

Gas Market Report Q3-2021

including Gas 2021 - Analysis and forecast to 2024



INTERNATIONAL ENERGY AGENCY

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Abstract

Natural gas markets started off the year with a strong rebound, supported by a combination of recovering economic activity in most markets along with a series of weather-related events – cold spells in Q1 followed by colder or drier than average temperatures in Q2. Rising demand in 2021 is expected to offset 2020's decline and even grow further with an anticipated 3.6% annual increase.

Demand growth is, however, not expected to maintain this pace in the medium term, but rather to slow to an average 1.7% annual rate for the 2022-2024 period, equally driven by economic activity and fuel switching from coal and oil. This slower growth may still be too high to match a net-zero emissions path, which requires higher substitution rates and efficiency gains – especially in mature markets, where most of the switching potential from coal and oil to gas has already been realised.

This new quarterly report offers a medium-term forecast and analysis of global gas markets to 2024, as well as a review of recent developments in major regional gas markets during the first half of 2021.

Table of contents

Gas 2021: Analysis and forecast to 2024	4
Overview and key findings	5
Demand.....	9
Supply	38
Tracking clean gas progress.....	48
Trade.....	61
Gas market update and short-term forecast	75
Annex	99

Gas 2021: Analysis and forecast to 2024

Overview and key findings

Global natural gas demand dropped by 1.9%, or 75 bcm, in 2020 because of an exceptionally mild winter in the northern hemisphere and the impact of the Covid-19 pandemic. We forecast global demand to rebound by 3.6% in 2021. And unless major policy changes to curb global gas consumption are introduced, demand is set to keep growing in the coming years, albeit at a slower pace, to reach nearly 4 300 bcm by 2024, a 7% rise from pre-Covid levels.

Gas demand growth is set to slow despite coal-to-gas switching, but more ambitious policies are needed to shift to a net zero path

Almost half of the increase in gas demand to 2024 is expected to come from the Asia Pacific region, driven by China and India as well as by emerging markets in South and Southeast Asia. The industrial sector plays a pivotal role in medium-term gas demand growth, accounting for about 40% of the total increase between 2020 and 2024 in our forecast. This includes the use of gas for industrial processes and as a feedstock for chemicals and fertilisers.

Natural gas demand is set to grow by 350 bcm between 2020 and 2024. This would have been 80 bcm higher were it not for energy efficiency improvements and measures to replace gas with other fuels. Of the 430 bcm increase that can be considered as “gross gas demand additions” over the period, growth driven by higher

economic activity can explain almost two-thirds (270 bcm), while the substitution of coal (and oil to a lesser extent) explains the rest (160 bcm). Strong natural gas demand growth in 2021 is mostly the result of the global economic recovery from the Covid-19 crisis. Growth in 2022-2024 is driven in equal proportions by economic activity and fuel substitution.

In spite of this limited medium-term growth, our forecast for global gas demand in 2024 is above what is called for in the IEA’s climate-driven scenarios, notably in the recent special report [Net Zero by 2050: A Roadmap for the Global Energy Sector](#). To get on track for the emissions pathway set out in the *Roadmap*, stronger policies would need to be introduced within our forecast period to underpin further fuel substitution and efficiency gains. This is especially the case in more mature markets, where much of the potential for switching from coal and oil to gas has already been tapped. Strong and early policy actions and investment are required, with impacts on gas demand that would commence during our forecast period and intensify significantly over the course of the 2020s. Switching from oil and coal to gas, particularly in emerging and developing economies, can reduce emissions and improve air quality, and already explains half of gas consumption growth in these markets in the 2022-2024 period.

Projects already under development meet most supply needs, and the focus on cleaner gas supply is growing

Global gas production in 2024 is expected to be 6% higher than 2019's pre-Covid levels. This additional supply comes almost exclusively from large conventional assets already under development, mainly in Russia and the Middle East. It is supplemented by new investment in US shale gas production to keep pace with expanding LNG export capacity. However, without strong policy measures to curb longer-term gas demand growth, market volatility and concerns over security of supply may arise in the last years of our forecast.

To reduce its emissions footprint and align with net-zero emissions objectives, the gas industry needs to continue reducing the intensity of its greenhouse gas emissions along the value chain, support the development of low-carbon gases and develop carbon management solutions to minimise emissions from combustion. Reducing methane emissions is an efficient way – in terms of both time and cost – of narrowing the industry's footprint. Analysis from the IEA Methane Tracker shows as much as 40% of current methane emissions could be avoided at no net cost. The transition to low-carbon sources of gas supply – such as biomethane, hydrogen and synthetic methane – requires the adjustment of regulations and infrastructure to ensure their cost-competitive integration into future energy systems. This report reviews recent market and policy developments supporting such a transition to cleaner gases.

LNG markets tighten; new sources of flexibility reinforce security of supply

Global LNG trade volumes in 2024 are expected to be 17% above the pre-Covid levels seen in 2019, driven by continued demand growth in Asia and in the absence of strong policy initiatives in major gas markets. At an annual average growth rate of 3.3% through 2024, this is much slower than the double-digit increases observed between 2016 and 2019. The wave of final investment decisions on LNG projects taken before 2020 should therefore prove sufficient to satisfy additional LNG demand in the coming years. The global liquefaction utilisation rate is expected to return progressively to its pre-2020 level by 2024. In the absence of major project delays or unplanned outages, the risk of a structurally tight market appears limited before 2024 with the possible exception of short seasonal episodes.

Further flexibility would help ensure security of supply in an increasingly interdependent global gas market, even if it is well supplied. The growth of long-term contracts without a destination clause for LNG exported from the United States is contributing to flexibility. US projects account for the large majority of additional LNG supply capacity to be commissioned over the next three years. Robust growth of the LNG carrier fleet is another contributor, with current order books for deliveries in the next two to three years representing a 25% increase in the vessel count. Underground storage capacity, another pivotal source of flexibility, is set to increase by 7% over the forecast period.

Main assumptions behind the forecast

2020 saw the worst economic downturn since World War II, with a 3.3% decline in global GDP. This forecast is based on the assumption of a strong economic rebound of up to 6% in 2021. Global GDP growth is then expected to slow, increasing by 4.6% in 2022 and about 3% on average per year in the following years.

The strong short-term recovery is underpinned by the assumption of a prompt rollout of Covid-19 vaccination in mature economies, and continuous efforts to deploy vaccines and protect the most vulnerable in emerging economies. Recovery packages, public investment and fiscal relief policies have been the primary engine of economic rebound. They are expected to remain the principal driver of growth in the short term as funds committed under stimulus packages keep pouring into the economy.

However, levels of uncertainty remain high for the course of the global health recovery. The main short-term risk is the appearance and spread of new Covid-19 variants, potentially more contagious and more resistant to current vaccines. Although the repetition of 2020's hard lockdowns looks less likely, further waves of infection are possible. They would delay the global recovery and increase disparities among economies in their individual growth paths.

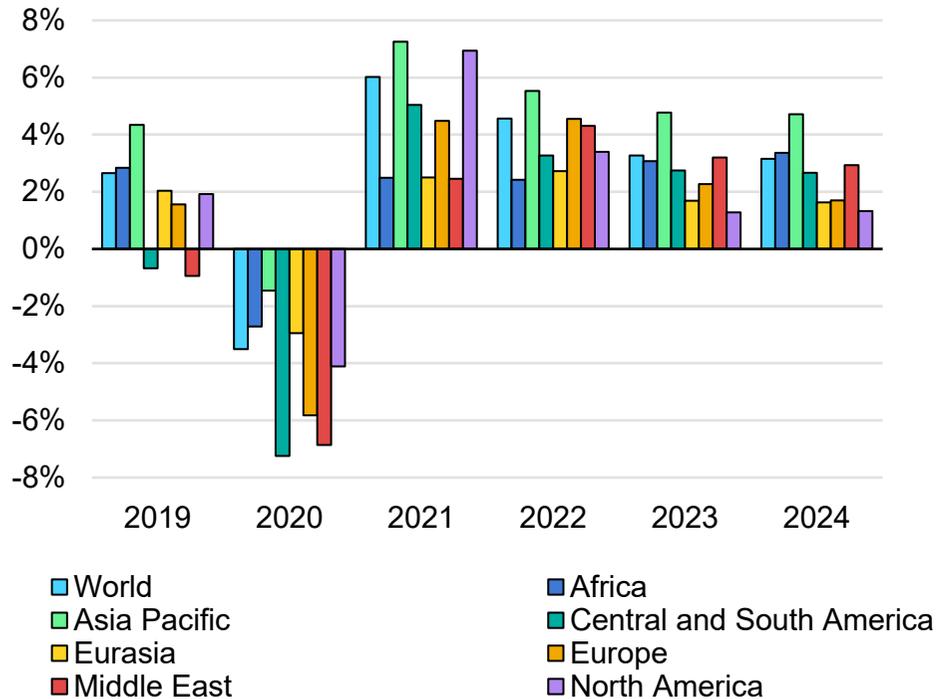
In spite of the unprecedented policy action to support the economy, some longer-lasting impacts are likely due to investment delays and

cancellations, bankruptcies and slower growth, especially in services. Emerging markets, which account for the bulk of natural gas demand growth, have been strongly affected by both the health and economic crises, which have led to rising debt and fiscal imbalances that could hamper medium-term growth.

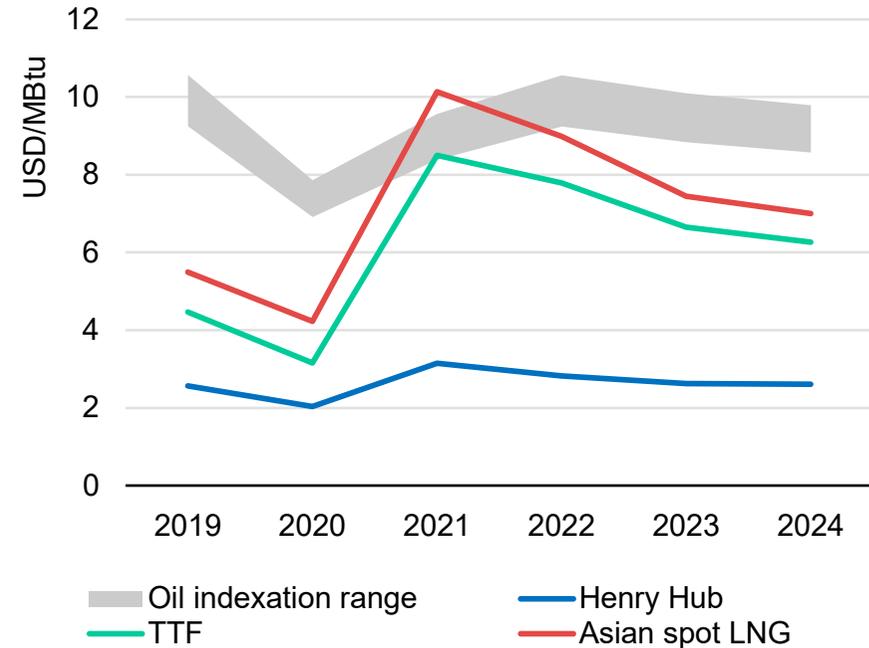
Natural gas demand is also particularly sensitive to temperature. After an exceptionally mild heating season in the northern hemisphere in 2020, 2021 saw more average – and even colder than usual – temperatures. This forecast assumes average winter conditions for the forthcoming heating seasons, and the report uses the average of futures prices during April 2021 as price indicators. When futures price curves do not extend to the full forecast horizon, we extend them to converge with medium-term fuel price assumptions contained in the [World Energy Outlook 2020](#) to provide an indication of assumed longer-term price evolution.

Economic activity and energy price assumptions

GDP growth assumptions, global and by region, 2019-2024



Gas price assumptions, 2019-2024



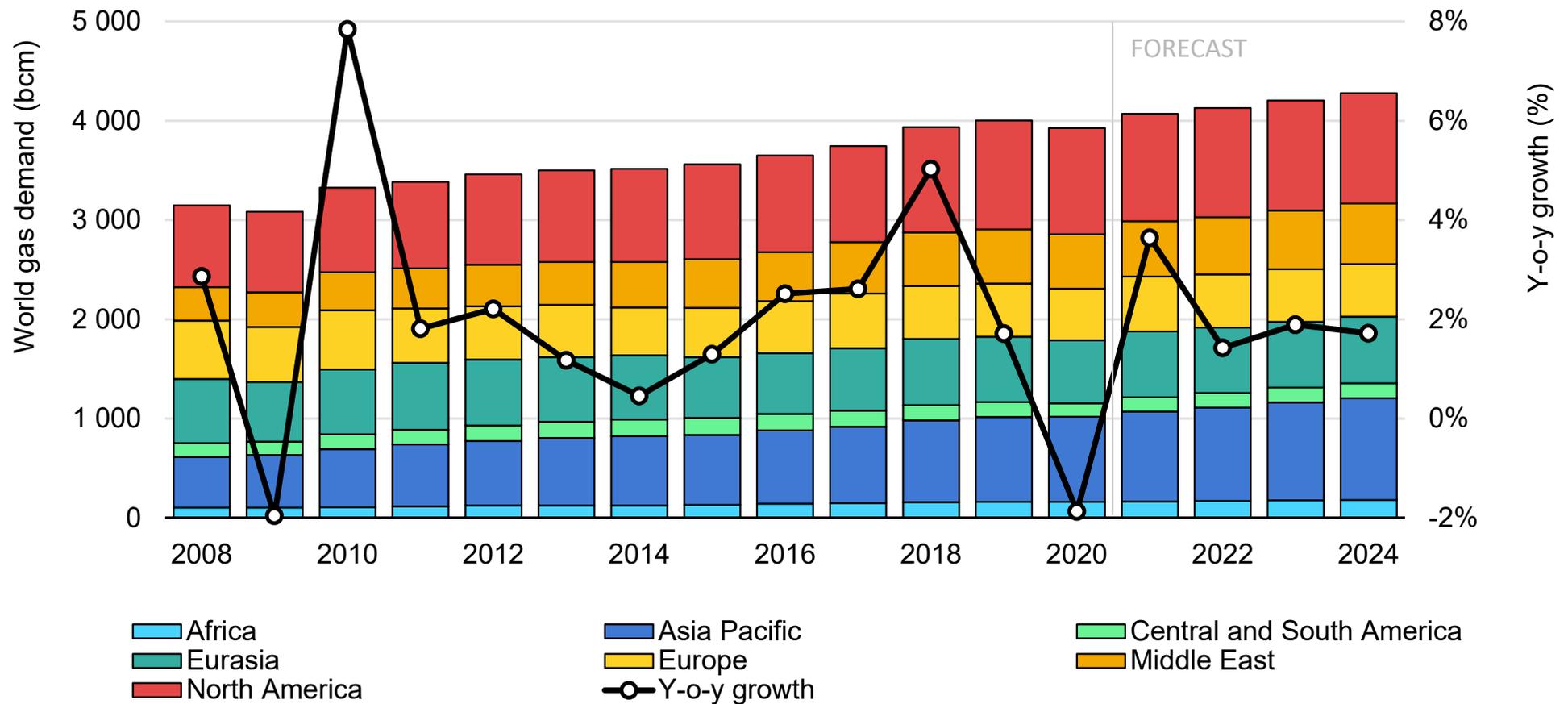
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Sources: IMF (2021), [World Economic Outlook](#); Oxford Economics (2021), [Economic Forecasts](#) (subscription required); CME (2021), [Henry Hub Natural Gas Futures Quotes](#); [Dutch TTF Natural Gas Month Futures Settlements](#); EIA (2021), [Henry Hub Natural Gas Spot Price](#); ICE (2021), [JKM-Japan Korea Marker LNG Future](#); ICIS (2021), [ICIS LNG Edge](#) (subscription required); Powernext (2021), Spot Market Data.

Demand

Gas demand is expected to fully recover in 2021 from its drop in 2020, although the recovery remains modest compared to the rebound after the 2008-2009 crisis

Global natural gas demand by region, 2008-2024



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Gas demand bounces back at lower average growth rates, but still too high to be compatible with net zero in the longer term

Natural gas demand is expected to reach close to 4 300 bcm by 2024, adding 350 bcm or 9% compared to its 2020 low point.

Short-term recovery plays a major role in the forecast period, with the demand gains expected in 2021 accounting for about 40% of the total increase. The global gas consumption growth rate stands at 3.6% in 2021, then declines progressively over the following years to 1.7% in 2024. Compared with 2019, natural gas increases by only 275 bcm over the forecast period – or about 7%.

The industrial sector, which provides the largest contribution to the 2021 recovery in global gas demand, maintains a leading role in the following years. The growing demand for natural gas, both for industrial processes and as a feedstock, is expected to account for a dominant 40% share of the total increase in gas consumption over the 2020-2024 period.

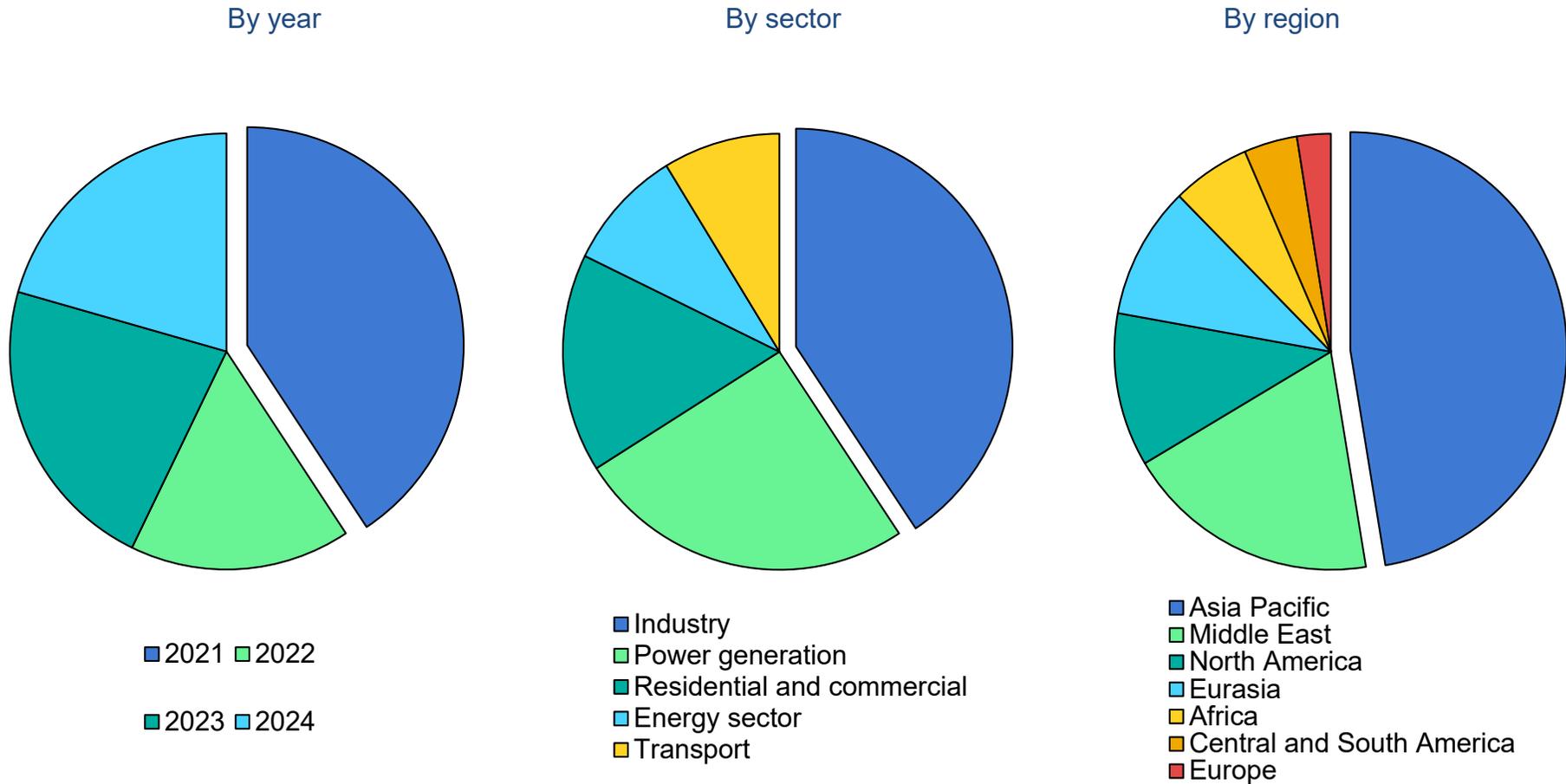
The Asia Pacific region alone is responsible for almost half of total gas demand growth, with a 47% share of the global increase. The Middle East, the second-largest contributor to growth, stands far behind at less than 20%. For most other regions, and especially mature markets, the bulk of the increase comes in the initial years as demand recovers from the 2020 downturn.

From 2020 to 2024, the substitution of gas and efficiency gains reduce natural gas demand by 80 bcm, mostly in power generation, moderating a gross demand increase of 430 bcm to a net increase of 350 bcm. The return to economic growth – driven by the industrial sector and led by Asia's fast-growing markets – remains the principal driver of rising gas consumption, accounting for almost two-thirds of the gross demand increase to 2024. Fuel substitution in favour of gas and at the expense of coal and oil, principally (but not only) in the power generation sector, covers the remaining third.

In spite of relatively modest demand growth in the coming years, projected gas demand in 2024 is already about 2% above the 2025 level of the World Energy Outlook 2020 Sustainable Development Scenario. This scenario maps out a trajectory consistent with global net-zero emissions by 2070. A faster decarbonisation path, as described in the IEA [Net Zero by 2050](#) report, would require even slower growth.

Asia is the largest source of gas demand growth, driven largely by industry, but the recovery from 2020's downturn plays a predominant role

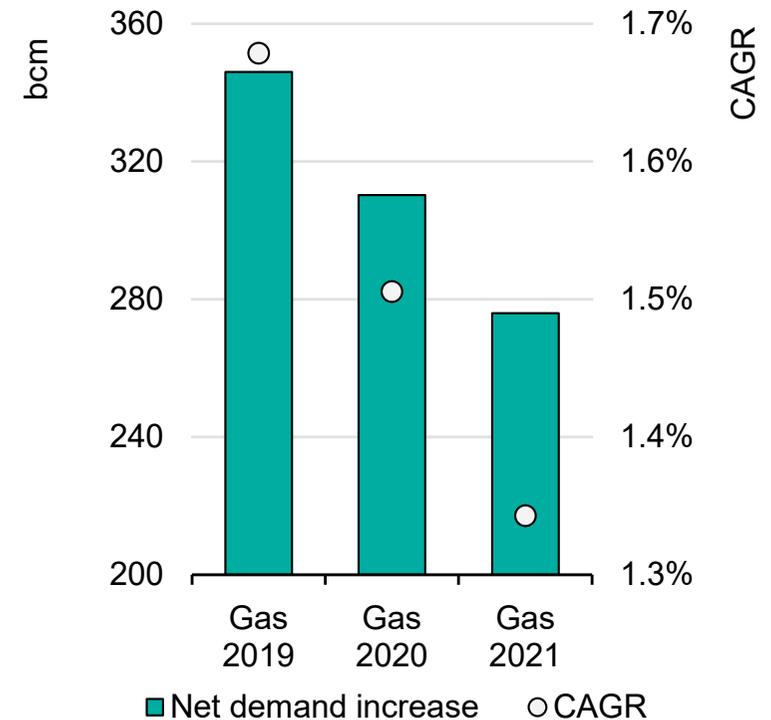
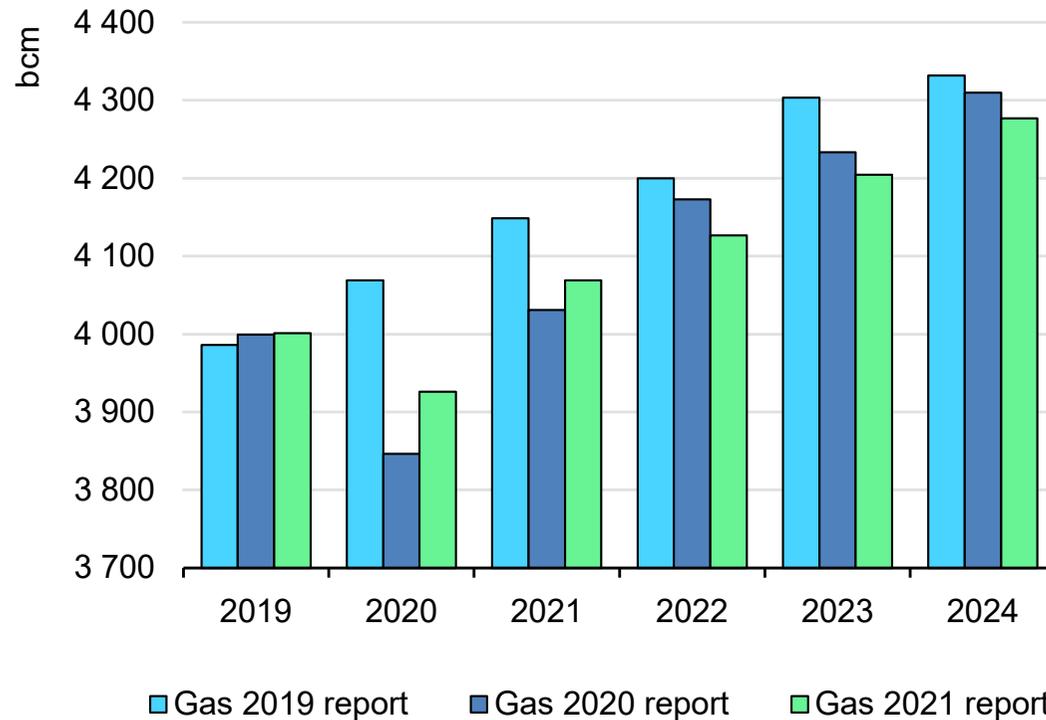
Breakdown of forecast growth in global natural gas demand, 2020-2024



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While the downturn in 2020 was less than expected, medium-term growth – following the rebound – loses speed in this latest forecast update

Evolution of global gas demand forecasts in the three latest issues of the IEA medium-term gas report, 2019-2024



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Gas demand from the industrial sector, which remained resilient in 2020, plays the lead role in medium-term growth

The sectoral breakdown of the fall and rebound in gas demand in 2020-2021 is asymmetric; the crisis had a limited impact on industrial uses of gas, which lead the recovery, whereas gas for power generation was the most affected in 2020 and will see one of the smallest increases in 2021.

The **industrial sector** is expected to be the main contributor to increasing gas demand to 2024, its consumption growing at an average annual rate of 3.4%. It provides a two-pronged contribution to growth: gas use as a fuel for industrial purposes on the one hand (principally driven by China, India and emerging Asian markets); and demand for natural gas as a feedstock for chemicals and fertilisers on the other hand (principally driven by gas producers and exporters).

Gas use for **power generation** declined by about 35 bcm in 2020, the equivalent of half of the total downturn in gas demand. The impact of the crisis could, however, have been much worse without the support of cheap gas prices that favoured coal-to-gas switching, principally in the United States (where gas-fired generation actually grew in 2020) and to a lesser extent in Europe. Higher gas prices in 2021 have reversed this effect and hindered US gas-fired generation versus coal – European gas competitiveness for power generation being more protected by high carbon prices. This

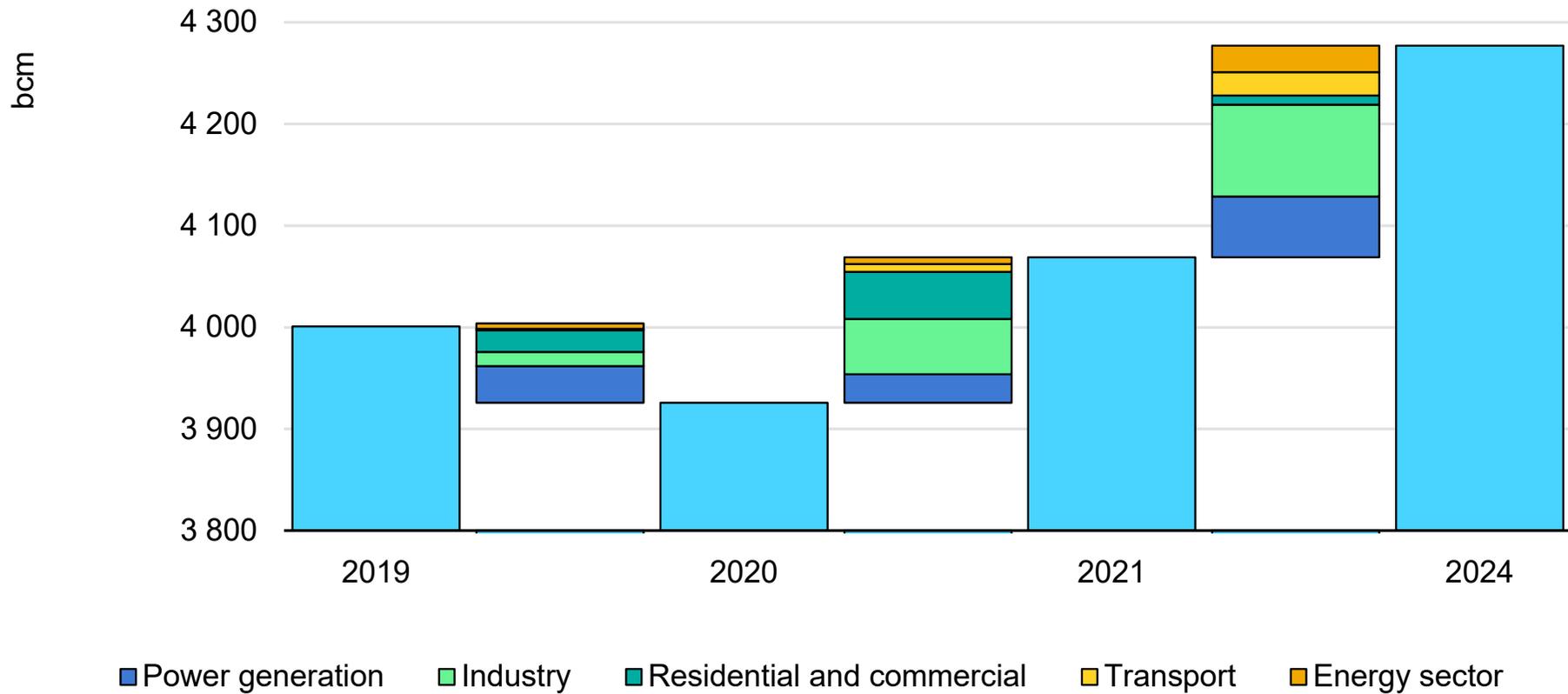
weakened contribution to the 2021 rebound limits the role of the power generation sector over the forecast period, with an average 1.4% annual growth rate for 2020 to 2024. Part of the increase in gas-fired generation (either from growing electricity demand or from fuel switching) is offset by the addition of renewable capacity and – to a lesser extent – by higher efficiency of combined-cycle plant replacing open turbines.

The **residential and commercial** sectors, hit in 2020 by the conjunction of a mild heating season and lockdown-induced restrictions on commercial activity, bounced back in early 2021 on colder-than-average winter temperatures. They should recover to their 2019 levels. Such a rebound is expected to remain a one-off event as growth potential remains limited outside a handful of countries – led by China, India and Iran – that continue developing their city gas distribution networks. Gas demand for residential and commercial uses is expected to grow at an average of 1.6% between 2020 and 2024.

Increasing gas production and processing capacity sustains the growth of the **energy sector's** own consumption, at an average 2% rate, while gas as a **transport** fuel is expected to grow at a higher rate of 4.8%, mainly driven by the growing use of LNG for trucks and river transport in Asia.

The industrial sector alone accounts for 40% of global growth in gas consumption over 2020-2024

Sectoral breakdown of global gas demand growth, 2019-2024



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Emerging regions and markets drive post-recovery growth in gas demand

In this forecast the **Asia Pacific** region is the main source of growth in demand for natural gas, with an average annual rate of 4.5% for the 2020 to 2024 period. It contributes almost half of the global consumption increase that follows the global recovery of 2021. China, India and other fast-growing markets in emerging Asia continue to drive the increase in gas demand, on a mix of economic growth-related expansion and fuel substitution. China is the single largest contributor to the growth in gas demand, accounting for close to 30% of the total increase during the 2020-2024 period, led by its industrial sector. In India industry keeps its leading role in gas demand growth, supplemented by the residential and commercial and transport sectors as the country rolls out its city gas distribution networks. Power generation remains the major driver of gas demand in emerging markets in South and Southeast Asia, supported by growing electricity demand and the development of new gas-fired generation capacity.

North American gas demand is expected to grow at an average of 1% per year during the 2020-2024 period. 2021 does not mark a full recovery to 2019 consumption levels as higher prices hamper US gas-fired power generation to the benefit of coal. The power sector slowly returns to growth over the forecast period, supported in Canada by Alberta's coal phase-out, to be completed in 2023. In the United States gas demand stagnates after an initial industry-driven rebound in the first years of the forecast, resulting in an average

0.7% annual growth rate. Canadian gas consumption follows a stronger average growth rate of 2.4% over the 2020-2024 period, principally supported by the abovementioned fuel switching in power generation. Gas demand in Mexico follows a moderate 1.3% average rate, as growth in gas-fired generation slows and increases in industry-related uses are partially offset by declining needs from the energy sector on lower domestic production.

Natural gas use in **Europe** remains broadly stable, with an expected 0.4% average annual increase. Demand bounces back in 2021 with a 6% increase, driven by the combination of colder winter temperatures, the return of industrial activity and limited competitiveness loss in power generation thanks to high carbon prices. The following years are marked by slight declines in gas demand, as the potential gains from the retirement of nuclear, coal and lignite-fired capacity are offset by the expansion of renewables in power generation and efficiency gains in other sectors.

