Global Gas Security Review 2023

Including the Gas Market Report, Q3-2023

INTERNATIONAL ENERGY AGENCY

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Abstract

Russia's invasion of Ukraine in 2022 triggered the first truly global gas crisis, with natural gas and LNG markets contending with supply disruptions and unprecedented price volatility. While the immediate effects of last year's supply shock have eased in recent months, the structural changes that emerged in 2022 will persist for years – and should be taken into account both by policy makers and market players.

In this context, the architecture of global gas supply security and the underlying flexibility of the market need to be carefully reassessed through an ever-closer dialogue between responsible producers and consumers. Ensuring secure supplies of LNG, in particular, will require policy makers, in close coordination with private actors, to facilitate the development of innovative commercial offerings, novel procurement mechanisms and new co-operative frameworks.

Since its establishment in October 2022, the International Energy Agency's (IEA) Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security has provided key market updates and a platform for the effective exchange of data and information among members. The Task Force has worked closely with the government of Japan ahead of the 12th LNG Producer-Consumer Conference on 18 July 2023, co-organised by the IEA and Japan's Ministry of Economy, Trade and Industry (METI).

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 in 2016. This year's edition includes the latest insights of the IEA's quarterly *Gas Market Report*, as well as a special spotlight on natural gas storage and evolving regulatory frameworks, taking into account the increased need for supply flexibility.

Beyond the growing complexity of gas supply security both in the short and long term, the decarbonisation of gas and the broader energy system will require the deployment and scaling up of low-emission gases. Part of the IEA's Low-Emission Gases Work Programme, this year's Review includes a special section on this topic, with a focus on the storage of low-emissions gases and the future role of liquefied low-emissions gases in the international maritime sector.

Table of contents

Executive summary – Towards a New Global Gas Market

A new global gas market is taking shape in the aftermath of the 2022 supply shock

The **global energy crisis** triggered by Russia's invasion of Ukraine **transformed natural gas markets in a structural manner** with profound implications both for policy makers and market players. LNG became a new baseload supply for Europe, while China's balancing role in the global gas market is set to increase. In this context, the **architecture of global gas supply security** and the underlying flexibility mechanisms need to be reassessed through an ever-closer dialogue between responsible producers and consumers.

Global gas supply security remains at the forefront of energy policymaking, with growing complexity both in the short- and long term. While market fundamentals have significantly eased since the start of 2023, and the European Union is well on track to fill up its storage sites to 95% of working capacity, **full storage sites are no guarantee against winter volatility**. Our simulations show that a cold winter, together with a full halt of Russian piped gas supplies to the European Union starting from 1 October 2023, could easily renew price volatility and market tensions.

The growing flexibility and liquidity of the global LNG market was crucial in the response to the gas supply shock of 2022. The non-observance of Russian piped gas contracts increased the European Union's reliance on spot procurements, which rose from just 20% of total gas supply in 2021 to over 50% in 2023. Through the medium term, a fine balance should be struck between long-term contracts from non-Russian suppliers and exposure to an increasingly liquid spot market. Our **review of LNG contracting trends** indicates that European buyers have increased their LNG contracting activity since Russia's invasion of Ukraine, though they still account for just 20% of total LNG volumes contracted since the start of 2022 – while China's share topped 25%.

Considering that in an increasingly globalised gas market, storage regulations can have extra-regional implications, the International Energy Agency carried out a survey on natural gas storage and its evolving regulatory frameworks across the members of the International Energy Agency's Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security. It showed that in the wake of the global gas crisis triggered by Russia, **more stringent storage regulations** have been adopted across key markets.

The **integration of low-emission gases** into the gas and broader energy system will be crucial to decarbonise gas supply streams. This year's *Global Gas Security Review* provides a special focus on the storage of low-emission gases and the future role of liquefied low-emission gases in the international maritime sector.

Natural gas markets moved towards a gradual rebalancing in H1 2023

Russia's steep cuts in gas deliveries to the Europe Union – a drop of almost 80 bcm, equating to 15% of global LNG trade – put **unprecedented pressure** on European and global gas markets in 2022. This gas supply shock caused by Russia led to a reconfiguration of global LNG flows, drove natural gas prices to all-time highs, both in Asia and Europe, and necessitated a readjustment in gas demand. Natural gas consumption fell by an estimated 1.5% in 2022 – similar to the drop experienced in 2020 following the first wave of Covid-19 lockdowns.

Since the start of 2023, natural gas markets moved towards a gradual rebalancing due to timely policy action, efficient market forces and favourable weather conditions over the 2022/23 heating season. Spot gas prices in Asia and Europe fell by over 50% year-on-year in H1 2023, albeit remaining 140% and 180% above their H1 average levels between 2016-20, respectively. In the United States, strong growth in domestic gas production, together with an unseasonably mild Q1 2023, put downward pressure on benchmark Henry Hub prices, which fell by 60% year-on-year in H1 2023.

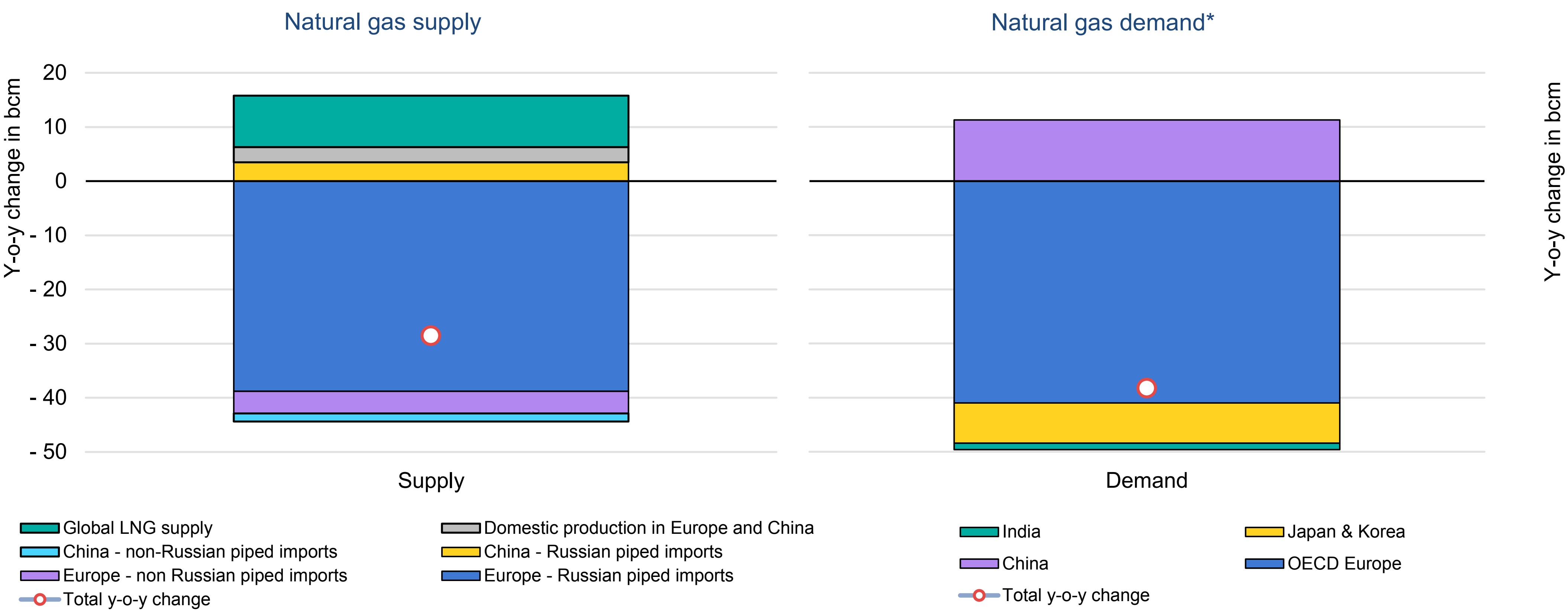
The steep decline in natural gas prices in Asia and Europe occurred despite a tight supply environment. Russia's piped gas deliveries to the European Union fell by over 75% (or 36 bcm) in H1 2023, while global LNG supply rose by an estimated 3% (or 9 bcm) – insufficient to offset the decline in Russian piped supplies. Several non-Russian pipeline suppliers faced heavy maintenance and unplanned outages, further tightening supply.

