Global Gas Security Review 2024

Including the Gas Market Report Q4-2024

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Abstract

Following the gas supply shock of 2022/23, natural gas markets have returned to more pronounced growth, with global gas demand expected to reach new all-time highs in both 2024 and 2025. At the same time, the global gas balance remains fragile amid limited LNG supply growth and geopolitical tensions.

The *Global Gas Security Review* has provided a thorough assessment of the evolution of gas supply security and LNG contracting trends each year since its first publication by the International Energy Agency (IEA) in 2016. This year's edition also includes the latest insights of the IEA's quarterly *Gas Market Report*, which provides a review of market developments over the first three quarters of 2024 and a short-term outlook for the remainder of the year and through 2025. It highlights the need for responsible producers and consumers to work together to reinforce the architecture of global gas supply security.

Beyond the growing complexity of gas supply security both in the short and long term, the decarbonisation of the global energy system will require the deployment and scaling up of low-emissions gases. As part of the IEA's Low-Emissions Gases Work Programme, this year's *Review* includes a special section on this topic, with a focus on the system integration of low-emissions gases in the transport sector.

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Executive summary

A fragile balance: Natural gas markets remain sensitive two years after the gas supply shock

Following the supply shock of 2022/23, **natural gas markets returned to more pronounced growth** in 2024. This forecast expects global gas demand to reach new all-time highs in 2024 and 2025. However, the **global gas balance remains fragile** as limited growth in LNG production is keeping supply tight, while geopolitical tensions continued to cause price volatility. **Markets remain sensitive** to unexpected supply or demand side movements. **LNG shipping constraints** emerged across the Panama Canal and the Red Sea in 2024. While this did not lead to a decline in LNG supply, it highlights the potential vulnerabilities of LNG trade in an increasingly interconnected global gas market. Responsible producers and consumers will need to work together to **reinforce the architecture for secure global gas supplies** amid mounting geopolitical tensions. Flexibility mechanisms along gas and LNG value chains could be enhanced by improving the liquidity of the global LNG market, integrating the Ukrainian gas storage system into the global gas market and considering potential frameworks for voluntary gas reserve mechanisms.

Global gas demand is set to grow to new all-time highs in 2024 and 2025, primarily supported by Asia

Preliminary data suggest that **natural gas consumption increased by 2.8%** year-on-year (y-o-y) in the first three quarters of 2024 (Q1-Q3 2024) – well above the 2% average growth rate between 2010 and 2020. The fast-growing markets of Asia accounted for the majority of this growth. First estimates indicate that growth in natural gas demand slowed to below 2% in Q3 2024 in the markets covered in this report.[1] In part, the easing reflects the gradual recovery in demand, which was already underway in the second half of 2023. Higher gas prices also contributed to slower demand growth in Q3 2024.

For the full year of 2024, global gas demand is forecast to grow by more than 2.5% (or just over 100 bcm) and reach a new all-time high of 4 200 bcm. The **Asia Pacific region** is expected to account for almost 45% of incremental global gas demand. **Industry and energy own use** is emerging as the primary driver behind stronger gas use and is projected to contribute more than half of demand growth. This is partly supported by the continued economic expansion in fast-growing Asian markets. The recovery in Europe's industrial gas demand is also contributing even though it remains well below its pre-crisis levels. **Global gas demand is forecast to increase by another 2.3%** (or nearly 100 bcm) in 2025. Similarly to 2024, this growth is **largely supported by Asia**, which alone is expected to account for over half of incremental gas demand.

1 Asia, Central and South America, Eurasia, Europe and North America.

Natural gas supply remains fundamentally tight, with uncertainties weighing on the 2025 outlook

Global LNG supply growth remained weak in Q1-Q3 2024, increasing by a mere 2% (or 7 bcm) y-o-y. This is well-below its 8% average annual growth rate between 2016 and 2020. **Project delays** together with **feedgas supply issues** at certain legacy producers (including in Angola, Egypt, Trinidad and Tobago) weighed on LNG production growth. The expected start-ups of the Plaquemines LNG export terminal in the United States and Tortue FLNG off the coast of West Africa are expected to improve LNG supply availability in Q4 2024. For the full year of 2024, global LNG supply is expected to grow by 2% (or 10 bcm) – **its slowest growth rate since 2020**.

LNG supply growth is set to accelerate to near 6% (or 30 bcm) in 2025 as several large LNG projects come online. **North America** is expected to account for about 85% of global incremental LNG supply in 2025, with nearly three-quarters (16 bcm) of these North American volumes coming from the United States. **Africa and Asia** are also expected to contribute to LNG supply growth in 2025. **Russia's Arctic LNG 2 project** is not considered as a source of firm LNG supply in the current forecast, considering the broader sanctions environment.

The future of Russian gas transit via Ukraine is a key uncertainty ahead of the 2024/25 winter, as Russia's gas transit contract with Ukraine expires at the end of 2024. **This forecast assumes no Russian piped gas deliveries via Ukraine to Europe from January 2025**. Our assessment indicates that the halt of Ukrainian transit **would not pose an immediate supply security risk** to Austria, Hungary and Slovakia considering their ample storage capacity, midstream interconnectivity and indirect access to the global LNG market. The **vulnerability of Moldova is significantly greater** and would require a close cooperation between Moldova and regional and international partners to ensure energy supply security over the winter season. An end to Ukrainian transit would reduce Russian piped gas supplies to Europe by around 15 bcm compared to 2024. This in turn could require higher LNG imports for Europe in 2025 and consequently lead to a tighter global gas balance.

The strong momentum behind LNG project development continued in 2024 even with no US projects reaching final investment decision

Since Russia's full-scale invasion of Ukraine, over 150 bcm per year of LNG liquefaction capacity has been approved. The **United States** alone accounted for 75% of the liquefaction capacity approved between 2022 and 2023. **The strong momentum behind LNG project development continued in Q1-Q3 2024**, with just over 45 bcm per year of LNG liquefaction capacity receiving approval, including Qatar's North Field West project.

In contrast, **no US LNG project has reached final investment decision (FID) since January 2024** following the introduction of a temporary pause on pending decisions for exports of LNG to countries that do not have free trade agreements with the United States. The Middle East was the driving force behind LNG project approvals globally in 2024, led by Qatar, the United Arab Emirates and Oman.

Together with Qatar's expansion projects, LNG liquefaction plants that have reached financial investment decision or are under construction would add over 270 bcm per year of export capacity by the end of 2030. This **strong increase in LNG production capacity** could loosen market fundamentals and ease gas supply security concerns in the second half of the decade.

Recent LNG contracting trends indicate a stronger interest in long-term, destination-fixed LNG contracts

LNG contracting activity since 2023 has displayed a trend towards long-term, destination-fixed contracts. **Agreements with a duration of at least 10 years** have accounted for 85% of the volumes contracted since the start of 2023. **Destination-fixed agreements** have regained traction and accounted for more than 70% of volumes contracted since 2023. **Large contracts** (over 4 bcm per year) accounted for 57% of contracted volumes in 2023, the largest share since 2017. Their share declined to 39% in 2024 but remained well above its five-year average. The **gas supply shock** of 2022/23 and consequent volatility may have reminded both buyers and sellers of the importance of long-term contracts to secure a stable supply and reduce short-term price variability.

The liquidity and pricing diversity of the global LNG market are expected to increase over the medium-term

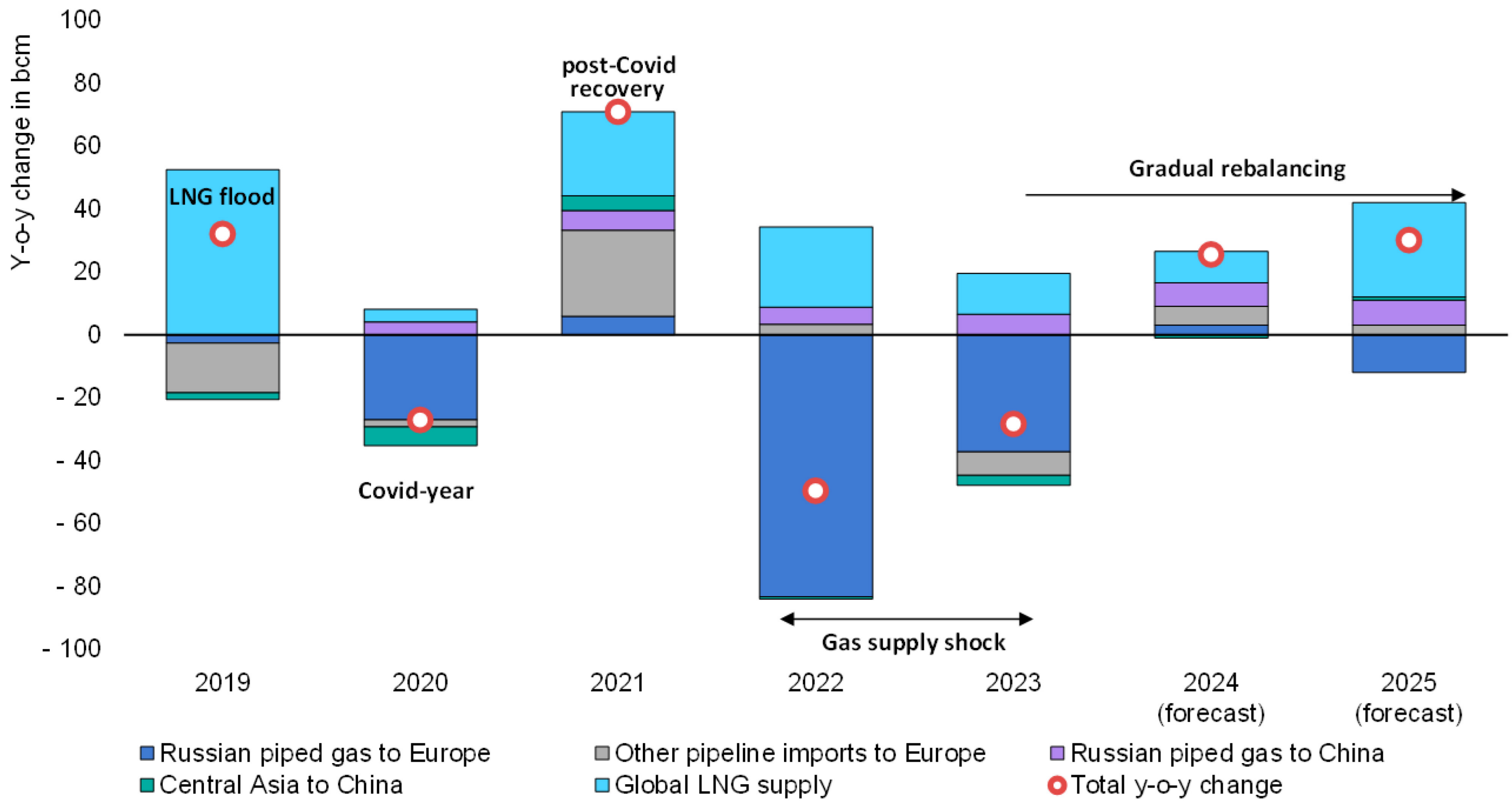
Despite the return to more traditional features in LNG contracting since 2023, the global LNG market is expected to gain in terms of depth and liquidity over the medium term. The share of **destination-free contracts** is expected to increase to 51% by 2027, amid the gradual expiry of destination-fixed legacy contracts and the entrance into force of new destination-flexible agreements. In addition to traditional suppliers, the role of **portfolio players** is set to further increase. Based on existing contracts, the share of portfolio players' procurement contracts in total LNG contracts in force is set to rise from 41% in 2023 to nearly 45% by 2027. **Pricing terms** are becoming more diverse. Based on existing contracts, the share of oil-indexed contracts is expected to shrink from 56% in 2023 to 52% by 2027 amid the growing role of gas-to-gas indexation and hybrid pricing formulae.

The transport sector can enable the system integration of low-emissions gases

Low-emissions gases can play an important role in the **decarbonisation of long-haul, heavy-duty transport,** where electrification so far has made slower progress compared with light-duty vehicles. The transport sector is expected to be a key driver behind incremental demand over the medium term. This year's *Global Gas Security Review* provides a special focus on the use of low-emissions gases in the transport sector.

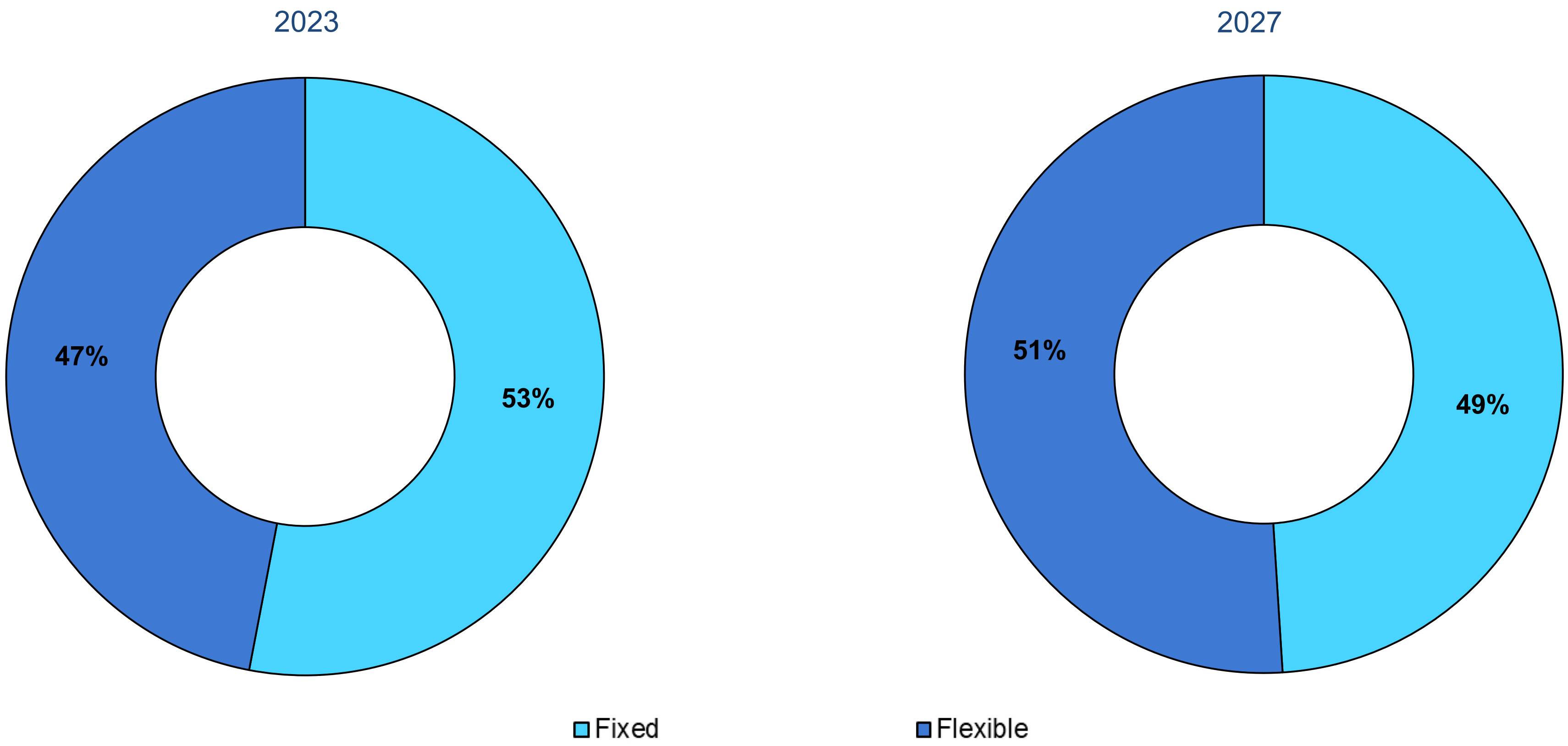
Global gas trade is set to continue to grow in 2025, supported by higher LNG supply

Year-on-year change in key piped natural gas trade and global LNG supply, 2019-2024



The flexibility of the global LNG market is set to increase over the medium term

LNG contracts by destination flexibility



Note: Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information. Destination-flexible contracts are typically underpinned by FOB shipping arrangements.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Review of key gas supply security events in 2024

Natural gas supply security concerns continued to fuel price volatility in 2024

Following the 2022-23 gas supply shock, **markets moved towards a gradual rebalancing** and returned to more pronounced growth in 2024. While natural gas prices have softened across all key markets compared to their 2022 highs, **the supply side remains fundamentally tight** amid below-average LNG supply growth. In this context, **markets remain sensitive and vulnerable** to unexpected supply- and/or demand-side movements. Uncertainties around future natural gas supplies, including from Russia, **continued to fuel price volatility**. Historical monthly volatility on the TTF month-ahead contract averaged 50% in Q1-Q3 2024, standing 34% above the historical average during 2010-21.

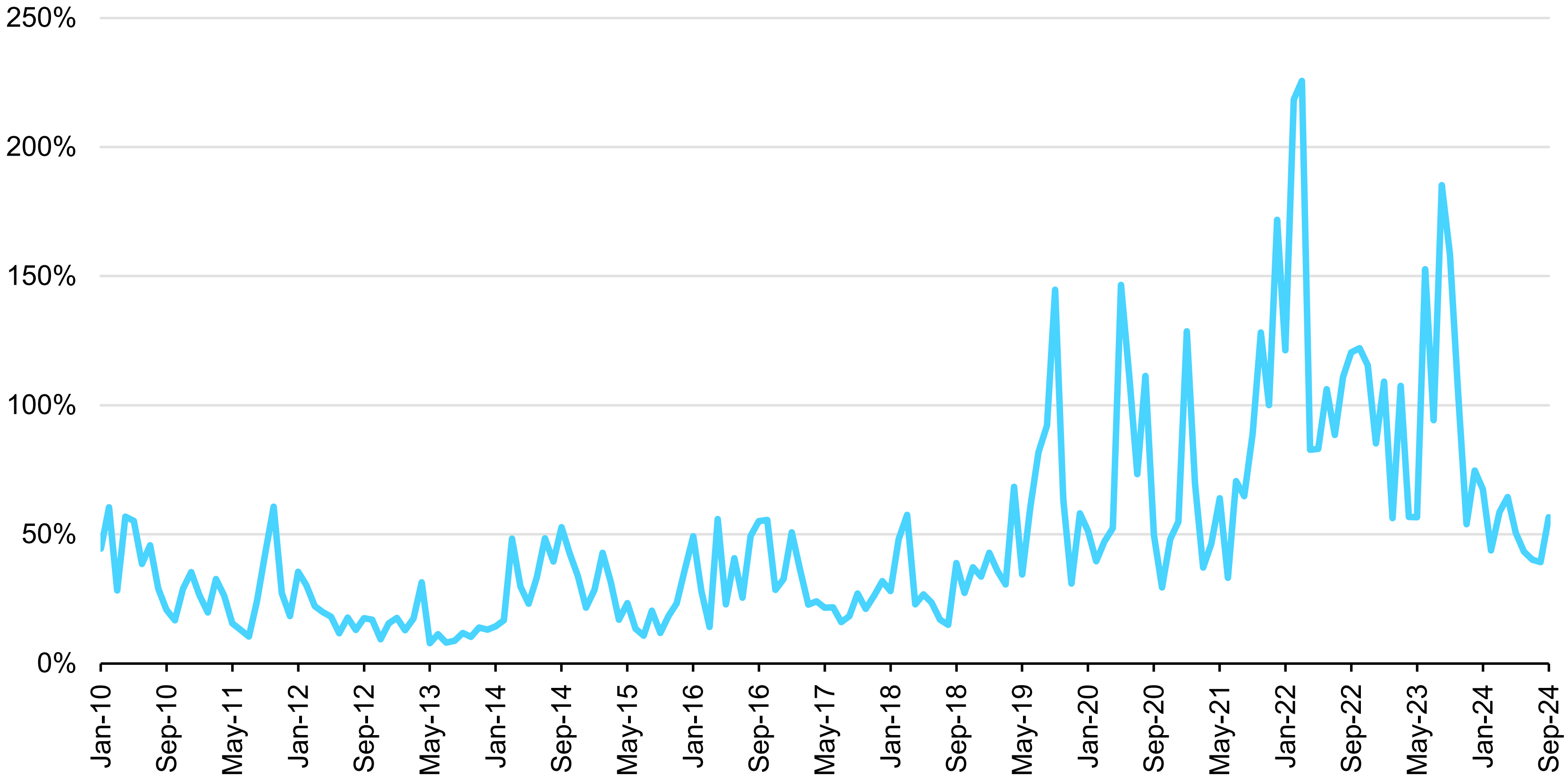
The interplay between gas supply flexibility and electricity security remained strong in 2024. In the **United States** winter storm Heather drove up electricity demand by nearly 20% in just four days, with gas-fired power generation meeting almost 80% of incremental demand. Gas storage played a crucial role in ensuring gas deliverability during the winter cold spell, as cold temperatures led to a steep decline in natural gas production due to wellhead freeze-offs. In **Colombia** in January the government declared a national disaster situation for a period of 12 months due to the impact of the El Niño weather phenomenon, which brought extreme drought and sizzling heatwaves. While Colombia's hydropower output decreased by over 25% y-o-y from January through to April, gas-fired power plants ramped up their output by more than 164% y-o-y during the same period. Colombia met the additional gas demand requirements primarily by increasing its LNG imports, which rose fifteen-fold y-o-y during the January-April period. **India** experienced its longest heatwave ever during the May-July period, with temperatures climbing to above 50 °C in certain parts of the country. Gas-to-power demand rose by 34% y-o-y during these three months, as higher cooling needs drove up electricity demand and increased the call on gas-fired power plants. LNG imports surged by 60% y-o-y during this May-July period, playing a key role in meeting incremental gas demand.

LNG shipping constraints emerged along key routes in 2024, with notable implications for global LNG trade. LNG shipping has practically dried up along the **Red Sea** since the beginning of 2024 due to rising security concerns amid the attacks by Houthis on commercial ships. The **Panama Canal** continued to face droughts in Q1, leading to restrictions on ship transits and increased congestion. While these events did not lead to a decline in LNG supply, they highlight the potential vulnerabilities of LNG trade in an increasingly interconnected global gas market.

The future of Russian gas transit via Ukraine is a key uncertainty ahead of the 2024/25 winter, as Russia's gas transit contract with Ukraine expires at the end of 2024. Some Central and Eastern European markets would be the most impacted by the halt of these transit flows.

Price volatility remained above historic averages in Q1-Q3 2024 amid tight supply fundamentals

Historical monthly price volatility on the TTF month-ahead contract (annualised), 2010-2024



Note: Historical volatility is a statistical measurement of the realised price variations of a specified contract over a specified time period.
Sources: IEA analysis based on Bloomberg (2024).

Flexible gas supplies play a key role in ensuring electricity supply security

Natural gas deliverability plays an increasingly important role in ensuring the security of electricity supply, especially during extreme weather events such as cold spells, droughts and summer heatwaves. As outlined below, the critical role of gas-fired power plants in meeting peak electricity demand has been demonstrated across various markets facing severe weather conditions in 2024. The flexibility of gas supplies was ensured via storage operations, LNG procurement and enhanced pipeline interconnectivity.

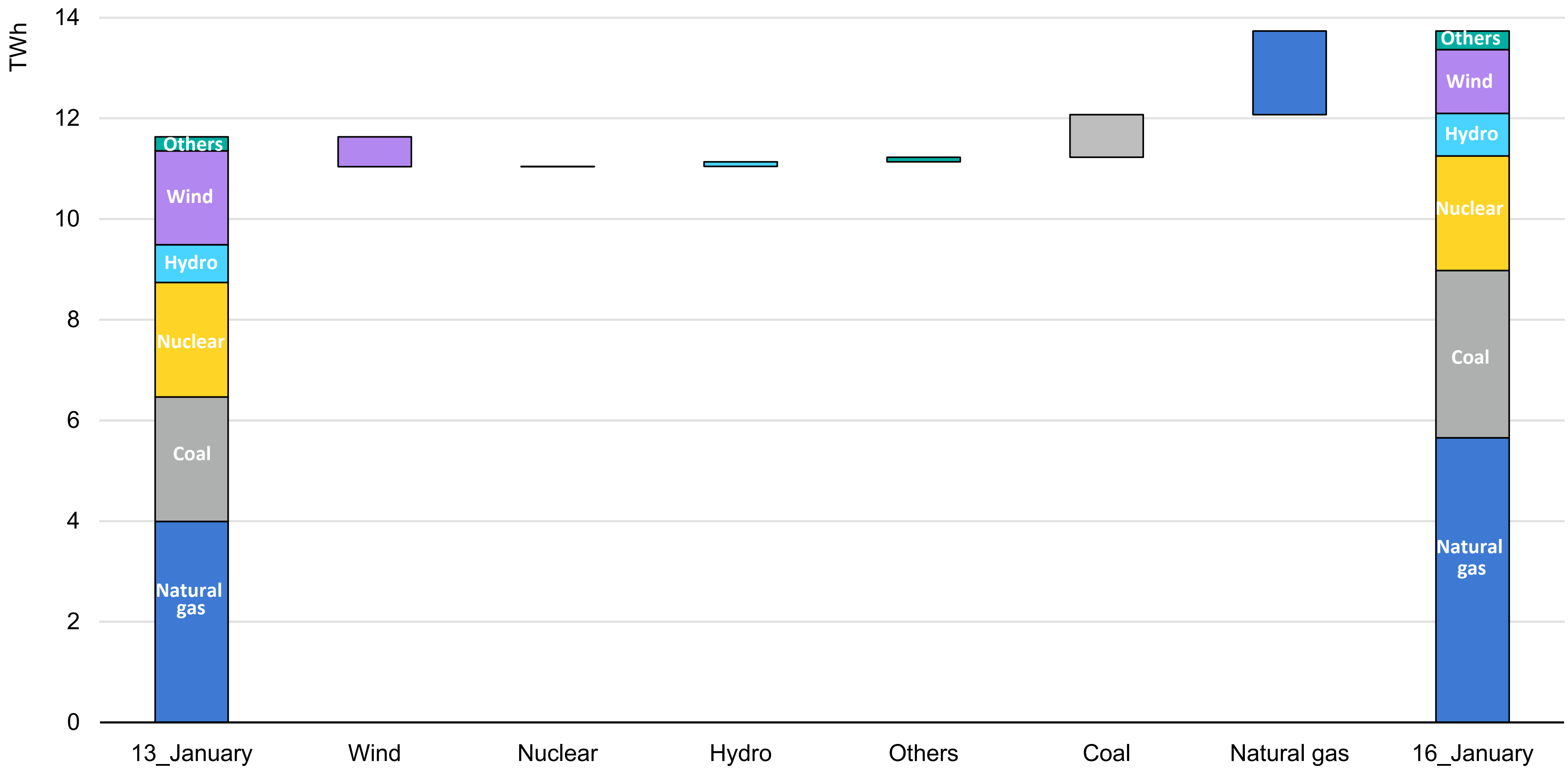
Winter storm Heather: A cold test for the US power system

Winter storm Heather entered the Northwest of the United States on 13 January 2024 and then spread to the Southern states during 15-17 January, including Texas and Louisiana. **Heating degree days** (HDDs) surged by 60% between 11 and 16 January and drove up natural gas demand to an all-time high of over 3.9 bcm/d. Natural gas demand in the **residential and commercial sectors** rose by 70% between 11 and 16 January as below-average temperatures supported higher space heating requirements**.**

Electricity consumption increased by nearly 20% between 13 and 16 January, primarily driven by households and commercial entities relying on electricity for space heating. **Wind power generation** declined by nearly 30% between the same dates, while hydro and nuclear power output remained broadly flat. In this context, coal- and gas-based generation met virtually all the incremental electricity demand. **Gas-fired power plants** increased their output by more than 40% between 13 and 16 January and alone accounted for nearly 80% of additional power generation. Consequently, the share of natural gas in the US electricity mix rose from 34% on 13 January to over 40% on 16 January. **Winter storm Heather also led to freeze-offs**, which occur when water and other liquids in the raw natural gas stream freeze at the wellhead or in natural gas gathering lines near production activities. Consequently, **natural gas production in the United States declined** by close to 8% week-on-week during the period between 11 and 17 January. In this context, natural gas **storage sites** played a key role in ensuring gas supply flexibility and deliverability. Net storage withdrawals more than doubled during the storage week ending 19 January. It is estimated that gas storage sites met approximately one-third of US gas demand during that period. Tight supply-demand fundamentals **drove up natural gas prices** during winter storm Heather, with Henry Hub spot prices spiking at USD 13/MBtu, its highest level since winter storm Uri in February 2021. Despite the severe weather conditions and tight supply-demand fundamentals, there was **zero system operator-initiated load shedding** during winter storm Heather. Generators reported fewer outages as compared to past winter storms partly due to improved winter preparedness and enhanced gas generator stability. **Winterisation measures** undertaken by natural gas entities enhanced gas deliverability compared to previous winter storms.

Natural gas played a key role in ensuring electricity supply security during winter storm Heather

Change in daily power generation, United States, 13-16 January 2024



Source: IEA analysis based on EIA (2024), Hourly Electric Grid Monitor.

As hydro falls short, gas powers Colombia through El Niño

From October 2023 to April 2024 Colombia faced a severe drought triggered by the El Niño phenomenon. As water levels in reservoirs plummeted, hydropower output – typically providing around 70% of Colombia's electricity – declined sharply, forcing the country to rely more heavily on thermal power plants to meet the increased demand, driven largely by higher temperatures.