Eurasia was the hardest-hit region in 2020, accounting for close to 40% of total gas demand loss. 2021 sees a return to pre-crisis demand levels, principally due to the return of colder winter temperatures that provided strong support for gas-fired heating and electricity consumption. Growth flattens in the following years and reaches an average annual rate of 1.4% over the 2020 to 2024 period. The Russian Federation ("Russia"), which contributes about

three-quarters of the region's gas demand, sets the trend with an expected 1.5% growth rate. Demand is more mature in Ukraine with close to zero growth, and turns negative in Belarus due to the commissioning of the two units at Ostravets nuclear power plant. Caspian and Central Asian economies provide slightly higher growth rates than the region's average, yet with limited additional growth potential in already highly gas-intensive markets.

The **Middle East** is the second-largest contributor to demand growth over the forecast period, after the Asia Pacific region, accounting for close to 20% of the total gas consumption increase. The region, which avoided gas demand decline in 2020, is expected to experience an average annual growth rate of 2.8% between 2020 and 2024. The bulk of additional demand comes from Iran and Saudi Arabia, and to a lesser extent from Iraq and Israel, while the United Arab Emirates makes a negative contribution due to the development of nuclear, coal and renewables in the country's electricity generation mix. Apart from this specific case, power generation and water desalination remain the key drivers of gas demand growth in the region, supported by demand from industry – especially for non-energy uses – and distribution customers (more specifically for Iran).

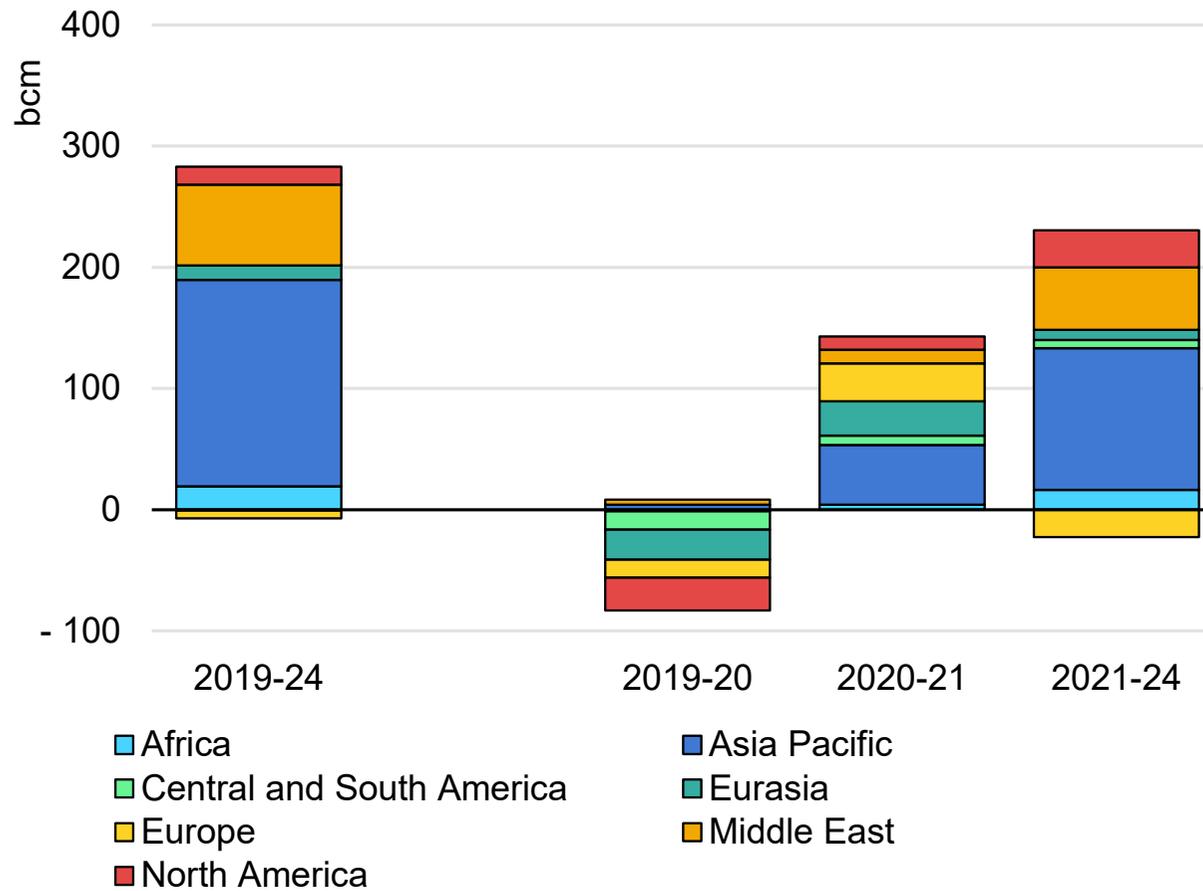
Central and South America represents the most affected gas market in 2020 in relative terms, with an estimated 9.9% y-o-y decline in demand. The path to recovery is expected to be rather slow as the region returns to its 2019 gas demand level only by the

end of the forecast period, with an average annual growth rate of 2.5% between 2020 and 2024. Demand prospects are more positive in Argentina and Brazil thanks to the development of domestic gas production, whereas smaller markets where gas is primarily used for power generation experience sluggish growth due to the deployment of renewables, and Venezuela's market is expected to continue declining on shrinking domestic production capacity.

Natural gas consumption is expected to grow in **Africa** at an average annual rate of 3.1% over the forecast period. While most of the increase remains concentrated among the region's three largest markets of Egypt, Algeria and Nigeria, which together account for three-quarters of total growth, smaller markets also experience consumption increases. This is particularly the case for West Africa, where the development of domestic resources in Mauritania and Senegal, and access to new LNG import capacity in Ghana, enable the substitution of oil with gas in power generation. Gas-fired capacity is also expected to start developing in South Africa from late 2022, with the planned commissioning of LNG-to-power projects.

Gas consumption rebounds in 2021 with most regions recovering from 2020's losses; Asia Pacific drives growth from 2022 with an overwhelming 55% share of total demand increase

Change in global natural gas demand by region, 2019-2024



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After the 2021 recovery, global gas demand growth is equally driven by economic activity and fuel substitution for the rest of the forecast period

This forecast expects global gas consumption to increase by 9% between 2020 and 2024 (adding 350 bcm), or 7% compared to 2019 levels. This results from the contributions of several different drivers, which play in favour of or against higher natural gas demand.

Growth in **economic activity** is the primary driver behind the global increase in natural gas demand, accounting for almost two-thirds of gross gas demand additions (or about 270 bcm). Due to the shape of assumed GDP growth rates, economic activity plays a much greater role in the initial years of the forecast and especially in 2021 when it is assumed to drive most of the increase in gas demand. Over the 2022 to 2024 period, the share of economic activity in gross gas demand growth falls to about 50%, on a par with fuel substitution.

Higher economic activity in emerging markets is primarily driven by industrial output, which in turn results in growing gas consumption in the power generation and industrial sectors – both for industrial processes and as a feedstock for chemicals and fertilisers. These two sectors cover over 70% of economic activity-driven growth in gas demand to 2024 vs 2021. Unsurprisingly the vast majority of such GDP-related consumption growth takes place in fast-growing gas markets, especially in Asia but also in Africa, the Middle East

and South America. Together these markets account for over two-thirds of total economic activity-driven growth. North America is the largest contributor among mature markets, principally thanks to the abundance of domestic gas resources to feed industrial demand.

The second contributor to demand increase is **the substitution of other fuels with gas**, where additional natural gas does not add to total energy consumption and emissions, but comes at the expense of other, more CO₂-emitting, fossil fuels. Replacement of coal and oil product volumes with natural gas results in an increase in gas demand of about 160 bcm over the forecast period.

Switching to natural gas arises from different types of incentive, including: market-based pricing competitiveness (with or without a carbon pricing component); policy measures such as coal and nuclear phase-outs in Europe and industrial and residential boiler conversion programmes in China; and physical supply debottlenecking solutions such as LNG-to-power value chains under development in Southeast Asia, sub-Saharan Africa and Central and South America.

The power generation sector provides the main contribution, accounting for half of total substitution with gas during the forecast period. This stems from the combination of coal-reduction and/or

phase-out agendas, development of domestic natural gas capacity and a desire to reduce oil import bills.

The large majority of gas demand gains from fuel substitution are in Asia and the Middle East, with these two regions together accounting for over two-thirds of the total increase. Fuel substitution in Asia is led by China and targets coal in both the industrial and residential sectors. It is complemented by a mix of power sector contributions from both mature and emerging markets, principally aimed at coal but in some instances also targeting oil products. In the Middle East, substitution gains are almost entirely driven by the power generation sector and at the expense of oil. These come primarily from Saudi Arabia (although revised downwards due to upstream project delays), and to a lesser extent from Israel and Iran.

Outside these two regions, gas demand growth from fuel switching principally comes from power generation in North America – on a combination of progressive recovery of US gas-fired generation and coal phase-out in the Canadian province of Alberta – complemented by Europe.

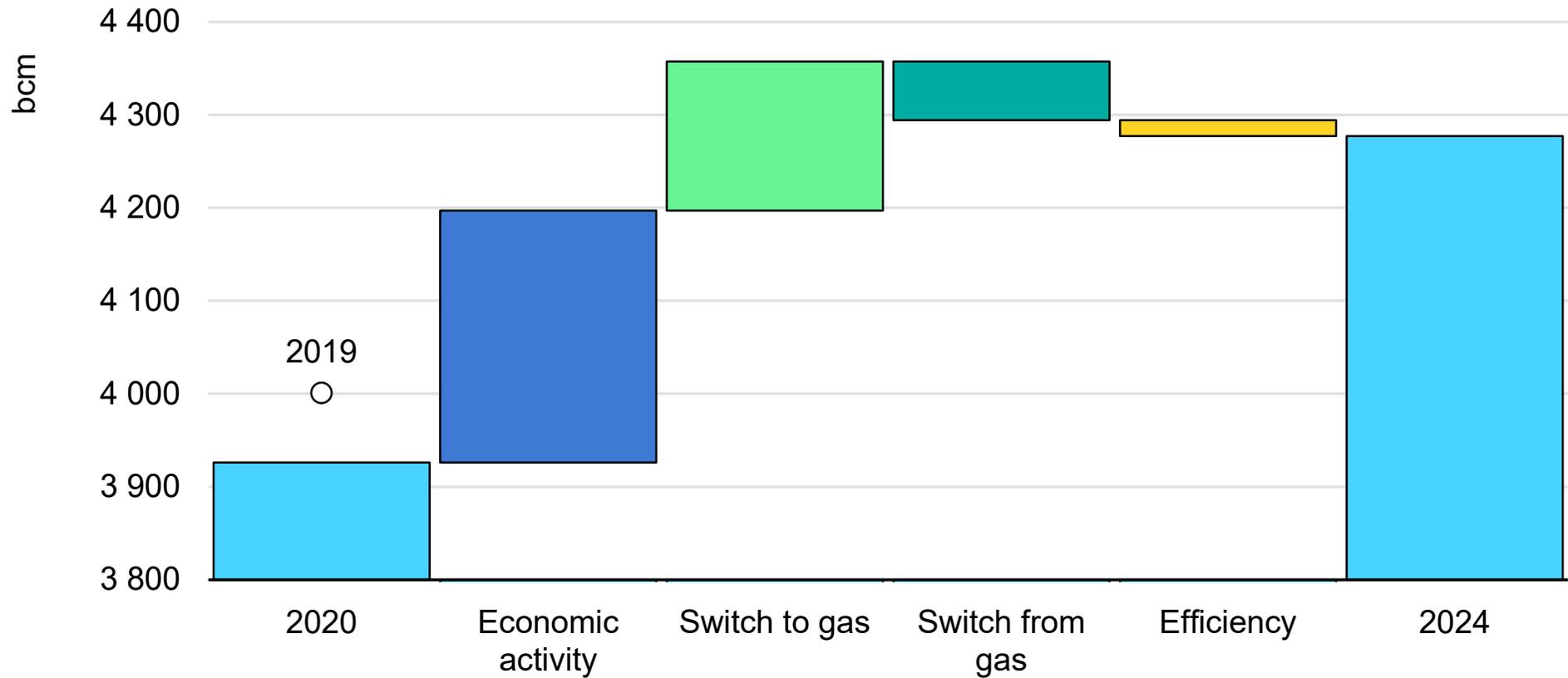
This primary increase is partially reduced by the joint impact of the **substitution of gas with other energy sources** and **efficiency factors**, which taken together subtract the equivalent of 80 bcm of gas demand. Switching away from gas occurs almost exclusively in power generation, which accounts for over 95% of the impact. Mature gas markets predominate, with a two-thirds share of global

substitution of gas, led by North America and Europe where the combination of renewable capacity expansion and limited electricity demand growth squeeze thermal generation. The deployment of renewables (and nuclear) in other regions also contributes to a reduction in the development of gas-fired generation, but this is partially offset by growing demand for electricity.

Efficiency has a more limited volumetric impact and is principally from the power generation and energy sectors, which account for 80% of its total impact. Short- to medium-term changes in these sectors are principally the replacement or retrofitting of turbines and drilling and production engines, as well as operational efficiency gains in gas production and processing. Other sectors, such as industry or residential, show fewer short-term efficiency gains due to their decentralised nature and longer life cycles, but provide an additional contribution over the forecast period. About three-quarters of the efficiency-related impact on gas demand growth occurs in mature gas markets.

Substitution of more CO₂-emitting fossil fuels drives one-third of gas growth to 2024

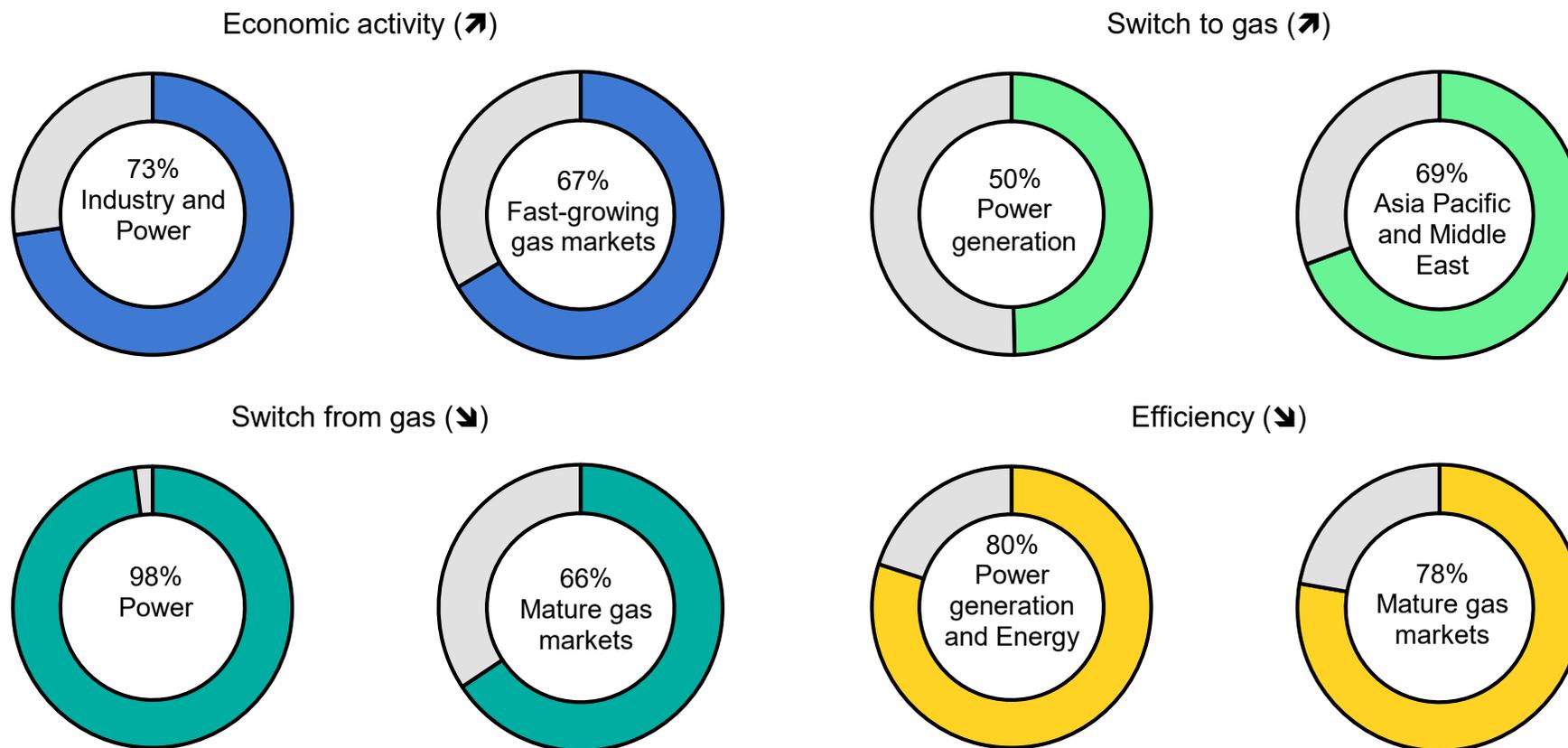
Evolution of global gas demand by driver, 2020-2024



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Power generation plays a central role in both sectoral demand increases and declines, while there is a clear regional difference driving trends between mature and emerging markets

Main sectoral and regional component in each gas demand driver



Note: "Fast-growing gas markets" include Africa, Asia Pacific excluding OECD countries (Australia, Japan, Korea and New Zealand), Central and South America, and the Middle East. "Mature gas markets" include Asia Pacific OECD countries (Australia, Japan, Korea and New Zealand), Eurasia, Europe and North America.

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Gas and energy transitions – at the crossroads on the way to 2050 net-zero emissions

The role played by natural gas in energy transitions is complex, with multiple and diverging contributions: a versatile fuel of growth in fast-growing markets, an enabler for reducing emissions when used as a substitute for oil or coal, but also a major source of emissions that needs to be reduced – especially in mature markets where much of the growth and substitution potential has already been tapped.

This diversity of factors is at play in our forecast to 2024. During this period, annual gas demand grows by 350 bcm. Fuel switching from gas and efficiency gains contribute to reduce annual demand by 80 bcm. Out of a total gross gas demand increase of 430 bcm, higher economic activity accounts for almost two-thirds (270 bcm), while fuel switching from coal and oil explain the rest (160 bcm).

The global increase in natural gas demand over the 2020 to 2024 period is rather modest, with a compound average annual growth rate of 2.2%. Yet this may still be too high to meet a net-zero emissions target by 2050. This report forecasts a 9% increase in annual gas demand between 2020 and 2024 to reach close to 4 300 bcm. By comparison, the *World Energy Outlook 2020* Sustainable Development Scenario, which maps out a trajectory consistent with global net-zero emissions by 2070, sees natural gas demand increase by only 4% between 2020 and 2025. In this forecast, demand then declines by 4% in the following five years to

reach 4 tcm by 2030, back to its 2019 level. The Net Zero by 2050 scenario requires a sharper decline to 3 700 bcm in 2030 – returning to the 2017 gas demand level.

The gas demand trajectory should therefore flatten to keep on track towards global net-zero emissions by 2050. However, part of this gas increase provides a positive contribution to lowering global emissions through fuel substitution, while economic activity-driven growth in gas demand results principally from the expansion of fast-growing markets and improved access to energy. The remaining drivers to slow demand growth would then be to further accelerate fuel switching from gas and efficiency, especially in the more mature markets.

Slower natural gas growth is needed to match a net-zero path, with a higher substitution rate and efficiency gains

Achieving such a reduction in global gas demand over the medium term is crucial to reaching net-zero emissions ambitions. But it requires strong policy action, industry investment and consumers' behavioural change for it to happen. Given the relatively long lifetime of gas infrastructure and appliances, the impact of decisions – even those taken today – may not be visible within the time horizon of this forecast.

One driver available to reduce gas demand growth in the coming years is to increase substitution. Any further acceleration in renewable capacity additions to 2024 would contribute to reducing the role of thermal generation, and therefore affect the amount of gas and coal consumed. This could, however, become more complex where electrification simultaneously occurs for end uses that have traditionally used gas, such as for cooking. Given a maximum potential for renewable capacity additions, electrification could result in additional electricity demand leading to an increase in thermal electricity generation.

Reducing gas consumption in the power generation sector can also be achieved by improving power plant efficiency; the vast majority of the world's gas-fired generation fleet comprises open-cycle gas or steam turbines with about half the efficiency of recent combined cycles. Besides, over a quarter of the fleet of open-cycle turbines is more than 30 years old. Accelerating their replacement with combined-cycle gas plants (ideally hydrogen-ready to ensure future fuel flexibility) could almost halve the individual gas consumption of each plant.

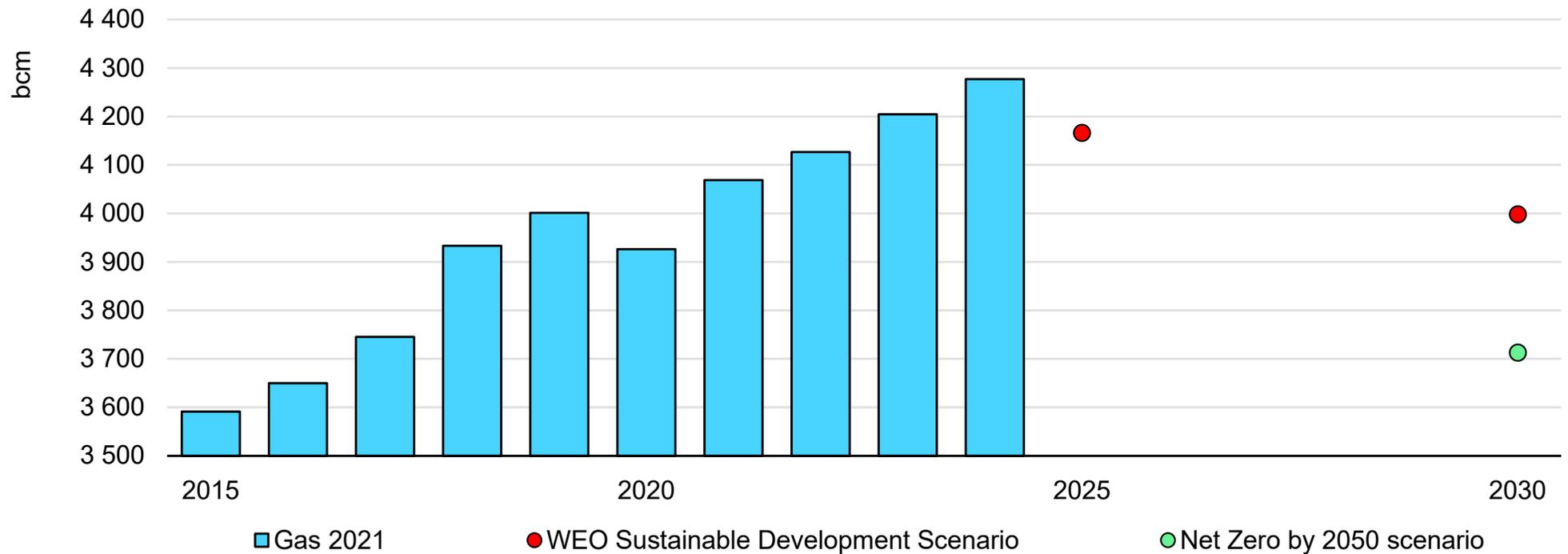
The other driver to lowering gas growth is to improve efficiency beyond power generation. Taking into consideration the limited time horizon of this forecast, visible improvements would come from a mix of small-scale investment and operational behaviour changes rather than large-scale changes that will require longer lead times. In the industrial sector, for instance, the combined effects of short-

term equipment investment (such as improving the insulation of furnace and oven walls and doors, or installing automatic controls to optimise air-fuel ratios for burners), regular maintenance and operating best practices (operate at close to full load capacity, reduce delays between cycles, recover heat from exhaust or flue gases to reduce primary generation) can lead to reductions in natural gas use of up to one-third.

In the case of residential heating, short-term efficiency gains can be obtained by replacing ageing individual appliances – for instance, switching from an old conventional gas boiler to a condensing boiler coupled with a heat pump water heater, which together can reduce fuel consumption by up to 30%. Behavioural changes – such as lowering the thermostat average temperature, or reducing it during the night or before leaving – also contribute to reducing average natural gas consumption in a range of 7% to 12%.

Despite its moderate growth rate, global gas demand by 2024 would already be 2% above the 2025 level in the Sustainable Development Scenario

Evolution of global gas demand compared to the WEO Sustainable Development Scenario and Net Zero by 2050 scenario



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Sources: IEA (2020), [World Energy Outlook 2020](#); (2021), [Net Zero by 2050](#).

Focus on Asian gas demand: China

China's economy rebounded quickly from the Covid-19-related lockdowns in 2020, and the rapid expansion of gas demand is set to continue over the forecast period. Total consumption is projected to increase at an average annual rate of nearly 7%, adding 95 bcm of incremental demand between 2020 and 2024. China is the single largest contributor to global gas demand growth, accounting for close to 30% of the net increase by 2024.

Nearly half of the aggregate growth is driven by fuel substitution. About 70% of this comes from coal-to-gas conversions in industry and the residential and commercial sector, and 30% from oil-to-gas substitution in the transport sector. Overall, the net contribution of fuel switching in China is almost twice as high as the global average. This underlines the fact that government policies incentivising a shift away from more polluting fuels remain an important driver of gas demand in China over the medium term.

The industrial sector is the primary engine of growth, accounting for 43% (41 bcm) of China's demand increase over the forecast period. This is driven roughly in equal parts by growing industrial activity on the back of a strong domestic (and global) economy and by the government-mandated replacement of small coal-fired industrial boilers to improve air quality. The power sector contributes a little more than 18% (17 bcm) of the total consumption growth between 2020 and 2024, thanks mainly to continuing additions of gas-fired

generation capacity. China's gas-fired fleet is set to expand by a third over the forecast period and reach 133 GW by 2024.

Residential and commercial users make up slightly less than 18% (17 bcm) of the demand growth in China, driven by new grid connections and the ongoing conversion of small and inefficient coal-fired boilers to cleaner fuels, including natural gas, to reduce pollution in urban areas. The transport sector represents 14% (14 bcm) of the incremental demand between 2020 and 2024. Nearly two-thirds of the growth within this segment comes from LNG-fuelled trucks and buses, which are supported by local policies and attractive payback times, followed by compressed natural gas (CNG) vehicles (20%), LNG-fuelled domestic shipping (12%) and transport by pipeline (3%).

The policy framework in China remains broadly supportive of growing gas demand in the medium term. The official launch of PipeChina in 2020, the country's new national midstream operator, marked a significant step towards improved third-party access, lower transmission tariffs and the streamlined development of the domestic gas grid. The new entity is expected to increase market competition, stimulate new investment and reduce the cost of gas to end users over time. Although it is yet to be translated into specific policies, China's recent pledge to reach net-zero emissions by 2060 is also set to encourage gas use (both as backup for renewables and as a substitute for coal), at least in the medium term.

Focus on Asian gas demand: India

While India's short-term outlook is clouded by a devastating second wave of Covid-19 infections, which had the most disruptive effect in April and May 2021, the prospects for continued growth in gas demand remain strong in the medium term, aided equally by expanding infrastructure and a highly supportive policy environment. India's annual gas consumption is expected to increase by 25 bcm in the 2020-2024 period, which translates into a 9% annual average growth rate. India is set to emerge as the second-largest driver of gas demand in Asia (after China) and the fifth-largest contributor globally (after China, Iran, Russia and the United States).

Almost two-thirds of India's 2020-2024 demand expansion comes from fuel substitution, primarily from liquid fuels to gas. In the industrial and energy sectors this means converting fertiliser plants and refineries to natural gas. In the residential and commercial sector, substitution is driven by the expansion of city gas distribution networks to areas previously served by LPG or other fuels. In the transport sector, CNG and to a lesser extent LNG displace oil products as the refuelling infrastructure expands.

Nearly 40% of India's net demand growth is expected to come from industrial users, while the remaining growth is roughly evenly split between the residential, transport and energy sectors. Gas use for power generation is projected to remain almost flat throughout the

forecast period, as most of the country's stranded gas-fired fleet is uncompetitive without subsidies or an outright collapse of international gas prices.

Natural gas enjoys considerable policy support in India, which provides a strong basis for gas demand growth in the medium term. The government has a stated ambition of building a gas-based economy and increasing the share of natural gas in the primary energy mix from around 6% today to 15% by 2030. To support this ambition, in 2019 the Ministry of Petroleum and Natural Gas announced a plan to invest USD 60 billion in natural gas infrastructure. As part of the programme, India plans to complete 17 000 km of new gas transmission lines by 2024, expand the city gas distribution network to cover 70% of India's population, and increase import capacity by nearly one half with the completion of new LNG terminals, at least five of which are currently under construction. Government targets also include the addition of up to 1 000 LNG refuelling stations over time, and the next (11th) bid round to further expand the gas distribution grid is expected to be launched in the near future. Recent reforms to introduce a unified tariff structure for domestic pipelines and plans to create an independent gas transmission system operator could further support India's gas demand growth in the years ahead.

Focus on Asian gas demand: Emerging Asia

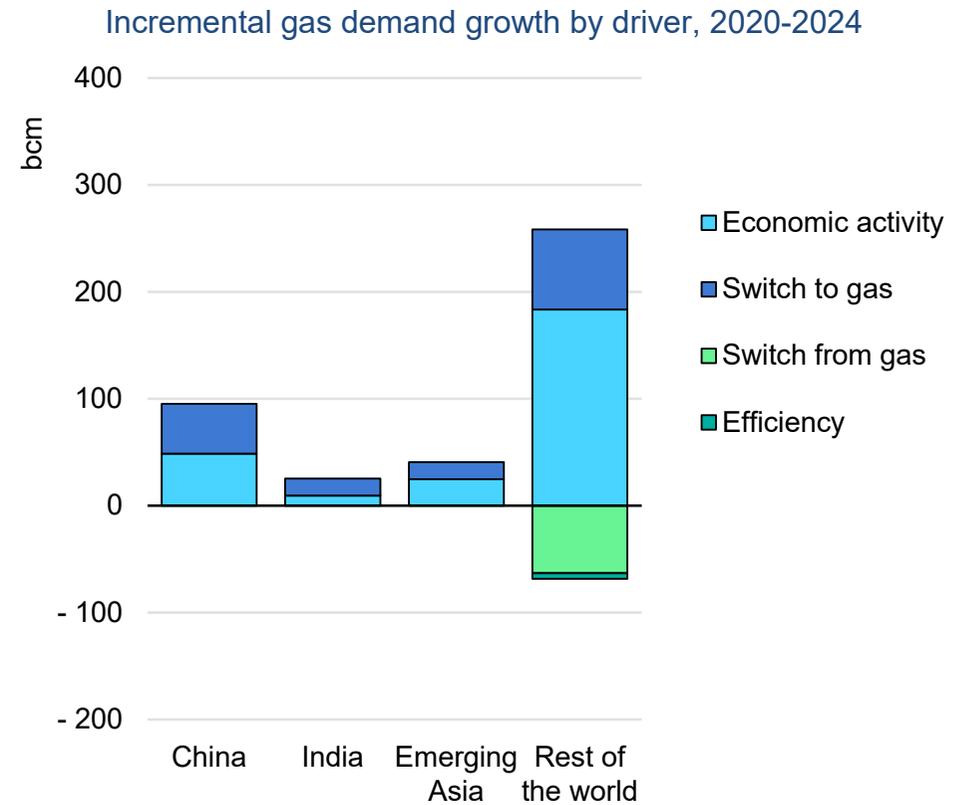
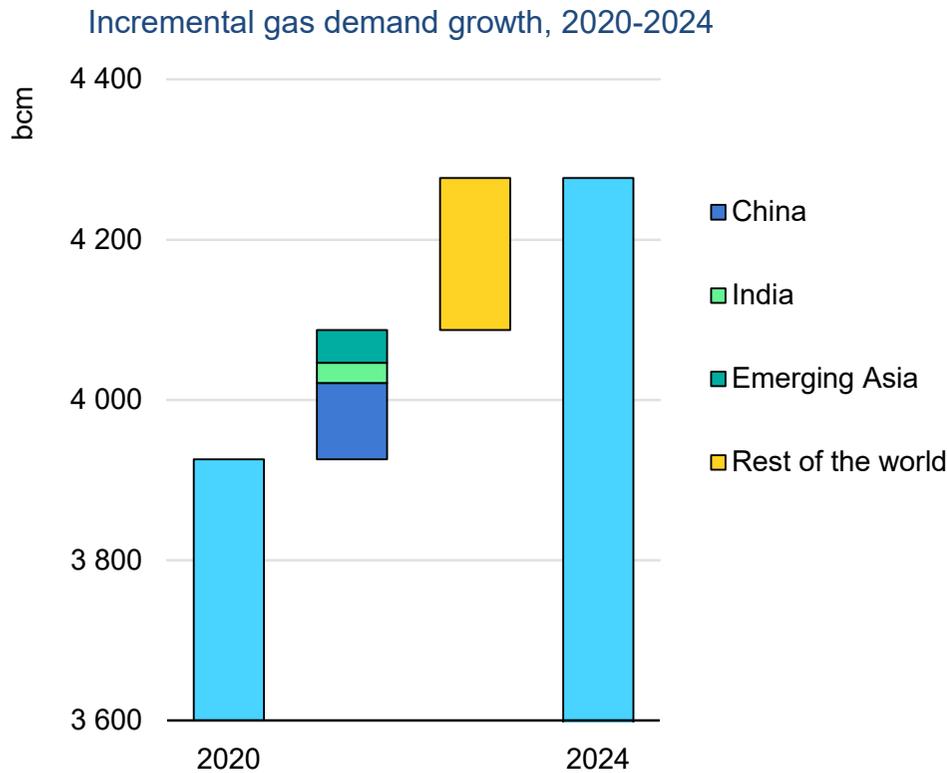
Emerging Asia is expected to add 41 bcm of incremental gas demand in the 2020-24 period, accounting for 25% of demand growth in the Asia Pacific region and 12% worldwide. The collective contribution of emerging Asia to global gas demand growth is greater than of any single country except China. Unlike in China and India, the bulk of the demand growth in emerging Asia is driven by rising economic activity. Fuel substitution – from coal to gas in power and oil to gas in industry – is only significant in Bangladesh and Thailand in our assessment.