In this context, **natural gas demand reductions played a key role in the softening of market fundamentals**. In **OECD Europe**, natural gas demand fell by an estimated 10%, or over 30 bcm. This was primarily driven by lower residential and commercial demand in Q1, a sharp drop in gas use in the power sector during Q2 and depressed gas consumption by industrial consumers. In key **Asian markets**, natural gas demand remained close to last year's levels in the first five months of 2023. While China returned to growth, these gains were almost entirely offset by demand drops in Japan and Korea, reflecting a mild Q1 and improving nuclear availability. Relatively muted demand in Asia has been a key contributor to the loosening of market fundamentals since the start of 2023.

Global gas demand is expected to remain broadly flat in 2023 and return to moderate growth of 2% in 2024, supported by the expansion of economic activity and assuming a return to average winter weather conditions in the Northern Hemisphere. The rapidly growing markets in the Asia Pacific region are expected to account for around 80% of incremental gas demand to the end of 2024. This short-term forecast is subject to an **unusually wide range of uncertainties** stemming from the broader geopolitical and macroeconomic environment.

Demand reductions played a key role in the softening of market fundamentals

Year-on-year change in natural gas supply and demand in key Asian and European import markets, H1 2023 vs H1 2022



*Natural gas demand includes change in net storage injections in Q2.

Sources: IEA analysis based on ENTSOG (2023), Transparency Platform; Eurostat (2023), Energy Statistics; Gas Transmission System Operator of Ukraine (2023), Transparency Platform; General Administration of Customs of the People's Republic of China (2023), Major Import Commodities in Quantity and Value; ICIS (2023), ICIS LNG Edge; JODI (2023), Gas World Database; NBS (2023), Output of Natural Gas; PPAC (2023), Gas Consumption.

Softer market conditions in H1 2023 are no reason for complacency ahead of winter

High natural gas inventory levels in key Asian and European markets provide **cautious optimism** ahead of the 2023/24 heating season in the Northern Hemisphere. However, **full storage sites are no guarantee against winter volatility and the risk of renewed market tensions**.

The European Union inherited relatively high storage levels after the 2022/23 heating season, with inventories standing 60% above their five-year average. If injections continue at the average rate observed since mid-April, **EU storage sites will reach 90% of their working capacity by early August** and could be filled close to 100% by mid-September. If Russian piped gas supplies were to cease completely in summer 2023, the European Union would still be able to fill up storage sites to 90-95% of working capacity on average by the start of the 2023/24 heating season.

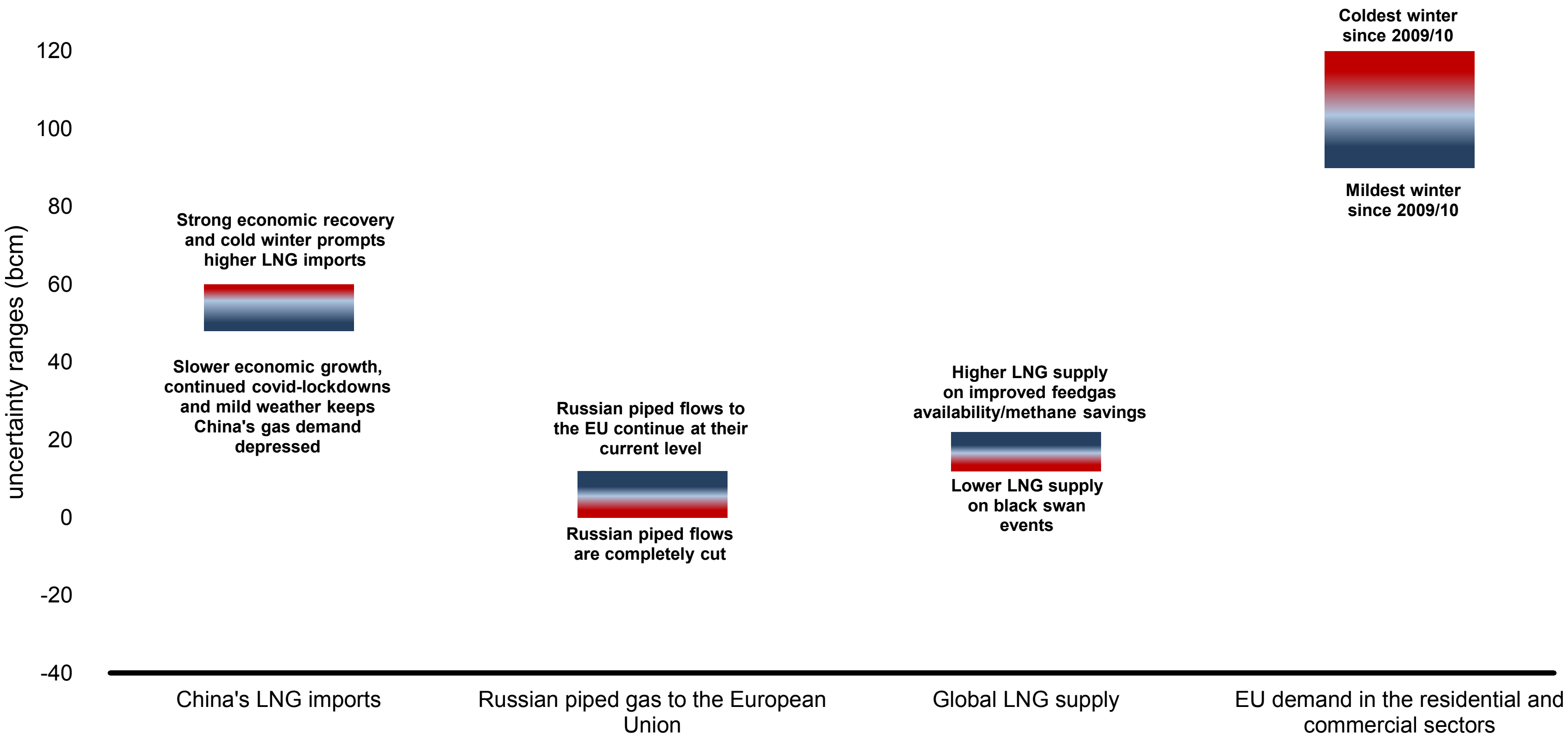
Nevertheless, key uncertainties remain ahead of Europe's 2023/24 winter season. A **cold winter** could increase natural gas demand in the EU's residential and commercial sectors by 30 bcm compared to the 2022/23 heating season. Given geopolitical uncertainties, a **further decline in Russian piped gas deliveries** to the European Union cannot be excluded. If Russian piped gas supplies were to fully stop from 1 October 2023, it would result in a total shortfall of 10 bcm. **Global LNG supply** is expected to increase by around 15 bcm y-o-y, though project delays and/or unplanned outages could reduce incremental LNG supply. **China's LNG imports** could fluctuate, with an uncertainty range of over 10 bcm through the 2023/24 winter.

Considering these risk factors, gas storage trajectories could vary widely over the upcoming heating season. Our simulations show that a cold winter, together with a full stop of Russian piped gas supplies to the European Union starting from 1 October, could renew market tensions. If we assume a mild winter and LNG flows remaining close to last year's levels, storage sites would end the heating season with inventory levels above 50% of capacity even without Russian piped gas. In contrast, a cold winter would put substantial pressure on the market. Higher LNG flows (a 15% y-o-y increase) would keep storage sites 34% full by the end of March. Yet if LNG flows remain at 2022/23 winter levels, storage sites would be just 25% full. Lower LNG availability (a 10% y-o-y decline) would further depress inventory levels to below 20% of capacity.

Storage sites are typically less reactive when filled below 30% of their capacity, as withdrawal ability is reduced due to the drop in reservoir pressure. This could increase the risk of price volatility and supply disruptions in the case of a late cold spell coupled with low wind power output. Continued structural gas demand reductions – including via enhanced energy efficiency, the more rapid deployment of renewables and quicker installation of heat pumps – will be required to ensure a secure gas balance for the 2023/24 winter.

