply growth before sanctions were imposed in 2018. The impact of the sanctions has been to cut effective capacity by 1.7 mb/d to around 2.1 mb/d.

Iran's production of crude oil fell by 1.2 mb/d during 2019 to an average 2.36 mb/d, the lowest annual rate since 1988. Exports of crude and condensate fell by 1.4 mb/d to 0.8 mb/d on average. Production of crude recently has been hovering around 2.1 mb/d while exports of crude and condensate are 0.4 mb/d.

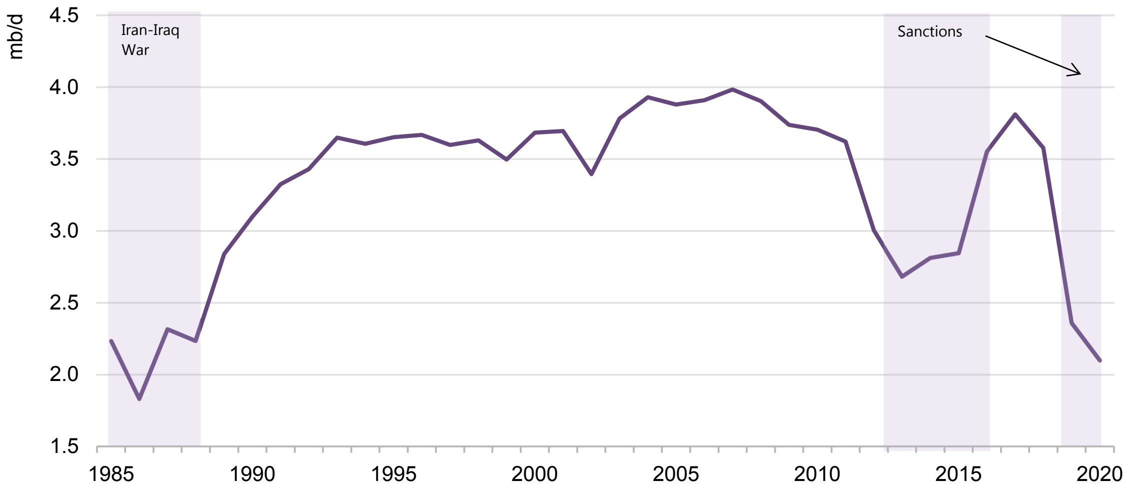
Lower wellhead production is likely to have led the National Iranian Oil Co to shut in more wells, especially at its more high-cost offshore fields, and complete maintenance at its mature oil fields. Shutting in output can be helpful for ageing oil fields as it will allow pressure to rebuild and make it easier for operations to restart.

Given the obstacles posed by the collapse of exports and the lack of foreign investment due to sanctions, Iran's capacity building is now on ice. The previous round of international sanctions had already left the oil sector in urgent need of foreign cash and technology, particularly in enhanced oil recovery methods to sustain and raise output at older oil fields.

Chinese oil companies, at work in Iran since the early 2000s, have wound down operations to avoid US sanctions. CNPC and Sinopec have suspended investments in South Pars and Yadavaran.

The virtual absence of foreign investors has left Iran striving to move forward with projects already under development by local companies, especially the West Karun oil fields of Azadegan, Yadavaran and Yaran. These fields, which straddle the border with Iraq, will help to sustain capacity and drive future growth beyond the medium term. Target output for West Karun is 1 mb/d versus current flows of 300 kb/d.

Figure 2.8 Iran's annual crude oil production



US sanctions cut Iranian crude production to 30-year low.

Saudi Arabia, Kuwait to benefit from Neutral Zone restart

Attacks on **Saudi Arabia's** oil facilities last September were a wake-up call for the world. The strikes briefly halted over half its crude supply and wiped out almost all the world's spare capacity: the Kingdom typically holds around 2 mb/d in reserve. Saudi Aramco's ability to restore operations and maintain customer confidence was impressive. Production capacity recovered to the pre attack level of 12 mb/d by the end of November. Saudi capacity is now set to reach 12.25 mb/d in 2021 thanks to an end-2019 agreement to restart the Neutral Zone shared with Kuwait. The return of production, shut for more than four years, is expected to be gradual and material volumes are not expected until later in 2020. Just before output was suspended, the offshore (mainly Khafji) and onshore (mostly Wafra) fields were pumping about 450 kb/d.

For years, Saudi Arabia has been bringing new projects online to make up for declines and enable older reservoirs in the 3.8 mb/d Ghawar onshore field to run at lower rates. Aramco is turning to higher cost offshore projects for that effort. To that end, the company has awarded USD 18 billion worth of contracts to boost capacity at the Marjan and Berri fields by a combined 550 kb/d. The 850 kb/d Zuluf field is also set for expansion.

Onshore, the Khurais project reached capacity of 1.5 mb/d in 2019. This expansion, together with a robust drilling programme, will help make up for natural declines, including at Ghawar, the world's biggest oil field. Saudi Arabia remains one of the world's lowest cost oil producers at an average of USD 4/bbl.

Kuwait is spending more on expanding its crude oil production capacity, which is expected to rise by 280 kb/d during the six-year outlook to reach 3.14 mb/d. Apart from the Neutral Zone, which adds 250 kb/d, the northern Ratqa oil field near the border with Iraq, due to start pumping in the early part of the forecast period, supports the expansion effort. Heavy crude output from the field is expected to ramp up gradually to around 75 kb/d and Shell will help raise it towards a target of 270 kb/d. It will also manage a water project at onshore oil fields that will lift production. BP is expected to expand the Burgan field which could produce up to 2 mb/d from roughly 1.6 mb/d now. For decades, Kuwait has struggled to develop upstream projects because its parliament has been critical of foreign involvement.

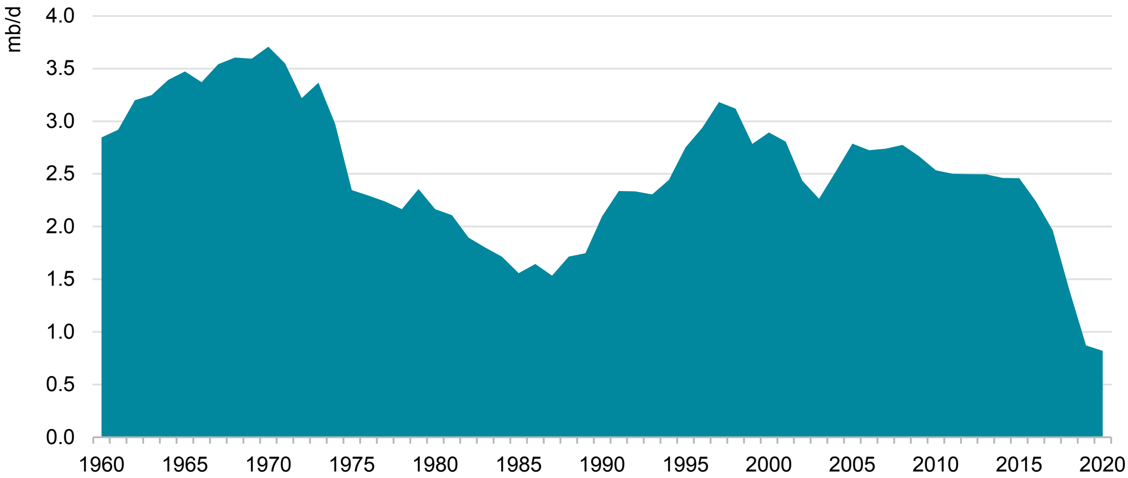
Venezuela stabilises

After two straight years with declines in excess of 0.5 mb/d, production in **Venezuela** may be stabilising. US financial sanctions, poor reservoir management and chronic underinvestment cut production to just 870 kb/d on average in 2019. This is just a quarter of the 3.4 mb/d peak level reached just before President Chavez took office in 1999. In this oil market report, we have assumed that following the 500 kb/d loss of actual production in 2019, output declines further in 2020 and then bottoms out at roughly 700 kb/d. We have held this level through the remainder of the forecast.

Reality, however, could look completely different. A turn-around of the political situation would provide the opportunity to rebuild the energy sector. Alternatively, if the situation worsens, the industry could collapse for an indeterminate period.

Output from mature conventional oil fields operated by Petroleos de Venezuela (PDVSA) has plunged and upgraders managed by foreign joint venture partners in the vast Orinoco heavy oil belt have malfunctioned due to the stress of late payments, security, corruption and the difficulty of securing equipment.

Figure 2.9 Venezuela's crude oil supply



Venezuelan annual crude oil production plunges below 1 mb/d for first time since birth of OPEC.

Shut out of the US market by sanctions, PDVSA last year temporarily adopted a new blending strategy to optimise crude exports. Orinoco upgraders were converted to blending operations to churn out heavy Merey 16 rather than the synthetic crude previously produced. Since the start of 2020, the Petropiar facility, a joint venture between PDVSA and Chevron, is once again operating as a crude upgrader. PDVSA's other upgraders are Petrocedeno, part owned by Total and Equinor; Petromonagas, part-owned by Rosneft and Petrosanfelix, wholly owned by PDVSA, that has been out of operation since last year.

So just how quickly could Venezuela rebuild should conditions allow? Before Chavez came to power, PDVSA was planning to boost production capacity to 5.5 mb/d by the mid 2000s by reorganising the company into a single integrated unit and opening up to foreign investment. Production did increase by nearly 900 kb/d in the four years to 1997 thanks to foreign investment and a disregard of the country's OPEC output quota.

Thus if Venezuela's diaspora of skilled oil workers return and investment capital were available, production could recover significantly over time. In the meantime, the Maduro government has looked to Russia and China to help revive the oil sector.

Ecuador leaves OPEC

Seeking to boost revenue through higher output free from restrictions, **Ecuador** announced its departure from OPEC, but this had not been officially confirmed as we prepared this report. Therefore, Ecuador is included within OPEC in this report. Production capacity is set to inch towards 560 kb/d by the end of the forecast. Only marginal growth is expected from the Ishpingo Tambococha-Tiputini block in the Amazon rainforest. Three years after start-up, production has only reached 90 kb/d, but it is the highest producing area in the country. Situated in a UNESCO world biosphere reserve, the heavy crude-producing block contains around 20% of Ecuador's total reserves of 8 billion barrels.

Africa loses steam

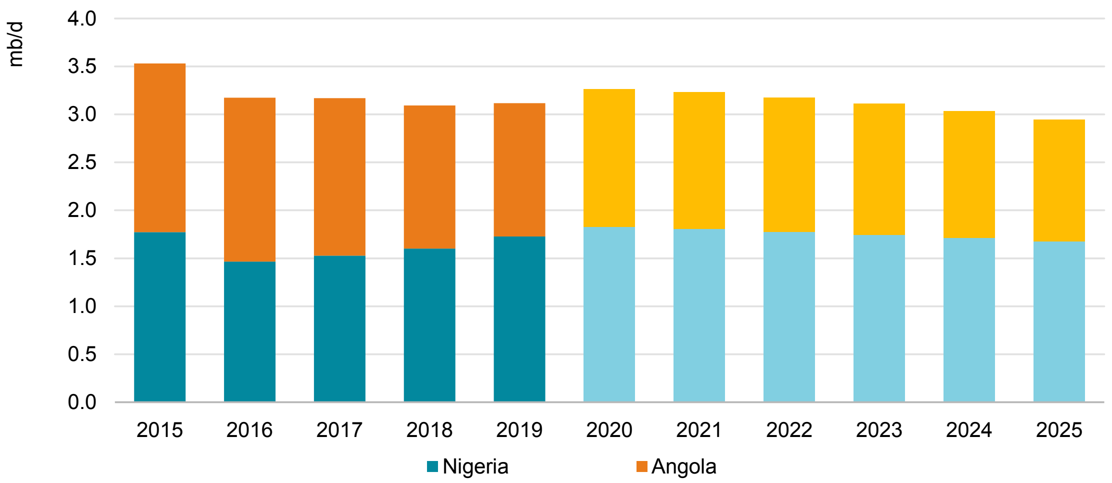
Crude oil production capacity from African producers, which make up half of OPEC's membership, is set to slump by 280 kb/d during the forecast period as producers struggle to drum up sufficient investment to arrest declines at fast-depleting offshore fields. Angola and Nigeria lead the losses, while Libya is due to post modest growth.

Capacity in **Angola** is set to fall by 160 kb/d to 1.27 mb/d by 2025 as operational and technical issues beset high-cost deep water oil fields. Production slumped to an average 1.39 mb/d in 2019 from a recent peak of 1.76 mb/d in 2015 and the decline would have been steeper if not for Total's USD 16 bn Kaombo project that is pumping more than 200 kb/d.

The Angolan government hopes to stave off a collapse by offering sweeter upstream terms and this is meeting some success. Angola has recently awarded offshore exploration blocks to Eni, Total, BP and Equinor and another licensing round for onshore blocks is set for later in 2020. Seeking to expand its presence in the deep offshore, Total has secured a deal for two blocks in the Kwanza Basin. Four discoveries – Cameia, Mavinga, Bicuar and Golfinho – have been made so far. Total also plans to move ahead with the Zinia 2, Clov Phase 2 and Dalia Phase 3 projects in Block 17 that will sustain output from the Pazflor field that came online in 2011.

Eni has started up the offshore Agogo field just nine months after making the initial discovery. Situated in Block 15, Agogo is due to pump 20 kb/d. Its rapid start-up was due to its proximity to the Ngoma floating production, storage and offloading vessel (FPSO). Agogo will support oil shipped via the FPSO and sold as Sangos crude. Agogo is one of five discoveries in Block 15 made by Eni in less than two years. Production from the Agidigbo field will be fast-tracked to the Armada Olombendo FPSO and exported as Olombendo crude.

Figure 2.10 **Nigeria, Angola crude production and capacity**



Note: Actual production from 2015-19; sustainable capacity thereafter.

Angola, Nigeria lead African declines.

In **Nigeria**, crude oil capacity declines steadily from 1.83 mb/d in 2020 to 1.67 mb/d by 2025 due to underinvestment. As other producers in Africa seek to improve commercial terms, Nigeria plans to raise taxes on its deep water oil production which could make investments far less attractive and threaten future development. Production rose 130 kb/d to 1.7 mb/d in 2019, the highest level since 2015, thanks to the start-up of the 200 kb/d Egina deepwater field, operated by Total, and a lull in militant attacks.

Total, however, is reportedly seeking to sell its 12.5% stake in deep water (OML) 118, which includes the Bonga field, as it rationalises its African portfolio. Output from the block is expected to rise whenever the Shell-operated Bonga Southwest project gets off the drawing board. However, the final investment decision on the project may be further delayed by uncertainty over commercial terms. Chevron, too, is reportedly seeking buyers for some of its Nigerian assets following a similar move by ExxonMobil in 2019. Shell and Chevron have already sold several blocks in recent years. Upstream spending has also been dwindling due to the lack of movement on the long-stalled Petroleum Industry Governance Bill, which aims to improve commercial terms and create a new national oil company.

Libya's production recovery stretched into a third year in 2019, with supply rising 120 kb/d to nearly 1.1 mb/d, the highest annual average since 2012. Capacity is expected to edge higher over the forecast period and reach 1.31 mb/d by the end of 2025.

Of course this depends upon political stability and sufficient revenue, perhaps including foreign investment, to fund infrastructure repairs. At the time of publication of this oil market report, Libya was in the grip of civil unrest that pits the UN-backed Government of National Accord against the Libyan National Army (LNA) and production had virtually ground to a halt.

Until early 2020, production and exports were broadly stable with much crucial infrastructure under the control of the LNA. However, facilities in the west and southwest that are not secured by the LNA are more vulnerable and stable conditions at more remote fields are crucial to sustaining higher output. El Sharara, Libya's largest oil field, experienced ups and downs during 2019, but at the end of the year was producing close to capacity at around 300 kb/d. The nearby El Feel was hit by air strikes, but was pumping roughly 70 kb/d by the end of last year.

Firmly secured by the LNA, the Waha Oil Co, located in the Sirte basin in the northeast, is also key to further growth. Some of its infrastructure, producing around 300 kb/d, has suffered extensive damage from attacks. Crude from Waha is delivered to the Es Sider export terminal. A top priority is to repair damage to the Es Sider and Ras Lanuf export outlets.

There is some hope that IOCs will return to the country. Total has finalised a deal with National Oil Corp (NOC) for a minority stake in a promising set of oil blocks. Total will help NOC boost production by 180 kb/d at the North Gialo and NC 98 fields in the Waha Oil Co. Tatneft has resumed upstream operations after a gap of more than five years and Eni, BP and Gazprom also plan to restart exploration.

Crude oil production in **Algeria** has been on the decline since peaking at 1.4 mb/d in 2007 and averaged 1.02 mb/d in 2019, the lowest since 2002. Capacity is expected to fall to 970 kb/d by the end of the forecast period. The new government, installed at the start of January, is facing an economic and political crisis triggered by falling oil and gas revenues. A new energy law, which features improved commercial terms and tax rates to attract investment, has also taken effect. For years, there has been a struggle to drum up interest from foreign firms, with companies complaining about tough commercial terms and red tape.

Production capacity in **Gabon** is set to slip to 190 kb/d by 2025, extending a decline from a peak of just below 400 kb/d in 1997. Ageing oil fields are seeing production slump due to a lack of development and long standing investors Total and Shell have sold off mature assets. Seeking to lure fresh spending, Gabon has opened a new licensing round that includes 12 shallow and 23 deep water blocks.

Equatorial Guinea is expected to hold capacity steady after two offshore finds come online. Recent discoveries by Noble Energy and Kosmos Energy are expected to provide a brief boost before capacity dips to 120 kb/d for the remainder of the forecast period. Crude output peaked at 310 kb/d in 2004. OPEC's smallest producer signed deals in January with companies including Noble Energy and Lukoil to develop oil exploration blocks. ExxonMobil intends to sell its holdings in the 90 kb/d Zafiro oil field as part of the disposal of USD 25 billion of global assets as it seeks to free up cash and focus on select mega-projects.

New discoveries and drilling programmes are expected to push production capacity in **Congo** to a peak of 380 kb/d in 2022-23. After sliding from 310 kb/d in 2010, output began to recover from 2017 on the back of production from deep-water fields such as Total's Moho Nord and Eni's Nene Marine that are helping to make up for losses at mature fields. In 2018, Congo awarded three production sharing contracts for offshore fields to Total, Kosmos and Perenco under the first phase of its latest licensing round. In the second phase, a consortium of Eni and Lukoil won two offshore blocks, while US-based Kosmos Energy won a single offshore block. Eni-Lukoil secured Marine XXXI and Marine XXIV and Kosmos snared Marine XXII.

Table 2.2 Estimated sustainable OPEC crude production capacity* (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2019-25
Algeria	1.05	1.03	1.01	1.00	0.99	0.98	0.97	-0.08
Angola	1.43	1.43	1.43	1.40	1.37	1.32	1.27	-0.16
Congo	0.35	0.35	0.37	0.38	0.38	0.37	0.36	0.01
Ecuador****	0.55	0.55	0.55	0.56	0.56	0.56	0.56	0.01
Equatorial Guinea	0.12	0.12	0.13	0.12	0.12	0.12	0.12	0.00
Gabon	0.22	0.22	0.21	0.21	0.20	0.20	0.19	-0.03
Iran***	2.10	3.80	3.80	3.80	3.80	3.80	3.80	1.70
Iran w/sanctions	2.10	2.10	2.10	2.10	2.10	2.10	2.10	0.00
Iraq	4.90	4.93	4.98	5.10	5.23	5.37	5.50	0.60
Kuwait**	2.86	3.04	3.14	3.14	3.14	3.14	3.14	0.28
Libya	1.17	1.20	1.22	1.25	1.27	1.29	1.31	0.14
Nigeria	1.83	1.83	1.80	1.77	1.75	1.71	1.67	-0.16
Saudi Arabia**	12.00	12.13	12.25	12.25	12.25	12.25	12.25	0.25
UAE	3.52	3.67	3.75	3.82	3.88	3.95	4.00	0.48
Venezuela	0.84	0.70	0.70	0.70	0.70	0.70	0.70	-0.14
Total OPEC	**32.94**	**34.99**	**35.34**	**35.49**	**35.63**	**35.75**	**35.84**	**2.90**
OPEC/Iran sanctions	**32.94**	**33.29**	**33.64**	**33.79**	**33.93**	**34.05**	**34.14**	**1.20**

*Assessed at end year. **Includes Neutral Zone starting from 2020. **In 2019, Iran at 2.1 mb/d reflects *effective* capacity.
****Ecuador to be included in non-OPEC in the next report.

OPEC condensates and NGLs

Production of condensate, other natural gas liquids (NGLs) and non-conventional resources is expected to increase by 211 kb/d to 5.7 mb/d by 2025 as Middle East OPEC countries make natural gas development a top priority.

The **UAE** will drive the growth as it presses on with an integrated gas strategy that aims to achieve self-sufficiency by 2030. It is due to add 118 kb/d of condensates and NGLs by 2025. The offshore

Ghasha ultra-sour gas scheme, requiring investment of over USD 20 billion, is expected to pump more than 100 kb/d of oil and condensates when it starts up in the mid-2020s.

US sanctions will stymie growth in **Iran**, the largest gas producer in OPEC, where its giant South Pars gas field is being developed to meet rising demand. Whereas the earlier round of international sanctions in 2012-15 allowed Iran to export condensate, unilateral US sanctions since 2018 ban shipments which had been running at 300 kb/d. In late 2018, Total quit the South Pars 11 project after it failed to secure a waiver from the United States. The scheme, due to produce 240 kb/d of NGLs and condensates, is now to be developed by Iranian contractor Petropars. During the previous round of international sanctions, NIOC had to store condensate on tankers. Production from South Pars has subsequently increased because most of the field's 24 phases have been developed.

Saudi Arabia, OPEC's largest producer of gas liquids, will add 56 kb/d to reach 2 mb/d by 2025 as the Hawiyah and Shaybah NGL developments gradually ramp up. **Iraq** plans to boost exports of LPG and condensates as it gathers more of the fuels from its southern fields.

Table 2.3 Estimated OPEC condensate and NGL production (kb/d)

	2019	2020	2021	2022	2023	2024	2025	2019-25
Algeria	466	477	479	474	473	466	462	-4
Angola	60	60	68	67	67	66	63	3
Congo	7	7	7	7	7	7	7	0
Equatorial Guinea	86	84	83	80	78	75	74	-12
Iran	1 037	1 030	1 030	1 030	1 030	1 030	1 030	-7
Iraq	100	105	110	115	120	125	130	30
Kuwait	305	312	318	321	326	328	330	25
Libya	72	66	83	85	90	92	94	22
Nigeria	381	368	367	373	378	381	380	-1
Saudi Arabia	1 944	1 970	1 973	1 978	1 980	1 990	2 000	56
UAE	832	843	833	852	857	906	950	118
Venezuela	108	91	90	90	90	90	90	-18
Total NGLs*	**5 398**	**5 413**	**5 441**	**5 472**	**5 496**	**5 557**	**5 610**	**212**
Non-Conventional**	96	95	95	95	95	95	95	-1
Total OPEC	**5 494**	**5 508**	**5 536**	**5 567**	**5 591**	**5 652**	**5 705**	**211**

*Includes ethane. **Includes gas-to-liquids (GTLs).

Non-OPEC oil supply

The start-up of a number of new offshore oil projects along with continued gains from the US shale patch is set to propel non-OPEC production 2.1 mb/d higher in 2020. Growth eases to 1.3 mb/d in 2021 and slows considerably thereafter unless higher prices unlock further US expansions and/or field developments elsewhere are sanctioned and brought on line.

Overall, non-OPEC oil supply is forecast to expand by 4.5 mb/d by 2025 to reach 69.5 mb/d. While the United States remains the largest source of growth, its share is expected to slow dramatically over the forecast period. Significant increases will also come from Brazil, Guyana, Canada and Norway. The biggest declines are expected in Colombia, the United Kingdom, Russia and various producers in Asia.

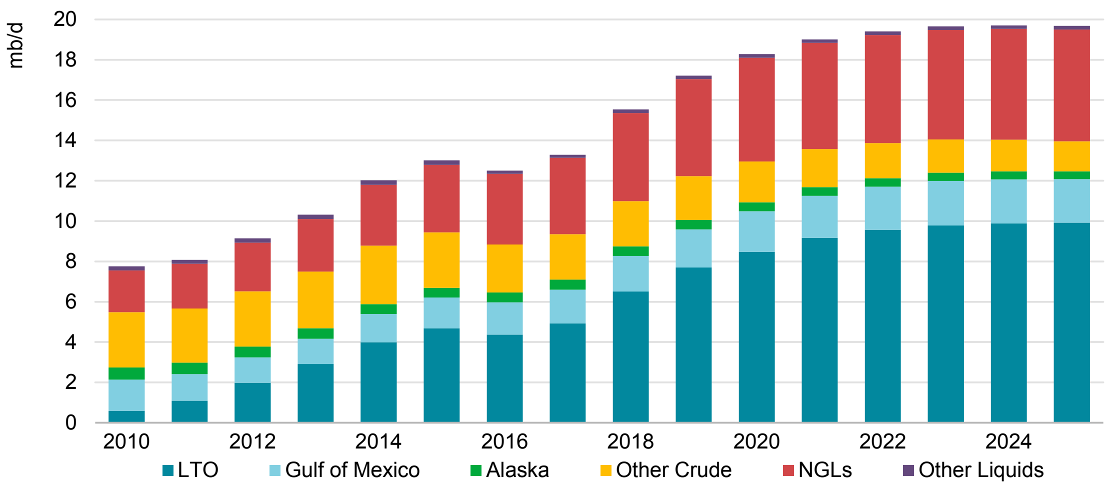
Table 2.4 Total Non-OPEC Supply (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2019-25
North America	24.7	25.9	26.9	27.3	27.5	27.5	27.5	2.8
Central and South America	4.8	5.1	5.2	5.2	5.6	6.0	6.3	1.5
Europe	3.6	3.9	4.0	3.9	4.0	3.8	3.6	0.0
Africa	1.5	1.4	1.3	1.3	1.3	1.4	1.4	0.0
Middle East	3.2	3.3	3.3	3.3	3.4	3.4	3.4	0.2
Eurasia	14.5	14.6	14.8	14.8	14.6	14.5	14.4	-0.1
Asia Pacific	7.6	7.6	7.5	7.4	7.3	7.2	7.0	-0.6
Non-OPEC oil production	**59.8**	**61.8**	**63.0**	**63.3**	**63.6**	**63.7**	**63.6**	**3.8**
Processing gains	2.3	2.4	2.4	2.4	2.5	2.5	2.5	0.2
Global biofuels	2.8	2.9	3.0	3.1	3.2	3.2	3.3	0.5
Total non-OPEC supply	**65.0**	**67.1**	**68.4**	**68.8**	**69.2**	**69.4**	**69.5**	**4.5**
Annual change	2.1	2.1	1.3	0.4	0.4	0.2	0.1	0.7

Pace of US oil expansion set to slow

Following a record increase of more than 2.2 mb/d in 2018, the pace of expansion in the United States slowed to 1.7 mb/d last year as independent producers cut spending and scaled back drilling activity. Growth is expected to ease further over the medium term unless higher oil prices unlock additional investments and resources. By 2025, total US oil production is forecast to reach nearly 20 mb/d, 2.5 mb/d higher than in 2019. The United States remains the largest contributor to non-OPEC growth in the medium term, accounting for 55% of the overall increase. Crude oil production rises 1.7 mb/d to 14 mb/d, led by higher light tight oil (LTO) output, primarily in the Permian Basin. Continued growth in natural gas production and new petrochemical capacity underpins gains of an additional 0.7 mb/d of natural gas liquids.

Figure 2.11 US total oil supply

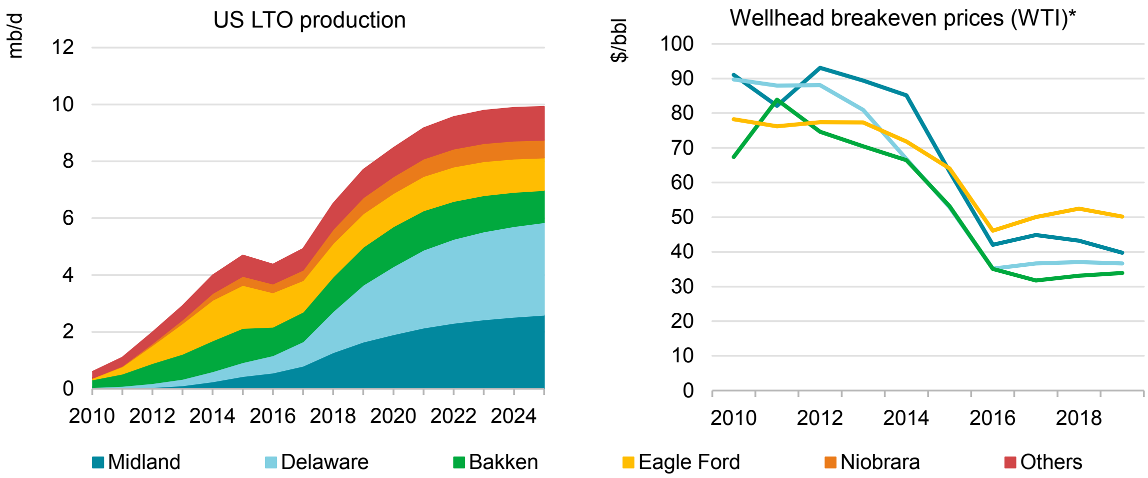


US total oil production to reach nearly 20 mb/d, even as the pace of the expansion slows.

The shift in strategy of the US industry to prioritise shareholder returns, capital discipline and stronger balance sheets led to a marked deceleration in spending and activity levels across the shale patch in 2019. Independent oil producers cut spending by 14%. As a result, the oil rig count dropped by a quarter to its lowest level in more than two years.

Even though investments and the number of rigs drilling new wells fell fast, US oil output continued to grow as cost control and efficiency measures provided an offset. In particular, rig efficiency and productivity increased to record levels in most big shale basins. Operators have not only significantly reduced the unit costs of drilling and completing tight oil wells but are drilling more wells faster from a single location and drilling multiple wells to produce oil simultaneously from different shale layers.

Figure 2.12 US LTO production and breakeven prices



*Source: Rystad Energy.

Tight oil output rises to 10 mb/d, led by continued Permian expansion.