Nearly half (20 bcm) of the region's demand expansion between 2020 and 2024 is projected to come from the power generation sector, driven by the addition of about 18 GW of gas-fired generation capacity. The industrial sector contributes another 31% (13 bcm) to emerging Asia's growth, led by Indonesia, Malaysia, Pakistan and Bangladesh. Given the lack of heating demand in the residential and commercial sector (with the exception of Pakistan), its natural gas use is not expected to increase materially during the forecast period, only adding 7% (3 bcm) to the region's net growth. Gas demand in the transport sector is led by Pakistan, Bangladesh and Thailand, the only countries with widespread adoption of CNG vehicles, but the sector's contribution of 4% (2 bcm) is relatively modest due to the slow growth of CNG fleets across the region as a whole. The remaining 10% (4 bcm) of the net increase comes from

the energy sector, mainly driven by upstream activities and the operation of LNG facilities across emerging Asia.

The region is increasingly dependent on LNG imports to bridge the widening gap between declining indigenous production and growing demand, and the medium-term outlook is highly dependent on further additions to the region's gas infrastructure. There are some encouraging signs that the region's infrastructure bottlenecks are gradually being addressed. Bangladesh completed the debottlenecking of its regasification terminals in 2020, which now enables the full utilisation of the country's LNG import capacity. New import terminals are scheduled to come online in Viet Nam (Hai Linh) and Indonesia (Jawa-1 FSRU) in 2021, and additional regasification capacity is in advanced stages of development in Thailand, Viet Nam and the Philippines. Indonesia and Thailand also added LNG reload capability (and completed their first-ever re-exports in early 2021), which could further enhance the flexibility of LNG supply across the region. Remaining infrastructure bottlenecks (e.g. in Pakistan) and further delays in the development of planned LNG-to-power projects, however, could still hamper the region's gas demand growth in the forecast period and beyond.

China, India and emerging Asia account for almost half of the demand growth globally in 2020-2024, driven mainly by fuel substitution



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Focus on Asian gas demand: Japan and Korea

Japan's gas demand declined by 4.5% in 2020 due to the negative impact of Covid-19. The declining trend is expected to continue during the 2021-2024 period due to the lingering impact of Covid-19 and the restart of nuclear power plants. Total consumption is set to decrease by 4% between 2020 and 2024.

The decline is driven by the power generation sector, where nuclear restarts and the increase in renewable generation reduce the need for gas-fired generation. The trajectory of gas demand in Japan is highly sensitive to power sector trends, particularly the timing and scale of nuclear reactor restarts, the rollout of renewables and the pace of improvements in generation efficiency. Other sectors are expected to grow modestly, partially offsetting the decline in power generation.

Japan's commitment to reduce its GHG emissions by 46% by 2030 compared to 2013 levels will have repercussions for gas demand. On the one hand, growing electrification of heating – combined with nuclear restarts and the expansion of renewable generation – are likely to reduce gas consumption. At the same time, further coal-to-gas switching in the power and industrial sectors could deliver quick reductions in GHG emissions, and thus support gas demand in the medium term.

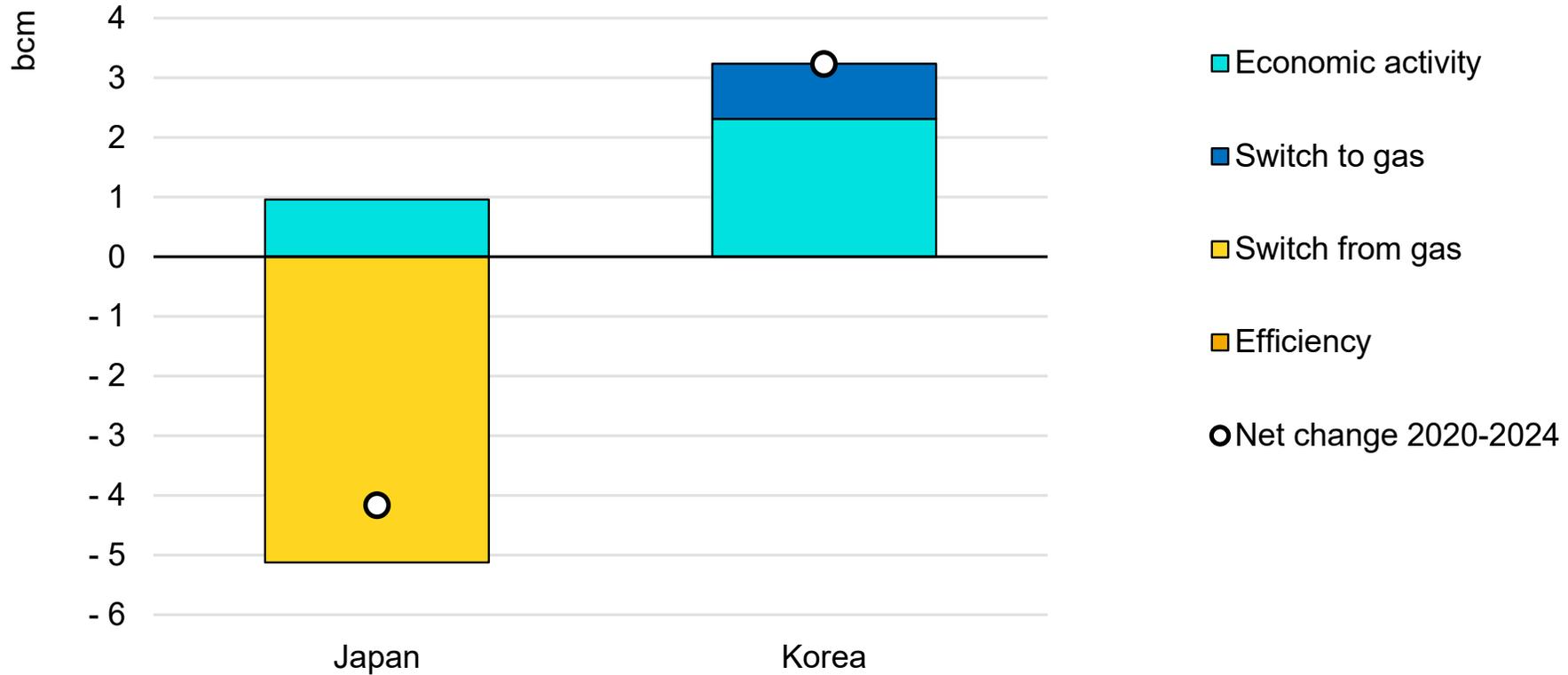
Korea's gas demand increased by 2% in 2020 thanks to the rapid containment of the spread of Covid-19. This trend accelerates in 2021 with a 5% y-o-y increase, mainly driven by the economic recovery and continued coal-to-gas switching in power generation.

From 2022, however, the expansion of gas demand is expected to slow, with annual growth rates averaging less than 0.4% in the remainder of the forecast period. This is mainly due to lower gas demand in the power sector following the addition of long-planned nuclear (5.6 GW) and coal-fired (7.3 GW) generation capacity. Some gas-to-coal substitution is expected to occur, despite the low overall utilisation of coal-fired power units in the wake of the government's policy push to reduce air pollution. At the same time, city gas demand continues to increase at an annual average rate of about 1%, led by the industrial and buildings sectors.

Korea's gas demand trajectory remains highly uncertain throughout the forecast period and will be greatly influenced by environmental policies adopted to support the government's 2050 net-zero emissions target, which was announced in October 2020. As part of the plan, Korea pledged to replace coal-fired power generation with renewable energy in the long term.

Gas demand in Japan and Korea take divergent paths in 2020-2024, led by different drivers

Incremental gas demand growth by driver, 2020-2024



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Oil to gas – the other fuel switching in power generation

Global electricity demand increased by about 26% between 2010 and 2019. This growth was primarily fuelled by the development of renewables, which account for over half of additional electricity generation over the past decade. Natural gas was the second-largest contributor, accounting for close to 30% of the increase, the balance being provided by coal. Oil-fired generation, which amounted to close to 1 000 TWh in 2010, declined by 22% to 2019.

Although the amounts at stake are far less important than for coal – oil-fired generation accounts for less than 2% of global electricity supply – its substitution nonetheless remains challenging. Indeed, oil-fired generation is concentrated in a limited number of national or local markets where it plays a dominant role, principally either because of its abundance as a fuel or because of the lack of alternatives. This is especially the case in isolated markets such as islands or remote regions where it is used to deliver electricity off-grid to industrial or residential customers.¹

In numerous emerging markets, the electricity system currently relies heavily on low-efficiency plants burning diesel or fuel oil, a source of high energy import bills and local air pollution. A review of the past decade shows that in markets where the share of oil-fired

generation declined, this coincided in almost half of cases with an increase in the share of gas-fired generation. The other half is principally correlated with a rise in renewable electricity's market share, with the balance of cases (about 15%) corresponding to an increase in other fuels – mainly coal.

Substitution is driven by domestic gas monetisation and the development of import projects

The main driver of switching is accessibility to alternative fuels, either from domestic or imported sources. The largest consumers of oil for power generation are almost all **major oil and gas producing and exporting countries**. Some of these countries are faced with strong electricity demand growth rates that have led to an increase in oil burning in absolute terms, albeit that oil's share in the electricity generation mix has declined over the past ten years.

In **Saudi Arabia**, the world's largest consumer of oil for power generation, the share of natural gas in power generation has increased strongly, especially in the eastern and central regions of the country (due to their proximity to gas production assets) where it accounts for over 95% and 70% of total generation respectively.

¹ Oil-fired capacity can also be found in more interconnected markets as back-up generation, generally used during demand peaks.

Other regions currently rely almost exclusively on crude oil and oil products. Aramco's planned expansion of the country's Gas Master System would enable it to further develop gas-fired generation in these regions.

In **Iran**, natural gas already dominates the power generation mix, although oil products are still used despite an objective to phase them out – this is due to natural gas supply constraints and the need to ensure back-up for hydropower fluctuations. In **Iraq**, the development of gas-fired generation would meet three strategic priorities: accommodating the country's growing electricity demand, monetising currently flared associated gas production, and reducing dependence on Iranian gas imports. The country aims to spend USD 15 billion with private partners to develop domestic gas production (notably monetising flared gas) in order to produce the equivalent of 12 GW of electricity.

Fast-track development of natural gas for power at the expense of oil products is also a feature of the **monetisation of recent gas discoveries** in less mature oil and gas producing countries. In **Egypt**, the consumption of natural gas has jumped by almost 50% over the past decade, with an acceleration since 2015 and the ramping up of the Zohr offshore gas field. The power generation sector accounts for over 60% of gas demand and close to 80% of the country's electricity is generated from gas – against about 15% from oil. In **Israel**, the development of the Tamar offshore gas field and start of production in 2013 enabled the country to increase its

energy self-sufficiency and boosted the share of natural gas in power generation. Gas-fired generation has more than doubled over the past decade to account for close to 70% of the country's electricity mix in 2019, while oil-fired generation has halved. The ramping-up of the Leviathan offshore gas field is expected to further increase the role of gas in power generation in the near future.

In **Senegal**, the development of the first phase of the Grand Tortue Ahmeyim offshore project (jointly owned with Mauritania) will mark the start of gas-fired generation, as part of the project's output is earmarked for domestic markets. First gas is expected by 2023 to feed the 300 MW Cap des Biches CCGT project, which would provide the equivalent of 25% of the country's current generation. It should lead to a 40% drop in electricity production costs according to state-owned utility Senelec. Oil products currently account for over 80% of the country's electricity mix, which has some of the highest electricity costs in West Africa.

LNG-to-power projects enable fast-track electricity access and oil-to-gas substitution in isolated systems

The development of LNG-based flexible supply chains, with either an onshore or floating regasification terminal, has fostered the transition to gas-fired generation in several electricity systems. While several LNG-to-power projects are now under development or discussion in Asia to limit the role of coal in energy supply, they first appeared in the context of oil-to-gas switching in small or

remote markets. **Central America** has a track record of developing such integrated supply chains in various countries and territories since the early 2000s – starting with Puerto Rico in 2000, followed by the Dominican Republic in 2003, Jamaica in 2016 with an initial floating terminal and in 2019 with a second, and Panama in 2018. Two new importers are set to join the group in 2021: Nicaragua and El Salvador. In all these markets, the LNG infrastructure is coupled with gas-fired combined cycles in order to displace oil products.

In **South America** several LNG projects have been developed to support power generation in remote markets, such as Chile's northern Mejillones terminal (initially floating in 2010 then replaced by an onshore terminal in 2014), or more recently Brazil's Sergipe LNG project, commissioned in 2020 together with 1 516 MW of gas-fired combined cycle, the largest in South America. According to the World Bank's analysis that supported its decision to finance the project, the Sergipe LNG project is expected to avoid about 2.5 million tonnes of CO₂ emissions a year by replacing diesel and fuel oil use.

LNG-to-power projects are also starting to take off in Africa. In **West Africa**, Ghana's Tema LNG floating regasification unit is expected to receive its commissioning cargo in July 2021. Ghana's National Petroleum Company stated that gas from the LNG terminal will contribute to improving electricity coverage and fuel the 1 500 MW domestic gas-fired power generation fleet. In Senegal, a floating power plant in operation since 2019 has been associated with the

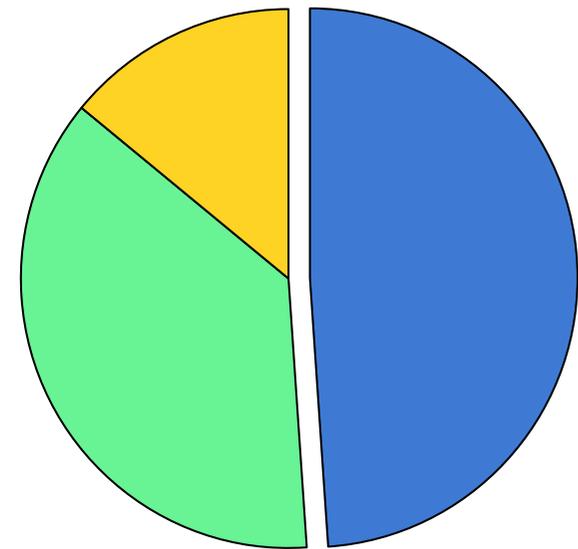
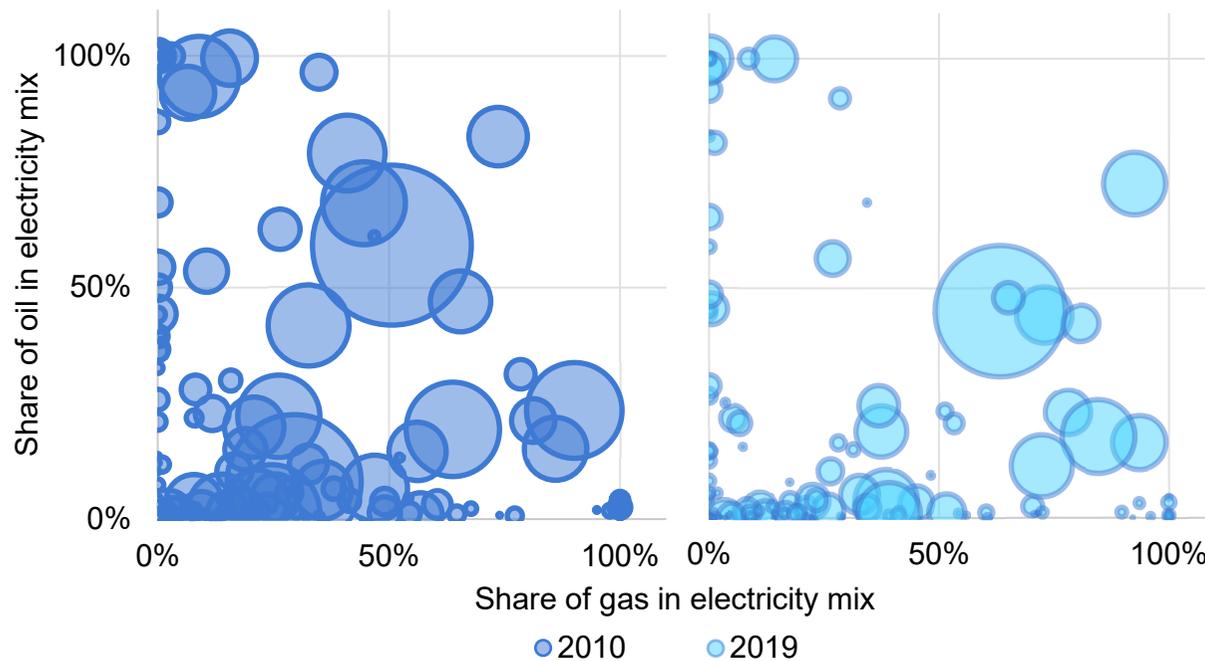
arrival of a floating regasification vessel in early 2021, allowing its conversion to LNG ahead of the planned start-up of domestic natural gas production in 2023.

In March 2021 **South Africa's** Department of Energy listed eight successful bidders for a total of 1 845 MW of power capacity as part of its Risk mitigation IPP Procurement Programme, designed to close the country's power supply gap and reduce its reliance on diesel-fired turbines. Three of the selected projects are floating LNG powerships totalling 1 220 MW, one is a hybrid solar and LNG project of 197 MW, and the remaining three are solar and wind projects with a total of 428 MW. These projects still need to confirm financial closing by end of July 2021 to go ahead, but they provide an example of the strong complementarity of gas and renewables in the drive to improve energy access and reduce emissions.

Natural gas has been the primary source of substitution for oil in power generation, which has declined by 22% over the past decade

Oil consumption for power generation and respective share of oil and gas in electricity mix by country, 2010 vs 2019

Oil substitution in power generation by replacement fuel, 2010-2019



Note: Bubble size indicates oil-fired generation output per country.

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Transport sector gas demand set to grow rapidly from a low base...

Transport is the smallest but fastest-growing sector for natural gas consumption, expanding at an annual average rate of 5% between 2020 and 2024. More than 60% of the growth comes from road transport, while the remainder is equally split between shipping and pipeline transport.

The most widespread use of natural gas in the road transport segment is in the form of CNG, with at least six countries having fleets exceeding one million CNG-fuelled vehicles. CNG consumption, which accounts for about 60% of the gas demand growth in road transport, is led by India and China. CNG uptake is supported by government policies and the expanding gas and refuelling infrastructure in both countries. India's programme to expand CNG access is the most ambitious globally; it will add another 4 500 CNG stations to its current network of 2 700 over the next four years as part of the ongoing rollout of city gas infrastructure. It is projected to more than double India's CNG demand between 2020 and 2024.

LNG consumption in the road transport sector is dominated by China, which had nearly 600 000 LNG-fuelled trucks and buses in 2020, the largest such fleet in the world. In the 2020-24 period, China's use of LNG in road transport is set to expand by more than 40%, driven by local incentives such as diesel bans and subsidies, and by lower fuel costs compared to diesel trucks. In 2020 India

also eased rules for setting up LNG filling stations and introduced a plan to build 1 000 of them along the country's main highway corridors. However, the pace of the rollout beyond the 50 initial LNG stations remains uncertain.

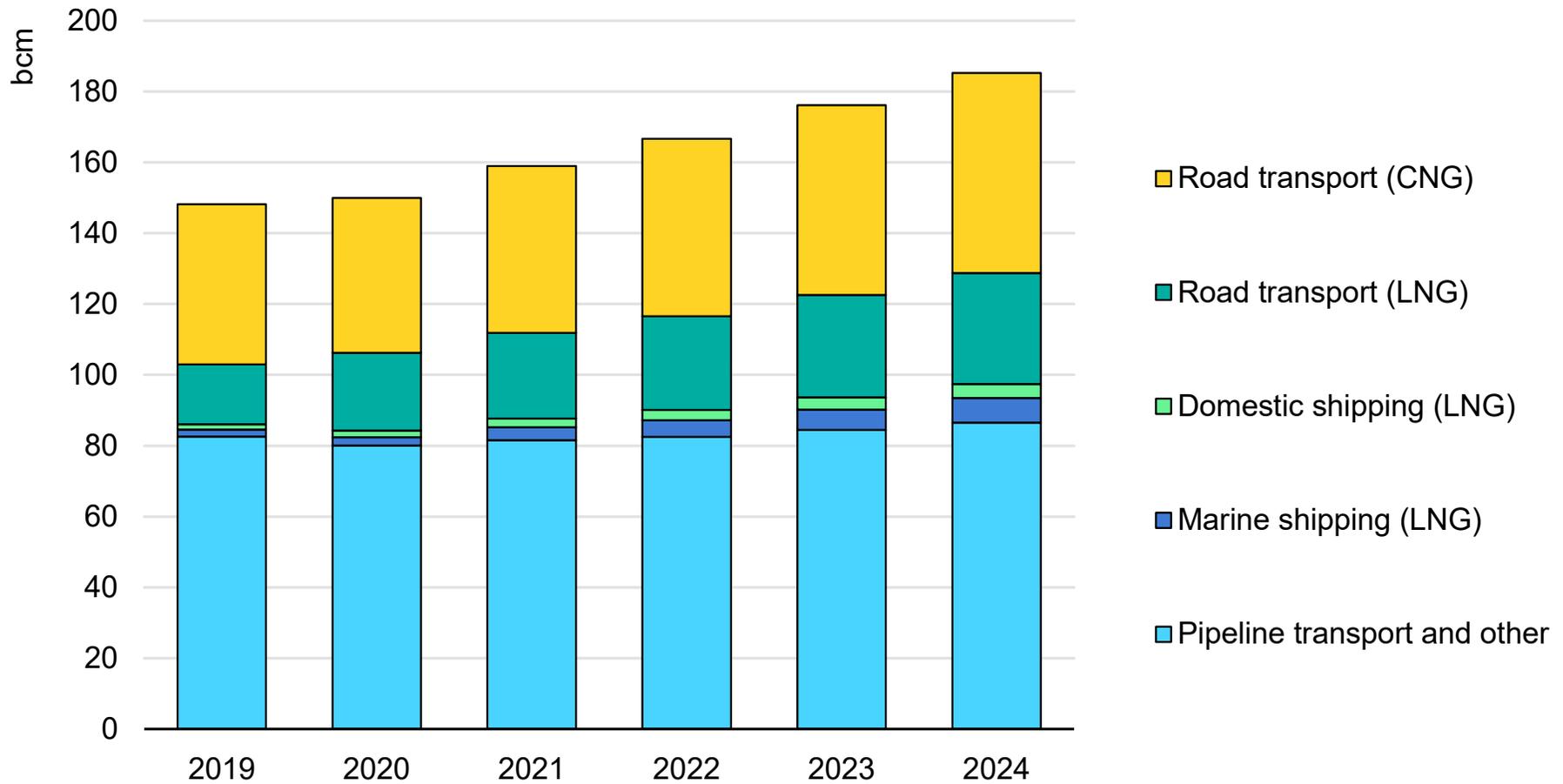
LNG use in marine transport has increased fivefold since 2016 and reached more than 2 bcm in 2020. LNG bunker fuel demand is set to triple from 2020 levels to nearly 7 bcm by 2024. The International Maritime Organization's global sulphur cap, which phased out high-sulphur fuel oil from the shipping sector in 2020, has accelerated the adoption of LNG as a bunker fuel. As of January 2021, LNG-fuelled ships made up about 8% of all vessels on order by one estimate, and the fleet of LNG-propelled vessels (excluding LNG carriers) is projected to expand by nearly 160% between 2020 and 2024. The inability of LNG to meet the IMO's long-term GHG reduction targets, however, casts doubt about the sustainability of LNG demand growth in the shipping sector beyond our forecast horizon.

LNG consumption for domestic shipping is expected to double during the 2020-24 period, led primarily by China, and – to a lesser extent – Europe.

Natural gas use in the pipeline transport segment increases more modestly at 8% (6 bcm) between 2020 and 2024, driven by growing pipeline gas flows, particularly in China, Russia and North America.

... driven by the road transport and shipping segments

Transport sector gas demand, 2019-2024



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Supply

Most medium-term gas production growth comes from projects already under development

Global natural gas production dropped by an estimated 2.9% y-o-y or 120 bcm in 2020, a larger impact than in the aftermath of the 2008 financial crisis (when gas supply declined by 100 bcm in 2009). Demand recovery in 2021 and further growth in emerging markets in the coming years are accompanied by gas supply expansion, as output grows by 9% between 2020 and 2024 in this forecast. It is worth mentioning, however, that this additional output comes at a slower rate than before 2020 and is almost exclusively from projects already under development.

North American gas production showed some resilience in 2020, with a modest 1.6% decline. This is particularly the case with US gas production outlets, as export capacity ramp-up provided further access to foreign markets, while lower prices triggered fuel substitution in the domestic market's power generation mix. This forecast expects North America's gas production to account for about a quarter of global supply growth to 2024, with a 7% increase between 2020 and 2024. Modest US gas production growth is principally driven by LNG export needs, and is delivered by dry shale gas plays in general – and by the Appalachian Basin in particular – with some support from the oil-driven Permian Basin as light tight oil production recovers. Canadian production stagnates as new domestic needs from Alberta's coal phase-out are offset by lower pipeline exports to the United States, increasing slightly over the end of the forecast period to prepare for the commissioning of

the LNG Canada project. Mexico's production continues to decline, although at a more moderate pace than in previous years.

Eurasia has taken the brunt of 2020's gas market adjustment, with a double impact on domestic and export sales that led to a close to 60 bcm decline in annual production compared to 2019 – about half of the world's total supply adjustment. The region's natural gas output is set to expand by 17% between 2020 and 2024, largely driven by Russia, which accounts for over 85% of Eurasia's growth. Russia's gas production is set to expand by 18%, mainly driven by the ramp-up of new and recent export projects (the Power of Siberia pipeline, the Yamal and Arctic LNG 2 plants) and the recovery of exports to Europe. Azerbaijan is the second contributor to export-driven production growth, with the ramping up of capacity to fill the TANAP and TAP pipelines to Europe. Turkmenistan leads the growth in Central Asia, while development potential appears more limited for Kazakhstan, and even more so for Uzbekistan where gas production is facing severe upstream issues that lead to an expected end to gas exports by 2025 (it stopped exporting to Russia in mid-2020).

The **Middle East** is another major contributor to the medium-term growth in global gas production, with a 9% increase between 2020 and 2024. This is related to the commissioning of a limited number of large-scale projects currently under development, aimed both at

domestic and export markets. The North Field/South Pars giant offshore field accounts for over half of the region's development, to meet Qatar's scheduled expansion of LNG export capacity and Iran's growing domestic gas market needs respectively. This is complemented by additional developments in Saudi Arabia and Israel.

Gas production in the **Asia Pacific** region is set to increase by 7% compared to 2020, to approach 700 bcm by 2024. Most of the region's growth is from China, which sees its domestic gas production increase by 23% over the forecast period to above 230 bcm by 2024, thanks to continued policy support to develop gas output. India is expected to grow and surpass its pre-2020 level of output. Australia's gas supply stabilises at around 150 bcm per year, while more mature producers such as Indonesia and Malaysia decline slightly over the forecast period.

Africa's gas production grows by 10% between 2020 and 2024 in this forecast to reach 265 bcm per year – a downward revision compared to our previous forecast. This is mainly due to the postponement of the Mozambique LNG export project, which is not expected to start operating before 2025 following the recent force majeure linked to security issues. The bulk of growth comes from the commissioning of other export-driven developments such as the

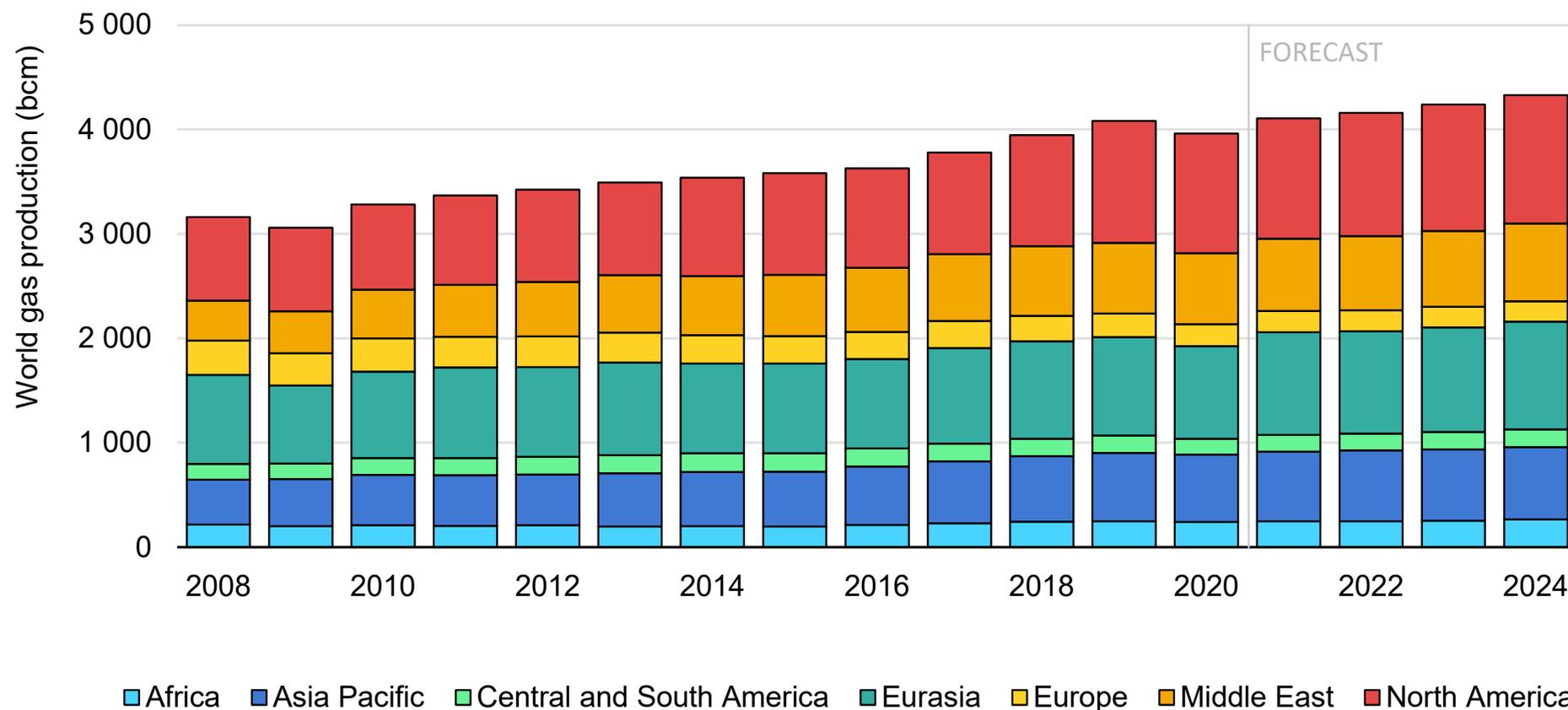
first phase of the Grand Tortue Ahmeyim complex developed across the maritime border of Mauritania and Senegal. Production in North Africa is generally stable, with some limited increase in Egypt offsetting declines in most other neighbouring markets.

Gas production in **Central and South America** is expected to grow by 10% over the forecast period, as output gradually returns to its 2019 level by 2024 after a notable decline in 2020. Most of the net increase compared to 2019 comes from Brazil's associated gas in pre-salt developments, which contributes to offsetting the net losses from Venezuela and other legacy producers.

Europe's natural gas production is expected to decline by 8% between 2020 and 2024, to below 200 bcm per year by the end of this period. While Norwegian output is recovering after the 2020 drop and heavy maintenance in 2021, other European domestic production is expected to decline by almost a quarter. This is driven by the combination of depleting fields in the North Sea, the closure of Groningen in the Netherlands and terminal output decline from smaller fields in the Netherlands and across Europe. Two outliers with modest growth emerge outside Norway: Denmark, with the restart of the Tyra field, which boosts the country's production to close to 3 bcm by 2024; and Romania, with some limited growth potential.

Gas production grows modestly, rising 6% above 2019 levels by 2024, principally driven by major developments in Eurasia and the Middle East as well as new US shale wells

Global natural gas production by region, 2008-2024



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US gas production is expected to resume growth, albeit at a slower pace

US natural gas production fell by about 15 bcm (or 1.6%) in 2020 from an all-time high of close to 970 bcm in 2019. Output dropped from a record 86 bcm in December 2019 to 76 bcm in June 2020 on a combination of lower domestic and export needs, before rebounding to 82 bcm in December 2020. Gas production is expected to grow further over the medium term, as prices recover from their low 2020 levels and export capacity ramps up, albeit at a more modest rate than previously observed.