Risks and uncertainties remain ahead of the 2023/24 Northern Hemisphere winter

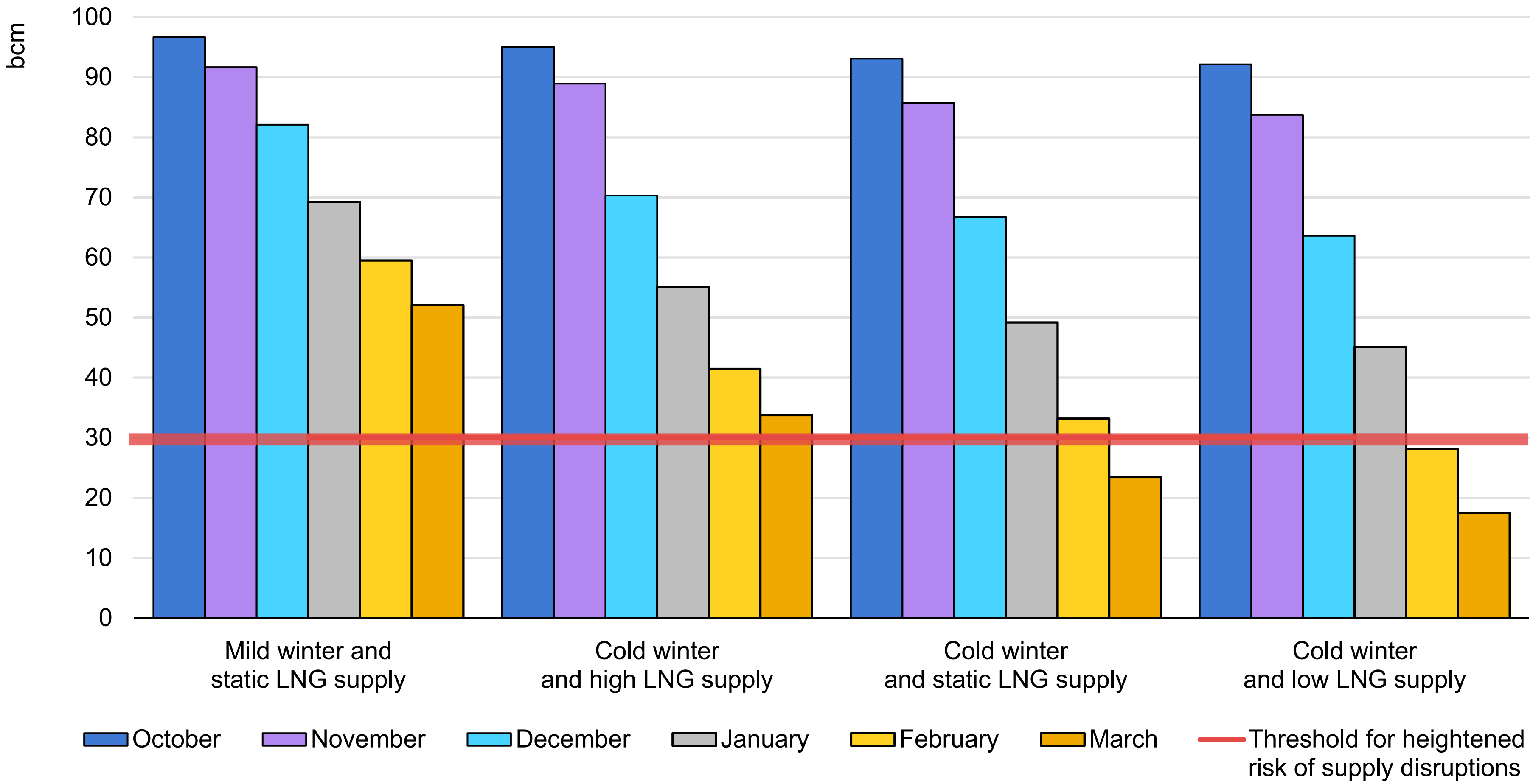
Uncertainty ranges of key exogenous risks to the European and global gas balance for the 2023/24 heating season



Note: Red indicates a tightening of the global/European gas balance. Blue indicates loosening of the gas balance.

Full storage sites are no guarantee against winter volatility and the risk of renewed market tensions

Potential EU gas storage trajectories without Russian piped gas under different scenarios during the 2023/24 winter season



The 2022 gas supply shock transformed natural gas markets in a structural manner

Russia's invasion of Ukraine profoundly transformed European and global gas markets. While the immediate effects of last year's supply shock have eased in recent months, the structural changes which emerged in 2022 will persist for years – and should be carefully assessed both by policy makers and market players.

LNG: a new baseload supply for the European market

The steep decline in Russian piped gas deliveries to the European Union – a drop of close to 120 bcm through 2022-23 – reconfigured global LNG flows towards Europe.

Consequently, **the role of LNG in the European market drastically shifted**. While in the past, LNG cargoes supplied the marginal molecule, LNG is now acting as baseload, in a similar fashion as Norwegian or North African piped gas. The share of LNG in the European Union's gas demand rose from an average of 12% over the 2010s to close to 35% in 2022 – **a share similar to Russia's piped gas before the invasion of Ukraine**.

Europe has repositioned itself as the new premium LNG market. TTF was trading at USD 6/MBtu above Asian spot LNG prices in 2022. The price signal provided by TTF and other liquid European hubs was crucial to attract the necessary volumes of flexible LNG to Europe. Forward curves at the end of June 2023 suggest that the **European premium** is expected to stay in the coming years, with TTF's premium over Asian spot LNG prices averaging USD 0.3/MBtu through 2023-25.

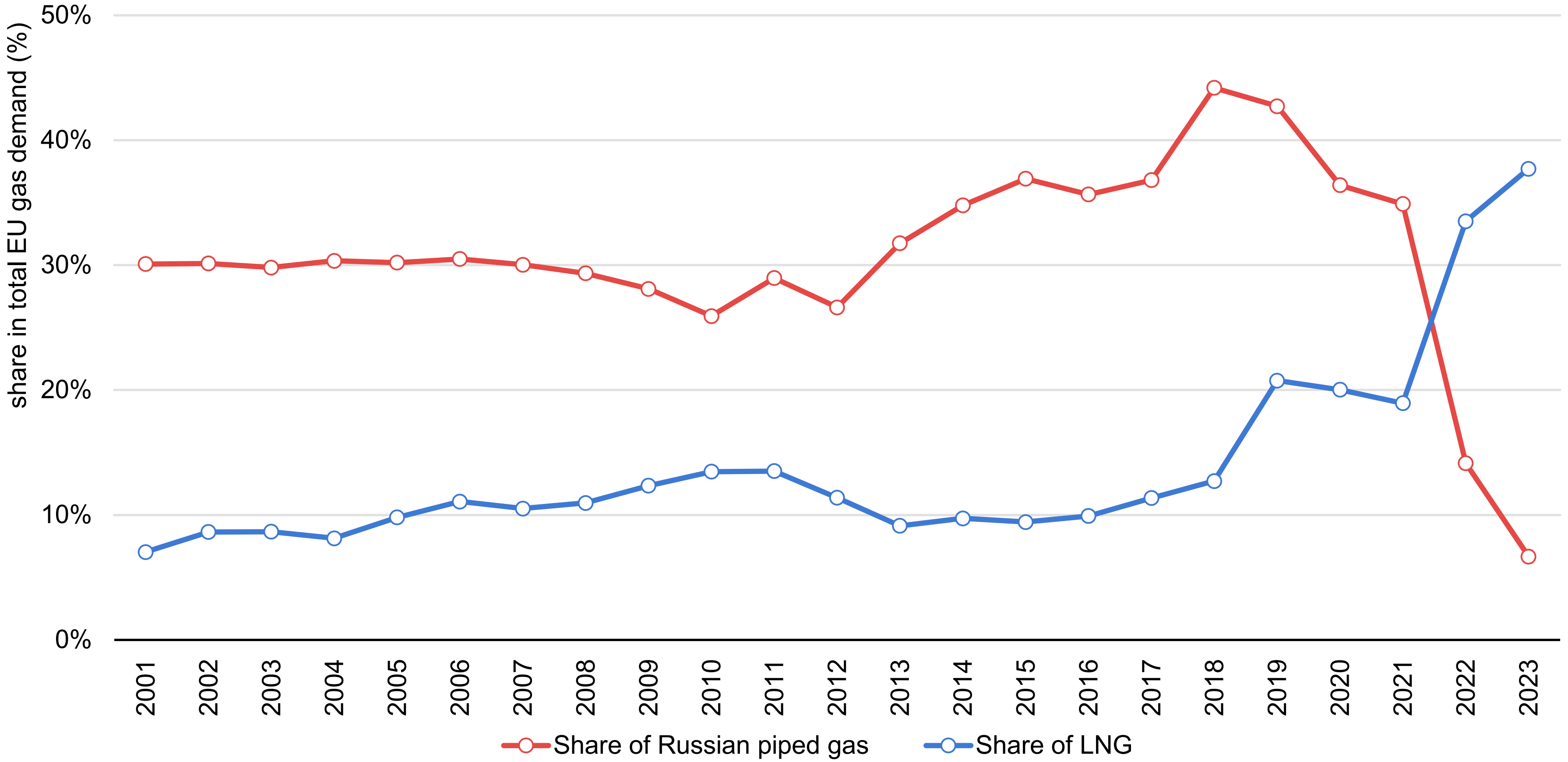
The European Union's exposure to the spot market is set to increase if no long-term contracts are signed

Through the past two decades, **long-term contracts, together with domestic production, met around 80-90% of EU gas demand** on an annual basis. The non-observance of Russian piped gas contracts steeply increased the European Union's reliance on spot procurements, rising from just 20% in 2021 to over 50% in 2023. **The share of spot volumes is expected to increase to more than 70% by 2030** – if expiring contracts are not renewed and no new contracts are signed.