The World Meteorological Organization warned of the development of an El Niño event as early as March 2023, which led Colombia to ramp up LNG imports by 370% or 0.82 bcm from April to December 2023 compared with the same period in 2022. Additionally, disruptions in Colombian gas company Canacol's domestic gas production and treatment facilities in the Caribbean region added to the strain, pushing utilities to import more LNG to fulfil firm energy obligations. LNG imports peaked at a historical monthly high of 0.27 bcm in September 2023, while natural gas reached its highest share of the electricity mix for that month (21.7%) as coal, even at its highest load factor, could not fully offset the hydro shortfall.

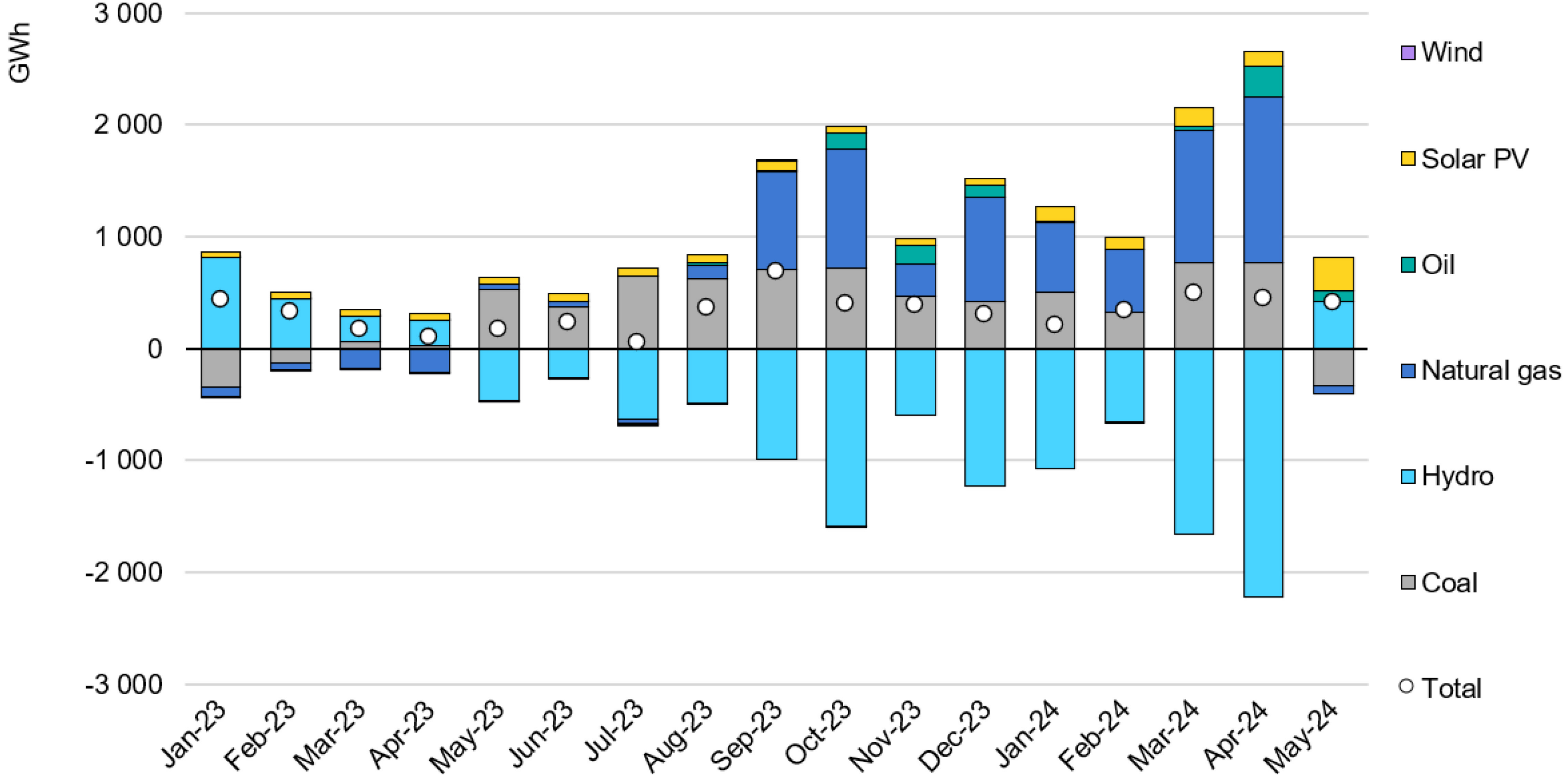
The situation worsened as rainfall remained well below average, particularly from January to mid-April 2024. Gas-fired power plants played a crucial role during this period, providing backup that helped maintain water reserves above the 27% critical level, the threshold below which the country would face its first electricity rationing in more than 30 years. Between January and April 2024 Colombia imported 1.1 bcm of LNG through the SPEC regasification terminal in Cartagena, accounting for nearly 30% of the facility's total imports since it began operations in December 2016. These imports, primarily from the United States and Trinidad and Tobago, were vital in managing the 2024 crisis.

Despite these efforts, including increased coal-fired power generation, halting electricity exports to Ecuador and implementing water rationing, reservoir levels dipped below 29% in mid-April 2024, approaching the critical threshold. Consequently, on 15 April the Minister of Energy and Mines, Andrés Camacho, ordered all Colombian thermal power plants to operate at maximum capacity every day. Gas-fired power generation surged to an average of 65 GWh per day in April 2024, quadrupling the previous April's output. During this time, hydropower generation fell by 40%, reaching its lowest share of the electricity mix since March 2016 (49.2%). The crisis came to a swift end with abundant rains in late April, which helped to replenish reservoir levels and stabilise the electricity supply.

With the Cartagena terminal working at full capacity (400 mcf/d) in April 2024, this episode of low hydro generation, high electricity demand and declining domestic gas production, coupled with limited coal-fired capacity, raised concerns about a potential power-demand supply gap of 4-5 TWh by 2027-2028. The Colombian gas industry has underscored the need for greater market flexibility, increased investment in domestic production, and expanded regasification and transport infrastructure to ensure the country's gas supply in the coming years.

Colombia’s gas-fired power generation provided backup amid low hydro availability

Y-o-y change in monthly power generation by fuel, Colombia, 2023-2024



Source: IEA Monthly Electricity Statistics.

India’s prolonged heatwave drives gas-fired power generation to multi-year highs

During Q2 2024 the Indian subcontinent experienced one of the longest and most intense heatwaves in recent decades. Temperatures remained above 40 °C for extended periods in several major cities across India, including New Delhi, and often exceeded 50 °C in the northern and central parts of the country between April and June 2024.

These extreme temperatures led to widespread droughts, water shortages, over 100 confirmed heat-related deaths and tens of thousands of heat-related illnesses, while surging cooling demand put a strain on the country’s electricity grid.

On average, cooling degree days were 7% higher in Q2 2024 compared with Q2 2023 across India. However, certain regions experienced much steeper increases in cooling demand than the national average, including the capital territory (up 21%) and Uttar Pradesh (up 12%).

Power demand in India surged by 11% y-o-y in Q2 2024, and gas-fired generation was up by 63% over the same period, pushing the country’s underutilised gas-fired fleet to dispatch levels not seen since the global gas price collapse in 2020.

The steep ramp-up of India’s gas-fired power generation was partly driven by relatively low spot LNG prices (averaging USD 11 per MBtu in Q2) and the Power Ministry’s decision to invoke Section 11 of the Electricity Act of 2003, directing idle gas-fired plants to operate during the power crunch.

LNG imports covered most of the increase in gas-to-power demand, which coincided with double-digit growth in gas use by other sectors, including city gas distribution, refining and small industries, during the Q2 2024 heatwave.

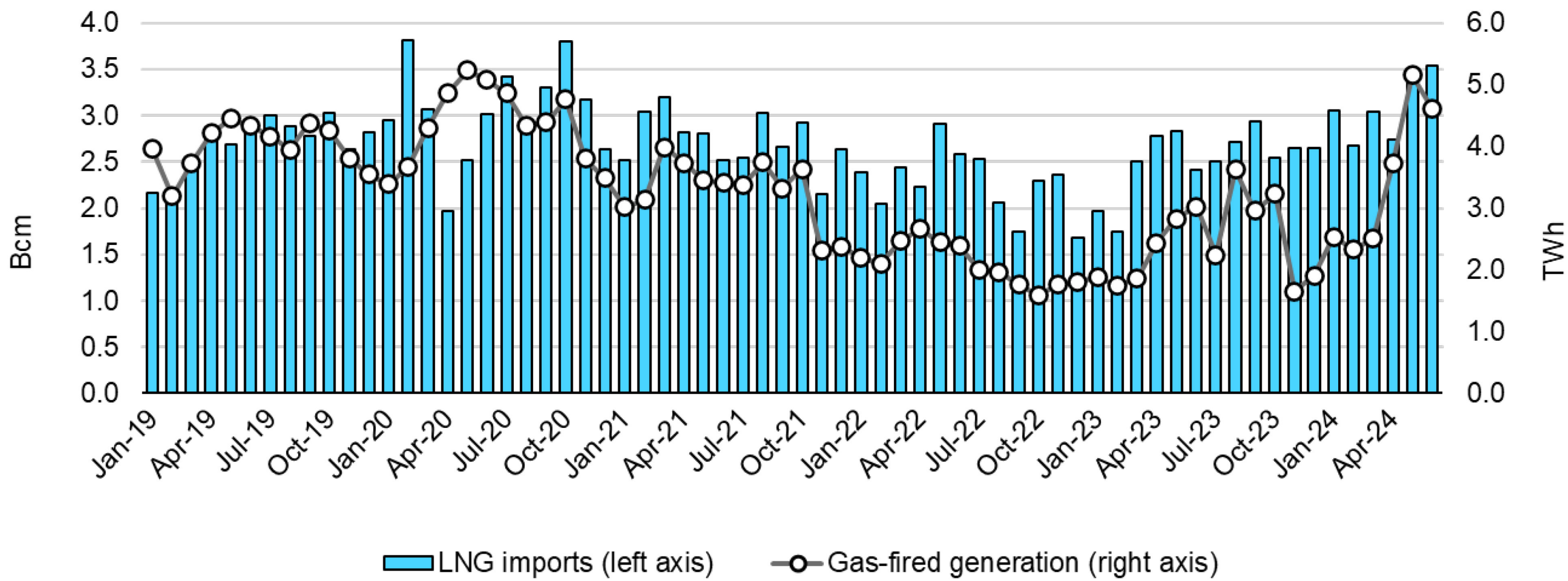
Total LNG imports in India rose by 20% y-o-y in Q2 2024, and monthly imports recorded a near 50% y-o-y increase in June, reaching their highest level (at over 3.5 bcm) since 2020.

Spot market purchases covered most of India’s incremental LNG imports. Indian buyers awarded more than two dozen LNG tenders with delivery windows in Q2 2024, about 30% more than a year earlier.

India has increased its effective LNG import capacity by half since 2020 with downstream infrastructure debottlenecking, terminal expansions and new regasification projects, and it also completed more than 6 500 kilometres of domestic gas transmission pipelines in the same period. This has greatly improved the country’s ability to tap into the spot LNG market during periods of tight domestic supply or low international prices.

India's gas-fired power generation rose to multi-year highs in Q2 2024

Monthly LNG imports and gas-fired power generation, India, 2019-2024



Sources: IEA analysis based on ICIS (2024), LNG Edge; Ember (2024), Yearly electricity data.

Shipping routes: At the crossroads of natural gas supply security

LNG shipping faced unprecedented logistical challenges in 2024 as low water levels in the Panama Canal and militant attacks near the Suez Canal imposed severe limitations on LNG flows through both major arteries of global LNG trade simultaneously. Although these bottlenecks have not led to major market dislocations or LNG trade disruptions so far, the risks to LNG shipping logistics have clearly increased.

The **Panama Canal,** which depends on sufficient rainfall and high water levels in Gatun Lake, was forced to reduce the number of daily transits during a severe drought that started in 2023 and continued into 2024. These restrictions initially caused major delays for all types of commodities, including LNG cargoes. The total number of vessels waiting to cross reached an all-time high of 163 (and waiting times reaching 21 days) in August 2023. By early 2024 LNG transits through the Panama Canal had almost completely dried up, and only started to recover slowly during the second and third quarters. In August 2024 the Panama Canal Authority eased some of the transit restrictions thanks to rising water levels at Gatun Lake and increased the number of booking slots available for LNG vessels to three slots per day from two previously. This was complemented by other measures to enhance transit operations. However, despite this increase in transit capacity for LNG tankers through the Panama Canal, actual LNG transits in August 2024 were still some 70% lower than a year earlier.

The **Suez Canal**, meanwhile, has been rendered nearly impassable by the worsening security situation in the Middle East since the beginning of 2024. Indiscriminate attacks on commercial vessels by Houthi rebels on the Red Sea forced shipping operators, including LNG tankers, to avoid the Suez Canal altogether, with only a few exceptions. LNG transits via the Suez Canal decreased by almost 90% y-o-y for the period covering January to September. Most of the remaining crossings in 2024 involved LNG vessels discharging at Aqaba in Jordan or Ain Sukhna in Egypt, thus avoiding crossing the Red Sea. However, a small number of ballast LNG vessels from Asia did manage to cross the Red Sea and pass through the Suez Canal on their way to Arctic LNG 2 and Murmansk in Russia.

This simultaneous disruption on the Panama and Suez canals forced LNG carriers to reroute around the Cape of Good Hope, which, in turn, saw an unprecedented spike in LNG transits. During the first eight months of 2024, laden LNG circumnavigations increased nearly fivefold y-o-y, adding to transit times and operational costs. Due to the longer shipping routes, LNG ton-mile demand increased by an estimated 11% during the first seven months of 2024, while LNG trade growth was virtually flat over the same period.

However, the LNG shipping fleet has been able to accommodate the increased ton-mile demand with little difficulty so far and hence limited the impact on LNG trade flows.

Despite the ongoing shipping constraints via the Panama Canal and the Red Sea, **spot LNG charter rates, which represent only a small fraction of the global LNG shipping market, have remained steady throughout this year and well below 2023 levels,** with quarterly averages 30% to 40% down from last year's levels. For example, the day rate for two-stroke LNG carriers in the Atlantic stands on average at USD 73 000 in Q3 2024, compared with more than USD 125 000 in Q3 2023. The Pacific and Atlantic LNG shipping spot markets seem to have found a new equilibrium, indicating a sufficient number of LNG vessels available in both basins, further facilitated by commercial swaps.

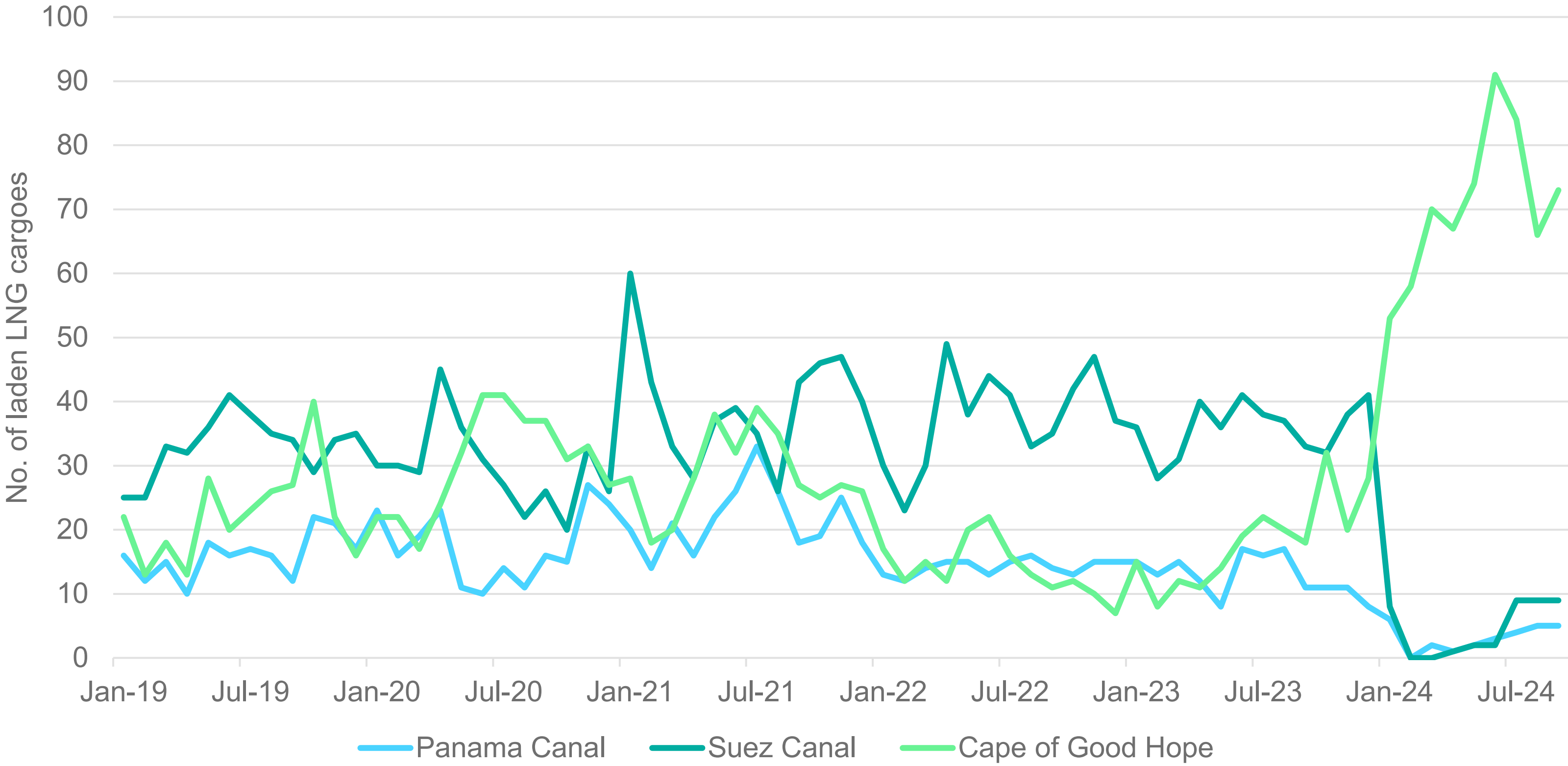
Considering the current order book, the LNG carrier fleet is set to grow considerably over the next few years. This is in line with orders for newbuild ships, which are intended to meet the future needs of new LNG liquefaction projects, particularly in Qatar and the United States, and to replace older ships with more efficient and lower-emission vessels. Delays at LNG production facilities, such as those already announced at Golden Pass in the United States, could result in a fleet of LNG carriers that is larger than is required for the world’s transport needs in 2025.

The remarkable ability of the LNG carrier fleet to adapt flexibly and without a dramatic price response to a dual disruption in shipping logistics should not lead to complacency. The substantial lengthening of journey times due to the canal constraints means that LNG importers are more exposed to sudden price spikes and temporary fuel shortages in the event of unexpected demand shocks, such as the January 2021 cold spell in Northeast Asia.

The geopolitical turmoil in the Middle East may also escalate and spread to other LNG shipping routes. Any disruption of LNG flows through the Strait of Hormuz, which accounts for more than 20% of global LNG transits, could easily trigger another global energy crisis, although the likelihood of a sustained blockade remains fairly low.

Red Sea disruption and Panama Canal bottleneck make LNG flows more regional, but also mean longer voyages via Cape of Good Hope

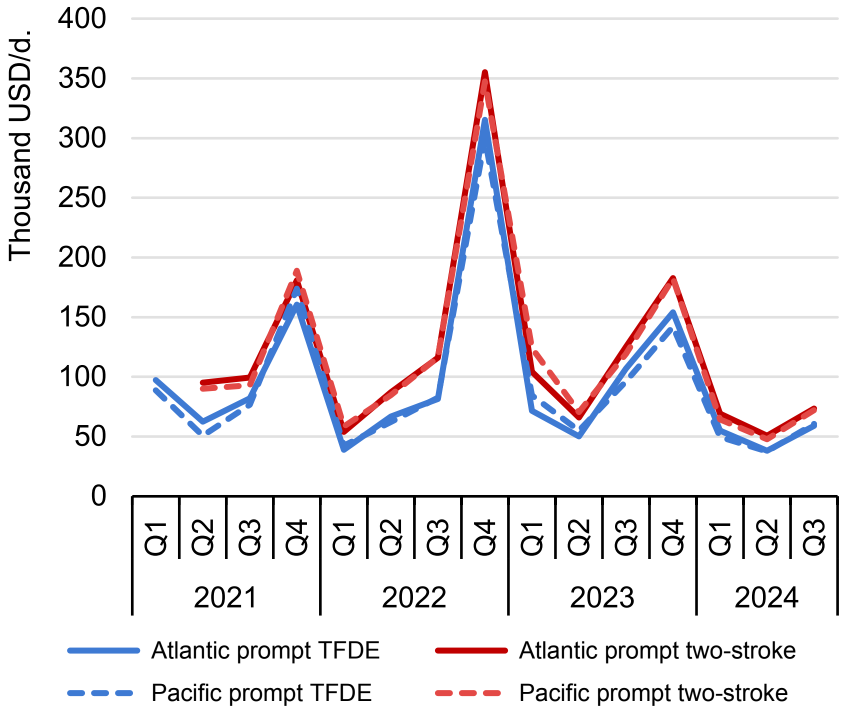
Monthly transit of laden LNG cargoes for the main shipping routes, January 2019-September 2024



Source: IEA analysis based on Bloomberg (2024).

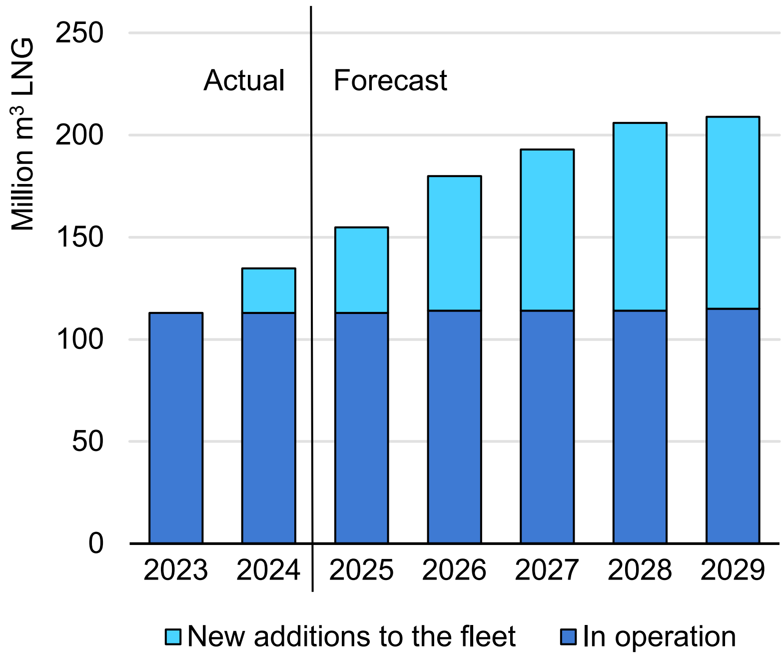
2024 spot LNG charter rates remain low amid full order books for new tankers

Quarterly average day rate for LNG carriers in Atlantic and Pacific basins, Q1 2021-Q3 2024



Note: This graph shows freight prices for TFDE (tri-fuel diesel electric) and two-stroke (the most modern) vessels, for prompt deliveries (up to 90 days' charter with delivery within 40 days), for both the Atlantic and Pacific basins.

Evolution in the transport capacity of the LNG tanker fleet, 2023-2029



Note: Vessels due to leave the fleet from 2025 are not included in this graph.

Source: IEA analysis based on ICIS (2024), LNG Edge.

Gas transit via Ukraine: A key uncertainty ahead of the 2024/25 winter season

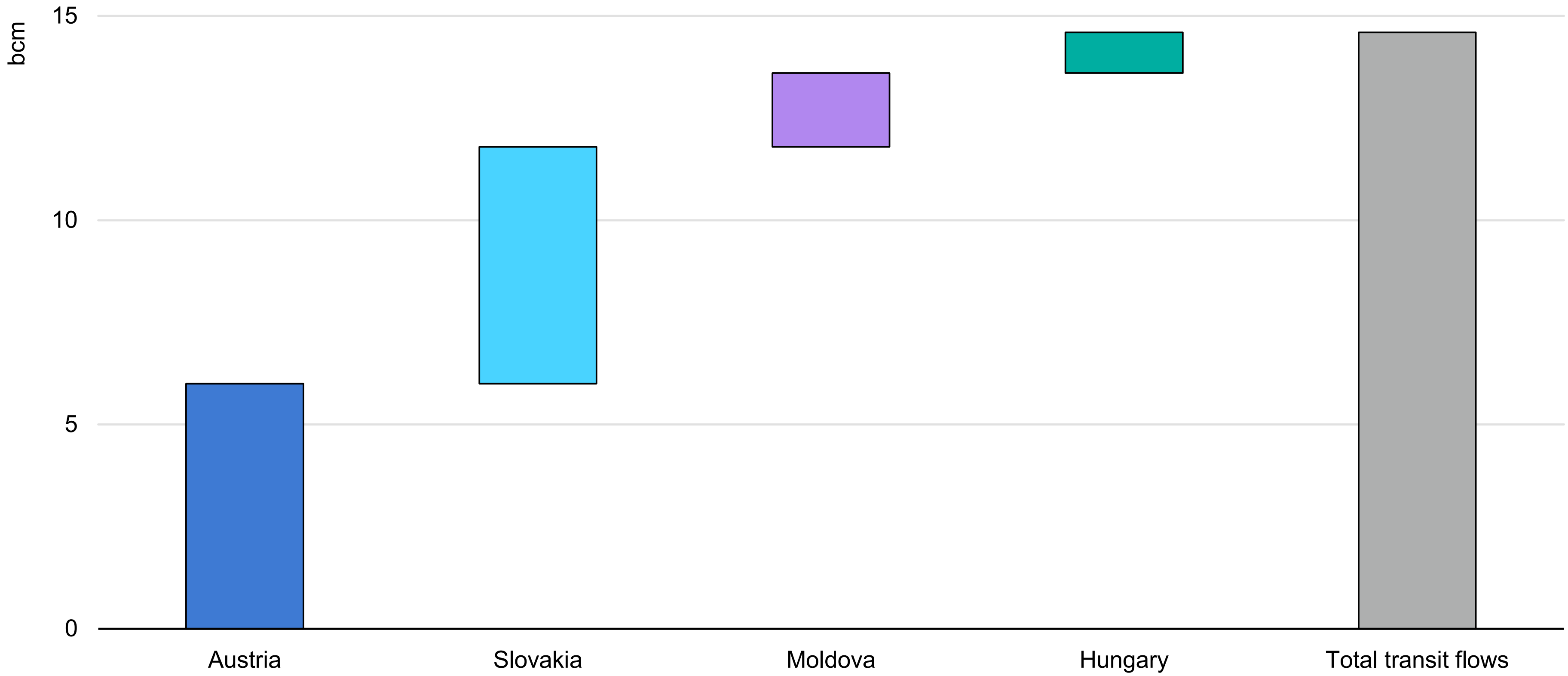
The future of Russian gas transit via Ukraine is a key uncertainty ahead of the 2024/25 winter, as both the transit and interconnector agreements between Russia and Ukraine expire at the end of 2024. While Russian gas transited via Ukraine met only a small share of total EU gas demand in 2023, the halt of these transit flows would significantly affect some Central and Eastern European markets and Moldova.

Gazprom and Naftogaz Ukrainy signed a five-year transit contract at the end of 2019. **The volumes transited via Ukraine have fallen steeply in recent years**, from around 90 bcm in 2019 to below 15 bcm in 2023. In 2023 Russian gas transit flows via Ukraine contracted by 28% y-o-y and totalled 14.65 bcm. Of this, around 12.8 bcm was sent to the European Union and an estimated 1.8 bcm was delivered to **Moldova**. The majority of these deliveries are performed under **long-term supply contracts** with a duration well beyond 2024. The main recipients of Russian piped gas via Ukraine in 2023 were **Austria, Hungary, Moldova and Slovakia**. While Russian gas transited via Ukraine accounted for less than 4% of total EU gas demand in 2023, the Ukrainian transit route met around 65% of the combined gas demand of Austria, Hungary and Slovakia. Flow data suggest that Hungary effectively reduced its reliance on the Ukrainian transit route in 2024. Furthermore, Ukraine received around 4.3 bcm of gas from the European Union and Moldova in 2023. Some of this gas is supplied through the reversal of Russian piped gas flows. **The transit and interconnector agreements between Ukraine and Gazprom expire at the end of 2024**. The Ukrainian gas transmission system operator has publicly stated that the interconnector agreement will not be renewed. While a political agreement might be still found, there are significant risks that transit via Ukraine will be discontinued from January 2025. The ability to **reroute transit volumes via Türkiye is limited**, as there is no additional capacity available through the TurkStream pipeline system.

This forecast assumes no Russian piped gas deliveries via Ukraine to Europe from January 2025. The halt of this gas transit would translate into the loss of around 6 bcm of gas supply into the European Union in Q1 2025 and would necessitate higher European LNG imports in Q1 2025. This in turn would drive stronger competition with Asian buyers for flexible LNG cargoes and lead to tighter market fundamentals. Our assessment indicates that the halt of Ukrainian transit would not pose an immediate supply security risk to Austria, Hungary or Slovakia considering their ample storage capacity, midstream interconnectivity and indirect access to the global LNG market (including via new FSRUs in Germany and Italy). The vulnerability of Moldova is significantly greater and would require close co-operation between Moldova and regional and international partners to ensure energy supply security over the winter season.