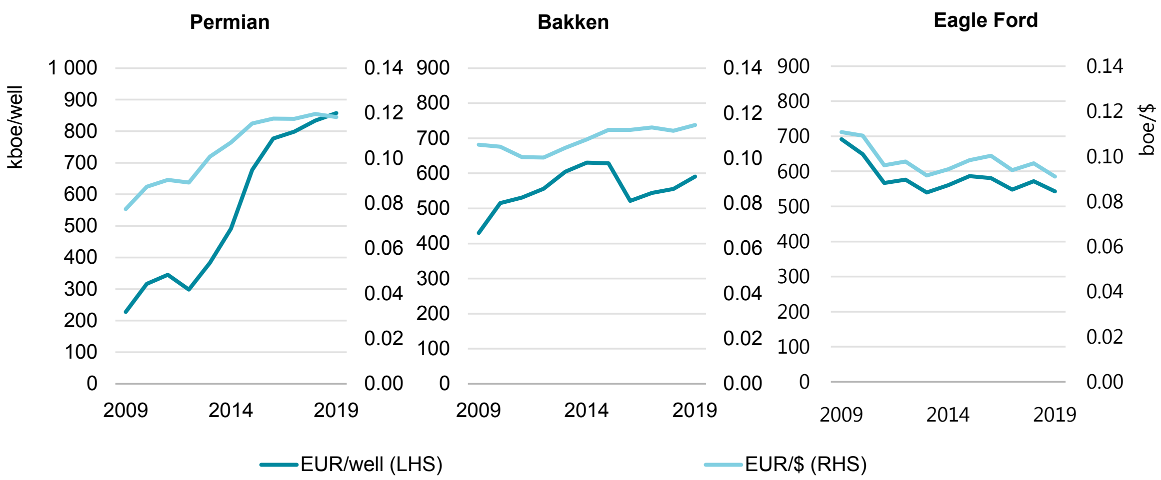
Moreover, the average well is producing more oil and gas. Longer horizontal sections, more intensive fracturing and wider well-spacing have boosted productivity. The horizontal length of the average tight oil well drilled today is 60% greater than in 2012 and it uses three times more water and proppant. Operators are focusing activity on their most productive areas to generate larger and faster returns on investment. Across the main shale plays, 40% of wells drilled in 2012 were in these core areas; by 2019 this had increased to nearly 70%.

While further efficiency and productivity improvements could be made in coming years, this will depend on technological breakthroughs and costs. It is possible that we will see a reversal in the trend over the medium term as some producers run out of core acreage and the most prolific areas in Bakken and the Eagle Ford mature.

An increasing number of new wells will be required to offset losses from the existing production base. Production from tight oil wells declines very rapidly after completion, often by as much as 70% within the first year. The decline is more severe for oil than for gas and natural gas liquids, resulting in increasing gas to oil ratios. A shift in investments from the Midland portion of the Permian to the gassier Delaware Basin has also played a part. Higher gas output is cutting into company profits as in some cases producers have to pay to get their gas taken away. In the last few years, several operators have seen fracture interference between existing production wells (parent wells) and newly fractured infill wells (child wells) that has had a negative impact on the production from both the parent and child wells.

There are also signs that improvements in initial production rates (due primarily to the increase in frac intensity) are not entirely flowing through to later stages of the well's lifetime. That shows up in a deceleration in per-foot productivity improvement, which has been one of the most significant factors behind the resilience of US tight oil production growth in recent years. The estimated ultimate recovery per well and per dollar spent is also tapering off.

Figure 2.13 Estimated ultimate recovery per well and per dollar spent in selected shale basins



The Permian sees continued gains in well productivity but at higher cost as increased efforts required.

Box 2.1 Supply growth at risk from lower prices

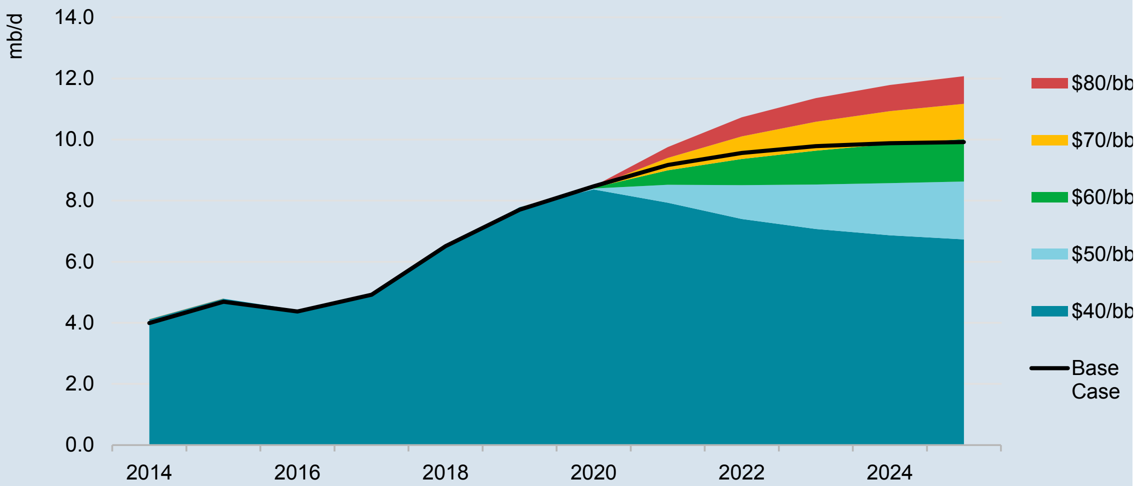
While the impact of the Coronavirus so far has been largely limited to demand, lower prices seen in early March could, if sustained, curb oil production. In the near-term, US LTO supply is likely to be hit the hardest. Producers must continuously drill new wells to sustain output and are under pressure to deliver positive cashflow.

This report uses a price assumption for modelling purposes of USD 60/bbl for Brent through to 2025. However, prices are highly volatile given the uncertainty surrounding the duration and impact of the epidemic and the response from OPEC+. Crude oil prices fell by roughly 25% since the start of 2020 to around USD 50/bbl for Brent in early March, with WTI USD 5/bbl lower.

While WTI at USD 45/bbl is still sufficient to cover operating expenses at existing wells, for many companies prices have fallen below the threshold to increase activity. Following spending cuts of 14% in 2019, US independent oil producers had already pledged to cut investments by another 10% in 2020. Lower prices might lead to further cost cutting for the heavily indebted shale industry.

According to Rystad Energy, WTI breakeven prices for shale acreage generally lie in the range of USD 40-50/bbl with the best locations coming in below USD 20/bbl. For all wells, Rystad estimates that full cost WTI breakeven prices dropped further in 2019, to USD 49/bbl for the Permian and USD 59/bbl for Eagle Ford. Wellhead breakeven prices were on average USD 10/bbl lower.

US LTO price sensitivities



The response of shale production to different prices is critical, as it will play a key role in balancing the market over the medium term. If prices hover around USD 60/bbl, LTO output is expected to rise by 2.2 mb/d to around 9.9 mb/d in 2025. Should prices for any extended period veer away from this level, however, producers are expected to respond accordingly. As an illustration, a price of USD 80/bbl throughout our forecast period could result in output rising by as much as 4.3 mb/d over the same period. Alternatively, a price of USD 40/bbl would cause LTO output to decline from 2021 onwards.

Gulf of Mexico set for further gains

With many developments set to come online, crude oil production in the US Gulf of Mexico is expected to continue to grow over the medium term. Output rises from 1.9 mb/d in 2019 to 2.15 mb/d in 2025. In 2020, gains will primarily come from projects still in the ramp-up phase. In particular, Shell's Appomattox project that started up ahead of schedule in May 2019 still has some way to go before reaching its 175 kb/d capacity. Increases will also come from Hess' Stampede and Chevron's Big Foot fields that have yet to reach plateau levels.

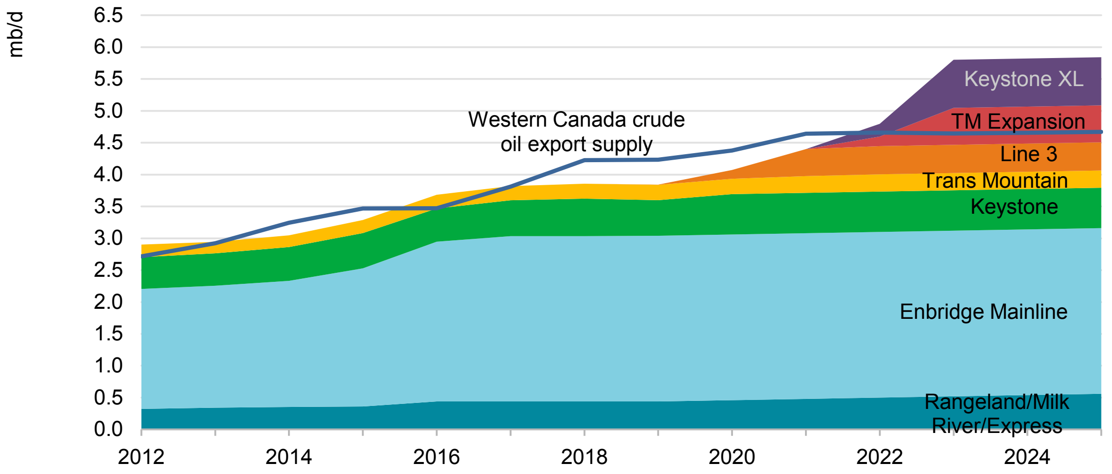
Later on, Shell's 100 kb/d Vito project will provide a substantial boost. First production is expected in 2021. Further gains will come from BP's 140 kb/d Mad Dog Phase 2 project, scheduled to see first oil by the end of 2021. Also expected online in 2021 is BP's Thunder Horse South Expansion phase 2 that will boost output by 50 kb/d.

In 2019, two significant new developments in the Gulf were sanctioned. In August, Murphy Oil greenlighted its King's Quay project that will have a production capacity of up to 80 kb/d and is set to start up by mid-2022. Chevron gave the go-ahead for the deep-water Anchor development in December 2019 and the project will produce 75 kb/d of crude oil and 28 mcf/d of natural gas from 2024.

Canadian oil supply picks up as takeaway capacity rises

Faced with export capacity constraints and mandatory production curtailments, Canada's largest oil producers cut output last year. Even so, output for 2019 as a whole was up 140 kb/d versus 2018 with production setting a fresh record by the end of the year. As production curtailments in Alberta ease further and new pipeline and rail capacity come on stream from 2020, growth is expected to continue. Oil supply is forecast to expand by 0.5 mb/d over the 2019-25 period, although this is significantly lower than the 1.4 mb/d seen in 2013-19.

Figure 2.14 Canada crude oil takeaway capacity vs export supply



Near-term incremental pipeline capacity to allow for higher supply but more is required.

Growth is mostly concentrated in the near term, with longer term projects put on hold due to concerns about price volatility linked to takeaway capacity constraintsand climate risk. In 2020, optimisation projects on a number of lines will add more than 200 kb/d of pipeline capacity and by year-end the completion of Enbridge's Line 3 replacement will allow another 370 kb/d of oil to move to the United States.

The additional takeaway capacity will allow the ramp-up of recently completed projects as well as further debottlenecking and optimisation of existing facilities. Notably, Phase G of Cenovus's Christina Lake facility will add 50 kb/d of production in 2020; Canadian Natural Resources Limited (CNRL) will bring on Kirby North in 2020; and Suncor plans to complete the 40 kb/d Meadow Creek West by 2023. Debottlenecking projects will also add capacity at ConocoPhillips' Surmont project.

In the longer term, growth slows considerably. Local opposition and legal challenges have delayed major pipeline projects needed to absorb Western Canada's production potential, and companies seem reluctant to sanction new projects until additional capacity from either Keystone XL or Trans Mountain can be brought online. Imperial Oil put on hold its Aspen project after government production curtailments were put in place.

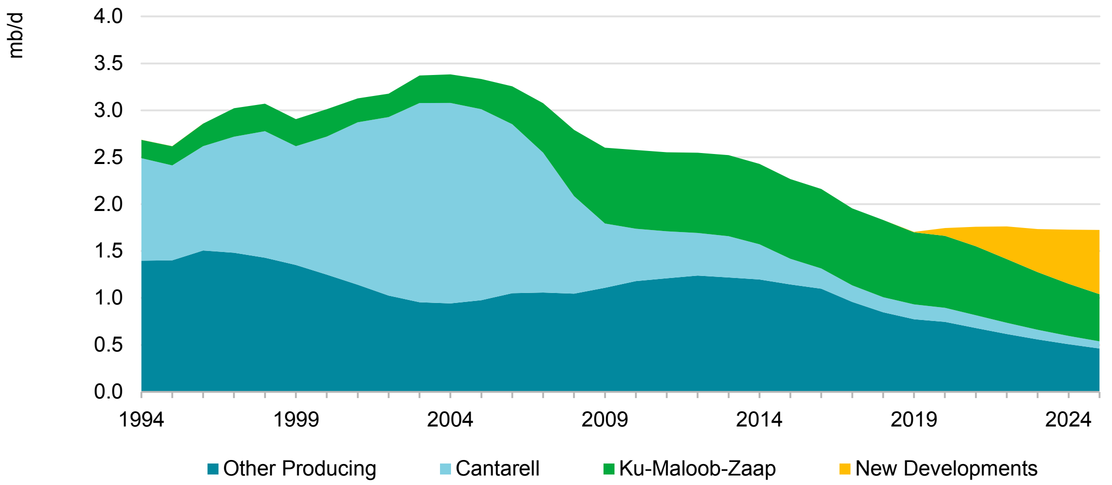
In the offshore sector, production is forecast to increase by 60 kb/d from 265 kb/d in 2019 to 325 kb/d in 2025. The bulk of the increase is expected in 2020 from ExxonMobil's Hebron field, even though the project had already reached capacity of 150 kb/d at the start of the year. Husky

Energy and ExxonMobil are moving ahead with their West White Rose development, sanctioned in 2018. First oil is expected in 2023, with an expected peak production rate of 75 kb/d in 2025. Equinor is planning to make a decision this year on whether to develop the deep-water Bay du Nord offshore project in which it holds a 65% stake. The project, which will target nearly 300 million barrels of oil reserves, could come online by 2025.

Mexican decline slows but growth target looks elusive

Despite an anticipated boost in the near term, Mexico's long term oil production decline is not expected to be reversed before 2025. A shift in focus towards short cycle developments onshore and in the shallow waters and away from deepwater and joint venture projects means that in the longer term, new project developments outlined so far will not produce enough to offset declines from mature fields. Based on current plans, total oil supply is seen falling by 150 kb/d over the period to 2025, to 1.8 mb/d (1.6 mb/d crude). While a marked improvement from the decline of more than 960 kb/d seen in 2013-19, output is expected to fall short of the government's goal of lifting crude oil production to 2.6 mb/d by 2024.

Figure 2.15 Mexican crude oil production



Mexican decline slows, but 2024 target looks elusive.

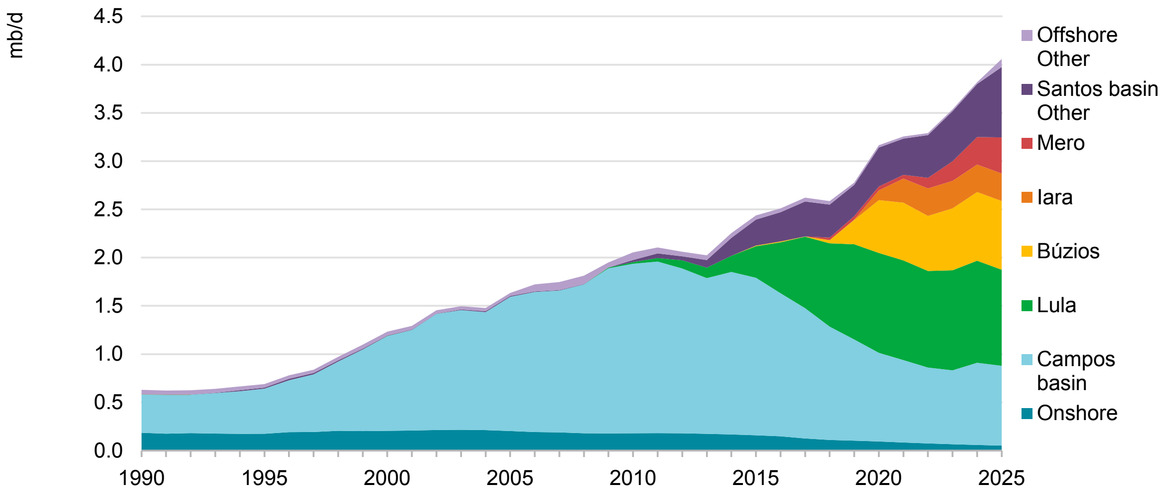
Mexican oil production has been on a downward slope since peaking in 2004, and the largest fields Ku-Maloob-Zaap and Cantarell are expected to see further declines in the medium term. Nevertheless, increased investment is starting to pay off. Pemex announced the development of 20 priority fields as its main strategy to increase oil production in the near term, targeting output from these fields of more than 300 kb/d by 2021. Production will also be supported by the start-up of Eni's Area 1 that includes the Amoca, Tecoalli and Mizdon fields.

There will also be growth from the Talos Energy-operated Zama and Hokchi Energy's Hokchi oil fields, both discovered in 2017 after the sector was opened up to private players. In December 2019, Pemex announced it had found a huge oil deposit in Tabasco that could yield 500 mb of crude, its largest discovery since 1987. Even so, the suspension of competitive oil auctions open to private and foreign oil companies and the cancellation of auctions to pick joint venture partners for Pemex will make it difficult to grow substantially.

Brazil growth spurt firmly underway

With annual growth rates exceeding 500 kb/d in late-2019, Brazil's supply surge is firmly underway. Production is expected to increase by a further 1.1 mb/d by 2025, securing Brazil the spot as the second-fastest growing non-OPEC oil producer over the medium term. Total output will surpass 4 mb/d in 2025.

Figure 2.16 Brazil Crude Oil Production



Prolific pre-salt deposits underpin sharp rise in Brazilian oil output.

In its updated five-year business plan that extends through 2024, Petrobras reduced its capital expenditures to USD 75.7 bn in 2020-24, down 10% from the USD 84.1 bn planned for 2019-2023. As in the previous plan, Petrobras intends to spend the bulk of its investments in the upstream, with 85% of the total earmarked for exploration and production, mainly to develop its prolific pre-salt deposits. Petrobras expects its own oil production to rise from 2.2 mb/d in 2020 to 2.9 mb/d in 2024, not taking into account potential divestments. Significant gains will also come from IOCs that are increasing their presence, often in partnership with Petrobras. The largest increases are expected to come from Shell, Total, CNOOC and CNPC.

To fuel growth, Petrobras intends to deploy 13 new FPSOs in the next five years, of which seven - P-70 (Atapu), Carioca (Sepia), Guanabara (Mero-1), Almirante Barroso (Buzios-5), Sepetiba (Mero-2), Anita Garibaldi (Marlim-1) and Ana Neri (Marlim-2) – have been contracted already. The company is currently tendering for three more units – Mero-3, Itapu and Parque das Baleias – with another three FPSOs to enter operation by 2024, including Mero-4 and Sergipe-Alagoas Deepwater.

In early February, Petrobras announced it is fast tracking developments at the Buzios field, looking to contract for two additional FPSOs this year. Buzios-6 and Buzios-7 are expected to have a handling capacity of at least 180 kb/d each and could come online as early as 2024 and 2025, respectively.

Meanwhile, Equinor, ExxonMobil and Galp Energia are moving ahead with their Bacalhau (previously known as Carcara) development. It was declared to be commercial late in 2019 and a 220 kb/d FPSO is reportedly being contracted for the development. This will be the largest such vessel to enter operations in Brazil. First oil is earmarked for the end of 2023 or in 2024. The consortium plans to bring onstream a second FPSO, possibly as large as the first one, with output expected between 2026 and 2028.

Efforts are also being made to stem output declines in the mature Campos Basin. In early January, Petrobras announced it would invest USD 8 bn over the next six years to revitalise operations in the mature Barracuda-Caratinga field. Petrobras had already said it intends to invest about USD 20 bn in the Campos Basin over the next five years, including exploration work at newly acquired blocks. Investments will be split between the Marlim, Marlim Sul, Marlim Leste, Roncador, Albacora, Albacora Leste, Tartaruga Verde and the Barracuda-Cartatinga fields, all in steep decline currently.

Guyana growth offsets Latin American declines

As for the rest of Latin America, oil supply is expected to rise by 380 kb/d to 2.2 mb/d by 2025. **Guyana** will be the key source of growth, as ExxonMobil, Hess and CNOOC plough ahead with new field developments in the Straebroek, Canje and Kaieteur Blocks offshore blocks. In early 2020, Exxon announced its 16th discovery on the Staebroek Block, raising the estimated recoverable resource to more than 8 billion barrels oil equivalent.

The Liza Phase 1 development achieved first oil in December 2019 and will produce up to 120 kb/d utilising the Liza Destiny FPSO. The Liza Unity FPSO, which will be employed for the second phase of the Liza development and will have a production capacity of 220 kb/d, is under construction and expected to start production by mid-2022.

Pending government approvals and project sanctioning of a third development, production from the Payara field north of the Liza discoveries could start as early as 2023, reaching an estimated 220 kb/d. The consortium has said that five FPSOs could take Guyana’s total production to 750 kb/d by 2025.

Growth will also come from **Argentina**, where significant investments are being made by Chevron, ExxonMobil, Shell and state-backed YPF in the Vaca Muerta shale play. Exxon last year kicked off a major long-term development of its onshore Bajo del Choique-La Invernada block in the Vaca Muerta shale play in the Neuquen province. Exxon plans to drill 90 wells over the next five years and produce 55 kboe/d. A possible second phase could see output boosted to 75 kboe/d. Total output rises 70 kb/d over the period. LTO production expands by 150 kb/d to 250 kb/d in 2025, more than offsetting declines at conventional fields.

In contrast, production is expected to decline in **Colombia** and **Trinidad and Tobago** on a dearth of new discoveries and new project approvals. In a push to turn the tide and attract new investments, Colombia held two oil auctions in 2019. Ecopetrol, the largest oil producer, is also planning to boost exploration and upstream capex for 2020, but is dedicating a larger share of investments to international developments (US Permian and Brazil offshore).

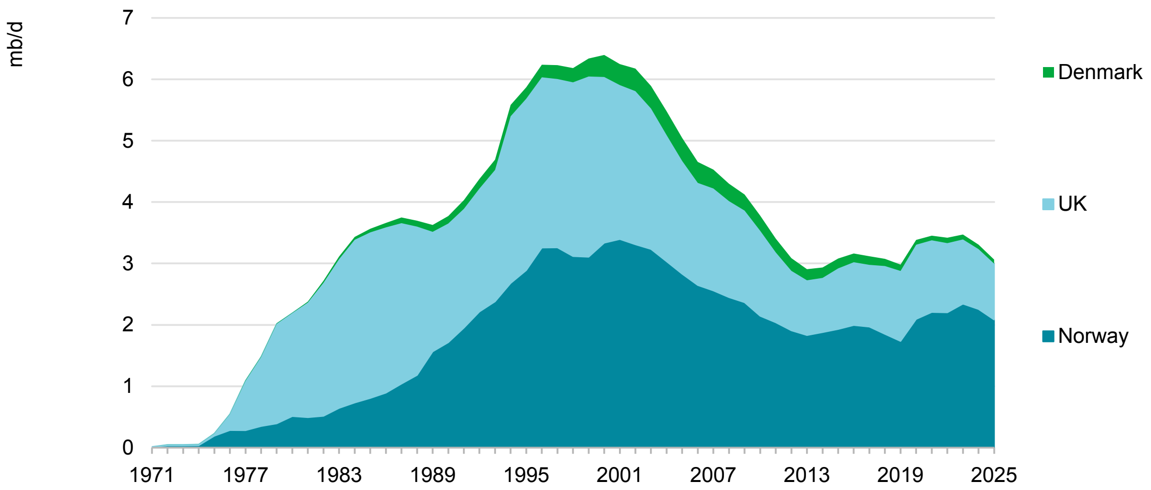
In September 2019, the government decided to maintain a moratorium on fracking. Colombia has the continent's second-highest estimated non-conventional reserves of up to 7 billion barrels (behind Argentina) but the government has not yet given the green light to exploit them because of environmental concerns.

Following declines of 35 kb/d over the 2013-19 period, production in Trinidad and Tobago falls by a further 30 kb/d to 50 kb/d by 2025.

Mature North Sea rebounds

In recent years, production from the North Sea has stabilised at around 3 mb/d, which is less than half the level seen when regional output peaked in 2000. Healthy growth of 490 kb/d in the early part of the forecast period will see flows reach 3.5 mb/d, the highest since 2010, thanks largely to Norway's giant Johan Sverdrup field, which started up in 2019. From 2024 onwards North Sea growth will be overwhelmed by steep declines in base production, although there are several identified opportunities that could be sanctioned and online before the end of the forecast period. However, for the most part, these are relatively small field tie-backs or plateau extensions.

Figure 2.17 North Sea total oil supply



Norwegian projects Johan Sverdrup and Johan Castberg spur modest North Sea revival. Steep declines in base production overwhelm growth by 2025.

Norway's medium term growth is assured as production from Johan Sverdrup is expected to reach 660 kb/d after phase 2 comes online in 2022. Norway's other medium term project start-ups, such as the redevelopment of the Tor field, Yme and Martin Linge, are relatively small. The exception is Equinor's Johan Castberg field, due onstream in 2022, which will add 170 kb/d. Production is expected to peak at 2.3 mb/d in 2023 before returning to steep decline at the end of the forecast period. Overall, output is 350 kb/d higher in 2025. The potential for more growth further out depends on exploration and appraisal activity. While this was stepped up in 2019, with 57 wells drilled and 17 discoveries made, it is several years since there was a significant find in Norwegian acreage.

With few sources of growth for **UK** oil production on the table, 2020 looks likely to be the only year when production rises in the medium term. To 2025, flows are set to fall by 230 kb/d to 910 kb/d. Independent and private-equity backed firms continue to increase their footprint but there has been little focus on exploration, with only a modest pick-up in activity from the decades-low level seen in 2018, according to the Oil and Gas Authority (OGA).

Box 2.2 Mature North Sea preparing for transition

With high awareness of climate concerns in Norway, Equinor has been keen to stress the steps it has taken to make new developments compatible with a lower carbon world. The Johan Sverdrup platform is supplied with electricity by underwater cables linked to the mainland and Norway's mostly hydroelectrically powered grid, and is therefore fuelled with renewable energy as opposed to gas or diesel. According to Equinor, this puts the carbon intensity of Johan Sverdrup production at 0.7 kg CO_2/bbl, around 200 times better than the global average.

Equinor is connecting several of its existing fields to hydro and wind-generated electricity with the aim to reduce the net emissions from its operations in Norway to zero in 2050. With further targets to halve the carbon intensity of its global production, including scope 1, 2 and 3 emissions, Equinor one of the leaders in its peer group and the company states that this will allow it to remain competitive as demand shifts to lower carbon energy. However, the company faces criticism for continuing the development of conventional oil and gas projects that are expected to produce for decades to come.

In the United Kingdom, the OGA has also called for increased electrification of production facilities to reduce the carbon intensity of output. BP, Total and Shell are together conducting feasibility studies in the Central North Sea, but without Norway's hydro-fuelled grid and existing power-links to the mainland this may be a more challenging economic prospect. Although the government has committed to a national emissions target of zero by 2050 and in 2019 halted shale exploration activity, there are no signs that it would like to deter other upstream investments and the United Kingdom continues to have an attractive fiscal regime.

The OGA has been granted funds specifically to allow it to work with the government and industry to facilitate platform electrification and has been vocal about the need for operators to use their technical experience and find innovative ways to adapt to the energy transition. Indeed, this may be even more relevant for the smaller players to prove that they are attractive investments.

The IEA estimates that the greenhouse (GHG) emissions from the oil and gas industry's operations account for 15% of the global total. The IOCs have recognised the importance of reducing methane leaks as this is a very potent GHG (one tonne of methane is equivalent to 30 tonnes of CO_2). While North Sea operations have relatively low methane emissions, there are potential risks of leaks from more mature infrastructure and challenges to accurately measure the scale of the issue. Again, Equinor appears to be leading the pack having strengthened procedures to detect and reduce methane emissions at its platforms. According to the Oil and Gas Climate Initiative, at 0.03% Equinor's methane intensity for its upstream and midstream operations is around 10% of the industry average. It is hoped that others will follow and BP have already announced plans to install methane measurement equipment at its major oil and gas processing sites by 2023.

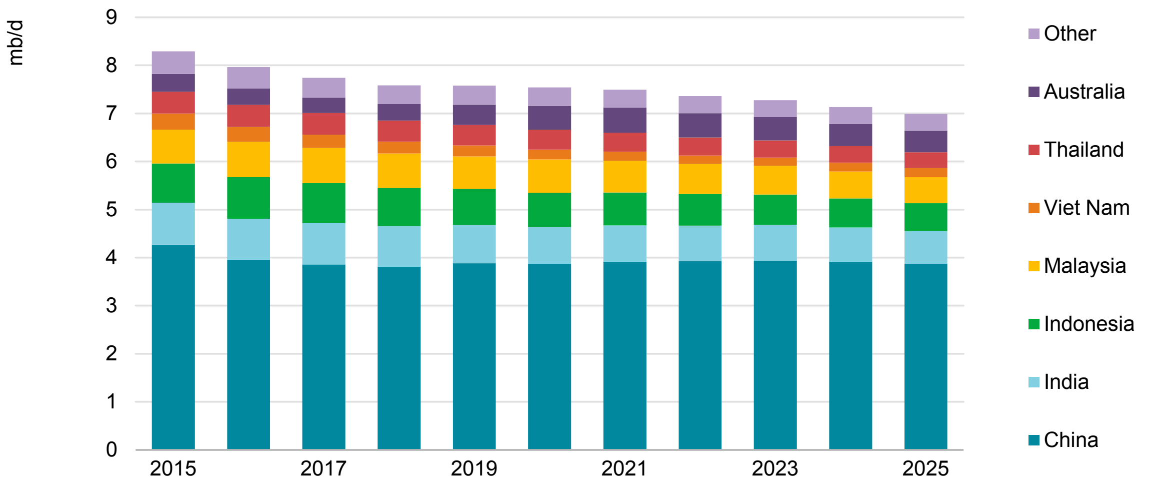
Australian upstream takes a pause

In 2019, there were no new significant oil projects sanctioned in **Australia**. However, production did rise to a seven year high of 420 kb/d. Increased condensate output associated with huge liquefied natural gas (LNG) projects in Western Australia were largely responsible but crude from Woodside's Greater Enfield project also contributed to total gains of 75 kb/d. The continued ramp-up and expansion of LNG projects will help Australia to grow further in 2020-21, but afterwards the lack of new investments will take its toll. Overall, output will end the forecast period only 25 kb/d higher than in 2019. Exploration activity did recover last year, and the successful appraisal of Santos' Dorado prospect may result in its approval in 2020. Dorado could add up to 100 kb/d of liquids later in the forecast period. Elsewhere in Australasia, activity levels are depressed. With no new developments tabled, New Zealand's oil output will halve to 15 kb/d in 2025.