This will naturally increase Europe's exposure to the greater volatility of spot markets over the medium term. Hence, **a fine balance should be struck** between non-Russian long-term contracts and procurements from an increasingly liquid spot market. A higher share of long-term contracts could potentially provide greater price and supply stability. Natural gas producers and consumers should work closely together to **reduce the emission intensity of gas and LNG supply**, in order to hedge against tightening emission regulations.

LNG became a new baseload supply for the European market

The share of LNG and Russian piped gas in the European Union's natural gas demand (2001-23)



Sources: IEA analysis based on ENTSOG (2023), Transparency Platform; Eurostat (2023), Energy Statistics; Gas Transmission System Operator of Ukraine (2023), Transparency Platform; ICIS (2023), ICIS LNG Edge; IEA (2023), Natural Gas Information.

Gas supply flexibility options need to be reassessed amid the phase-out of Russian piped gas imports into the European Union

Russian piped gas contracts included significant intra-annual and inter-annual flexibility, with the nomination rights ultimately lying with the buyers. This flexibility – underpinned by the country's huge swing fields – played a key role in meeting short-term demand variability and seasonal swings. This contributed to the balancing of European and global gas markets. Overall, the inter-annual flexibility provided by Russian piped gas averaged close to 10 bcm on an annual basis through the 2010s. Intra-annual swings averaged close to 200 mcm/d between 2016-21, amounting to over 10% of EU gas demand on a cold day.

This structurally lower gas supply flexibility means that **other flexibility options**, such as storage and LNG peak-shaving and demand response, **will have to play a greater role in coming years**. Based on projects currently in development, global **natural gas and LNG storage capacity** in import markets is expected to expand by 10% (or 45 bcm) during 2023-28. In addition, a closer dialogue between producers and consumers should facilitate the development of **innovative commercial offerings**, new **procurement mechanisms** and **co-operation frameworks** favouring a more flexible supply of LNG. A prime example is the coordination mechanism agreed between Japan and Thailand, building on seasonal differences in natural gas demand in the two countries.

China's role as a balancing market is set to increase, with potential ripple effects for energy supply security and clean energy transitions

Prior to the 2022 gas supply shock, Europe played a key role in balancing the global gas market. This role was underpinned by several unique features of the European market, including: 1) flexible piped gas supply from Russia; 2) coal-to-gas switching potential in the power sector; 3) spare LNG regasification capacity; 4) vast underground storage capacity; 5) open, non-discriminatory third-party access to natural gas infrastructure and 6) liquid, well-traded gas hubs.

Russia's steep gas supply cuts in 2022 largely eroded Europe's role as a balancing market. The unprecedented 20% drop in China's LNG imports – reflecting lower spot procurements and exercising destination flexibility rights in long-term LNG contracts – was a key factor in enabling higher LNG shipments to the European market.

In contrast to Europe, **China's role as a balancing market is expected to increase** over the medium term, especially when considering the country's active role in securing LNG contracts. China alone accounted for 30% of all LNG sales and purchase agreements (SPAs) signed in the past five years. As a result, China's share of active LNG contracts is expected to rise from 12% in 2021 to close to 25% by 2030. This is set to boost the role of Chinese companies in LNG trading and the optimisation of global

LNG flows. Nevertheless, **China's potential role as a balancing market will have ripple effects,** both in terms of energy supply security and energy transitions:

- **China has limited underground storage capacity**. At the end of 2022, China's working gas storage capacity was estimated at 18 bcm, accounting for just 5% of the country's annual consumption – well below the level in mature markets. This contrasts with the European Union's 100 bcm of working storage capacity (accounting for over 25% of annual gas demand), although China relies to a larger extent on its domestic production and portfolio of LNG contracts.
- **China does not have the same access to flexible piped gas supplies** that Europe had in the past. Central Asian flows displayed often-negative seasonal swings due to cold spells during the winter seasons, while Russian deliveries via the Power of Siberia pipeline system have limited flexibility in absolute terms.
- **A key contributor to China's gas demand flexibility is the country's significant gas-to-coal switching potential**. In 2022, coal-fired generation rose by an estimated 1.9%, largely at the expense of gas-fired power plants, which reduced their output by close to 10% y-o-y. This **translated into higher emissions** (estimated at 15 Mt CO_2-equivalent), further putting tensions on clean energy transitions.
- **The majority of China's LNG importers are state-owned companies**. Market-driven decision-making might be overwritten by supply security concerns or geopolitical considerations.

The medium- to long-term outlook for natural gas demand is being revised downwards

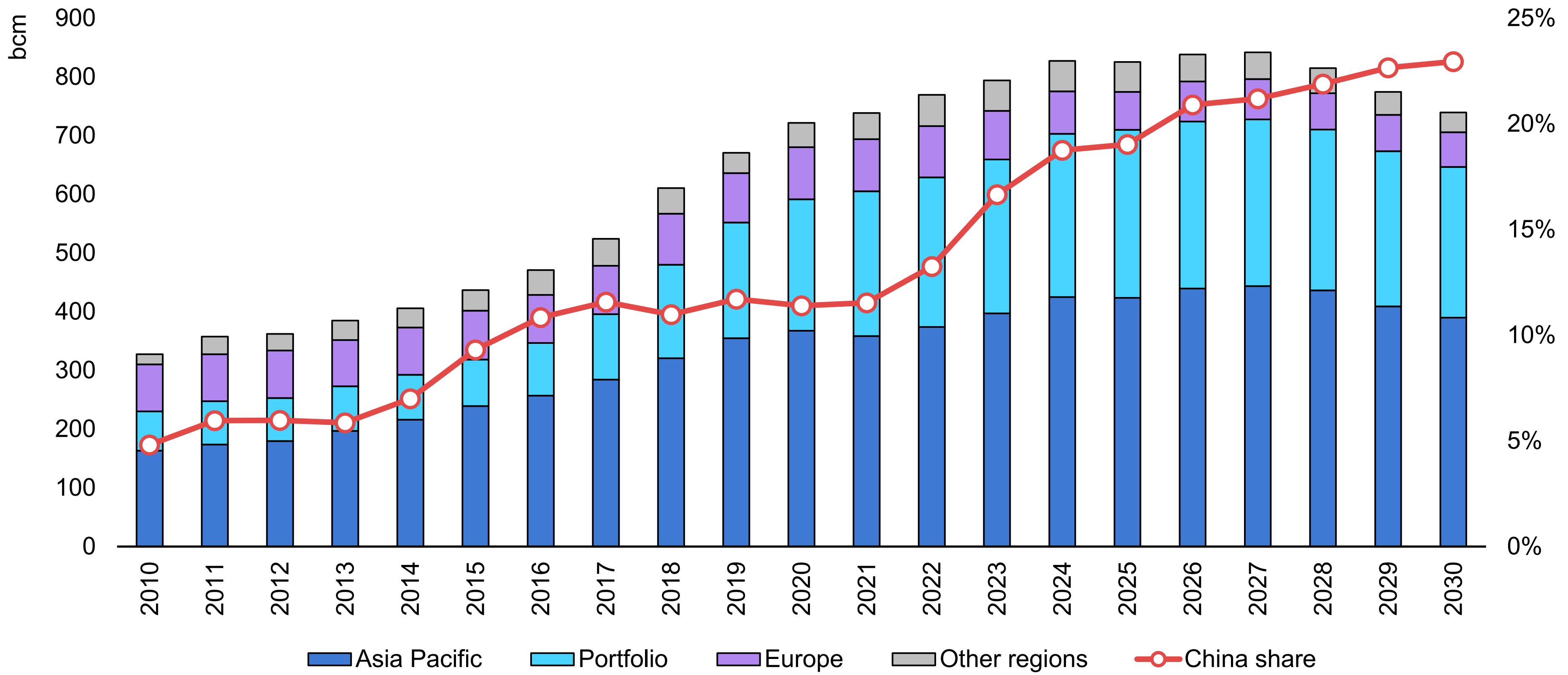
The global gas crisis triggered by Russia **deeply damaged the medium- to long-term growth prospects for natural gas demand**. The sharp increase in natural gas prices reduced its competitiveness vis-à-vis other sources of energy supply, while its image as a "reliable" fuel has been called into question by steep supply cuts of Russian piped gas.