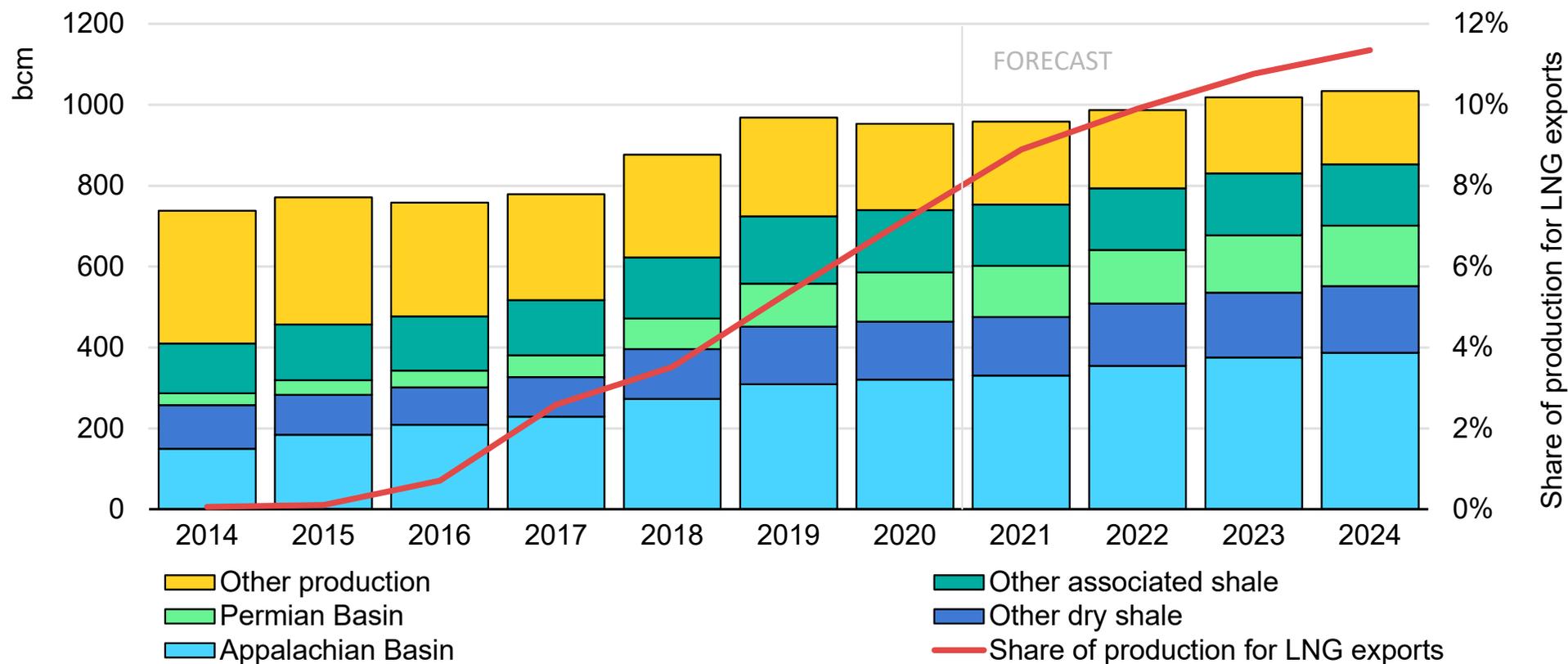
Pure-play shale gas producers have confirmed their financial objectives for 2021, with investment kept flat and the objective of delivering returns to investors as market prices continue their recovery. This financial cautiousness is likely to contribute to lower growth in the coming years. In the Appalachian Basin, the country's largest contributor to gas production, output was maintained throughout 2020 and even grew by 3% y-o-y in spite of a 30% decline in monthly drilling activity. Production kept growing thanks to the start-up of previously drilled but uncompleted (DUC) wells, providing a lower-cost alternative to new developments. Over the past 18 months the Appalachian Basin's DUC count has shown a steep decline of nearly 30%. The trend is less visible in the Haynesville gas play, where drilling activity remained more stable throughout 2020.

In addition to delivering returns to investors, the US gas industry is also expected to face tougher environmental performance targets. As the new US administration puts climate considerations among its top priorities, producers will have to accelerate planned activities such as tackling flaring and methane leakage, and progressing carbon capture and sequestration. US producing companies have started to focus more on environmental, social and corporate governance issues, topics that remained more marginal in previous years.

This corporate context, together with almost flat domestic demand, does not provide strong support for US gas production growth over the medium term, which will instead be driven mainly by the country's growing LNG export capacity. This forecast expects US dry gas output to pass the 1 tcm mark and reach above 1 030 bcm in 2024, or a 9% increase compared to 2020 (7% compared to 2019). Dry shale gas plays are expected to provide most of the additional volumes, led by the Appalachian Basin. This modest growth is also supported by developments in tight-oil production (dominated by the Permian Basin). Contributions from other associated shale basins stagnate, while dry gas output from conventional assets continues its decline.

US dry gas production progresses slowly from 2022, driven by LNG exports' feedgas needs

Dry gas production by main source in the United States, 2014-2024



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Export-oriented projects are set to drive Russia's gas production...

Russia's annual gas production is expected to expand by over 17% (or close to 120 bcm) between 2020 and 2024, to account for approximately one-third of incremental global gas supply during the forecast period. This will be largely supported by demand recovery in 2021 and the country's growing exports (both pipeline and LNG), together driving almost 80% of additional gas supply requirements between 2020 and 2024.

Russia's gas production is set for a strong recovery in 2021.

Following a steep drop in 2020, gas output is expected to increase by 12% (over 80 bcm) y-o-y to above 2019 levels as domestic consumption returns to growth and exports climb to above pre-crisis levels. The recovery in gas supply will be supported by Russia's large fields in **Western Siberia**, including Urengoyskoe, Yamburgskoye and Zapolyarnoe, all of which produced well below their nameplate capacities in 2020. In addition, the giant Bovanenkovo field is expected to reach its nameplate capacity of 115 bcm/y in 2021/22. In **Eastern Siberia**, the continued ramp-up of supplies to China via the Power of Siberia pipeline is expected to increase annual production from the Chayandinskoe field by approximately 6 bcm in 2021.

Russia's gas production is expected to increase by close to 2% per year between 2021 and 2024, amidst moderate domestic demand

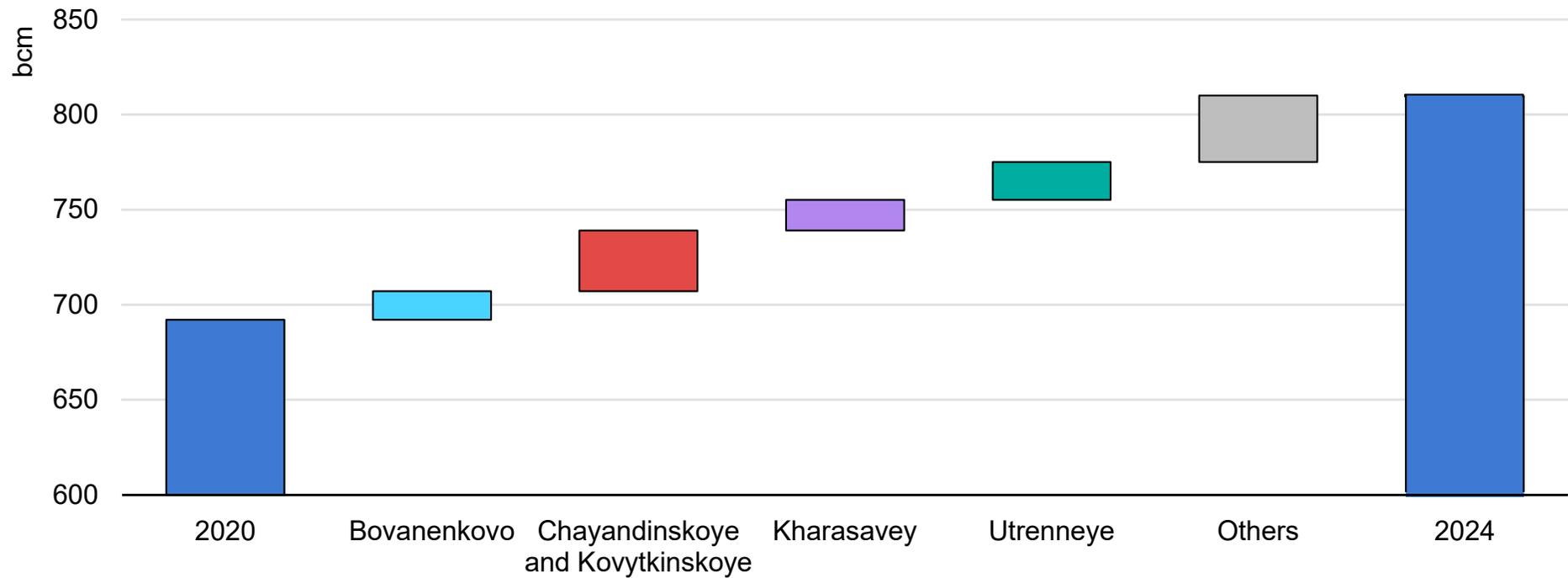
growth and the continued ramp-up of exports through both traditional and new export channels.

The **Yamal Peninsula** is set to drive Gazprom's production growth through the forecast period, while the traditional production centres in Western Siberia continue to deplete. Besides Bovanenkovo reaching its 115 bcm/y nameplate capacity, the Kharasavey field is expected to be commissioned by 2023 (although reaching its nameplate capacity of 32 bcm/y beyond our forecast period). Novatek's **Utrenneye field** in the Gydan Peninsula will support the company's Arctic LNG 2 export project, with its production expected to reach approximately 20 bcm/y by 2024. **Rosneft** is set to continue its gas development programme in Western Siberia. This includes the phased commissioning of the Rospan fields throughout the forecast period and the project launch of the Kharampur field (expected to reach its nameplate capacity of 11 bcm/y by 2022/23).

In **Eastern Siberia**, the **Chayandinskoe field** is expected to reach its 25 bcm/y design capacity by 2024, whilst production capacity from the **Kovyktinskoye field** is set to reach 15 bcm/y. This results in an incremental output of 30-32 bcm/y between 2021 and 2024 as supplies to China via the Power of Siberia pipeline continue to ramp up. The **Amur gas processing plant** is expected to reach its 42 bcm/y design capacity by 2025.

...expanding by close to one-fifth between 2020 and 2024

Natural gas production growth in Russia by key fields, 2020-2024



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Source: IEA analysis based on various companies reports.

Middle Eastern natural gas production is set for rapid expansion...

The Middle East's annual gas production is set to expand by 9% (or 64 bcm) between 2020 and 2024, driven by the region's strong demand growth – particularly in Iran and Saudi Arabia – and partly supported by the continued oil-to-gas switching in the power sector. As such, the region is expected to contribute over 17% of the world's additional gas supply during the forecast period.

The North Field/South Pars Gas Condensate field, shared between Iran and Qatar, is expected to account for over half of the region's production growth between 2020 and 2024. This is partly driven by the continued strong demand growth in **Iran**, expected to expand by almost 15% by 2024. The ramp-up of **South Pars Phases 13, 14 and 22-24** will add close to 30 bcm/y of production capacity over the forecast period. Drilling started in late 2020 at **South Pars Phase 11**, which is expected to begin production by March 2022 and add an estimated 20.5 bcm/y of production capacity by the end of the forecast period.

Qatar's gas output is expected to increase by 2% per year between 2020 and 2024, driven by growing domestic production amidst the commissioning of new gas-fired power generation and desalination facilities. This includes the commissioning of the 2.6 GW Facility E, with the first power and water from the plant due in June and July 2023 respectively. Beyond our forecast, the expected start-up of the **North Field East project** in Q4 2025 increases the country's LNG

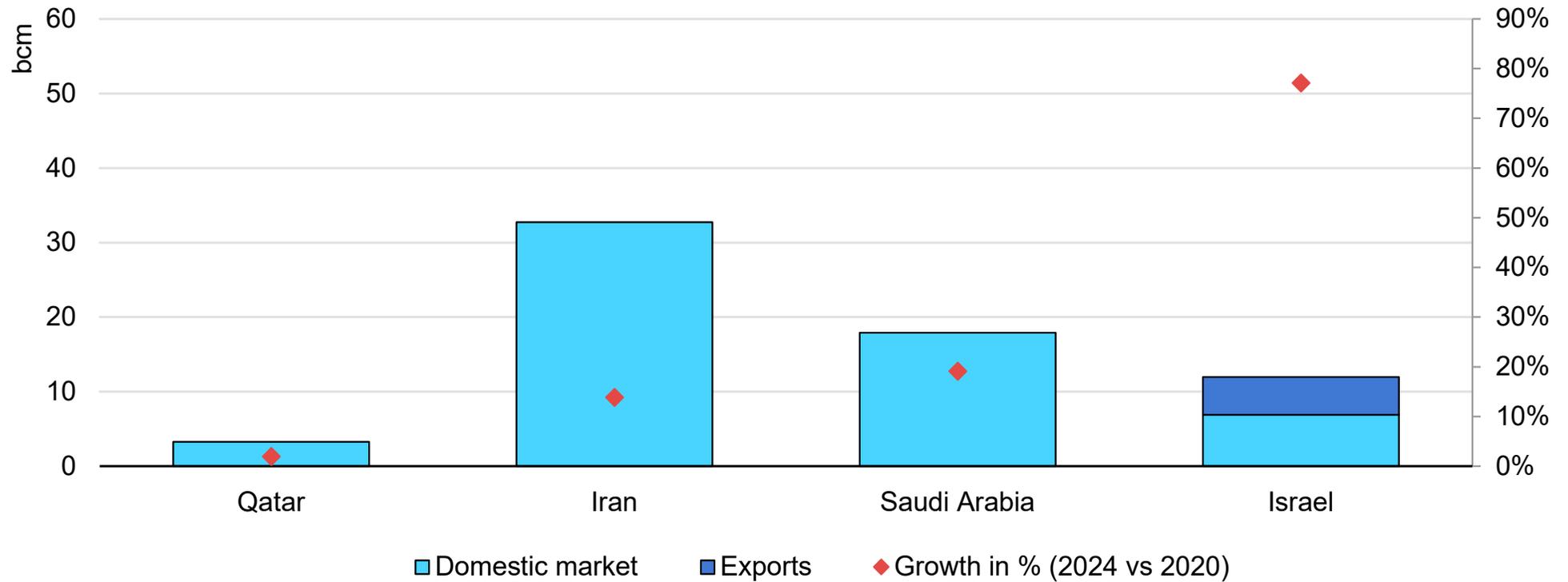
export capacity by over 40% (or 45 bcm/y). This is set to provide a major boost to Qatar's gas output, expanding the country's production to close to 230 bcm (or 30% above 2020 levels).

Saudi Arabia's annual production is set to increase by nearly 20% (18 bcm) in 2020-24, driven mainly by the 10 bcm/y expansion of the Hawiyah gas processing plant and growing associated gas output from existing fields. Recent capex cuts pushed the online date of the Marjan increment programme and the 26 bcm/y Tanajib gas processing plant to 2025. Production start-up at the Jafurah shale development is expected in 2024, but unconventional gas only contributes materially to supply growth beyond our forecast horizon.

Israel is projected to see a substantial 77% (12 bcm) production increase between 2020 and 2024, as the Leviathan field ramps up to full capacity, output from Tamar recovers after the removal of takeaway capacity bottlenecks and the Karish development starts production from 2022. About 60% of the incremental supply is directed to the domestic market to meet growing demand and displace LNG imports. The remaining 40% is exported by pipeline to Egypt and Jordan to satisfy existing contractual commitments.

...driven by strong domestic growth and rising exports

Natural gas production growth in key Middle Eastern gas markets, 2020-2024



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Source: IEA analysis based on various companies and news reports.

Tracking clean gas progress

The neighbour's gas is always greener: Clean gas policies and market developments

Natural gas alone accounted for more than one-fifth of global CO₂ emissions in 2020. With the recovery of natural gas demand, carbon emissions from natural gas combustion are set to increase by 3% in 2021, to reach an all-time high of 7.35 Gt. Moreover, natural gas operations were responsible for over 40 Mt of methane emissions in 2020 – equating to over half of the total energy-related CO₂ emissions of the European Union. Given the immediate need to reduce the climate impact of fossil fuels, the gas industry will need to rapidly undertake several measures, including: (1) reduce the GHG emission intensity of its various supply chains; (2) support the integration and deployment of low-carbon gases; and (3) minimise emissions occurring from the combustion of natural gas through carbon management solutions.

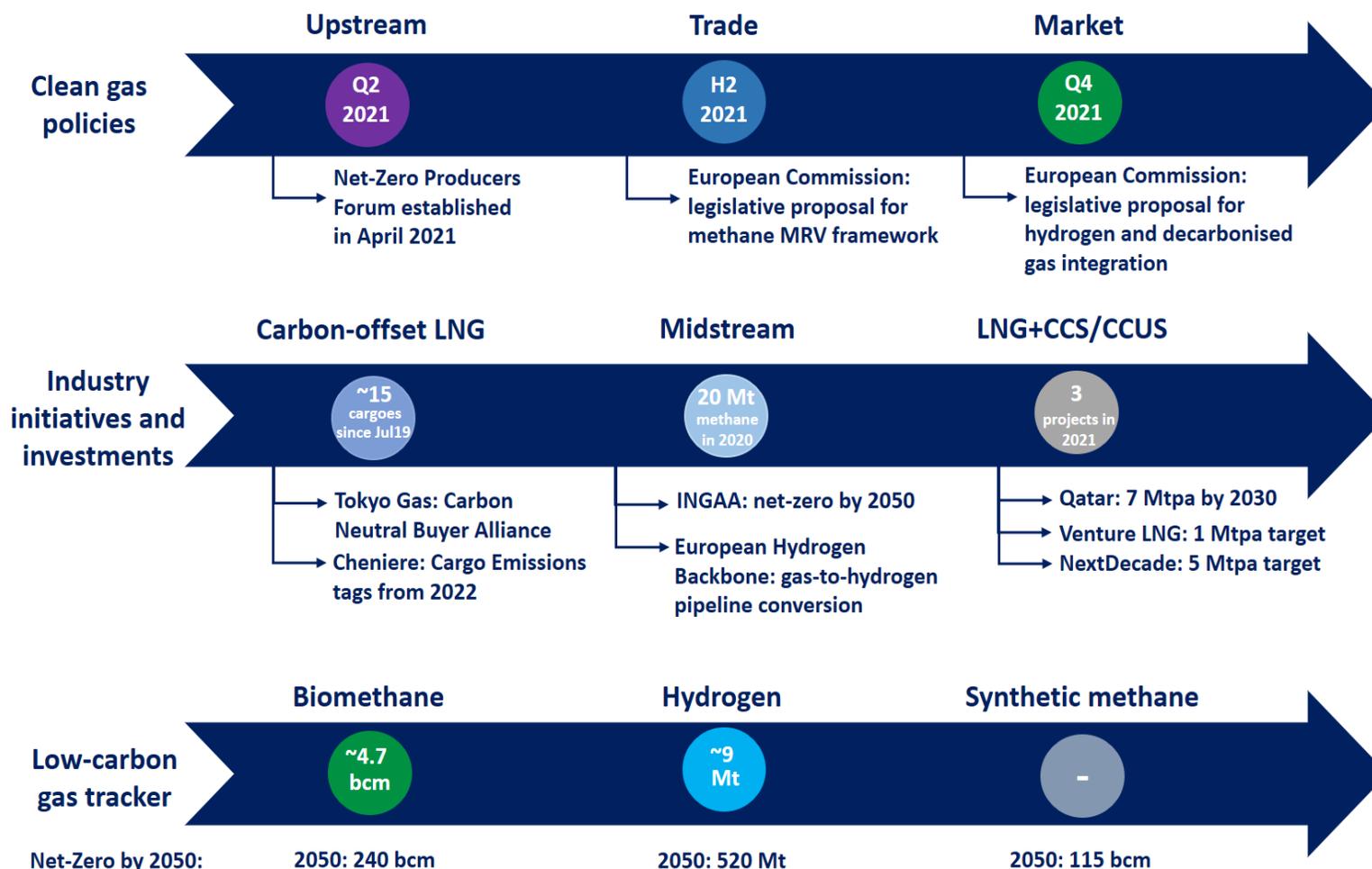
Reducing methane emissions through the gas value chain would be a time- and cost-efficient manner for the gas industry to act on climate change. Around 40% of current methane emissions from oil and gas operations could be avoided at no net cost. A number of jurisdictions are considering the introduction of regulations to tackle the gas industry's GHG emissions and to incentivise their reduction. The European Commission announced the **EU Strategy to reduce methane emissions** in October 2020, to be followed by a set of legislative proposals in 2021. In April 2021 the governments of Canada, Norway, Qatar, Saudi Arabia and the United States

announced the establishment of the **Net-Zero Producers Forum** to develop zero-emission strategies, including methane abatement. Also in April, the US Senate voted in favour of reinstating methane emission regulations. Meanwhile, the industry is developing new commercial proposals, such as **carbon/GHG-offset LNG** and is advancing carbon management technologies associated with LNG production.

The production of **low-carbon gases** (including biomethane, hydrogen and synthetic methane) remains expensive and their deployment will take time; however, the industry, infrastructure and regulation should begin adapting now to **enable their cost-efficient integration into the gas system** in the future. The European Commission is set to publish its **Hydrogen and clean gas package** on the integration of low-carbon gases by the end of 2021. The deployment of **carbon management technologies** (including carbon capture and storage [CCS] and carbon capture, utilisation and storage [CCUS]) could significantly reduce the emissions from the end use of natural gas, in both the industrial and the power sectors, including for the production of gas-based low-carbon hydrogen.

In this section we review recent gas market developments and policy initiatives supporting the reduction of GHG emissions along the gas value chain and the deployment of low-carbon gases.

Principal clean gas policies, industry initiatives and market developments, 2019-2021



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Note: MRV = measurement, reporting and verification.

Sources: IEA analysis based on IEA (2021), [Net Zero by 2050: A Roadmap for the Global Energy Sector](#); industry data, press releases and various news reports.

In the spotlight: Reducing the emission intensity of LNG supply

GHG emissions associated with LNG have come under increased scrutiny from governments and market participants in recent years. Global LNG trade has more than tripled since the beginning of the century, while GHG emissions from LNG supply and end use had reached an estimated 1.25 Gt CO₂-eq (~17% of emissions from natural gas) by 2020.² Expectations of tightening future regulations and emission standards are set to drive investment in GHG emissions reduction measures over the medium term. Meanwhile, emission intensity is emerging as a critical differentiator among LNG projects, as lower emission profiles are seen as a natural hedge against regulatory uncertainties.

Reducing emissions will require effort through the entire value chain. The **upstream segment** (including production, gathering, processing and transmission to the liquefaction plant) typically accounts for 10-25% of total (well-to-use) emissions. **CCS/CCUS-based solutions** can reduce the GHG emission intensity of feedgas supply by capturing and storing reservoir CO₂ during the processing of raw gas. Currently only Snøhvit LNG in **Norway** and Gorgon LNG in **Australia** are using CCS in association with their upstream operations. **Qatar** announced in October 2019 the commissioning of a CO₂ recovery and sequestration facility in

Ras Laffan with a capacity of 2.1 Mtpa. The North Field East LNG project is set to be developed in association with a CCS facility, integrated into the wider CCS scheme in Ras Laffan.

Qatar Petroleum's sustainability strategy states that the company aims to capture more than 7 Mtpa of CO₂ emissions by 2030.

Russia's Novatek is currently investigating the potential to develop CCS-based solutions to reduce the carbon intensity of its operations associated with LNG production. The company is targeting a final investment decision (FID) by 2022. BP is considering the development of the Ubadari field in **Indonesia** in association with a CCS project to supply Tangguh LNG. Besides CCS, the emission intensity of feedgas supply can be reduced through the mitigation of methane leaks/venting and the electrification of compressor stations along the transmission system.

The **liquefaction process** itself accounts typically for 6-10% of LNG's overall emissions. Using electricity from **renewable sources** can significantly reduce emissions associated with LNG plant operations. **LNG Canada** will rely on hydropower for all of its auxiliary power needs. **Qatar Petroleum's** sustainability strategy stipulates the addition of more than 4 GW of renewable (mainly solar) power capacity to its portfolio by 2030, partly to supply

² Assuming that life-cycle emissions of a conventional LNG cargo (~175 000 m³) translate into around 250 000 t CO₂-eq.

electric power to the North Field East LNG project. The use of **electric drives** instead of gas turbines to power the liquefaction compressors can significantly improve the environmental performance of the LNG plant, provided that electricity originates from low-carbon sources. **CCS-based solutions** can be applied directly at the liquefaction plant level. NextDecade announced in March 2021 that its yet-to-be-sanctioned **Rio Grande LNG project** in the United States would be equipped with a 5 Mtpa CCS unit, enabling it to reduce its permitted carbon emissions by more than 90%. Venture Global LNG plans to capture and sequester ~1 Mtpa from its Calcasieu Pass and future LNG projects.

Shipping typically accounts for 5-10% of total emissions, largely depending on the vessel's propulsion system, boil-off rate, speed and distance travelled. Better fuel efficiency and enhanced boil-off management systems can reduce the emission intensity of LNG shipping. The share of less-efficient carriers with steam turbine propulsion systems dropped from over 50% of the fleet in 2015 to 38% in 2020, while the share of vessels with **ME-GI** and **XFD** propulsion systems (50% higher fuel efficiency compared to steam vessels) rose from 1% to 16% during the same period. Altogether they account for over 85% of the order book.

Regasification represents only a fraction of total emissions, typically 1-3%. Enhanced boil-off recovery, low-carbon electricity sourcing and mitigation of venting/methane leaks can further reduce emissions at the regas plant. The majority of emissions stem from

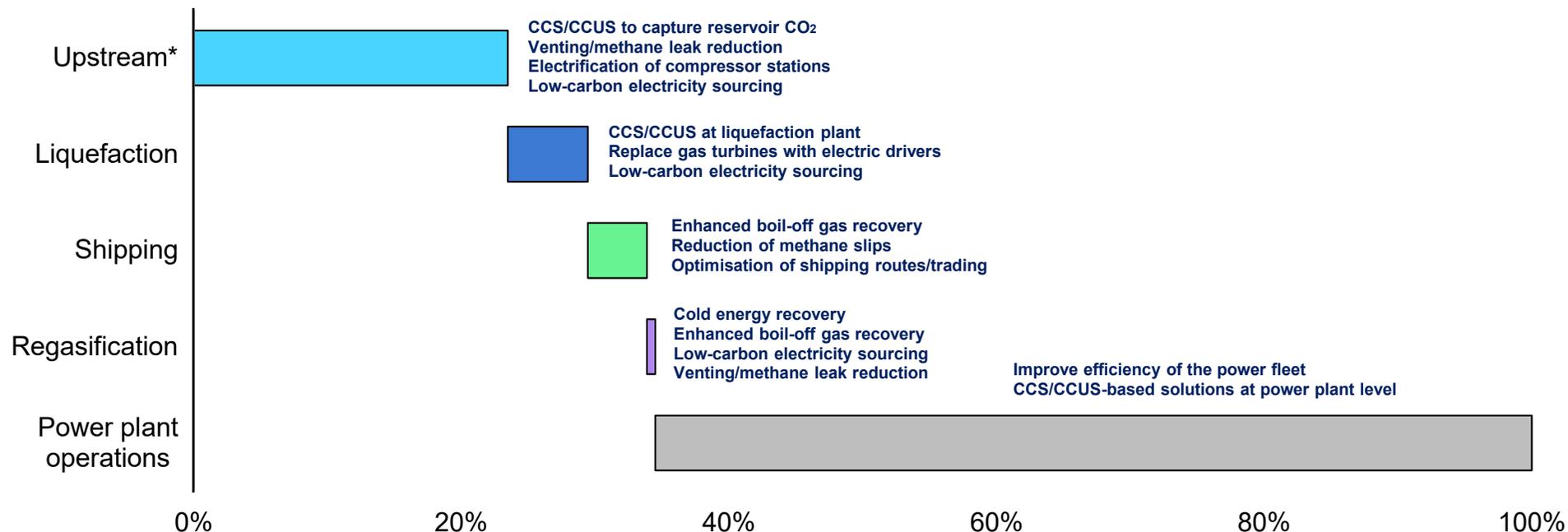
the **end-use combustion** of regasified LNG, typically 60-80% of total emissions. Improving the efficiency of the power fleet and CCS/CCUS-based solutions can reduce end-use emissions.

Carbon/GHG-offset LNG continues to gain traction. Under this mechanism, stakeholders involved in LNG trading can agree to buy **carbon credits to offset GHG emissions** from the LNG value chain. Since July 2019 at least 15 carbon/GHG-offset LNG cargoes have been delivered, of which 12 were to Asian buyers. The **scope of emissions** typically covers all the segments of the value chain, including combustion (well-to-use), whilst a few cargoes have been delivered with partial emission offsets. In more recent deals, emissions have been expressed in CO₂-eq, whilst others explicitly indicated the inclusion of methane emissions.

LNG carbon offset mechanisms would benefit from **greater transparency** and a standardised MRV framework across the industry. The **European Commission** is set to present legislative proposals for a compulsory MRV framework for all energy-related methane emissions in 2021. Singapore's **Pavilion** recently awarded two contracts with obligations to quantify GHG emissions associated with each LNG cargo. **Cheniere** plans to provide GHG emissions data associated with each LNG cargo produced from its US liquefaction facilities, starting from 2022. **Tokyo Gas**, together with 14 other Japanese companies, announced in March 2021 the establishment of a Carbon Neutral LNG Buyers Alliance to promote the use of carbon-neutral LNG.

Reducing emissions will require effort along the entire LNG value chain

Indicative breakdown of life-cycle GHG emissions for US LNG shipped to Europe, showing carbon reduction options



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* Upstream includes natural gas extraction, gathering and boosting, processing and domestic pipeline transport.

Note: GHGs are based on the common mass basis of CO₂-eq using the global warming potential of each gas from the IPCC Fifth Assessment Report (AR5).

Source: IEA analysis based on National Energy Technology Laboratory (2019), [Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 update](#).

Keep counting: Carbon/GHG-offset LNG continues to gain traction

Date	Seller	Buyer	Source	Destination	Volume	Offset scope	Mechanism
July 2019	Shell	Tokyo Gas	QCLNG Australia	Japan	1 cargo	CO ₂ well-to-wheel	Shell project portfolio
July 2019	Shell	GS Energy	QCLNG Australia	Korea	1 cargo	CO ₂ well-to-wheel	Shell project portfolio
July 2019	JERA	-	Das Island UAE	India	1 cargo	CO ₂ end-use combustion	CER
March 2020	Shell	CPC	Sakhalin Russia	Yung-An Taiwan	1 cargo	CO ₂ well-to-wheel	Shell project portfolio
June 2020 (announced)	Shell	CNOOC	-	China	2 cargoes	CO _{2eq} well-to-wheel	Shell project portfolio
October 2020	Total	CNOOC	Ichthys Australia	Dapeng China	1 cargo	CO ₂ well-to-wheel	VCS
November 2020	Shell	CPC	Bonny Island Nigeria	Yung-An Taiwan	1 cargo	CO _{2eq} well-to-wheel	Shell project portfolio
March 2021	Mitsui	Hokkaido Gas	Sakhalin-II Russia	Ishikari Japan	1 cargo	CO ₂ well-to-wheel	Mitsui portfolio
March 2021	Gazprom	Shell	YAMAL LNG Russia	Dragon United Kingdom	1 cargo	GHG well-to-wheel	VCS
March 2021	RWE	Posco	Pluto LNG Australia	Gwangyang Korea	1 cargo	CO ₂ well-to-tank	VER
April 2021	Diamond Gas	Toho Gas	Cameron LNG United States	Chita Japan	1 cargo	-	Carbon credits
April 2021		Pavilion Energy	Corpus Christi United States	Jurong Singapore	1 cargo	CO ₂ well-to-tank	VCS+CCB
April 2021	Cheniere	Shell	Sabine Pass United States	United Kingdom	1 cargo	GHG well-to-wheel	Shell project portfolio
June 2021	Oman LNG	Shell	Qalhat Oman	-	1 cargo	CO ₂ well-to-wheel	Verified Nature-Based Carbon Credits

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Notes: CER = Certified Emission Reduction; VCS = Verified Carbon Standard; VER = Verified Emission Reduction; CCB = Community and Biodiversity Standard.

Sources: IEA analysis based on companies' press releases and various news reports

Biomethane continued to grow strongly in 2020...

In contrast with natural gas, biomethane production continued to grow strongly in 2020. Preliminary data suggests that it expanded by 18% last year to reach 4.7 bcm, a tenfold increase since 2010. This has been largely driven by the European Union and the United States where biomethane production benefits from a wide range of policies and subsidies.

The **United States** emerged as the world's largest biomethane producer in 2019 when it surpassed Germany. The country's biomethane output rose more than fivefold from 2010 to reach over 1 bcm in 2019. Over 80% of biomethane production units have grid injection capability. According to the Coalition for Renewable Natural Gas, transport accounted for over 80% of biomethane end use in 2019. Over half of producing units were using landfill gas as a feedstock at the end of 2019. Preliminary data indicates that biomethane production capacity increased by 30% y-o-y in 2020, driven by projects using agricultural waste as a feedstock.