Steep declines and investment slump sees Asia drop further

With its ageing oil fields and investments increasingly geared towards gas, Asia accounts for the largest output declines over the medium term. Oil production, already down 780 kb/d over the 2010-19 period, is set to fall by a further 575 kb/d by 2025. The largest declines are expected to come from Indonesia, Malaysia, India and Thailand.

Figure 2.18 Asia total oil production



Note: Including non-conventional oil production, excluding biofuels.

Steep declines at mature fields and dearth of new projects sees Asian oil output slump further.

Indonesia's oil production is on a steady downward trajectory due to a lack of investment in the upstream sector. Output declined by 4% in both 2018 and 2019. At 735 kb/d in 2019 crude and condensate production fell short of the government's target of 775 kb/d. Total oil output is forecast to drop another 165 kb/d by 2025, to 600 kb/d. Following a small boost expected in 2020, **Malaysian** crude oil production is forecast to resume declines. By 2025, total oil supply is 120 kb/d lower than in 2019. Near term growth comes from the completion of Sabah Shell Petroleum's phase 2 of its Gumusut-Kakap project that will increase the production of key export crude, Kimanis, by an estimated 50 kb/d.

Indian production also failed to hit government targets in 2019, falling by 40 kb/d, or 5%, on average due to increased water cut at a number of wells. Delays in getting the KG-DWN-98 project off the ground, and a scaling back of the FPSO's oil processing capacity from 90 kb/d to 50 kb/d, have curbed growth compared with earlier expectations. That said, state-controlled Oil and Natural Gas Corporation and Oil India (OIL) have announced plans to invest around USD 58 billion by 2023 in oil and gas exploration and production activities in a bid to boost output.

Production is nevertheless seen declining by 125 kb/d over the forecast period, to 675 kb/d in 2025. **Thailand**'s oil production is expected to fall by 100 kb/d, to 325 kb/d (including ethane) while **Viet Nam**'s oil output drops by 35 kb/d, to 190 kb/d.

In contrast, the outlook for **Chinese** production continues to improve as companies step up efforts to increase domestic output in order to enhance oil supply security. State-producers, CNPC, Sinopec and CNOOC, which account for the bulk of China's oil production, lifted upstream spending by 30% in 2018, to USD 45.5 bn, with a further 18% increase planned for 2019. As a result, domestic crude oil output rose by 50 kb/d last year, reversing declines in place since 2016. In the longer term, aging oil fields will cap further upside. We expect crude production to revert back to the long term decline path by the mid-2020s and in 2025 output is expected to be 280 kb/d lower than in 2019. Rising coal-to-liquids production could offset the decline however, so that total Chinese oil supply holds steady at around 3.9 mb/d through the medium-term.

Africa struggles to get projects off the ground

With the exception of Senegal, where projects are moving apace, technical problems and delays in bringing new projects online continue to derail growth plans in Africa. New projects are nevertheless expected to offset declines at mature assets with production rebounding to 2019 levels of 1.5 mb/d by 2025.

In **Uganda**, a FID on the Lake Albert oil project that is being developed by Total, CNOOC and Tullow Oil has yet again been delayed by a series of tax and other disputes. Work was suspended last August, but in December the Ugandan government announced it had reached a tax resolution with the consortium that could pave the way for a FID this year on the project that includes a crude export pipeline to the Tanzanian coast. Output of up to 230 kb/d from the Tilenga and Kingfisher fields is expected to start up in 2024.

An FID is also expected in 2020 for the proposed South Lokichar project in **Kenya**. In the first phase, Tullow Oil and its partners aim to produce 60-80 kb/d of oil that will be shipped to the port of Lamu on the Indian Ocean. The full development plan sees production reaching 100 kb/d during the second half of the decade. The consortium exported its first trial crude cargo last August from the pilot scheme already in place. Around 2 kb/d of Kenyan crude is still being trucked by road from South Lokichar to Mombasa.

Senegal's first oil development, Sangomar, which received its FID in January, is expected to start up in early 2023. The offshore field, previously known as SNE, is being developed by Woodside, Cairn Energy, Far and Senegal's state-owned Petrosen. It is expected to produce up to 100 kb/d from an FPSO.

In contrast, **Ghana**'s growth prospects have been derailed by technical problems and delays. Output is now expected to decline by 25 kb/d to 175 kb/d in 2025. In a 2019 investor update, Tullow Oil, Ghana's largest oil producer, announced that it had been struggling with mechanical issues at its Jubilee field and a delay in completing a well at the TEN offshore field. The company significantly pared back its production guidance for the next few years. The growth outlook has also been affected by delays to Aker Energy's proposed Pecan project after its most recent development plan proved to be unworkable. The project was targeting first oil in 2022 through a 110 kb/d FPSO. Aker is now looking to simplify the technical concept and reduce development costs of the project which holds resources of 450-550 mb. Output is now expected to decline marginally

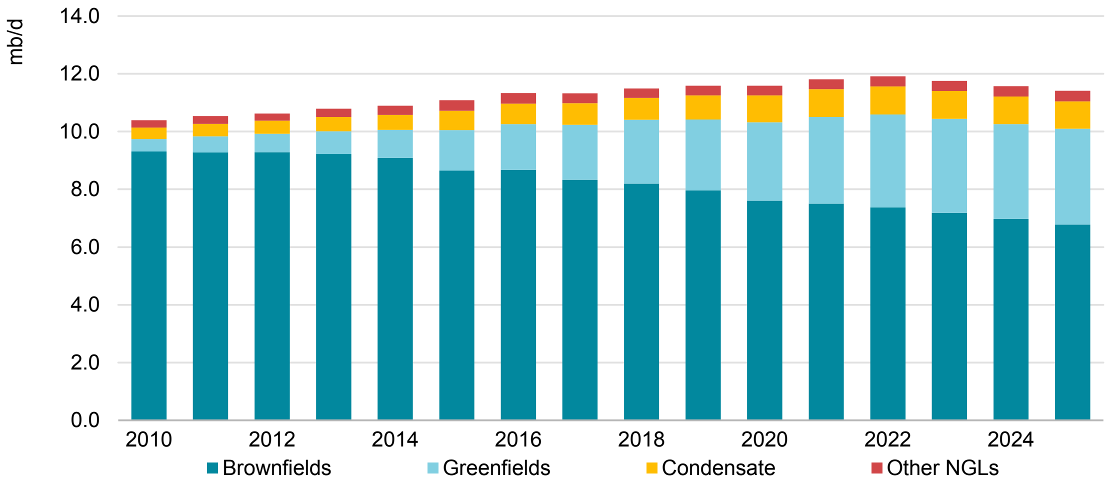
Russia: Near-term potential, longer-term risk

Russian oil supply, currently constrained by OPEC+ output cuts, could get a near term boost when and if the deal expires. In the longer term, production is expected to see a marginal decline if prices stay at current levels and the tax system remains unchanged. Total oil output is forecast to reach a peak of 11.9 mb/d in 2022 before going into gradual decline. Overall, Russian oil supply falls 210 kb/d by 2025, to 11.4 mb/d. Crude oil and condensates output slips from 11.25 mb/d in 2019 to 11 mb/d by the end of the forecast period.

Despite an active OPEC+ market management policy, Russian oil production has increased in recent years. Output rose by 1.2 mb/d over the 2010-19 period and as much as 260 kb/d over the past two years, firmly establishing Russia as the world's second largest oil producer. The near term outlook is clouded by uncertainty over the duration of the OPEC+ deal. Russia has pledged to reduce its crude oil production by 300 kb/d below October 2018 levels through March 2020. If the deal stays in place through to the end of the year, output is likely to hold steady in 2020.

Production is expected to bounce back if the deal ends, however. At the start of 2020, output was 155 kb/d below the all-time peak reached at the end of 2018 as companies shut in production and put on hold new greenfield developments.

Figure 2.19 Russian total oil production



Near term outlook hinges on production policy, declines to set in.

Growth will come from new fields that have yet to reach plateau capacity and new assets yet to start production. For example, further gains are expected to come from Rosneft's Suzun, Kondinskoe, Srednebotuobinskoe (Tass-Yuryakh), Yurubcheno-Tokhomskoe greenfields as well as from East Messoyakha that it is developing with Gazpromneft. Gains will also come from the Kuyumba field that is set to reach peak production of 60 kb/d at the same time, and from Tagul that is still ramping up towards its 90 kb/d capacity target. Rosneft has brought Russkoe, a new hard-to-recover oilfield, online at the end of 2018. Production will reach 130 kb/d by the mid-2020s.

Lukoil is also focusing on hard-to-recover reserves, which receive significant tax breaks, and expects production from its Yaregskoye and Usinskoye fields to ramp up over the next few years, driven largely by steam injection technology. In West Siberia, the Imilorskoe field, also condsidered a hard-to recover oil field eligble for special tax rates, could add furhter growth.

The company also has a major offshore focus on the Caspian Sea, where the existing Filanovsky and Yuri Korchagin fields are increasing output as new stages of their development are brought online. Output from Korchagin rose by 21% y-o-y in 2019 and a third stage of Filanovksy was launched last November. The nearby Grayfer field could add an additional 25 kb/d from 2023. Lukoil is looking to expand gas condensate production in the Yamal-Nenets Autonomous District and started pilot production at the Yuzhno-Messoyakhskoye gas condensate field late last year.

Finally, GazpromNeft continues to ramp up production at its Arctic fields that includes Prirazlomnoye, Novy Port and Vostochno-Messoyakhskoye. Output at East Messoyakha is expected to peak at 120 kb/d in the early 2020s. The use of multi-lateral horizontal wells has helped to overcome difficult geological conditions, and the economics of the field have been enhanced by export duty concessions that will run to 2024. Gazpromneft plans to bring West Messoyakha online by 2021.

Companies are also expected to manage the natural decline of existing fields using increasingly complex recovery techniques. Increased drilling, in particular of horizontal wells, has enabled producers to stem declines at mature fields in West Siberia.

Oil minister Novak, meanwhile, warned that oil production in Russia, which has enough reserves of crude to sustain current production for over 50 years, could decline if the tax system remains unchanged. Russian oil is taxed at a rate of around 70% of revenues, and as much as 85% for Western Siberian fields. These are are amongst the highest rates in the world. According to Novak, much of the country's reserves cannot be developed economically under the current tax regime. Like many other oil producers, Russia depends heavily on revenues from crude oil and gas development. The Finance Ministry has repeatedly opposed lowering taxes on the oil industry.

Caspian producers

In the Caspian region, the biggest gains will come from **Kazakhstan**, where international consortia have launched a number of projects to shore up output. Most notably, Chevron's Future Growth Project at Tengiz will bump up the field's capacity by 260 kb/d to 850 kb/d in 2023. In 2019, partners in the Eni-led Karachaganak gas and condensate development took an FID on a USD 5 bn gas injection compressor project, the last of a series of investments aimed at extending the duration of the plateau phase. As for the offshore Kashagan field, which has fuelled growth in recent years, output reached a record level of 390 kb/d by end-2019, higher than the nameplate capacity of 370 kb/d. According to the Ministry of Energy, expansion projects could lead to an increase in field output to 420 kb/d in 2022 and 500 kb/d in 2027. Overall, Kazkahstan's total oil production is forecast to rise by 100 kb/d over the forecast period to reach 2.04 mb/d in 2025.

In **Azerbaijan**, production is expected to see continued declines until 2023 as output from the Azeri-Chirag-Deepwater Gunashli (ACG) complex falls further. ACG production, which accounts for roughly three-quarters of Azeri oil supply, averaged 535 kb/d in 2019, down from 585 kb/d in 2018 and 835 kb/d in 2010. Capacity is expected to rise when the new Azeri Central East platform comes on line in 2023. BP and its partners sanctioned the project last April, planning to spend USD 6 billion to add 100 kb/d of capacity. Azeri output is expected to rebound to 740 kb/d by 2025.

Oil supply in **Uzbekistan,** meanwhile, will get a boost from a new 30 kb/d gas-to-liquids plant that will start up by the end of 2020 or early in 2021. The plant will process 3.6 billion cubic meters of gas to produce synthetic jet fuel, naphtha, LPG and Euro5 specification diesel.

Qatar to fuel Middle East growth

Qatar will lead net growth in the Middle East of 190 kb/d over the forecast period, thanks to further development of condensates from the North Field. Its total oil supply is due to rise to 2.1 mb/d by 2025, an increase of 140 kb/d. Qatar, the world's second largest LNG supplier after Australia, announced plans to raise its liquefaction capacity by nearly two-thirds to 126 million tonnes by 2027. That means adding six new trains to its existing 14 over time, which will also raise NGL supply. The original four-train expansion was to produce some 260 kb/d of condensate, 11 000 tons per day of LPG, and 4,000 t/d of ethane. However, a slump in international LNG prices might push back the full development.

In 2017, Qatar lifted a self-imposed ban on development of the North Field, the world's biggest gas field that it shares with Iran, where it is known as South Pars. Qatar's crude production of around 600 kb/d is expected to stay broadly steady over the next six years.

Oman, which, as part of the OPEC+ deal agreed to reduce crude oil production, is expected to see a 50 kb/d increase in supply by 2025 split fairly evenly between crude and condensates. Condensate supply received a boost from BP's Khazzan tight gas field, which is producing 35 kb/d of liquids. Output is expected to rise to 50 kb/d after a further phase of development, the Ghazeer project, starts up in 2021. **Yemen** could see output edge up by 25 kb/d to 95 kb/d by 2025. We have assumed there will be no change to supply in **Syria**, where conflict continues.

Biofuels

Global conventional biofuel production in 2019 was 2.8 mb/d, up 6% on 2018. The forecast has been revised upwards since last year's report, with production expected to grow by around 490 kb/d to reach 3.3 mb/d in 2025. Biofuels are anticipated to account for around 4.5% of road transport energy demand by the end of the forecast. This more optimistic outlook is primarily due to robust growth prospects in emerging economies in Asia, Brazil and stronger market prospects for hydrotreated vegetable oil (HVO)[2] in the United States and Europe.

Strengthened policy support for domestically produced biofuels in China, India and Association of Southeast Asian Nations (ASEAN) countries has been introduced as a means of offsetting some crude oil and petroleum product imports. Rising road transport fuel demand, combined with new biofuel policy initiatives, stimulates increased biofuel production and consequently Asia provides half of forecast production growth. These countries are also strengthening policy support to boost demand for nationally important agricultural commodities.

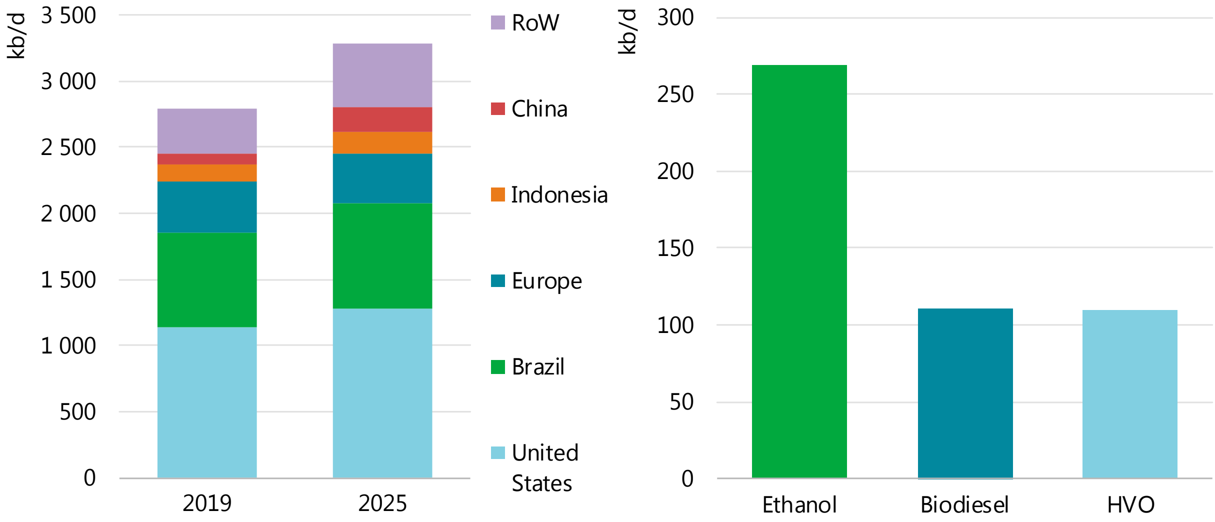
World fuel ethanol production in 2019 grew almost 4% year-on-year to 2 mb/d. Over the forecast period average annual growth of 2% will see output reach just over 2.2 mb/d by 2025. Growth is principally driven by Brazil and China. Combined biodiesel and HVO production increased 13% in 2019 versus 2018 levels, to 820 kb/d. Over the next five years, average annual growth of 4% is anticipated, with production reaching around 1.1 mb/d in 2025. Market expansion is driven by

[2] Known as "renewable diesel" in North America.

supportive policies in the United States, Brazil and some ASEAN countries. Over the forecast period HVO production grows as much as biodiesel.

The United States and Brazil were the largest biofuel producers in 2019. Together they are anticipated to account for almost 45% of output growth over the period to 2025, and provide around two-thirds of production at the end of the forecast period.

Figure 2.20 Biofuel production by country and region (left), 2019-25 output growth by fuel



Note: Biofuel production is the sum of ethanol, biodiesel and HVO. "Ethanol" refers to fuel ethanol only; "biodiesel" refers to fatty acid methyl ester (FAME) biodiesel.

United States and Brazil continue to dominate market.

Overview of key biofuel markets

In the **United States**, ethanol production decreased slightly to 1.02 mb/d in 2019. Output is forecast to broadly stabilise at this level, with 1.06 mb/d anticipated in 2025. The Renewable Fuel Standard (RFS2)[3] is the key federal policy mechanism supporting US biofuel consumption, and corn ethanol has now reached its statutory limit under the policy. Nevertheless, ongoing process improvements and technical modifications at existing plants will increase capacity to an extent, and utilisation is high.

Blending gasoline with 10% ethanol (known as E10) is standard practice. However, a slight contraction of gasoline demand over the forecast period will moderately reduce domestic ethanol consumption. Nevertheless, increased exports are expected to keep production stable. Fuel ethanol exports reached a record 112 kb/d in 2018, before a slight reduction in 2019. The forecast assumes a resumption of growth from expanding exports, especially to Asia.

Higher consumption of E15[4] ethanol blends has a lower impact on the forecast. Regulatory reform permitting year-round E15 sales introduced in 2019 makes it more attractive for service

[3] The RFS2 runs until 2022; however, because of the policy's importance to the agriculture sector and ethanol's octane value, IEA biofuel forecasts assume that the policy remains in place throughout the forecast period.

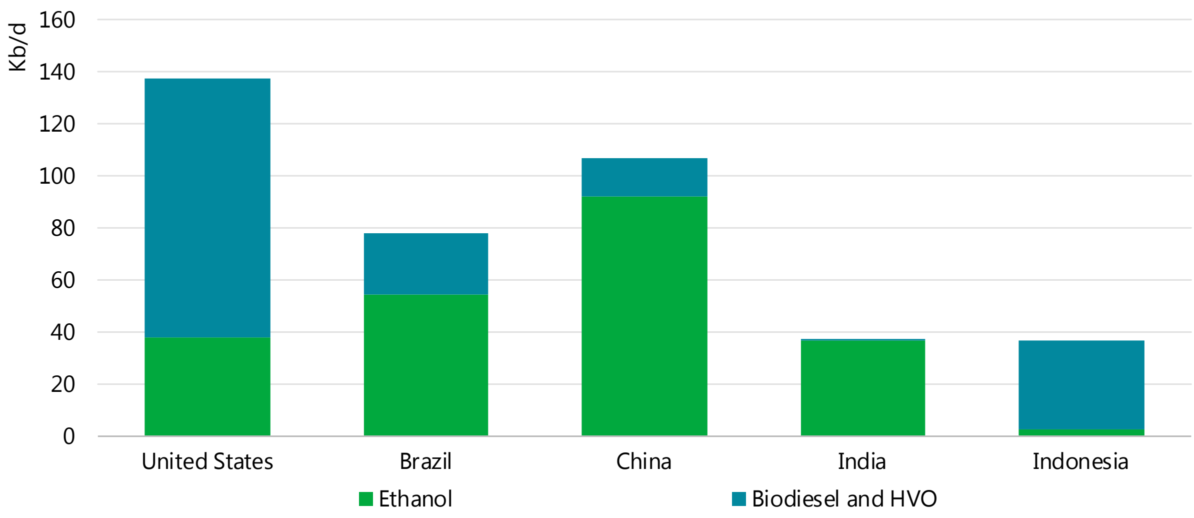
[4] Gasoline blended with 15% fuel ethanol by volume.

stations to supply the blend. However, only around 1% of them offer E15 nationally, and expanding supplies to the approximately 20 states where the blend is not currently available will take considerable time.

US biodiesel and HVO production in 2019 matched 2018's record output of 120 kb/d. Demand is underpinned by the RFS2 and California's Low Carbon Fuel Standard (LCFS). Domestic output was also supported by anti-dumping duties on biodiesel imports from Indonesia and Argentina that rendered them uneconomic.

Output is expected to increase strongly to 220 kb/d by 2025. Significant investment in HVO capacity is evident with a number of large scale projects anticipated to come online over the forecast period. Given stagnant diesel demand, production growth is driven by policies. These include demand driven by RFS2, a tightening of the transport fuel carbon intensity requirements of California's LCFS and the re-introduction of the USD 1/gallon blenders' tax credit for biodiesel and renewable diesel until 2022.

Figure 2.21 Forecast production growth for selected countries (2019-25)



Asian countries provide half of biofuel production growth, led by China, India and Indonesia.

Ethanol output in **Brazil** increased significantly in 2019. Record production of 620 kb/d represented 13% y-o-y growth, on top of the strong increase in output observed in 2018. This was achieved by mills maximising ethanol production at the expense of sugar due to low international sugar prices. In the centre-south region, which accounts for most production, a record 65% of recoverable sugars were dedicated to ethanol production during the 2018/19 harvest. This share has been maintained in 2019/20 to date. Robust hydrous ethanol demand was also a factor as a result of its price competitiveness at the pump versus gasoline, supported by lower levels of federal taxation on ethanol.

Ethanol production is anticipated to increase to around 670 kb/d by 2025. Growth is driven by the improved economics of biofuel production under the Renovabio scheme, introduced in 2020. RenovaBio introduces emissions reduction targets for fuel distributors which can be met via obtaining traded emissions reductions certificates awarded to biofuel producers.

RenovaBio is expected to provide a supportive framework for further ethanol production capacity investment. This is anticipated from the expansion of existing sugar mills, idle mills coming back into use and greenfield investments. Ethanol production from corn feedstock is currently relatively small compared to that derived from sugar cane, but is expected to grow over the forecast period with a number of plants in development and ample domestic corn supply.

Brazil produced a record 100 kb/d of biodiesel in 2019 – a 10% y-o-y increase – with soybean oil as the main feedstock. A good soybean harvest, combined with stronger demand resulting from the blending mandate increase to 11% during the year, spurred greater production.

Output growth of over 20% is forecast to 2025, with production scaling up to over 120 kb/d and consequently reducing biodiesel plant overcapacity. The primary impetus for higher output is a staged mandate increase to 15% by 2023. The next incremental increase to 12% is due in March 2020. Each step will be dependent on positive results from automotive industry testing the effects of using higher blend levels. RenovaBio may stimulate more biodiesel production from lower carbon waste oil and animal fat feedstocks, which currently account for less than a fifth of output.

Table 2.5 Annual production in selected biofuel markets (kb/d)

Country/region	Fuel	2019 output	2025 output	Forecast overview
OECD Europe	Ethanol	85	91	Contracting gasoline demand; stronger policy support post-2020 not anticipated; EU anti-dumping duties on US ethanol repealed; growing E10 demand in France.
China	Ethanol	69	161	12% gasoline demand growth; expanding consumption from 11 to 15 provinces; new facilities are under construction; nationwide E10 programme suspended.
India	Ethanol	36	73	12% gasoline demand growth; record consumption in 2019, long-term 20% blending target for 2030; government loans to expand production capacity.
OECD Europe	Biodiesel / HVO	287	285	6% diesel demand contraction; stronger EU policy support post-2020 not anticipated; HVO project development; ARG and IDN anti-dumping duties removed.
Indonesia	Biodiesel	136	170	Move to B30 mandate in 2020, new plants coming online and underutilised capacity ramping up; lower share of output exported; trade barriers in key export markets.
Malaysia	Biodiesel	27	40	Transition from B7 to B10 mandate in 2019, then B20 during forecast; 16% increase in diesel demand; plant overcapacity; uncertainty over future EU exports.

Note: ARG = Argentina; IDN = Indonesia.

HVO production surges

HVO production is set to double from around 110 kb/d in 2019 to 220 kb/d by 2025, as policy frameworks in Europe and the United States spur higher demand. In Europe, the Renewable Energy Directive for 2021-30 will stimulate waste- and residue-based HVO consumption as fuels produced from used cooking oil and animal fat feedstocks are permitted to make up 3.4%[5] of the

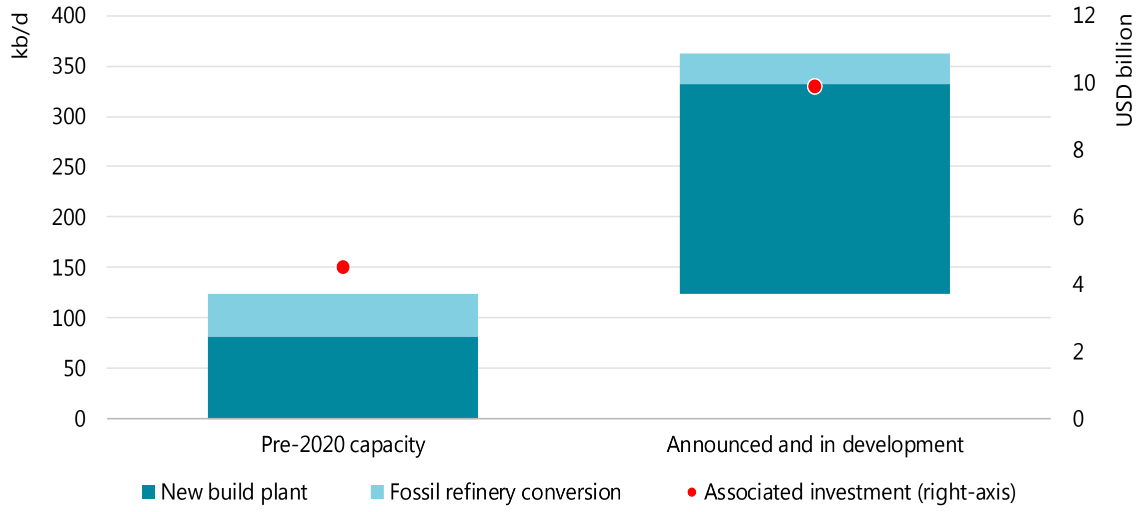
[5] The 3.4% is the share taking account of provisions within the directive that allow countries to double-count the energy content of biofuels made from UCO and animal fats towards the transport renewable energy target. The physical share of demand is 1.7%.

14% of renewable energy in transport targeted for 2030, equivalent to approximately 95 kb/d of HVO. In the United States, the RFS2 and California's LCFS are driving HVO deployment: it accounted for 5% of fuels used in compliance with the RFS2 in 2018 and 20% under the LCFS.

The fact that HVO is less constrained by blend limits than biodiesel, offering higher flexibility for blenders, is another factor behind growing demand. HVO is technically a "drop-in" fuel, and can be used unblended in some diesel engines and without modifications to fuelling infrastructure. The value of co-products from HVO production is also a driver of production growth. Renewable propane, naphtha, chemicals and aviation biofuels are part of an HVO plant's product slate.

These factors have spurred a raft of new announcements, with several projects in an advanced stage of development. Overall this would equate to around USD 10 billion of investment in new capacity if fully delivered. However, the forecast anticipates that around 60% of these projects will be realised. Most are new refineries in Europe and the United States. The capacity of fossil fuel refineries converted to HVO production also increases because investment costs are lower and project delivery is quicker than for new-build plants. Most new plants intend to use waste and residue feedstocks for production, so mobilising supply of these feedstocks is crucial to deliver the forecast.

Figure 2.22 HVO capacity overview



Note: Excludes the capacity of co-processing of biomass feedstocks to produce HVO in fossil fuel refineries, which currently makes a minor contribution to overall production.

Policy driven demand spurs HVO capacity investment in Europe and the United States.

3. Refining and Trade

Highlights

- The impact of energy transitions is increasingly evident in the pattern of refined product demand growth. Transport fuels, which account for the bulk of refinery earnings, see a sharply lower pace of growth over the forecast period. Light products demand increases the most, and this is overall balanced by growth in the lighter categories of oil supply.

- Refiners, nevertheless, continue ramping up capacity, adding another 6.2 mb/d over the next five years. This is higher than the increase in demand for refined products, estimated at 4.4 mb/d. More than 70% of capacity additions are in countries that are already net exporters of refined products.

- With increased competition and the push for decarbonisation, the refining industry must adapt its strategies. One option is petrochemical integration. However, the scope is limited, given the expected supplies from NGL-based projects. Integrating biofuel production through co-processing of renewable diesel or the conversion into bio-refineries is becoming popular. In the meantime, refiners also have to consider near-term challenges and opportunities such as production of fuels compliant with the new International Maritime Organisation (IMO) rules.