Global gas demand growth for the period between 2020 and 2024 was reduced by 40% compared to projections prior to Russia's invasion of Ukraine. The IEA's Gas 2021 report projected an increase of 350 bcm through 2020-24, which is revised down to 200 bcm in our latest forecast. Europe alone accounts for more than half of this downward revision. This reflects more stringent energy efficiency standards, the accelerated deployment of renewables and quicker electrification of heat, as well as a reduced role of natural gas in industry.

The IEA's **World Energy Outlook 2023** edition and the **Gas report Q4 2023** will provide an in-depth analysis of the medium- and long-term prospects of natural gas and gaseous fuels.

China's active contracting strategy is set to reinforce its position in LNG trading and future optimisation of global LNG flows

The share of China in active LNG contracts (2010-30)



Sources: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Gas market update and short-term forecast

Global gas demand is expected to remain broadly flat in 2023 before returning to moderate growth in 2024

Global gas consumption contracted by an estimated 1.5% y-o-y (or 65 bcm) in 2022 – comparable to demand drops seen in 2009 in the aftermath of the financial crisis and during the global Covid-19 pandemic in 2020. The bulk of the demand reduction was concentrated in key Asian and European import markets. All-time high prices in these markets supported gas-to-coal switching in the power sector and depressed gas use in energy-intensive industries (either via fuel-switching or production curtailments).

Preliminary data indicate that this downward trend continued in H1 2023 across key gas markets. **OECD Europe** recorded the steepest decline in natural gas consumption, with a drop of over 10% (or more than 30 bcm) y-o-y in H1 2023. This was primarily driven by depressed gas use in industry, lower residential and commercial demand in Q1, and a sharp drop in gas burn in the power sector during Q2. In **North America** natural gas consumption fell by an estimated 0.6% y-o-y (close to 5 bcm) amid unseasonably mild weather conditions in Q1 and subdued economic activity. In **Asia Pacific** natural gas demand remained close to last year's levels in the first four months of 2023. While China and certain markets in emerging Asia returned to growth, these gains were almost entirely offset by the demand drops in Japan and Korea, reflecting a mild Q1 and improving nuclear availability.

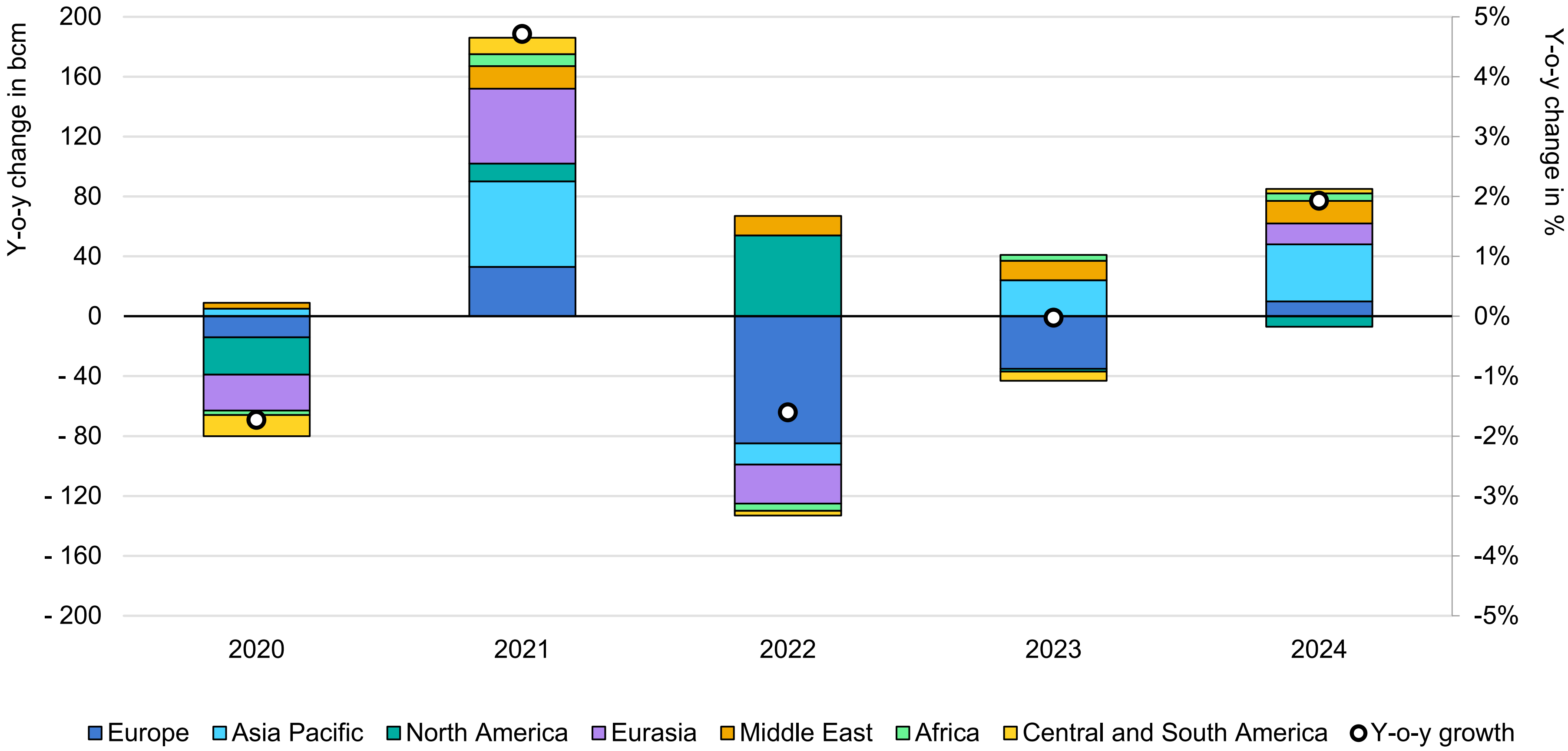
Global gas supply is set to remain tight in 2023, as incremental LNG supply (20-25 bcm) will not be sufficient to offset the expected drop in Russia's piped gas deliveries to Europe (a decline of over 40 bcm). While incremental gas supply is limited in 2023, it would be enough to cover **global gas demand assuming demand remains broadly flat, as expected**. Most demand growth is projected to be driven by the Asia Pacific region, the Middle East and Africa; however, this growth is almost entirely offset by falling demand in North America and Europe. After its first decline in four decades, China's natural gas demand is expected to expand by just over 6% in 2023. The country's LNG imports are forecast to increase by close to 15%, albeit remaining below the record levels reached in 2021.

Global gas demand is expected to return to moderate growth of 2% in 2024, supported by the expansion of economic activity and assuming a return to average winter weather conditions in the Northern Hemisphere. Again, the bulk of demand growth is projected to be concentrated in Asia Pacific, accounting for around 80% of incremental gas demand to the end of 2024.

This short-term forecast is subject to an unusually wide range of uncertainties, stemming from the broader geopolitical and macroeconomic environment.

The Asia Pacific region is expected to account for around 80% of demand growth in 2023-2024

Y-o-y change in global natural gas demand, 2020-2023



North American natural gas demand is expected to decline in 2023 and remain flat in 2024

Natural gas consumption in North America fell by an estimated 0.6% (close to 5 bcm) y-o-y in the first half of 2023. Unseasonably mild weather conditions in Q1 together with subdued business activity are weighing on natural gas demand.

In the **United States** natural gas consumption dropped by just over 0.5% y-o-y in the first half of 2023 according to preliminary data. This was largely driven by lower natural gas use in the **residential and commercial sectors** as unseasonably mild weather conditions put downward pressure on space heating requirements. Heating degree days during the January-April period were down by 8% y-o-y, which decreased gas demand in the residential and commercial sectors by more than 9% compared with the same period in 2022. In January and February 2023, the United States saw its lowest levels of natural gas consumption since 2018. In addition, the **industrial sector** also recorded a 2% decrease in consumption in H1 2023 amid subdued economic activity. The US Manufacturing Purchasing Managers' Index (PMI), published by the Institute for Supply Management, averaged 47 over the first half of 2023, indicating a contraction in manufacturing activity.