Central and Eastern European markets would be the most affected by a halt of Russian piped gas flows via Ukraine

Estimated deliveries of Russian piped gas via Ukraine by country, 2023



Source: IEA analysis based on ENTSOG (2024), Transparency Platform.

Gas market update

Global gas demand in Q1-Q3 2024 grew by more than its historical average growth rate

Natural gas demand **returned to more pronounced growth in 2024** as markets gradually rebalanced following the 2022-23 gas supply shock triggered by Russia's invasion of Ukraine. Around half of this demand growth was concentrated in Q1. Limited LNG supply growth and geopolitical tensions provided upward pressure on gas prices across key import markets in Q2-Q3, which in turn weighed on gas demand growth rates. Improving hydro availability in China and South America further limited gas-to-power demand growth.

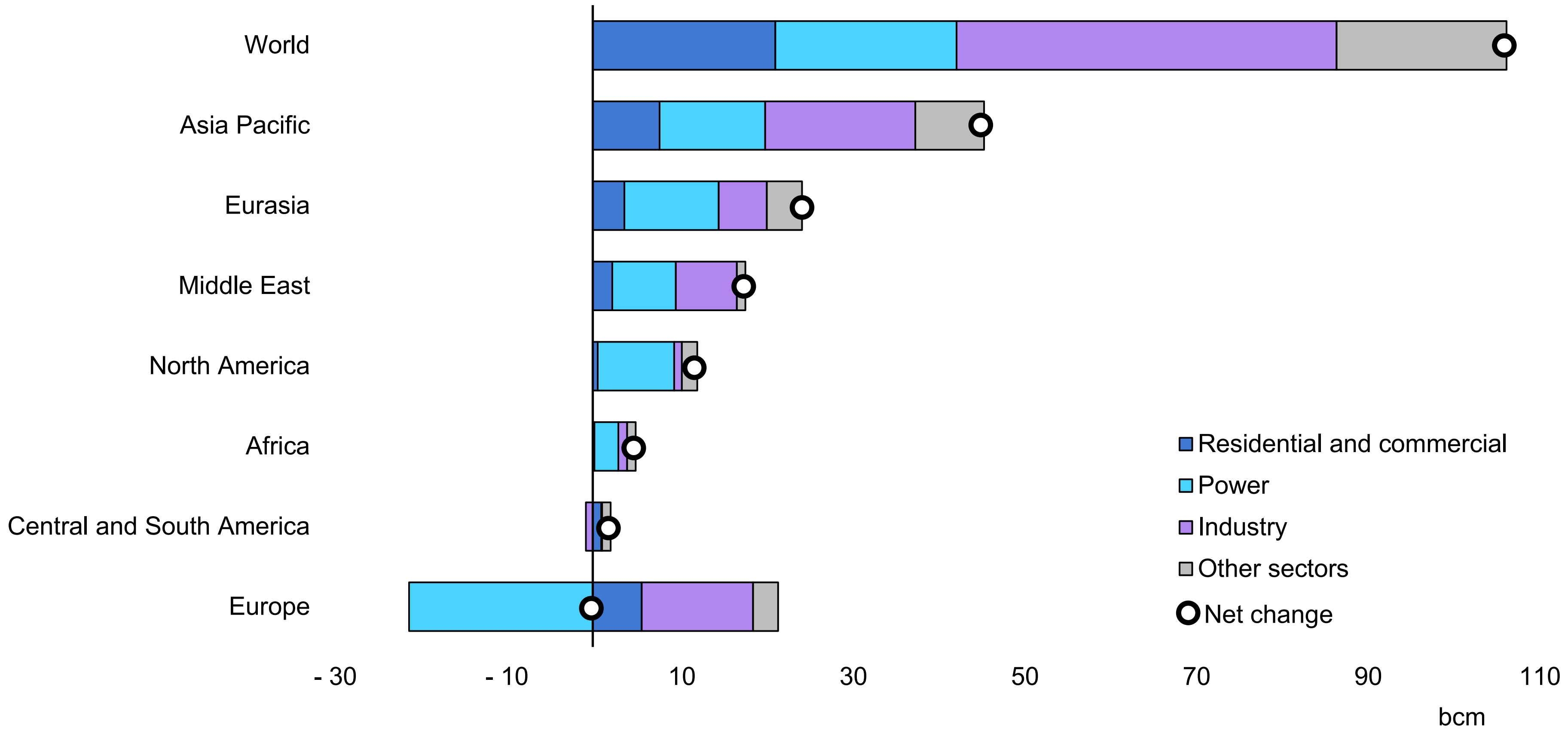
Preliminary data suggest that **natural gas demand increased by 2.8%** (or 65 bcm) in Q1-Q3 2024 in the selected markets covered by this market update.[2] This is well above the historical 2% average growth rate between 2010 and 2020. Asia alone accounted for around 60% of the incremental gas demand, primarily driven by China and India. Demand growth was largely supported by **higher gas use in industry**, contributing almost 60% of the demand growth in Q1-Q3 2024. **Gas-to-power demand** grew by an estimated 2% y-o-y, as the strong gains in North America, the fast-growing Asian markets and Eurasia were partially offset by lower gas-fired power generation in Europe. Gas demand in the **residential and commercial** sector grew by just over 2% y-o-y as an **unseasonably warm Q1** weighed on space heating requirements in Europe and North America.

For the full year of 2024, global gas demand is forecast to grow by just over 2.5% (or more than 100 bcm). Gas demand in the **Asia Pacific region** is forecast to expand by close to 5% compared with 2023 and account for almost 45% of incremental gas demand. **Industry and energy own use** are expected to account for nearly 55% of incremental gas demand in 2024. This is partly supported by continued economic expansion in the fast-growing Asian markets, as well as recovery in Europe's industrial gas demand – albeit remaining well below the region's pre-crisis levels. Natural gas demand in the **residential and commercial sector** is expected to increase by 2.5% in 2024, assuming average weather conditions in Q4. **Gas-to-power** demand is forecast to increase only marginally, as higher gas burn in gas-rich regions and the fast-growing Asian markets is partially offset by projected declines in Europe. **Global gas demand is forecast to increase by another 2.3%** (or nearly 100 bcm) in 2025. Similarly to 2024, this growth is **largely supported by Asia**, which alone is expected to account for over half of incremental gas demand. **Industry remains the primary driver** behind stronger gas use and is projected to account for over one-third of demand growth. **LNG supply growth** is forecast to increase by 6% (or near 30 bcm), while **Russia's piped gas transit via Ukraine** is expected to halt, resulting in a supply loss of nearly 15 bcm.

[2] Asia Pacific, Central and South America, Eurasia, Europe and North America.

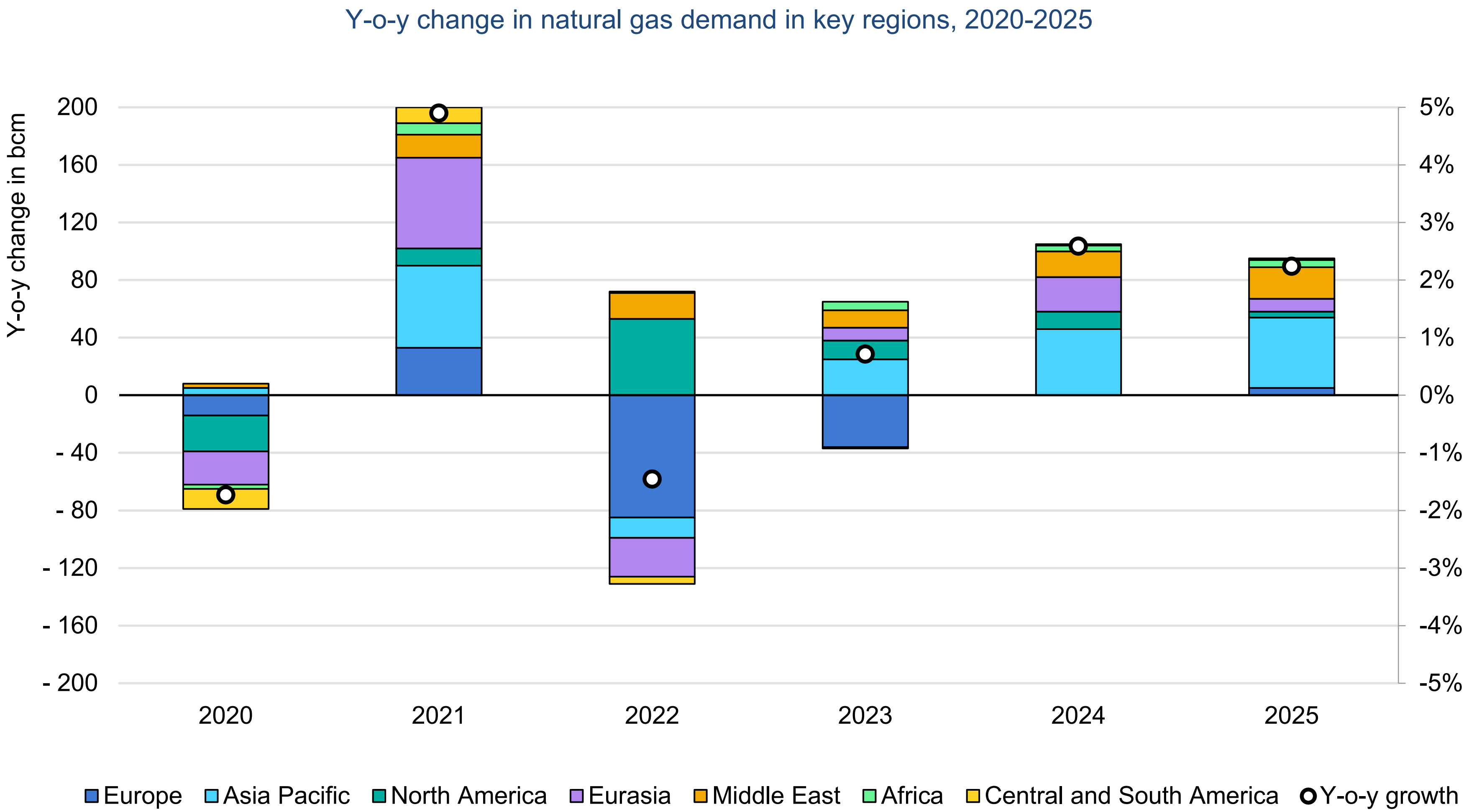
Industry emerges as the primary driver behind incremental gas demand in 2024

Forecast change in natural gas consumption by region and sector, 2024 vs 2023



IEA. CC BY 4.0.

Asia is expected to account for over half of gas demand growth in 2025



North American gas demand increased by an estimated 1% in Q1-Q3 2024…

Natural gas consumption in North America rose by an estimated 1.5% (or 11 bcm) y-o-y in the first three quarters of 2024. This growth was **primarily supported by gas-to-power demand**, which increased in all markets of the region. In contrast, natural gas use in the residential and commercial sectors declined amid unseasonably mild weather conditions in Q1. Natural gas demand in industry increased marginally compared with 2023. Demand **growth was concentrated in H1 2024** (up by 2% y-o-y), while preliminary data suggest that natural gas consumption remained close to last year's levels in Q3 2024.

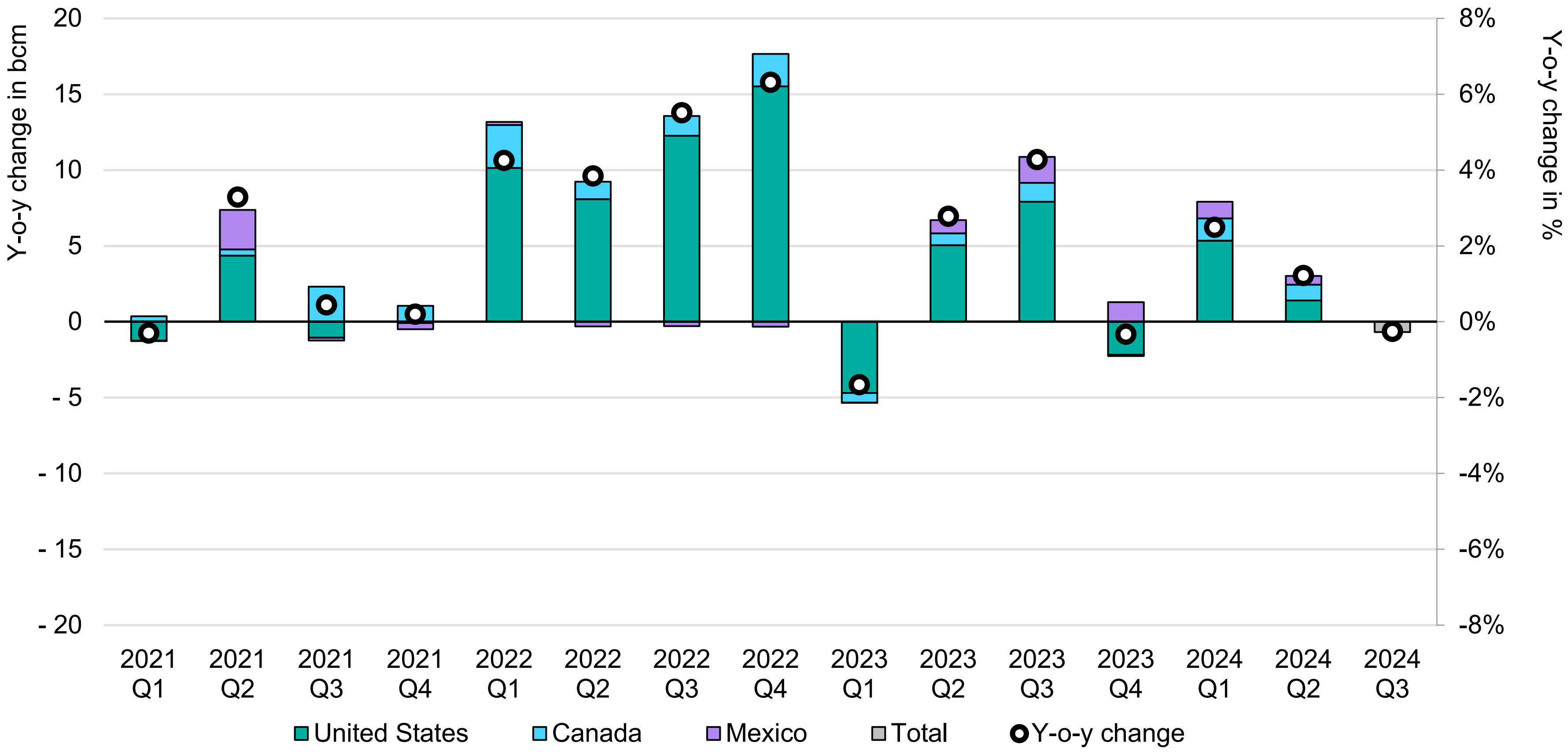
In the **United States** natural gas consumption increased by an estimated 1% (or 6.5 bcm) y-o-y in Q1-Q3 2024, with growth primarily driven by the power sector. Natural gas demand in the residential and commercial sector fell by around 2% (or 3 bcm) y-o-y during the same period. While winter storm Heather boosted space heating demand in January, milder weather conditions during February-May moderated gas use in the residential and commercial sector. In contrast, gas burn in the **power sector** continued its expansion and rose by nearly 3% (or over 8 bcm) y-o-y in Q1-Q3 2024. This growth was primarily supported by higher electricity consumption. Sizzling heatwaves pushed up gas-fired power generation to an all-time high in July. Preliminary data suggests, that gas-to-power demand stood slightly below its last year's levels during August and September. Natural gas demand in **industry** remained close to last year's levels in Q1-Q3 2024.

In **Canada** natural gas consumption increased by an estimated 3.5% (or 3 bcm) y-o-y in Q1-Q3 2024. Similarly to the United States, unseasonably mild weather conditions weighed on gas use in the residential and commercial sector, which declined by 9% (or almost 2 bcm) y-o-y in the first five months of 2024. Combined gas demand in the industrial and power sectors rose by over 8% y-o-y in the first seven months of 2024, largely supported by stronger gas-fired generation at the expense of coal-fired power plants. In **Mexico** natural gas consumption grew by an estimated 2% (or 1.5 bcm) y-o-y in Q1-Q3 2024 amid the continued expansion of gas-fired power generation. Higher gas demand in Mexico supported stronger piped gas imports from the United States (up by 5% y-o-y in H1 2024). In August, Mexico exported its first LNG cargo from the Altamira floating LNG (FLNG) facility, which relies on US feedgas supplies.

For the full year of 2024, natural gas demand in North America is forecast to increase by 1%, with growth primarily supported by the power sector. In 2025 natural gas demand is projected to remain close to its 2024 levels. After reaching an all-time high in 2024, gas-to-power demand is expected to marginally decline in 2025 amid the continued expansion of renewables. In contrast, gas use in the residential and commercial sector is expected to increase, assuming average weather conditions.

…with growth primarily concentrated in H1 2024

Estimated y-o-y change in quarterly natural gas demand, North America, 2021-2024



Sources: IEA analysis based on EIA (2024), Natural Gas Consumption; Natural Gas Weekly Update; ICIS (2024), LNG Edge; Statistics Canada (2024), Supply and disposition of natural gas, monthly.

Extreme weather spurs gas demand, but fundamentals cap growth in Central and South America

Preliminary data show that natural gas consumption in Central and South America rose by 0.7% y-o-y in the first three quarters of 2024, driven by increased usage for power generation and in the residential and commercial sector. This demand growth led to a 7.3% y-o-y rise in LNG imports, although trends varied between countries.

In **Argentina**, the region's largest gas market, natural gas demand increased by 2.5% or 0.62 bcm in the first 7 months of 2024. While the second-coldest winter in 60 years boosted residential and commercial demand by 10% or 0.47 bcm y-o-y in H1 2024, industrial gas use fell by 3% or 0.23 bcm due to the ongoing recession. In contrast, gas-to-power demand rose by 3% or 0.24 bcm, despite June and July seeing a sharp decline as gas input to power plants fell by a quarter compared with the previous year. Increased shale gas production in the Vaca Muerta formation supported a 5% rise in exports and a 47% reduction in LNG imports, which reached just 1.41 bcm in the January-August period, the lowest in over a decade.

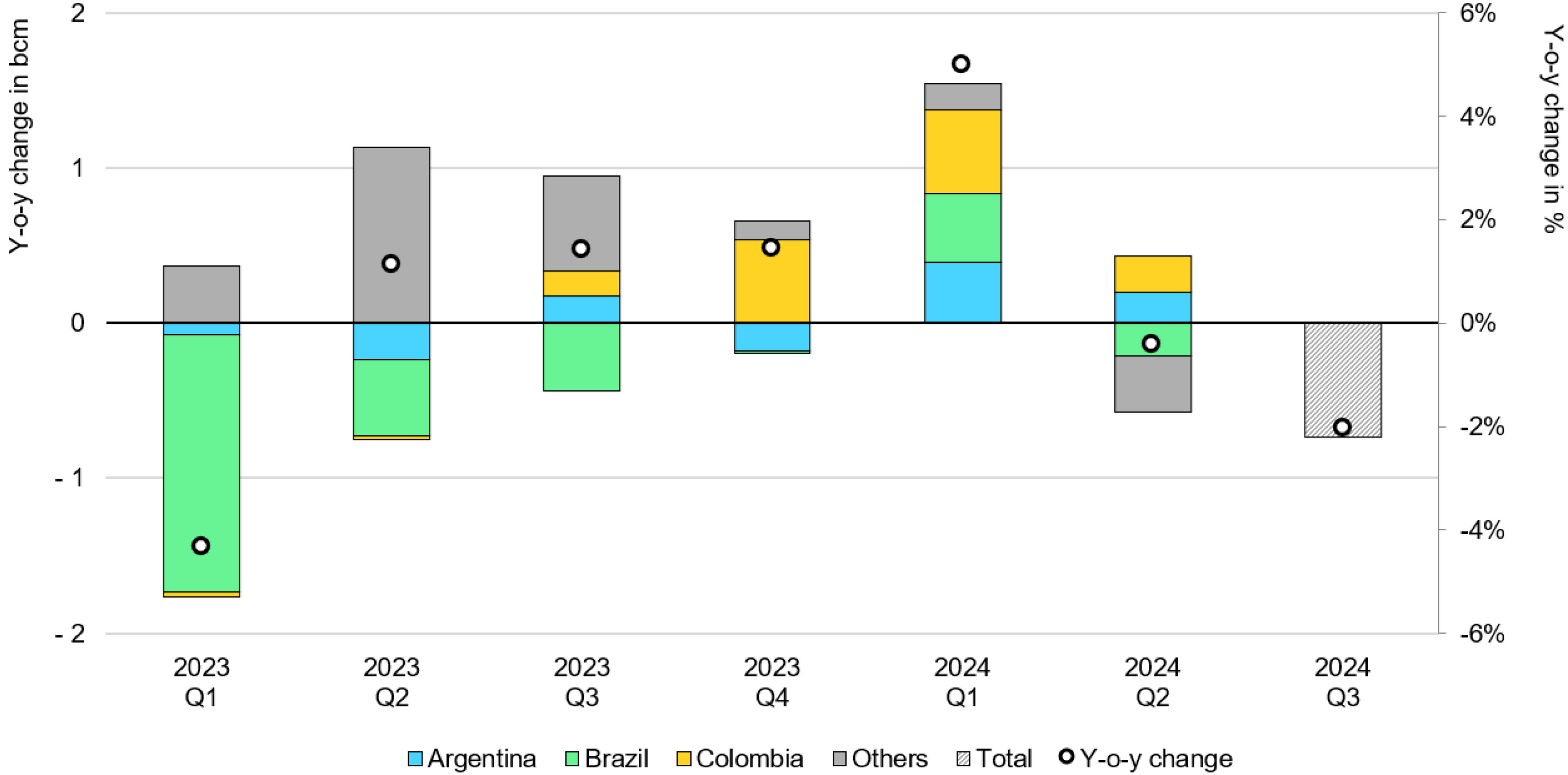
Droughts in **Brazil** are leading to the lowest hydropower output since mid-2021, and resulted in a 20% increase in backup gas-fired power output during the first eight months of 2024. While gas demand in oil and gas upstream activities increased by 7.5% or 0.35 bcm in H1 2024, natural gas use in industry decreased by 7% or 0.4 bcm. Due to stronger gas demand, Brazil's LNG inflows, mainly from the United States, increased by 1 bcm y-o-y between January and August. In contrast, piped gas imports from Bolivia dropped by 17%.

In **Trinidad and Tobago** planned maintenance activities, including turnarounds and a process safety incident in Woodside's upstream facilities, significantly affected production, which fell below 2 bcf/d (0.057 bcm/d) in June – the lowest monthly output since 2002. These challenges also led to decreases in demand and LNG exports, by 2% or 0.13 bcm and 7% or 0.41 bcm respectively y-o-y in H1 2024. Observed consumption in **Venezuela** increased by 10% or 0.8 bcm y-o-y during the same period. **Colombia** successfully navigated the severe impacts of El Niño without resorting to electricity rationing thanks to an 80% increase in the output of gas-fired power plants and a fifteen-fold y-o-y increase in LNG imports between January and July. In contrast, aggregate demand in the industrial and residential and commercial sectors experienced a slight decline of 1.5%. Natural gas demand continued to grow in **Central America** and the Caribbean markets, where combined LNG imports rose by 2% y-o-y in the first eight months of 2024.

This **forecast** expects natural gas demand in Central and South America to increase by 0.9% in 2024. Extreme weather events in the region are fuelling demand growth both for heating and cooling, while gas-fired power generation has become a regular backup for low hydropower output in many countries. However, slow industrial activity continues to act as a brake on more rapid demand expansion this year.

Central and South America's growing gas demand has seen volatility in 2023 and 2024

Y-o-y change in quarterly gas demand, Central and South America, Q1 2023-Q3 2024



Sources: IEA analysis based on ANP (2024), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2024), Informes Mensuales; Central Bank of Trinidad and Tobago (2024), Statistics; CNE (2024), Generación bruta SEN; ENARGAS (2024), Datos Abiertos; ICIS (2024), ICIS LNG Edge; IEA (2024), Monthly Gas Data Service; JODI (2024), Gas Database; MME (2024), Boletim Mensal de Acompanhamento da Industria de Gás Natural; OSINERG (2024), Reporte diario de la operación de los sistemas de transporte de gas natural.

Asia has returned to strong gas demand growth in 2024

Asian gas demand expanded by near 7% y-o-y in Q1-Q3 2024, driven mainly by China and, to a lesser extent, India. This notable growth was supported by weather events, including widespread heatwaves across Asia in Q2, and relatively low LNG prices in H1 2024. Preliminary data indicate a modest deceleration in Asian gas demand growth in Q3 due to recovering spot LNG prices, increasing nuclear and hydro availability, and slowing industrial activity in China, which could present headwinds for gas use in the second half of the year. In 2024 Asian gas consumption is set to increase by more than 5%, with 70% of the growth coming from China alone, and industry accounting for 40% of the increase. In 2025 Asia's total consumption is projected to increase by another 5% on the back of growing LNG supply in the global market.

China's total gas consumption rose by close to 10% y-o-y during the first three quarters of 2024. Based on sector-level data reported for the first seven months, this expansion was led by the city gas segment (up 14% y-o-y), where stronger-than-average heating demand in Q1 and robust LNG truck sales throughout the period sustained rapid growth. The power sector also experienced a healthy 11% y-o-y increase, fuelled mainly by hot summer temperatures. Industrial demand, by contrast, increased by less than 6% in the first seven months of 2024 amid slowing economic activity. Preliminary data indicate a marked deceleration of demand growth since April (from 11% in January to April to 7% in May to July). This is due partly to the base period effect and partly to weaker manufacturing activity and surging hydro generation since Q2 2024. Overall gas consumption growth in 2024 is expected to reach 8%, led by the industrial sector but also supported by power generation, residential and commercial users, and the transport sector. Gas demand growth is projected to slow only marginally to just under 8% in 2025, as increasing LNG supply (with a large share expected to land in China) partly compensates for slowing economic growth.

India's apparent gas consumption (including net production and LNG imports) rose by 14% y-o-y during the first eight months of 2024 according to the Petroleum Planning and Analysis Cell. Demand growth was led by oil refining (up 36%) and industry (up 30%), but gas consumption in the power generation (up 15%), residential and commercial (up 15%), and transport sectors (up 14%) also registered double-digit growth rates. India's strong demand growth was supported by a 5% increase in domestic production and a 25% surge in LNG inflows. India's LNG imports approached 3.5 bcm per month between May and July 2024, a level not seen since the 2020 LNG price collapse. This LNG surge was driven by increased gas-fired power generation amid high temperatures and delays in domestic gas production, supported by relatively low spot prices in H1. India's total gas demand in 2024 is expected to increase by nearly 9%, driven by the country's growing energy needs and rapid economic expansion, supported by an 18% overall rise in LNG imports. Similarly healthy growth of 8% is projected for 2025, with most of the growth coming from the industrial sector and, to a lesser extent, a continued rise in power sector gas burn. The possible inclusion of natural gas in India’s goods and services tax (GST) regime could lower prices for industry and consumers, presenting further upside for 2025 consumption growth. A decision on GST is expected by the end of March 2025.