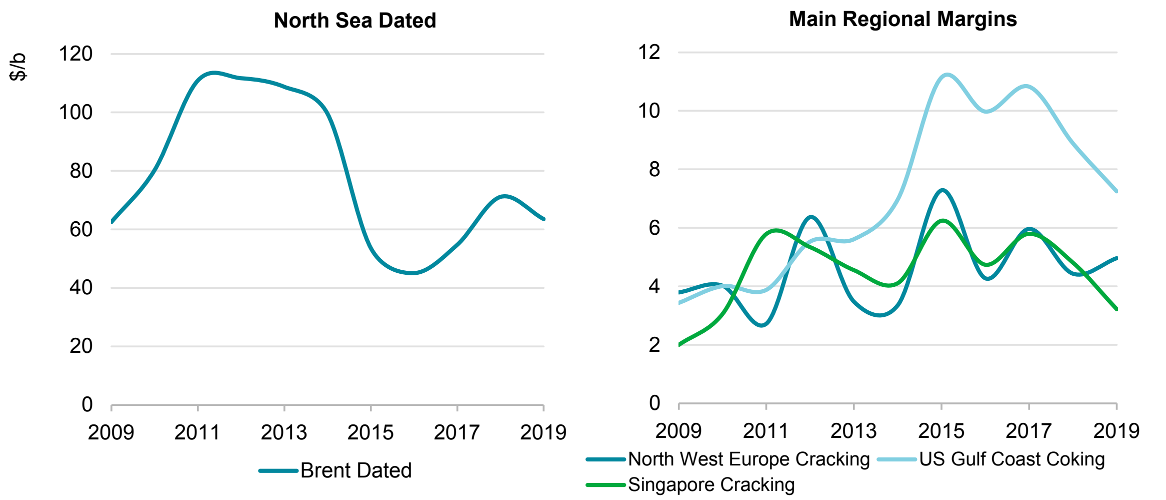
- The United States (US) becomes a net seaborne crude oil exporter and the Gulf Coast expands its role as the second largest crude export hub outside the Middle East. In the second half of the forecast period, the call on Middle East exports increases with the flat-lining of US production growth. The reliance of Asia on net oil imports from other regions reaches 81 % of demand.

- Europe and all the regions of the southern hemisphere remain reliant on product imports from the United States, the Russian Federation (hereafter "Russia"), the Middle East and the People's Republic of China (hereafter "China"). The United States overtakes Russia as the top product exporter and China surpasses India in product exports, becoming the largest supplier in Asia.

Global overview

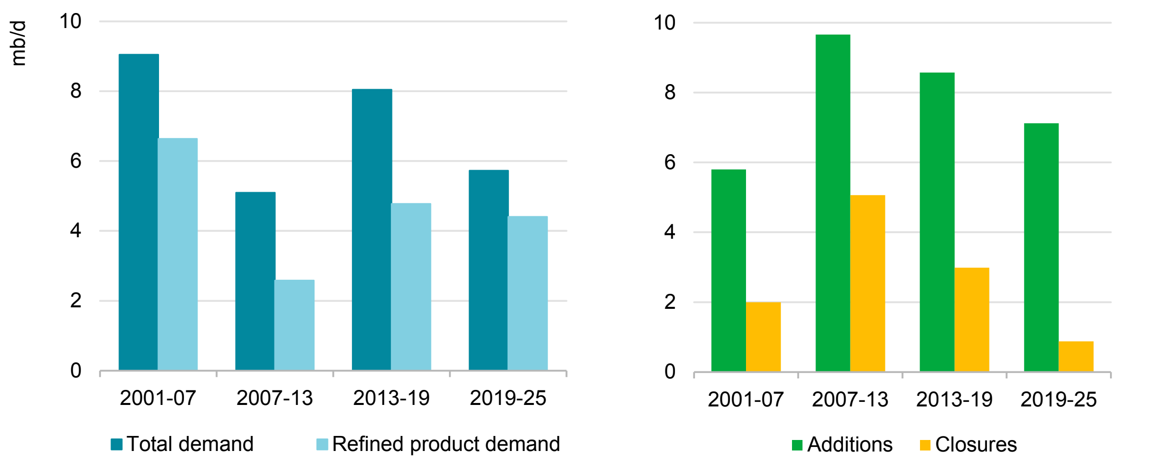
The global refining sector experienced a rare phenomenon in 2019. For the first time in recent decades, refining throughput declined year-on-year even as oil demand continued to increase and capacity additions were at a near-record level. This was partly explained by higher maintenance and more frequent unplanned outages. Even so, refining margins dipped below 2018 levels despite lower average crude oil prices. In the United States, refiners scaled back their processing from the historical high rate of 2018 to the levels seen in 2017, when throughput was affected by hurricane Harvey. This was the most symptomatic example, but it is interesting to note the particularly wide base of declines. In 2019, the number of countries where activity fell year on year was higher than the number of countries where it increased. The fact that weaker refining activity did not support margins indicates destocking after overproduction in 2017-18, when an increase in refinery runs exceeded the growth in refined products demand.

Figure 3.1 Oil price and refining margins



Sources: IEA/KBC; Argus Media Ltd

Figure 3.2 Changes in oil demand, refined products demand and refining capacity



Notes. 2019-25 shutdowns include only announced plans. 2001-07 capacity data are partly based on BP Statistical Review of World Energy 2019. See Table 3.1 for the breakdown of refined products demand calculation

Past capacity additions have triggered shutdowns to balance.

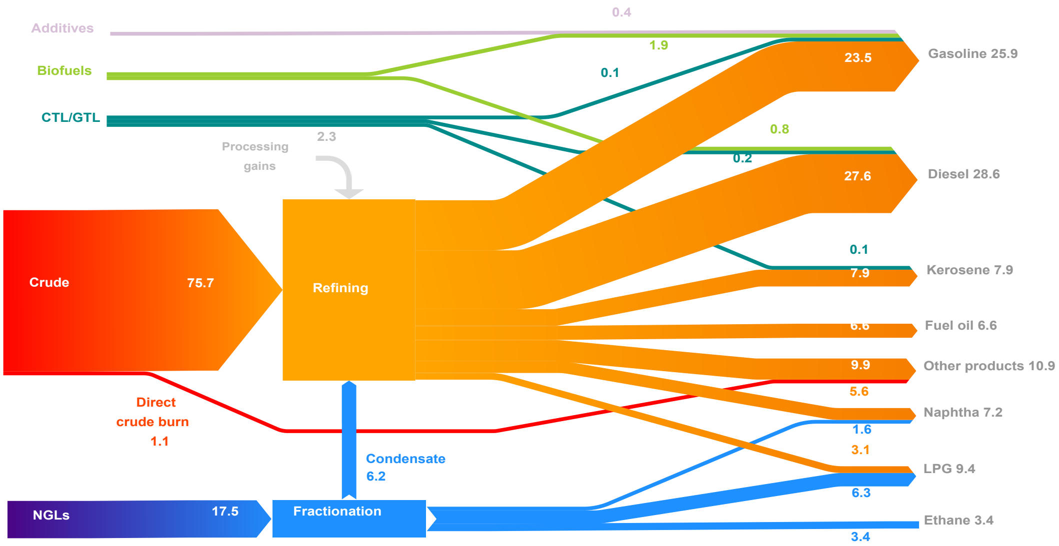
The future looks challenging as the slowdown in oil demand growth alongside the continued build-up of refining capacity will intensify competition. Global oil demand is forecast to increase by 5.7 mb/d to 2025, which is 2.3 mb/d lower than in the previous six-year period. Consequently, the pace of growth for refinery-supplied products also slows, from almost 4.8 mb/d in the previous six years to 4.4 mb/d over the forecast period, even as the gap between the headline demand growth and the call on refineries is narrower. Increased supplies of natural gas liquids (NGLs), biofuels and coal-and gas-based alternative fuels and petrochemical feedstock amount to 1.5 mb /d, while direct crude use declines by 0.2 mb/d.

Table 3.1 Total oil demand and call on refined products (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2019-25
Total liquids demand	100.1	99.9	102.0	103.1	104.1	104.9	105.7	5.7
of which biofuels	2.8	2.9	3.0	3.1	3.2	3.2	3.3	0.5
Demand net of biofuels	97.2	97.0	99.0	100.0	100.9	101.7	102.4	5.2
of which CTL/GTL* and additives	0.8	0.8	0.8	0.9	1.0	1.0	1.1	0.3
direct use of crude oil	1.1	1.0	1.0	0.9	0.9	0.9	0.9	-0.2
Total oil product demand	95.4	95.2	97.2	98.2	99.0	99.8	100.5	5.1
of which NGLs bypassing refineries**	10.8	11.2	11.2	11.3	11.3	11.4	11.5	0.7
Refinery products demand	84.5	84.0	86.0	86.9	87.7	88.4	89.0	4.4
Refinery market share	84.6%	84.1%	84.3%	84.3%	84.3%	84.2%	84.1%	-0.4%

*CTL/GTL: Coal-to-liquids and gas-to-liquids. **Ethane, petroleum liquefied gas (LPG) and pentanes plus, excluding estimated diluent use in North America.

Figure 3.3 Global liquid fuel supply in 2019



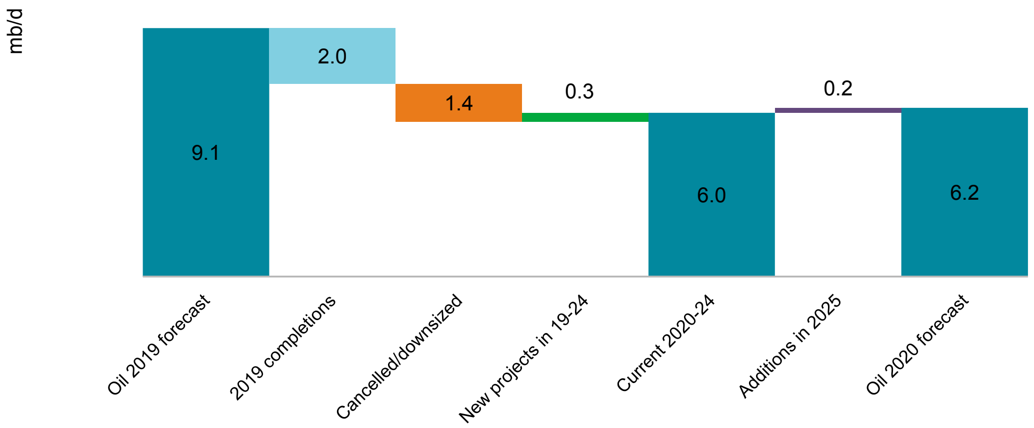
The cyclical nature of oil demand is not a recent phenomenon. Oil demand growth was also significantly lower during 2008-13 (when the financial crisis was followed by a period of higher oil prices), compared to the 2001-07 period. The refining industry is used to operating in a cyclical environment, not only due to exogenously driven changes in oil demand, but also due to variations in refining capacity additions. The more pertinent question for refiners, and indeed, oil producers, is whether the expected slowdown in demand growth in the next five years is cyclical or genuinely structural. The oil demand trajectory of the Sustainable Development Scenario (SDS) from the IEA's World Energy Outlook 2019, the scenario most consistent with sustainable energy development path, implies oil demand peaking before 2025 and a subsequent average annual decline of 2 mb/d. In this scenario, oil use declines in all sectors, except petrochemicals.

While the global energy system so far is charting a trajectory far from aligned with the SDS, our forecast for oil demand has some similarities. Taking non-oil elements out of total oil demand, petrochemical feedstock use grows slightly more than transport sector demand by 2025.

Refining capacity developments

Following near record expansions of 2 mb/d in 2019, the growth in refinery capacity slows through 2025. A number of projects were cancelled or postponed and few projects are expected to start up in 2025. Even so, 6.2 mb/d of net additions of crude distillation units (CDU) and condensate splitters are expected, 1.6 mb/d more than required to meet incremental demand for refined products.

Figure 3.4 Changes to refining capacity forecast vs Oil 2019

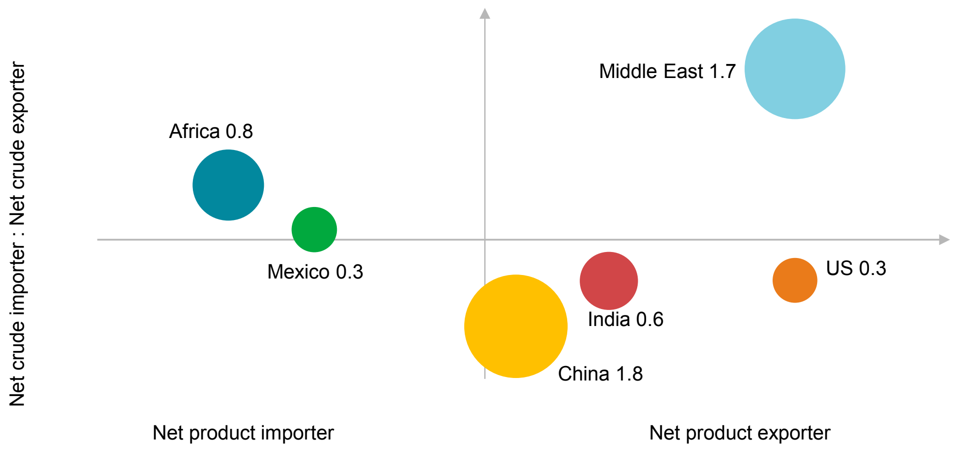


In general, new capacity additions are skewed towards countries and regions that are already net exporters of refined products. Some, such as the Middle East and the United States, are also major crude oil exporters (net and gross, respectively), while India and China are the top two net crude oil importers worldwide.

China continues to lead, building another 1.8 mb/d of capacity, mostly from large petrochemically-integrated projects. But the Middle East is not far behind, with just under 1.7 mb/d of net additions. Africa's 0.8 mb/d additions include the 650 kb/d Lekki plant in Nigeria, and smaller facilities in Algeria and Egypt. We have a conservative view on the timing of the 1.2 mb/d Indian joint venture refinery involving Saudi Aramco and ADNOC and think it will be launched well beyond 2025. In the meantime, several smaller projects provide an incremental 0.6 mb/d of capacity in India. Another 0.6 mb/d comes from North America, including Pemex's greenfield Dos Bocas refinery in Mexico and ExxonMobil's expansion project at its Beaumont, Texas, plant.

Last year we talked about a paradigm change in refining investments as the relative abundance of light sweet crude requires simpler rather than more complex refining capacity. Upgrading capacity additions, combining units at new sites and additions at existing sites total 3.6 mb/d. While we do not have information on secondary units for some projects, notably, the Dos Bocas refinery, it is still possible to say that the ratio of upgrading capacity to CDU additions has been trending downwards, reflecting an earlier buildup and lower perceived need in the future. In 2019, some upgrading projects were cancelled; most notably the 60 kb/d coker project at Marathon's Garyville, Louisiana refinery, where narrowing heavy/light differentials were cited as the main reason. Several Russian refiners, particularly those owned by Rosneft, indefinitely postponed coker, hydrocracker and fluid catalytic cracker additions representing a combined capacity of 250 kb/d.

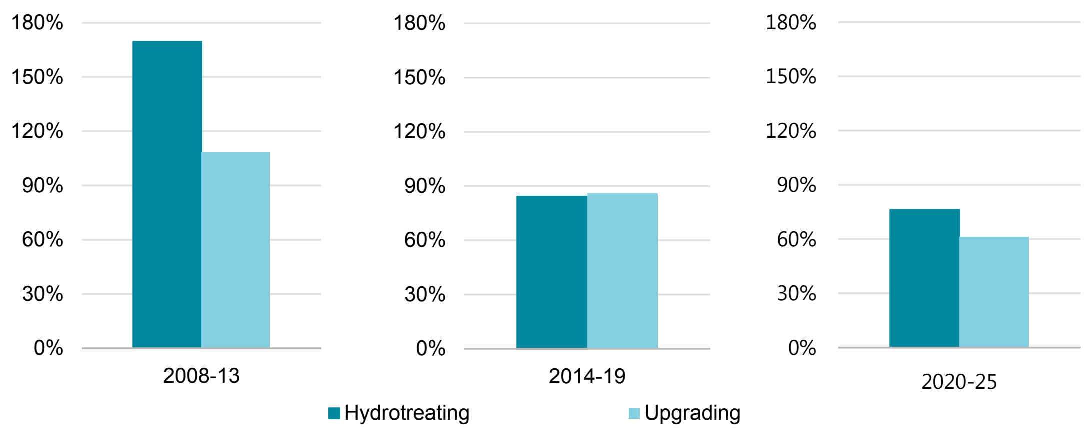
Figure 3.5 Refining capacity change for selected regions (2019-25)



Note: Bubble size indicates net capacity change from 2019 to 2025

At the same time, desulphurisation capacity additions remain relatively robust, at 4.3 mb/d, with the Middle East accounting for almost half of the total, and achieving more than 100% coverage of forecast crude distillation additions. This matches well with their refining requirements as local crude grades have some of the heaviest sulphur content.

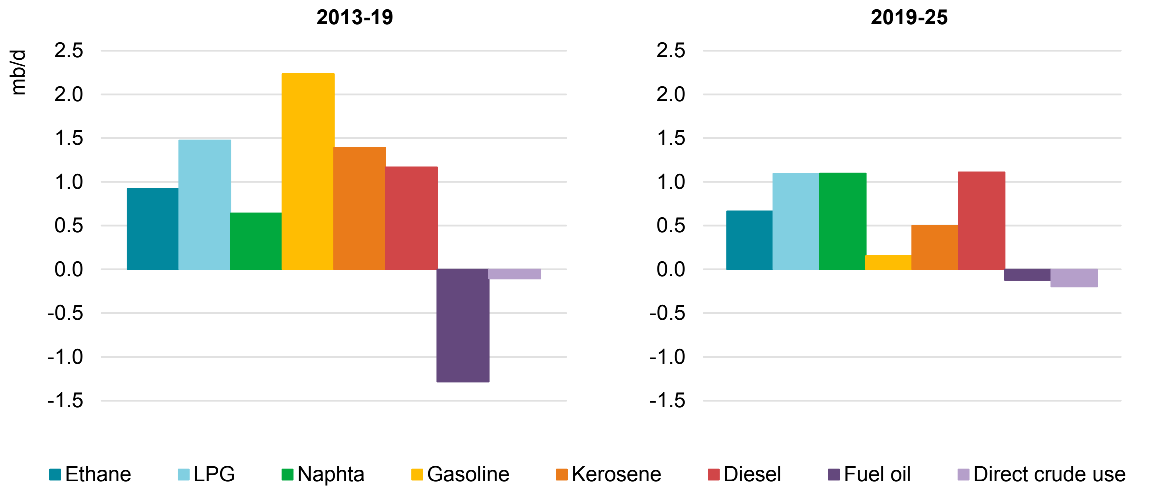
Figure 3.6 Ratio of upgrading and hydrotreatment capacity additions to CDU additions



Matching supply with demand

Less complex refining capacity additions fit into the picture of both supply and demand developments. In the next six years refinery gasoline demand growth shrinks to just 35 kb/d on average, a far cry from 365 kb/d seen in the previous six years. Demand for refinery-supplied middle distillates (diesel and kerosene) slows from an average 430 kb/d in 2013-19 to 290 kb/d in 2019-25. These premium transport fuels that support refinery margins are most susceptible to replacement by alternative fuels and technologies such as electric vehicles, compressed natural gas vehicles and LNG-fuelled trucks (see *Demand*). Also, biofuels and derivatives from coal-to-liquids and gas-to-liquids plants continue taking market share from refiners.

Figure 3.7 Demand growth for oil products, excluding non-oil components



Gasoline demand growth falls to almost nothing, when biofuels and other non oil components are netted out.

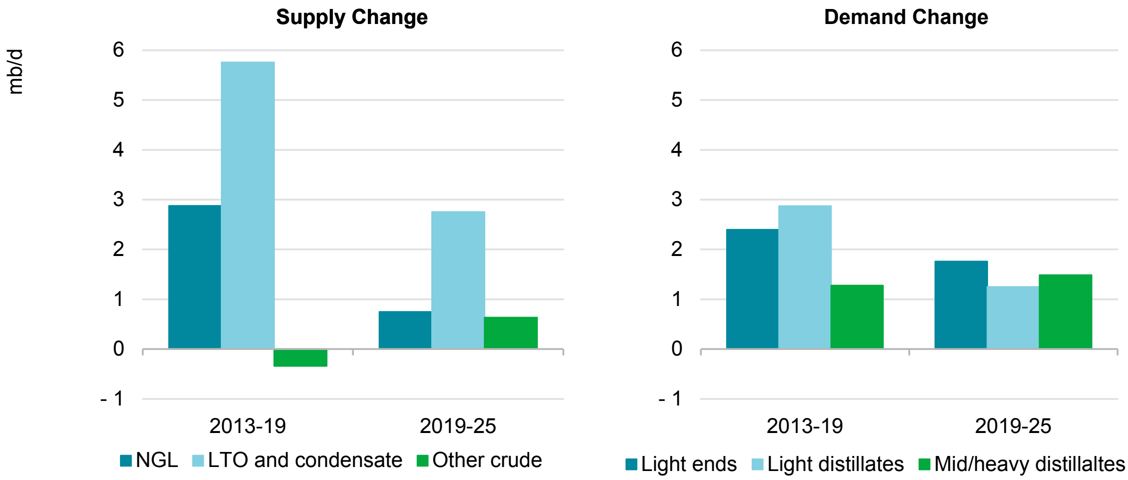
Demand for heavier fuels, on the other hand, is expected to decline more moderately than in the past. High sulphur fuel oil is replaced by a new type of bunker fuel that will largely defy the traditional logic of fuel categorisation – occupying a space that overlaps heavy residues and lighter components from atmospheric distillation or upgrader flows (see *VLSFO blending*).Light ends, such as LPG and ethane continue to lead oil demand growth, albeit somewhat more slowly.

Table 3.2 Matching supply with demand

Demand categories	Corresponding category in Supply
Light ends (LPG and ethane)	NGL
Light distillates (naphtha and gasoline)	Light tight oil and condensates
Middle and heavy distillates (kerosene, diesel, fuel oil, direct use of crude oil)	Other crudes

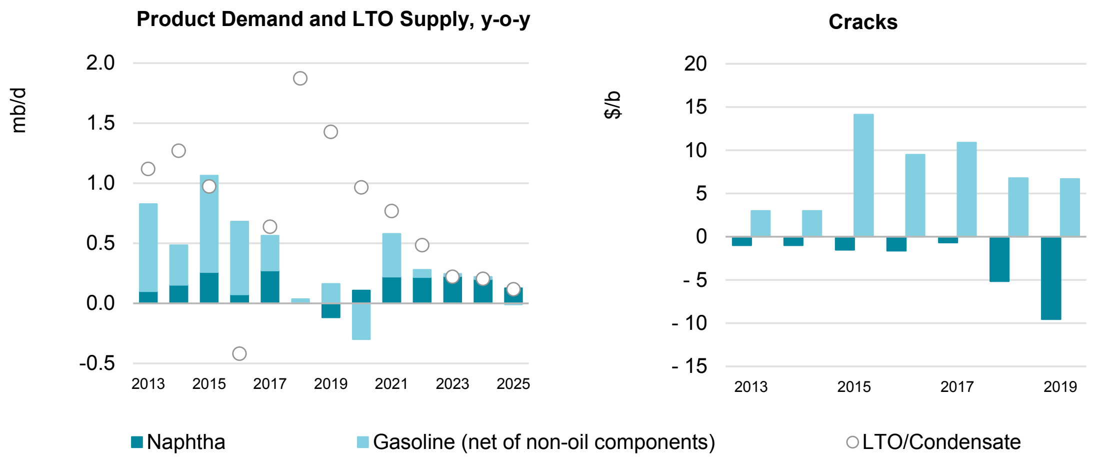
Developments in recent years showed that concerns about a mismatch between the quality of the US shale liquids output (NGLs and light tight oil [LTO]) and the demand barrel were misplaced. In the 2013-19 period, the growth in light ends demand was matched by strong growth in NGL supply. The 5.8 mb/d increase in LTO/condensate supply coincided with a 2.9 mb/d growth in light distillates demand, suggesting a relative equilibrium. Even light crude grades usually do not yield more than 50% of light distillates.

Figure 3.8 Oil demand and supply growth by type



Nevertheless, light distillate markets reached saturation in 2018-19 as LTO output shot up. Meanwhile, naphtha demand growth came to an abrupt halt and gasoline demand growth slowed sharply. The average annual gasoline crack fell below USD 10/bbl and has not recovered since. Average naphtha cracks fell from a USD 2/bbl discount to crude in 2017 to almost USD 10/bbl discount in 2019.

Figure 3.9 Light distillates market fundamentals

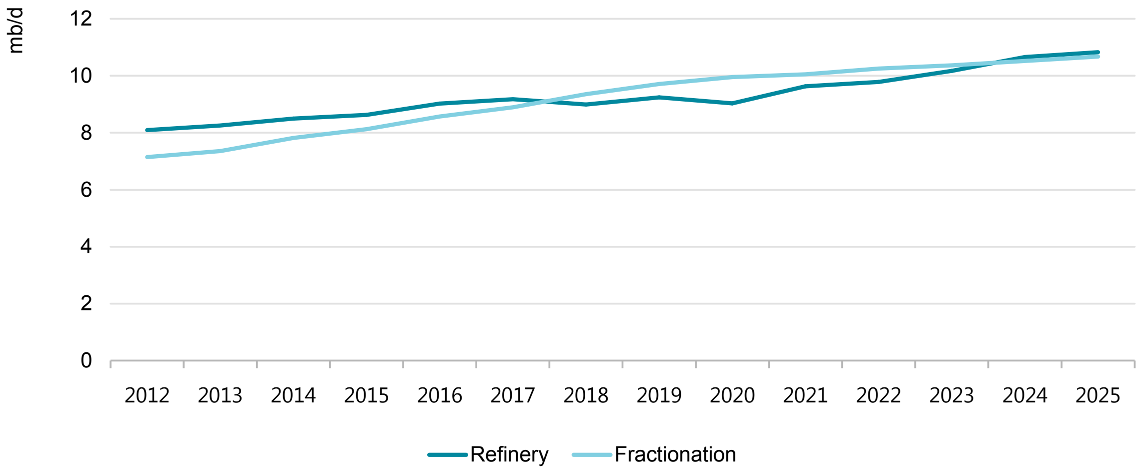


A sharp slowdown of naphtha and gasoline demand in 2018 affected gasoline and naphtha cracks.

It is also interesting to note that the growth in middle distillates demand in 2013-19 was partly offset by declines in fuel oil demand and direct crude burn (see *Figure 3.8*), turning the middle/heavy product group into the least performing among the three. This incentivised refiners to upgrade more unused heavy molecules into middle distillates, thus compensating for the overall lower middle distillates yields from lighter crudes.

In the next six years, NGLs and LTO output are expected to decelerate (see *Supply*), but they continue to lead supply growth even as the output of other types of crude oil, mostly medium-heavy grades, increases by 0.6 mb/d. A lower production growth rate for NGLs is a consequence of deteriorating wellhead economics as natural gas oversupply pressures prices. This may give refiners an opportunity to increase output to meet light product demand, even as NGLs supplied from fractionation units have already overtaken refinery output

Figure 3.10 The battle of refiners and NGL producers in the "light" category



Note: fractionation shows volumes of ethane and LPG from NGL plants, refinery production includes LPG and naphtha.

Petrochemicals – a silver bullet?

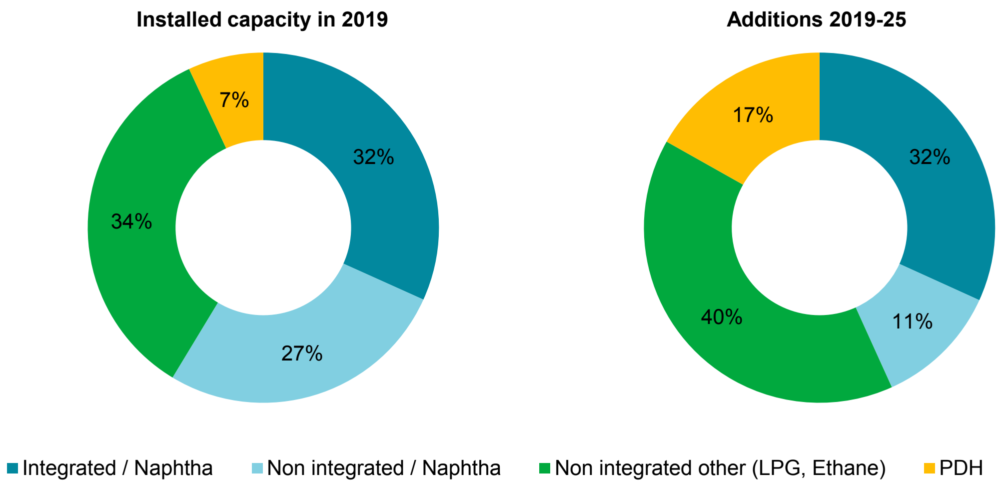
While the increased "call" on refinery-supplied LPG and naphtha is good news for refiners, these products are typically priced at a discount to crude oil. From a practical point of view, these are refinery by-products derived from producing premium transport fuels such as diesel, kerosene and gasoline. On the other hand, petrochemical margins usually exceed margins from transport fuels, where taxes tend to take up a large proportion of the retail price. Petrochemical base products – olefins and aromatics, are higher value goods and are not taxed in the same way as fuels.

Petrochemical integration has become very popular with refiners, in part due to the significant operational synergies (energy and by-product flows) and in part due to expectations of an imminent peak in oil use in the transport sector as the energy transition progresses. Refiners are looking to offset potential loss in earnings from declining sales of transport fuels.

The benefits of the operational integration include shared infrastructure and overheads and the utilisation of by-product hydrogen from steam crackers or dehydrogenation units. Hydrogen is a key input in the hydrotreatment of products to meet increasingly stringent quality specifications. By using by-product hydrogen, in lieu of volumes generated through on-purpose steam methane reforming, refineries reduce CO_2 emissions and also total energy costs.

Will refiners' efforts to capture a share of this market eventually result in refining overcapacity spilling over into the petrochemical sector? The growth rate for petrochemicals demand remains robust and is well-correlated with economic activity (see *Demand*) but NGL supply growth has provided an alternative pathway to refinery-integrated naphtha or LPG cracking. Historically, ethane crackers were not able to compete fully with naphtha crackers due to skewed yields – 80% ethylene and only 2-3% of another valuable petrochemical base product, propylene - compared to propylene yields of about 15% from naphtha crackers. Increased LPG supplies from US shale production enabled the commercialisation of propane dehydrogenation (PDH) technology, an on-purpose propylene productio method.

Figure 3.11 Petrochemical capacity by type



Note: IEA calculations based on S&P Global Platts.