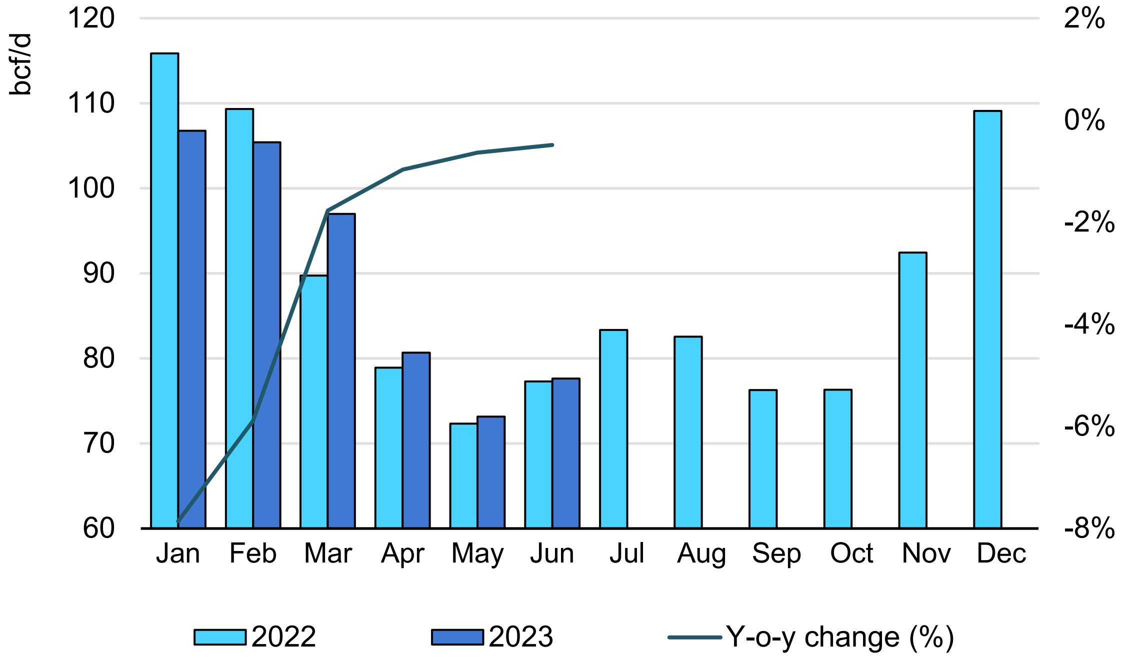
In contrast, **gas-to-power demand** increased by 8% y-o-y in H1 2023, amid lower hydropower output (down 6% y-o-y) and coal-to-gas switching in the power sector. Coal-fired generation declined by 25% y-o-y, largely in favour of gas-based power output. This can be attributed to the continuing retirement of coal power plants, coupled with a decline in natural gas prices increasing the competitiveness of gas-fired power plants. Consequently, the share of gas-fired power generation rose to above 39% in the first half of 2023, up from 35% during the same period in 2022.

Natural gas consumption in **Canada** dropped by an estimated 1% y-o-y in the first half of 2023. This decrease can be attributed to the reduction in demand from the residential and commercial sectors. Gas demand continued to increase among wholesale customers, particularly in large industry and power generation, due to the ongoing transition from coal to gas in the power mix. **Mexico**'s apparent natural gas consumption remained close to last year's levels in the first five months of 2023.

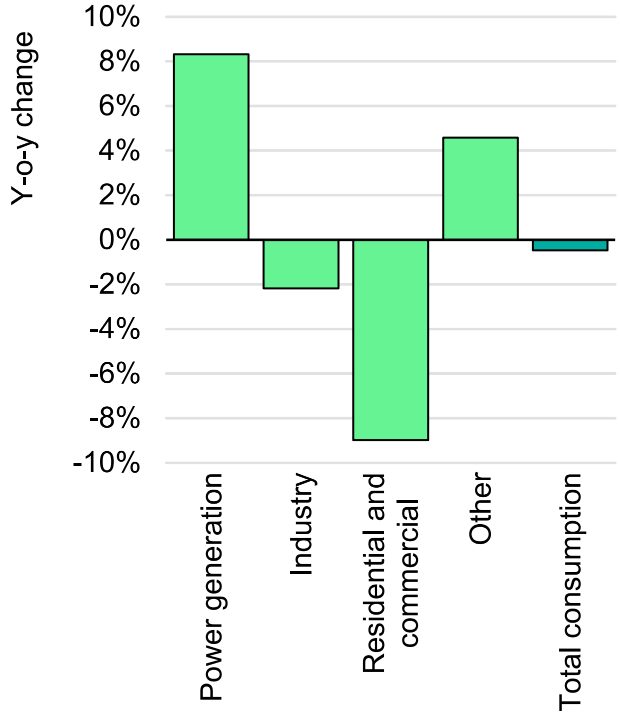
This **forecast** expects North American gas demand to remain broadly flat in 2023. In the United States slower economic growth is set to depress gas demand in industry, while the unseasonably mild Q1 reduced gas use in the residential and commercial sectors, weighing on the outlook for the full year. The economic slowdown together with the rapid expansion of renewables is set to moderate the growth in gas-fired generation during the second half of 2023. North American gas consumption is expected to decline by 0.5% in 2024. Residential and commercial gas demand is projected to recover under the assumption of average weather conditions, while the continued expansion of renewables is expected to reduce gas burn in the power sector.

US gas consumption fell by over 0.5% in H1 2023 amid an unseasonably mild winter and subdued economic activity

Monthly natural gas consumption, United States, 2022-2023



Gas consumption by sector, United States, H1 2023 vs H1 2022



Note: bcf/d = billion cubic feet per day.
Sources: IEA analysis based on EIA (2023), Natural Gas Consumption; Natural Gas Weekly Update.

Healthy hydro availability weighs on natural gas demand in Central and South America

Natural gas consumption in Central and South America declined by 3% in 2022. This was primarily driven by lower gas demand in Brazil, where gas-fired generation contracted by more than 60% compared with 2021, following a recovery in hydropower generation. The region's gas demand continued to decline in Q1 2023, falling by over 5% (or close to 2 bcm) y-o-y amid healthy hydro availability.

In **Argentina**, the region's largest gas market, gas demand declined by 1% (or 0.15 bcm) y-o-y in the first four months of 2023 according to preliminary data. Higher hydro generation exerted downward pressure on gas use in the power sector, which declined by close to 4% y-o-y. Gas demand in the residential and commercial sectors dropped by 12% y-o-y, while gas use in industry increased by close to 8% y-o-y.

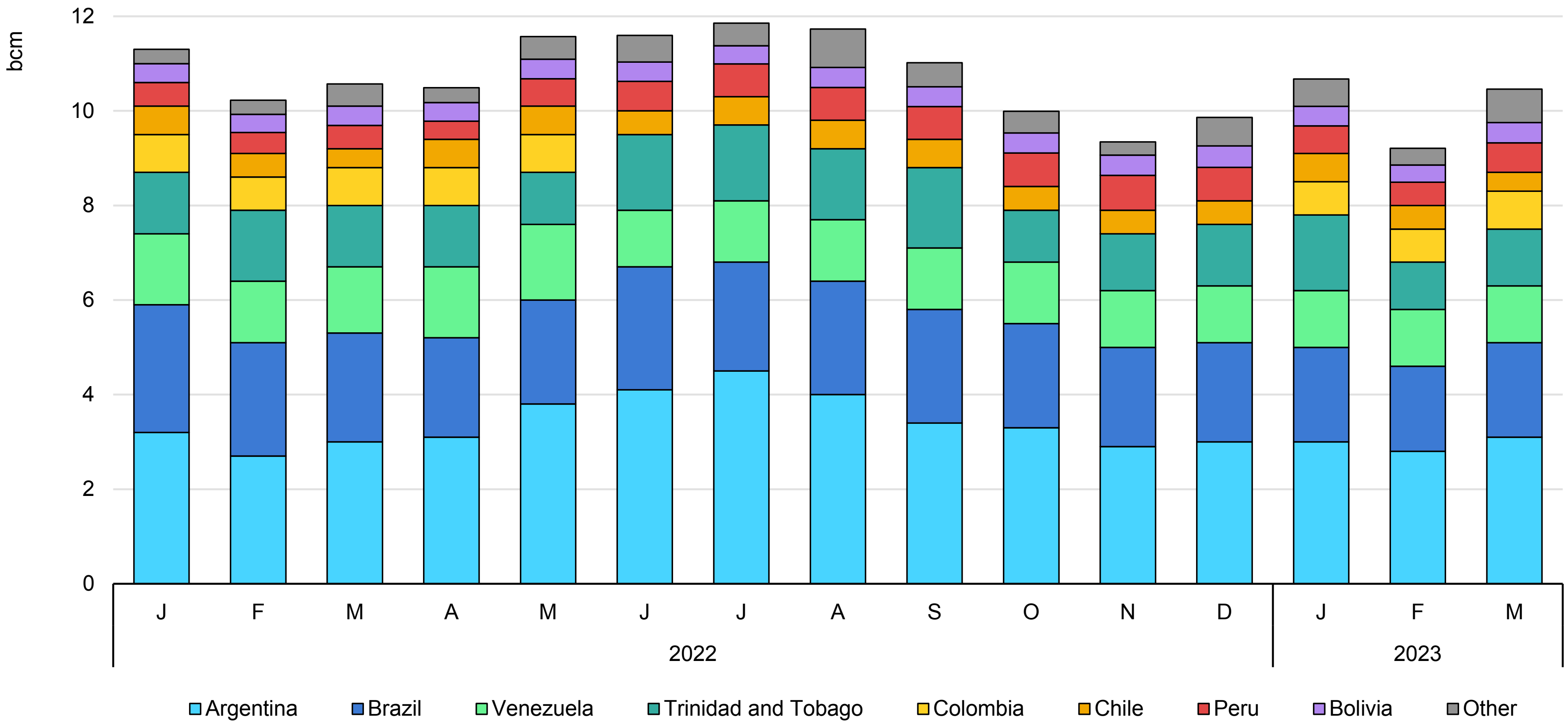
In **Brazil** gas consumption continued its steady decline, falling by an estimated 15% (or close to 2 bcm) y-o-y in the first five months of 2023, primarily driven by lower gas burn in the power sector. Gas-fired power generation decreased by 37% (or 5 TWh) y-o-y in H1 2023, while hydro generation remained close to last year's levels during the same period. In Q2 2023 hydropower output declined by 3.5% y-o-y, which supported an increase in gas-fired power output, albeit not sufficient to offset the losses in Q1. As a consequence of lower gas demand, Brazil reduced its piped gas imports from Bolivia by 15% (or 0.5 bcm) y-o-y, while its LNG inflows dropped by 75% (or 1.6 bcm) y-o-y in the first half of 2023.