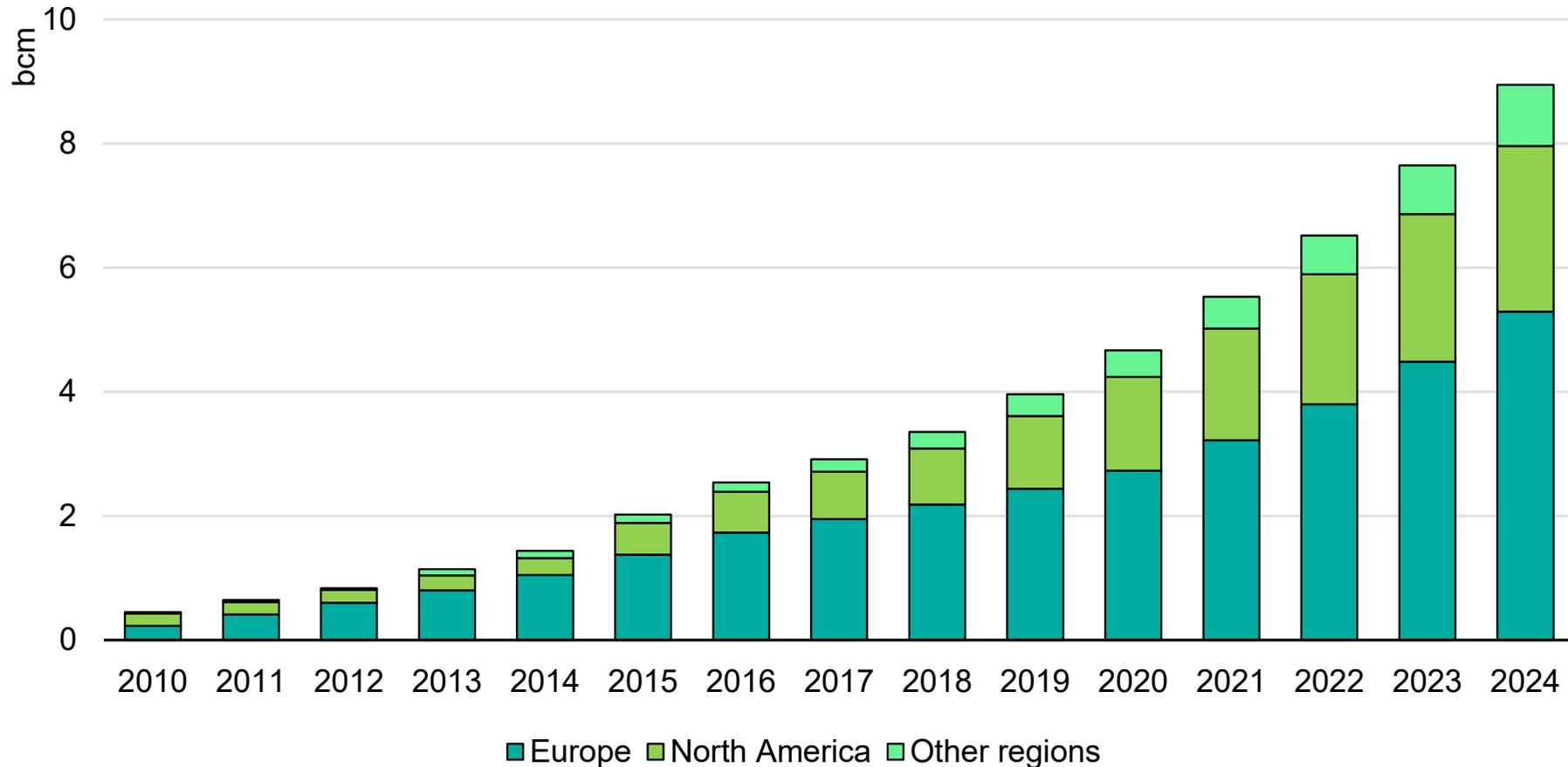
In **Europe**, biomethane production rose more than tenfold from 2010 to reach almost 2.5 bcm in 2019. It is estimated that close to 80% of biomethane is injected into gas transmission and distribution networks. Preliminary data suggests that biomethane grew strongly in some of the key European markets in 2020. Biomethane injection into **Denmark's** transmission system rose by close to 50% y-o-y to

account for ~17% of total gas supply in 2020. The share of biomethane reached a daily record of 40% in July 2020. In **France**, biomethane injected into the distribution network rose by 82% to reach 0.15 bcm. In **Germany**, which accounts for 40% of Europe's output, biomethane production capacity rose by a moderate 5% in 2020 according to data from Biogas Partner.

Biomethane production is **expected to grow** at an average rate of 18% per year through the forecast period to reach ~9 bcm by 2024. This growth will be largely driven by Europe and North America, where biomethane is supported through various subsidy schemes and is benefiting from well-developed and interconnected gas grids. France's multiannual energy plan foresees biomethane grid injection at 14-22 TWh by 2028, whilst Denmark's transmission system operator expects biomethane to cover over 60% of Danish gas consumption by 2030. The relatively high production costs of biomethane remain a challenge over the medium term. The **right set of policies** could provide additional upside potential for biomethane development, especially in the rapidly growing markets of the Asia Pacific region. **China** and **India** announced ambitious targets recently, which could support global biomethane production reaching 28 bcm by 2024. For an in-depth review of the biomethane market, please refer to the IEA World Energy Outlook special report, [Outlook for Biogas and Biomethane](#).

...and is expected to almost double by 2024

Biomethane production by region, 2010-2024



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Sources: IEA analysis based on Argonne National Laboratory (2020), [Database of Renewable Natural Gas \(RNG\) Projects: 2020 Update](#); Biogas Partner (2021), [Biogaspartner Einspeiseatlas Deutschland](#); Cedigaz (2021), [Global Biomethane Database](#); Energinet (2021), [Energi Data Service](#); GRDF (2021), [Production annuelle de biométhane par site d'injection](#).

Beyond biomethane: Hydrogen and synthetic methane make inroads on the gas grid

The existing natural gas infrastructure can facilitate the deployment of low-carbon gases beyond biomethane, including low-carbon hydrogen and synthetic methane. **Blending hydrogen** in gas networks can provide a transitional solution until dedicated hydrogen networks are developed, whilst in the longer term parts of the **gas infrastructure can be converted to hydrogen**, resulting in substantial cost savings.

Due to its chemical properties, hydrogen can lead to the **embrittlement** of steel pipelines, i.e. the possibility of fissure in pipelines as a result of the reaction of H₂ with the steel they are made from. Depending on the characteristics of the gas transmission system, hydrogen can be blended at rates between 2% and 10% by volume without requiring substantial retrofitting. The **hydrogen tolerance** of polymer-based distribution networks is typically greater, allowing blending of hydrogen up to 20% by volume. The **grid injection capacity** of low-carbon hydrogen projects has more than quadrupled since 2013; however, volumes remain limited (1-2% of low-carbon hydrogen production fed into the grid). The estimated grid injection capacity of low-carbon hydrogen projects reached 40 mcm in 2020, almost all of which is in Europe and dominated by Germany. Several **pilot blending projects** have been undertaken in recent years, including in France (GRHYD), Italy (in Contursi Terme) and the United Kingdom (HyDeploy).

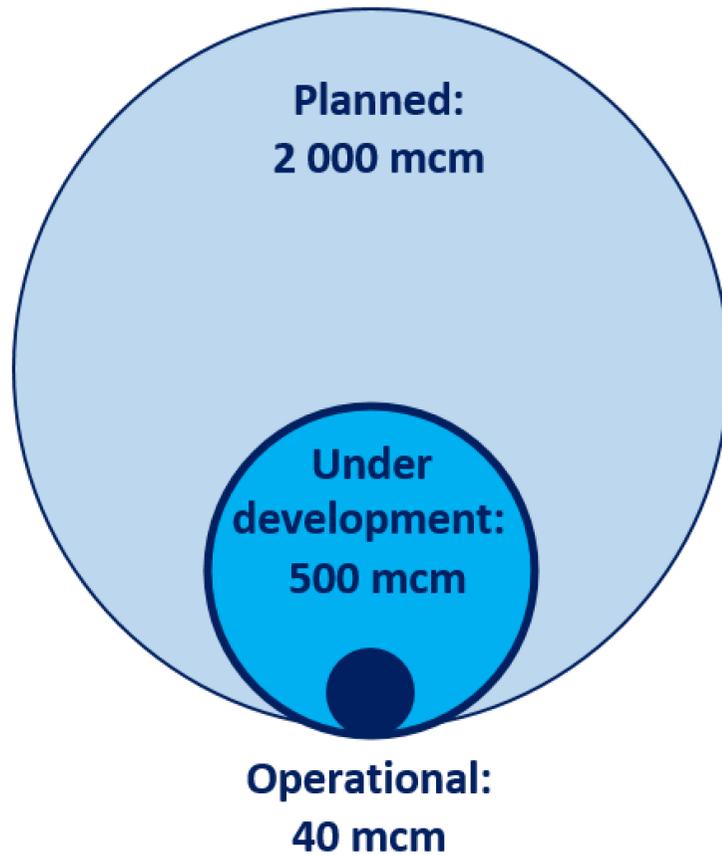
Australia's first pilot project was launched in May 2021. Canada and California are set to launch their first pilot projects later in 2021. Based on projects that have reached FID or are under construction, hydrogen blending capacity could increase more than tenfold by 2024, largely driven by Europe. Supporting policies and regulatory mechanisms, including guarantees of origin, could further facilitate the development of hydrogen trading and transport via pipeline.

Gas-to-hydrogen pipeline conversions are expected to gradually take off in the medium term, mainly in Europe. Gasunie converted the first gas pipeline fully to hydrogen in the Netherlands in November 2018 and several pilot projects are under consideration in Germany and France. Based on project submissions from European gas network operators, ENTSOG assessed in its latest Ten-Year Network Development Plan that some 500 km of gas pipelines could be converted to hydrogen by 2024, although these projects have yet to be confirmed.

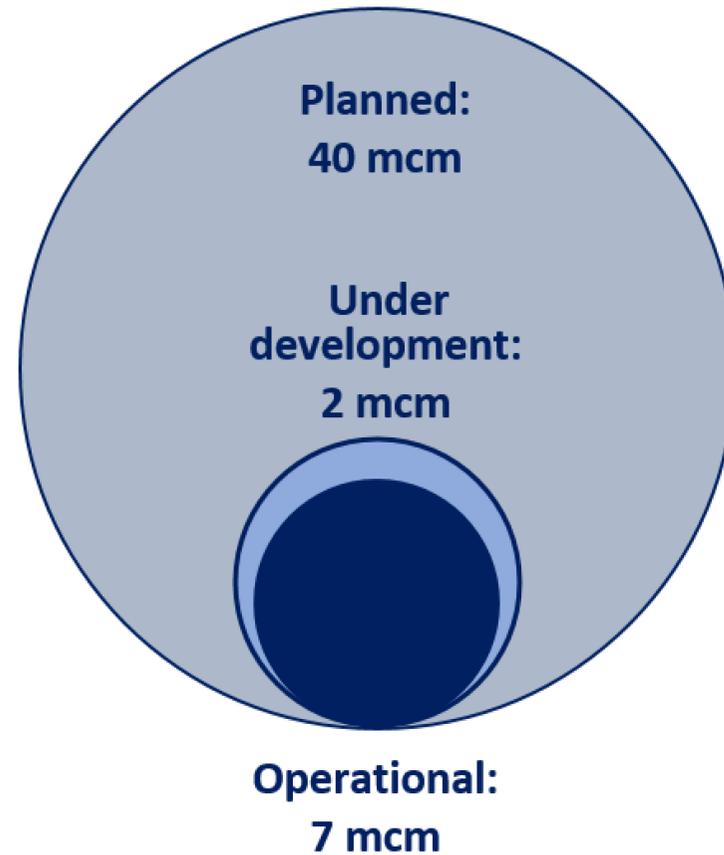
Synthetic methane (SNG) is struggling to take off. While SNG is perfectly interchangeable with natural gas, its production would require the development of a separate CO₂ value chain. Hydrogen-based SNG production capacity was less than 10 mcm in 2020 – almost all of which is in Europe and connected to gas grids. Only a few projects are currently under development, indicating potential stagnation in SNG production in the medium term.

Hydrogen blending capacity is set to increase tenfold, while syngas stagnates

Hydrogen grid injection capacity
2020-2024



Synthetic methane grid injection capacity
2020-2024



Source: analysis based on IEA [Hydrogen Projects Database](#).

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Fit for 55: Can the surge in European carbon prices create an alliance between natural gas, CCS and low-carbon hydrogen?

Carbon management solutions, such as CCS/CCUS, can significantly reduce the emissions from conventional hydrogen production, including from steam methane reforming (SMR). Fossil fuel-based hydrogen currently accounts for over 98% of global hydrogen production, resulting in over 900 Mt CO₂ emissions per year globally, of which about 70-100 Mt are in the European Union.

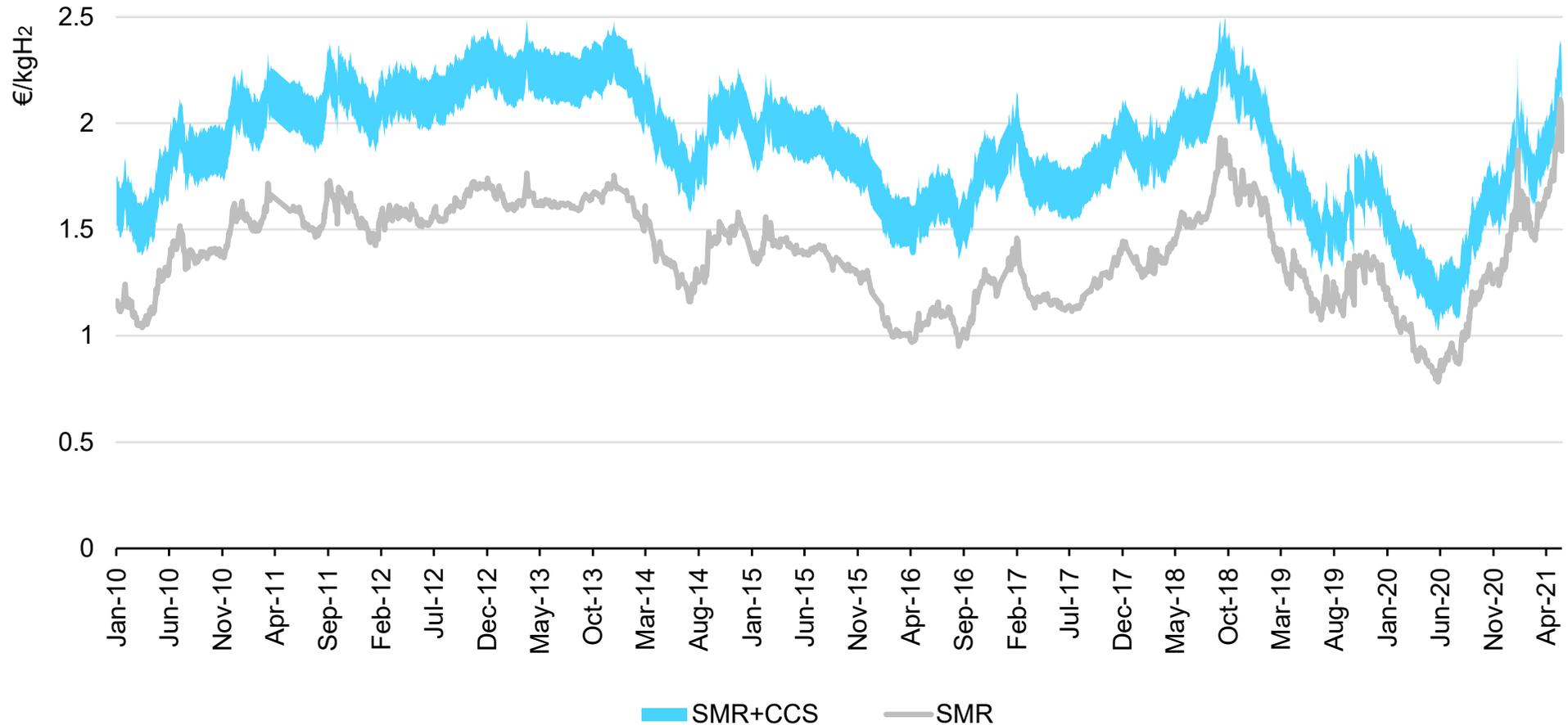
SMR+CCS accounts for the majority of global low-carbon hydrogen production, albeit on a tiny scale. The first commercial-scale SMR facility equipped with CCS technology started operations in 2013 at **Air Product's** facilities in Port Arthur, Texas, with a carbon capture capacity of 1 Mtpa. It has been followed by **Shell's Quest Project** in Canada (commissioned in 2015 with 1 Mtpa capacity) and the **Tomakomai CCS Demonstration Project** in Japan (operating between 2016 and 2019 and capturing ~0.3 Mt CO₂). In Europe, **Shell's Pernis refinery** in the Rotterdam area captures carbon emissions from hydrogen production as part of the OPAC project, which reuses CO₂ for enhanced crop growth. In 2015 **Air Liquide** equipped its Port-Jérôme hydrogen production facility in France with a cryogenic CO₂ purification system (~0.1 Mtpa). Progress on new SMR+CCS project development has been meagre since 2016 due to a combination of poor project economics and often challenging regulatory environments.

The recent surge in European carbon prices is rapidly improving the cost-competitive position of low-carbon hydrogen produced via SMR+CCS. EU ETS prices rose from an average of EUR 12/t CO₂-eq during the last decade to over EUR 55/t CO₂-eq in May 2021. This has been partly driven by the agreement reached in December 2020 to raise the 2030 emission reduction target from 40% to 55% and its anticipated impact on the EU ETS. The new target will be underpinned by the **"Fit for 55" legislative package** to be presented in summer 2021. Consequently, the cost differential between SMR and SMR+CCS decreased, which in turn, could support additional investment in CCS in the medium term.

Several large-scale **SMR+CCS/CCUS projects** are currently under development in Europe. In **Sweden**, a pilot project at the hydrogen gas plant of the Lysekil refinery started operations in May 2020. The target is to scale up CCS capacity to 0.5 Mtpa by 2025. In **the Netherlands**, the 2.5 Mtpa Porthos CCS project is expected to take FID in 2022 and start operations in 2024. Porthos would receive CO₂ from various sources, including from hydrogen production. In **the United Kingdom** several projects are undergoing feasibility studies, potentially adding 20 Mtpa of CCS capacity either entirely or partly associated with hydrogen production.

The cost spread between conventional and low-carbon gas-based hydrogen is tightening

Production costs of hydrogen via SMR vs SMR+CCS in the European Union, 2010-2021



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Notes: Capex: SMR without CCUS = EUR 910/kW H₂; SMR with CCUS = EUR 1 580-2 100/kW H₂; gas price = TTF; carbon price: EU ETS.

Source: Bloomberg (2021), TTF and EUA prices.

Trade

LNG remains the main driver of global gas trade after 2021, though growth is slower than before

Global gas trade – including both LNG and long-distance pipeline – is expected to expand more quickly than demand growth over the forecast period, principally driven by LNG expansion.

Global LNG trade is expected to expand by 16% between 2020 and 2024, driven by continued growth in Asia. The annual average growth rate of 3.8% over the forecast period is a far cry from the double-digit rates observed between 2016 and 2019, but represents a recovery from 2020's low rate of 1.4%. Investment in new liquefaction projects stalled in 2020 due to the Covid-19 pandemic, but the growth in gas demand is also slower compared to pre-Covid levels. In the 2021-2024 period incremental LNG demand growth only marginally exceeds liquefaction capacity additions, which limits the risk of a structurally tight LNG market in the next three years. China, India and emerging Asian markets account for most of the future growth in LNG imports. Europe remains the main importing market after Asia, keeping its role as the balancing market for LNG. On the supply side, North America accounts for more than 70% of the growth as the primary engine of export development.

Long-distance pipeline trade³ is expected to expand by over one-fifth between 2020 and 2024, driven by a strong recovery in

2021 and by the rising import requirements of Europe and China through the rest of the forecast period. Following a steep drop of 10% in 2020, **European pipeline imports** are set to recover to close to their 2019 levels in 2021, and increase at an average growth rate of 2% between 2021 and 2024, largely driven by the region's rapidly declining domestic production. This will be met by a combination of higher Norwegian deliveries, the ramp-up of Azerbaijani flows via the TAP pipeline to 10 bcm/y and higher Russian pipeline exports.

Similarly, **China's pipeline imports** are expected to expand by more than two-thirds between 2020 and 2024. This growth will be largely dominated by the ramp-up of Russian export flows via the Power of Siberia pipeline, which are set to reach 30 bcm/y by the end of our forecast. In North America, US net imports from Canada are expected to oscillate in the range of 50-55 bcm/y during the forecast period, and play a critical role in meeting seasonal demand swings. Additional pipeline capacity between the United States and Mexico will allow US exports to Mexico to expand by close to 10% between 2020 and 2024.

³ For the purpose of this analysis, long-distance pipeline trade includes Europe's pipeline imports (including deliveries from Norway), North American net pipeline trade and China's pipeline imports.

LNG import growth is dominated by Asia; LNG supply growth is led by North America and Russia

Global LNG trade is expected to reach 561 bcm by 2024, an increase of 16% compared to 2020.

LNG import growth is predominantly driven by the Asia Pacific region, where demand for LNG is set to rise by 26% (89 bcm) between 2020 and 2024. The region's share of global LNG imports is projected to increase from 71% in 2020 to 77% in 2024. China alone is expected to account for nearly 30% of global LNG demand growth in the 2020-2024 period, and is on track to become the world's largest importer of LNG on a yearly basis in 2021 or 2022. India is responsible for more than 20% of the net increase globally; import growth is expected to re-accelerate from 2022 as the post-Covid gas demand recovery coincides with a slowdown in production growth. Emerging Asian countries are projected to double their LNG imports between 2020 and 2024, driven by strong demand growth and the decline of domestic production. Japan's LNG imports are expected to gradually decrease, while Korea's LNG demand continues to expand over the forecast period.

European LNG imports reached record levels in 2019 and 2020, and are expected to decrease and oscillate around 90 bcm in the 2021-2024 period as the region continues to play the role of swing consumer to balance the market. Europe's share of total LNG imports is expected to decrease from 23% in 2020 to 16% in 2024. LNG imports into Africa (led by Ghana, Senegal and South Africa)

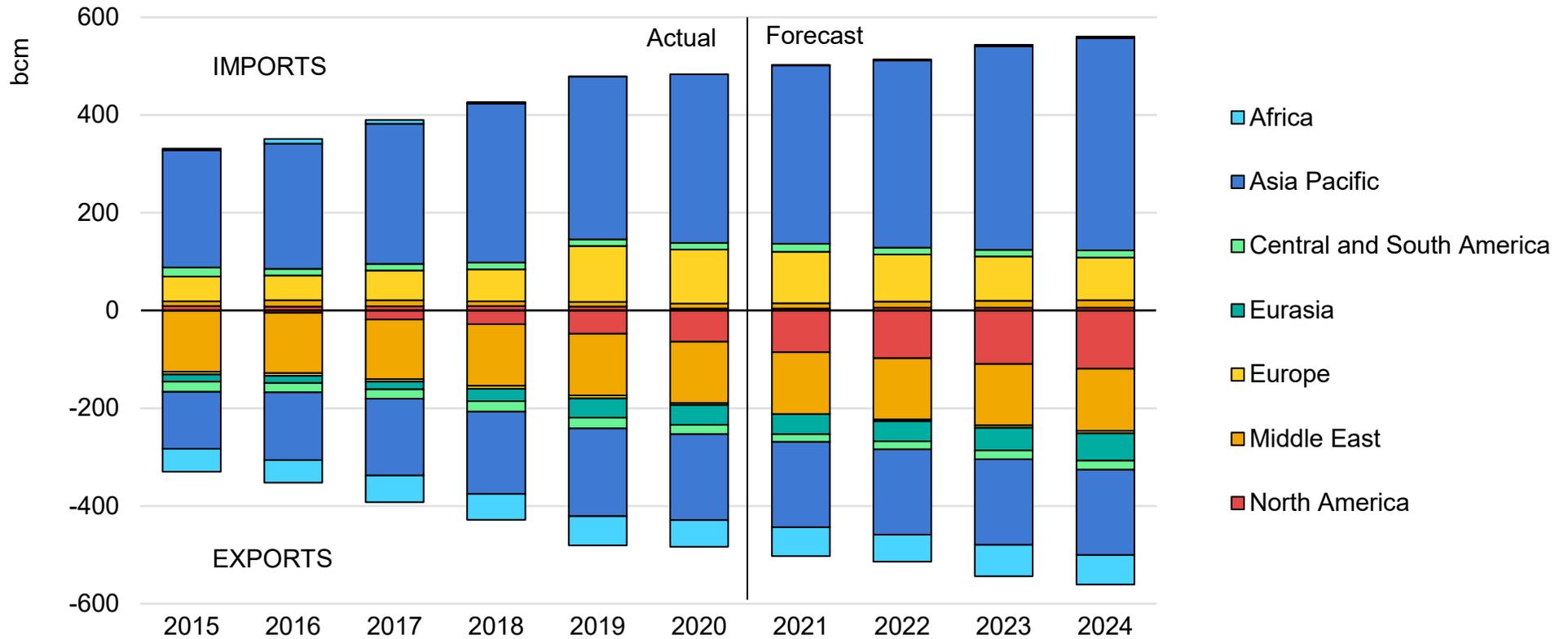
and the Middle East (driven by Kuwait) also register small increases throughout the forecast period.

LNG export growth is led by North America, which is projected to boost production by 86% (55 bcm) between 2020 and 2024. This strong growth is driven by already sanctioned liquefaction projects, albeit some of these will not start production (or reach full capacity) within the forecast period. Russia is the second-biggest source of LNG supply growth, with a 38% increase between 2020 and 2024. Export growth from Africa is limited due to the delay of the Mozambique LNG project. Output from the Middle East remains stable through to 2024, as Qatar's expansion project is not expected to ramp up before 2025. Exports from Asia Pacific and South America are on course for a slight decline between 2020 and 2024.

The utilisation of available liquefaction capacity is expected to gradually recover from the low point of 88% in 2020, but remains slightly below the 2019 level of 93% at the end of the forecast period. Therefore, the risk of persistent supply shortfalls and a structurally tight LNG market remains limited throughout the forecast period. However, periods of temporary tightness may occur – and lead to dramatic price swings – as was illustrated by the Northeast Asian energy crisis in January 2021, when a combination of surging demand, supply constraints and a lack of storage pushed spot LNG prices to record-high levels for a brief period.

Global LNG trade reaches more than 560 bcm by 2024

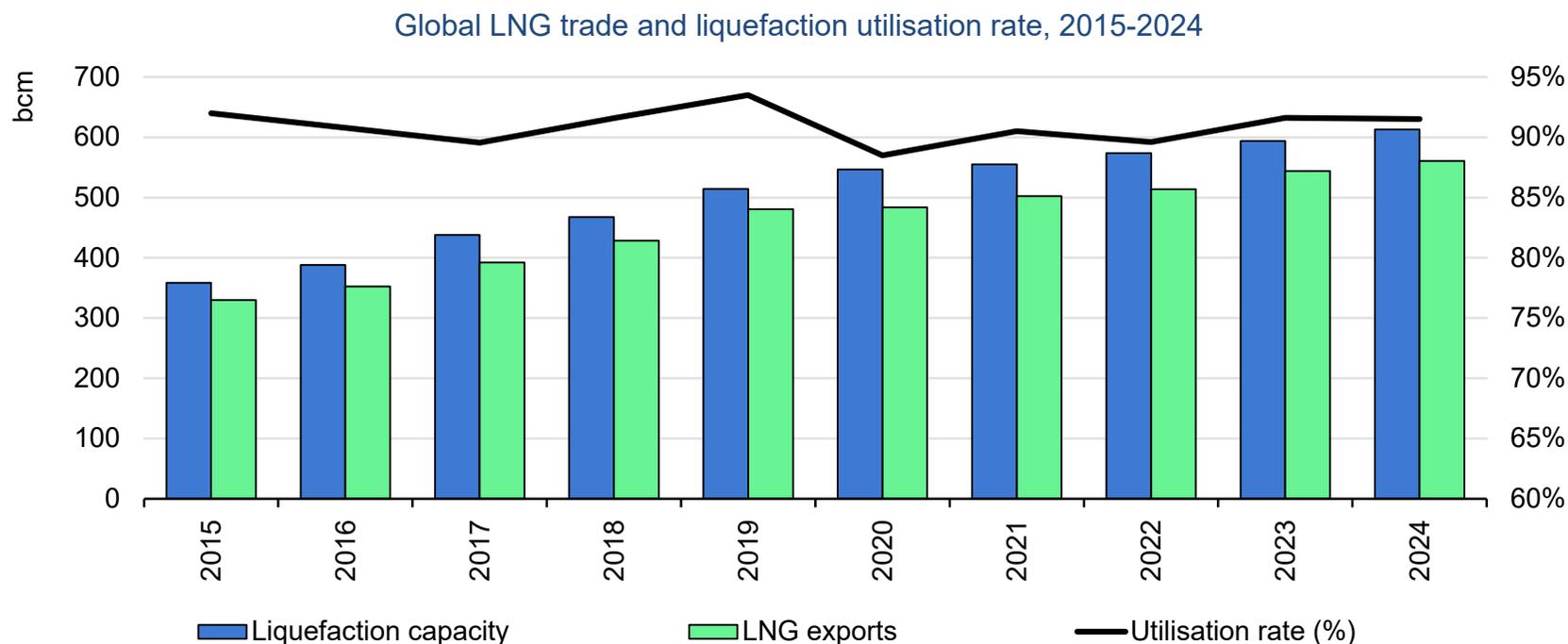
World LNG imports and exports by region, 2015-2024



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Source: IEA analysis based on ICIS (2021), [ICIS LNG Edge](#).

LNG trade growth only marginally exceeds capacity expansions, leading to a slow increase in utilisation rates



Note: Liquefaction capacity and utilisation rate are based on assessed available capacity – adjusted to take into account the assumption that several liquefaction plants will remain offline or run below their nameplate capacity because of technical issues, lack of feed gas, weather-related issues or security risks.

Source: IEA analysis based on ICIS (2021), [ICIS LNG Edge](#).

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LNG investment: Tentative post-Covid recovery underway

True to the cyclical nature of the LNG business, the pace of FIDs on new LNG capacity have fluctuated wildly in recent years. In 2019 developers approved nearly 100 bcm of new capacity (worth USD 65 billion), an all-time high far exceeding any previous records. This was followed by a near collapse of activity in 2020, with only one project (the 4 bcm Energía Costa Azul plant in Mexico) taking FID as the Covid-19 crisis brought new investments to a standstill. 2021 has seen a sharp rebound of sanctioned capacity, but so far this has been solely driven by Qatar's 45 bcm expansion project, the largest FID in the history of LNG. Notwithstanding the wide fluctuations in project approvals in recent years, the spending profile associated with already sanctioned projects is expected to recover steadily from a low point of USD 14 billion in 2020 to USD 30 billion in 2024. Annual spend on liquefaction projects is expected to average USD 24 billion in the 2020-2024 period, 13% lower than in the preceding five years.

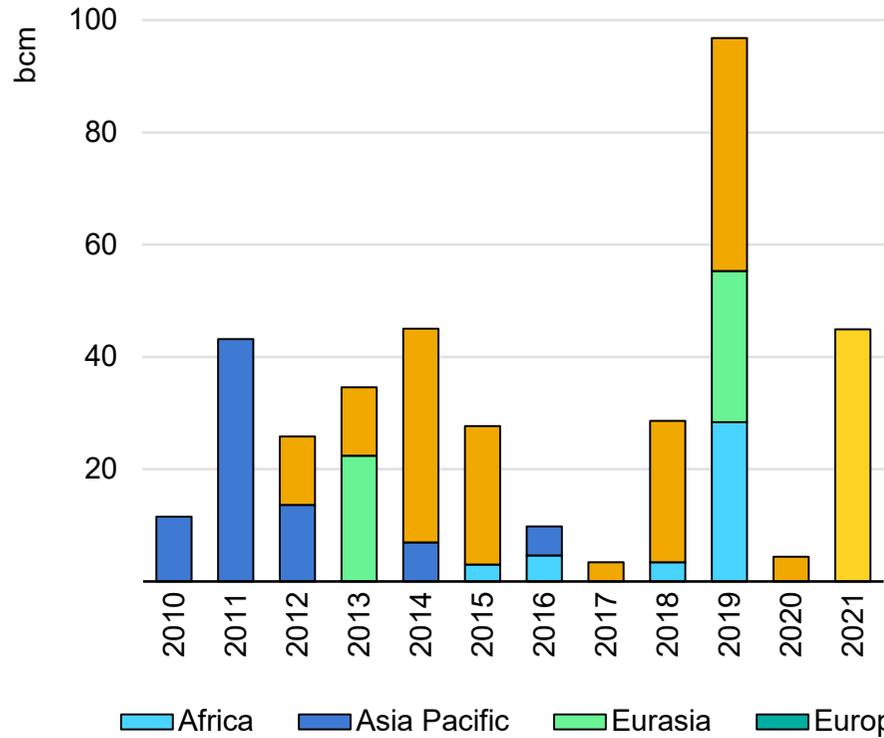
The previous wave of LNG FIDs in 2018-2019 was led by the major portfolio players, which participated as offtakers, equity partners or developers in all of the liquefaction projects sanctioned in that period. Confidence in long-term market growth – combined with the widespread use of the equity-lifting structure – enabled projects to reach FID without having to secure end-use demand for equity LNG volumes in advance. This trend is unlikely to be repeated on the

scale seen in 2018-2019. The appetite for additional uncommitted LNG among portfolio players could be limited by the overhang of such volumes from the previous cycle, which will be compounded by the expiry of nearly 200 bcm of long-term LNG contracts between 2021 and 2025. Capex cuts and write-downs on LNG-related assets – combined with greater uncertainty about future LNG demand and investor pressure to limit fossil fuel investment – could present further headwinds to another investment wave led by international oil companies in the foreseeable future. Independent developer-led projects (especially in North America) also suffered setbacks, saw their FID target dates pushed back and in some cases were outright cancelled in the past 18 months as buyer appetite for new long-term LNG contracts dried up during the pandemic.