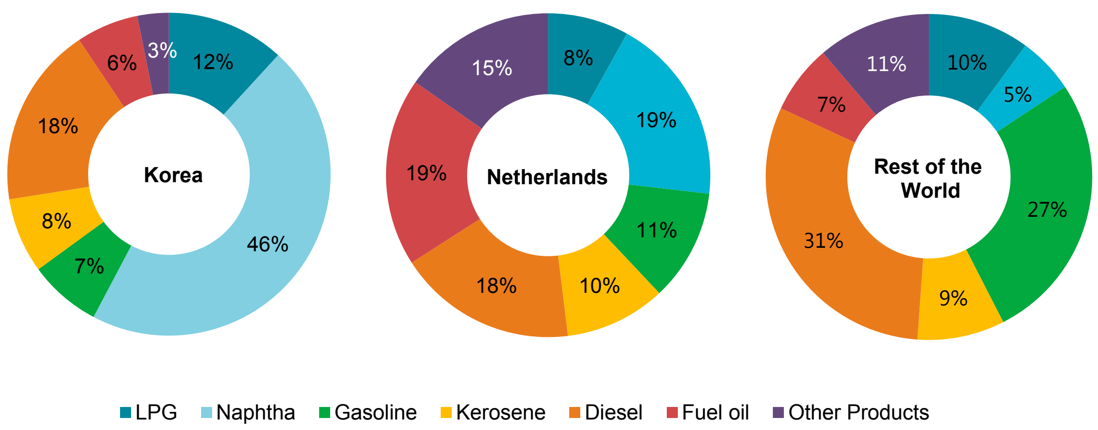
The share of integrated naphtha crackers is stable thanks to Asia, but PDH is increasing the most.

The parallel, but not necessarily coordinated, deployment of ethane crackers and PDH units that we forecast based on available data on projects presents a serious alternative to naphtha-based petrochemical production without compromising the yield slate. Indeed, while ethane crackers and PDH units combined account for just above 40% of petrochemical capacity today, their share of the capacity additions is close to 60%. The share of refinery-integrated naphtha crackers remains flat over the next six years, largely thanks to new integrated complexes in China, India and the Middle East, but this does not automatically imply that there is scope for refiners elsewhere to massively invest into petrochemical capacity. Globally, gasoline and naphtha account for 25% and 7% of oil-based liquids demand (excluding biofuels, CTL/GTL and additives), respectively. Petrochemical feedstock demand, however, is 12% of total oil demand, increasing to 14% in 2025 in our forecast. The scope for a shift from gasoline production to naphtha-based petrochemicals is thus limited.

Korea provides a well-known case of a high level of petrochemical integration. A strong strategic focus resulted in the country accounting for almost one fifth of global naphtha demand in 2019. The share of naphtha in Korean oil demand is 46%, requiring substantial imports of naphtha products on top of local refinery output. In the Netherlands too, the share of naphtha demand is higher than that of gasoline and similar to the share of diesel in domestic consumption, albeit post-refinery gate blending into the gasoline pool is also a reason. Increasing naphtha's share in global oil demand to the same level as in the Netherlands (19%) would imply global petrochemical capacity doubling from 2019 levels. There is no plausible scenario of plastics demand doubling by 2025.

On the other hand, there are no clear first-movers advantages in the globally-connected and margin-oriented refining and petrochemical businesses, which deal in bulk commodities. The incumbents are as much at risk from overcapacity as the newcomers. China's build-up of capacity is primarily aimed at reducing import dependence on key petrochemical base products. This might have consequences for utilisation rates of petrochemical facilities elsewhere.

Figure 3.12 Share of naphtha demand



HVO – responding to decarbonisation challenges

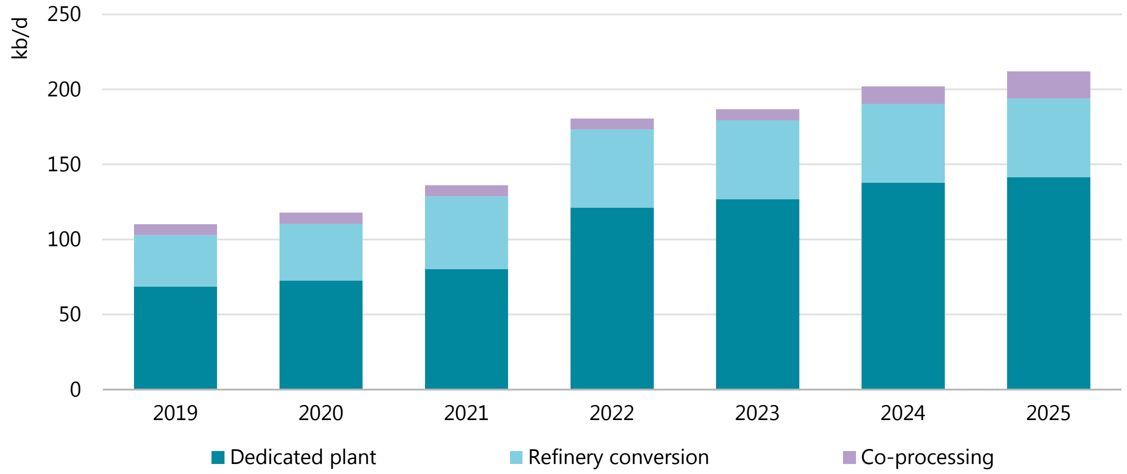
Another pathway for refineries to adjust to the decarbonising world is to lower the carbon intensity of their products by integrating biofuels in their operations. The two most commonly used biofuels are ethanol and biodiesel. Ethanol and oxygenates are blended into fuel used in gasoline engines. Biodiesel is FAME (fatty acid methyl ester) blended with diesel and is largely suitable for all of its premium uses, be it in road transport or heating and industrial sectors.

Ethanol and biodiesel blending into transport fuel, generally mandated, provides mostly logistical and blending synergies in fuel wholesale and distribution. In contrast, production of hydrotreated vegetable oil (HVO), which is also referred to as renewable diesel, is a more natural extension of refining activities, with the emphasis being on the processing of renewable feedstock into diesel and other products (LPG, naphtha and aviation biofuel).

Depending on technology and type of feedstock, biofuels can be classified as "conventional" e.g. based on crop feedstocks, and "advanced" where waste and residue feedstocks are used. Most advanced biofuel production currently comes from biodiesel and HVO produced from feedstocks such as used cooking oil and animal fats, while technologies to utilise agricultural and forestry residues and municipal solid waste are not widely commercialised.

Refiners are increasingly considering HVO projects to respond to renewables fuel mandates and carbon intensity policies such as California's Low Carbon Fuel Standard. Currently, HVO output is estimated at 110 kb/d and is expected to double to 220 kb/d by 2025 (see *Supply*), with most production in Europe and the United States. In addition to dedicated facilities, biomass feedstocks can also be co-processed with petroleum gasoil in hydrotreatment units. Thus, refiners have several options: investing in new renewable diesel units (RDU), transforming an existing hydrotreater, or co-processing with petroleum feedstock.

Figure 3.13 HVO production forecast



Co-processing is becoming increasingly popular.

New units have the advantage of being specifically designed for this type of challenging feedstock, but the last two options require lower capital investment, benefitting from synergies with the existing refining processes. Several new RDU projects are currently being developed by oil refiners not only for complying with future mandates, but also to gain experience in this developing industry. Neste is a case on point in the transformation from traditional refining to a portfolio more focused on sustainability via biofuels. Waste and residue raw materials represent about 80% of their feedstock for a total of 60 kb/d HVO production.

Several refineries have completely shut down their petroleum feedstock processing operations and been converted to biofuel refineries. Examples include Total's La Mede site in southern France which was previously a 160 kb/d refinery; and Eni's 80 kb/d Venice and 100 kb/d Gela plants in Italy. The combined HVO output of these three plants is 35 kb/d. Marathon recently announced plans to convert its 19 kb/d Dickinson, North Dakota, plant to a biofuel site, while MOL is considering this option for its 44 kb/d Sisak refinery in Croatia. Co-processing of vegetable oils, usually in small proportions, is already a common practice in some European refineries.

Hydrotreatment is an essential part of refinery processing and plays a key role in conditioning fuels for end-use sectors. It involves several reactions, in the presence of hydrogen, for not only deshulpurisation, but also denitrification (removal of nitrogen compounds), deoxygenation, demetallation and aromatics and olefins saturation. Roughly a third of hydrogen consumption in refineries is met by naphtha reforming by-product, but the rest is mostly from on-purpose steam methane reforming, which is a source of CO_2 emissions. Carbon capture and storage (CCS) and electrolysis using low carbon electricity are options to decarbonise hydrogen production. Several refineries in the United States, Canada and Europe have launched or are building CCS or electrolysis projects, but it is likely to take time before we see a more widespread use of green hydrogen in refining.

A dedicated hydrotreating unit inside a refinery has pros and cons vs co-processing. In both cases, special considerations are required when feeding fatty acids from different raw materials, unlike petroleum distillates. Presence of a wide range of contaminants demands an adequate pre-treatment of the feedstock. Some are easily removed through filtration and other non-expensive processes, but heavy metals, phosphorus and sodium compounds can reduce catalyst life. In addition, phosphorus contributes to rubber formation, increasing the differential pressure and limiting the feedstock flow rate. Also, high total acid number (TAN) levels cause steel corrosion. These problems are more easily managed in newly designed plants, rather than in converted units or during co-processing.

Hydrogen consumption is another key consideration for further development of HVO. For petroleum diesel fractions, the main objective of hydrotreatment is desulphurisation. The purpose of hydrotreatment of renewable feedstock is very different, however, as it contains only traces of sulphur. The target reaction is hydrogenation of fatty acids, so hydrogen is consumed as feedstock, rather than as a reagent. As such, hydrogen consumption of renewable feedstock hydrotreatment can be around 5-7 times higher compared to petroleum feedstock. For refinery-integrated projects, this requires expansion of existing hydrogen production capacity to avoid bottlenecks in the operations.

Table 3.3 Properties of biodiesel compared to European specification diesel

	EN590 diesel*	FAME	HVO
Cetane number	51	50-65	80-100
Oxygen (%)	0	11	0
Density (15°C) (g/ml)	Max 0.845	0.88	0.77-0.78
Distillation range (°C)	250-360	350-370	200-320
Sulphur (ppm)	Max 10	0	0
Storage (stability)	Good	Challenging	Good

*EN 590 is European specification diesel.

Apart from meeting mandatory biofuel standards, HVO output can help optimise diesel blending. Much like ethanol's oxygen content boosting gasoline's octane number and allowing blending of low-octane low-value components, HVO diesel allows to optimise on such important parameters as cetane number and stability especially compared to FAME fuels. Also, its low aromatic content means it emits lower levels of air pollutants than petroleum diesel when used in vehicles with older, less sophisticated engines and exhaust after treatment.

VLSFO blending

While petrochemical expansion and renewable diesel production are aimed at coping with the impact of decarbonising transport sector, refiners also have to consider challenges and opportunities arising from near-term market developments. The introduction of new sulphur emission standards for bunker fuels by the IMO is the most relevant example. The new rules that limit sulphur emissions to 0.5% from 3.5% came into effect in January 2020. Very low sulphur fuel oil (VLSFO) is one of the options for complying with the new regulations. Fuel oil traditionally refers to residues from atmospheric distillation or secondary processing units. As already highlighted above, VLSFO defies formal categorisation and may refer to different types of fuels:

- Atmospheric residue (straight-run fuel oil), 0.5% sulphur. About 2-3 mb/d is produced globally from very low sulphur crude oils (e.g. US shale, Algeria, Nigeria, Brazil, the

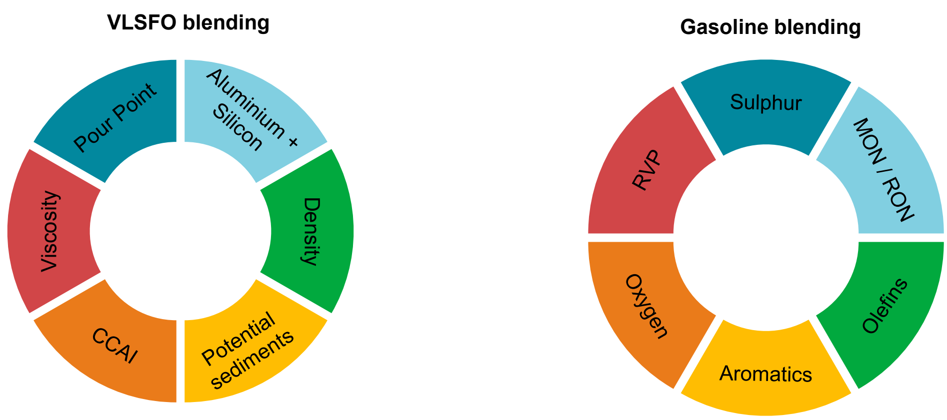
North Sea, Australia, etc). However, most of this is locked in refinery processes to produce diesel, gasoline, etc.

- Desulphurised atmospheric residue. An estimated 3.5 mb/d is used as feedstock by upgrading units to produce premium transport fuels. The desulphurisation process may lower the aromatics content, which affects the fuel's compatibility.
- Blended from various refinery streams, including the above. On-purpose blending by the refiner optimising various streams: vacuum gas oil (VGO), light cycle oil (LCO), upgrader "bottoms", etc. The refiner is responsible for the quality and consistency.
- Blended after the refinery gate from various middle distillates and residue feedstocks. In a simplistic case, a mix of 80% gasoil and 20% fuel oil is required. In reality, it involves more diverse blendstocks.
- Blended on the basis of heavy sweet crude oil.

Only the first two options for VLSFO can be unequivocally categorised as fuel oil, while the rest are overlaps of various intermediate feedstocks that previously would end up either in the middle distillates or in the fuel oil pool. There have been several instances of heavy sweet crudes used as blendstock to improve viscosity and density properties. Several refiners produce VLSFO by desulphurising residual fuels. Blending, however, seems to account for the largest share of new VLSFO supply. In oil trading, gasoline blending used to be the most complex activity. Now, VLSFO blending is emerging as a complex blending business too.

In the past, viscosity and density were the main targets for bunker fuel blending, which aimed to also minimise the giveaway in cutter stock. Giveaway refers to situations when the overall quality of the blended fuel is higher than required by the specifications without commanding a price premium. Sulphur or viscosity giveaways are two common examples. Currently, with the 0.5% sulphur cap, other parameters are becoming increasingly relevant. The use of low value streams like slurry, petrochemical waste products, etc., while ensuring higher margins, carries the risk of undesirable behaviour of the final product.

Figure 3.14 Key parameters for optimisation in gasoline and VLSFO blending



Notes: CCAI is Calculated Carbon Aromaticity Index; RVP is Reid Vapour Pressure, MON/RON is motor and research octane numbers.

In earlier forecasts it was largely expected that middle distillates would be the preferred cutters to control the sulphur content of the fuel. But the market has turned to other non-traditional blendstocks that comply with the fuel specifications at a lower price. Using low-sulphur VGO helps formulate VLSFO with good properties, thanks to the higher aromatic nature of this stream. Indeed, VLSFO blending has supported VGO prices despite weak gasoline cracks.

There are typically several cutters involved in an optimised VLSFO blending. The goal is to comply with specifications at the lowest possible price, and this requires different shares of each available cutter stock. Stability and compatibility of IMO-compliant fuels was the main concern of ship operators: at the time of writing it seems to have subsided somewhat. Problematic situations are likely to arise due to the relative lack of experience of the industry in the new bunker fuel formulation. On the other hand, ensuring a reliable bunker fuel supply offers competitive advantages to the suppliers. For refineries, this is an opportunity to add blending margins to their earnings, especially with growing competition from new capacity additions and lower demand growth for premium transport fuels demand. This is why VLSFO is likely to continue as the main compliance option and further solidify its market share over the forecast period.

Early assessments of the impact of the new IMO's regulations made long before their implementation often emphasised the role of diesel as a bridge fuel to fill the gap in the marine bunker market as HSFO demand collapsed. This would allow refiners time to develop a low-sulphur fuel tailored for bunker use. Over the last three years several unexpected developments in the oil market contributed to a smoother start of the regulations. US oil production, including LTO, will be higher than initially forecast in 2016, and rising exports have provided support for less complex refineries in Europe and Asia. While these grades have lower middle distillate yields than achieved by the complex processing of heavy crude oils, they contribute to IMO-compliant fuel supply by freeing up VGO previously used in gasoline production, to be directed to the VLSFO blending pool.

Table 3.4 Pros and cons of various blendstocks

Cutter stock	Pros	Cons
Diesel	Very low sulphur, with low viscosity and density Combined with other lower quality streams, may reduce giveaways	High price Often paraffinic origin Compatibility risks
Marine gasoil	Commonly, 0.1% sulphur. Similar density and viscosity properties as diesel	High price Stability risks similar to diesel
Light cycle oil (LCO)	Good viscosity at lower price than distillates Aromatic stream with good stability properties Weight price market	Not easy to find low sulphur grades
Low-sulphur vacuum gasoil	Cheaper than distillates to adjust sulphur Better stability properties Higher margin of VGO hydrotreating vs gasoline production	Some paraffinic VGOs may cause problems Higher viscosity than middle distillates and LCO
Low-sulphur straight run residue	Good stability properties	Increasingly limited availability
Slurry/processed fuel oil	Cheaper, often lower sulphur content	Quality risks (Al+Si*, stability, etc.)

*Aluminium and Silicium combined limit.

The new IMO regulations were widely expected to cause disruption across the oil complex. Early experience in 2020 has been relatively quiet, but we cannot be sure that this will be maintained. Diesel demand in the first quarter typically declines seasonally by 700 kb/d on average. The 2019-20 heating season in the northern hemisphere has seen higher than average temperatures against a backdrop of lower economic activity, combined with the added uncertainty caused by the coronavirus. Several large ship owners and traders built compliant fuel inventories in 2019 that they are likely drawing on in early 2020. The full impact of the IMO regulations has yet to be seen.

Table 3.5 Expectations and reality for IMO 2020, as of early 2020

Indicators	Expectations	Early stage reality	Explanation
Heavy (high sulphur) crude oil differentials	Steep discounts	Narrowing of discounts	Lower availability of heavy grades due to output cuts and sanctions
High sulphur fuel oil cracks	Steep discounts	Rebounded after a period of low levels in 2019	Increased processing of lighter grades, more complex refining capacity
Diesel cracks	High, above USD 20/bbl	Low, under USD 15/bbl	Lower diesel demand growth
Gasoline cracks	Higher due to feedstock diversion	Lower	Increased availability from light crude processing
Sweet margins	Boost	Boosted	VLSFO and LSFO well supported by the IMO. Sweet crudes oversupply
Sour complex margins	Large boost	Declining	Narrow sour crude differentials

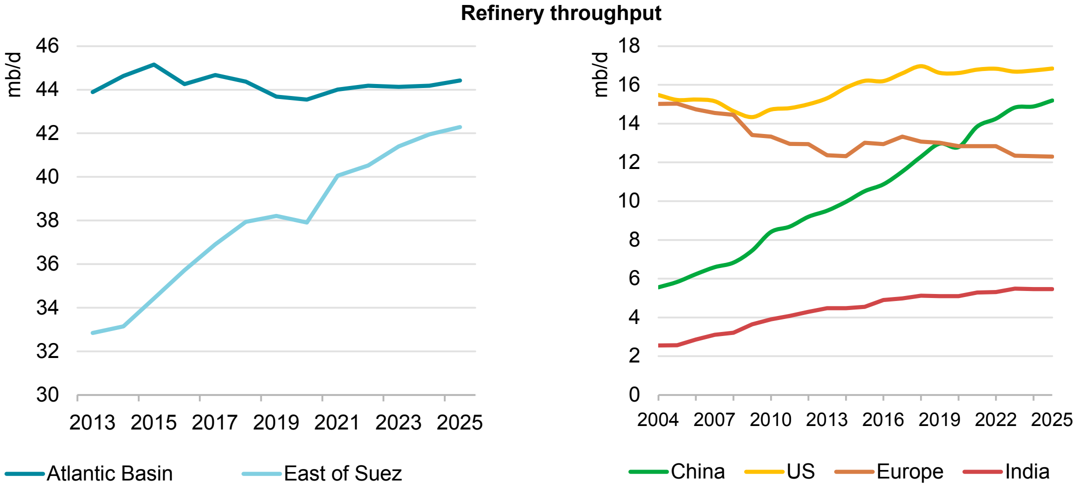
Regional outlook

In our forecast, global refining runs increase by 4.8 mb/d to 2025, with 3.9 mb/d seen in the East of Suez region. Given that this region also accounts for more than half of new capacity being built, utilisation rates increase only marginally, from 81.1% to 81.8%, led by China and the Middle East. In the Atlantic Basin, runs increase by only 0.7 mb/d, but there are vast differences between different regions. European throughput is set to fall by 0.7 mb/d, with utilisation rates falling to 80.5 %, while runs in North America and Africa will ramp up by 0.8 mb/d each one of them. The Former Soviet Union (FSU) is the only other region with a negative change over the outlook period. Latin America registers small growth. Refining activity in the Atlantic basin is unlikely to recover to its historical peak of 45 mb/d set in 2015, but East of Suez throughput will continue growing unabated barring peak oil demand.

Table 3.6 Regional developments in refining capacity and throughput

	2019	2025	Change	2019	2025	2019-25	2019	2025
	Total capacity (mb/d)			Refinery throughput (mb/d)			Utilisation rates	
North America	22.7	23.4	0.7	18.9	19.7	0.8	83.5%	84.4%
Europe	15.3	15.3	0.0	13.0	12.3	-0.7	85.1%	80.5%
FSU	9.0	9.1	0.1	6.8	6.5	-0.4	76.4%	71.4%
China	16.9	18.7	1.8	13.0	15.2	2.2	76.6%	81.3%
India	5.2	5.8	0.6	5.1	5.5	0.4	98.0%	94.9%
Other Asia	14.9	15.5	0.6	11.9	12.1	0.2	80.1%	78.4%
Middle East	9.4	11.1	1.6	7.7	9.0	1.3	81.7%	81.6%
Latin America	5.9	5.9	0.0	3.4	3.6	0.2	57.9%	60.8%
Africa	3.5	4.3	0.8	2.0	2.8	0.8	56.6%	64.0%
World	**102.8**	**109.0**	**6.2**	**81.9**	**86.7**	**4.8**	**79.7%**	**79.6%**
Atlantic Basin	55.6	57.3	1.7	43.7	44.4	0.7	78.5%	77.5%
East of Suez	47.1	51.7	4.6	38.2	42.3	4.1	81.1%	81.8%

Figure 3.15 Atlantic Basin vs East of Suez



The gap between refining activity of the Atlantic Basin and East of Suez shrinks to just 2 mb/d.

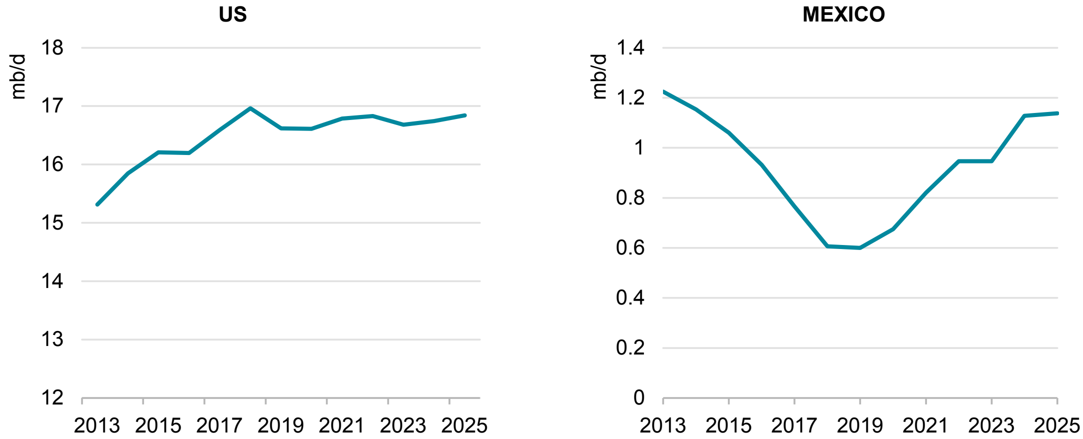
Atlantic Basin

Our medium-term outlook for Atlantic Basin refining activity is less optimistic in this report than in previous years. Throughput is set to increase by only 0.7 mb/d in our forecast period compared to 1.2 mb/d seen last year. This follows a downward demand revision of 1 mb/d, of which about 0.8 mb/d is for refined products, in particular, gasoline and diesel. Demand for oil products, excluding biofuels, is now set to increase by 0.8 mb/d, but this is a net result of ethane and LPG demand growth (0.9 mb/d) offsetting a small decline in refined products. North America and Europe, the largest demand regions by far, are mature markets for oil-based fuels. Demand growth slows in the FSU and West Africa, but North Africa and Latin America partly rebound from the demand declines seen in the last six-year period.

Americas

Stagnant demand is the main reason behind the downward revision our **US** throughput forecast, which is now expected to increase by only 0.2 mb/d vs 2019, and stay below 2018's historical high. With narrowing light-heavy crude differentials, US refiners are increasingly running imported secondary feedstocks through their upgrading units in search of better margins. This has a negative impact on crude distillation utilisation rates. In addition, the closure of the 330 kb/d Philadelphia refinery in 2019 after a fire is likely to be permanent. However, the top spot of the US refining in the global throughput ranking remains uncontested. The United States continues as the second largest refined product exporter, but overtakes Russia to become the top total oil products exporter, with large flows of LPG and ethane.

Figure 3.16 Refining activity in the United States and Mexico.



Forecast Mexican rebound caps US refining activity growth.

Our **US** forecast depends to some extent on the ability of the Mexican refining industry to restore higher utilisation rates and whether the 350 kb/d Dos Bocas refinery will materialise, as forecast, by 2024. Mexico is a home to 30% of US Gulf Coast refiners' exports and is thus a significant outlet for them. With **Mexico's** average refinery utilisation rate having dropped as low as 36% in 2019, imports from the United States cover 80% of gasoline and 65% of domestic diesel demand, respectively. The government is aiming to cut this dependence. However, this requires large and costly repairs and upgrades to ramp up to normal utilisation rates. Given the financial burden, it is unlikely that both the new project and the repairs will be completed within our forecast period. We expect some improvement in the operating rates of existing refineries. Combined with the commissioning of the new refinery, total throughput could reach 1.1 mb/d by 2025, the same as two decades ago. As domestic demand is slightly declining, overall product imports fall, but Mexico remains a net importer overall.

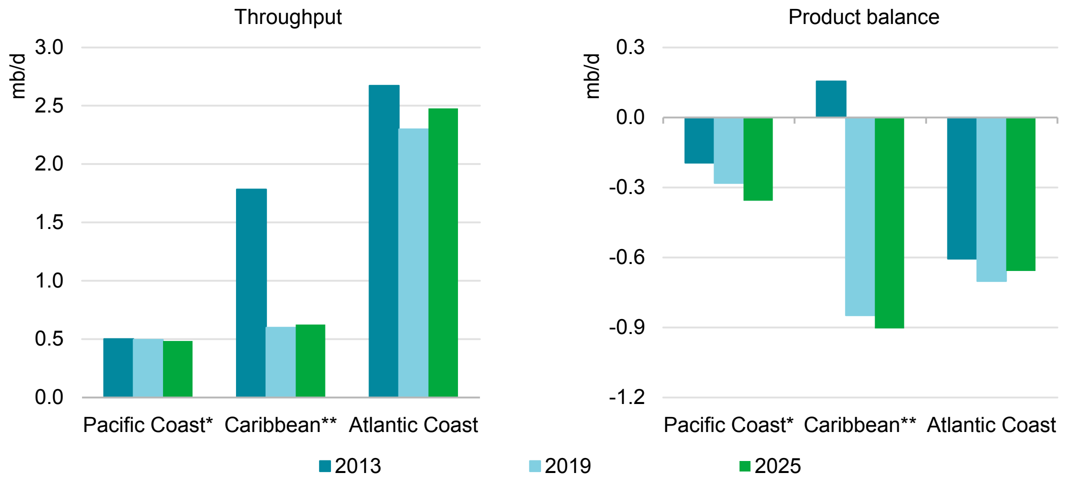
Canada has only a 35 kb/d expansion project for the Come By Chance plant in Newfoundland. The planned second stage of the North West Redwater bitumen refinery has been postponed. The first stage of this refinery started up in 2018 but is yet to start processing bitumen, currently relying on synthetic crudes for feedstock.

In Latin America, the only capacity addition in the forecast period is the 33 kb/d extension at **Peru**'s Talara refinery. In **Brazil**, Petrobras formally scrapped the 165 kb/d second phase of the Comperj refinery. In fact, the first phase is now hanging in the balance as work stopped after reaching 80% completion. Petrobras stated in December 2019 that they are in the process of selling refineries, not building them. The company plans to divest 1.1 mb/d of refining capacity.

At the same time, there has been a flurry of interest in mothballed refineries in and around the Caribbean. **Trinidad**'s 160 kb/d site that was shut down in 2018 was sold to a company owned by the workers' union, but the deal had not been finalised at the time of writing. Klesch Group signed a preliminary deal with the **Curaçao** government to operate the island's 335 kb/d refinery. The former operator, Petroleos de Venezuela (PDVSA), stopped refining activity on the site in 2018. The 525 kb/d refinery in the **US Virgin Islands,** previously jointly owned by PDVSA and Hess, is expected to be turned into a 200 kb/d processing complex in a bid to capture bunker fuel margins.

There is significant lack of clarity on start-up dates and operational details of the projects, especially in terms of crude vs feedstock processing/blending and terminal operations. We have not included these projects in our forecast.

Figure 3.17 Latin American regional markets



*Peru, Ecuador, Chile. **includes Colombia and Venezuela.

The Caribbean region has turned from a small surplus in 2013 to a net importer of almost 0.9 mb/d, as refining activity has dwindled. But proximity to the US Gulf Coast refining centre is a serious competitive pressure for current or new refineries. The more remote Pacific Coast and Atlantic Coast regions are less import-dependent, but the volumes are large and stable over the forecast period.

Europe

European refining activity fared much better over the last few years than was generally expected. The region, however, is heavily dependent on external developments. Unexpectedly solid global gasoline demand growth in recent years, combined with a significant slowdown in Mexican and Caribbean activity helped European refiners not only maintain but increase utilisation rates. Our new forecast, however, is again mostly pessimistic: due to near-zero gasoline demand growth, an expected recovery in Mexican activity and the completion of a large new refinery in Nigeria. European runs are expected to fall 0.7 mb/d by 2025. Given declining demand, refined product imports increased by only 50 kb/d, but that is from an already high level of 1.9 mb/d.