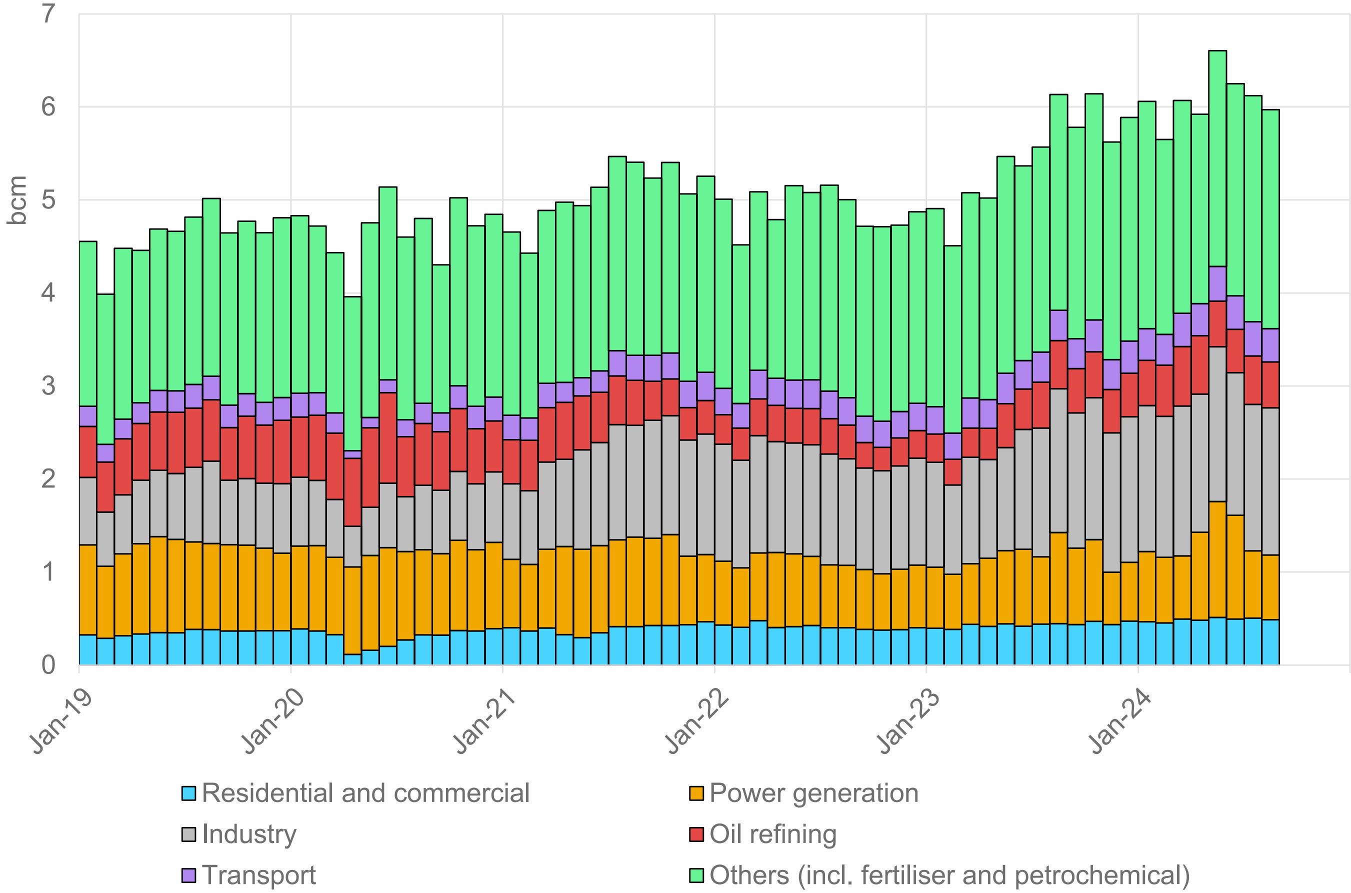
Japan's gas demand remained broadly flat y-o-y in the first seven months of 2024. The industrial sector saw a 3% decline between January and June, with economic sluggishness assumed to be one of the reasons for this decline. This weakness in the industrial sector was offset by a 0.5% y-o-y expansion between January and June in the residential and commercial sector and a 3% y-o-y increase between January and May in gas-fired power generation, driven by cold winter temperatures in March. Overall gas demand in 2024 is projected to remain flat. However, further delays to the restart of the Shimane 2 and Onagawa 2 nuclear units and renewed government subsidies for gas and electricity consumers between August and October 2024 could provide a boost to gas consumption in the city gas and power generation sectors in H2 2024. Gas demand in 2025 is set to drop by 3%, driven by increasing nuclear availability and renewable power generation.

Korea's gas demand increased by 7% y-o-y between January and July 2024. LNG imports increased by 4% y-o-y between January and August, with the remainder coming from higher withdrawals from LNG stocks in H1 2024. Total gas demand in 2024 is projected to increase by 1%, with growing demand in the city gas sector, which includes industrial users. Gas-for-power demand is constrained by growing nuclear availability, following the April 2024 start-up of the Shin Hanul 2 nuclear block, and rising renewable generation throughout the year. In 2025 gas demand is expected to decrease by 1%, as power sector gas demand is further squeezed by nuclear and renewable generation. The Saeul 3 and 4 reactors are under construction and could reduce gas use in the power sector once they come online. They are scheduled to start up in October 2024 and 2025 respectively, but further delays may extend these timelines beyond our forecast horizon.

Emerging Asia’s gas consumption increased by an estimated 4% y-o-y in the first seven months of 2024. Most of this growth occurred in the first five months of the year, driven by low LNG prices and high cooling demand across the region in April and May. However, demand growth has slowed since June due to rising spot LNG prices in Asia. Thailand’s gas consumption decreased by 0.4% y-o-y in the first seven months of 2024, as modest power demand growth (up 2%) was offset by steep declines in industry (down 13%) and transport (down 17%). Indonesia’s gas demand grew by 5% y-o-y in the first seven months of 2024, primarily driven by the industrial sector. Natural gas demand in emerging Asia is forecast to increase by 3% in 2024, mainly driven by the power sector. Demand growth is set to accelerate further to more than 5% in 2025 as greater LNG supply availability unlocks additional demand.

India's gas consumption reached its highest level on record in Q2, led by oil refining and industry

Monthly gas consumption by sector, India, January 2019-August 2024



Sources: IEA analysis based on Petroleum Planning and Analysis Cell (2024), Sectoral Consumption.

European natural gas consumption continued to decline in Q1-Q3 2024…

Natural gas consumption in OECD Europe fell by 3% (or 9 bcm) y-o-y in Q1-Q3 2024. This decline was primarily concentrated in the first half of the year, while natural gas demand remained close to last year's levels in Q3 2024. Gas demand in the residential and commercial sector remained depressed amid mild winter weather in Q1. But the power sector continued to be the most important driver behind lower gas use, as the strong expansion of renewables and improving nuclear availability weighed on gas-fired power generation during Q1-Q3. In contrast, gas use in the industrial sector continued to recover, largely supported by gas- and energy-intensive industries.

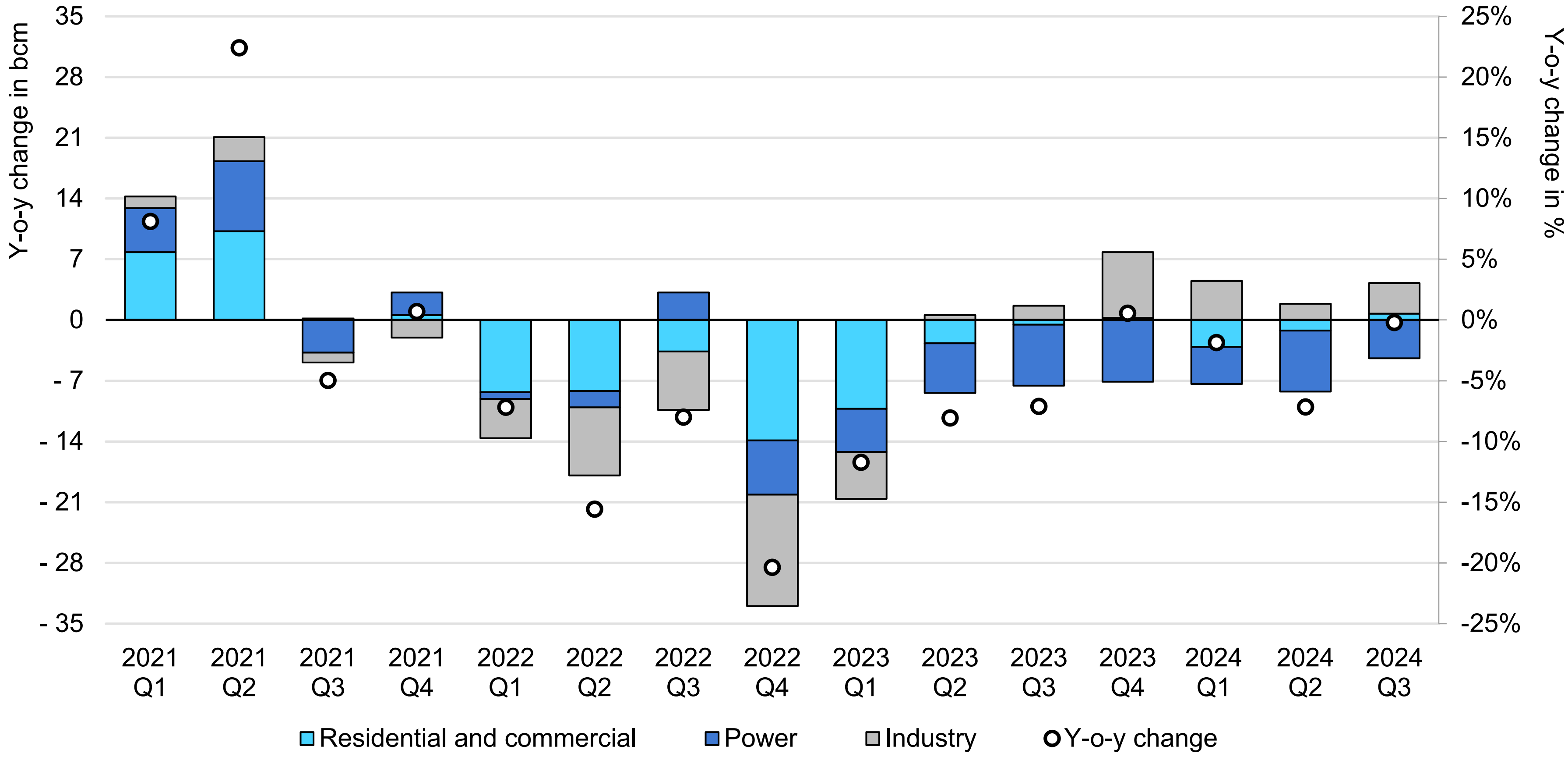
Distribution network-related demand fell by an estimated 3% (or 3.5 bcm) y-o-y in Q1-Q3 2024. This decline was entirely concentrated in the first half of the year. Heating degree days declined by 8% y-o-y in Q1 2024, which naturally weighed on space heating requirements in buildings. Residential and commercial gas demand continued to decline in Q2, although preliminary data suggest a modest year-on-year increase in Q3. This growth might have been driven by stronger gas use by commercial entities.

Gas-to-power demand plummeted by 16% (or 16 bcm) y-o-y in Q1-Q3 2024. The steep decline in gas-based power output was primarily driven by the strong increase in renewable electricity generation, which rose by an estimated 16% (or over 140 TWh) y-o-y in Q1-Q3 2024. Improving hydro availability contributed over 40% of the increase in renewable electricity output and primarily weighed on gas-fired power generation in the hydro-rich markets of Southern Europe (including Italy and Spain). The continued expansion of wind and solar power generation (up by 15% y-o-y), together with higher nuclear availability (up by 4% y-o-y), further reduced the call on fossil-based thermal power plants, which reduced their output by close to 15% y-o-y in Q1-Q3 2024. Natural gas consumption in **industry** continued to recover in Q1-Q3 2024, benefiting from the lower price environment. Preliminary data indicate that gas use in industry increased by around 9% (or 10 bcm) y-o-y in Q1-Q3 2024 – albeit remaining 10% below its 2021 level.

For the full year of 2024, this **forecast** expects natural gas demand in OECD Europe to decline by 2%, as higher gas use in buildings and industry is more than offset by lower gas-fired power generation. Gas burn in the power sector is forecast to drop by more than 10% amid the rapid expansion of renewables and higher nuclear output. Gas demand in the residential and commercial sector is expected to increase marginally compared with 2023, assuming average winter weather conditions in Q4. Gas use in industry is forecast to continue its recovery, although remaining well below its pre-crisis levels. Natural gas demand in OECD Europe is projected to increase by 1% in 2025 as stronger gas use in the residential and commercial and industrial sectors is expected to offset lower gas burn in the power sector.

…with demand reduction primarily concentrated in H1 2024

Estimated y-o-y change in quarterly natural gas demand, OECD Europe, 2021-2024



Sources: IEA analysis based on Enagas (2024), Natural Gas Demand; ENTSOG (2024), Transparency Platform; EPIAS (2024), Transparency Platform; Trading Hub Europe (2024), Aggregated consumption.

Y-o-y declines in US dry natural gas production slowed in Q3 on the back of price recovery

Q3 US dry natural gas production dynamics continued to highlight the gradual rebalancing of the world's largest gas market in 2024, reflected in steep price movements and a slowing y-o-y decline in supply. As upstream activity continues to respond to evolving market fundamentals, y-o-y movements are likely to remain volatile in the short term, but underlying trends point to production recovery in 2025.

The effects of early 2024's precipitous fall in US spot natural gas prices on production were swift and persistent. Dry natural gas production responded by an equally marked decline, falling to its lowest monthly level in nearly 18 months by May 2024 as some upstream players cut back on drilling activity and operations. Prices subsequently whiplashed in Q2, gaining more than USD 1/MBtu from their March low of USD 1.55/MBtu to their June peak of USD 2.64/MBtu as restrained production dynamics met with early and strong seasonal power demand.

This helped dry gas production switch to a growth trend by late Q2, with July bringing the first y-o-y output growth since February. Still, Q3 production remained marginally down y-o-y, although losses were far less acute than in Q2. With prices rebalancing to an average of around USD 2.20/MBtu in Q3 and natural gas storage levels sitting comfortably above last year's levels, production recovery was uneven throughout the quarter. Still, underlying regional production dynamics remained relatively constant.

The Haynesville and Appalachian basins continue to be the primary downside factors in the US production picture. Haynesville production hit a two-year low in the spring as one of the regions hardest hit by CAPEX rollbacks. Monthly output levels flattened out in Q3, but remained 13% below Q3 2023 levels and are likely to remain subdued for much of 2025.

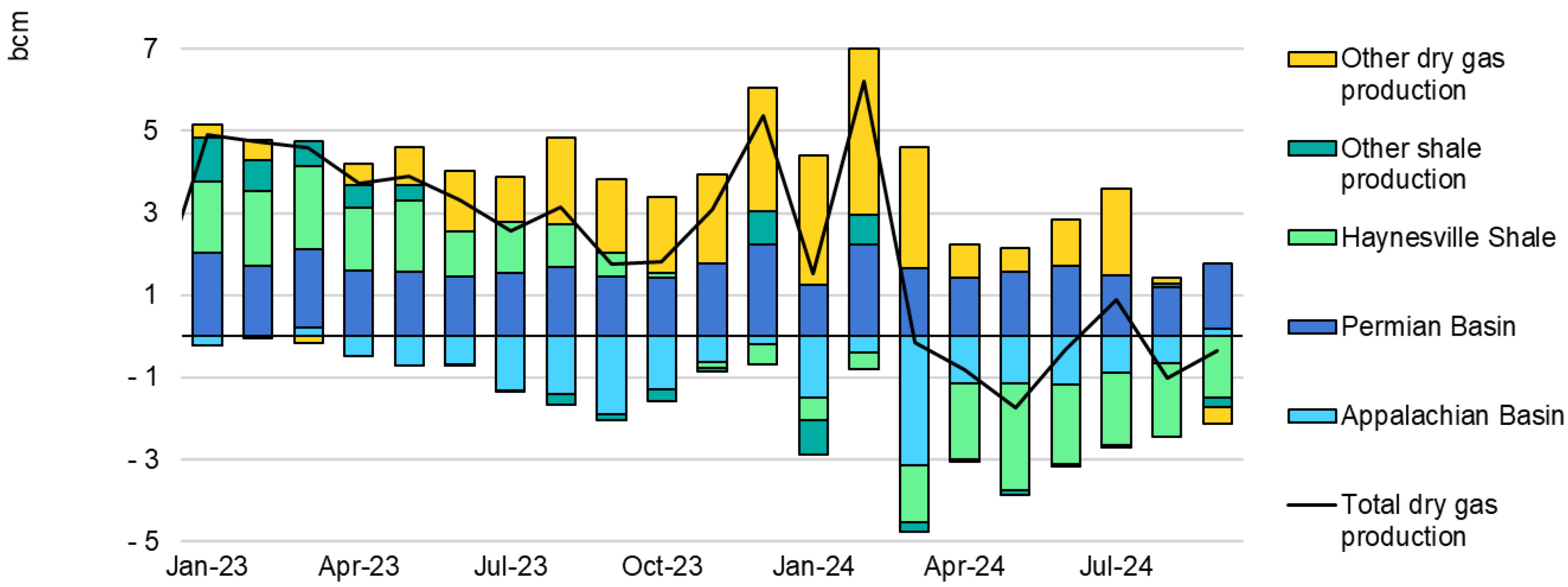
Appalachian production suffered a smaller shock in relative terms, with Q2 output falling 4.4% against the same period in 2023. The commercial start of the Mountain Valley Pipeline (MVP) in July helped ease the Q3 downside to just 2% y-o-y, as the ~21 bcm/yr pipeline added long-awaited incremental takeaway capacity to a bottlenecked production basin. However, MVP's connection to the Transcontinental Gas Pipeline, which connects New York to Texas, is unlikely to turn around production trends in the region, helping stabilise output more than stimulate growth in 2025.

Permian production remains the main upside factor in US dry gas production. Robust oil market fundamentals have supported drilling activity, feeding into strong well renewal and well productivity. Q3 Permian production was close to 10% higher y-o-y, with continued growth prospects for 2025 thanks in part to increased pipeline takeaway capacity improving trading prospects.

Overall, improving fundamentals in H2 2024 are set to help keep full-year 2024 US dry gas production output broadly flat y-o-y, feeding into growth of around 1% in 2025.

US dry gas production remains in a rebalancing phase

Y-o-y change in monthly dry gas production, United States, 2022-2024



Notes: August and September include estimated data.
Sources: IEA analysis based on EIA (2024), Natural Gas Data, Natural Gas Weekly Update.

Liquefaction project delays risk extending tight LNG market conditions into 2025

Global LNG trade grew by about 2% y-o-y in Q3 2024, up from a slight y-o-y decrease in Q2. This reflected Russian exports realising an expected y-o-y recovery from heavy maintenance in 2023, export trends in Africa shifting to more positive dynamics, and certain key producers in Asia buoying the region's exports. On the demand side, Q3 dynamics mirrored trends from H1 2023, with Europe reducing its call on LNG – albeit less steeply than in Q2 – facilitating continued y-o-y growth in Asian imports.

Russia was among the single largest contributors to incremental volumes in Q3 as both the Yamal and Sakhalin 2 liquefaction facilities saw better utilisation rates than over the same period in 2023. While incremental Sakhalin 2 volumes were all in all relatively minor, extra Yamal exports were more substantial as August loadings soared in what has often been a slow month due to routine maintenance.

Although total African export volumes were slightly down year-on-year in Q3, important shifts in trends were at play at the national level to ease the continent's 6.2% (or 1.7 bcm) y-o-y decline racked up over H1. In particular, Algeria, Egypt and Nigeria underpinned this shift. Algerian LNG exports started dipping below last year's levels in late Q2, and the trend accelerated through the summer months due to a combination of upstream impairments and increased domestic demand. In Q3, this led to a 14% (or 1.2 bcm) y-o-y cut in Algerian LNG exports. Egypt stood out by its relatively flat y-o-y profile in Q3, in sharp contrast to the steep y-o-y decline observed in the first half of the year. While its H1 2024 exports were down by 76% (or 3.1 bcm) y-o-y, losses amounted to just 0.2 bcm in Q3 due to the fact that exports over the same period in 2023 were already strongly impaired. The Egyptian LNG export situation remains bleak, squeezed by strong domestic demand, a faltering upstream situation and uncertain pipeline imports from Israel, but downside risk compared with last year has already been exhausted in 2024. Finally, Nigerian underperformance in Q2 turned to recovery in Q3 as August exports were up by more than 50% y-o-y (or 0.8 bcm). Over the entire quarter, Nigeria was among the largest upside markets globally, adding 0.8 bcm to the global balance compared with the same period in 2023.

Asia Pacific as a region was the largest contributor to supply growth throughout the quarter. Australia, Indonesia and Brunei together more than compensated for a y-o-y dip in exports from Papua New Guinea, bringing the region's exports up by about 5% (or 2.2 bcm) over the quarter.

US LNG export dynamics also marked an important shift over this period, growing by 2.8% (or 0.8 bcm in Q3 after having contracted by a similar amount y-o-y in Q2. Despite the overarching trend of improved utilization rates, outages at Freeport LNG in July partially ate into Q3 gains.

On the demand side, Asia continued to take in more LNG, although the pace of growth eased and China did less of the heavy lifting than in H1. After accounting for over 40% of the region's gross upside in early 2024, China drove only 11% of y-o-y gross incremental imports in Q3, reflecting already robust import levels in the second half of 2023. Indian import growth also slowed in mid-Q3, following a record buying spree over the late spring–early summer period driven by increased power sector gas burn amid a severe heatwave.

Korea extended its Q2 import upside into Q3, taking in 1.9 bcm (or 16%) more LNG than over the same period in 2023, as record-breaking summer temperatures drove strong power sector gas burn. Japanese LNG imports grew by about 1.1 bcm (or 5%) y-o-y over the same period, driven by similar weather patterns.

Despite its relatively small import volumes, Bangladesh stood out by its drastic change in import dynamics over the summer months. Up by 25% y-o-y in the first five months of the year, imports sank precipitously in June and remained low through the summer months. One of the country's two LNG import terminals was shut following cyclone-induced damage in May. Subsequently, civil unrest dampened domestic demand for gas and power, and a change in government called into question ongoing spot purchasing processes. The overall Q3 y-o-y drop was small (just 0.3 bcm), but reflects how quickly demand dynamics can shift among small and developing LNG markets.

Over the first three quarters of the year, global LNG trade grew by approximately 2.8% y-o-y. Although we expect many of the ongoing import and export trends to carry through to the end of the year, growth is set to slow slightly given a strong Q4 2023 base period. In total, therefore, the global LNG market is expected to grow by about 2% in full-year 2024, on a par with growth in 2023 but well below the annual average of about 6.6% over the 2019-23 period.

Growth is set to accelerate to about 6% (up by 31 bcm) in 2025 as the market is on the cusp of the next long-awaited wave of liquefaction capacity additions. Following record final investment decisions (FIDs) taken in 2019 – as well as the single largest ever FID, taken in 2021 – the first of these LNG exporting facilities have started to come online in 2024, with the majority expected to start reaching the market particularly after 2025. Although incremental supply is expected to help ease market tensions that have accumulated from the global gas supply shock in recent years, sanctions and project delays have pared back the expected capacity gains in 2025.

North America is set to account for over 80% of global incremental LNG supply in 2025, with over 60% (or about 16 bcm) of these North American volumes coming from the United States, already the world's largest LNG exporter today. **Plaquemines LNG Phase 1** will be the largest contributing project in the short term, with production expected to start in Q4 2024 and ramp up in 2025 toward the ~18 bcm/yr nameplate capacity. Despite not being a new project, **Freeport LNG** is expected to provide sizeable upside in 2025 as operations recover from significant outages in 2024, and as debottlenecking works deliver a 10% increase in nameplate capacity. The **Corpus Christi Stage 3 expansion** is set to add seven small-scale trains over the coming years for a total annual capacity of nearly 13 bcm/yr. Although first volumes could reach the market as early as Q4 2024, completion of the trains is expected to be gradual, with only limited incremental exports in 2025. Finally, **Golden Pass LNG** could add to the US export growth in 2025, but by far less than originally planned. A series of delays to commissioning, from originally Q1 2024 to mid-2025 and then to end-2025 – partially stemming from the bankruptcy of the project's lead contractor in Q2 2024 – have significantly scaled back the project's production potential in 2025 and suggest that exports might start only in 2026.

Canada and Mexico should also contribute to growing North American LNG exports. **LNG Canada**, with an annual export capacity of 19 bcm, is expected to start operations in 2025. In Mexico, the FLNG facility **Altamira** (1.9 bcm/yr capacity) exported its first cargo in August this year and is expected to continue ramping up exports in 2025. Delays affected another Mexican project previously slated for a 2025 start. Originally anticipated to launch in 2024 and subsequently delayed to mid-2025, **Energia Costa Azul** (4.4 bcm/yr capacity) – located on Mexico's Pacific coast – was recently further delayed to Q1 2026, the latest example of slippage in project executions reducing potential supply-side market relief in 2025.

The African continent is also set to contribute to extra supply in 2025. After delays to the original timeline, **Tortue FLNG** (3.1 bcm/yr capacity) off the coast of Senegal is expected to start exports in Q4 2024, growing them in 2025. **Congo LNG** (3.2 bcm/yr capacity), another floating terminal, is expected to reach operational status in 2025, joining Congo's 0.8 bcm **Tango FLNG** that started exporting in Q1 2024. In total, new and recent projects across the continent are likely to add close to 5 bcm of incremental LNG supply in 2025. However, continued underperformance in certain markets like Egypt – where net exports have ceased and imports have ballooned in 2024 – and Nigeria – where upstream impairments continue to undermine liquefaction utilisation – is likely to weigh on total African LNG exports.

In the Asia Pacific region, **Tangguh LNG Train 3** (5.2 bcm/yr capacity) exported its first cargo in Q4 2023 and, after ramping up in 2024, is likely to provide further incremental volumes in 2025. Across the rest of the region, some markets could be negatively affected by ageing resource basins.

Russia is the scene of a particularity in new liquefaction projects. While the country accounted for a significant chunk of FID volumes in 2019, the project in question, **Arctic LNG 2 train 1** (9 bcm/yr capacity), was hit by international sanctions in late 2023. Despite having come online in December 2023, it has remained officially idle throughout 2024. Reports have emerged of shadow vessels – cargoes falsifying location data to circumvent sanctions – loading volumes from the facility in Q3 2024, but this is likely to yield only marginal volumes.

Notable by its size and its absence from the outlook for 2025 is Qatar's **North Field East Expansion**. As the largest single liquefaction project ever, the Qatari expansion is set to add 45 bcm/yr of capacity in the coming years. However, while expectations were for a potential Q4 2025 start, progress reports suggest a delay out to early 2026.

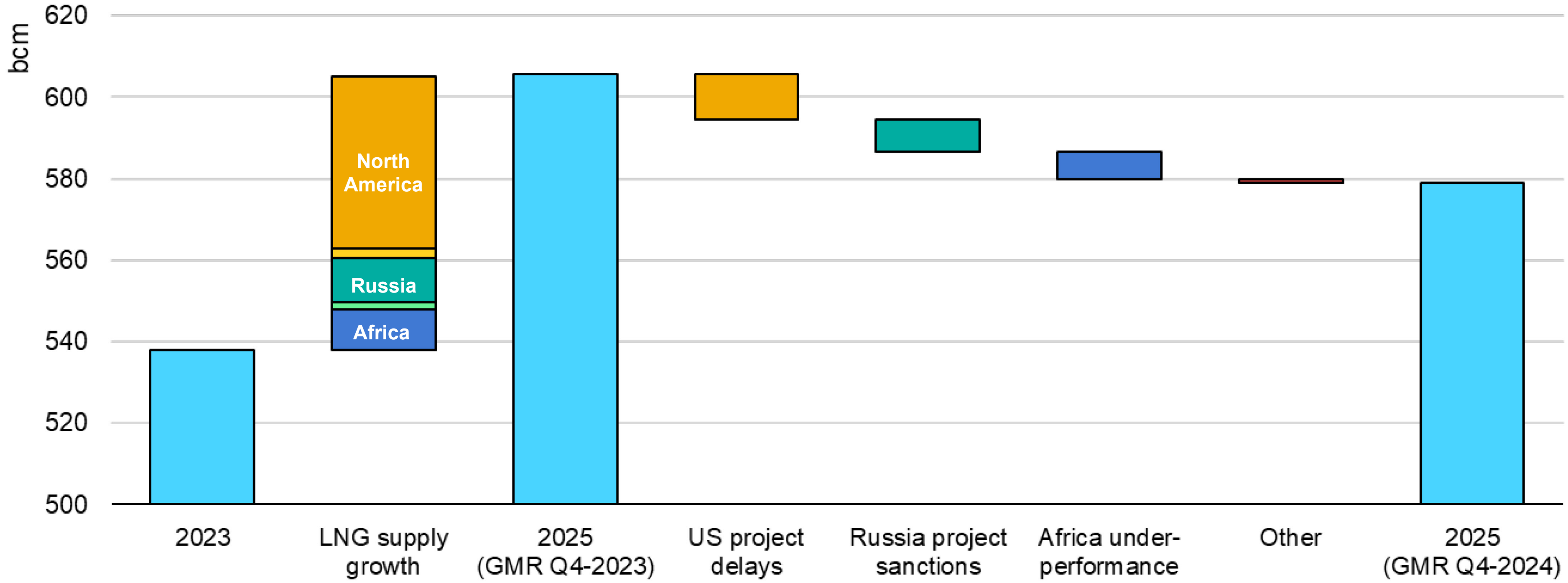
On the demand side, one significant change is set to come into play. While Asia remains a key driver of demand growth for LNG, Europe is set to re-emerge as a growth market following a 15% contraction in 2024.

Asian dynamics are set to be led foremost by China, whose LNG imports are expected to grow by about 10 bcm from 2024 levels. A relative easing of LNG market fundamentals is also expected to allow small and emerging LNG markets in the region to continue tapping the spot market, extending gains from 2023 and 2024.

However, increased European LNG imports – sourced primarily from the spot market – are likely to act as a cap on the potential upside in Asia. Faced with the prospect of further losses in pipeline gas supply from Russia and a progressive recovery in overall natural gas demand, Europe is set to resort to LNG to balance its market. LNG imports are set to grow by 11% (or 15 bcm) y-o-y under the assumption that Russian pipeline flows to the European Union cease with the end of the Ukrainian transit agreement. That being said, a scenario with continued Russian flows would ease Europe's incremental call on LNG, softening global LNG market dynamics for 2025.

LNG supply outlook for 2025 has been downgraded between IEA Gas Market Reports

2025 LNG supply outlook comparison, GMR Q4-2024 vs GMR Q4-2023



Note: GMR stands for IEA Gas Market Report.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Europe significantly reduced its call on LNG in Q1-Q3 2024…

OECD Europe's primary natural gas supply fell by an estimated 6% (or almost 20 bcm) y-o-y in Q1-Q3 2024. Lower gas demand together with high storage levels reduced the call on LNG imports, while the region's domestic production continued to decline.