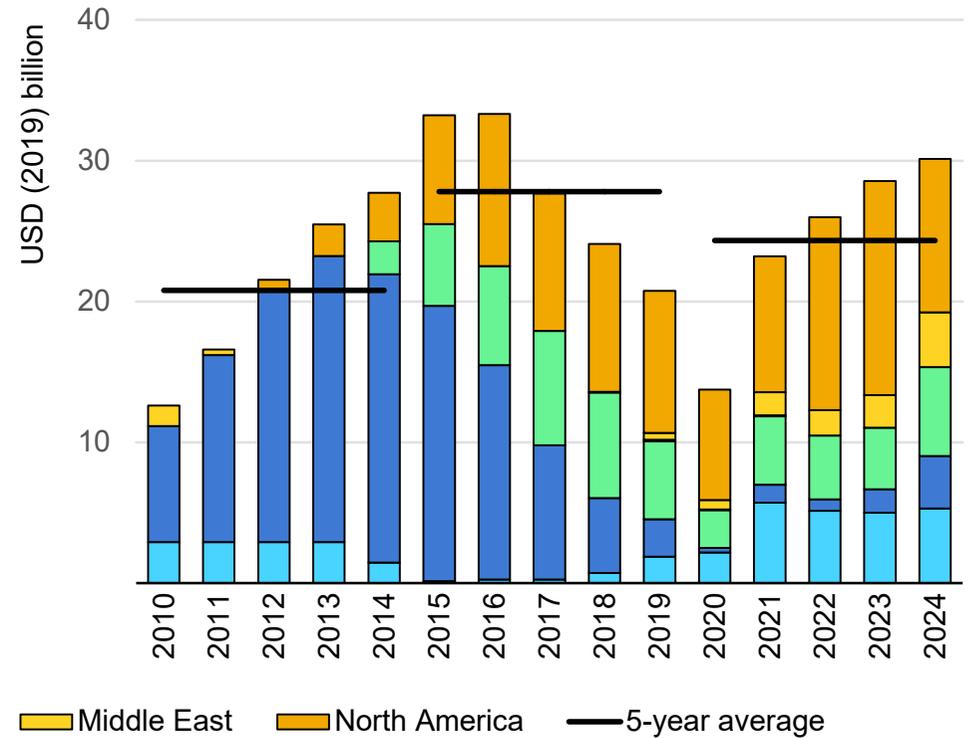
Nonetheless, market developments in H1 2021 indicate that there may well be room for further investments in 2021 and beyond. In the month of May 2021 alone, North American pre-FID projects secured two binding long-term sales purchase agreements with offtakers, more than in 2020 as a whole. Qatar Petroleum announced that it is planning to approve the second 22 bcm phase of its expansion project by early 2022, and that the company is evaluating additional capacity increases beyond the six-train development envisaged by 2027.

LNG investment: 2018-2019 wave and 2021 recovery drives sustained capex growth to 2024

FIDs for new LNG liquefaction capacity, 2010-2021



Investment in new LNG liquefaction capacity, 2010-2024



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LNG shipping: Robust order book mitigates risk of capacity shortfall in the medium term

The LNG shipping market has been characterised by substantial volatility and periods of seasonal tightness in recent years. Daily spot LNG vessel charter rates have spiked above USD 100 000 in each of the last three northern hemisphere winters, and hit an all-time high of well above USD 200 000 during the unexpected cold spell in northeast Asia in January 2021 – amid physical shortages of available shipping capacity. Expectations of growing shipping demand are supported by the lengthening of shipping routes on the ramp-up of export capacity from the United States and Russia, as well as by the latest wave of LNG FIDs in 2018-2019, with the bulk of sanctioned capacity entering the market in the 2021-2024 period.

These fundamental drivers have incentivised fleet operators to maintain a robust order book for LNG vessels. At the end of 2020 as many as 150 LNG vessels were on order, which represents a quarter of the active carrier fleet (excluding FSRUs). Of these, nearly 60 ships are scheduled for delivery in 2021, adding close to 10 million m³ of capacity, an 11% y-o-y increase. The market entry of the remaining 15 million m³ of capacity on order is spread across the period between 2022 and 2025. The vast majority (98%) of the order book is so-called *Neopanamax* vessels ranging between 170 000 m³ and 180 000 m³ in size, which can navigate the new locks on the Panama Canal. One of the largest contingents of ships

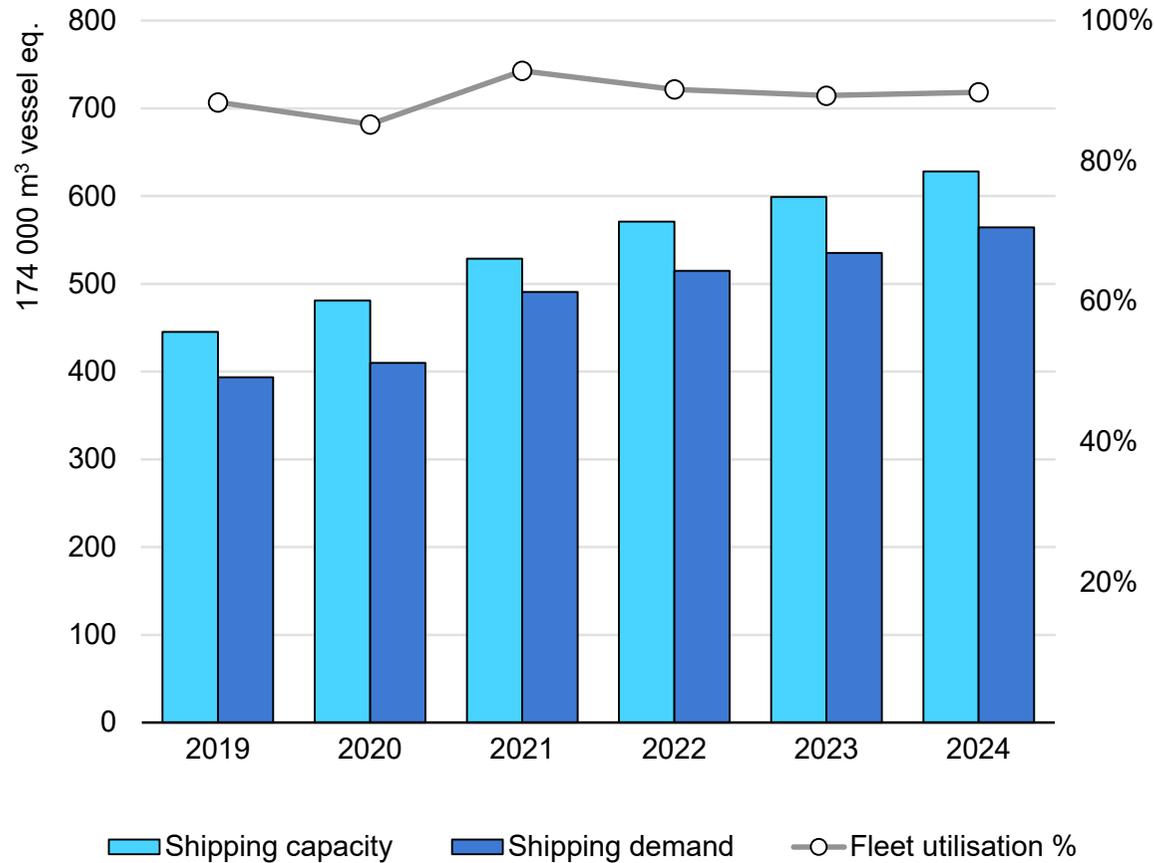
(21 vessels in total) are Arc7 class carriers dedicated to serve the Arctic LNG 2 project in Russia.

In addition to the substantial capacity already on order, Qatar Petroleum announced in 2020 that it had booked slots for nearly 120 newbuild vessels at Chinese and Korean shipyards. These units – if converted into firm orders – are only expected to enter the market after 2024, however, as the vessels are primarily intended to serve Qatar's recently approved 45 bcm expansion project and the Golden Pass LNG project on the US Gulf Coast, which is being jointly developed by ExxonMobil and Qatar Petroleum. Both plants are scheduled to ramp up production from 2025.

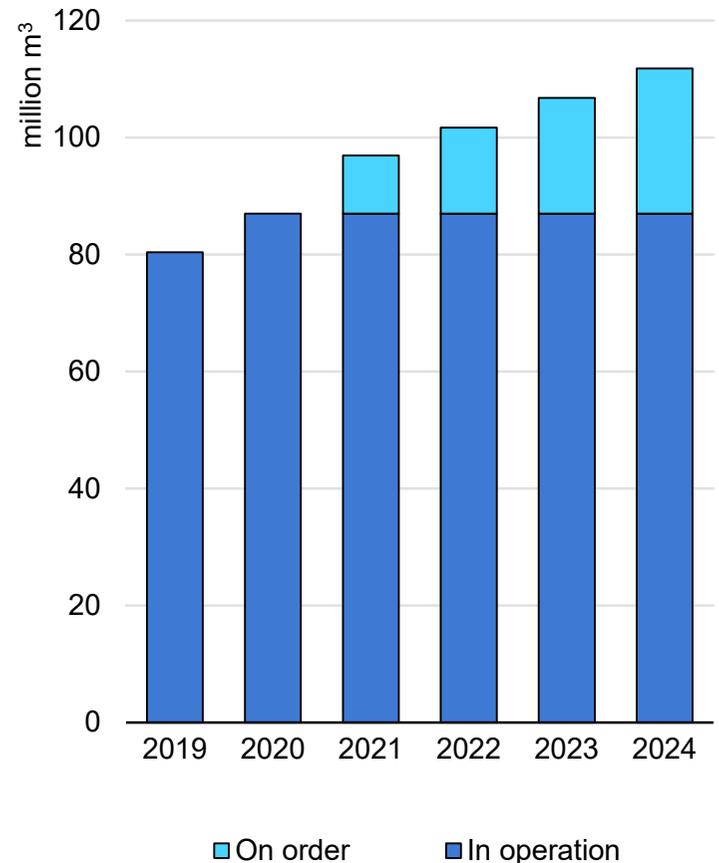
Global LNG shipping demand is expected to rise by 38% in the 2020-2024 period. Despite this strong increase, we estimate that the 31% expansion in shipping capacity is sufficient to maintain fleet utilisation at around 90% through to 2024, if no retirements occur. If Qatar's anticipated large-scale shipbuilding programme is fully executed, the risk of capacity shortfalls could be limited even beyond the end of our forecast horizon. Such long-term visibility is unusual in the LNG shipping market, where the investment cycle is relatively short, approximately two to three years. However, as projects in Russia and Qatar in particular take a more strategic approach to vessel procurement, the visibility horizon can hence be expected to lengthen in the years ahead.

LNG shipping: Capacity growth helps keep the market in balance through to 2024

LNG shipping capacity, demand and fleet utilisation, 2019-2024



Evolution of LNG shipping capacity, 2019-2024



Sources: IEA analysis based on GIIGNL (2021), [Annual Report](#); ICIS (2021), [ICIS LNG Edge](#).

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Pipeline trade is set to expand by over one-fifth by 2024

Following a record drop in 2020, long-distance pipeline trade⁴ is expected to expand by over one-fifth (or 100 bcm) during the forecast period, meeting close to 30% of incremental demand between 2020 and 2024. This is driven by a strong recovery in 2021 and supported through the rest of the forecast by the rising import requirements of Europe and China.

Europe's net pipeline imports declined by over 10% in 2020, owing to the steep drop in pipeline flows from Russia, North Africa and Iran. Norway's pipeline deliveries remained resilient, while Azeri exports increased by over 20% y-o-y. Pipeline flows are expected to recover to over their 2019 levels in 2021, driven by a strong increase in Russian and North African imports (up by 18% and 130% y-o-y respectively in H1 2021) and the initial ramp-up of Azeri flows to Italy and Southeast Europe through the TAP pipeline. Approximately 3 bcm of natural gas has been exported via TAP in H1 2021 and flows are set to exceed 5 bcm in 2021 as a whole. Norwegian deliveries are expected to remain close to levels seen 2020 due to a heavy maintenance schedule on the Norwegian continental shelf and pipeline system during Q2-Q3 2021.

Europe's pipeline imports are expected to expand by 6% between 2021 and 2024, primarily driven by the region's rapidly declining

domestic production. **Norwegian deliveries** to the rest of the continent are set to recover to above their 2019 levels and hover between 110 bcm/y and 115 bcm/y for the rest of the forecast period. The **Baltic Pipe** is expected to be commissioned by October 2022 and will provide Norway with the option to supply 10 bcm/y of natural gas to Denmark and Poland, with Poland's PGNIG having already booked over 8 bcm/y capacity. **Azeri pipeline flows** through the **TAP pipeline** – commissioned in January 2021 – are expected to ramp up to their 10 bcm/y nameplate capacity in the next two years, providing additional supply diversity to the Italian and Southeast European gas markets. **North African exports** to Italy and the Iberian gas markets are expected to average close to 30 bcm/y during the forecast period. In May 2021 Algeria's Sonatrach commissioned a “**loop**” between its **GME and Medgaz pipeline systems**. The loop could potentially increase direct export flows to Spain via the Medgaz pipeline, once the capacity of the latter is expanded from its current 8 bcm/y. **Russia's** net pipeline exports are expected to reach 200 bcm/y by the end of the forecast period, supplied through a combination of traditional export routes and the commissioning of new pipeline infrastructure. This includes midstream capacity being built-up in Southeast Europe to enable a higher offtake from TurkStream's second string. The new

⁴ For the purpose of this analysis, long-distance pipeline trade includes Europe's pipeline imports (including deliveries from Norway), North American net pipeline trade and China's pipeline imports.

interconnector between Serbia and Hungary (with a capacity of 6 bcm/y) is expected to be commissioned by Q4 2021.

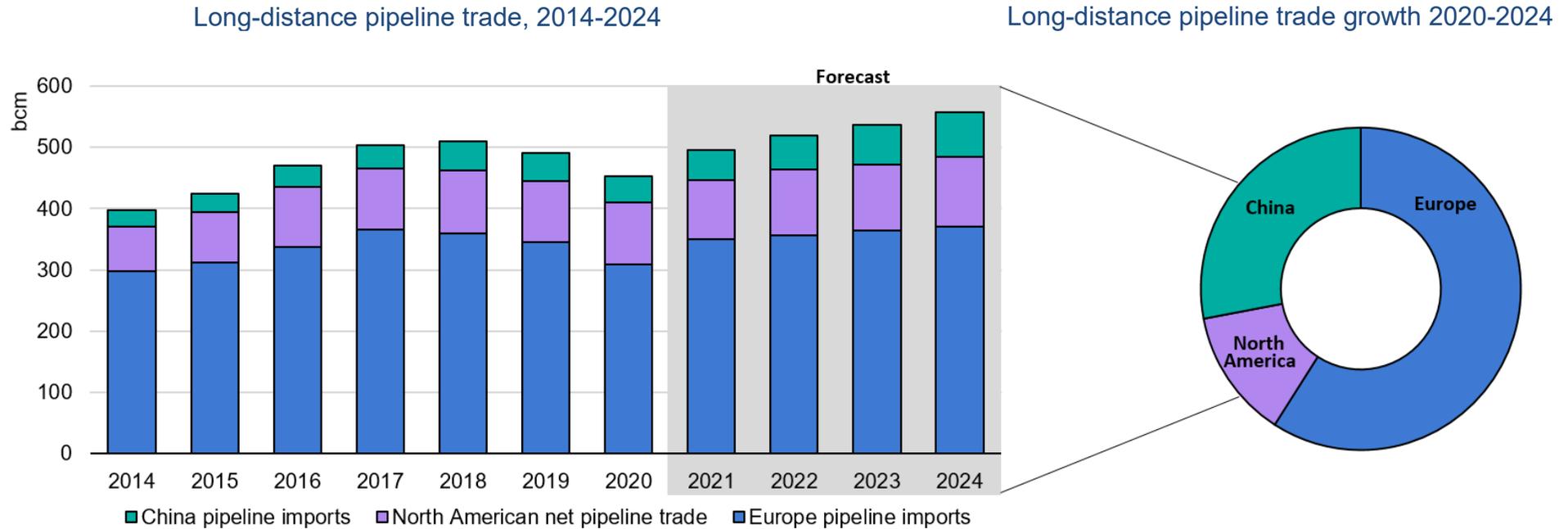
China's pipeline imports fell by 5% y-o-y in 2020, as the initial ramp-up of flows via the Power of Siberia pipeline from Russia (4.1 bcm) was not sufficient to offset plummeting gas deliveries from Central Asia (dropping by 13% y-o-y). China's pipeline imports are expected to recover to close to their 2019 levels in 2021. This will be largely driven by the continued ramp-up of flows via the Power of Siberia, reaching 4 bcm in the first five months of 2021 and set to total 10 bcm in the year as a whole. Pipeline deliveries from Central Asia are expected to recover only marginally in 2021 and to remain below their 2019 levels, due to lower supplies from Kazakhstan and Uzbekistan.

Flows via the **Power of Siberia** are expected to triple between 2021 and 2024, reaching 30 bcm at the end of our forecast. This will be enabled by the ramp-up of production from the Chayandinskoye field and the Kovyktinskoye field (to be commissioned in late 2022) and the start-up of the Amur gas processing complex. In China the middle section of the **China-Russia East pipeline** started commercial operations in December 2020, allowing Russian gas flows to reach the Beijing-Tianjin-Hebei region. Construction works started on the final, southern section of the pipeline in the summer of 2020. The section is expected to be commissioned in 2025, channelling gas down to Shanghai and enabling the Power of Siberia to reach its 38 bcm/y supply capacity. **Pipeline deliveries**

from Central Asia are expected to hover between 40 bcm/y and 45 bcm/y during the forecast period, as higher export flows from Turkmenistan are likely to be offset by declining deliveries from Uzbekistan – the country aims to cease exports by 2025.

North American net pipeline trade remained flat y-o-y in 2020, as declining net imports from Canada to the United States (down by 7%) were compensated by higher pipeline deliveries from the United States to Mexico (up by 7% y-o-y). **Net imports from Canada** are expected to recover to above their 2019 levels in 2021, increasing by close to 20% y-o-y in H1 2021. This was partly supported by the cold spell in February 2021, when Canada's pipeline deliveries played a key role in meeting the spike in US gas demand. Canadian net exports are expected to oscillate at 50-55 bcm/y during the forecast period and play a key role in meeting seasonal demand swings. **US pipeline exports to Mexico** rose by 45% between 2016 and 2020 and grew strongly in H1 2021, up by 15% y-o-y (despite a temporary decline during the February cold spell). The sharp increase in US-Mexico gas trade in recent years was enabled by the expansion of cross-border capacity and the expansion of Mexico's pipeline system. Recent capacity additions include completion of the **Samalayuca-Sásabe pipeline** (4.8 bcm/y), which started commercial operations in January 2021. The **Tula-Villa de Reyes pipeline** (10 bcm/y) is set to be commissioned later this year, allowing for a further increase in US pipeline exports to Mexico. US exports to Mexico are expected to increase by close to 10% between 2020 and 2024.

The growing import requirements of Europe and China are set to drive pipeline trade growth



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Sources: IEA analysis based on CEDIGAZ (2021), [Trade – Annual Flows](#); China Customs Office (2021), [Customs Statistics](#); EIA (2021), [Natural Gas Data, Imports/Exports](#); ENTSOG (2021), [Transparency Platform](#); Eurostat (2021), [Imports of Natural Gas by Partner Country – Monthly Data](#).

Global underground gas storage capacity is expected to expand by 9% in the next five years...

Underground gas storage (UGS) in porous reservoirs (such as depleted fields and aquifers) plays a critical role in meeting seasonal demand swings, whilst fast-cycling salt caverns are well-suited to meeting short-term demand fluctuations. Global UGS capacity is set to expand by 9% from 420 bcm in 2020 to over 455 bcm by 2026, largely driven by China, Europe and Eurasia. Salt caverns are expected to account for one-third of total capacity additions over the forecast period. Project delays and regulatory uncertainties present a risk to the current storage outlook.

China is expected to add 17 bcm of UGS capacity in 2021-2026, accounting for nearly half of the increase globally. At the end of 2020, China's working gas capacity was estimated at between 14 bcm and 16 bcm by various sources, close to or exceeding the 2020 target of 14.8 bcm under the 13th five-year plan, but less than 5% of total consumption, well below the level in mature markets. The government has stepped up support for new storage capacity since 2018, but progress has been slow due to the long lead time of USG projects. Expansion is set to accelerate in the next five years, led by CNPC and Sinopec. PipeChina, which assumed control over three UGS facilities at its inception in 2020, is also expected to play a more active role in UGS development in the next five years.

Europe's UGS capacity is set to increase over the forecast period. This is largely driven by Turkey, with the expansion of the Tuz Gölü

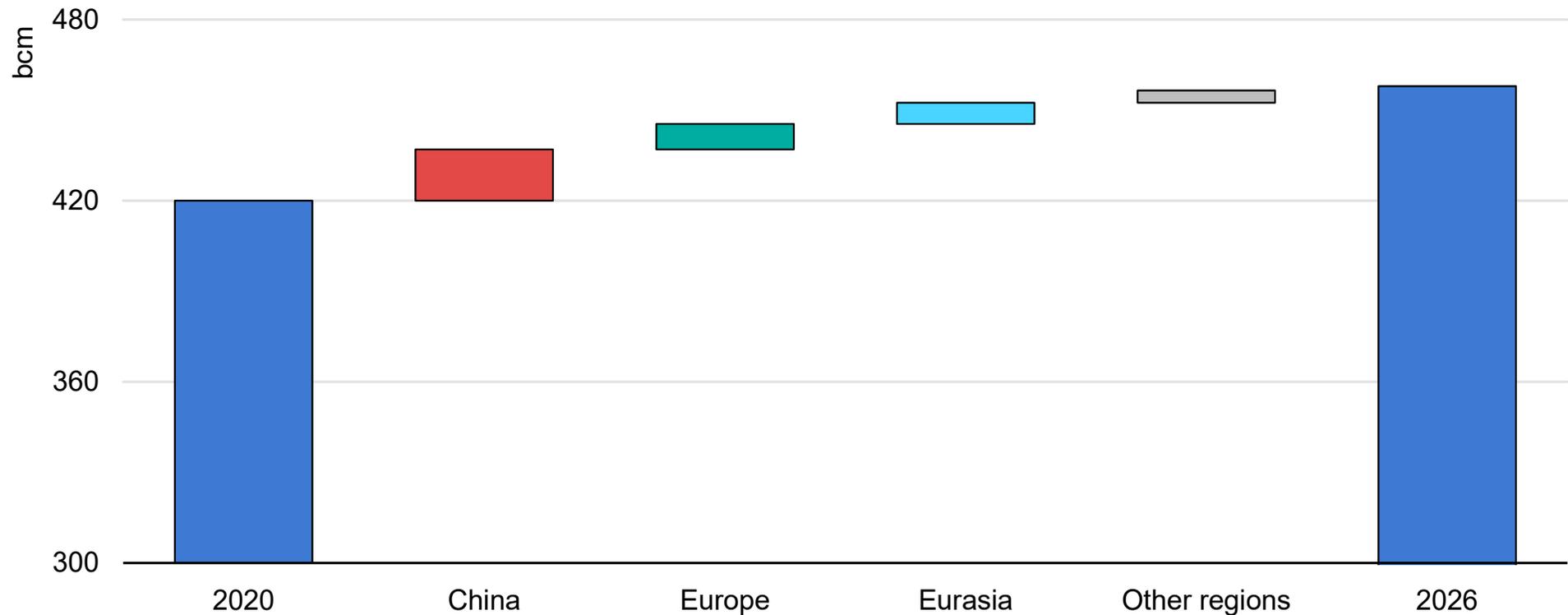
(salt cavern) and Silviri storage facilities from 0.6 bcm to 5.4 bcm and from 2.8 bcm to 4.6 bcm respectively. In Italy, the Cornegliano storage site is expected to ramp up its working capacity from the current 0.2 bcm to over 1 bcm in the forecast period.

In Russia, Gazprom continues to expand the country's gas storage capacity, with the target to increase the daily withdrawal capacity from 0.84 bcm in 2020/21 to 1 bcm. This includes the redevelopment and expansion of existing storage facilities, the construction of fast-cycling salt caverns and the build-up of new UGS facilities in regions with high natural gas demand. Based on projects currently under development and/or construction, Russia's gas storage capacity is expected to increase to close to 80 bcm through the medium term. In Belarus, the Mozyrskoe salt cavern's capacity is set to expand from the current 0.3 bcm to 0.65 bcm by 2023.

Storage additions are expected to be limited in other regions. In the Middle East, **Iran** is set to increase the combined working capacity of its Sarajeh and Shourijeh storage sites from 3.25 bcm to 6.5 bcm by 2023. In the **United States**, Sempra has asked the Federal Energy Regulatory Commission for permission to build a new salt dome facility with a working storage capacity of 0.55 bcm, expected to start up in Q1 2024.

...with China accounting for almost half of incremental storage capacity

Expected UGS capacity additions in key gas markets, 2020-2026



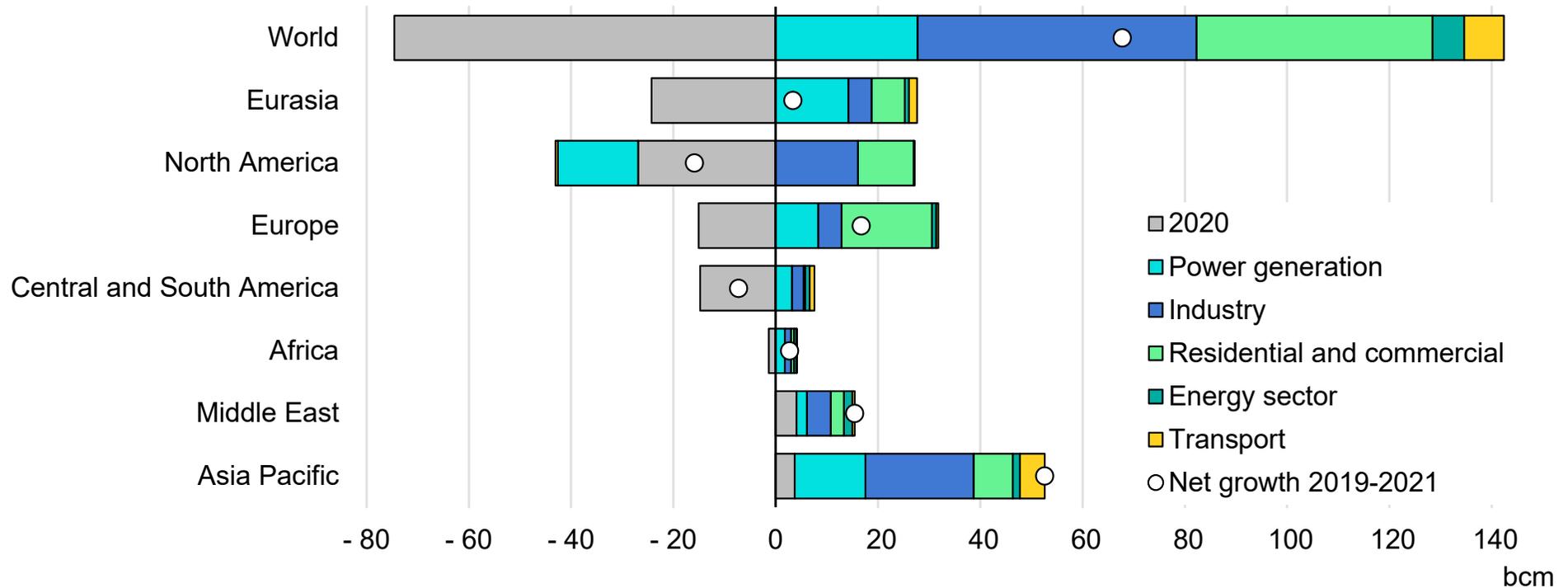
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Source: IEA analysis based on various companies and news reports.

Gas market update and short-term forecast

Gas demand growth in 2021 is expected to offset 2020 losses globally, although some mature markets are not fully recovering

Change in gas demand by region, 2019-2021



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North American gas consumption almost recovered during Q2 2021 after a mixed winter, although 2021 gains are still not likely to offset 2020 losses

Natural gas demand in the **United States** declined by an estimated 0.2% y-o-y during the first half of 2021. Support from cold temperatures drove heating demand up in the first two months of the year, but these gains were offset by lower gas-fired electricity generation (down 3.8% y-o-y over the first six months) due to higher fuel prices than in 2020. At the end of the first quarter of 2021 gas burn for power generation lost close to 9% compared to 2020, as colder weather kept prices at higher levels. Gas-fired generation resumed growth over the second quarter as fuel competitiveness improved. Rising temperatures by the end of June supported electricity demand, with price spikes in California and Texas. Higher demand combined with higher capacity outages put a strain on system operators who issued early summer conservation alerts.

Lower than usual temperatures raised consumption for heating needs in the residential and commercial sector, which was up to 5% higher y-o-y at the end of the first quarter. It then declined over the shoulder months, yet remained above 2020 levels with a 1.6% y-o-y increase for the first six months.

Industrial customers provided the strongest source of support for natural gas demand, with a 2.4% y-o-y increase during the first half of the year. Much of this growth occurred during the second quarter,

on a combination of recovering economic activity and lower gas prices after the end of the heating season.

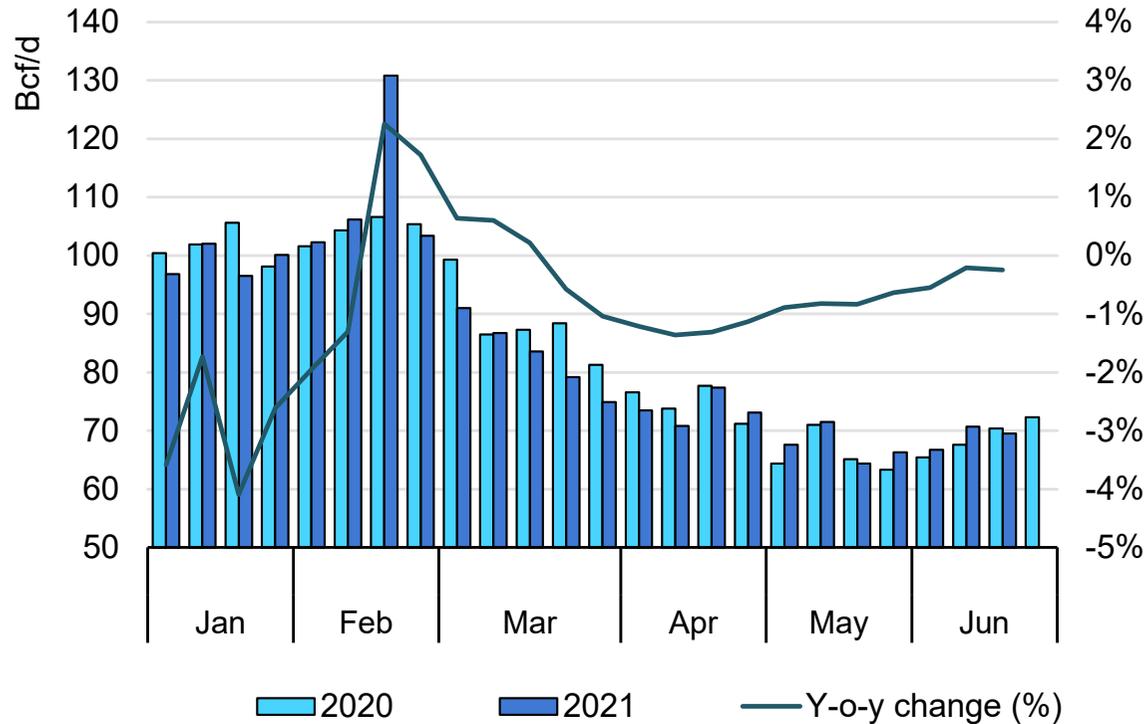
Canada's natural gas demand slightly increased by 1% y-o-y in the first quarter of 2021, principally supported by wholesale consumption for power generation and in industry (up 2%), while retail customers' demand stagnated. Canadian pipeline exports rose strongly in the first half of 2021, increasing by close to 20% y-o-y. This was primarily a response to US production constraints in February.

Mexico's apparent natural gas consumption followed a y-o-y increase during the four first months of 2021, as the growth in imports more than compensated for the decline in domestic production. The commissioning of new pipelines has eased access to the Mexican market for producers in the US Permian Basin, with volumes ramping up and resulting in a 15% y-o-y increase in US pipeline exports for the first half of 2021.