Several other countries in the region experienced similar declines. In **Trinidad and Tobago** natural gas production remained broadly flat in Q1 2023 compared with the same period in 2022. The country's LNG exports rose by more than 8% y-o-y, suggesting that domestic gas consumption declined by over 5% y-o-y in Q1 2023. In **Venezuela** observed gas consumption decreased by 13% (or 0.8 bcm) y-o-y in the first four months of 2023. In **Colombia** gas demand declined by 5% (or 0.2 bcm) y-o-y in the first five months of 2023, primarily driven by lower gas burn in the power sector (down 27% y-o-y). The region's smaller markets displayed varied demand patterns over Q1 2023, not sufficient to offset the declines recorded in the five largest gas markets.

Taking into account the declines in Q1 and assuming average weather conditions for the remainder of the year, **this forecast** expects natural gas demand in Central and South America to decline by almost 4% in 2023. Gas demand in 2024 is forecast to increase by close to 2% in 2024 amid economic growth and assuming average hydro generation levels.

Lower gas consumption in Argentina and Brazil depressed gas demand in Central and South America in Q1 2023

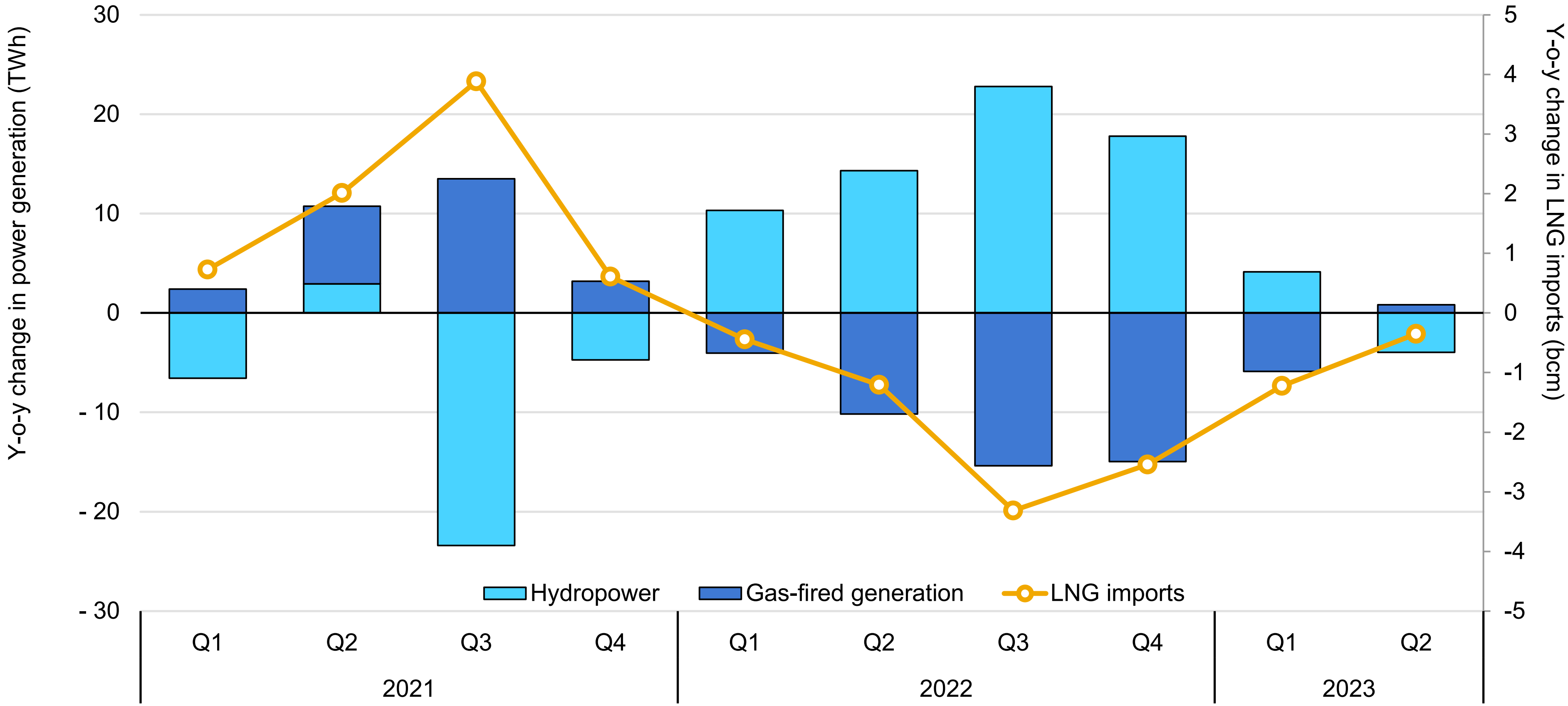
Monthly natural gas consumption, Central and South America, 2022-Q1 2023



Sources: IEA analysis based on ANP (2023), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2023), Informes Mensuales; Central Bank of Trinidad and Tobago (2023), Statistics; CNE (2023), Generación bruta SEN; ENARGAS (2023), Datos Abiertos; ICIS (2023), ICIS LNG Edge; IEA (2023), Monthly Gas Data Service; JODI (2023), Gas Database; MME (2023), Boletim Mensal de Acompanhamento da Industria de Gás Natural; OSINERG (2023), Reporte diario de la operación de los sistemas de transporte de gas natural.

Healthy hydro availability depressed gas-fired generation in Brazil in H1 2023, leading to a steep decline in LNG imports

Y-o-y change in quarterly hydropower and gas-fired electricity generation and LNG imports, Brazil, 2021-2023



Sources: IEA analysis based on EPE (2023), Monthly Review of the Electricity Market; ICIS (2023), ICIS LNG Edge; ONS (2023), Power Generation.

European gas demand dropped by over 10% in the first half of 2023

Natural gas consumption in OECD Europe fell by more than 10% (or over 30 bcm) y-o-y during H1 2023. The pace of demand reduction moderated from the 13% (or 22 bcm) drop experienced in Q1 to a 10% (or 9 bcm) y-o-y decline during Q2. Lower gas burn in the power sector accounted for 70% of the overall reduction in gas demand in Q2, amid depressed electricity demand and stronger renewable power output.