Former Soviet Union

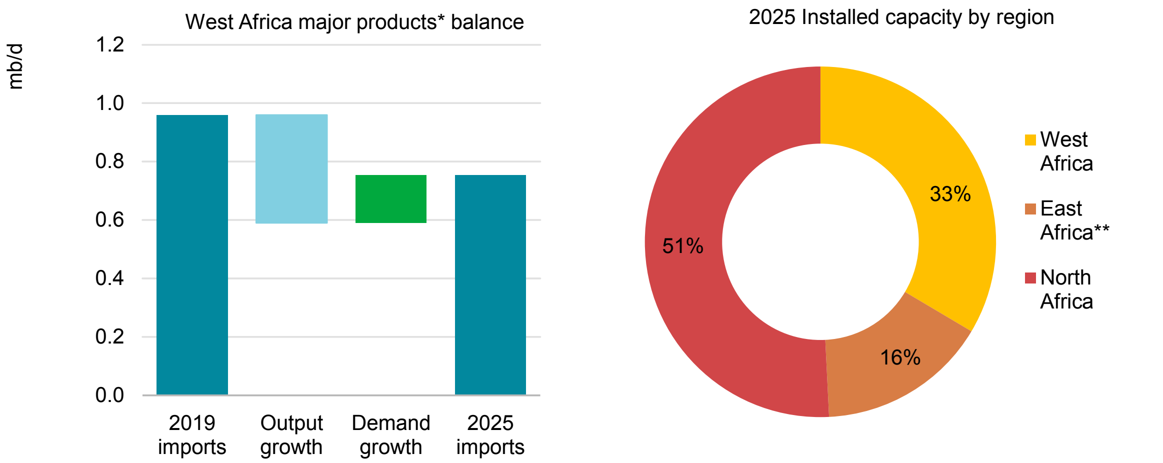
In **Russia**, the massive state-mandated refinery modernisation programme that started almost a decade ago is expected to largely wind down over the forecast period. However, about 250 kb/d worth of upgrade projects were cancelled or put on hold last year. Consequently, fuel oil yields decline less than previously expected. They are now forecast at about 10% in 2025, down from 12.4% in 2019. Throughput declines by 400 kb/d to 5.3 mb/d largely due to lower activity at simple refineries. During the forecast period, India overtakes Russia as the world's third largest refiner. **Uzbekistan** cancelled the 100 kb/d Jizzakh refinery project, focusing instead on upgrading existing capacity. **Belarus** is another source of uncertainty in our forecast. The country relied on Russian crude supply for its 560 kb/d refining sector, which was a subject of negotiations at the time of writing. Belarus is asking to extend the discounted Urals supplies. For the landlocked country, it would be a challenge to secure alternative sources of supply offering the same profitability. Two thirds of refined product output is exported, however, with local needs at a more modest 150-200 kb/d.

Africa

In 2019, there were both positive and negative developments for the future of African refining. **Cameroon**'s sole 42 kb/d refinery suffered a major accident and was taken offline. **Angola** cancelled the 60 kb/d Cabinda project. **Uganda**'s 60 kb/d project was officially postponed to a 2024 start-up date, but we assume it may not happen until after 2025. On the other hand, in **Nigeria**, the CDU column of the 650 kb/d single-train Lekki refinery arrived on the ground, after travelling from Sinopec's facilities in China. The refinery is forecast to be up and running by 2023. We are sceptical about Nigeria's plans to restore and repair its three other refineries with a total capacity of 450 kb/d. In principle, the West African market, currently 0.9 mb/d net short of refined products, could absorb increased output from all of Nigeria's refineries, to the detriment of US and European exporters, but the capital investment burden may be prohibitive.

Overall, West African regional throughput is expected to increase by 640 kb/d in 2025, but due to demand growth, gasoline and diesel net imports decline by only 200 kb/d to 750 kb/d, with the region remaining an important outlet for refineries elsewhere in the Atlantic Basin. In North Africa, a 100 kb/d refinery in **Algeria** and a 60 kb/d extension in **Egypt** are the only two projects over the forecast period. The region's refined product balances remain unchanged, however. Gasoline and diesel imports are still forecast to cover 45% of demand, and low sulphur fuel oil will be exported to the global bunker fuel blending pool.

Figure 3.18 African developments in refining and product balances



*Includes gasoline, kerosene and diesel. ** Includes the Republic of South Africa.

New refinery production in West Africa is partly offset by growing demand. The continent's installed capacity remains heavily concentrated in the north.

East Africa, which includes the Republic of South Africa, should be discussed in the context of the East of Suez as its oil trade is carried out predominantly with countries around the Indian Ocean. The sole project expected to come online in the forecast period is a 25 kb/d mini-refinery in

South Sudan. The region's net product import requirements grow to 700 kb/d. Several plans for refineries, from Equatorial Guinea to South Africa, became public last year, but we are waiting for more details before including them in our forecast.

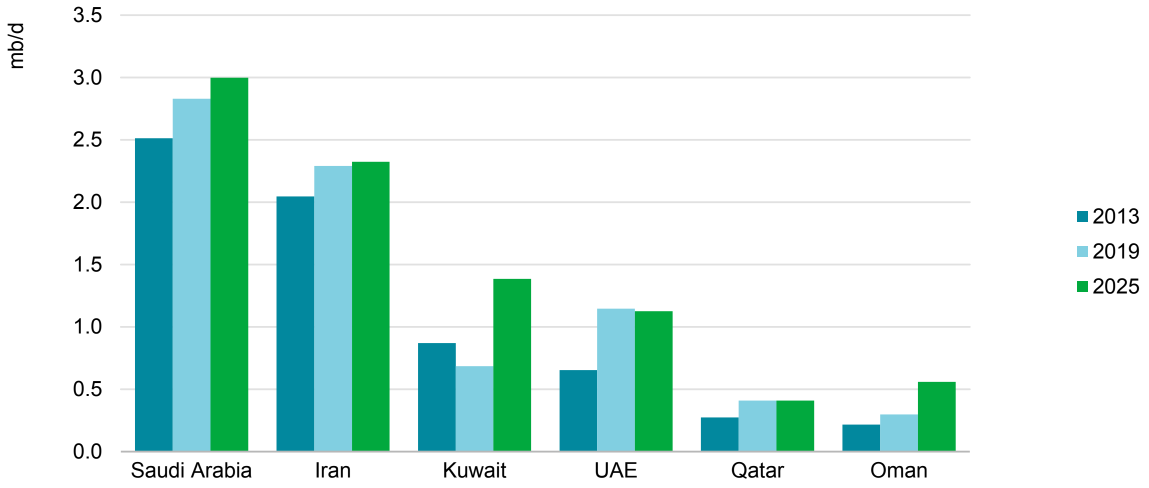
East of Suez

East of Suez, which comprises the Middle East and Asia, accounts for just under 80% of global refined product demand growth, or 3.4 mb/d, and throughput is expected to increase by 4 mb/d to cover incremental consumption. Expected capacity additions to 2025 are 3.3 mb/d, implying a slight improvement in overall utilisation rates from 81.1% to 81.8% in 2025.

Middle East

A large-scale refinery construction and modernisation programme is ongoing in the Middle East, though increasingly concentrated in a smaller number of countries. The forecast for gross additions to capacity is essentially unchanged from our last report, at 2.3 mb/d. However, shutdowns are higher at 0.7 mb/d, as they now include an 85 kb/d refinery in the **United Arab Emirates** (hereafter "UAE"). Saudi Aramco's 400 kb/d Jazan refinery start-up was pushed back and is now expected in 2020. **Kuwait**'s 615 kb/d Al-Zour refinery remains the largest project in the region. Along with the start-up of the clean fuels project tying the Mina Abdulla and Mina al-Ahmadi refineries, it will double the country's refining capacity.

Figure 3.19 Capacity developments in selected Middle East countries



Capacity additions continue in a smaller number of countries.

India

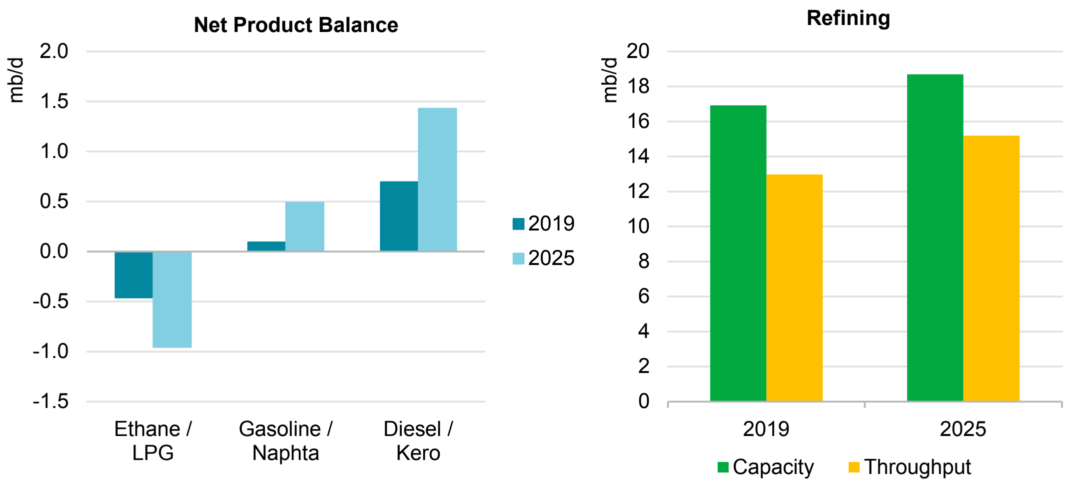
About 0.6 mb/d of new crude distillation capacity is expected to come online in India, and runs are forecast to increase by 0.4 mb/d, with utilisation rates dropping slightly to 95%. This assumes increased downtime due to refineries moving to production of ultra-low sulphur gasoline and diesel for the country's Bharat VI standards expected to kick off in the fiscal year of 2020. Production of higher quality fuels typically entails higher frequency of stoppages.

India remains a net product exporter, but volumes halve during our forecast period. Capacity additions are likely to accelerate in the second half of the 2020s. The most notable project is the 1.2 mb/d Raigad refinery, a joint venture between three Indian state-owned firms, Saudi Aramco and ADNOC. Its prospects have become somewhat uncertain since the capital investment estimate swelled to USD 70 bn and it was dubbed the most expensive oil industry project ever. For Saudi Aramco, its Initial Public Offering in late 2019 means there will be more scrutiny over its participation in large projects.

China

After a record level of 1.2 mb/d of capacity additions in 2019, the pace slows over the forecast period, with a cumulative 1.8 mb/d of new capacity. Petrochemical-oriented projects, such as Zhejiang Petrochemical's 400 kb/d second phase and Shenghong's 320 kb/d refinery, account for 40% of the additions. We have removed from our list independent refinery capacity expansions, totalling 270 kb/d. Sinopec's Gulei, Zhangzhou project is now going ahead as a petrochemical-only plant, with the CDU unit postponed, which is also the case for the expansion project at the çompany's Zhenhai site. Driven by petrochemical base product self-sufficiency goals, China's throughput is forecast to increase by 2.2 mb/d, with average utilisation rates improving from 76.6% to 81.3%. Further improvement could come from consolidation in the small-scale independent refinery sector, especially in Shandong. While still behind the United States in terms of refining throughput, China overtakes India to become the third largest net exporter of refined products after Russia and the United States.

Figure 3.20 China's product balance and refining developments

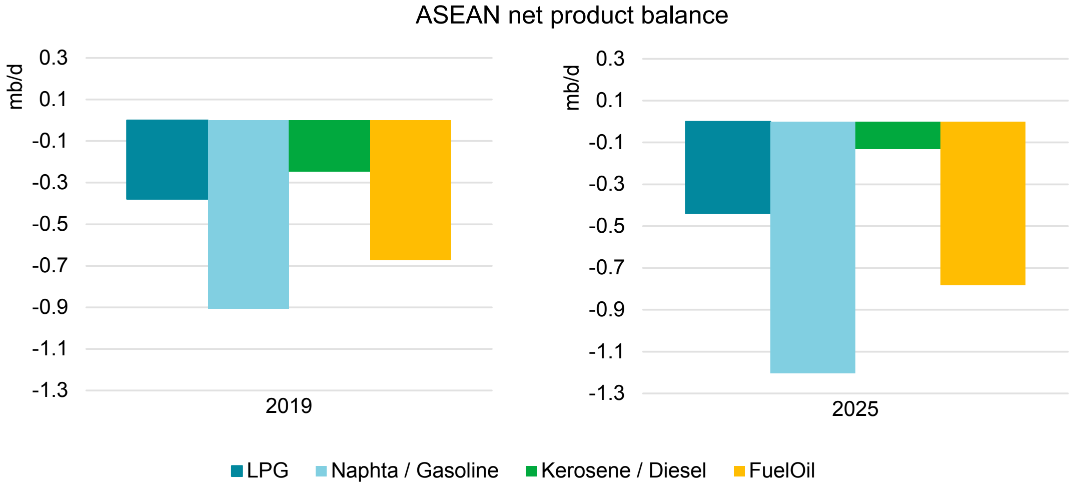


Transport fuel exports increase while petrochemical feedstock imports continue.

Other Asia

The only capacity change expected in OECD Asia over the forecast period is the shutdown of the 115 kb/d Osaka refinery in **Japan**. Elsewhere, three refinery projects were removed from the forecast period due to cancellation or delay: a 50 kb/d extension at **Indonesia**'s Cilacap refinery, a 90 kb/d extension in **Malaysia**'s Port Dickson site and a 50 kb/d expansion at the Limay refinery in the **Philippines**. New projects include small-scale sites in **Mongolia** and Malaysia and an expansion in **Pakistan**.

Figure 3.21 Growing reliance on naphtha imports in Southeast Asia



Southeast Asian countries in total add 0.6 mb/d of new capacity and ramp up throughput by an even higher 0.7 mb/d. Refined products imports nevertheless increase as demand grows by 0.9 mb/d. The second phase of Chinese firm Hengyi Petrochemical's refinery in **Brunei** is the largest project, adding 280 kb/d, with smaller additions in Indonesia, Viet Nam, Pakistan and Mongolia. In **Malaysia**, a commodity trader is building a small unit aimed at the marine bunkers market.

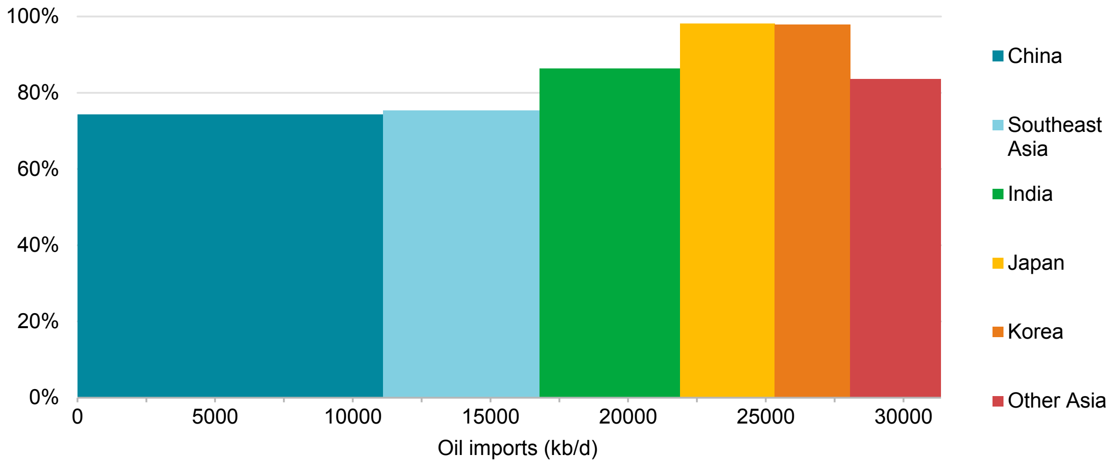
Japan is still seen as the country most vulnerable to increasing competition in Asia, with refinery throughput expected to fall by 0.5 mb/d to 2025. By 2025 Japanese gasoline and diesel demand will fall behind naphtha, which sees continued solid demand from the petrochemical sector. The latter is the reason for the relative robustness of **Korea**'s refining sector, where the activity forecast is more steady.

Crude and products trade

Two major parallel developments are forecast in oil trade: the United States becoming a net oil exporter and Asia driving towards 31 mb/d of net oil imports. For several months at the end of 2019 the United States registered net oil exports. We forecast the United States achieving a positive net oil balance on a sustained basis in 2021, including coverage of the oil consumption of US dependent territories. For US-50, net oil exporter status is reached in 2020.

The consequences of Asian demand growth are most acute in terms of its impact on oil trade logistics and security. Already in 2019 Asia imported 27 mb/d of crude oil and products, more than the OECD's peak net imports at the start of the millennium. Excluding OECD Asia, where emergency stockholding is generally high, the rest of Asia's imports will increase from 20 mb/d in 2019 to 24.3 mb/d in 2025. For comparison, the net oil imports of OECD Europe and North America combined were 20.4 mb/d in 2005, their historical peak. At that time, their stockholding was 3.3 bn barrels, representing 160 days of coverage for net imports. In developing Asia, China seems to have progressed most in building inventories: however, the precise level of stocks is not publicly available. Estimates range between 700 mb observed by satellites (only above-ground floating roof facilities) and about 1 bn barrels implied by oil balance calculations. India has started a strategic reserves programme and can benefit from the relative oversupply of crude oil in global markets in the first half of the forecast period. Similar programmes elsewhere in the region are at early stages. By 2025, at least a quarter of Asian imports will have to come from the Atlantic Basin: increasing voyage duration and inherently limiting flexibility when dealing with emergencies.

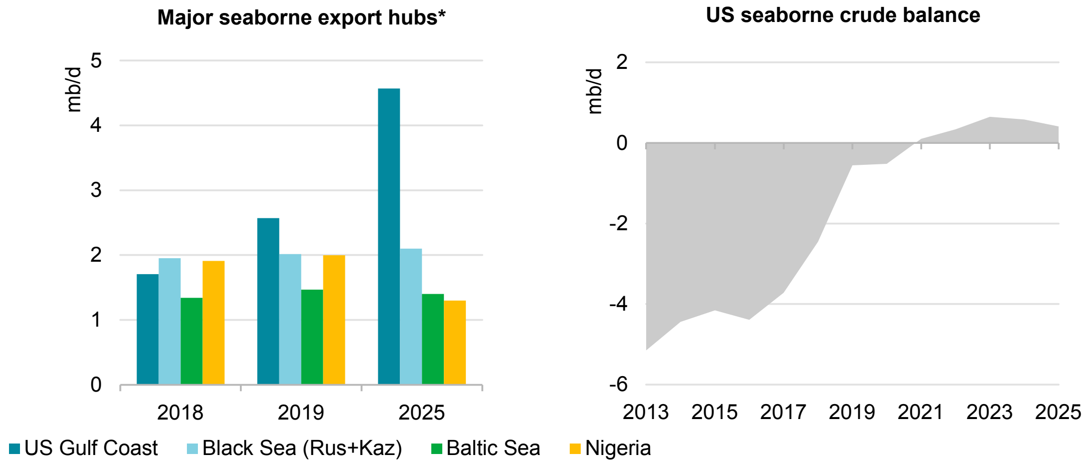
Figure 3.22 Net oil imports in 2025 and level of dependence



Crude oil trade developments

Increased crude exports out of the United States dominate global crude trade developments in the first half of the forecast period. In the second half, as non-OPEC production growth flattens, the call on production and exports out of the Middle East increases. Currently, the region sits on significant spare capacity (see *Supply*).

Figure 3.23 United States leads seaborne crude exports growth

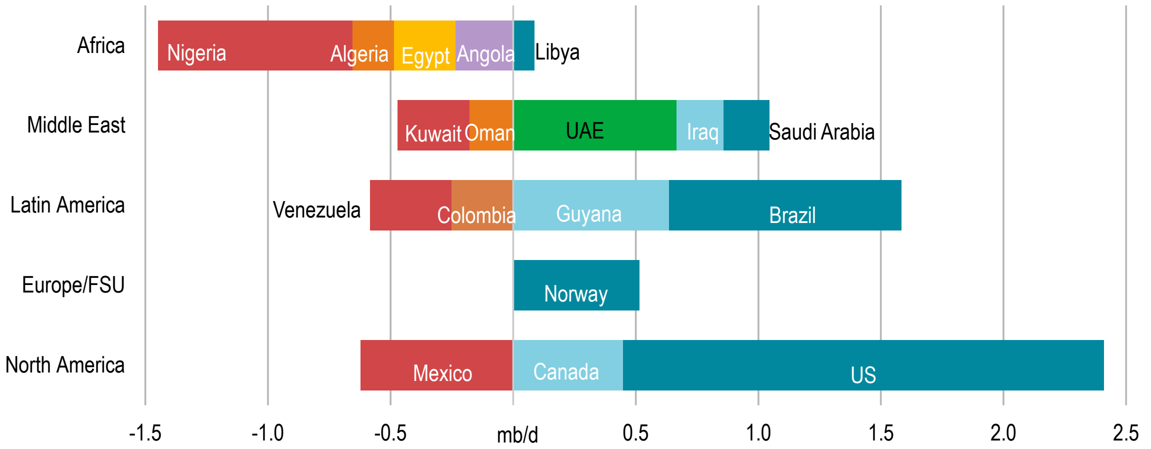


* Outside the Middle East.

With our outlook for US crude production revised slightly upward and the outlook for crude processing revised lower, US export availability is forecast to be higher in this report. The US Gulf Coast has become the second largest oil export hub after the Persian Gulf. In 2019, seaborne exports totalled 2.6 mb/d, overtaking Kuwait and Nigeria. Russia's 5 mb/d of exports, by contrast, are spread between several outlets. The largest by volume – the Baltic Sea ports, delivered 1.5 mb/d. In 2019 the United States supplied more crude oil to seaborne markets in the Atlantic Basin than Russia.

Taking into account landlocked Canadian crude deliveries to US refiners in the Midwest and the Gulf Coast, the export availability of US crude increases, and the United States becomes a net seaborne crude oil exporter in 2023. This means that crude oil exports out of the Gulf Coast more than offset imports into the West Coast and the US North East. These regions do not have easy access to US domestic barrels given the prohibitive shipping costs associated with Jones Act rules and will continue relying on external suppliers.

Figure 3.24 Changes in net crude exports, 2025 vs 2019



Note: FSU = former Soviet Union.

The emergence of this new trade paradigm is commonly attributed to quality issues. US grades are lighter, while the Gulf Coast refining system has some of the most complex processing capacity in the world. However, increased exports out of the Gulf Coast were not accompanied by increased imports. Since the crude oil export ban was lifted in 2015, total imports have almost halved, and seaborne imports fell by more than half to just 1.2 mb/d. This means that the US refiners absorbed the larger share of the LTO production (currently around 8 mb/d) as only 2-3 mb/d is being regularly exported. Asia has been the largest destination for these exports, but Europe and Latin America are regular takers of US crude, too. In fact, some of the Latin American importers are net crude oil exporters themselves: e.g. Colombia and Brazil, in search of lighter and lower sulphur grades for their refining sector. The UAE also regularly imports light US crude grades for processing in condensate splitters.

Even as the pace of growth of US production is slowing, it remains the biggest source of incremental crude supply and exports. US exports increase by another 2 mb/d, followed by Brazil, Saudi Arabia, the UAE and Norway. Chinese imports grow by 2.4 mb/d while Southeast Asian nations collectively increase inflows by 1.1 mb/d.

Figure 3.25 Selected net crude oil importers

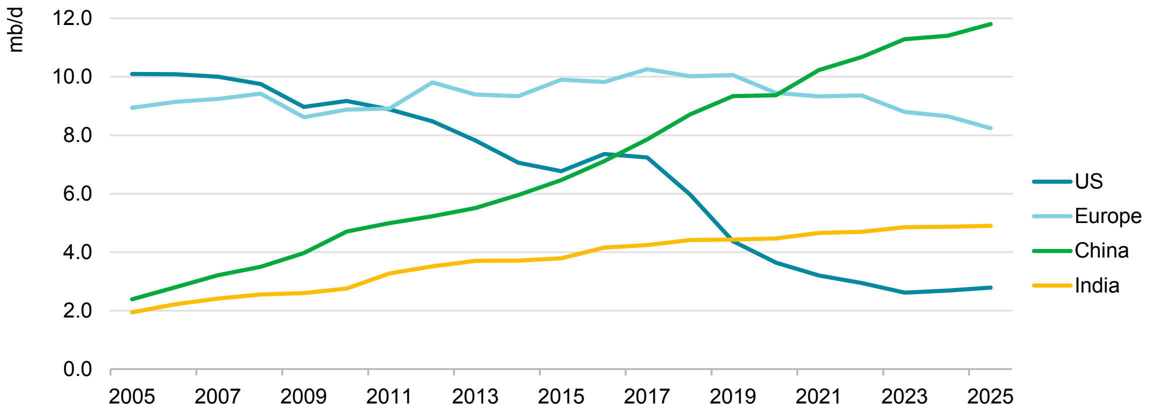
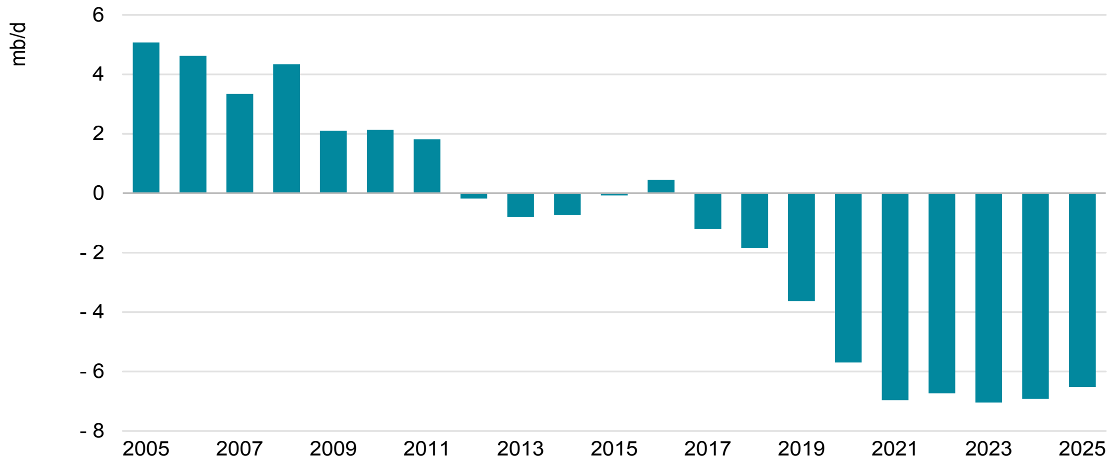


Figure 3.26 East of Suez crude oil balance



Despite increased exports from the Middle East, East of Suez crude oil balances fall further into deficit, reaching 7 mb/d in 2023 before falling slightly to 6.5 mb/d as higher Middle East output starts offsetting. The gap is filled by barrels out of North America, Latin America and Africa.

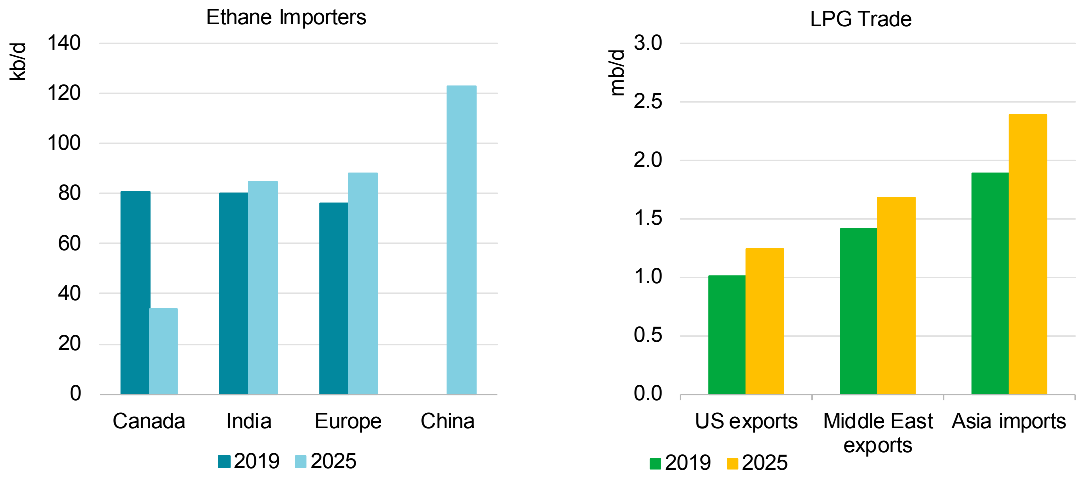
Product trade developments

More than 70% of refining activity growth comes from countries that are already net product exporters. Exports decline in only one of them, India, where demand growth more than offsets refining growth. The rest, notably the United States, China and the Middle East, increase their share in global products trade. Europe and Southeast Asian countries remain large net product importers. What is less evident is the extent to which southern hemisphere countries rely on product imports from the north. Latin America, sub-Saharan Africa, Australia and other Asian countries south of the equator have become large net importers, relying on very long-distance supply routes.

Ethane/LPG

Increased supplies of US NGLs drive incremental ethane and LPG exports towards countries with a growing appetite for light ends, mostly in Asia. The Middle East is another important source of supply growth for light molecules. The two regions together will export 600 kb/d more NGLs, far ahead of any other source. China overtook India in LPG imports and will continue ramping up. It is also expected to become the largest export market for US ethane.