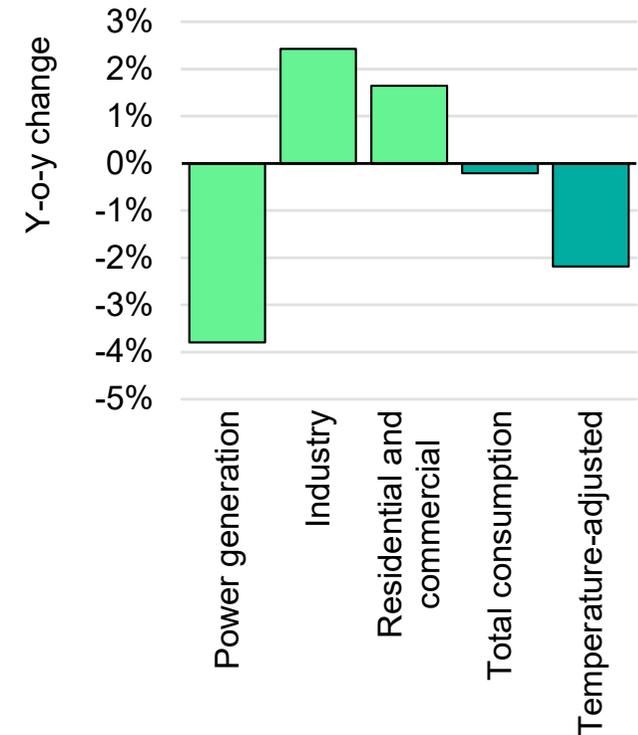
This forecast does not assume North American gas demand to fully recover from its 2020 2.2% annual drop over this year. The expected 1% annual growth for 2021 in the region is principally the result of the lower market share of gas in the US power mix, as higher prices favour a rebound in coal consumption at the expense of gas.

Lower use for power generation is a drag on US natural gas demand, after a temperature-driven increase in residential consumption during the first quarter

Weekly natural gas consumption in the United States, 2020-2021



Gas consumption by sector in the United States, 2021 relative to 2020



Note: Bcf/d = billion cubic feet per day.
 Sources: IEA analysis based on EIA (2021), [Natural Gas Consumption](#); [Natural Gas Weekly Update](#).

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Severe droughts drive gas for power demand in Brazil and other South American markets, while Argentina's lower industry needs hamper gas demand recovery

Natural gas consumption in **Brazil** increased 12% y-o-y during the first quarter, mainly due to a jump in gas-fired power generation. Severe droughts – the worst recorded in almost a century – greatly impacted hydroelectricity generation, which drove gas use for power generation up 24% y-o-y. Gas use in industry provided further support with a 7% y-o-y increase, while the commercial and transport sectors dropped by 19% and 5% y-o-y respectively on the impact of Covid-19 containment measures.

Exceptionally low rainfall levels are likely to have a prolonged impact on the country's power mix, as it entered the dry season with hydro reservoirs at a weighted average of 45%, lower than the five-year average of 53% according to the Electricity Sector Monitoring Committee. Rising domestic gas production provides some support, with a 4.5% m-o-m increase in April (or 6% y-o-y), but is not sufficient to meet increasing needs. LNG imports more than doubled over the first quarter compared to 2020 to supplement declining pipeline imports from Bolivia. The Ministry of Mines and Energy is seeking to expand energy supply, but has not at the time of writing yet considered it necessary to arrange emergency energy contracting.

Chile is also affected by lower hydro levels, which prompted a 40% y-o-y increase in LNG imports over the first five months of the year.

Argentina's gas demand fell by an estimated 10% y-o-y in the first quarter, in spite of rising needs from the power generation sector, as industrial demand remains low compared to last year. Floating regasification capacity has risen ahead of the austral winter to ensure additional supply and offset the decline in Bolivian pipeline imports. The Escobar terminal reopened in February after a federal judge decision lifted a suspension order enacted in October on technical risk concerns, and a second vessel started operations in Bahia Blanca in early June to cover the following three months.

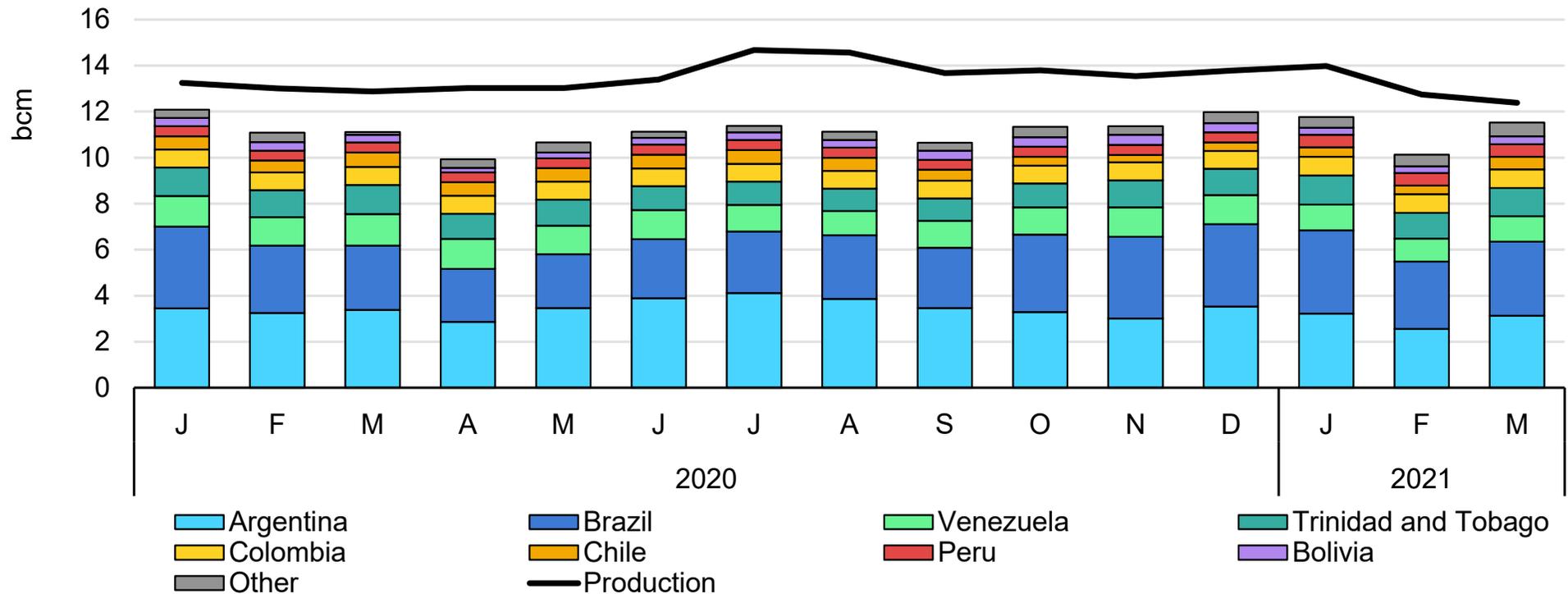
Apparent gas consumption rose in **Central America and the Caribbean** as LNG imports jumped over 55% y-o-y in the first five months of the year, prompted by higher needs in the Dominican Republic and Puerto Rico.

According to preliminary data, **Venezuela's** gas consumption declined by 17% y-o-y in the first quarter of 2021.

This forecast expects a 5% increase in gas demand in Central and South America for 2021, insufficient to offset the close to 10% fall in consumption observed in 2020.

South American gas demand rises in March from a low February level, supported by power generation needs in Brazil, Argentina and neighbouring markets

Monthly natural gas demand and production, Central and South America, 2020-2021



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Sources: IEA analysis based on ANP (2021), [Boletim Mensal da Produção de Petróleo e Gás Natural](#); ICIS (2021), [ICIS LNG Edge](#); IEA (2021), [Monthly Gas Data Service](#); JODI (2021), [Gas Database](#); MME (2021), [Boletim Mensal de Acompanhamento da Indústria de Gás Natural](#).

Cold spring temperatures and economic recovery boosted European gas consumption...

European gas consumption rose by an estimated 25% in Q2 2021 – its largest y-o-y quarterly increase since at least 1985. This exceptionally strong recovery has been driven by the combination of an extended heating season due to lower than average temperatures, higher gas burn in the power sector and economic activity recovering to close to pre-Covid-19 levels.

First estimates suggest that **distribution network-related gas demand** increased by close to 35% y-o-y and accounted alone for over half of total growth in gas consumption. According to the measurements of the De Bilt meteorological station in the Netherlands, April 2021 was the coldest April month since 1986, whilst heating degree days in May 2021 averaged at their highest since 2010 for that month of the year. This translated into higher space heating requirements for households, whilst the gradual recovery in commercial/service sector activity provided additional support to distribution network-related gas demand.

Colder spring temperatures together with improving macro-economic conditions also led to higher electricity consumption (up by 10% y-o-y). This higher electricity demand led to higher thermal generation needs, including **gas-fired power plants**, which increased their output by over 25% y-o-y. Most of the growth in gas to meet power demand has been concentrated in April (up by 65% y-o-y). The sharp increase in gas prices gradually reduced the cost-

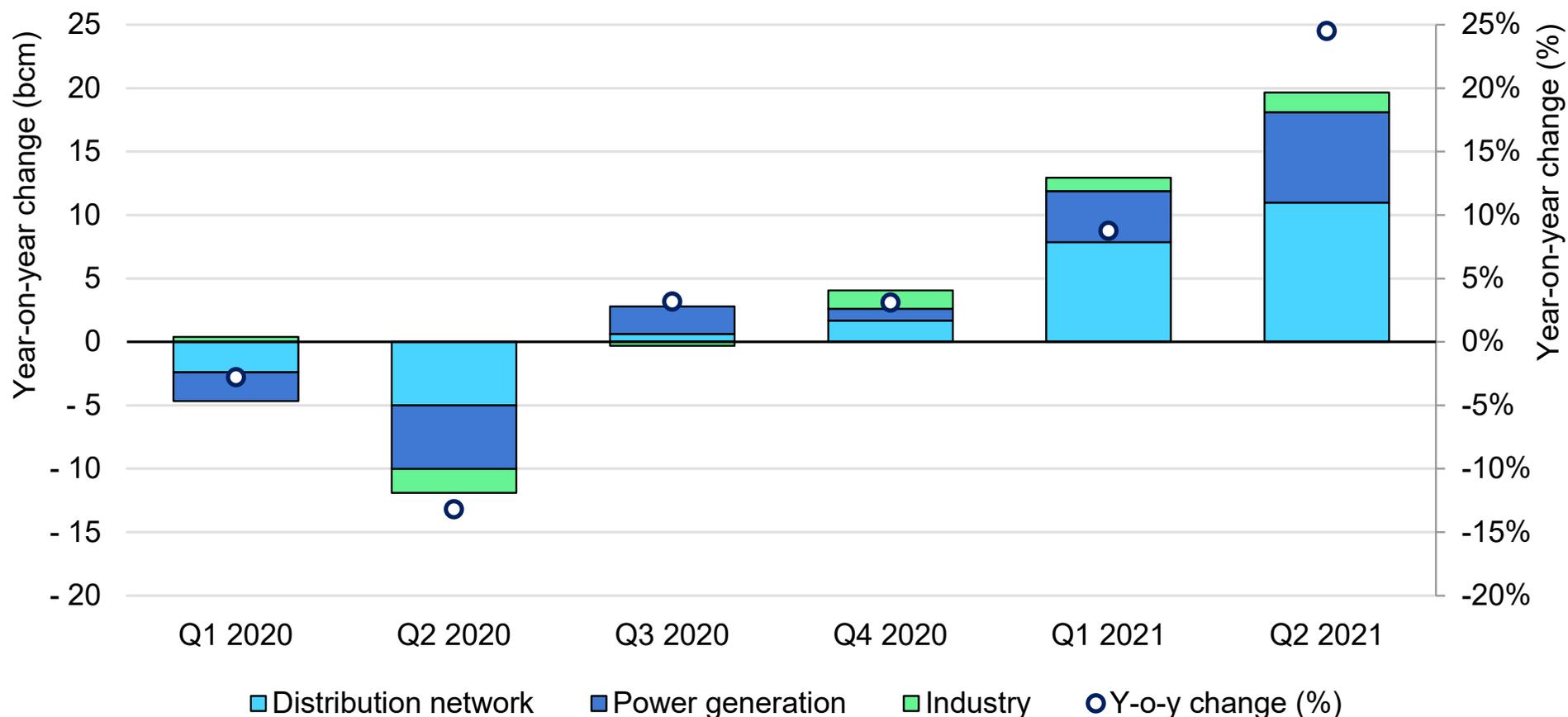
competitiveness of gas-fired power generation vis-à-vis coal- and lignite-based generation, despite carbon prices reaching new highs to oscillate in the range of EUR 50-55/t CO₂-eq. Nevertheless, gas-fired power generation continued to increase in May (up by 20%) and remained close to last year's levels in June. Turkey alone accounted for over half of additional gas burn in the power sector in Q2, as lower hydro availability together with economic recovery supported gas-fired power generation (increasing by more than threefold y-o-y).

Gas consumption in industry increased strongly across key markets compared to Q2 2020 – when most European countries imposed lockdowns and other restrictive measures, weighing on economic activity. First estimates indicate that industrial gas consumption increased by 20% y-o-y in Italy and 8% in France in Q2 and was up by over 25% y-o-y in Spain in April and May.

As a result of the strong, largely weather-driven demand growth in Q2, the **forecast** for European gas demand in 2021 is revised up to 6%, with most of the demand growth concentrated in H1 2021. Additional demand is largely driven by the industrial sector, while high gas prices are expected to weigh on gas demand for power generation. For further details, please refer to our Electricity Market Report.

...rising by over 20% year-on-year in Q2 2021

Estimated change in quarterly European gas consumption by sector (Q1 2019-Q2 2021)



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Sources: Enagas (2021), [Natural Gas Demand](#); ENTSOG (2021), [Transparency Platform](#); Gaspool (2021), [Consumption Data](#); NCG (2021), [Consumption Data](#); EPIAS (2021), [Transparency Platform](#).

Asia's gas demand recovery remains uneven; 2021 growth is expected to be 6%

Asia's gas demand recovery gained further momentum in Q1 2021, initially driven by an unseasonably cold winter across northeast Asia in January, and then by a sharp rebound in economic activity, especially in China. Preliminary data for April and May 2021 indicate that the China-led recovery of Asian gas demand continued into Q2. In 2021 total gas consumption in Asia is set to increase by 6%. China alone accounts for two-thirds of the net demand growth in 2021. A group of emerging Asian economies together contribute another 25%, while India's share of the net demand increase is more modest – at around 6% – following a downward revision to our forecast in light of the country's second wave of Covid-19. Declines in Japan are expected to be fully offset by increases in the rest of Asia.

China's gas consumption grew at double-digit y-o-y rates in each of the first five months of 2021, and recorded a 17% y-o-y increase in the January to May period. This remarkable expansion was supported by cold winter weather in January as well as by a robust post-pandemic recovery throughout the first five months. Gas use in the power generation sector was further boosted in May as hot early summer weather in southern China led to surging electricity demand at a time when nuclear, hydro and coal availability was limited. In 2021 total gas demand is projected to increase by 10%, driven by a strong economic recovery, coal-to-gas conversions and

expanding gas infrastructure. The industrial sector remains the main driver, accounting for 42% of the net increase, followed by power generation, residential and commercial users and the transport sector, which are responsible for 25%, 16% and 10% of the total growth respectively.

India's gas consumption contracted by 5% y-o-y in the first quarter of 2021 as high spot LNG prices in the aftermath of the northeast Asian winter energy crisis tempered demand, especially in the refining and petrochemical sectors, where some operators reportedly switched from imported LNG to liquid fuels. India's second wave of Covid-19 infections in April and May likely had a negative effect on gas demand in Q2 2021 as well. Preliminary data indicate that total consumption declined by 6% m-o-m in April (despite a spectacular 34% y-o-y rise, which is due to the low base in April 2020, when India's first Covid-19-induced demand drop was the steepest). LNG imports were down by 12% m-o-m in April 2021 according to provisional shipping data. The city gas segment registered the sharpest decline, dropping by 11% m-o-m in April, as lockdown measures hit CNG demand and small industries particularly hard. In 2021 India's gas consumption is expected to increase by 4.5%, but the economic fallout from the ongoing second wave and high LNG prices present downside risks to our forecast.

Japan's gas consumption increased by 9% y-o-y in the first four months of 2021. The seasonal jump was driven by the residential and power generation sectors, where gas demand rose sharply during a cold blast in January. Power sector gas demand was further boosted by low nuclear availability, especially during the first quarter. Gas demand in the industrial sector also remained strong, despite Japan's second and third states of emergency, which spanned most of the January to April period. In 2021 gas consumption is expected to decrease by 2% as nuclear restarts and growing solar generation limit gas burn in the power generation sector for the remainder of the year.

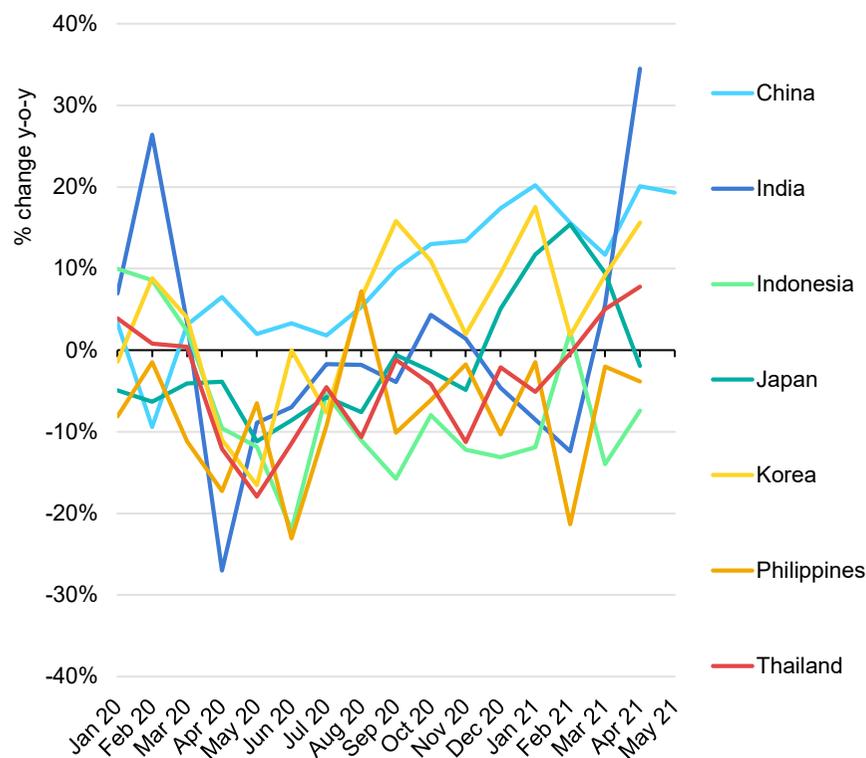
Korea's total gas consumption increased by 11% y-o-y in the first four months of 2021, driven by strong growth in both the power generation and city gas sectors, especially during the weather-driven demand spike in January. Preliminary shipping data indicates that LNG demand remained strong and expanded by 7% y-o-y in the first five months of 2021. In 2021 as a whole, Korea's gas demand is expected to increase by 5% y-o-y, fuelled by sustained high demand in the power and city gas segments. This comes despite the addition of 3 GW of new coal-fired capacity in 2021, as

the impact of the new units will be offset by lower utilisation of the coal fleet due to the ongoing restrictions on plant operations. Our forecast includes the addition of a new 1.4 GW nuclear unit (Shinhanul 1) in the second half of 2021. Any delays in the commissioning of the plant represent further upside potential for gas demand in the remainder of the year.

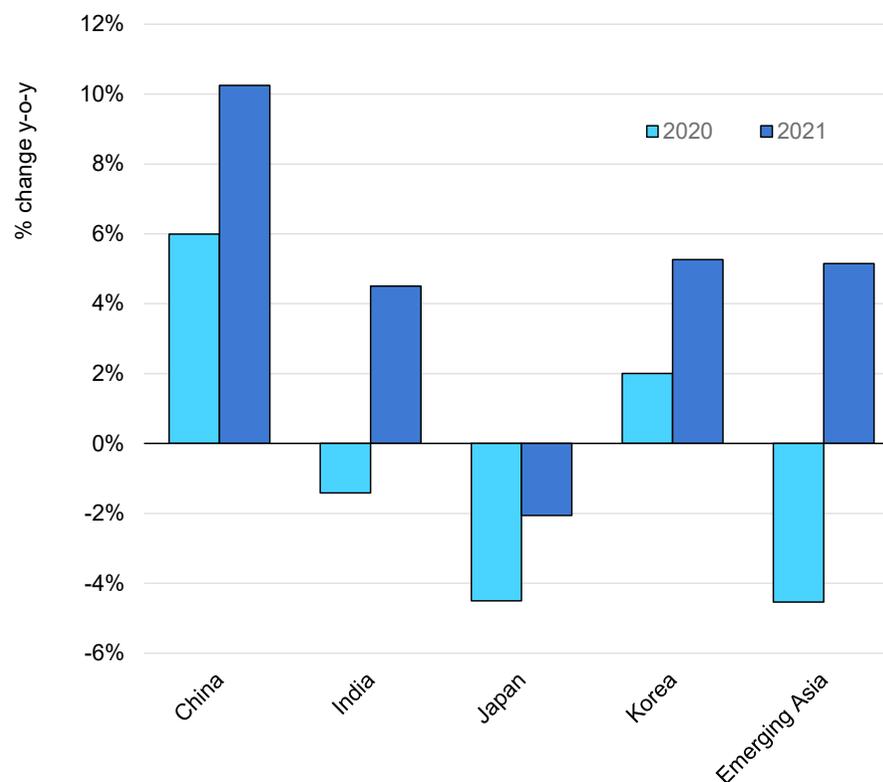
Emerging Asia's gas demand recovery remained muted in early 2021 as price-sensitive markets, such as Pakistan and Bangladesh, curtailed consumption in the face of record-high spot LNG prices in January. However, there are tentative signs of recovering demand in the remainder of Q1 and in Q2, with LNG imports into the region up by 13% y-o-y in the first five months of 2021 and y-o-y gas consumption growth in Thailand moving into positive territory from February. In 2021 total consumption is expected to increase by 5%, fuelled by an ongoing economic recovery and strong power demand growth. New waves of Covid-19 infections across the region, however, could present downside risks to our forecast.

Asia's demand recovery is led by China for now; others are likely to catch up in 2021

Monthly gas demand in selected Asian countries



Gas demand in selected Asian countries, 2020 and 2021



Sources: IEA analysis based on ICIS (2021), [ICIS LNG Edge](#); CQPGX (2021), [Nanbin Observation](#); IEA (2021), [Monthly Gas Data Service](#); JODI (2021), [Gas World Database](#); PPAC (2021), [Gas Consumption](#).

US gas output stabilises in Q2 after a volatile first quarter; shale industry shows signs of further consolidation and developing environmental certification

US dry gas production recovered in March from its low point in February, returning to 81 bcm – comparable to January. The second quarter saw a stable level of production, around 80 bcm per month, slightly below March's level, but about 3% above average production in the second quarter of 2020.

Drilling activity continues its increase since the beginning of the year, with close to 100 active gas rigs as of the end of June, some 19% above the early January number and 25% higher than a year ago. About half of the gas drilling activity is in the Haynesville play, whereas most of the remaining half takes place in the Northeast Marcellus and Utica plays in the Appalachian Basin. This recovery is, however, expected to remain modest, as shale gas producers have confirmed strict financial discipline for 2021 to deliver short-term returns.

This second quarter also showed additional merger and acquisition activity as the shale industry consolidates. With an estimated USD 30 billion in shale M&A activity as of mid-June, 2021 is set to surpass the previous year's USD 41 billion total. Several of the most recent deals involved gas-driven players, such as EQT's acquisition of Alta Resources' Marcellus gas assets (USD 2.9 billion), Appalachian-centred Cabot Oil & Gas merging with Cimarex Energy

(USD 8.5 billion), and Southwestern expanding its gas portfolio with the acquisition of Haynesville producer Indigo Natural Resources (USD 2.7 billion).

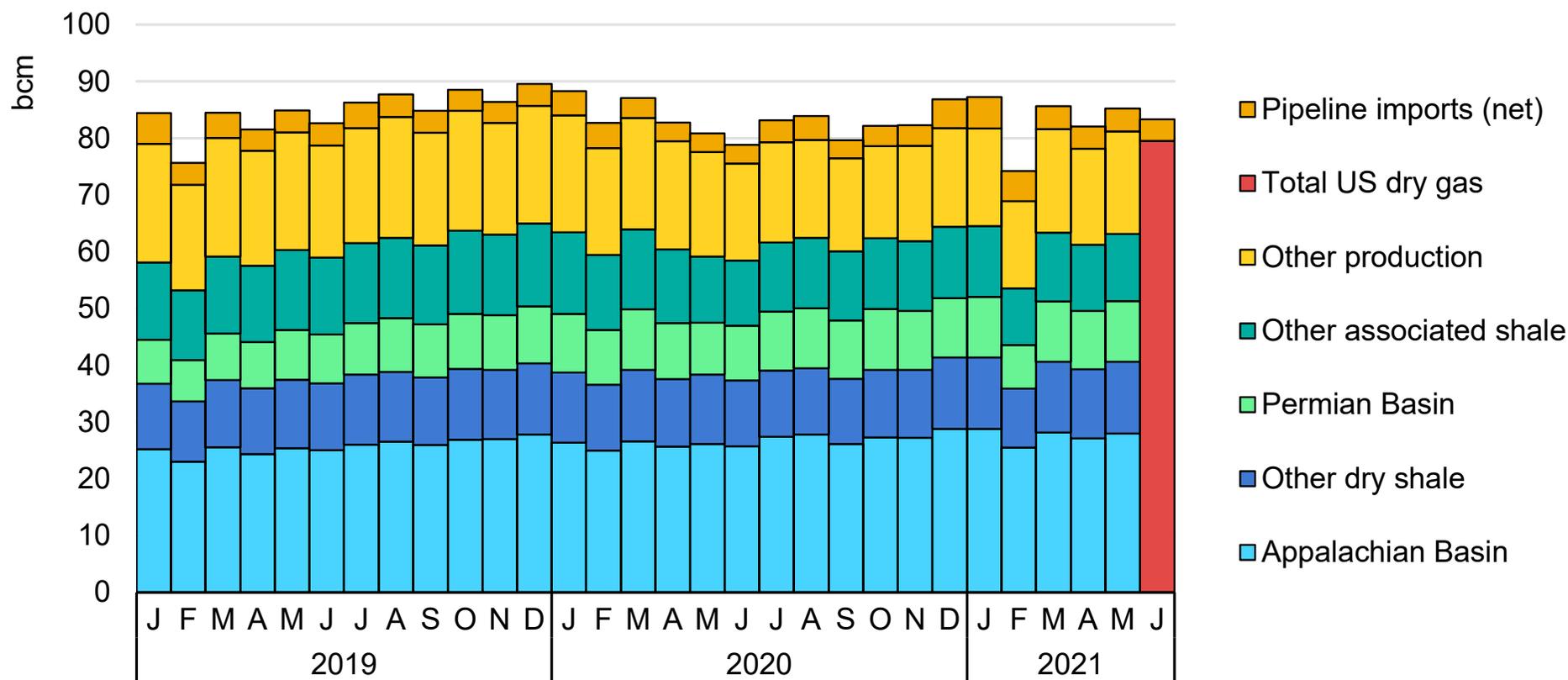
Shale gas players are also increasingly seeking to certify their production as responsibly sourced. EQT, the United States' largest shale producer, announced in April a test programme covering over 200 Pennsylvania well pads. About 4 Bcf/d (110 mcm/d) of production is to be certified according to its environmental, social and governance performance (including quantification of methane emissions). This follows similar statements made earlier this year by shale producer Chesapeake Energy, as well as LNG export project owners Cheniere Energy and Next Decade.

In the oil-driven Permian Basin, the commissioning of the Permian Highway natural gas pipeline in January increased takeaway capacity by 2.1 Bcf/d (59 mcm/d). It is contributing to reducing gas flaring and supporting exports to Mexico, which increased by 15% y-o-y in the first half of 2021.

US dry gas production is expected to stabilise in 2021, with shale gas (both dry and associated with light tight oil) providing limited growth to compensate for a slight decline in conventional gas production.

US gas production keeps recovering from its February drop, standing 2% below 2020's level over the first half of 2021

Gas production by type in the United States, 2019-2021

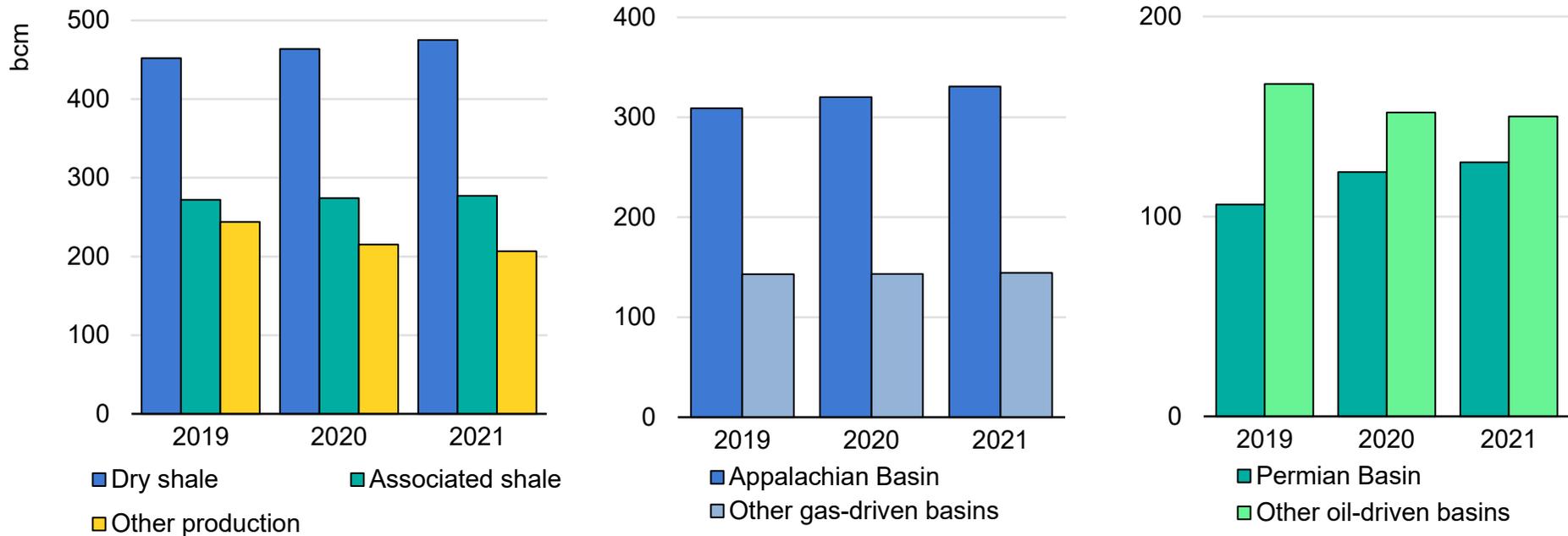


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Sources: IEA analysis based on EIA (2021), [Natural Gas Data](#); [Natural Gas Weekly Update](#).

US dry gas production is expected to stabilise in 2021, as growth from pure shale gas plays offsets declines from other sources

Dry gas production by main source in the United States, 2019-2021



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Sources: IEA analysis based on EIA (2021), [Natural Gas Data](#); [Natural Gas Weekly Update](#).

Eurasian gas production grew by close to 10% in the first five months of 2021...

Natural gas production in Eurasia grew by an estimated 10% y-o-y in H1 2021, supported by a combination of higher extra-regional exports, recovery in domestic demand and higher injection needs into storage following a cold and long heating season.