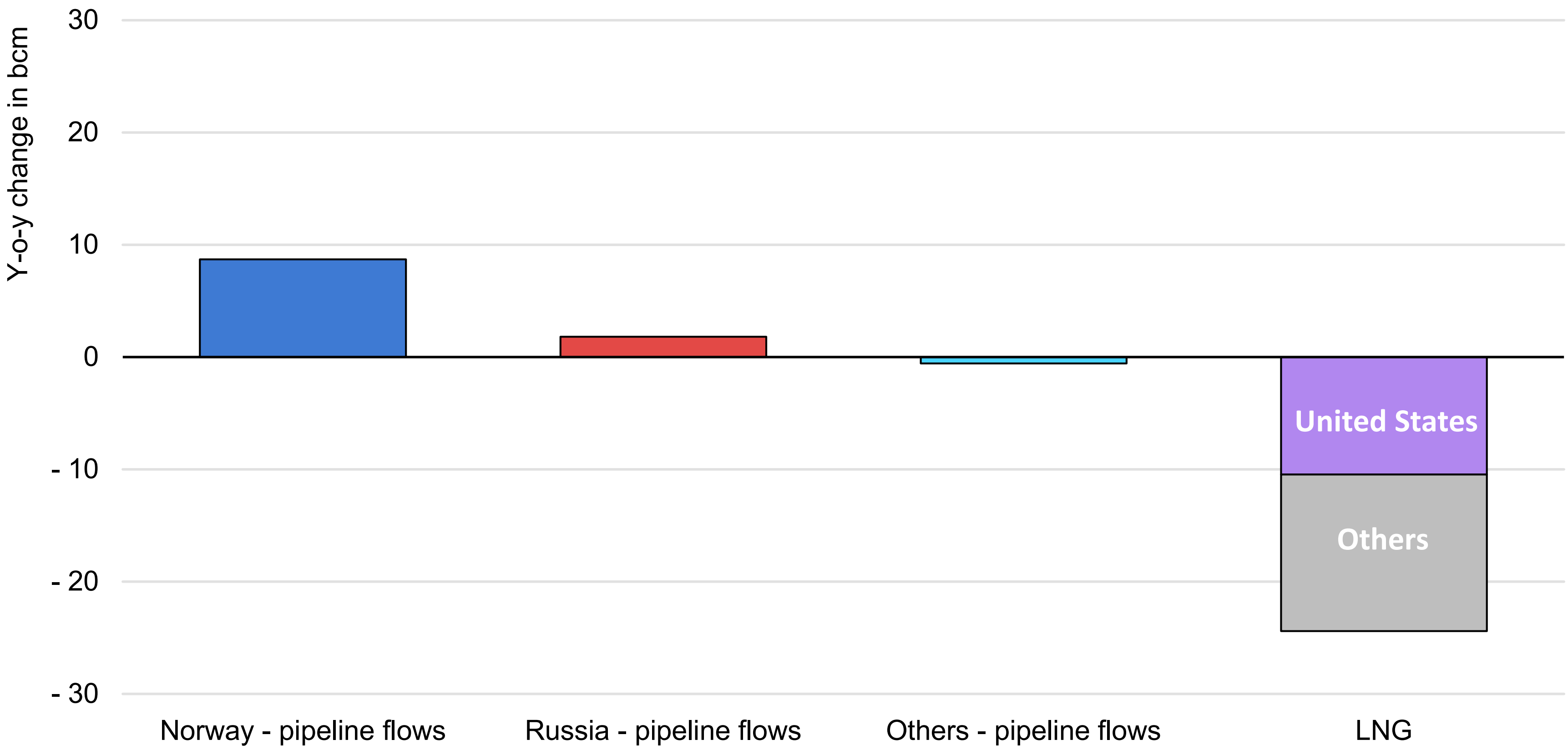
Europe's **LNG imports** declined by nearly 20% (or around 25 bcm) y-o-y in Q1-Q3 2024. The continued decline in natural gas demand, together with lower storage injection needs and stronger piped gas deliveries, kept European hub prices below Asian spot LNG prices in Q1-Q3 2024. This in turn incentivised flexible LNG cargoes to flow towards Asia instead of Europe. Nevertheless, LNG retained its position as Europe's dominant source of primary gas supply, its share declining from 38% in Q1-Q3 2023 to 32% during the same period of 2024. LNG flows from the United States fell by 18% (or more than 10 bcm) y-o-y. Still, **the United States kept its position as Europe's largest LNG supplier** to account for over 45% of Europe's LNG imports in Q1-Q3 2024. LNG flows from Qatar declined by 33% (or 5 bcm) y-o-y, as flows were redirected towards the more lucrative Asian markets. Security issues along the Red Sea further weighed on Qatari LNG flows towards Europe. In contrast, **Russian LNG** inflows rose by 16% (or 2 bcm) y-o-y, solidifying Russia's position as Europe's second-largest LNG supplier. Russian LNG deliveries remain highly concentrated: Belgium, France and Spain accounted for 85% of Europe's total LNG imports from Russia in H1 2024.

Norway's piped gas deliveries to the rest of Europe increased by nearly 10% (or 9 bcm) y-o-y compared with Q1-Q3 2023, reflecting a lower level of maintenance works. **Non-Norwegian domestic production** fell by around 7% (or 4 bcm) y-o-y in the first eight months of 2024. This decline was primarily driven by **Netherlands** and the **United Kingdom** amid the closure of the Groningen field and the continuing reduction in output from the ageing gas fields in the North Sea. **Russia's piped gas supplies** increased by over 5% (or 1.5 bcm) y-o-y in Q1-Q3 2024, albeit remaining 70% below their 2021 levels. Deliveries to the European Union increased by more than 10% (or over 2 bcm). Exports to Türkiye fell by 3% y-o-y in the first eight months of 2024. The share of Russian piped gas in Europe's gas demand stood just above 10% in Q1-Q3 2024. Piped gas deliveries from **North Africa** fell by 9% y-o-y, while **Azeri flows** via the TAP remained close to last year's levels in Q1-Q3 2024.

This **forecast** expects Russian piped gas supplies to OECD Europe to increase by 10% in 2024 compared with 2023, although their profile remains a major uncertainty. LNG imports are expected to decline by 20% amid high inventory levels, weak demand and stronger piped gas deliveries. This forecast assumes that Russia's piped gas deliveries via Ukraine will halt at the beginning of 2025 due to the expiry of the transit contract. Lower Russian piped gas supplies, together with the expected increase in gas demand, is forecast to increase Europe's LNG imports by 15% in 2025.

…with the region's LNG inflows dropping by 20% compared with last year

Y-o-y change in natural gas imports and deliveries from Norway, OECD Europe, Q1-Q3 2024 vs Q1-Q3 2023



Sources: IEA analysis based on ENTSOG (2024), Transparency Platform; Eurostat (2024), Energy Statistics; Gas Transmission System Operator of Ukraine (2024), Transparency Platform; ICIS LNG Edge; JODI (2024), Gas World Database.

North Africa and West Africa are set to drive African natural gas and LNG exports respectively

Africa holds vast natural gas reserves, representing over 9% of the global total. Historically, the continent has had established natural gas trade relations with Europe and is now pursuing new market opportunities through its developing LNG export capacity. Despite the disparate trends observed among African countries, the continent is poised to enhance its natural gas production and benefit from a tight global LNG market to reach new markets. Following the 2022-23 increase in flows of African LNG to Europe, driven by the need to replace the lost 120 bcm of piped Russian gas, **there has been a reorientation of LNG flows from Africa towards Asian countries since the beginning of 2024**. This shift is due to the 20% y-o-y decrease in LNG demand observed in Europe this year and part of a wider effort from Asian importers to diversify their sources of supply. Indeed, LNG flows from Africa to the Asia Pacific region increased by over 80%, or close to 7 bcm, y-o-y during the initial nine months of 2024, primarily driven by West African countries. Conversely, LNG flows from Africa to Europe decreased by 34%, or 8 bcm, y-o-y, during the same period.

The majority of Africa's natural gas production is driven by North Africa, which accounts for 70% of the continent's output. Algeria and Egypt, the first and second largest natural gas producers in Africa, produced 105 bcm and 60 bcm of natural gas respectively in 2023.

In recent years, the output from **Egypt**'s largest natural gas field, Zohr, has been declining, affecting the country's overall gas production, while natural gas imports from Israel remain uncertain. Moreover, Egypt has had to prioritise domestic energy needs, especially during peak periods like the summer months. This has led to a significant reduction in LNG exports to ensure sufficient supply for domestic consumption. Egypt has had to renegotiate or temporarily halt some of its LNG export contracts. During the first nine months of 2024, LNG exports from Egypt barely reached 1 bcm, marking a 75% y-o-y decline, with exports curtailed since May. Meanwhile, to address the energy shortfall, Egypt has initiated five tenders to secure emergency LNG shipments, with a total of 65 cargoes tendered since June, and 45 cargoes already awarded. The most recent tender aimed to purchase 20 cargoes for delivery between October and December 2024. However, this temporary fix is unlikely to resolve Egypt's energy crunch in the long term. As a result, Egypt has transitioned from being a net exporter to a net importer of LNG so far in 2024. This shift has been facilitated by the restart of the Ain Sukhna FSRU in Egypt and the use of the LNG regasification facility in Aqaba, Jordan.

In contrast, **Algeria** has managed to maintain a balance between domestic demand and supply, allowing an increase in exports either by pipelines or in LNG form. Given its vast resource potential and underutilised infrastructure, Algeria is well-positioned to attract more international oil companies, particularly as European nations seek alternatives to Russian gas.

Despite a slight decline in LNG exports during the first nine months of 2024 in comparison with the record-breaking levels observed in 2023, Algeria continued to perform well, exporting over 10 bcm during this period.

In terms of LNG, West African countries represent the leading producing and exporting region, with Nigeria, Angola, Equatorial Guinea, Cameroon and Congo representing almost 60% of total LNG exports from Africa during the first nine months of 2024.

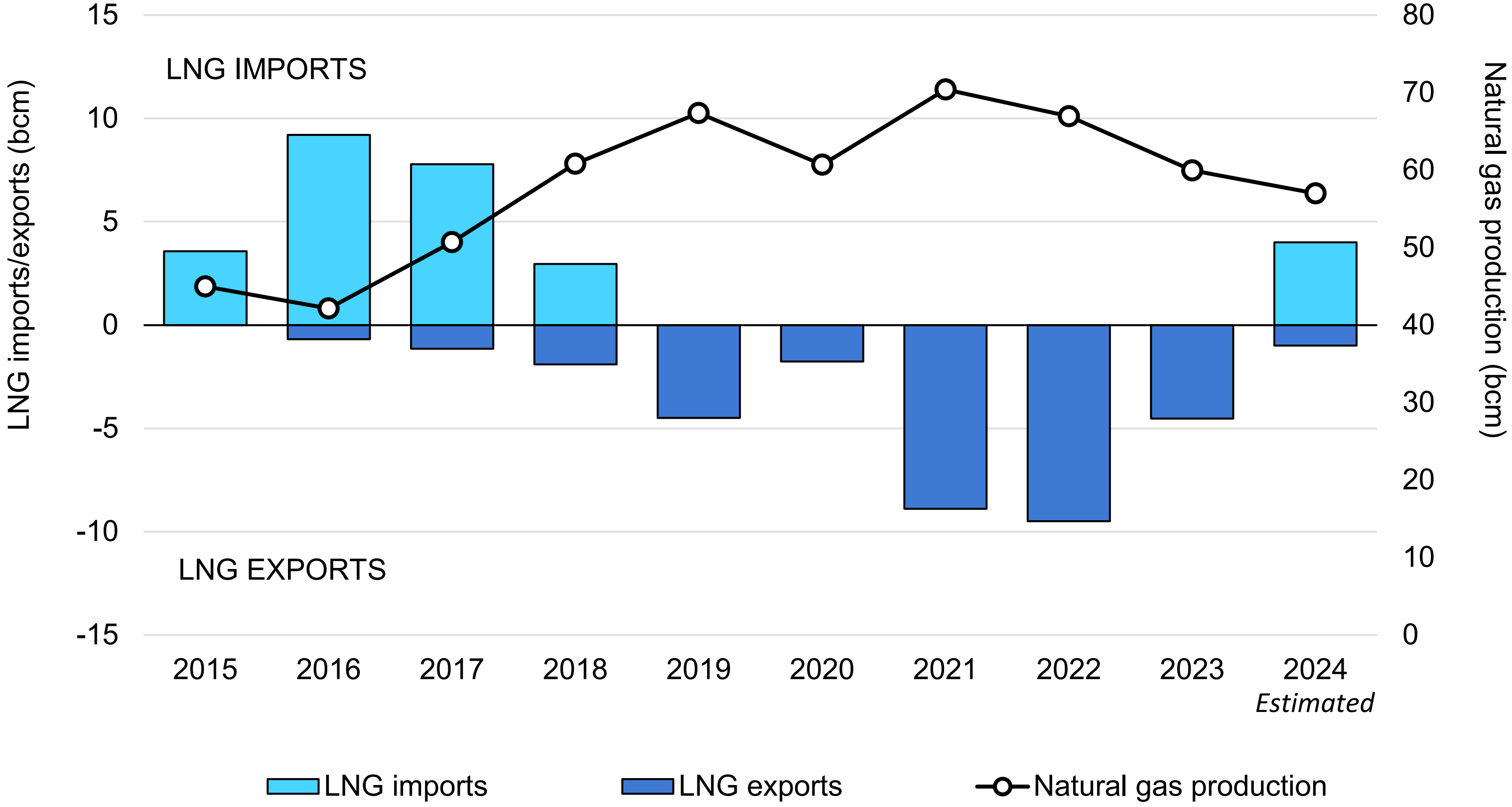
Senegal and Mauritania are set to add just over 3 bcm/yr of additional liquefaction capacity to their existing 43 bcm/yr, with the start of LNG production from their joint Greater Tortue Ahmeyim project expected by the end of the year.

Nigeria is the top LNG exporter in Africa, despite ongoing upstream challenges such as pipeline vandalism. The country is making efforts to improve security and developing new gas pipelines to increase gas volumes available for LNG exports. In addition, the NLNG train 7 has faced delays but is expected to add an additional 5 bcm/yr of liquefaction capacity by 2026.

The advancement of African LNG projects has faced substantial delays due to several factors, including technical challenges, security issues, regulatory hurdles, higher cost of capital and increasing engineering, procurement and construction (EPC) related costs, and environmental concerns. These issues have affected the projects’ economic benefits and long-term viability. The African LNG sector now faces the additional challenge of the upcoming global wave of new LNG capacity, mainly in Qatar and the United States, which is expected to come online from 2026. The surge in global liquefaction capacity has led to increased competition, lower prices and reduced profit margins for African LNG projects.

Egypt's LNG dilemma: Balancing export commitments with domestic demand

Natural gas production, LNG exports and imports, Egypt, 2020-2024



Sources: IEA analysis based on ICIS (2024), ICIS LNG Edge; JODI (2024), Gas World Database.

Gas prices continued to rise across key Asian and European import markets in Q3 2024

Natural gas prices recorded gains across key Asian and European markets in Q3 2024 compared with the previous quarter, while remaining at multi-year lows in the United States.

In **Europe**, TTF spot prices rose by 14% on the quarter to an average of USD 11.5/MBtu in Q3 2024 – more than double their Q3 average over the 2016-20 period. Lower LNG inflows (down by 22% y-o-y) and renewed uncertainties around Russian piped gas flows provided upward pressure on prices. The intensifying fighting on the Russia-Ukraine border – including near the Sudzha gas metering station – fuelled additional price volatility in August. TTF month-ahead prices rose by 13% between 5 and 9 August to USD 13/MBtu, their highest level since early December 2023. As Russian piped gas flows continued via the Sudzha gas metering station, TTF prices moderated towards the end of August, but remained above their Q2 levels.

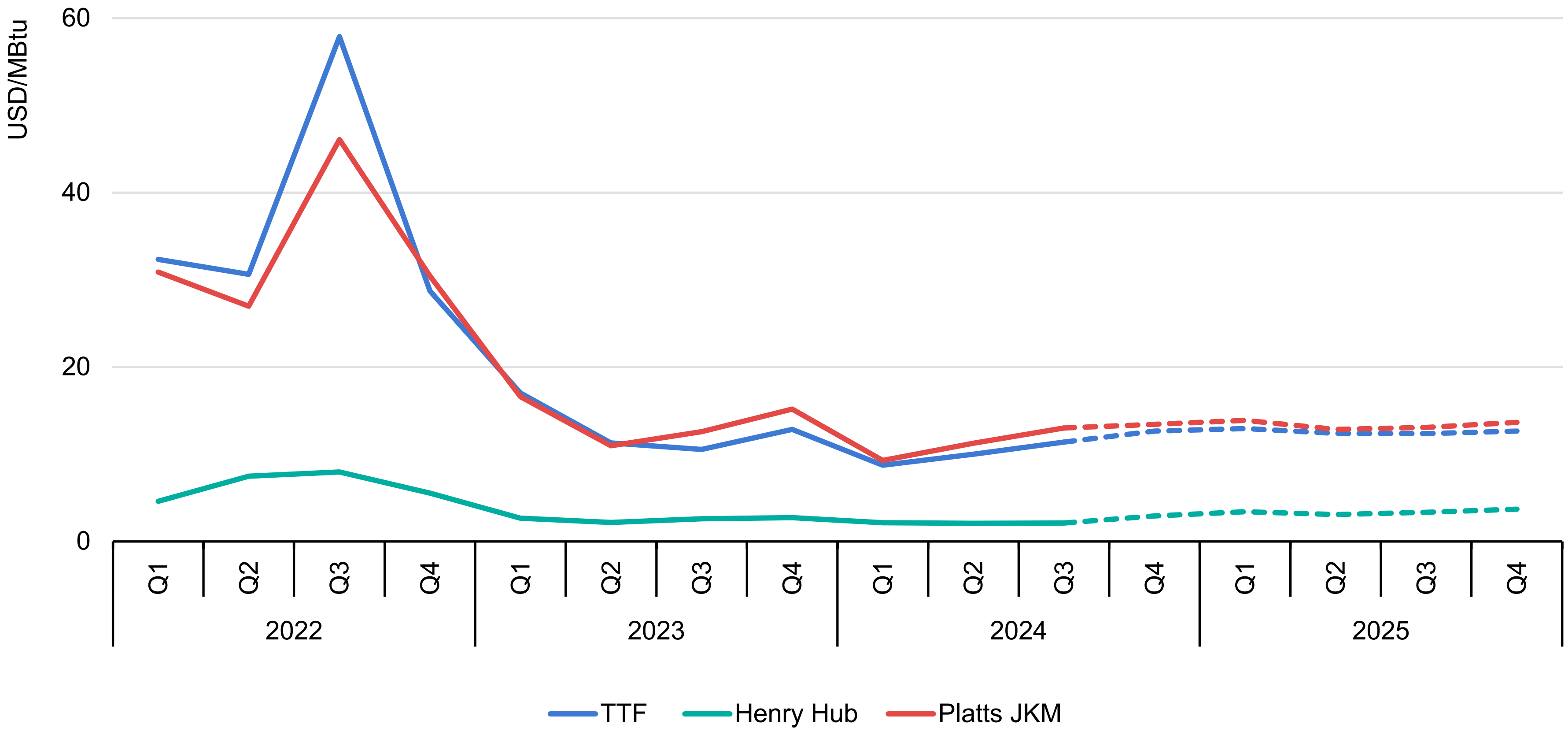
In **Asia**, Platts JKM prices followed a similar trajectory and rose by 15% on the quarter to an average of over USD 13/MBtu in Q3 2024 – almost double their Q3 average during the 2016-20 period. Continued demand growth, sizzling heatwaves and weaker than expected LNG supply growth provided upward pressure on Asian spot prices. The JKM premium over TTF rose from USD 1.3/MBtu in Q2 2024 to USD 1.65/MBtu, which continued to attract LNG cargoes away from Europe. While Asia's LNG imports grew by 11% y-o-y, Europe's declined by 22% y-o-y in Q3 2024.

In the **United States**, Henry Hub prices stayed close to their Q2 levels and averaged USD 2.1/MBtu in Q3 2024, their lowest Q3 average since 2020. Strong associated petroleum gas production, together with weaker gas demand and relatively high storage levels, provided downward pressure on gas prices. Record high associated gas production and the saturation of processing and pipeline takeaway capacity drove down Permian gas prices into negative territory. Natural gas prices at the Waha hub averaged *minus* USD 1/MBtu in Q3 2024, their lowest quarterly average on record.

Forward curves as of the end of September 2024 suggest that TTF is set to average 18% below its 2023 levels in 2024 at around USD 11/MBtu. Forward curves also show Asian spot LNG prices retaining their premium over European hub prices in 2024, with JKM averaging USD 1.1/MBtu above TTF. Based on forward curves, Henry Hub prices in the United States are set to decline by 9% to average USD 2.3/MBtu – their lowest annual average since 2020. Forward curves suggest that TTF and Asian spot LNG prices could increase by 18% and 14% in 2025 respectively, likely reflecting the market's expectation of tighter supply–demand fundamentals. The price differential between JKM and TTF is expected to tighten to USD 0.8/MBtu in 2025 as the competition between Asia and Europe for flexible LNG cargoes heats up. Based on forward curves, Henry Hub prices in the United States are expected to increase by 45% to average USD 3.4/MBtu amid tighter market fundamentals.

The price differential between Asian and European hub prices is expected to tighten in 2025

Main spot and forward natural gas prices, 2022-2025



Note: Future prices are based on forward curves as of the end of September 2024 and do not represent a price forecast.
Sources: IEA analysis based on CME Group (2024), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements, LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2024), Henry Hub Natural Gas Spot Price; Powernext (2024), Spot Market Data; S&P Global (2024), Platts Connect.

Q3 storage injections sufficient to set Europe and United States in a robust position for winter

Natural gas inventories in key markets ended Q3 well above historical average levels. While injections remained noticeably lower than average throughout the entire filling season, record stocks at the end of the previous winter helped keep storage levels on a par with or ahead of last year's curve over the period. Overall, natural gas storage levels are in a robust position ahead of winter 2024/25.

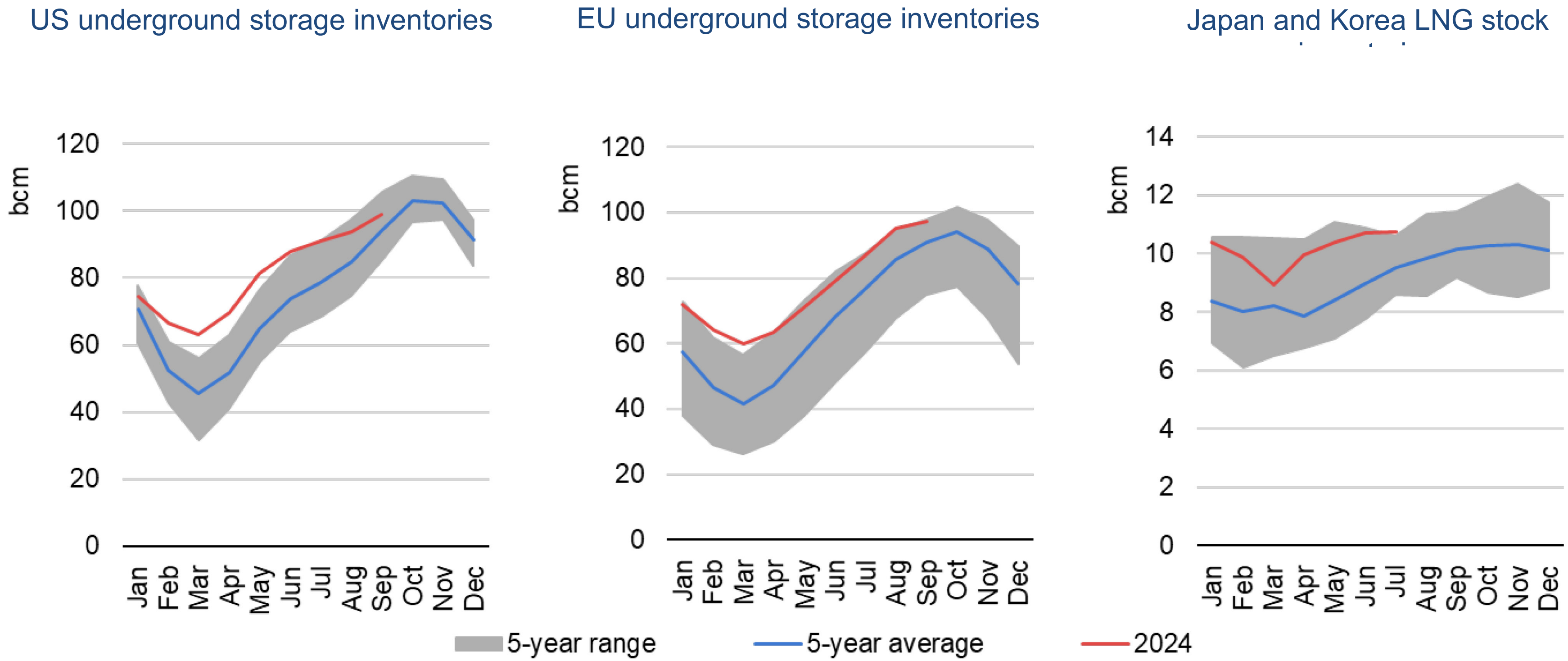
In the European Union storage levels reached the EU-imposed 90% fill target in mid-August, well ahead of the 1 November cutoff date and in line with last year's trajectory. Throughout much of 2023, EU gas storage had already trended at the top of the historical range, ending the filling season at record highs and subsequently closing the 2023/24 winter season at a new record high as well. As such, 2024 storage trends have had relatively limited space to establish new records. The 6 bcm (10%) surplus above 2023 fill levels that existed mid-April had broadly disappeared by mid-summer, and storage fill closed September at a 1 bcm (1%) deficit to 2023 levels as injections remained about 24% below the five-year average rate over the Q2-Q3 period. Still, EU storage levels were 94% full by 1 October, about 6.5 bcm (7%) higher than the five-year average.

Ukrainian natural gas storage fill has not kept pace with last year's levels, reaching just 7.6 bcm by the start of October, compared with slightly over 11 bcm on the same date in 2023. Following strong drawdown during winter 2023/24, stocks ended March 2024 at levels nearly 30% (or 1.3 bcm) below end-March 2023. While Q2 injections were about 16% higher in 2024 than in 2023, Q3 injections tailed off to just 65% of 2023 rates. While European market actors had shown sizable interest in storing gas in Ukraine in 2023 – leading to an acceleration in injections over the month of August and a total of 2 bcm of stored gas – interest has remained more modest in 2024, partially influenced by above-ground infrastructure security concerns due to Russian attacks.

US storage levels have remained well above the five-year average throughout 2024, ending winter with over 20% more gas in store than in 2023 and keeping ahead of the curve throughout the entire filling season. Given high base levels, storage fill has remained below average, particularly in Q3 as injections tapered even more noticeably than the usual seasonal profile. Nevertheless, US storage is approaching winter 2024/25 in a robust position, having closed Q3 with storage levels above the norm and 2023 levels.

Combined LNG stocks in Japan and Korea were on a par with 2023 levels at the end of July after recovery from lower end-winter levels in the former and consistently high stocks in the latter. Strong power sector gas demand in summer is likely to have drawn Japanese stocks down in subsequent months in a similar fashion to the 2023 trend, although strong LNG imports during Q2 and Q3 also kept the market well supplied. Overall, combined LNG stocks in the two markets remained about 13% above the five-year average by the end of July.

Despite slower summer injections y-o-y, storage levels on par with 2023 highs ahead of winter



Sources: IEA analysis based on EIA (2024), Weekly Working Gas in Underground Storage; GIE (2024), AGSI+ Database; IEA (2024), Monthly Gas Data Service; JODI (2024), Gas World Database.

LNG contracting and flexibility update

Update on LNG contracting trends

This section provides an overview of the most recent LNG contracting trends, analysing LNG supply availability and the evolution of destination flexibility in LNG contracts. The analysis is based on the contractual positions of exporters and importers and their actual traded volumes, using **the IEA internal LNG contract database**. Unless otherwise stated, only firm supply contracts are taken into account. These include LNG sale and purchase agreements (SPAs), equity entitlements and tolling agreements linked to an LNG supply project that is either operational, under construction or has reached a final investment decision (FID).

Since the first issue of the Global Gas Security Review in 2016, the **LNG market has gained in depth and liquidity**. Total traded volumes expanded by 55% between 2016 and 2023, while both buyers and sellers are displaying a greater diversity in their commercial preferences and flexibility requirements. The share of **destination-free contracts** rose from 30% in 2016 to 47% in 2023, largely driven by the expansion of US LNG supplies. Destination-fixed agreements have regained traction and accounted for more than 70% of volumes contracted since 2023. Despite this, the share of destination-free contracts is expected to increase to 51% by 2027, amid the gradual expiry of destination-fixed legacy contracts.