Figure 3.27 Ethane/LPG

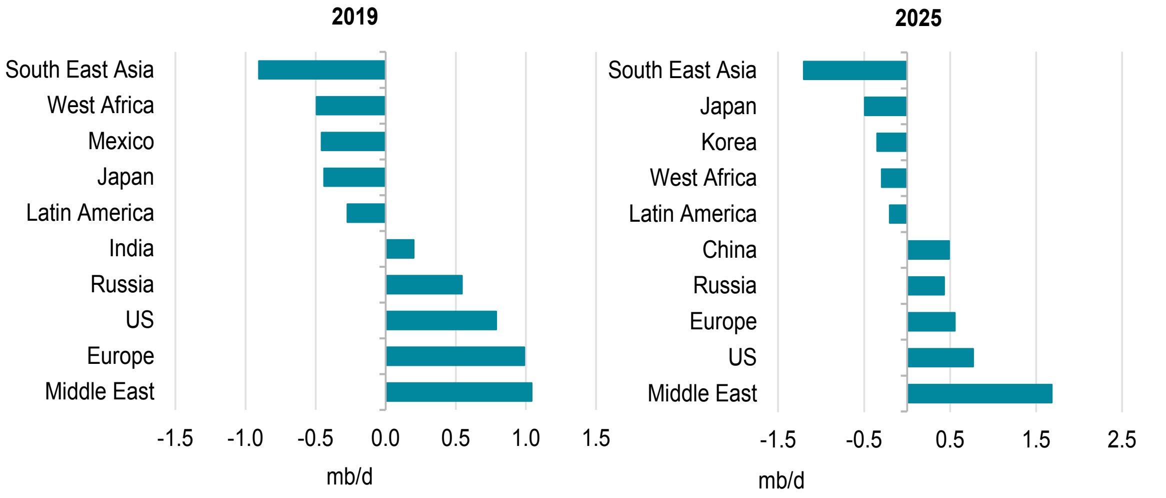


Gasoline/naphtha

For gasoline/naphtha, trade volumes are expected to concentrate on Middle East to Asian markets flows. Refiners in the Atlantic Basin will have reduced availability due to downward revisions to refining throughput forecasts. Chinese and Indian combined gasoline/naphtha balances are expected to be mostly positive but this is a net result of naphtha import flows and gasoline export flows.

OECD Asia and Southeast Asian countries will be the largest net importers of these products globally, with around 1-1.2 mb/d each. Latin America and Mexico also remain large import markets, as well as African countries.

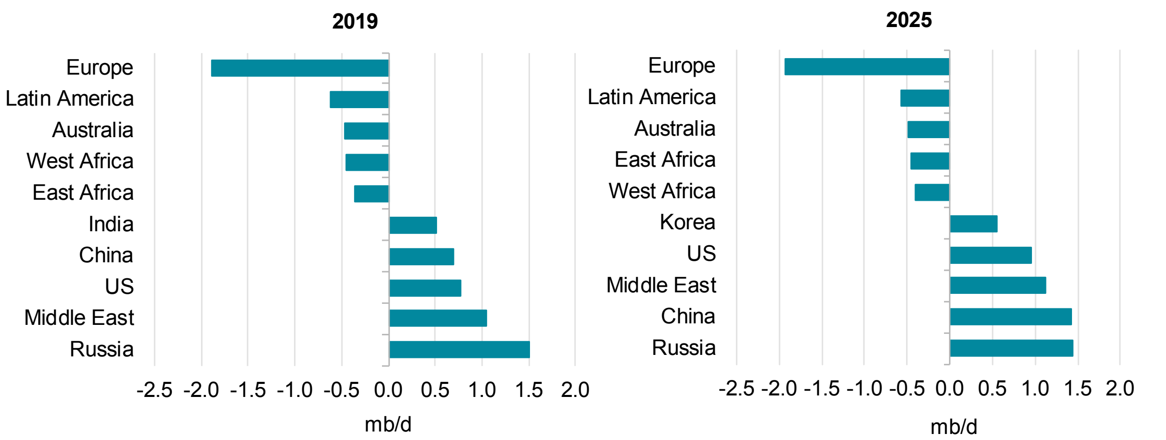
Figure 3.28 Main gasoline/naphtha exporters (positive) and importers (negative)



Diesel/kerosene

The Atlantic Basin remains a net importer of middle distillates through our forecast. Europe's deficit is not possible to fix through refining as yields are already at some of the highest levels in the world at around 48.5%. However, the share of diesel and kerosene in the product demand barrel is higher, at 55%. Increasing refinery throughput would result in higher gasoline production, for which demand growth prospects have vanished. Latin America and Africa also remain large diesel importers. Exports out of the United States and Russia do not fully cover the gap. The need for supplies from Middle Eastern refineries and even Asia remains stable.

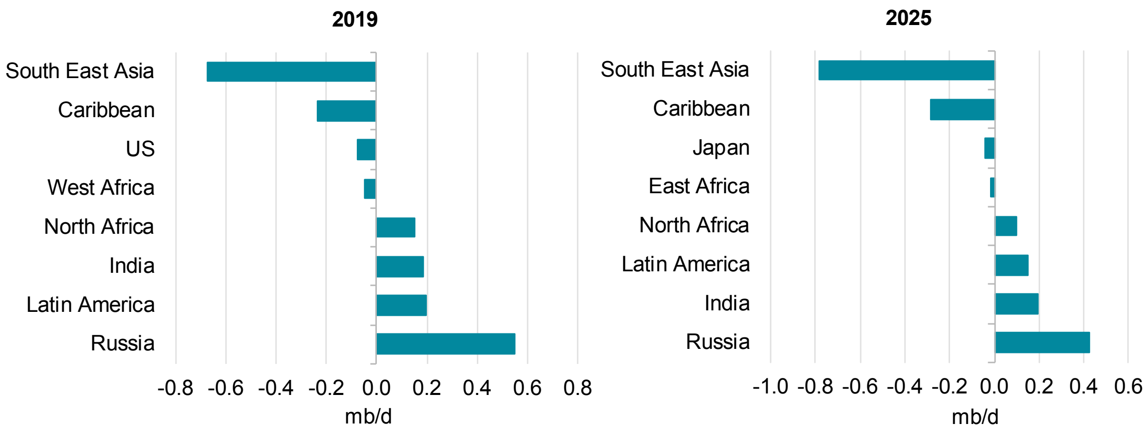
Figure 3.29 Main diesel/kerosene exporters (positive) and importers (negative)



Fuel oil

On a global scale, the fuel oil trade is undergoing a quality and directional change rather than a quantity change. Russia, the main source of heavy, high sulphur fuel oil, will still export at least 400 kb/d of fuel oil in 2025, but these flows increasingly find outlets in feedstocks markets (such as the US Gulf Coast, and, potentially, Europe and China) rather than bunkers. Stable Asian import volumes come from bunker fuel requirements, and are expected to be filled with blending components for the new VLSFO from Europe, Latin America, North Africa and the United States.

Figure 3.30 Main fuel oil exporters (positive) and importers (negative)



Tables

Table 1
WORLD OIL SUPPLY AND DEMAND
(million barrels per day)

	1Q19	2Q19	3Q19	4Q19	2019	1Q20	2Q20	3Q20	4Q20	2020	2021	2022	2023	2024	2025
OECD DEMAND															
Americas	25.4	25.4	25.9	25.7	25.6	25.1	25.4	26.2	25.9	25.7	25.8	25.8	25.9	25.8	25.7
Europe	13.9	14.1	14.6	14.0	14.1	13.7	13.7	14.4	13.9	13.9	14.0	14.1	14.0	14.0	14.0
Asia Oceania	8.3	7.5	7.6	8.1	7.9	8.1	7.2	7.6	8.1	7.8	7.9	8.0	8.0	8.0	8.0
Total OECD	**47.6**	**47.0**	**48.1**	**47.7**	**47.6**	**46.9**	**46.4**	**48.3**	**47.9**	**47.4**	**47.7**	**47.8**	**47.9**	**47.8**	**47.7**
NON-OECD DEMAND															
FSU	4.5	4.7	4.9	4.8	4.7	4.6	4.7	5.0	4.9	4.8	4.9	4.9	4.9	4.9	5.0
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
China	13.0	13.7	13.8	14.1	13.7	11.2	13.8	14.3	14.3	13.4	14.2	14.6	14.9	15.3	15.5
Other Asia	14.6	14.3	13.8	14.4	14.3	14.7	14.5	14.1	14.8	14.5	15.0	15.4	15.8	16.1	16.6
Latin America	6.2	6.3	6.4	6.3	6.3	6.1	6.3	6.4	6.4	6.3	6.4	6.4	6.5	6.6	6.6
Middle East	8.1	8.2	8.8	8.4	8.4	8.0	8.3	9.0	8.2	8.4	8.6	8.6	8.6	8.6	8.7
Africa	4.4	4.3	4.2	4.3	4.3	4.4	4.4	4.2	4.4	4.3	4.4	4.5	4.7	4.8	4.8
Total Non-OECD	**51.5**	**52.3**	**52.6**	**53.2**	**52.4**	**49.8**	**52.8**	**53.8**	**53.7**	**52.5**	**54.2**	**55.3**	**56.2**	**57.1**	**58.0**
Total Demand[1]	**99.1**	**99.2**	**100.7**	**100.9**	**100.0**	**96.7**	**99.2**	**102.0**	**101.7**	**99.9**	**102.0**	**103.1**	**104.0**	**104.9**	**105.7**
OECD SUPPLY															
Americas	24.1	24.5	24.7	25.6	24.7	25.5	25.6	26.1	26.5	25.9	26.9	27.3	27.5	27.5	27.5
Europe	3.5	3.2	3.2	3.5	3.3	3.7	3.7	3.7	3.9	3.7	3.8	3.8	3.8	3.6	3.4
Asia Oceania	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5
Total OECD	**28.0**	**28.2**	**28.4**	**29.6**	**28.5**	**29.7**	**29.9**	**30.3**	**30.9**	**30.2**	**31.3**	**31.6**	**31.8**	**31.7**	**31.4**
NON-OECD SUPPLY															
FSU	14.8	14.4	14.6	14.7	14.6	14.7	14.6	14.6	14.7	14.7	14.8	14.9	14.7	14.6	14.5
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Other Asia	3.3	3.2	3.1	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.0	2.9	2.8	2.7	2.6
Latin America	4.5	4.6	4.9	5.0	4.7	5.0	5.1	5.2	5.2	5.1	5.2	5.2	5.5	5.9	6.3
Middle East	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.2	3.3	3.3	3.3	3.4	3.4	3.4
Africa	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.4	1.4
Total Non-OECD	**31.4**	**31.0**	**31.3**	**31.6**	**31.3**	**31.7**	**31.5**	**31.6**	**31.6**	**31.6**	**31.7**	**31.6**	**31.8**	**32.0**	**32.2**
Processing Gains[2]	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
Global Biofuels	2.3	3.0	3.2	2.7	2.8	2.4	3.0	3.3	2.9	2.9	3.0	3.1	3.2	3.2	3.3
Total Non-OPEC[3]	**64.0**	**64.5**	**65.2**	**66.3**	**65.0**	**66.2**	**66.8**	**67.6**	**67.8**	**67.1**	**68.4**	**68.8**	**69.2**	**69.4**	**69.5**
OPEC															
Crude[3]	30.7	30.1	29.5	29.8	30.0										
OPEC NGLs	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.6	5.6	5.7	5.7
Total OPEC[3]	**36.2**	**35.6**	**35.0**	**35.3**	**35.5**										
Total Supply	**100.1**	**100.1**	**100.2**	**101.6**	**100.5**										
Memo items:															
Call on OPEC crude + Stock ch.[4]	29.7	29.2	30.0	29.1	29.5	25.0	26.9	28.9	28.4	27.3	28.0	28.8	29.3	29.9	30.6

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
2 Net volumetric gains and losses in the refining process and marine transportation losses.
3 Total Non-OPEC excludes all countries that are currently members of OPEC.
Total OPEC comprises all countries which are current OPEC members.
4 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

Table 1a

WORLD OIL SUPPLY AND DEMAND: CHANGES FROM LAST MEDIUM-TERM REPORT

(million barrels per day)

	1Q18	2Q18	3Q18	4Q18	2018	1Q19	2Q19	3Q19	4Q19	2019	2020	2021	2022	2023	2024
OECD DEMAND															
Americas	0.1	0.0	0.0	-0.4	-0.1	-0.2	-0.4	-0.3	-0.6	-0.3	-0.4	-0.3	-0.3	-0.1	-0.2
Europe	-0.1	0.0	-0.1	-0.2	-0.1	-0.2	-0.4	-0.3	-0.5	-0.3	-0.5	-0.3	-0.2	-0.2	-0.1
Asia Oceania	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.2	0.2	0.2	0.2
Total OECD	**0.1**	**0.1**	**0.1**	**-0.5**	**-0.1**	**-0.4**	**-0.7**	**-0.4**	**-1.0**	**-0.6**	**-0.9**	**-0.3**	**-0.3**	**-0.1**	**-0.2**
NON-OECD DEMAND															
FSU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	-0.1	-0.2	-0.2
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	-0.1	-0.1	-0.1	0.0	0.0	-0.1	0.3	0.2	0.4	0.2	-0.4	0.0	0.1	0.2	0.3
Other Asia	0.4	0.3	0.2	0.2	0.3	0.4	0.0	-0.1	0.0	0.1	-0.2	-0.2	-0.2	-0.3	-0.3
Latin America	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.0	-0.1	-0.2	-0.2	-0.2	-0.3	-0.3
Middle East	0.0	-0.1	0.0	-0.2	-0.1	-0.1	-0.4	-0.1	0.2	-0.1	-0.2	-0.3	-0.4	-0.5	-0.7
Africa	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2
Total Non-OECD	**0.1**	**0.0**	**0.0**	**-0.2**	**0.0**	**0.0**	**-0.3**	**-0.2**	**0.5**	**0.0**	**-1.2**	**-1.0**	**-1.1**	**-1.2**	**-1.3**
Total Demand	**0.2**	**0.1**	**0.1**	**-0.7**	**-0.1**	**-0.3**	**-1.1**	**-0.5**	**-0.5**	**-0.6**	**-2.1**	**-1.3**	**-1.4**	**-1.3**	**-1.4**
OECD SUPPLY															
Americas	0.2	0.2	0.2	0.4	0.3	0.6	0.8	0.4	1.1	0.7	0.7	0.8	0.7	0.7	0.6
Europe	0.0	0.1	0.1	0.1	0.1	0.0	-0.1	-0.2	0.0	-0.1	0.1	0.0	0.0	-0.1	-0.2
Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total OECD	**0.3**	**0.2**	**0.3**	**0.5**	**0.3**	**0.6**	**0.6**	**0.2**	**1.1**	**0.6**	**0.8**	**0.8**	**0.7**	**0.6**	**0.4**
NON-OECD SUPPLY															
FSU	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	-0.1	0.0	-0.1	0.0	0.2	0.0	0.0
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3
Other Asia	0.0	0.0	0.0	0.0	0.0	0.1	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1
Latin America	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.1	0.0	-0.1	0.1	0.1	-0.1	0.0	0.1
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.2	-0.2	-0.2
Total Non-OECD	**0.1**	**0.0**	**0.0**	**0.1**	**0.0**	**0.1**	**-0.1**	**-0.1**	**0.0**	**0.0**	**0.0**	**0.2**	**0.1**	**0.1**	**0.3**
Processing Gains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Global Biofuels	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.0	0.0	0.1	0.1	0.1
Total Non-OPEC	**0.3**	**0.2**	**0.3**	**0.6**	**0.4**	**0.6**	**0.6**	**0.3**	**1.1**	**0.7**	**0.8**	**1.1**	**0.9**	**0.8**	**0.7**
OPEC															
Crude	0.0	0.0	0.0	0.0	0.0										
OPEC NGLs	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0
Total OPEC	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**										
Total Supply	**0.3**	**0.2**	**0.3**	**0.5**	**0.3**										
Memo items:															
Call on OPEC crude + Stock ch.	0.0	-0.1	-0.2	-1.2	-0.4	-0.9	-1.7	-0.7	-1.6	-1.2	-2.8	-2.3	-2.2	-2.0	-2.1

Table 1b
WORLD OIL SUPPLY AND DEMAND - WEO Regions
(million barrels per day)

	1Q19	2Q19	3Q19	4Q19	2019	1Q20	2Q20	3Q20	4Q20	2020	2021	2022	2023	2024	2025
DEMAND															
North America	25.0	25.0	25.5	25.3	25.2	24.7	25.0	25.8	25.6	25.3	25.4	25.4	25.5	25.4	25.4
Central and South America	6.5	6.6	6.7	6.7	6.7	6.5	6.6	6.7	6.7	6.7	6.7	6.8	6.9	7.0	7.0
Europe	15.3	15.5	16.1	15.5	15.6	15.1	15.2	15.9	15.4	15.4	15.5	15.6	15.6	15.6	15.6
Africa	4.4	4.3	4.2	4.3	4.3	4.4	4.4	4.2	4.4	4.3	4.4	4.5	4.7	4.8	4.8
Middle East	8.1	8.2	8.8	8.4	8.4	8.0	8.3	9.0	8.2	8.4	8.6	8.6	8.6	8.6	8.7
Eurasia	4.1	4.2	4.5	4.4	4.3	4.2	4.3	4.6	4.5	4.4	4.5	4.5	4.5	4.5	4.6
Asia Pacific	35.7	35.3	35.0	36.3	35.6	33.7	35.3	35.7	36.9	35.4	36.8	37.7	38.4	39.1	39.8
Total Demand[1]	**99.1**	**99.2**	**100.7**	**100.9**	**100.0**	**96.7**	**99.2**	**102.0**	**101.7**	**99.9**	**102.0**	**103.1**	**104.0**	**104.9**	**105.7**
NON-OPEC SUPPLY															
North America	24.0	24.5	24.6	25.5	24.7	25.5	25.6	26.1	26.5	25.9	26.9	27.3	27.5	27.5	27.5
Central and South America	4.5	4.6	4.9	5.0	4.8	5.1	5.1	5.2	5.2	5.1	5.2	5.2	5.6	6.0	6.3
Europe	3.7	3.4	3.4	3.7	3.6	3.9	3.9	3.9	4.1	3.9	4.0	3.9	4.0	3.8	3.6
Africa	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.4	1.4
Middle East	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.2	3.3	3.3	3.3	3.4	3.4	3.4
Eurasia	14.7	14.3	14.5	14.6	14.5	14.7	14.5	14.5	14.6	14.6	14.8	14.8	14.6	14.5	14.4
Asia Pacific	7.6	7.6	7.5	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.5	7.4	7.3	7.2	7.0
Total Non-OPEC	**59.3**	**59.2**	**59.6**	**61.2**	**59.8**	**61.4**	**61.4**	**61.9**	**62.5**	**61.8**	**63.0**	**63.3**	**63.6**	**63.7**	**63.6**
Processing Gains[2]	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
Global Biofuels	2.3	3.0	3.2	2.7	2.8	2.4	3.0	3.3	2.9	2.9	3.0	3.1	3.2	3.2	3.3
Total Non-OPEC[3]	**64.0**	**64.5**	**65.2**	**66.3**	**65.0**	**66.2**	**66.8**	**67.6**	**67.8**	**67.1**	**68.4**	**68.8**	**69.2**	**69.4**	**69.5**
OPEC SUPPLY															
Crude[3]	30.7	30.1	29.5	29.8	30.0										
OPEC NGLs	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.6	5.6	5.7	5.7
Total OPEC[3]	36.2	35.6	35.0	35.3	35.5										
Total Supply	**100.1**	**100.1**	**100.2**	**101.6**	**100.5**										
Memo items:															
Call on OPEC crude + Stock ch.[4]	29.7	29.2	30.0	29.1	29.5	25.0	26.9	28.9	28.4	27.3	28.0	28.8	29.3	29.9	30.6

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
2 Net volumetric gains and losses in the refining process and marine transportation losses.
3 Total Non-OPEC excludes all countries that are currently members of OPEC. Total OPEC comprises all countries which are current OPEC members.
4 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	1Q19	2Q19	3Q19	4Q19	2019	1Q20	2Q20	3Q20	4Q20	2020	2021	2022	2023	2024	2025
Demand (mb/d)															
Americas	25.4	25.4	25.9	25.7	25.6	25.1	25.4	26.2	25.9	25.7	25.8	25.8	25.9	25.8	25.7
Europe	13.9	14.1	14.6	14.0	14.1	13.7	13.7	14.4	13.9	13.9	14.0	14.1	14.0	14.0	14.0
Asia Oceania	8.3	7.5	7.6	8.1	7.9	8.1	7.2	7.6	8.1	7.8	7.9	8.0	8.0	8.0	8.0
Total OECD	**47.6**	**47.0**	**48.1**	**47.7**	**47.6**	**46.9**	**46.4**	**48.3**	**47.9**	**47.4**	**47.7**	**47.8**	**47.9**	**47.8**	**47.7**
Asia	27.6	28.1	27.6	28.5	27.9	25.9	28.3	28.3	29.1	27.9	29.2	30.0	30.7	31.4	32.0
Middle East	8.1	8.2	8.8	8.4	8.4	8.0	8.3	9.0	8.2	8.4	8.6	8.6	8.6	8.6	8.7
Latin America	6.2	6.3	6.4	6.3	6.3	6.1	6.3	6.4	6.4	6.3	6.4	6.4	6.5	6.6	6.6
FSU	4.5	4.7	4.9	4.8	4.7	4.6	4.7	5.0	4.9	4.8	4.9	4.9	4.9	4.9	5.0
Africa	4.4	4.3	4.2	4.3	4.3	4.4	4.4	4.2	4.4	4.3	4.4	4.5	4.7	4.8	4.8
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Total Non-OECD	**51.5**	**52.3**	**52.6**	**53.2**	**52.4**	**49.8**	**52.8**	**53.8**	**53.7**	**52.5**	**54.2**	**55.3**	**56.2**	**57.1**	**58.0**
World	**99.1**	**99.2**	**100.7**	**100.9**	**100.0**	**96.7**	**99.2**	**102.0**	**101.7**	**99.9**	**102.0**	**103.1**	**104.0**	**104.9**	**105.7**
of which:															
USA	*20.6*	*20.7*	*21.0*	*20.9*	*20.8*	*20.4*	*20.7*	*21.3*	*21.2*	*20.9*	*21.0*	*21.0*	*21.0*	*21.0*	*21.0*
*Euro5**	*8.1*	*8.1*	*8.3*	*8.0*	*8.1*	*7.9*	*7.8*	*8.2*	*8.0*	*8.0*	*8.0*	*8.0*	*7.9*	*7.9*	*7.9*
China	*13.0*	*13.7*	*13.8*	*14.1*	*13.7*	*11.2*	*13.8*	*14.3*	*14.3*	*13.4*	*14.2*	*14.6*	*14.9*	*15.3*	*15.5*
Japan	*4.1*	*3.4*	*3.4*	*3.8*	*3.7*	*3.8*	*3.2*	*3.4*	*3.8*	*3.5*	*3.6*	*3.6*	*3.5*	*3.5*	*3.5*
India	*5.1*	*5.1*	*4.8*	*5.0*	*5.0*	*5.2*	*5.2*	*4.8*	*5.2*	*5.1*	*5.3*	*5.5*	*5.7*	*5.8*	*6.0*
Russia	*3.4*	*3.5*	*3.7*	*3.6*	*3.6*	*3.5*	*3.5*	*3.8*	*3.7*	*3.6*	*3.7*	*3.6*	*3.6*	*3.6*	*3.7*
Brazil	*3.0*	*3.0*	*3.2*	*3.2*	*3.1*	*3.0*	*3.1*	*3.2*	*3.2*	*3.1*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*
Saudi Arabia	*3.0*	*3.1*	*3.5*	*3.1*	*3.1*	*2.8*	*3.2*	*3.6*	*3.0*	*3.2*	*3.2*	*3.1*	*3.1*	*3.1*	*3.1*
Korea	*2.6*	*2.5*	*2.6*	*2.7*	*2.6*	*2.6*	*2.4*	*2.6*	*2.7*	*2.6*	*2.7*	*2.8*	*2.8*	*2.8*	*2.8*
Canada	*2.5*	*2.4*	*2.6*	*2.5*	*2.5*	*2.4*	*2.4*	*2.6*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*
Mexico	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*2.0*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*
Iran	*2.0*	*1.9*	*1.9*	*2.0*	*2.0*	*2.0*	*1.9*	*2.0*	*2.0*	*2.0*	*2.0*	*2.1*	*2.0*	*2.0*	*2.0*
Total	***69.4***	***69.3***	***70.6***	***70.7***	***70.0***	***66.9***	***69.2***	***71.7***	***71.3***	***69.8***	***71.2***	***71.9***	***72.3***	***72.7***	***73.1***
% of World	***70.0***	***69.9***	***70.2***	***70.1***	***70.0***	***69.2***	***69.8***	***70.2***	***70.1***	***69.8***	***69.8***	***69.7***	***69.5***	***69.3***	***69.1***
Annual Change (% per annum)															
Americas	0.4	0.3	0.0	0.2	0.2	-1.1	0.0	1.4	1.1	0.3	0.3	0.2	0.2	-0.1	-0.3
Europe	-1.2	-1.2	-0.7	-0.9	-1.0	-1.7	-2.6	-1.0	-0.3	-1.4	0.7	0.2	-0.2	-0.3	-0.2
Asia Oceania	-3.7	-3.1	-1.4	-0.3	-2.1	-2.9	-3.4	-0.6	0.1	-1.6	2.1	0.4	0.1	0.1	0.1
Total OECD	**-0.8**	**-0.7**	**-0.4**	**-0.2**	**-0.5**	**-1.6**	**-1.3**	**0.4**	**0.5**	**-0.5**	**0.7**	**0.2**	**0.1**	**-0.1**	**-0.2**
Asia	3.0	2.9	2.8	4.4	3.3	-6.3	0.9	2.8	2.2	-0.1	4.5	2.9	2.3	2.3	2.0
Middle East	0.2	-2.9	1.2	3.1	0.4	-1.2	2.3	2.7	-2.6	0.3	2.2	0.7	-0.4	0.1	0.7
Latin America	-1.0	0.2	-0.4	-0.1	-0.3	-0.3	0.1	0.2	0.2	0.0	1.3	1.0	1.1	1.1	0.6
FSU	2.7	2.7	1.7	2.1	2.3	2.1	1.3	1.9	1.5	1.7	1.9	-0.1	0.6	0.6	1.3
Africa	1.5	2.1	1.7	1.5	1.7	0.7	1.1	1.1	1.3	1.0	1.8	1.7	3.4	2.1	2.0
Europe	3.3	6.3	3.8	0.9	3.5	1.6	1.1	2.2	2.5	1.9	1.5	1.3	1.4	1.4	1.4
Total Non-OECD	**1.9**	**1.6**	**1.9**	**3.1**	**2.1**	**-3.4**	**1.1**	**2.2**	**1.1**	**0.3**	**3.3**	**1.9**	**1.7**	**1.6**	**1.6**
World	**0.6**	**0.5**	**0.8**	**1.5**	**0.8**	**-2.5**	**0.0**	**1.3**	**0.8**	**-0.1**	**2.1**	**1.1**	**0.9**	**0.8**	**0.8**
Annual Change (mb/d)															
Americas	0.1	0.1	0.0	0.1	0.1	-0.3	0.0	0.4	0.3	0.1	0.1	0.0	0.0	0.0	-0.1
Europe	-0.2	-0.2	-0.1	-0.1	-0.1	-0.2	-0.4	-0.1	0.0	-0.2	0.1	0.0	0.0	0.0	0.0
Asia Oceania	-0.3	-0.2	-0.1	0.0	-0.2	-0.2	-0.3	0.0	0.0	-0.1	0.2	0.0	0.0	0.0	0.0
Total OECD	**-0.4**	**-0.3**	**-0.2**	**-0.1**	**-0.3**	**-0.8**	**-0.6**	**0.2**	**0.2**	**-0.2**	**0.3**	**0.1**	**0.0**	**-0.1**	**-0.1**
Asia	0.8	0.8	0.7	1.2	0.9	-1.7	0.3	0.8	0.6	0.0	1.3	0.8	0.7	0.7	0.6
Middle East	0.0	-0.2	0.1	0.2	0.0	-0.1	0.2	0.2	-0.2	0.0	0.2	0.1	0.0	0.0	0.1
Latin America	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0
FSU	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1
Africa	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.2	0.1	0.1
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Non-OECD	**1.0**	**0.8**	**1.0**	**1.6**	**1.1**	**-1.7**	**0.6**	**1.2**	**0.6**	**0.1**	**1.7**	**1.0**	**0.9**	**0.9**	**0.9**
World	**0.5**	**0.5**	**0.8**	**1.5**	**0.8**	**-2.5**	**0.0**	**1.4**	**0.8**	**-0.1**	**2.1**	**1.1**	**0.9**	**0.9**	**0.8**
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
Americas	-0.2	-0.4	-0.3	-0.6	-0.3	-0.8	-0.3	0.0	-0.4	-0.4	-0.3	-0.3	-0.1	-0.2	
Europe	-0.2	-0.4	-0.3	-0.5	-0.3	-0.4	-0.7	-0.3	-0.4	-0.5	-0.3	-0.2	-0.2	-0.1	
Asia Oceania	0.0	0.1	0.1	0.0	0.1	0.0	-0.1	0.1	0.0	0.0	0.2	0.2	0.2	0.2	
Total OECD	**-0.4**	**-0.7**	**-0.4**	**-1.0**	**-0.6**	**-1.3**	**-1.1**	**-0.2**	**-0.8**	**-0.9**	**-0.3**	**-0.3**	**-0.1**	**-0.2**	
Asia	0.2	0.2	0.1	0.5	0.2	-2.3	-0.2	0.2	0.0	-0.6	-0.2	-0.2	-0.1	0.0	
Middle East	-0.1	-0.4	-0.1	0.2	-0.1	-0.3	-0.3	0.0	-0.4	-0.2	-0.3	-0.4	-0.5	-0.7	
Latin America	-0.1	-0.1	0.0	0.0	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	
FSU	0.0	0.0	0.0	-0.1	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	
Africa	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2	
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total Non-OECD	**0.0**	**-0.3**	**-0.2**	**0.5**	**0.0**	**-2.9**	**-0.9**	**-0.2**	**-0.9**	**-1.2**	**-1.0**	**-1.1**	**-1.2**	**-1.3**	
World	**-0.3**	**-1.1**	**-0.5**	**-0.5**	**-0.6**	**-4.2**	**-1.9**	**-0.4**	**-1.7**	**-2.1**	**-1.3**	**-1.4**	**-1.3**	**-1.4**	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	-0.6	-1.2	-0.6	0.2	-0.5	-3.9	-0.9	0.1	-1.2	-1.4	0.8	-0.1	0.0	-0.1	

* France, Germany, Italy, Spain and UK

Table 3

WORLD OIL PRODUCTION

(million barrels per day)