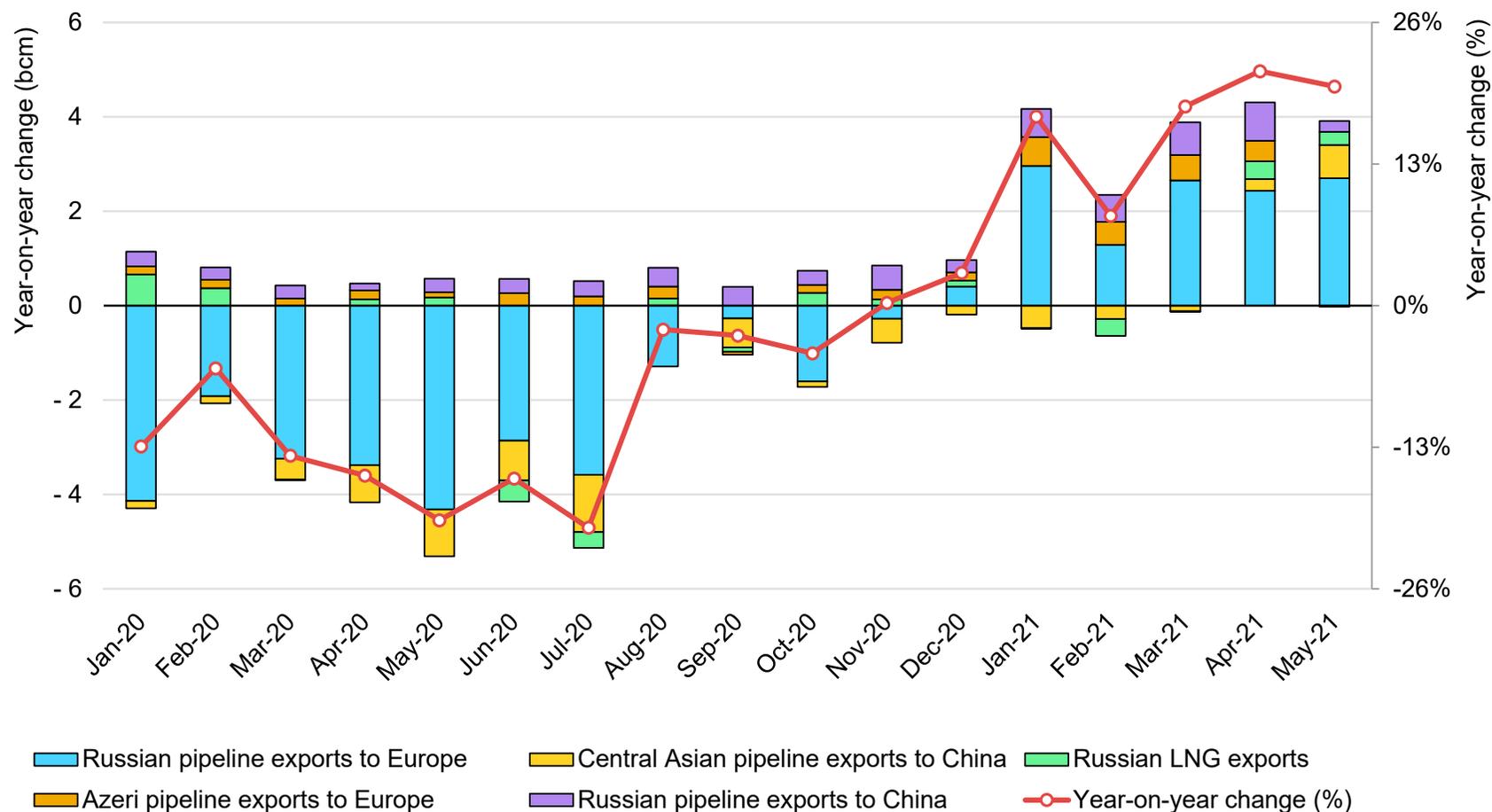
In **Russia**, natural gas production grew by 11% y-o-y in the first five months of 2021, with recovery accelerating in April and May when gas output increased by 18% (almost 20 bcm) y-o-y. This has been partly supported by **higher deliveries to the domestic market**, as the combination of a colder winter and spring temperatures, recovery in economic and commercial activity and higher gas burn in the power sector supported Russian gas demand. Russia's vast storage sites closed the heating season at an historical low of 12 bcm, meaning that **storage injections** would need to average over 330 mcm/d through the gas summer to reach the country's 72.6 bcm fill target by the start of the heating season. Higher injection needs are set to provide further support to gas output through the summer. Net **pipeline exports** to Europe rose by close to 20% y-o-y in the H1 2021, largely supported by higher deliveries to Turkey (more than doubling in January-May compared to last year). Pipeline deliveries to China via the Power of Siberia pipeline totalled over 4 bcm in the first five months of 2021. **LNG exports** declined marginally by less than 0.5% in the first five months of 2021, largely due to lower output from Sakhalin-II.

Central Asian pipeline exports to China remained flat, increasing by a mere 0.4% y-o-y in the first five months of 2021. Higher pipeline deliveries from Turkmenistan (up by 8%) were not sufficient to offset lower export flows from Kazakhstan, down by 29%. In **Azerbaijan**, natural gas production increased by close to 8% y-o-y in the first five months of the year. This has been driven by strong export growth, up by over 40% y-o-y. Deliveries via the TAP pipeline continued to ramp up and reached 2.5 bcm in the first five months of the year. In **Ukraine**, gas production fell by close to 7% in the first five months of 2020. .

Eurasian gas production is expected to increase by over 10% y-o-y in 2021, supported by recovery in domestic demand, higher injection needs and strong export growth. This will be partly enabled by the ramp-up of flows through **new export channels**. Gas deliveries via the Power of Siberia to China are set to reach 10 bcm in 2021, whilst exports via TAP are expected to total 5-5.5 bcm. The commissioning of YAMAL Train 4 in June could increase Russia's LNG exports by ~0.6 bcm in H2 2021. The first string of Nord Stream 2 was completed in June 2021. Combined pipeline exports from Russia to Europe and Central Asia to China are expected to increase by close to 15% y-o-y.

... supported by a strong recovery in extra-regional exports

Estimated change in monthly Eurasian gas exports (January 2020-May 2021)



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Sources: ENTSOG (2021), [Transparency Platform](#); Eurostat (2021), [Imports of Natural Gas by Partner Country – Monthly Data](#); General Administration of Customs of People’s Republic of China (2021), [Customs Statistics](#); ICIS (2021), [ICIS LNG Edge](#).

LNG inflows into Europe remained subdued in Q2 2021...

The combination of strong demand recovery, together with falling domestic production and higher LNG spot prices, created additional market space both for new and traditional pipeline suppliers to Europe in Q2 2021.

European LNG imports dipped by 40% y-o-y through the 2020/21 heating season (October to March) and remained below last year's levels in Q2, down by 6% y-o-y. The spread between Asian LNG spot and European hub prices averaged over USD 1/MBtu in the second quarter (more than double compared to last year), sufficient for LNG flows to favour the Asia Pacific region instead of the Europe market. The drop in LNG imports has been largely driven by northwest Europe (down by 4% y-o-y) and Turkey (plummeting by over 60%), whilst LNG inflow into southwest European markets rose by 5% (mainly due to higher imports into Portugal). The United States has been the largest source of supply, increasing its exports by over 30% y-o-y and accounting for almost 30% of Europe's total LNG imports. In contrast, Qatari flows dropped by almost one-third, being increasingly redirected to the Asia Pacific market.

Despite the strong demand growth and prices climbing to multi-year highs, **Norwegian pipeline deliveries** to the rest of Europe increased by a mere 1% y-o-y in H1, being limited by a combination of planned maintenance works and unplanned outages on key Norwegian gas infrastructure. **Non-Norwegian domestic**

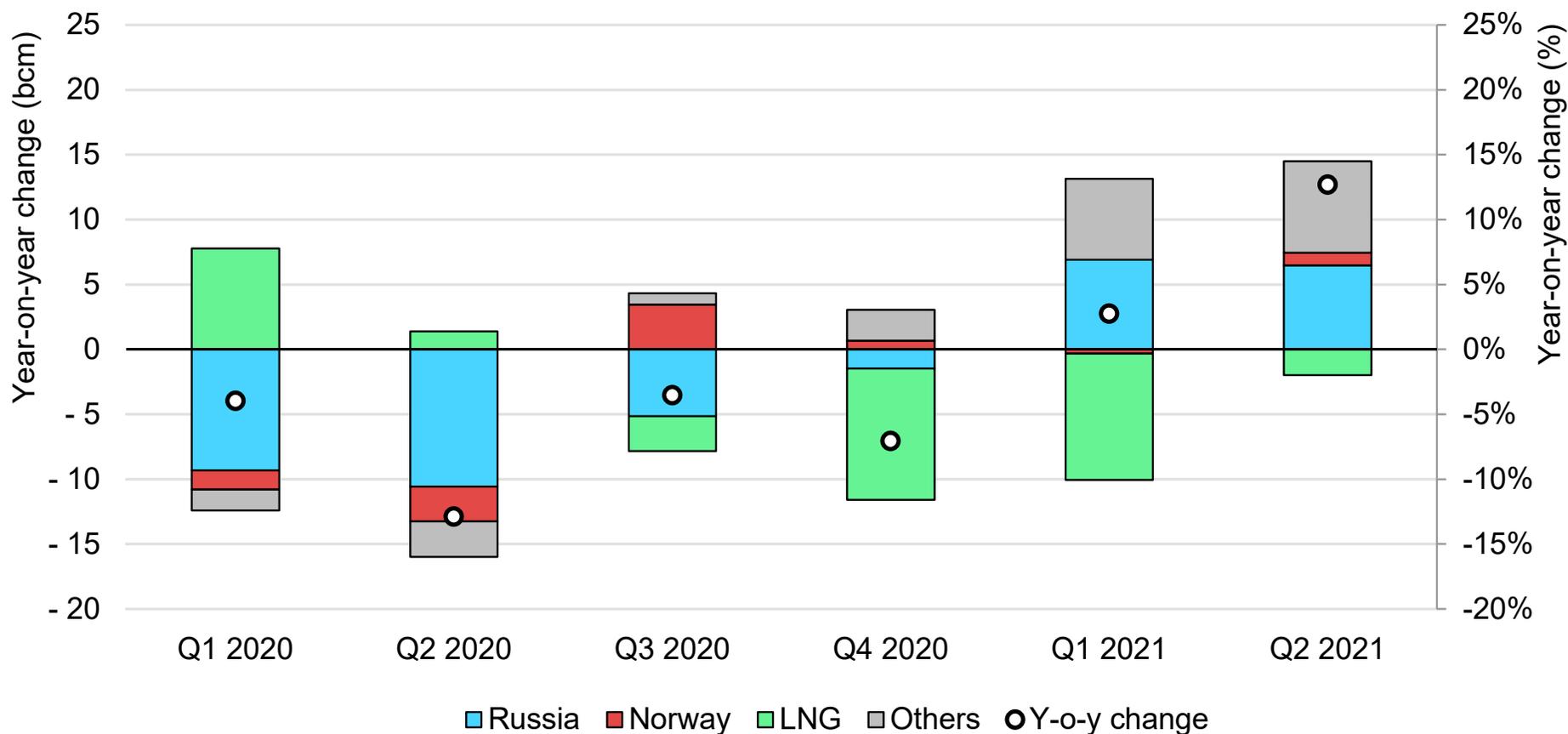
production continued to decline, down by over 10% in the first four months of 2021 – largely due to lower output in the Netherlands and the United Kingdom, together accounting for approximately 75% of the drop.

North African pipeline exports recovered strongly in Q1 (up by 70%) and more than doubled compared to last year in Q2, largely driven by higher Algerian gas deliveries to Italy and Spain, whilst pipeline flows from Libya dropped by over 40%. Oil-indexed Algerian prices remained at a significant discount compared to European hub prices (~30% lower compared to TTF in the first four months of 2021). **Net pipeline exports from Russia** continued their recovery during Q2 and increased by 18% y-o-y. This has been partly supported by the strong recovery in export flows to Turkey, more than doubling compared to last year in January-May 2021. **Azeri flows** to the European Union via the TAP pipeline started in January 2021 and totalled over 3 bcm in H1 2021.

Low European storage levels (23% below their five-year average) are expected to **create additional market space** both for LNG and pipeline suppliers during the summer season. Pipeline imports are expected to increase by close to 20% y-o-y in 2021, with LNG inflows settling below last year's levels. Europe's future infrastructure set-up is a major uncertainty factor in this forecast.

... leaving additional market space for pipeline suppliers

Estimated change in monthly European gas imports and deliveries from Norway, Q1 2019-Q2 2021



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Sources: IEA analysis based on ENTSOG (2021), [Transparency Platform](#); Eurostat (2021), [Energy Statistics](#); Gas Transmission System Operator of Ukraine (2021), [Transparency Platform](#); GIE (2021), [ICIS LNG Edge](#); JODI (2021), [Gas World Database](#); Norwegian Petroleum Directorate (2021), [Monthly Production Figures](#).

Global LNG trade is expected to increase by a modest 4% in 2021

In the first half of 2021 global LNG trade expanded by nearly 5% y-o-y. The Asia Pacific region remained the primary engine of import growth, registering 12% y-o-y expansion in the January to June 2021 period. China saw the largest absolute expansion, with LNG inflows increasing by 28% y-o-y in the first six months. This was fuelled by cold winter weather, a strong economic recovery, subdued pipeline gas imports from Central Asia and a hot start to the summer in south China in May. Japan and Korea sustained healthy LNG import growth, driven by a cold blast in January, the subsequent replenishment of LNG stocks and growth in gas-fired generation. The majority of emerging Asian importers – led by Pakistan and Bangladesh – experienced a sharp increase in LNG arrivals thanks to rising gas demand in the power sector. Meanwhile, India's LNG imports dropped by 3% y-o-y, as record-high spot prices in January and a devastating second wave of Covid-19 in April and May dampened LNG demand.

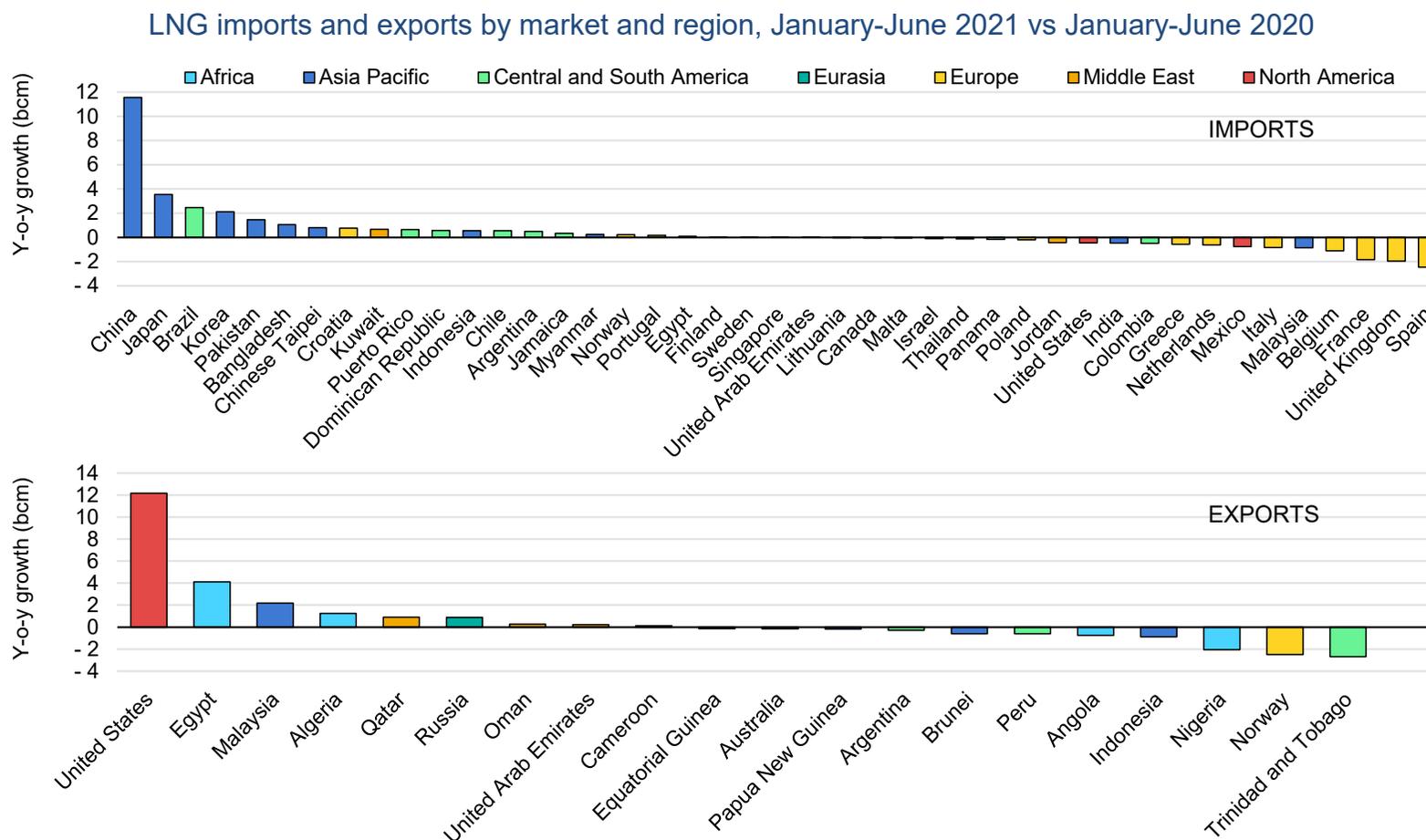
Central and South America registered strong gains, boosting LNG imports by more than 75% y-o-y in the first six months of 2021. Brazil accounted for the bulk of the growth, where LNG-fired power plants were dispatched to compensate for low hydro generation amid an unusually dry southern hemisphere winter. European LNG imports dropped by nearly 20% y-o-y in the first half of 2021 as Atlantic Basin cargoes were redirected to Asia. The reduction in

LNG intake was offset by increased storage withdrawals and pipeline gas imports into Europe. The Middle East recorded a minor y-o-y increase, while North American imports dropped by almost 50% y-o-y as US pipeline gas continued to displace LNG in Mexico.

North America has dominated LNG export growth so far this year, with US LNG output expanding by more than a third y-o-y in the first six months of 2021. This remarkable growth comes despite a sharp 29% m-o-m drop in February 2021 during the Texas electricity crisis, and is largely the result of a 50% increase in US liquefaction capacity since the beginning of 2020. Africa's LNG exports rose by 9% y-o-y, driven by a sharp rebound in LNG exports from Egypt, which was further boosted by the reopening of the Damietta plant in February 2021. LNG output in the Middle East rose by 2% y-o-y as Qatar produced in excess of nameplate capacity in the first half of 2021. LNG exports from Eurasia (i.e. Russia) were up by 5% y-o-y. Exports from the Asia Pacific region remained flat, while output in Europe and Central and South America saw steep declines due to the ongoing outage at the Hammerfest LNG terminal in Norway and reduced feed gas availability at the Atlantic LNG plant in Trinidad and Tobago, respectively.

In 2021 global LNG trade is expected to increase by 4%, with import growth driven entirely by the Asia Pacific region and export growth fuelled mainly by North America.

Asia Pacific leads LNG import growth and North America leads LNG export growth so far in 2021



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Notes: Based on preliminary shipping data. LNG trade is net of reloads. Reference period is 1 January to 25 June.

Source: IEA analysis based on ICIS (2021), [ICIS LNG Edge](#).

Spot gas prices and charter rates recorded strong gains in Q2 2021...

Tighter market fundamentals supported spot gas prices rising to multi-year highs in Q2 2021 across all major gas-consuming regions.

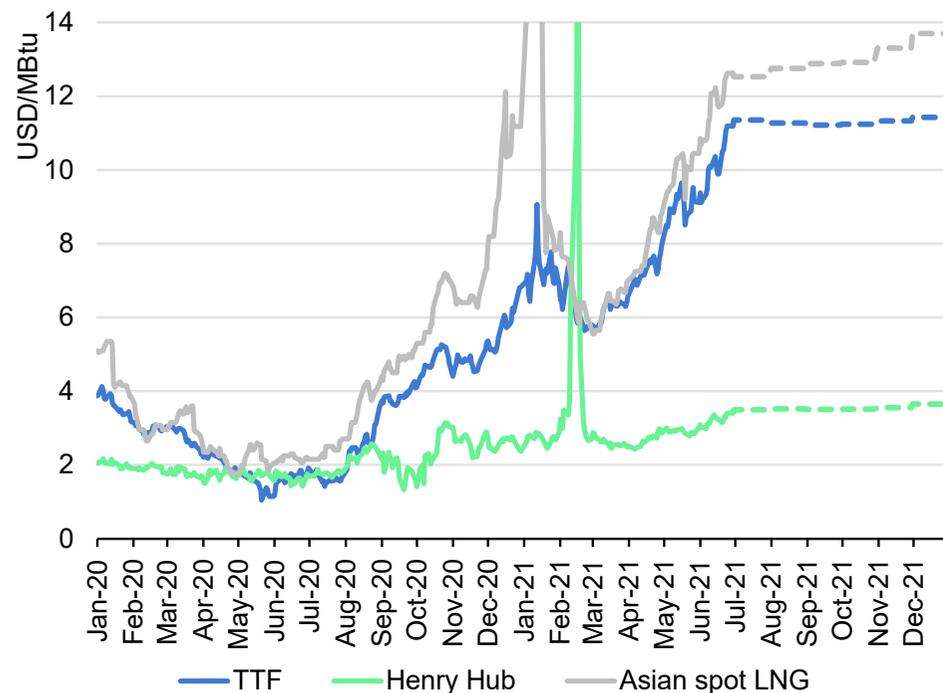
In the United States, Henry Hub prices increased by over 70% y-o-y in Q2, to an average of USD 2.9/MBtu – their highest Q2 average since 2017. This has been largely supported by the surge in LNG exports (up by 30% y-o-y), which increased overall system demand, whilst gas production remained close to last year's levels. Forward curves as at the end of June indicate that Henry Hub prices are expected to average USD 3.5/MBtu through the second half of 2021, translating into an annual average of USD 3.4/MBtu – its highest since 2014. **In Europe**, cold spring temperatures during April and May, together with lower LNG inflows, supported a strong increase in TTF prices, rising by fivefold in Q2 y-o-y to an average of USD 8.7/MBtu – its highest Q2 average since 2013. Forward curves as at the end of June suggest that gas prices will remain well above their five-year averages during the second half of 2021, at USD 11/MBtu. Overall TTF prices are expected to average USD 9.5/MBtu in 2021 – their highest level since 2013. **In Asia, LNG spot prices** more than quadrupled y-o-y in Q2 to reach an average of USD 9.8/MBtu – their highest Q2 average since 2014. Strong buying interest from China, India and Korea, together with a combination of planned and unplanned outages in liquefaction

plants, provided upward support to LNG spot prices. Forward curves at the end of June indicate that Asian spot prices are set to average close to USD 13/MBtu through the second half of the year, resulting in an overall annual average of over USD 11/MBtu – the highest level since 2014.

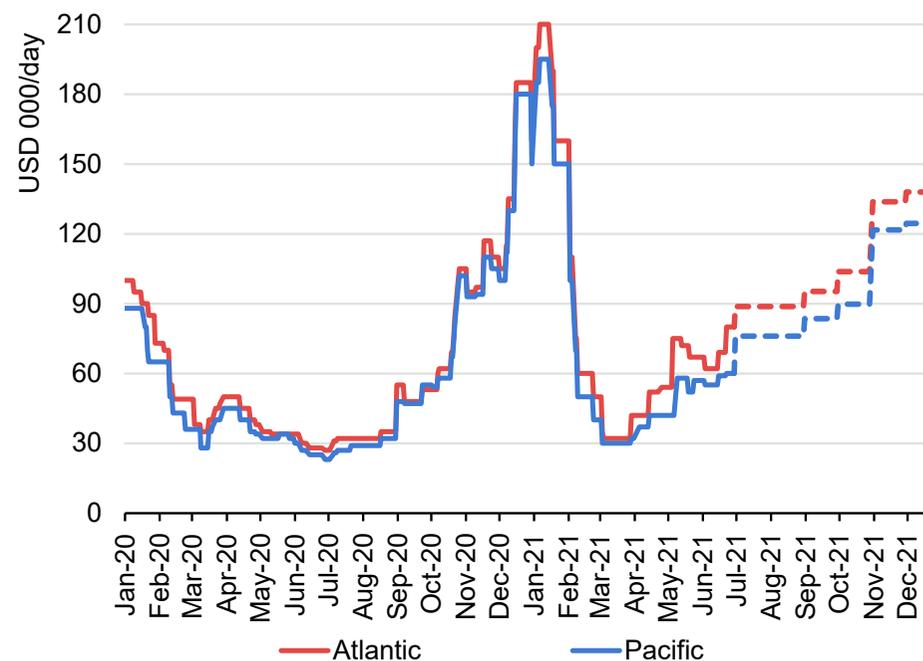
Oil-indexed LNG prices gained an estimated 10% y-o-y in Q2, and are expected to average 70% higher compared to last year in H2 2021. The strong gains in spot prices have been accompanied by widening **regional price spreads** compared to last year. The price differential between Asian spot LNG and Henry Hub, and TTF and Henry Hub, averaged close USD 7/MBtu and USD 6/MBtu respectively in Q2 (from close to zero last year). Price spreads between Asian spot LNG and TTF averaged USD 1/MBtu in Q2, supporting higher LNG flows towards the Asia Pacific region. Forward curves suggest that spreads between Asian spot LNG and Henry Hub, and between TTF and Henry Hub, will average USD 9.5/MBtu and USD 7.8/MBtu respectively in H2 2021. Strong growth in LNG trade in Q2 led to an increase in tonne-mile demand, providing upward pressure on **charter rates** in both the Atlantic and Pacific basins. They are averaging respectively 70% and 50% higher in Q2 compared to last year. Forward curves indicate that Atlantic and Pacific charter rates are set to average 50% and 40% above last year's levels in H2 2021, respectively.

... filtering through the forward curve for the rest of the year

Main spot and forward natural gas prices, January 2020-December 2021



Atlantic and Pacific spot and forward charter rates, January 2020-December 2021



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Sources: Gas prices: IEA analysis based on CME (2021), [Henry Hub Natural Gas Futures Quotes](#); [Dutch TTF Natural Gas Month Futures Settlements](#); CME Group (2021), [LNG Japan/Korea Marker \(Platts\) Futures Settlements](#); EIA (2021), [Henry Hub Natural Gas Spot Price](#); ICIS (2021), [ICIS LNG Edge](#); Powernext (2021), [Spot Market Data](#). Charter rates: IEA analysis based on ICIS (2021), [ICIS LNG Edge](#); Spark Commodities (2021), [LNG Freight Dashboard](#).

Tight summer-winter spreads weighed on storage injection in Europe and the US in Q2...

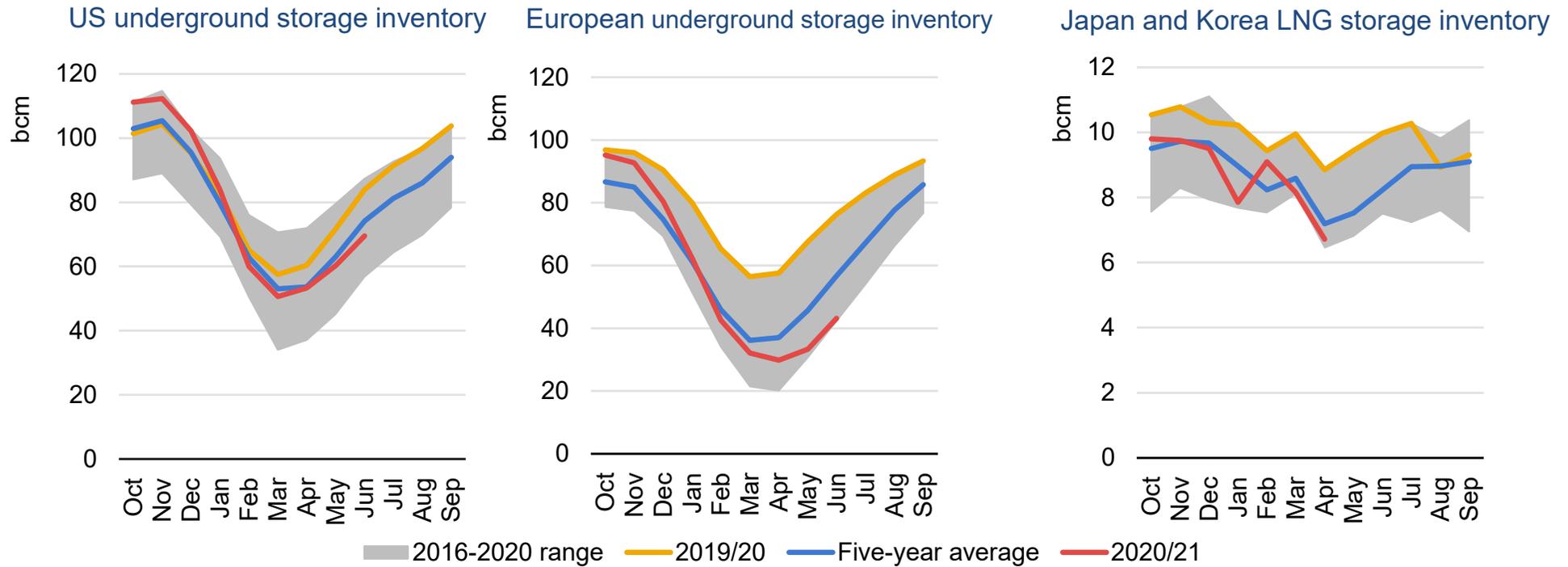
Underground gas storage sites both in Europe and North America closed the first half of the injection season with inventory levels below their five-year average. Tighter than expected supply-demand fundamentals during Q2 led to more pronounced uplift in spot prices compared to winter contracts. This, in turn, translated into tighter seasonal price spreads, reducing the incentive for storage injections.

In **Europe**, unseasonably cold temperatures in early spring extended the withdrawal season from the end of March until the second half of April. The strong demand increase throughout April and May firmed up spot prices, rising more strongly than 2021/22 winter contracts. Consequently, seasonal price spreads have fallen from over USD 2/MBtu in Q2 2020 to USD 0.25/MBtu in Q1 2021. Tighter seasonal spreads have depressed net storage injections, falling by close to 40% y-o-y in the second quarter. This in turn resulted in working gas inventories standing 40% below last year's levels and 23% below their five-year average at the end of June. Net injections would need to increase to 460 mcm/d in Q3 (up by 60% compared to their five-year average) for European storage to reach 90% fill rates by the beginning of the next heating season. In **Ukraine**, net injections have fallen by a factor of 30 compared to

last year, whilst working gas inventories stood 42% below last year's levels at the end of June according to data published by Gas Infrastructure Europe. In **Russia**, where working gas inventories dropped to a record low of 12 bcm at the end of the heating season, storage injections would need to average over 330 mcm/d to reach the 72.6 bcm fill target by the start of the heating season.

In the **United States**, seasonal price spreads between 2021/22 winter contracts and spot prices averaged at USD 0.28/MBtu in Q2, down from USD 1.1/MBtu during the same period of last year. This naturally weighed on net storage injections, which declined by 30% y-o-y from 29 bcm in Q2 2020 to 20 bcm in Q2 2021. Consequently, US gas inventory levels stood 17% below last year's levels and 6% below their five-year average levels by mid-June, despite starting the injection season 1.3% below their five-year average. The reclassification of ~1.4 bcm of working natural gas storage to base gas in Northern California contributed to this decline. In **Canada**, storage injections declined by 30% y-o-y during Q2, depressing inventory levels to 6% below their five-year average by mid-June. In **Japan and Korea**, LNG closing stocks stood 7% below their five-year average in April, as tighter supply-demand fundamentals weighed on LNG restocking.

...leaving inventory levels below their five-year average by the middle of the injection season



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Sources: IEA analysis based on EIA (2021), [Weekly Working Gas In Underground Storage](#); GIE (2021), [AGSI+ Database](#); IEA (2021), [Monthly Gas Data Service](#).

Annex

Summary tables (1/2)

World natural gas demand by region and key country (bcm)

	2018	2019	2020	2021	2022	2023	2024
Africa	157	161	160	164	170	176	180
Asia Pacific	824	853	857	907	940	986	1 024
<i>of which China</i>	283	307	325	359	377	400	421
Central and South America	153	152	137	145	147	149	151
Eurasia	666	658	633	661	659	662	670
<i>of which Russia</i>	493	482	460	485	481	484	489
Europe	536	537	522	553	537	531	530
Middle East	544	543	547	559	577	591	610
North America	1 061	1 097	1 070	1 081	1 098	1 109	1 111
<i>of which United States</i>	854	888	869	873	886	894	895
World	3 940	4 001	3 926	4 069	4 127	4 205	4 277

Summary tables (2/2)

World natural gas production by region and key country (bcm)

	2018	2019	2020	2021	2022	2023	2024
Africa	244	248	240	247	249	253	265
Asia Pacific	627	654	648	669	677	683	694
<i>of which China</i>	160	174	189	200	210	221	232
Central and South America	167	167	152	160	163	166	168
Eurasia	932	941	884	982	977	1 002	1 033
<i>of which Russia</i>	726	738	692	774	764	785	814
Europe	246	227	211	203	203	199	195
Middle East	666	677	680	694	709	725	744
North America	1 062	1 166	1 145	1 150	1 179	1 211	1 229
<i>of which United States</i>	868	968	953	959	987	1 019	1 034
World	3 944	4 080	3 960	4 105	4 158	4 239	4 328

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other countries and territories.¹

Asia Pacific – Australia, Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, the People's Republic of China,² the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other countries and territories.³

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other countries and territories.⁴

Eurasia – Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, the Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Europe – Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,^{5,6} Czech Republic, Denmark, Estonia, Finland, the Former Yugoslav Republic of North Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo,⁷ Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,^{5,6} Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta,

Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain and Sweden.

Middle East – Bahrain, the Islamic Republic of Iran, Iraq, Israel,⁸ Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

North Africa – Algeria, Egypt, Libya, Morocco and Tunisia.

North America – Canada, Mexico and the United States.

¹ Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda.

² Including Hong Kong.

³ Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

⁴ Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, St. Lucia, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

⁵ Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

⁶ Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

⁷ The designation is without prejudice to positions on status, and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.

⁸ The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Abbreviations and acronyms

ANP	Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (Brazil)
CAPEX	capital expenditure
CME	Chicago Mercantile Exchange (United States)
CNG	compressed natural gas
CNY	Chinese yuan
CQPGX	Chongqing Petroleum and Gas Exchange (China)
EIA	Energy Information Administration (United States)
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Enerji Piyasaları İşletme A.Ş. (Turkey)
EPPO	Energy Policy and Planning Office (Thailand)
ERCOT	Electric Reliability Council of Texas (United States)
FID	final investment decision
GDP	gross domestic product
GECF	Gas Exporting Countries Forum
GIE	Gas Infrastructure Europe
HH	Henry Hub
IEA	International Energy Agency
ICIS	Independent Chemical Information Services
JODI	Joint Oil Data Initiative
LNG	liquefied natural gas
NBP	National Balancing Point (United Kingdom)

NCG	NetConnect Germany
NDRC	National Development and Reform Commission (China)
PPAC	Petroleum Planning & Analysis Cell (India)
SENER	Secretaría de Energía (Mexico)
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
w-o-w	week-on-week
y-o-y	year-on-year

Units of measure

bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcm	billion cubic metres
bcm/y	billion cubic metres per year
mb/d	million barrels per day
MBtu	million British thermal units
mcm/d	million cubic metres per day
tcm	trillion cubic metres
TWh	terawatt hour

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