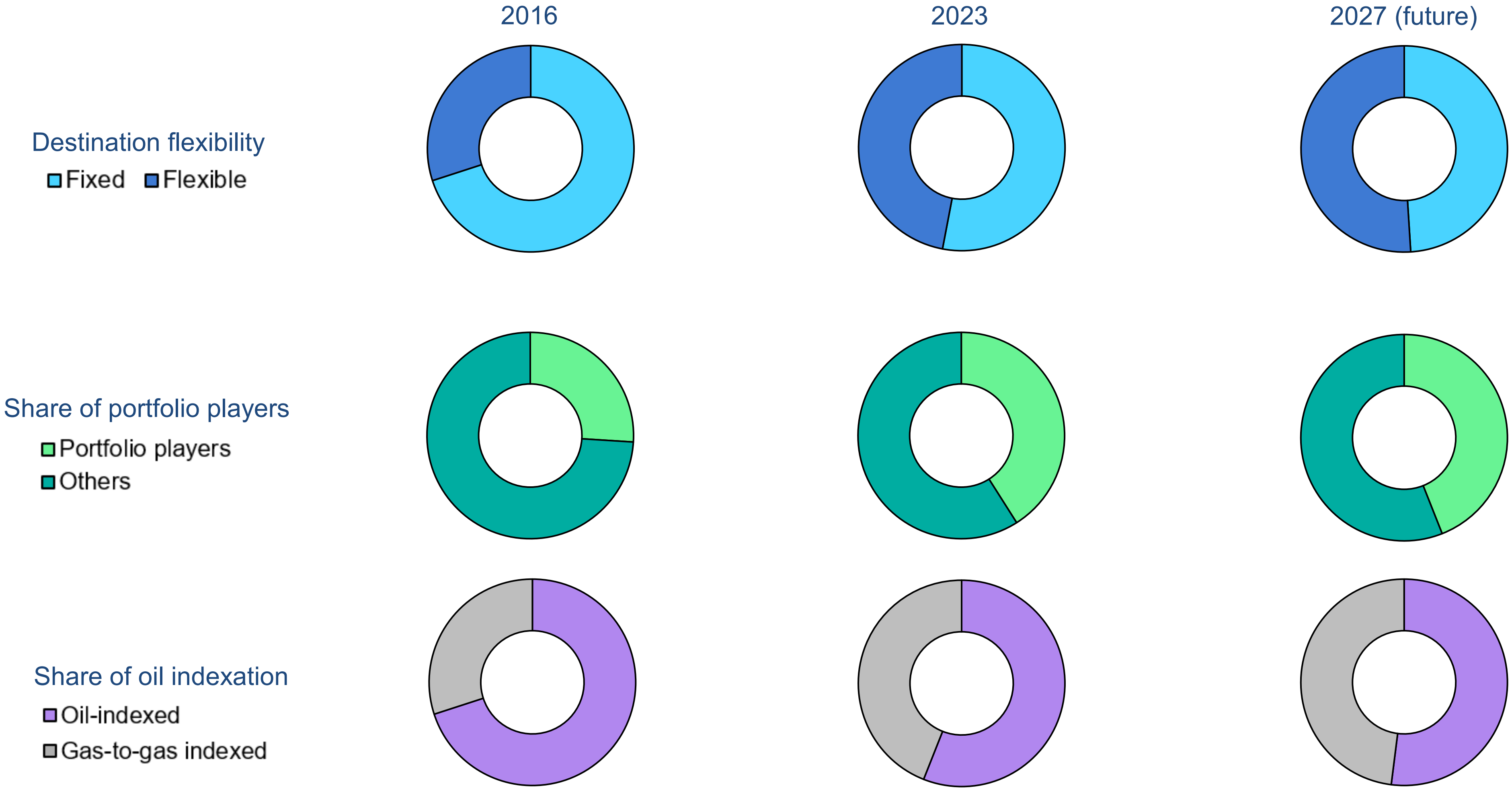
Pricing terms are becoming more diverse, with the share of oil-indexed LNG export contracts declining from over 70% in 2016 to 56% in 2023, replaced by hub indexation and hybrid pricing formulae. Based on active existing contracts, the share of oil-indexed contracts is expected to shrink further to 52% by 2027, with buyers' preferences shifting towards more diverse pricing terms.

In addition to traditional suppliers, the role of **portfolio players** in LNG trade has increased significantly in recent years: their procurement contracts' share of total LNG contracts in force rose from 26% in 2016 to over 41% in 2023. Based on existing contracts, this share is expected to increase to near 45% by 2027. Portfolio players are key enablers of short-term supply flexibility, facilitated by their net open positions and commercial ability to resell long-term LNG supply to customers on a short-term or spot basis.

While the global LNG market is becoming more flexible and liquid, **the role of long-term contracts remains crucial** as an effective risk-sharing mechanism between sellers and buyers. Long-term agreements (with a duration of 10 years and over) accounted for 85% of the volumes contracted since 2022, reflecting sellers' and buyers' preference for demand and supply security, respectively.

The **growing flexibility and liquidity of the LNG market** is becoming increasingly important in responding to gas supply and demand shocks to **ensure energy supply security**. This was highlighted during the 2022-23 gas supply shock and more recently by the low availability of hydropower in South America.

The global LNG market continues to gain liquidity and pricing diversity



Note: Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information. Destination-flexible contracts are typically underpinned by FOB shipping arrangements.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

The strong momentum behind LNG project development continued in 2024…

Since Russia's invasion of Ukraine in February 2022, **over 150 bcm/yr of LNG liquefaction capacity has been approved**, including **Qatar**'s North Field South and North Field West expansion projects. The **United States** alone accounted for 75% of the liquefaction capacity sanctioned between 2022 and 2023. In contrast, no US LNG project has reached FID since January 2024, after the introduction of a temporary pause on pending decisions on exports of LNG to non-free trade agreement countries. The **Middle East** emerged as the most important driver behind new LNG project approvals in 2024, led by Qatar, the United Arab Emirates and Oman. Project developers, including in North America and the Middle East, are increasingly focusing on **reducing emissions intensity across LNG supply chains** via the use of CCUS-based solutions, electrification and relying on renewable power supply.

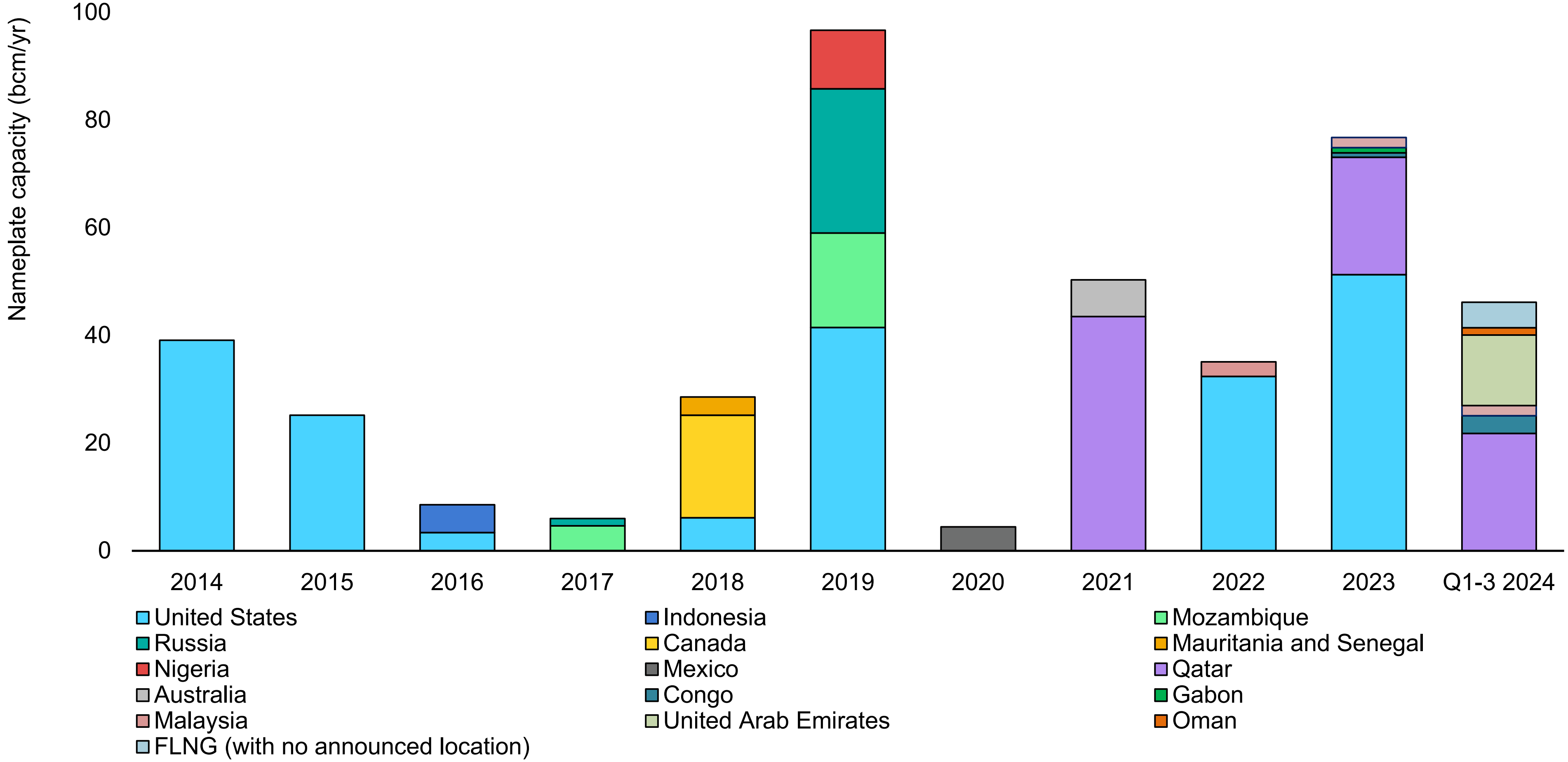
Qatar announced in February 2024 that it is proceeding with the **North Field West expansion project**, with a capacity of around 22 bcm/yr. This follows Qatar's previously announced projects, North Field East in 2021 and North Field South in 2023. Altogether, these expansion projects will increase Qatar's LNG liquefaction capacity by 85% (or more than 88 bcm/yr) to over 190 bcm/yr by 2030. In parallel, Qatar is developing **CCUS-based solutions** to reduce the emissions intensity of its LNG exports. By 2023 QatarEnergy had deployed 2.2 Mtpa of CCUS capacity. Its target is a total capacity of 7-9 Mtpa by 2030 and over 11 Mtpa by 2035.

In April 2024 the **Marsa LNG project** reached FID in **Oman** with a capacity of 1.36 bcm/yr. The liquefaction plant is expected to start operations by Q1 2028 and is primarily targeting the LNG bunkering market in the Gulf. The liquefaction plant will be 100% electrically driven and supplied with solar power. In the **United Arab Emirates**, the **Ruwais LNG** project reached FID in June 2024. The 13 bcm/yr project is expected to start operations in 2028. The facility will have an electrically powered liquefaction system and will rely on renewable power supply, which is set to reduce the emissions intensity of the LNG. In **Canada**, the **Cedar FLNG** project (4.5 bcm/yr) took FID in June 2024 and is expected to start operations towards the end of 2028. The facility will rely on renewable electricity. In **Mexico**, the **Altamira FLNG 2 project** (1.9 bcm/yr) closed the loan for its construction in July 2024 and is due to deliver first LNG in H1 2026. In September 2024, Golar LNG took FID on the conversion of an LNG carrier to a FLNG with capacity of 4.8 bcm/yr.

Together with Qatar's expansion projects, LNG liquefaction plants that have reached FID or are under construction would add approximately 270 bcm/yr of export capacity by the end of 2030. This strong increase in LNG production capacity could loosen market fundamentals and ease gas supply security concerns in the second half of the decade.

…primarily supported by the Middle East

FIDs for new LNG liquefaction capacity, 2014-2024*



* Includes Qatar's North Field South and North Field West expansion projects.
Sources: IEA analysis based on various public statements.

The Middle East and North America led new LNG contracts on the export side in 2023

The contract volumes concluded with post-FID projects in 2023 totalled 54 bcm/yr, representing a 24% decrease compared with 2022, when they totalled 71 bcm/yr. Including contracts with pre-FID projects, the contracted volumes in 2023 stood at 83 bcm/yr, exceeding the volume concluded in 2021 (79 bcm/yr), but 18% lower than the volume signed in 2022 (100 bcm/yr). Combined volumes from North America and the Middle East accounted for over 70% of the contracted volumes signed in 2023, showing a trend similar to 2022.

On the export side, the Middle East alone accounted for 55% (or 30 bcm/yr) of the volumes contracted with post-FID projects in 2023. In 2021 and 2022 North America accounted for the largest share of post-FID LNG export contracts, but in 2023 the Middle East surpassed North America as the largest source of supply. Qatar accounted for more than 40% (or 23 bcm/yr) of concluded volumes in 2023 and was the largest source by country, supported by the North Field East and North Field South expansion projects. North America was the second-largest source of supply in 2023, accounting for 23% (or 12 bcm/yr) of the contracted volumes signed with post-FID projects in 2023, continuing to contribute to the growth of new LNG contract volumes as a source of exports. Portfolio players and the Asia Pacific region accounted for 11% (or 6 bcm/yr) and 3% (or 1.5 bcm/yr) respectively of the total contracted volumes signed in 2023.

When including pre-FID projects, contracted volumes in 2023 with North America as the source of supply were 40 bcm/yr, exceeding the contracted volumes sourced from the Middle East. North America has a number of new LNG projects under consideration, supporting the view that new LNG contracts were signed with pre-FID projects.

On the import side, Asian countries accounted for the largest share of the contracted volumes concluded in 2023 with post-FID projects (42%, or 22 bcm/yr). By country, China accounted for 24% (or 13 bcm/yr), retaining a similarly large share as in 2022 (26%). Europe took the next largest share, accounting for 34% (or 18 bcm/yr) of the contracted volumes signed in 2023. Europe’s contracted volumes signed in the year reached their highest level in at least five years. However, its share of the contracted volume signed in 2023 remains lower than Asian buyers. Portfolio players accounted for 24% (or 13 bcm/yr) of the contracted volumes concluded in 2023. During the period 2017-2023 they accounted for around 40% of the total volumes signed with post-FID projects, indicating their major contribution as buyers of new LNG contracts.

When considering pre-FID projects, Asia, Europe and portfolio players accounted for 38% (or 31 bcm/yr), 26% (or 22 bcm/yr) and 35% (or 29 bcm/yr) respectively of the total contracted volumes concluded in 2023. The volume that portfolio players contracted as buyers in 2023 had a high proportion of contracts sourced from North America. Given that the contracted volumes sourced from North American includes a number of pre-FID projects, it might indicate that portfolio players play an important role in meeting the longer-term offtake contracts required for project FID.

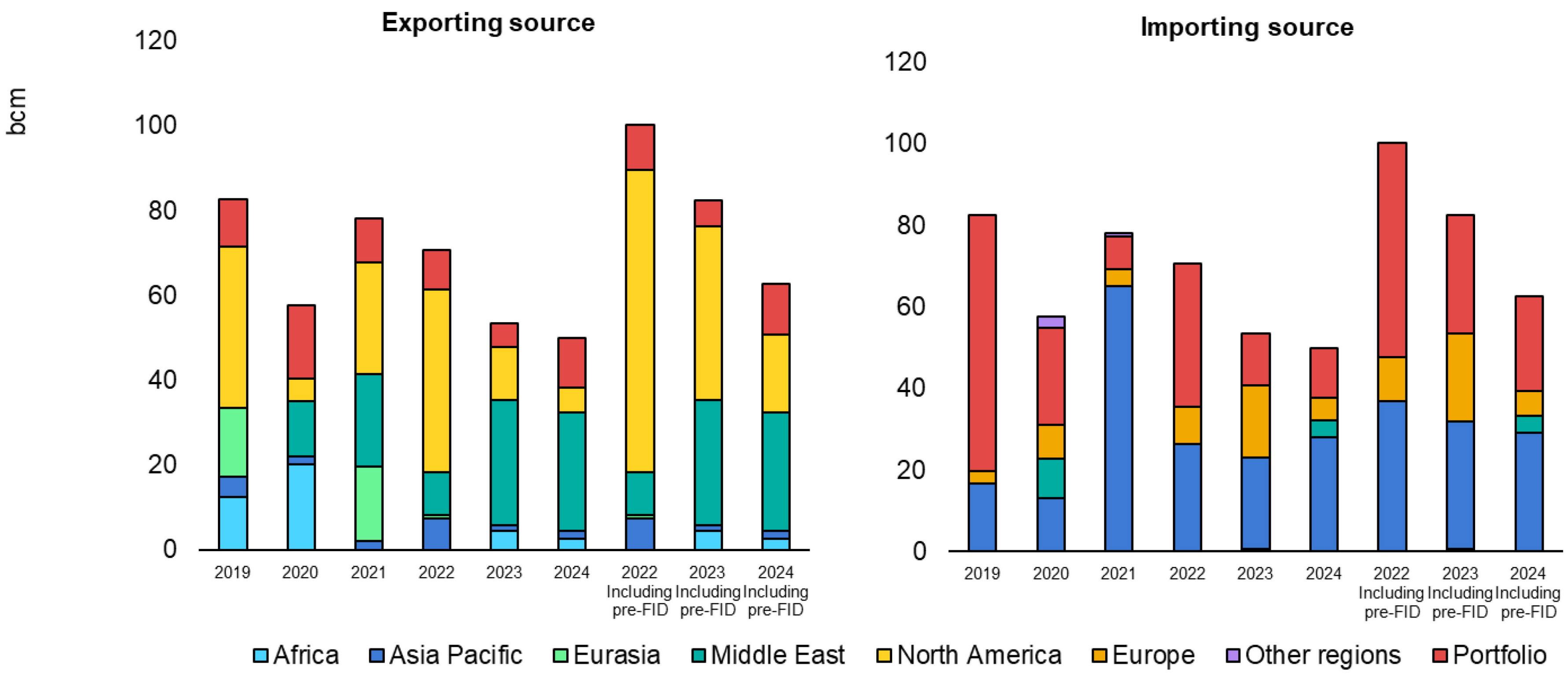
The volume of contracts signed with post-FID projects in the first eight months of 2024 was 50 bcm/yr, representing a 65% increase compared with the same period in 2023. Buyers in Asian countries accounted for 56% of the volumes contracted, with India signing the highest proportion (30%) by country. When pre-FID projects are included, 63 bcm/yr of contracts were signed in the first eight months of 2024, increasing by 18% compared with the same period in 2023. The strong expansion of LNG liquefaction capacity (expected to increase by approximately 270 bcm/yr by 2030) is offering additional contracting opportunities, especially from projects that still have uncontracted capacity.

On the export side, the Middle East accounted for the highest share of contract volumes signed in the first eight months of 2024 (56% or 28 bcm/yr), showing a similar trend to 2023. By country, Qatar showed the highest share (42% or 21 bcm/yr). Asia Pacific accounted for 3% (or 2 bcm/yr) of contracted volumes, led by Australia. Portfolio players accounted for 24% (or 12 bcm/yr) and North America 12% (or 6 bcm/yr). The volume of contracts sourced from North America decreased by around 50% compared with the same period in 2023. When pre-FID projects are included, 18 bcm/yr of contracts from North America were signed in the first eight months of 2024, compared with 35 bcm/yr in the same period in 2023, also representing a decrease of about 50%.

On the import side, Asia accounted for the highest share of contract volumes signed in the first eight months in 2024 (56% or 28 bcm/yr). India accounted for a high proportion (30% or 15 bcm/yr), representing the largest share by country. China accounted for 1 bcm/yr, decreasing by around 90% compared with the same period in 2023. By country, China led the import side between 2021 and 2023, but a different trend has been seen in 2024. China signed around 80 bcm/yr of contracts with post-FID projects between 2021 and 2023, and more than 90 bcm/yr when contracts with pre-FID projects are included. Based on firm contracts, the active contracted volumes with China as the buyer in 2027 could exceed 160 bcm/yr. Portfolio players accounted for 12 bcm/yr (or 25%) of the contracted volumes with post-FID projects, which was broadly flat on the same period in 2023. Europe accounted for 11% (5 bcm/yr), representing lower volumes than the same period in 2023.

Asian buyers continue to drive new LNG purchase contracts

Volume of contracts concluded in each year split by exporting and importing source, 2019-2024



Notes: Contracted volumes used for the analysis are associated with confirmed export projects that have taken FID. 2024 represents volumes signed by the end of August 2024. “Portfolio” volumes are contracted by a market player who may source product from one or multiple regions to fulfil contractual obligations.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Long-term agreements have dominated contracting activity since 2018

Contracts concluded in 2023 showed a high share of long-term agreements (with a duration of 10 years and over) and high-volume contracts (over 4 bcm/yr). The trend of a growing share of long-term agreements has continued since 2018.

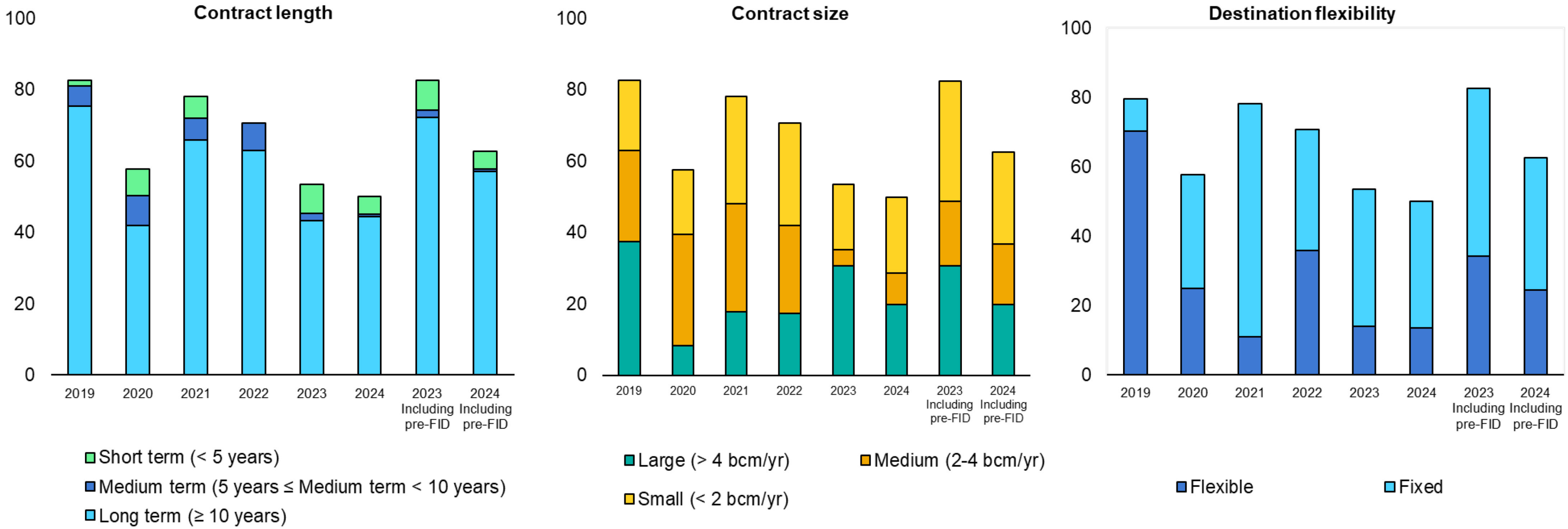
Long-term agreements dominated contracted volumes in 2023, accounting for 81%, a slight decrease from 89% in 2022 but still a high share. Asian buyers were the driving force behind long-term agreements, accounting for 46% of long-term agreements by volume. The Middle East led with long-term agreements as suppliers, Qatar signing five contracts in 2023 with a contract duration of 27 years. Agreements with a medium duration (five years and over, but under ten years) and with a short duration (under five years) accounted for 4% and 15% of the total contracted volume, respectively. Long-term agreements also dominated during the first eight months in 2024, accounting for 89%. In this period Asian buyers signed long-term agreements accounting for more than 60% of the total long-term contracted volume. Of the total contracted volumes signed since 2018, long-term agreements have accounted for more than 80%, of which Asian buyers accounted for more than 40%. Notably, China accounted for over 20%, leading the volume of long-term agreements.

Large contracts (over 4 bcm/yr) accounted for 57% of contracted volumes in 2023, the largest share since 2017. Qatar accounted for over 60% of large contract volumes, signing four contracts with a volume exceeding 4 bcm/yr. Medium-sized contracts (2-4 bcm/yr) accounted for 8%, while contracts for small volumes (< 2 bcm/yr) accounted for 34%. In the first eight months of 2024, the share of large contracts was high (39%), similar to 2023. The share of large contracts among all contracts concluded since 2022 is close to 40%, and Asian buyers accounted for a high share of these (45%).

Destination-fixed contracts account for around 70% of all volumes contracted since 2023. This has mainly been driven by Asian buyers, accounting for more than 60% of total contracted volumes with a fixed destination. Conversely, the share of destination-free contracts decreased from around 50% in 2022 to around 30% in 2023 and 2024. The decrease in destination-flexible contracted volumes sourced from North America in 2023 and 2024 compared with 2022 is assumed to be one of the reasons for the decline in the share of destination flexibility since 2023. Although the share of contracts concluded in 2023 and 2024 with a fixed destination was high, the overall trend for total active contracts to have a flexible destination is increasing – their share was 47% in 2023, but this is assumed to increase to around 51% in 2027. This is due to the expiry of existing contracts with a fixed destination.

The contracting trend in 2023 and 2024 shows a high share of destination-fixed LNG supply

Volume of contracts concluded in each year, split by contractual element, 2019-2024



Note: 2024 represents volumes signed by the end of August 2024. Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Portfolio players have key role in providing LNG supply flexibility

Portfolio players have an important role in meeting buyers' growing need for volume and supply source flexibility. They procure a mix of LNG supplies from various origins and resell to customers to meet their requirements through term and spot contracts. The role of portfolio players has increased significantly in recent years.

The share of contract volumes procured by portfolio players is on the rise. In 2024 their procurement volume as a share of total LNG contracts stands at 41%, increasing from 26% in 2016. The share of contracted volumes concluded by portfolio players between 2018 and 2022 was 45% of the total, raising the share of their procurement volume among all active LNG contracts. The average contract duration for newly contracted volumes procured by them in 2016 and 2017 was less than ten years. However, for new contract volumes they procured in 2023 and 2024, the average contract duration increased to more than 15 years. In contrast, the average duration of contracts portfolio players signed for the sale of LNG in 2023 and 2024 was less than 11 years.

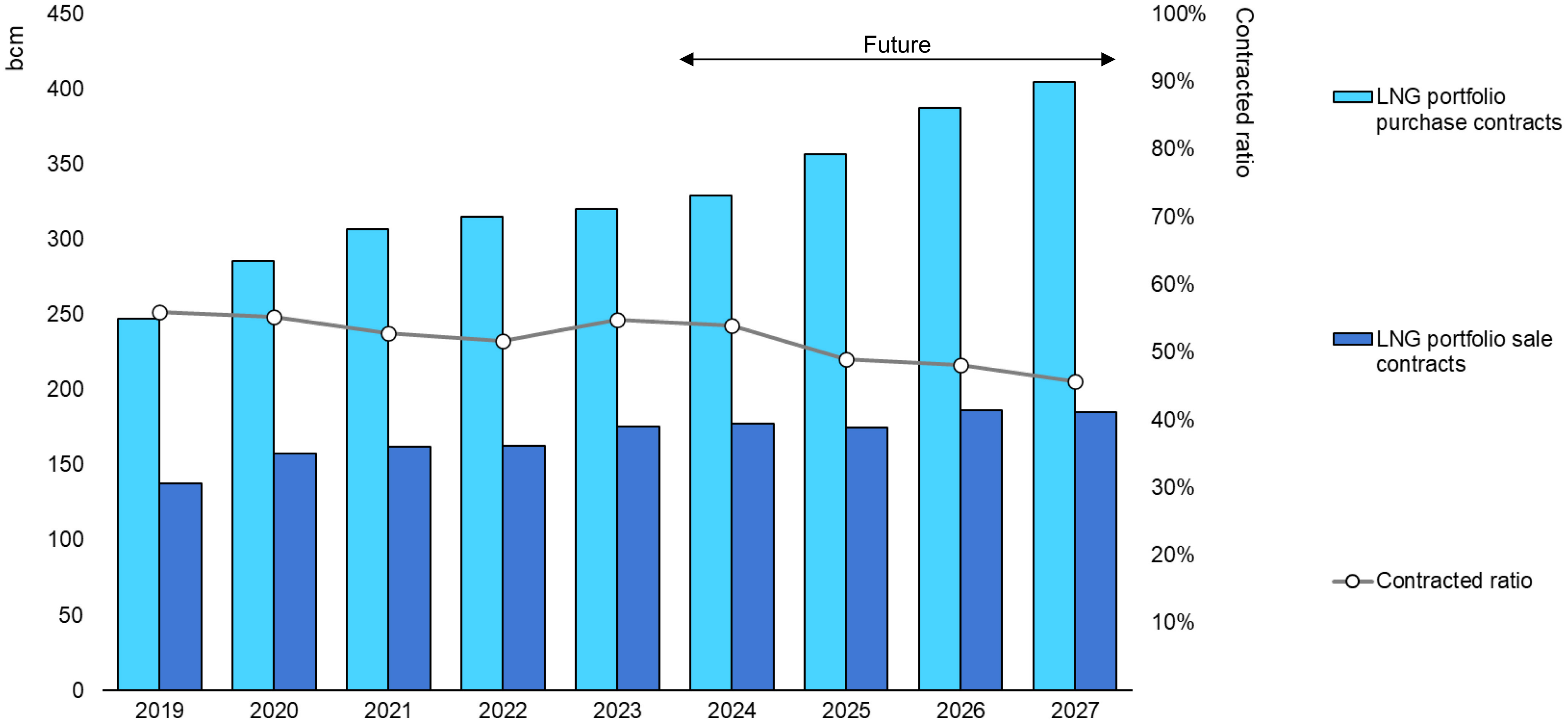
Portfolio players' share of contracts for the sale of LNG was approximately 50% of total contracted volumes signed in 2016 and 2017. Conversely, their share of contracted volumes concluded since 2022 stands at 15%. Since the price increase in key gas markets due to the gas supply shock of 2022, gas prices have remained higher than between 2016 and 2020 levels. It therefore appears that the recent market situation may be attractive for short-term sellers. The trend for portfolio players' decreasing share of term contract sales might reflect their preference under the market conditions since 2022 to sell their LNG volumes on the spot market.