	1Q19	2Q19	3Q19	4Q19	2019	1Q20	2Q20	3Q20	4Q20	2020	2021	2022	2023	2024	2025
OPEC															
Crude Oil															
Saudi Arabia	10.06	9.76	9.49	9.91	9.80										
Iran	2.74	2.41	2.19	2.11	2.36										
Iraq	4.70	4.73	4.79	4.63	4.71										
UAE	3.07	3.13	3.17	3.34	3.18										
Kuwait	2.71	2.68	2.65	2.68	2.68										
Neutral Zone	0.00	0.00	0.00	0.00	0.00										
Angola	1.43	1.43	1.35	1.35	1.39										
Nigeria	1.69	1.72	1.81	1.70	1.73										
Libya	0.96	1.15	1.09	1.15	1.09										
Algeria	1.03	1.02	1.02	1.02	1.02										
Congo	0.34	0.35	0.34	0.31	0.33										
Gabon	0.21	0.22	0.21	0.21	0.21										
Equatorial Guinea	0.11	0.11	0.11	0.11	0.11										
Ecuador	0.53	0.53	0.55	0.51	0.53										
Venezuela	1.11	0.86	0.75	0.78	0.87										
Total Crude Oil	**30.67**	**30.10**	**29.51**	**29.82**	**30.02**										
Total NGLs[1]	**5.51**	**5.51**	**5.45**	**5.50**	**5.49**	**5.48**	**5.51**	**5.52**	**5.52**	**5.51**	**5.54**	**5.57**	**5.59**	**5.65**	**5.70**
Total OPEC[2]	**36.18**	**35.61**	**34.96**	**35.33**	**35.51**										
NON-OPEC[3]															
OECD															
Americas	**24.05**	**24.52**	**24.65**	**25.56**	**24.70**	**25.55**	**25.63**	**26.06**	**26.50**	**25.94**	**26.91**	**27.29**	**27.47**	**27.51**	**27.53**
United States	16.64	17.08	17.19	17.93	17.21	17.81	18.15	18.41	18.73	18.28	19.01	19.40	19.65	19.70	19.68
Mexico	1.91	1.91	1.94	1.95	1.93	1.98	1.97	1.97	1.97	1.98	1.95	1.91	1.82	1.78	1.78
Canada	5.49	5.52	5.52	5.67	5.55	5.74	5.49	5.67	5.79	5.67	5.93	5.96	5.99	6.02	6.06
Chile	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Europe	**3.48**	**3.19**	**3.19**	**3.52**	**3.34**	**3.66**	**3.70**	**3.69**	**3.86**	**3.73**	**3.81**	**3.77**	**3.81**	**3.63**	**3.38**
UK	1.21	1.15	1.09	1.13	1.14	1.21	1.20	1.18	1.25	1.21	1.17	1.13	1.05	0.98	0.91
Norway	1.77	1.57	1.65	1.95	1.74	2.03	2.08	2.09	2.18	2.09	2.21	2.20	2.34	2.26	2.08
Others	0.49	0.47	0.45	0.43	0.46	0.42	0.42	0.42	0.43	0.42	0.43	0.44	0.42	0.40	0.38
Asia Oceania	**0.43**	**0.48**	**0.52**	**0.52**	**0.49**	**0.54**	**0.55**	**0.57**	**0.58**	**0.56**	**0.58**	**0.56**	**0.54**	**0.51**	**0.49**
Australia	0.37	0.41	0.44	0.46	0.42	0.48	0.49	0.50	0.52	0.50	0.52	0.50	0.48	0.46	0.44
Others	0.06	0.07	0.08	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05
Total OECD	**27.96**	**28.19**	**28.36**	**29.60**	**28.53**	**29.75**	**29.88**	**30.32**	**30.94**	**30.22**	**31.30**	**31.62**	**31.82**	**31.66**	**31.40**
NON-OECD															
Former USSR	**14.81**	**14.42**	**14.62**	**14.69**	**14.63**	**14.75**	**14.61**	**14.63**	**14.67**	**14.66**	**14.84**	**14.90**	**14.67**	**14.58**	**14.49**
Russia	11.67	11.50	11.57	11.59	11.58	11.62	11.57	11.57	11.59	11.59	11.78	11.87	11.72	11.53	11.37
Others	3.14	2.92	3.04	3.10	3.05	3.13	3.04	3.05	3.08	3.07	3.06	3.03	2.96	3.05	3.12
Asia	**7.20**	**7.15**	**7.00**	**7.05**	**7.10**	**7.04**	**7.04**	**6.99**	**6.98**	**7.01**	**6.94**	**6.83**	**6.76**	**6.64**	**6.52**
China	3.88	3.91	3.88	3.86	3.88	3.86	3.89	3.86	3.88	3.87	3.92	3.92	3.93	3.91	3.88
Malaysia	0.71	0.69	0.60	0.68	0.67	0.70	0.70	0.70	0.69	0.70	0.66	0.63	0.60	0.57	0.55
India	0.83	0.81	0.79	0.78	0.80	0.77	0.77	0.76	0.75	0.76	0.75	0.74	0.75	0.71	0.68
Indonesia	0.79	0.75	0.76	0.75	0.76	0.75	0.74	0.74	0.73	0.74	0.71	0.68	0.65	0.62	0.60
Others	1.00	1.00	0.97	0.97	0.99	0.96	0.95	0.94	0.92	0.94	0.90	0.85	0.83	0.82	0.82
Europe	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.10**	**0.09**	**0.10**	**0.10**
Latin America[2]	**4.51**	**4.58**	**4.85**	**5.02**	**4.74**	**5.05**	**5.06**	**5.20**	**5.20**	**5.13**	**5.18**	**5.19**	**5.55**	**5.94**	**6.26**
Brazil	2.67	2.74	3.01	3.17	2.90	3.13	3.12	3.25	3.26	3.19	3.28	3.32	3.57	3.85	4.03
Argentina	0.59	0.60	0.61	0.61	0.60	0.61	0.61	0.61	0.61	0.61	0.61	0.62	0.63	0.65	0.67
Colombia	0.90	0.90	0.88	0.89	0.89	0.89	0.88	0.87	0.86	0.88	0.83	0.78	0.73	0.68	0.63
Others	0.36	0.35	0.35	0.36	0.35	0.43	0.46	0.47	0.46	0.45	0.46	0.46	0.62	0.76	0.93
Middle East[2]	**3.25**	**3.24**	**3.24**	**3.24**	**3.24**	**3.26**	**3.26**	**3.25**	**3.25**	**3.25**	**3.30**	**3.34**	**3.38**	**3.41**	**3.43**
Oman	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	1.02	1.02	1.03	1.03	1.03
Qatar	1.98	1.96	1.96	1.96	1.96	1.97	1.97	1.97	1.97	1.97	1.98	2.03	2.06	2.09	2.10
Syria	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Yemen	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.09	0.10
Others	0.20	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.20	0.20	0.19	0.19	0.18
Africa[2]	**1.48**	**1.49**	**1.46**	**1.47**	**1.47**	**1.44**	**1.42**	**1.40**	**1.39**	**1.41**	**1.35**	**1.30**	**1.29**	**1.36**	**1.44**
Egypt	0.64	0.64	0.63	0.62	0.63	0.61	0.61	0.60	0.59	0.60	0.57	0.54	0.51	0.49	0.46
Sudan	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.05	0.05	0.05	0.04
Others	0.76	0.78	0.76	0.78	0.77	0.75	0.74	0.74	0.73	0.74	0.72	0.70	0.73	0.82	0.94
Total Non-OECD	**31.38**	**31.00**	**31.28**	**31.60**	**31.31**	**31.66**	**31.51**	**31.59**	**31.59**	**31.59**	**31.72**	**31.65**	**31.75**	**32.03**	**32.24**
Processing Gains[4]	2.35	2.35	2.35	2.35	2.35	2.38	2.38	2.38	2.38	2.38	2.41	2.44	2.46	2.49	2.52
Global Biofuels	2.26	2.96	3.22	2.74	2.80	2.37	3.00	3.29	2.89	2.89	2.96	3.07	3.15	3.23	3.29
TOTAL NON-OPEC[2]	**63.95**	**64.49**	**65.21**	**66.28**	**64.99**	**66.15**	**66.76**	**67.57**	**67.80**	**67.07**	**68.38**	**68.77**	**69.18**	**69.41**	**69.45**
TOTAL SUPPLY	**100.13**	**100.10**	**100.17**	**101.60**	**100.50**										

1 Includes condensates and oil from non-conventional sources.
2 Total OPEC comprises all countries which are currently OPEC members.
Total Non-OPEC excludes all countries that are current members of OPEC.
3 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
4 Net volumetric gains and losses in refining and marine transportation losses.

Table 3a
SELECTED NON-OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
OECD Americas				China	Luda 05-2N (Bo) 2	20	2021
USA	Appomattox/Vicksburg	175	2019	China	Mahu	20	2021
USA	Atlantis North	40	2020	China	Penglai 9-1/15-2	90	2022
USA	Thunder Horse South ph 2	50	2021	China	Caofeidian 06-4	30	2023
USA	Mad Dog ph 2	140	2021	China	Liuhua 21-2	20	2023
USA	Vito	100	2021	China	Qinhuangdao 29-2/29-2E	50	2023
USA	Kings Quay	80	2022	China	Shidong 1	20	2024
USA	Anchor	75	2024	China	Laxi	20	2024
Mexico	Hokchi	25	2020	China	Jinhuazhen	30	2025
Mexico	Ixachi	50	2021	India	KG-DWN-98/2	50	2022
Mexico	Amoca	50	2021	Vietnam	Lac Da Vang	55	2023
Mexico	Mizton	30	2021	**FSU**			
Mexico	Zama	150	2023	Russia	Yurubcheno-Tokhomskoe	100	2017
Mexico	Tecoalli	10	2024	Russia	Yamal LNG	115	2018
Canada	Cenovus Christina Lake ph G	50	2020	Russia	Tagul	90	2018
Canada	Kirby North	40	2020	Russia	Taas-Yuryakh (Srednebotuobinskoe)	100	2018
Canada	West White Rose	75	2023	Russia	Erginskoye/Kondaneft	170	2019
Canada	Suncor - Meadow Creek East ph 1	40	2023	Russia	Russkoe	130	2019
OECD Europe				Russia	Kuyumba	65	2019
Italy	Tempa Rossa	50	2020	Russia	Rospan	100	2020
Norway	Johan Sverdrup ph 1	440	2019	Russia	Lodochnoe	40	2021
Norway	Valhall West Flank	50	2019	Russia	Chonsky	50	2025
Norway	Njord/Bauge/Fenja	60	2020	Azerbaijan	Azeri Central East (ACE)	100	2023
Norway	Yme Redevelopment	30	2020	Kazakhstan	Tengizchevroil FGP	260	2023
Norway	Martin Linge	40	2020	**Latin America**			
Norway	Snorre Expansion Project	80	2021	Brazil	Buzios 1 & 2 (P-74, P-75)	300	2018
Norway	Ærfugl ph 1 & ph 2	30	2021	Brazil	Lula Ex South (P-69)	150	2018
Norway	Johan Sverdrup ph 2	220	2022	Brazil	Tartaruga Verde	130	2018
Norway	Johan Castberg	190	2022	Brazil	Buzios 3 & 4 (P-76,P-77)	300	2019
Norway	Balder X	35	2022	Brazil	Lula Norte (P-67)	150	2019
UK	Mariner	55	2019	Brazil	Berbigào (P-68)	150	2019
UK	Seagull	30	2021	Brazil	Atapu (P-70)	150	2020
UK	Penguin	45	2021	Brazil	Sepia	180	2021
OECD Asia Oceania				Brazil	Mero 1 (Guanabara)	180	2021
Australia	Ichthys	130	2018	Brazil	Buzios 5 (Almirante Barroso)	150	2022
Australia	Prelude	40	2019	Brazil	Lula (P-71)	150	2022
Australia	Greater Enfield	40	2019	Brazil	Marlim redevelopment (Module 1)	80	2022
Africa				Brazil	Parque das Baleeias	100	2023
Ghana	Mahogany-Teak-Akasa (MTAB)	30	2023	Brazil	Mero 2 (Sepetiba)	180	2023
Kenya	South Lokichar	50	2023	Brazil	Marlim redevelopment (Module 2)	70	2023
Uganda	Albert Basin (Kingfisher/Tilenga)	80	2024	Brazil	Itapu	120	2024
Senegal	Sangomar ph 1 (SNE)	100	2023	Brazil	Bachalhau-1	220	2024
Mauritania	Greater Tortue Ahmeyim FLNG	10	2022	Brazil	Sergipe Deep Water (SEAP-1)	100	2024
Mozambique	Inhassaro	10	2023	Brazil	Mero 3	180	2024
Mozambique	Coral FLNG	10	2024	Brazil	Mero 4	180	2025
Mozambique	Area 1 LNG	10	2024	Guyana	Liza ph 1	120	2019
Asia				Guyana	Liza ph 2	220	2022
China	Penglai ph 3	30	2018	Guyana	Paraya	220	2023
China	Bozhong 34-9	25	2019	Guyana	Other	190	2025
China	Liuhua16-2/20-2/23-1	35	2020	**Middle East**			
China	Shunbei	25	2020	Oman	Ghazeer	50	2021
China	Luda 21-2/16-3	30	2020	Qatar	North Field Expansion	100	2024

Table 3b
SELECTED OPEC UPSTREAM PROJECT START_UPS

Country	Project	Capacity (kbd)	Start Year	Country	Project	Capacity (kbd)	Start Year
Crude Oil Projects				**NGL & Condensate Projects**			
Angola	Kaomba (ph 2)	115	2019	Iran	South Pars 22-24 (condensate)	75	2019
Angola	Zinia 2, Clov 2, Dalia 3	110	2020-21				
Kuwait	Ratqa	270	2020				
Neutral Zone	Khafji (restart)	300	2020				
Neutral Zone	Wafra (restart)	240	2020				
Nigeria	Egina	200	2019				
Saudi	Marjan Expansion	300	-				
Saudi	Berri Expansion	250	-				
UAE	Nasr (ph 2)	40	2019				
UAE	Haliba	40	2019				
UAE	Upper Zakum (ph 2)	250	-				

Table 3c
NON-OPEC SUPPLY - OIL MARKET REPORT AND WEO DEFINITIONS
(million barrels per day)

	Calculation	2018	2019	2020	2021	2022	2023	2024	2025
Medium Term Oil Market Report definitions									
NON-OPEC SUPPLY		**62.9**	**65.0**	**67.1**	**68.4**	**68.8**	**69.2**	**69.4**	**69.5**
Processing gains		2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5
Global biofuels		2.6	2.8	2.9	3.0	3.1	3.2	3.2	3.3
NON-OPEC PRODUCTION (excl. processing gains and biofuels)	**1**	**58.0**	**59.8**	**61.8**	**63.0**	**63.3**	**63.6**	**63.7**	**63.6**
Crude	2	48.3	49.7	51.3	52.3	52.5	52.7	52.7	52.5
of which: Condensate	3	3.8	4.0	4.2	4.3	4.4	4.4	4.4	4.4
Tight oil	4	6.9	8.2	8.9	9.5	9.9	10.2	10.3	10.4
Un-upgraded bitumen	5	1.9	1.8	2.0	2.2	2.2	2.2	2.3	2.3
NGLs	6	7.7	8.2	8.5	8.6	8.7	8.8	8.8	8.9
Syncrude (Canada)	7	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
CTL, GTL, kerogen oil and additives[1]	8	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.0
World Energy Outlook definitions									
NON-OPEC PRODUCTION (excl. processing gains and biofuels)	=1	58.0	59.8	61.8	63.0	63.3	63.6	63.7	63.6
Conventional		**47.3**	**47.8**	**48.9**	**49.2**	**49.0**	**49.0**	**48.9**	**48.8**
Crude oil	=2-3-4-5	35.8	35.6	36.2	36.2	35.9	35.8	35.7	35.5
Natural gas liquids (total)	=3+6	11.5	12.2	12.8	13.0	13.1	13.2	13.2	13.3
Unconventional		**10.7**	**12.0**	**12.9**	**13.8**	**14.3**	**14.6**	**14.8**	**14.9**
EHOB (incl. syncrude)[2]	=5+7	3.1	3.1	3.2	3.5	3.5	3.5	3.5	3.5
Tight oil	=4	6.9	8.2	8.9	9.5	9.9	10.2	10.3	10.4
CTL, GTL, kerogen oil and additives[1]	=8	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.0

1 CTL = coal to liquids; GTL = gas to liquids.

2 Extra-heavy oil and bitumen

Table 4

WORLD REFINERY CAPACITY ADDITIONS

(thousand barrels per day)

	2019	2020	2021	2022	2023	2024	2025	Total[4]
Refining Capacity Additions and Expansions[1]								
OECD Americas		-20	50	50	285	340		705
OECD Europe	200	40						40
OECD Asia Oceania	40		-115					-115
FSU	170			100		30		130
Non-OECD Europe		-44						-44
China	1,200	310	230		800	320	100	1,760
Other Asia	448	162	150	120	666	160		1,257
Latin America	-168			33				33
Middle East	82	570		-5	340	755	-20	1,640
Africa	67			675		60	100	835
Total World	2,039	**1,018**	**315**	**973**	**2,091**	**1,665**	**180**	**6,241**
Upgrading Capacity Additions[2]								
OECD Americas					58			58
OECD Europe	30			51	20			71
OECD Asia Oceania	-38		-27				-36	-63
FSU	102	150	220	45	42	222	58	737
Non-OECD Europe		38			20			58
China	669	227	107		430	227	50	1,041
Other Asia	171	14	160	130	282	66	35	687
Latin America	-78			29				29
Middle East	111	253			275	208	45	781
Africa	57			10	240	25		275
Total World	1,024	**683**	**460**	**265**	**1,367**	**748**	**151**	**3,674**
Desulphurisation Capacity Additions[3]								
OECD Americas		17	10					27
OECD Europe						38		38
OECD Asia Oceania	-100	37	-89				-43	-95
FSU	47	156	20				80	256
Non-OECD Europe								
China	754	280	54		500	60	80	974
Other Asia	255	237	163		126	230		756
Latin America	-180			64				64
Middle East	22	607	120		337	739	27	1,829
Africa	42				200			200
Total World	840	**1,334**	**278**	**64**	**1,163**	**1,067**	**144**	**4,049**

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

2 Comprises gross capacity additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC or RFCC capacity.

3 Comprises additions to hydrotreating and hydrodesulphurisation capacity.

4 Total for 2020-25.

Table 4a
WORLD REFINERY CAPACITY ADDITIONS: CHANGES FROM OIL 2019
(thousand barrels per day)

	2019	2020	2021	2022	2023	2024	Total
Refining Capacity Additions and Expansions[1]							
OECD Americas	-20	-40		50	-65	90	15
OECD Europe		40					40
OECD Asia Oceania	40		-45				-5
FSU	-60			70	-100	30	-60
Non-OECD Europe		-44					-44
China	-240	70	-570	-720	400	320	-740
Other Asia		-11	-200	-243	386		-68
Latin America	36		-165				-129
Middle East	-471	513	-635	-238	90	755	14
Africa	49			90	-120	-40	-21
Total World	**-666**	**528**	**-1,615**	**-991**	**591**	**1,155**	**-998**
Upgrading Capacity Additions[2]							
OECD Americas			-60		26		-34
OECD Europe	30		-43	51			38
OECD Asia Oceania			-27				-27
FSU	-100	-410	145	-75	-18	187	-271
Non-OECD Europe	-13	13		-20	20		
China	-100	-86	-163	-89	268	227	57
Other Asia			-87	-10	219	30	152
Latin America							
Middle East	-177	173		-316	137	208	26
Africa	57	-70	-25	-230	240	25	-3
Total World	**-303**	**-380**	**-260**	**-689**	**892**	**677**	**-63**
Desulphurisation Capacity Additions[3]							
OECD Americas		17	10				27
OECD Europe	-79					38	-41
OECD Asia Oceania			-89				-89
FSU	18	-82					-64
Non-OECD Europe					-20		-20
China	-96	-96	-140		204	60	-68
Other Asia		-32	-90	-90	56	80	-76
Latin America	37						37
Middle East	-505	264	-538	-312	327	739	-25
Africa	42	-4		-200	200		38
Total World	**-583**	**68**	**-847**	**-602**	**767**	**917**	**-282**

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.

3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

Table 4b
SELECTED REFINERY CRUDE DISTILATION PROJECT LIST

Country	Project	Capacity (kbd)	Start Year
OECD Americas			
Canada	NLRC - Come By Chance	35	2023
Mexico	Petroleos Mexicanos - Dos Bocas	340	2024
United States	ExxonMobil Refining & Supply - Beaumont	250	2023
United States	GCC - Galveston	50	2022
United States	Meridian Resources - Davis North Dakota	50	2021
OECD Europe			
Germany	Hestya - Wilhelmshaven	40	2020
OECD Asia Oceania			
Japan	JX Energy - Osaka	-115	2021
FSU			
Azerbaijan	SOCAR - Heydar Aliev	30	2022
Russia	Ilsk Refinery - Krasnodarskiy Kray	70	2022
Russia	Yayski - Irkutsk	30	2024
Non-OECD Europe			
Croatia	Ina-Industrija Nafte d.d. - Sisak	-44	2020
China			
China	PetroChina - Jieyang	400	2023
China	Rongsheng Petrochemical - Zhoushan island phase 2	400	2023
China	Shenghong Petchem - Lianyungang	320	2024
China	Sinopec/KPC - Zhanjiang	200	2020
China	CNOOC - Ningbo Zhejiang	100	2021
China	Sinopec - Yangpu	100	2025
China	PetroChina - Daqing	70	2021
China	Wudi Xinyue - Binzhou	70	2020
China	Sinochem - Quanzhou	60	2021
China	Sinopec - Luoyang	40	2020
Other Asia			
Bangladesh	BPC / KPI - Chittagong	60	2024
Brunei	Zhejiang Hengyi Petrochemicals - Pulau Muara Besar	280	2023
India	HPCL - Visakhapatnam	150	2021
India	Nagarjuna Oil - Cuddalore	120	2023
India	Indian Oil - Koyali	100	2023
India	BPCL - Mumbai	60	2020
India	HPCL - Mahul, Mumbai	60	2020
India	Indian Oil - Barauni	60	2022
Indonesia	Pertamina - Balikpapan, Kalimantan	100	2024
Malaysia	Vitol - Tanjong Bin	35	2020
Mongolia	Mongolsekiu - Altanshiree	30	2022
Pakistan	National Refinery - Karachi	30	2022
Thailand	Thai Oil - Sriracha	126	2023
Vietnam	Petro Vietnam/gazpromNeft - Quang Ngai/Dung Quat	40	2023
Latin America			
Peru	Petroperu - Talara, Piura	33	2022
Middle East			
Bahrain	Bahrain Petroleum - Sitra	-265	2023
Bahrain	Bahrain Petroleum - Sitra	355	2023
Iran	National Iranian Oil - Abadan	-235	2022
Iran	National Iranian Oil - Abadan	200	2022
Iraq	INOC-ORA - Karbala	140	2024
Iraq	South Refining Company - Basra	65	2025
Kuwait	Kuwait National Petroleum - Al-Zour	615	2024
Kuwait	Kuwait National Petroleum - Mina Abdulla	200	2020
Kuwait	Kuwait National Petroleum - Mina al-Ahmadi	-115	2020
Oman	Oman Refinery - Duqm	230	2023
Oman	Sohar Bitumen Refinery - Sohar	30	2022
Saudi Arabia	Saudi Aramco - Jizan	400	2020
UAE	ADNOC - Umm-al-Nar	-85	2025
Africa			
Algeria	Sonatrach - Hassi Messoud	100	2025
Egypt	MIDOR - Alexandria	60	2024
Nigeria	Dangote Oil Refining Company - Lekki Free Trade Zone (Lagos)	650	2022
South Sudan	Trinity Energy - Paloich	25	2022

Table 5
WORLD ETHANOL PRODUCTION[1]
(thousand barrels per day)

	2018	2019	2020	2021	2022	2023	2024	2025
OECD North America	**1,078**	**1,059**	**1,066**	**1,068**	**1,095**	**1,096**	**1,097**	**1,103**
United States	1,048	1,024	1,030	1,030	1,055	1,055	1,055	1,060
Canada	30	34	34	36	37	38	38	38
OECD Europe	**96**	**87**	**90**	**90**	**90**	**89**	**89**	**91**
Austria	4	4	4	4	4	4	4	4
Belgium	6	6	6	6	6	6	6	7
France	21	15	15	15	15	15	15	15
Germany	14	13	15	16	16	16	16	16
Italy	0	0	1	0	0	0	0	0
Netherlands	7	7	7	7	7	7	6	6
Poland	4	4	5	5	5	5	5	5
Spain	9	9	9	8	8	8	8	8
UK	9	5	5	6	6	6	6	6
OECD Pacific	**5**	**5**	**5**	**6**	**6**	**6**	**6**	**6**
Australia	4	4	4	5	5	5	5	5
Total OECD	**1,178**	**1,151**	**1,161**	**1,165**	**1,191**	**1,192**	**1,193**	**1,200**
FSU	3	4	4	4	4	4	4	4
Non-OECD Europe	1	1	1	2	2	2	2	2
China	56	69	86	111	128	149	155	161
Other Asia	**60**	**71**	**82**	**93**	**102**	**111**	**122**	**132**
India	28	36	40	45	51	57	67	73
Indonesia	0	0	0	1	1	1	1	3
Malaysia	0	0	0	0	0	0	0	0
Philippines	4	5	5	7	7	7	8	8
Singapore	1	1	1	1	1	1	1	1
Thailand	25	27	33	36	38	40	41	43
Latin America	**591**	**665**	**642**	**656**	**656**	**671**	**706**	**724**
Argentina	19	19	19	20	21	22	23	23
Brazil	547	621	596	606	605	620	653	671
Colombia	8	8	8	9	9	9	9	9
Middle East	1	1	1	1	1	1	1	1
Africa	6	7	8	11	12	12	12	12
Total Non-OECD	**720**	**819**	**825**	**878**	**904**	**950**	**1,002**	**1,036**
Total World	**1,898**	**1,970**	**1,985**	**2,043**	**2,095**	**2,141**	**2,195**	**2,236**

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.

Table 5a
WORLD BIODIESEL PRODUCTION
(thousand barrels per day)

	2018	2019	2020	2021	2022	2023	2024	2025
OECD North America	**126**	**122**	**143**	**165**	**192**	**203**	**216**	**229**
United States	121	116	135	157	183	195	208	221
Canada	5	6	8	8	9	9	9	9
OECD Europe	**275**	**287**	**303**	**297**	**297**	**292**	**291**	**285**
Austria	4	6	5	5	5	5	5	5
Belgium	5	6	7	6	6	6	6	6
France	52	52	50	51	49	48	47	43
Germany	65	66	67	64	62	60	59	57
Italy	15	18	28	31	32	32	32	32
Netherlands	36	37	37	39	37	39	37	36
Poland	17	18	20	18	18	18	17	15
Spain	33	35	35	33	33	33	33	33
UK	10	10	12	9	9	9	9	9
OECD Pacific	**12**	**16**	**17**	**18**	**18**	**18**	**18**	**18**
Australia	1	1	2	2	2	2	2	2
Total OECD	**413**	**425**	**463**	**480**	**506**	**514**	**525**	**532**
FSU	4	4	4	4	4	4	4	4
Non-OECD Europe	6	6	7	6	6	6	6	7
China	12	11	12	15	18	22	25	25
Other Asia	**132**	**213**	**242**	**245**	**270**	**283**	**291**	**297**
India	3	3	3	4	4	4	4	4
Indonesia	69	136	149	150	154	160	165	170
Malaysia	15	27	31	30	33	35	38	40
Philippines	3	3	3	4	4	4	4	4
Singapore	15	15	18	20	36	41	41	41
Thailand	27	30	38	38	38	39	39	39
Latin America	**154**	**159**	**167**	**168**	**170**	**177**	**178**	**181**
Argentina	47	43	43	44	42	40	40	40
Brazil	92	102	95	106	110	119	120	123
Colombia	11	8	12	12	12	12	12	12
Middle East	1	1	1	1	1	1	1	1
Africa	4	4	5	5	5	6	6	6
Total Non-OECD	**313**	**398**	**438**	**444**	**474**	**499**	**512**	**521**
Total World	**726**	**823**	**901**	**925**	**980**	**1,013**	**1,037**	**1,053**

List of acronyms, abbreviations and units of measure

ACG	Azeri-Chirag-Deepwater Gunashli
ADNOC	Abu Dhabi National Oil Co
ASEAN	Association of Southeast Asian Nations
BEV	battery electric vehicles
BOC	Basra Oil Co
CCS	carbon capture and storage
CDU	crude distillation units
CNPC	China National Petroleum Corporation
CNRL	Canadian Natural Resources Limited
CSSP	Common Seawater Supply Project
EV	electric vehicle
FAME	Fatty acid methyl ester
FCC	Fluid catalytic cracker
FID	final investment decision
FPSO	floating production, storage and offloading
FSRU	floating storage and regasification unit
FSU	former Soviet Union
GDP	gross domestic product
GHG	greenhouse gas
GTL	gas-to-liquids
HEV	hybrid electric vehicle
HSFO	high sulphur fuel oil
HVO	hydrotreated vegetable oil
IMF	International Monetary Fund
IMO	International Maritime Organisation
IOC	international oil companies
KRG	Kurdistan Regional Government
LCFS	Low Carbon Fuel Standard
LCO	light cycle oil
LCV	light commercial vehicles
LDV	light duty vehicles

LEZ	low emission zones
LNA	Libyan National Army
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTO	light tight oil
NEV	new energy vehicle
NGL	natural gas liquids
NOC	national oil companies
OGA	Oil and Gas Authority
OGCI	Oil and Gas Climate Initiative
ONGC	Oil and Natural Gas Corporation
PHEV	plug-in hybrid electric vehicle
RDU	renewable diesel units
SIIP	Southern Iraq Integrated Project
SUV	sports utility vehicle
TAN	total acid number
ULEZ	ultra-low emission zone
UAE	United Arab Emirates
UK	United Kingdom
UN	United Nations
US	United States
VGO	vacuum gas oil
VLSFO	very low sulphur fuel oil

Units of measure

bbl	barrel (of oil)
bn	billion
GW	gigawatt
kb/d	thousand barrels per day
mb/d	million barrels per day
Mt	million tonnes
Mt/y	million tonnes per year
y-o-y	year-on-year

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Oil 2020 – Analysis and forecast to 2025

Oil 2020, the International Energy Agency's annual outlook for global oil markets, examines the key issues in demand, supply, refining and trade to 2025.

This year, the report considers topics such as the impact of the new coronavirus (COVID-19) on demand; slowing supply growth in the United States and other non-OPEC countries; and the level of spare production capacity in OPEC countries to help meet demand growth.

Oil 2020 looks at the interplay between the expanding US influence in global oil supply and the demand from Asia for exports from the Middle East. At the same time, global energy transitions are affecting the oil industry: companies must balance the investments needed to ensure sufficient supplies against the necessity of cutting emissions. In a decarbonising world, refiners face a big challenge from weaker transport fuel demand.

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