Portfolio players' contract ratios – sales offtake as a percentage of purchase obligations, a metric of relative exposure to certain types of market risk – declined to 55% in 2023 from 71% in 2017. This means that the share of their purchase obligations not covered by term sales contracts – or their net open position – increased from 29% to 45% between 2017 and 2023. Based on existing contracts, their net open position is set to increase to an average of close to 50% between 2024 and 2027. The growing net open position of portfolio players will contribute to market stabilisation by providing increased trading flexibility with regard to contract duration and volume.

With approximately 270 bcm/yr of new LNG liquefaction capacity expected to be added by the end of 2030, the additional LNG supply could reduce gas market prices compared to the current situation. But equally, some buyers may be attracted to long-term contracts to ensure future energy security and avoid future price volatility risks. In this complex future situation, portfolio players are expected to continue to play an important role in providing flexibility to the global LNG market.

A wider net open position of portfolio players can provide flexibility to the global LNG market

LNG portfolio players' contractual position and contracted ratio, 2019-2027



Note: This graph represents the volumes signed by the end of August 2024.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

North America is set to drive additional LNG supply volume over the medium term

The volume of firm active contracts (including portfolio players) by 2027 is expected to increase by about 20% compared with 2023. The average growth rate for the past three years (2021-2023) was about 2.5% and it is expected to increase to around 4% per year between 2023 and 2027. This higher growth rate in active contract volumes is supported by the expected start-up of several new LNG liquefaction plants by 2027.

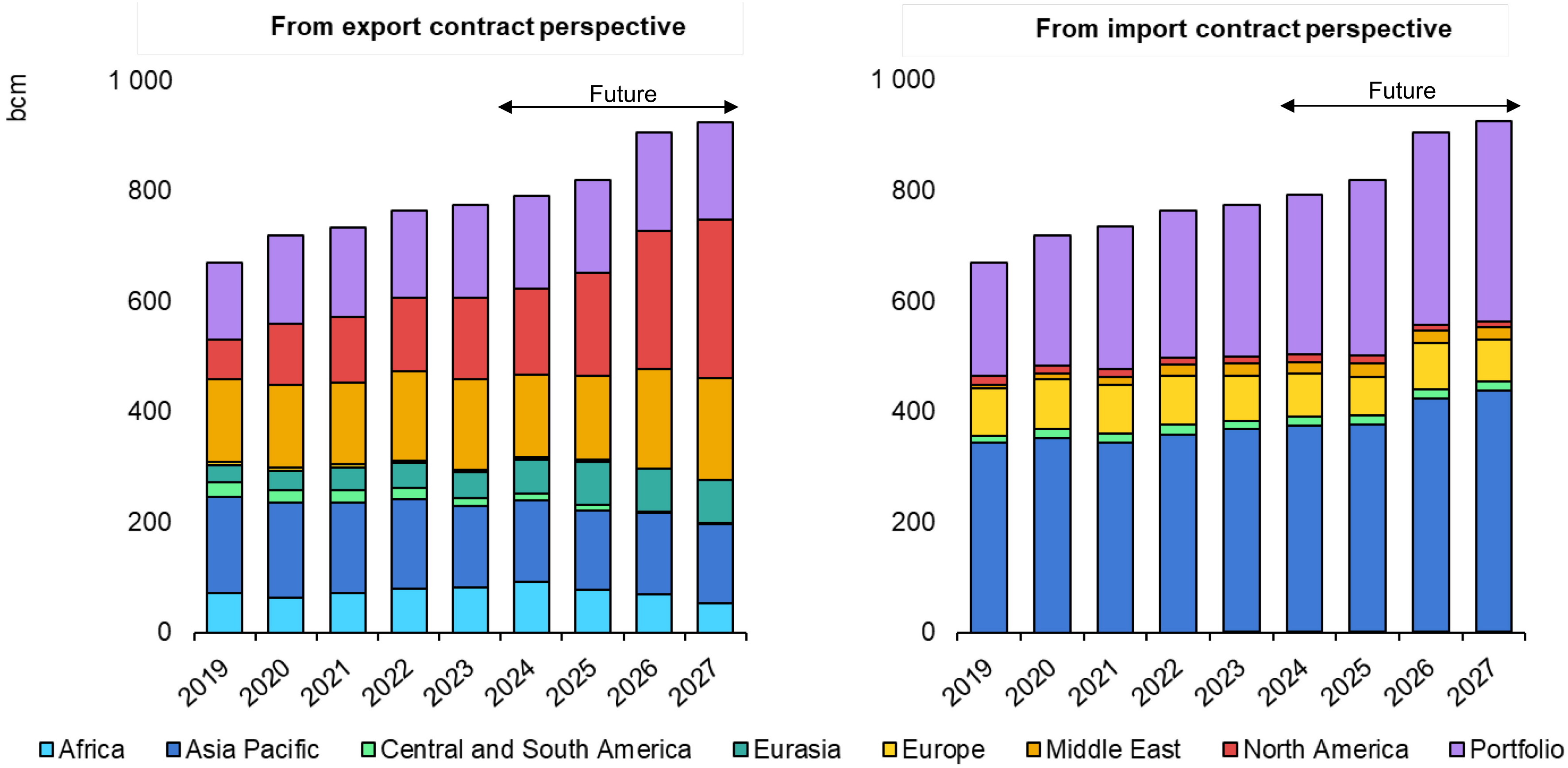
On the export side, the volume of supply contracts from North America is expected to increase by approximately 90% between 2023 and 2027. New LNG liquefaction plants are expected to commence operation in North America, which are assumed to drive global LNG supply growth over this period. North America's share of total active contracts is set to increase from 19% in 2023 to 31% by 2027. Over the same period, the volume of supply contracts from the Middle East is set to increase by about 13%, primarily supported by Qatar's expansion projects. In contrast, during the same period, active contracted volumes from Africa and Central and South America are set to decrease by 34% and 87% respectively as existing contracts expire. On the import side, the Asia Pacific region's share of total import contract volumes is set to be around 50% in 2027. The volume contracted by Asian buyers is assumed to increase by 20% between 2023 and 2027. China's active contracted volume is set to increase by 43% between 2023 and 2027, increasing the country's share of active global LNG contracts to around 18% by 2027. India is assumed to increase its volume of active contracts by 26% over the same period. In contrast, Japan and Korea are expected to see a gradual decline in their contracted volumes during this period due to the expiry of existing contracts. The volume of active contracts held by Europe-focused buyers is set to decrease by approximately 8% between 2023 and 2027.

Based on firm contracts, the proportion of destination-flexible contract volumes as a share of primary[3] LNG export contracts is set to grow to 59% by 2027, up from 55% in 2023. With several new LNG liquefaction plants expected to start operation by 2027, the total volume of uncontracted capacity and contracts with a flexible destination is set to increase over the medium term. This trend is expected to provide flexibility and liquidity to the global LNG market.

[3] Sourced directly from export projects owners, as opposed to secondary volumes sold by portfolio players.

Active LNG contracting volume is expected to expand over the medium term

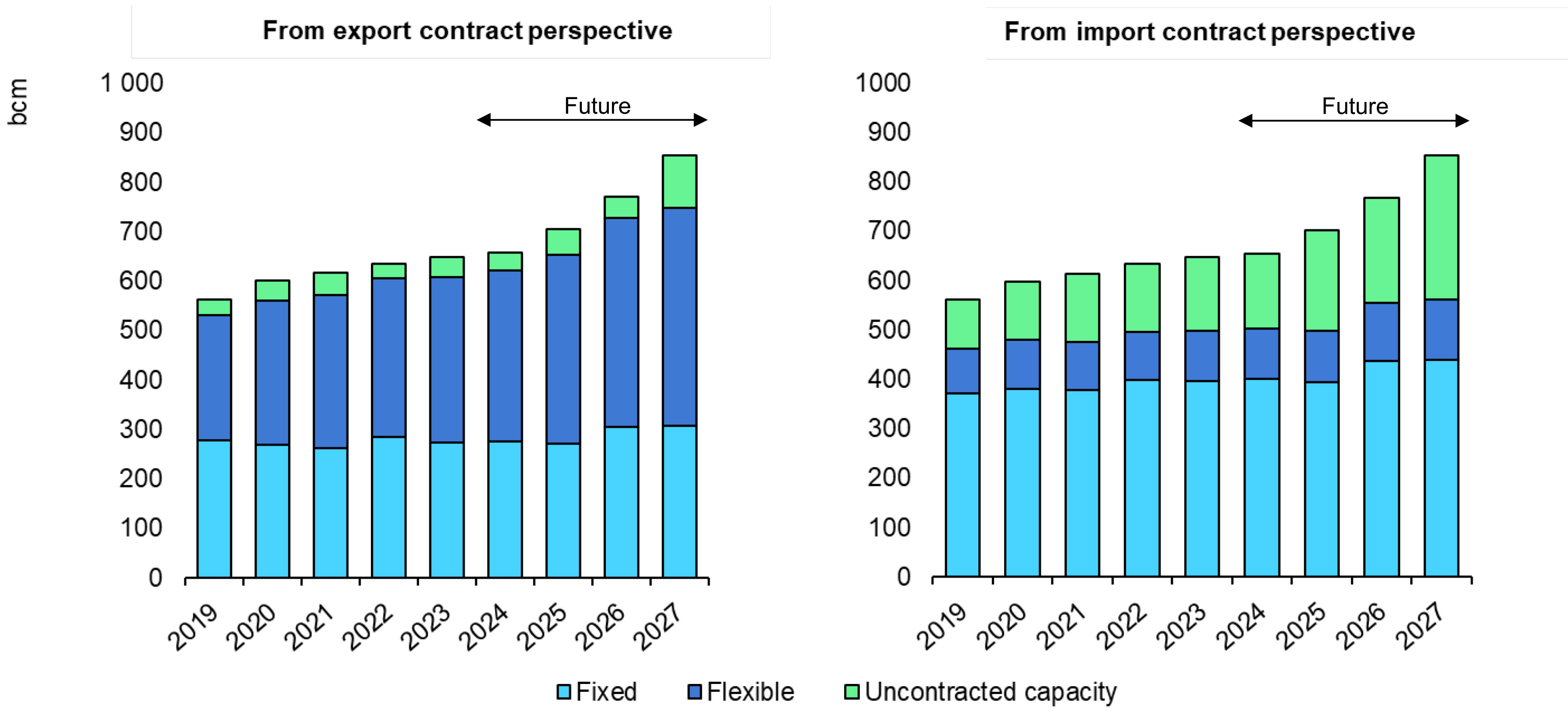
Total active LNG contracts, 2019-2027



Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Destination-flexible contracts and uncontracted capacity are set to improve market flexibility

LNG supply capacity by destination flexibility (excluding portfolio contracts), 2019-2027



Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Expiring contract volumes could improve market flexibility

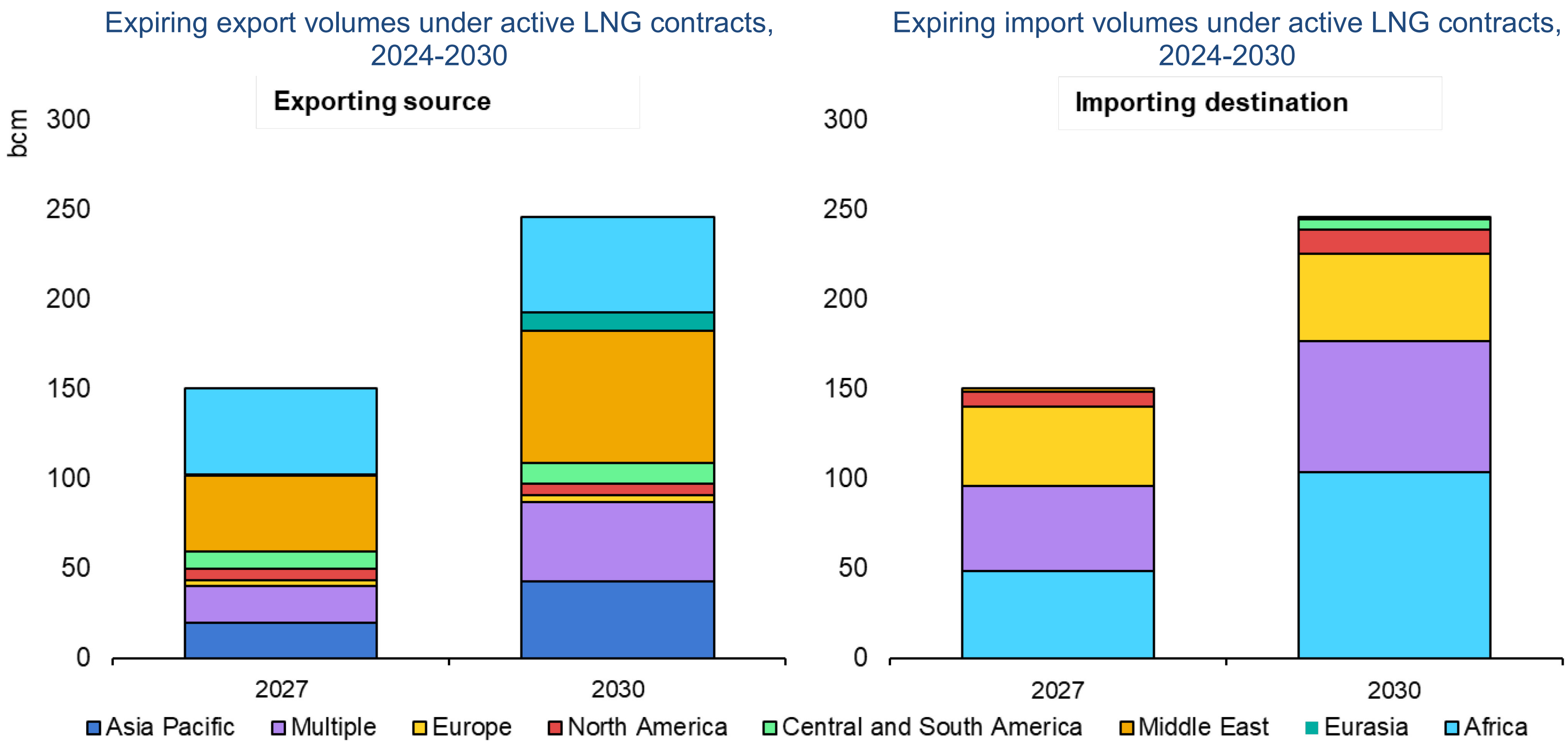
Based on firm contracts, it is assumed that about 150 bcm/yr of active LNG contracts are set to expire between 2024 and 2027. Furthermore, an additional 95 bcm/yr of contract volumes are set to expire between 2027 and 2030. These expiring contract volumes are expected to create new contracting opportunities in the medium term.

On the seller side, Africa accounts for the highest share of expiring contract volumes in the period 2024-2027, with about 32% (or 48 bcm/yr). When taking into account the period up to 2030, it is assumed that an additional 5 bcm/yr of contracts are set to expire. The Middle East has the next highest share in the period 2024-2027, accounting for 28% (or 42 bcm/yr), followed by an additional 31 bcm/yr between 2027 and 2030. The Middle East is assumed to see the highest volume of contracts expiring between 2024 and 2030. In the period 2024-2027, Asia and portfolio players are each set to see active contract volumes expire in the amount of 20 bcm/yr (or 13% of total expiring volume).

On the buyer side, Asia, portfolio players and Europe account for 33% (or 49 bcm/yr), 31% (or 47 bcm/yr) and 29% (or 44 bcm/yr) of the total expiring volumes between 2024 and 2027, respectively. The total volume of active contracts held by Asian buyers in this period is expected to increase by approximately 60 bcm/yr due to the increase in new contracts. In contrast, Europe is expected to see its active contract volume decrease by 3 bcm/yr in this period, as the reduction from expiring contracts is larger than the increase from new contracts.

LNG contracting has historically been dominated by oil indexation. Based on available information, the share of oil-indexed volumes in total active LNG export contracts was approximately 70% in 2017 but fell to about 56% in 2023 and is assumed to fall again to about 52% in 2027. By contrast, the share of the gas-to-gas indexation in LNG export contracts increased from about 30% in 2017 to about 44% in 2023 and is assumed to reach 48% in 2027. In addition to contracts with oil-indexation and Henry Hub formulae, contracts with JKM, TTF and hybrid formulae were signed between 2023 and 2024. This trend would indicate that pricing mechanisms underpinning long-term LNG contracts are becoming more diverse. When the gas supply shock happened in 2022, gas market prices spiked, leading to a sharp increase in the trading prices with gas-to-gas indexation. Conversely, the trading prices with oil-indexation increased more modestly than gas-to-gas indexation. Securing long-term LNG contracts with some form of oil indexation can be one way to moderate exposure to gas price volatility.

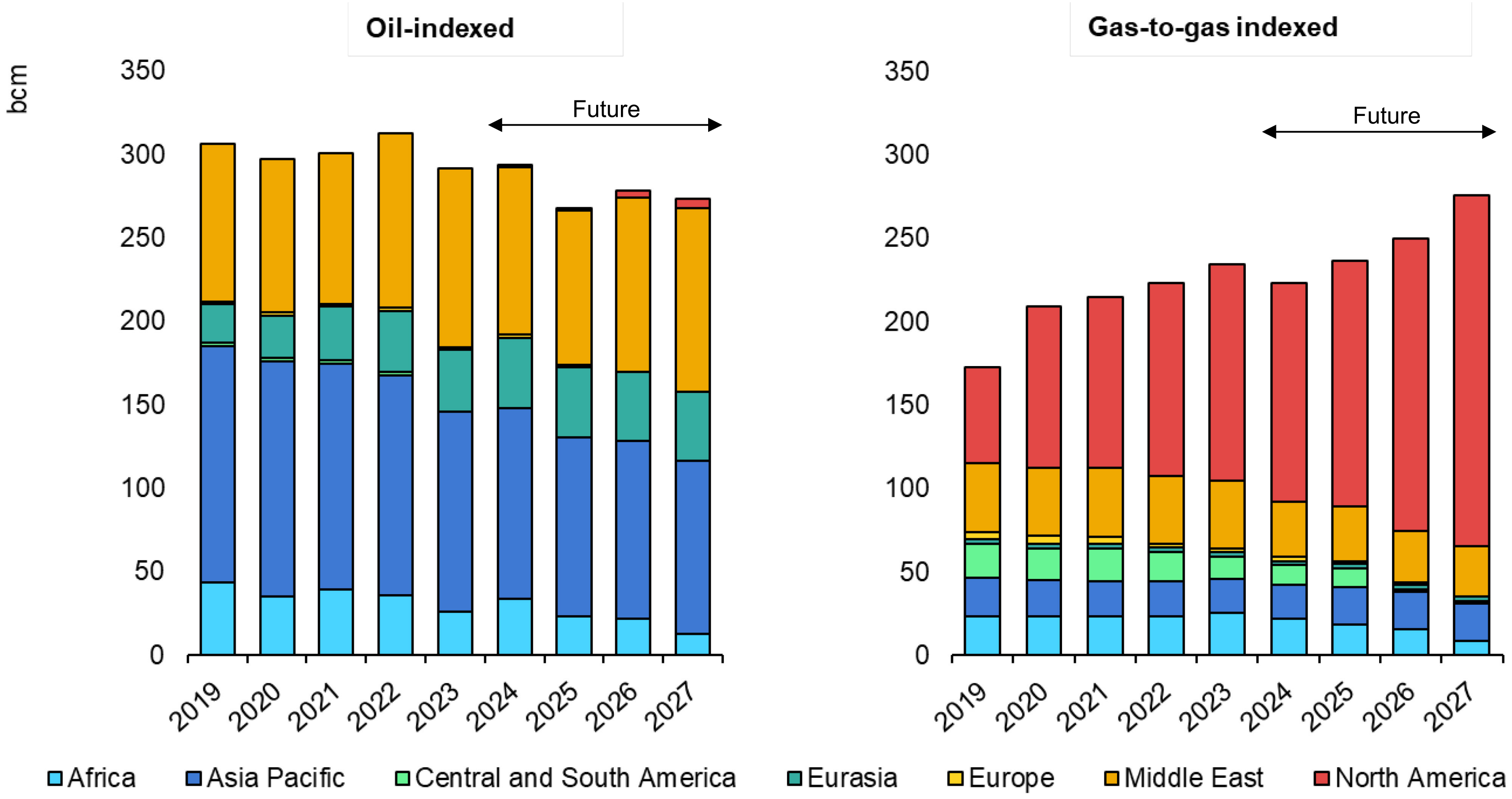
About 150 bcm of LNG contracts are expiring by 2027, mainly from Africa and the Middle East



Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

LNG export volumes with gas-to-gas indexation are set to expand, driven by North America

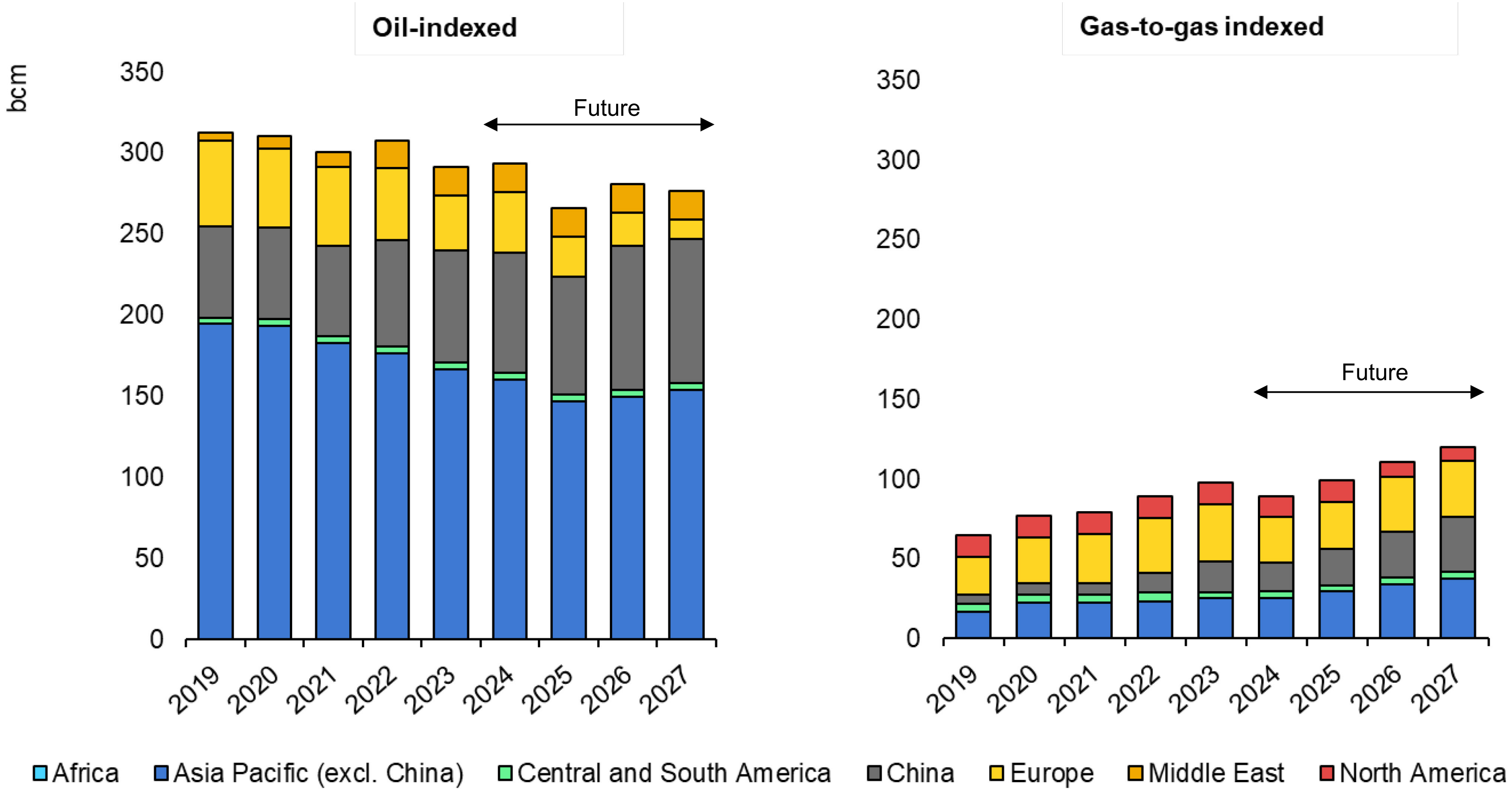
LNG export contract volumes with oil-indexed and gas-to-gas pricing, by region and country, 2019-2027



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Although oil-linked pricing is decreasing, it remains dominant in import contracts

LNG import contract volumes with oil-indexed and gas-to-gas pricing, by region and country, 2019-2027



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

System integration of low-emissions gases

Low-emissions gases can play a significant role in the decarbonisation of hard-to-abate segments of the transport sector

Low-emissions gases (including biomethane, low-emissions hydrogen[4] and e-methane[5]) can play an important role in decarbonising gas supply chains and the broader energy system. Recognising their growing importance, the International Energy Agency has developed a **Low-emission Gases Work Programme** to provide regular market analysis, including on the evolving system integration of low-emissions gases. This section focuses on the role of low-emissions gases in the transport sector.

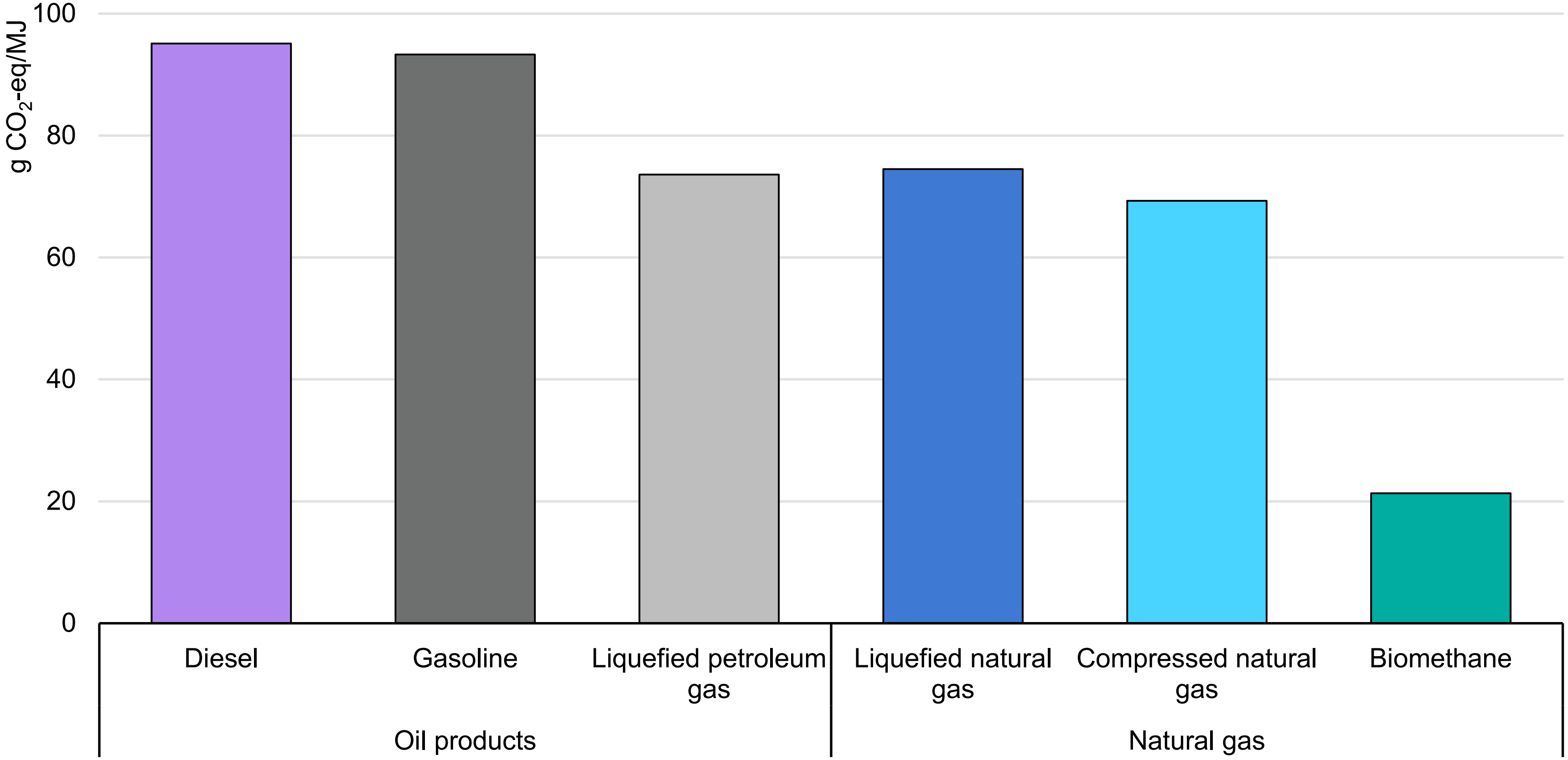
Low-emissions gases can play an important role in the **decarbonisation of long-haul, heavy-duty transport,** where electrification has so far made slower progress than in the light-duty vehicle segment. **Biomethane, also known as renewable natural gas (RNG), offers significant GHG emissions savings** when compared with fossil fuel alternatives in the transport sector. Considering the average reported GHG intensity of biomethane in the European Union, its GHG emissions reduction potential compared to diesel and gasoline is over 75%. Depending on the production route and feedstock, RNG can lead to negative GHG emissions (in cases where the biogas would otherwise be released to the atmosphere). Today, the transport sector alone accounts for almost half of global biomethane consumption and it is expected to be a key driver behind incremental demand over the medium term. In the United States RNG use in the transport sector has more than quadrupled since 2016 and today accounts for around 80% of all on-road fuel used in natural gas vehicles. In the European Union biomethane accounts for approximately one-third of the total gaseous fuels used in road transport. In addition, biomethane is gaining traction as **"fuel gas"** used in natural gas pipeline systems. Compressor stations consume over 50 bcm/yr of natural gas globally, offering a sizeable market for RNG. Pipeline companies and transmission system and storage site operators are developing "green" transport and storage products where biomethane is used as fuel gas to reduce the emissions intensity of natural gas supply.

The use of **hydrogen** in road transport remains limited, although it is increasing at a rapid pace. Hydrogen demand in road transport increased by around 45% in 2022 to just over 30 000 t H_2, with growth primarily supported by China and Korea. **Fuel cell electric vehicles** (FCEVs) produce no harmful tailpipe emissions and can reduce GHG emissions by nearly 100% compared with diesel or gasoline – if hydrogen is supplied from low-emissions sources.

[4] Low-emissions hydrogen includes hydrogen produced via electrolysis where the electricity is generated from a low-emissions source (renewables or nuclear), biomass or fossil fuels with CCUS.
[5] E-methane refers to synthetic methane produced from electrolytic hydrogen. The definition of low-emissions synthetic methane used by the IEA for analytical purposes in its reports considers that any carbon inputs, e.g. from CO_2, are not from fossil fuels or process emissions. Beyond this definition, a commercial proposition for carbon-neutral e-methane could consider the use of CO_2 captured at industrial or power plants and offset through carbon credits (similar to the commercial offers of carbon-neutral LNG).

Biomethane offers significant GHG emissions savings in the transport sector

GHG intensity by fossil fuel type and average reported GHG intensity of biomethane in the European Union



Source: IEA analysis based on European Environment Agency (2023), Greenhouse gas intensities of transport fuels in the EU in 2021.

In the United States, biomethane growth is primarily driven by the transport sector

The use of biomethane (referred to as RNG in the United States) has increased exponentially from a very low base over the past ten years. In 2023 total RNG production was estimated at 3.2 bcm, marking a 22% increase from the previous year and a nearly sixteen-fold jump from a decade earlier.

At the end of 2023 there were 305 operational projects and 125 under construction, with a combined production capacity of around 1 bcm, according to the Argonne National Laboratory's RNG database. A further 111 projects were at various stages of planning at the beginning of 2024.

US biomethane production primarily comes from landfills (68%), agriculture (25%), and various streams of food and organic waste (7%). The predominance of landfill-sourced feedstock in the United States is due to existing mandates to capture and treat landfill gas, combined with the relative economies of scale for typical projects and the proximity of potential RNG offtakers to landfill sites.

The low cost of conventional natural gas in the US presents challenges for RNG, the production cost of which can exceed USD 30 per MBtu. The adoption of RNG has largely been driven by federal and state-level incentives, which are heavily directed towards the transport sector.

The federal Renewable Fuel Standard (RFS) programme enables RNG producers to earn and monetise D3 RIN credits, the price of which averaged USD 3.1 per gallon (equivalent to around USD 35 per MBtu of RNG) in H1 2024. In addition, the Inflation Reduction Act has extended the USD 0.5 per gallon (USD 5.5 per MBtu) Alternative Fuels Tax Credit (AFTC) until the end of 2024, and state-led Low Carbon Fuel Standard (LCFS) programmes in California, Oregon and Washington offer generous subsidies on RNG sales in addition to the federal incentives.

California's LFCS credits traded at around USD 58 per ton of avoided CO_2 in the first half of 2024, which translates into between USD 2 and USD 25 per MBtu of RNG, depending on the carbon intensity of the feedstock. Proposed amendments to California's LCFS, expected to take effect in 2025 if adopted, aim to substantially tighten the system's underlying carbon intensity targets. This could potentially boost the price of LCFS credits, which peaked at USD 200 per ton in 2021 but collapsed by more than two-thirds in the ensuing three years as credit generation by low-carbon fuel suppliers proliferated.

Due to the focused incentives targeting renewable transport fuels, well over half of current RNG consumption in the United States is concentrated in the road transport sector, while the remainder is blended into local distribution grids, used for power generation, or purchased by commercial and industrial players to meet voluntary emission reduction targets.

Industry sources estimate that RNG accounted for 79% of gas consumption by natural gas-fuelled vehicles in the United States in 2023, up from only 32% in 2018.

RNG adoption outside the transport sector has been more modest in volume terms, but has accelerated in recent years thanks to federal, state and local policy support and voluntary adoption by companies with decarbonisation commitments.

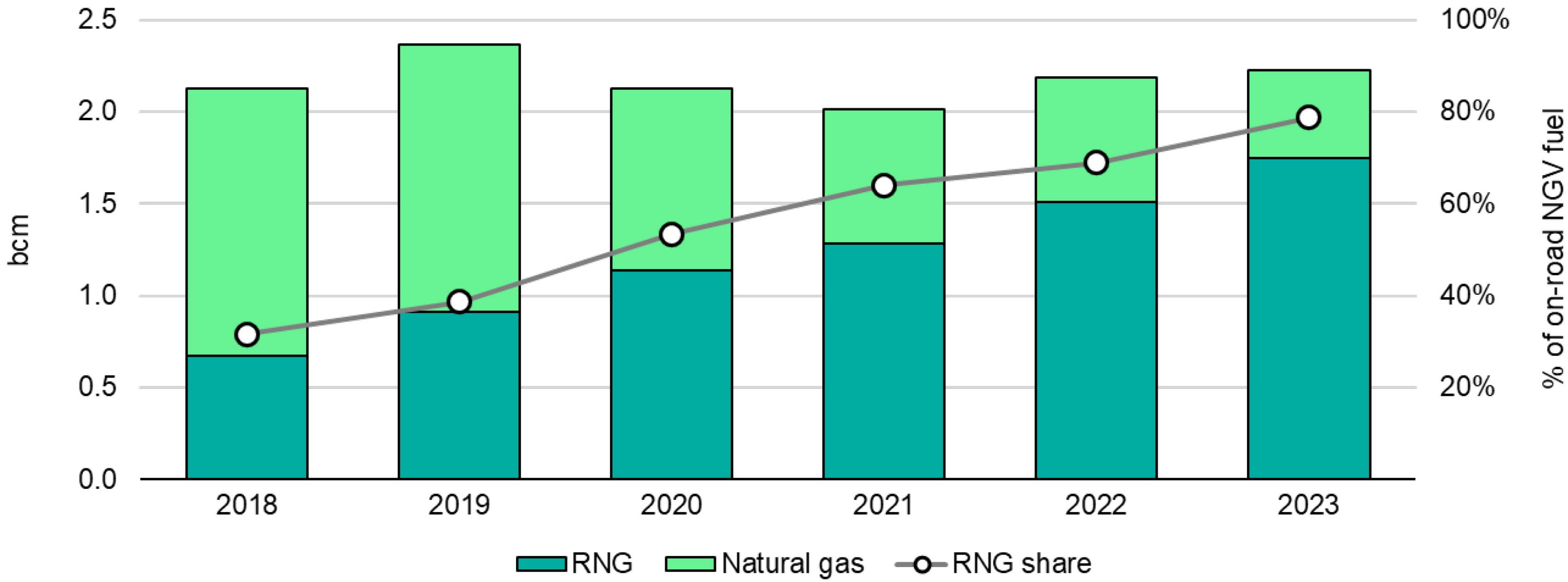
The 2022 Inflation Reduction Act extended an investment tax credit (ITC) of up to 50% to eligible biogas and biomethane projects. This applies to any type of RNG project regardless of end use, but the positive effect of this programme on RNG growth is relatively short-lived as qualifying projects are required to start construction by the end of 2024. The act also extended a ten-year production tax credit (PTC) worth up to 1.5 cents per kWh to biomethane-fuelled power projects until the end of 2024. The ITC and PTC programmes are expected to continue under a different tax code heading and in a technology-neutral form between 2025 and 2027, while the eligibility of biomethane facilities is pending further clarification by the US Treasury.

Some US states, notably Oregon and Nevada, have allowed gas utilities to institute voluntary RNG targets to inject biomethane into their respective networks and recoup some of the associated capital and operating costs from customers. California's Senate Bill 1440 went further, introducing a mandatory RNG procurement target for the state's four investor-owned utilities, set at 17.6 bcf (0.5 bcm) for 2025 and expected to increase to 72.8 bcf (2 bcm) by 2030. The 2030 target is subject to revision in 2025.

In addition to utility-based procurement, some large corporations and universities with ambitious decarbonisation goals have concluded long-term RNG purchase agreements with suppliers on a voluntary basis. Such business-to-business arrangements have emerged as an additional driver of RNG growth outside the traditional transport sector uses in recent years.

RNG dominates the natural gas vehicle fleet in the United States

RNG used in the natural gas vehicle fleet, United States, 2018-2023



Source: IEA analysis based on NGV America and Coalition for Renewable Natural Gas (2023), On-Road RxNG Use Report.

System integration of biomethane is led by the transport sector in several EU countries

Biogas and biomethane have traditionally been used for heating and power generation in the European Union. However, biomethane use in transport has accelerated markedly in recent years thanks to supportive policies in a handful of countries where incentive schemes prioritise the transport sector. In 2022 the transport sector accounted for between a fifth and a quarter of total biomethane use in the European Union.

Italy is currently the biggest EU market for biomethane for transport, and as of 2022 all of the country's biomethane production was used as a vehicle fuel. The rapid uptake of bio-CNG has been fuelled by generous financial support since 2018 and aided by Italy's large network of CNG filling stations. The main incentive scheme today is the 2022 Biomethane Decree, which allocates EUR 1.73 billion from the EU Recovery and Resilience Facility to support biomethane projects, and a further EUR 2.8 billion to provide incentive tariffs for biomethane projects to bridge the gap between biomethane and natural gas costs for the first 15 years of operation.

Germany is a mature market for biogas and biomethane, but the transport sector accounts for only less than 10% of total biomethane consumption. However, the use of biomethane (especially bio-LNG) as a transport fuel has been growing rapidly since the launch of Germany's national emissions trading system in 2021, which covers transport sector emissions (alongside buildings and other sectors).

France has seen near exponential growth in biomethane use in recent years, driven by the country's generous feed-in tariffs and blending mandates for biomethane producers. The transport sector represents a relatively small share of total demand (at less than 15%), but bus fleets and heavy-duty vehicles in particular have been strong drivers of France's rapid biomethane uptake.

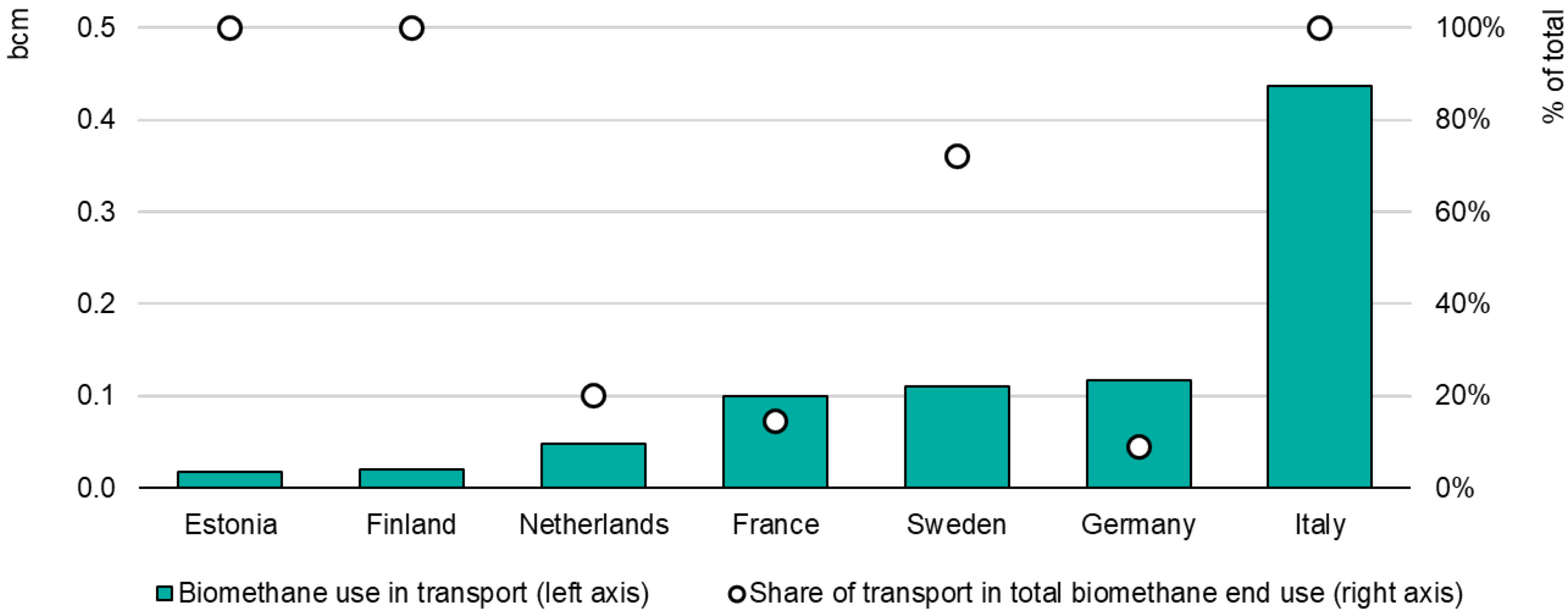
The **Netherlands** uses about 0.05 bcm of biomethane for transport, which represents a fifth of the country's total biomethane production. The main policy instrument to support biomethane deployment in the transport sector is the Energy for Transport Annual Obligation, which requires the share of renewable transport fuels to progressively increase from 18.9% in 2023 to 28.0% in 2030. Future growth is mainly expected in the form of bio-LNG, where the Netherlands is targeting a 2 TWh (0.2 bcm) of production capacity by 2025.

Sweden has been supporting biomethane use for transport since the 1990s via tax breaks from energy and carbon taxes, which are particularly high in the transport sector. The country also introduced a long-term investment support scheme in 2022, which provides a flat premium for biomethane producers. About 70% of Swedish biomethane use is concentrated in the road transport sector.

Finland and Estonia use all of their respective biomethane production in the transport sector, supported chiefly by a national biofuel mandate in Finland, a feed-in premium in Estonia, and additional investment incentives in both countries.

Biomethane use in transport is concentrated in a handful of countries in the European Union

Biomethane use in transport, selected EU member states, 2022



Source: IEA analysis based on European Biogas Association (2023), EBA Statistical Report 2023.

Transport offers uptake potential for hydrogen, but policy incentives are the major determinant

Hydrogen use for transport is almost entirely concentrated in road transport, with only marginal volumes used in rail and shipping applications. While road transport is set to retain its dominance over hydrogen demand in the short term, pilot projects and testing and development of new technologies continue to take place in non-road transport sectors – including in aviation – such that alternative sources of hydrogen demand in transport could yet emerge. Policy incentives will be key in helping realise potential demand growth, laying down the tracks for the transport segments best placed to capitalise on hydrogen's benefits.

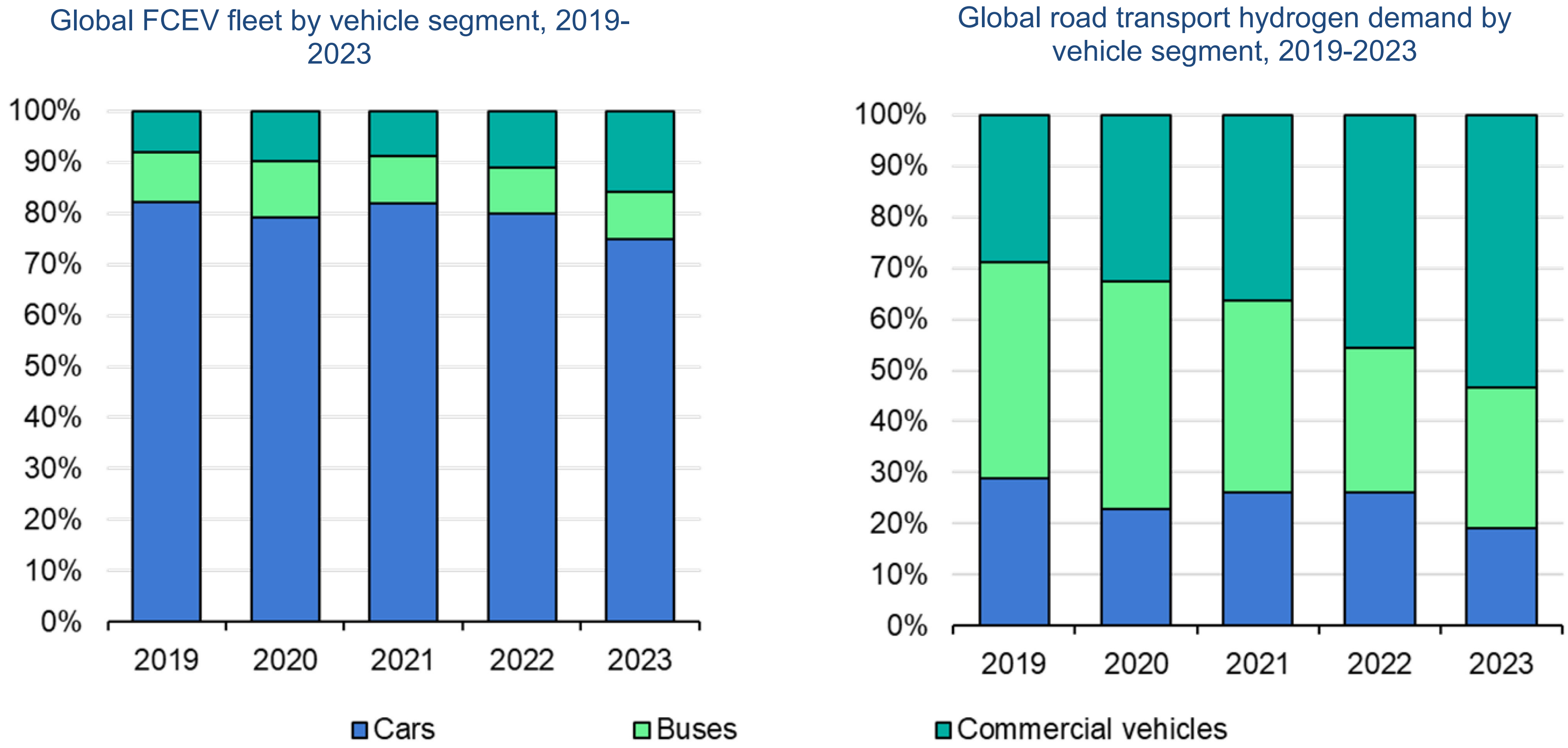
Global y-o-y growth in road transport hydrogen demand accelerated to around 55% in 2023, up from around 40% in 2022 as fuel cell electric vehicle (FCEV) fleets continued to grow across a handful of key markets. While light-duty vehicles (cars and vans) make up by far the largest share of the global FCEV fleet today, deployment of FCEV trucks and buses accelerated significantly in 2023. With much higher uptime and longer distances travelled, the heavy-duty vehicle segment has become a key driver of road transport hydrogen demand, notably in China. Despite accounting for only about 23% of the global FCEV fleet, China made up over 65% of global road transport hydrogen demand in 2023 thanks to its policy focus targeting the heavy duty FCEV segment.

In contrast, policy and industrial decisions around FCEVs in Japan and Korea have targeted the lower-consumption light-duty vehicle segment. While this has led to much higher shares of the global FCEV fleet thanks to wider deployment, it has also meant that, combined, the two countries accounted for only 15% of the world's road transport hydrogen demand in 2023.

Hydrogen-powered transport has also been tested and proven in rail and shipping applications. Europe leads the way in fuel cell rail projects, where electrification of remaining diesel-powered lines may prove too complicated or costly. The first hydrogen-powered trains have been in regular service in northern Germany since 2018, matching the range of conventional diesel trains, although newer projects have been scaled back.

In shipping, dozens of hydrogen-derived pilot and demonstration projects exist, spanning fuel cells, hydrogen combustion, ammonia combustion and methanol solutions. Here, regulation and incentives – such as the FuelEU maritime initiative – are key in guiding the types of low-emissions fuel solutions that will emerge. Another EU initiative, ReFuelEU, aims to decarbonise aviation through sustainable aviation fuel (SAF) targets, and particularly through hydrogen-derived synthetic fuels, adding to potential hydrogen demand in the future. Nonetheless, while policy around the globe has facilitated hydrogen-powered initiatives and projects across different transport segments and drivetrain technologies, technical and market realities will continue to modulate the uptake of hydrogen in transport applications.

Commercial FCEVs are increasingly driving global road transport hydrogen demand



Notes: Commercial vehicles include light commercial vehicles (LCV), medium freight trucks and heavy freight trucks. Assumptions on annual mileage and fuel economy come from the IEA Global Energy and Climate Model. For further analysis on the role of hydrogen in transport, please see the IEA Global Hydrogen Review 2024.

Sources: Advanced Fuel Cell Technology Collaboration Programme; Hydrogen Fuel Cell Partnership; Korea, Ministry of Land, Infrastructure, and Transport; International Partnership for Hydrogen and Fuel Cells in the Economy; and Clean Energy Ministerial Hydrogen Initiative country surveys.

IEA analysis based on European Alternative Fuels Observatory (2024), Vehicles and Fleet.

Using existing gas infrastructure can introduce e-methane smoothly and flexibly

E-methane is produced by combining low-emissions hydrogen with carbon resources and could play an important role in decarbonising gas networks. Since e-methane has almost the same properties as natural gas and LNG, it is easy to inject and mix it into existing gas infrastructure such as LNG ships, LNG receiving terminals, LNG tankers, gas pipelines and consumer gas equipment. It is possible to switch from natural gas to e-methane seamlessly and limit the social costs associated with its introduction. In addition, e-methane, like LNG, can be liquefied and traded globally. In other words, once it is liquefied, it can be efficiently transported and distributed using existing LNG and gas infrastructure.

E-methane could be a key option to decarbonise demand sectors where electrification is difficult, such as the heavy-duty transport sector. In Finland a number of projects aim to produce e-methane for decarbonising these demands. Koppö Energia is developing a project in Kristinestad with the aim of producing e-methane to decarbonise the heavy-duty transport sector. Gasum and Nordic Ren-Gas announced an offtake agreement where Gasum will procure e-methane produced at a planned project in Tampere and it distribute it to its customers. This project is set to produce e-methane for the heavy-duty road and maritime transport sectors. In addition, Tree Energy Solutions and Kawasaki Kisen Kaisha announced that they are teaming up to work towards net zero greenhouse gas emissions in the maritime sector by 2050. According to the announcement, both companies are exploring potential collaboration opportunities, including broadening the scope of e-methane partnerships and the various facets of the value chain to accelerate the adoption of cleaner fuels in maritime transport.

In Japan e-methane is expected to be one of the promising options to achieve decarbonisation of the heat demand sector. Heat demand accounts for around 60% of energy consumption in the residential and commercial and industrial sectors in Japan. In addition, some areas are difficult to electrify, such as high-temperature industrial processes. Hence, decarbonisation of heat demand is important to achieve carbon neutrality and e-methane could play a role in decarbonising these sectors. Studies aim to test the utilisation of e-methane in Japan’s existing gas infrastructure. In May 2024 Toho Gas started a pilot project to produce e-methane and use it as a raw material for city gas. This is the first time e-methane has been used as a city gas feedstock in Japan. Osaka Gas and INPEX are planning a demonstration project to produce e-methane and inject it into an existing gas pipeline. This project aims to start operation in FY 2025.

Japan aims to build value chains to introduce e-methane by 2030

Key e-methane pilot projects located in Japan

Main companies involved	Start date	Production capacity	Description of the project
Tokyo Gas	2022	12.5 Nm^3/hr	Verification test to develop a series of technologies and gain knowhow, from renewable energy-derived power procurement to e-methane production and utilisation. It aims to obtain the actual values and issues for water electrolysis devices and methanation equipment, and learn about the efficiency of the overall system.
Osaka Gas	2022	5 Nm^3/hr	Demonstration project to build a supply chain that performs methanation using hydrogen from renewable sources and biogas produced by the fermentation of food waste, and which subsequently transports the produced methane through pipes for use in city gas-consuming appliances.
Toho Gas	2024	5 Nm^3/hr	Pilot project to produce e-methane combined with biogenic CO_2 and utilise the produced e-methane as a feedstock for city gas.
Osaka Gas and INPEX	FY 2025	400 Nm^3/hr	Development of CO_2 utilisation technology for gaseous fuel and development of practical technology for pipeline injection using a CO_2-methanation system.

Annex

Summary table

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

	Consumption					Production				
	2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
Africa	169	170	176	180	185	260	251	254	252	260
Asia Pacific	891	877	902	948	997	648	660	670	686	710
of which China	*367*	*364*	*391*	*422*	*455*	*205*	*216*	*230*	*245*	*260*
Central and South America	153	148	147	148	149	148	151	148	146	148
Eurasia	649	622	631	656	664	960	865	830	860	875
of which Russia	*516*	*487*	*495*	*516*	*524*	*762*	*672*	*638*	*675*	*687*
Europe	609	524	489	488	493	222	230	215	220	216
Middle East	562	580	592	610	632	692	715	725	743	770
North America	1 091	1 144	1 157	1 169	1 173	1 172	1 240	1 285	1288	1315
of which United States	*874*	*919*	*928*	*935*	*934*	*984*	*1 021*	*1 061*	*1 060*	*1 074*
World	**4 124**	**4 064**	**4 093**	**4 200**	**4 293**	**4 102**	**4 112**	**4 127**	**4 195**	**4 294**

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the 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, Georgia, Kazakhstan, Kyrgyzstan, the Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] the 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, the Republic of Moldova, Montenegro, the Netherlands, Norway, Poland, Portugal, Romania, Serbia, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine and the United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the 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, the 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 the Republic of Türkiye.
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. The Republic of Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, The Republic of Türkiye 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 Türkiye. 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	National Petroleum Agency (Brazil)
AFTC	Alternative Fuels Tax Credit
ANP	National Petroleum Agency (Brazil)
BMC	Colombian Mercantile Exchange (Colombia)
CAPEX	capital expenditure
CBG	compressed biogas
CCUS	Carbon Capture, Utilisation and Storage
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
CO_2	carbon dioxide
CQPGX	Chongqing Petroleum Exchange (the People's Republic of China)
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOG	European Network of Transmission System Operators for Gas
EPC	engineering, procurement and construction
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
EU	European Union
EUR	Euro
FCEVs	fuel cell electric vehicles
FID	final investment decision
FLNG	floating liquefied natural gas
FOB	free on board
FSRU	floating storage and regasification unit
FY	fiscal year
GHGs	greenhouse gases
GIE	Gas Infrastructure Europe
GMR	IEA Gas Market Report
GST	goods and services tax
HDDs	heating degree days
HH	Henry Hub
HoA	Head of Agreement
IEA	International Energy Agency
ICE	Intercontinental Exchange
ICIS	Independent Chemical Information Services
IEA	International Energy Agency
ITC	investment tax credit
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JPY	Japanese yen
LBG	liquefied biomethane
LCFS	Low Carbon Fuel Standard
LCV	light commercial vehicles
LEGWP	Low-Emission Gases Work Programme
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
MoU	Memorandum of Understanding
MME	Ministry of Mines and Energy (Brazil)
MVP	Mountain Valley Pipeline
NBP	National Balancing Point (United Kingdom)

NDRC	National Development and Reform Commission (the People's Republic of China)
NLNG	Nigeria liquefied natural gas
OECD	Organisation for Economic Co-operation and Development
ONS	National Electric System Operator (Brazil)
OSINERG	Energy Regulatory Commission (Peru)
PPAC	Petroleum Planning and Analysis Cell (India)
PTC	production tax credit
RNG	renewable natural gas
RFS	Renewable Fuel Standard
SAF	sustainable aviation fuel
SBL	Strategic Buffer LNG
SMR	steam methane reforming
SPA	Sales and Purchase Agreement
TAP	Trans Adriatic Pipeline
TFDE	Tri-fuel diesel electric
TFFS	Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security
TTF	Title Transfer Facility (the Netherlands)
UGS	underground storage
USD	United States dollar
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_{eq}	billion cubic metre equivalent
bcm/yr	billion cubic metres per year
GJ	gigajoule
GW	gigawatt
kWh	kilowatt hour
MBtu	million British thermal units
Mt	million tonnes
Mt/yr	million tonnes per year
m^3/hr	cubic metres per hour
m^3/yr/hr	cubic metres per year per hour
m^3/yr	cubic metres per year
Nm^3	normal cubic metre
TWh	terawatt hour

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For questions and comments, please contact GCP (gcp@iea.org) or Gergely Molnár (Gergely.Molnar@iea.org).

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