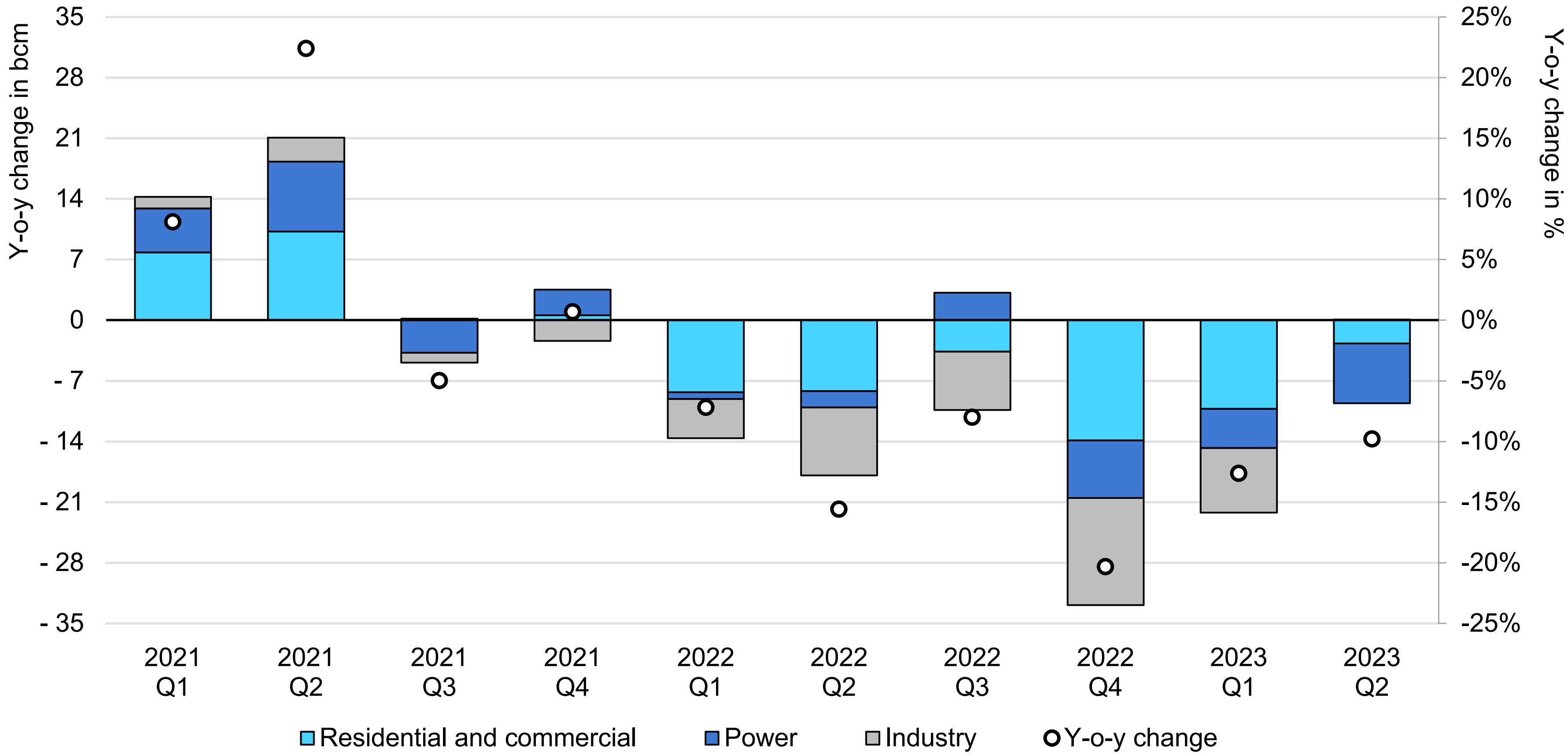
Distribution network-related demand fell by an estimated 8% (or 2.5 bcm) y-o-y in Q2 2023. This decline occurred despite a colder spring, with heating degree days in April and May standing 10% above their 2022 levels. Hence, non-weather-related factors explain the bulk of this demand reduction. These include gas-saving measures enacted in public buildings, fuel-switching in rural households, the continued deployment of heat pumps, efficiency gains and behavioural changes. Rising affordability issues are also likely to have contributed to lower gas use in households.

Gas-to-power demand dropped by an estimated 20% (or 7 bcm) y-o-y in Q2 2023. This steep decline was driven by a combination of factors. Subdued activity in energy-intensive industries together with continued improvements in energy efficiency and behavioural changes depressed electricity consumption, which fell by around 7% (or 50 TWh) y-o-y in Q2. In addition, stronger renewable power output and improving nuclear availability further reduced the call on coal- and gas-fired power plants, which saw their combined output declining by over 20% (or close to 55 TWh). Coal-based generation declined more steeply, reflecting the deteriorating competitiveness of coal-fired plants amid the sharp drop in gas prices and high cost of emission allowances. Estimated **gas demand in industry** stayed close to last year's levels in Q2 2023. While the steep fall in gas prices since mid-December 2022 supports gradually improving activity in gas-intensive industries, industrial sector gas demand remains 20% below its Q2 2021 levels.

For 2023 as a whole, OECD Europe's gas demand is forecast to decline by 7%. This is largely driven by lower gas burn in the power sector, down by 15% amid rapidly expanding renewables and lower electricity consumption. Gas use in industry is expected to stay close to last year's levels, as lower gas prices enable demand recovery in the second half of the year, offsetting the losses in H1. Considering the declines in the year to date, demand in the residential and commercial sector is expected to fall by 4% in 2023. **In 2024**, OECD's Europe gas demand is forecast to increase by a moderate 1.5%, as the expected decline in gas for power generation is not offset by higher gas use in other sectors. A return to average temperature conditions would increase residential and commercial demand, while gas use in industry is expected to continue its gradual recovery, albeit remaining well below its pre-crisis levels.

Lower gas burn in OECD Europe's power sector was the main driver behind reduced gas demand in Q2 2023

Estimated quarterly change in gas demand, OECD Europe, 2021-2023



Sources: IEA analysis based on Enagas (2023), Natural Gas Demand; ENTSOG (2023), Transparency Platform; EPIAS (2023), Transparency Platform; Trading Hub Europe (2023), Aggregated consumption.

Asian gas demand is expected to recover by 3% in 2023, supported by lower prices

Following a 2% decline in 2022, **natural gas demand in the Asia Pacific region remained broadly stable** in the first half of 2023. While China and certain emerging Asian markets recorded an increase in their gas consumption, this was almost entirely offset by falling demand in Japan and Korea. Asian gas demand for 2023 is projected to increase by 3% based on the assumption of weather normalisation and modest gas consumption growth in India and emerging Asia. In 2024 we expect gas demand to continue to grow by over 4%.

Following the country's first recorded drop in demand in four decades in 2022, **China**'s apparent natural gas consumption returned to growth in Q1 2023, up by an estimated 6% (or 11 bcm) y-o-y in the first five months of 2023. This was supported by the easing of the country's strict Covid policy, lower hydropower output and prospects of stronger economic growth compared with last year. Gas burn in **the power sector** rose by an estimated 10% y-o-y in the first five months of 2023, as lower hydro output (down by 23% y-o-y) increased the call on gas-fired power plants. In addition, China experienced historic heat waves in the spring of 2023, recording the highest temperatures in 100 years, leading to production shortfalls at hydroelectric power plants. Preliminary data suggest that natural **gas use in industry** and in the city gas segment returned to growth, largely supported by the recovery of economic activity compared with the first half of 2022 when the country faced disruptions due to widespread Covid-induced lockdowns. China's gas demand growth is partially supported by higher domestic production, which rose by 6% (or 6 bcm) y-o-y in the first five months of 2023. The gradual recovery in gas demand increased the call on LNG imports, rising by over 10% (or 4.5 bcm) y-o-y in the first half of 2023, albeit remaining below the record levels set in 2021. China's **gas consumption in 2023** is projected to increase by over 6%, led by the industrial and power sectors. Stronger electricity demand together with reduced hydro output and lower gas prices are expected to benefit gas demand for power generation for the remainder of the year. Assuming average weather conditions, gas demand in the residential and commercial sectors is projected to recover close to 2021 levels. **In 2024** we expect China's gas demand to increase by 7%, supported by economic growth and higher gas burn for power.

Japan's gas consumption decreased by 12% (or 4 bcm) in the first four months of 2023. Gas-fired power generation in the first three months declined by 16% (or 15 TWh) y-o-y according to data from METI. This was primarily driven by lower electricity consumption (down by 6% y-o-y in electricity supply volume in the first five months according to OCCTO data) and improving nuclear availability. Japan's nuclear power output rose by 47% (or 12 TWh) y-o-y in the first half of 2023. In addition, city gas sales for commercial and industrial use in the first four months decreased by

3% and 12% respectively according to data from METI. For 2023 Japan's gas demand is forecast to decrease by about 5% compared with the previous year. This is mainly driven by the power sector, due to the increased operation of nuclear power plants. However, gas consumption may fluctuate depending on prevailing temperatures and the operational status of nuclear power. Gas demand in 2024 is expected to decrease by 1% compared with 2023, as improving nuclear availability together with the continued expansion of renewable power generation are set to weigh on gas burn in the power sector.

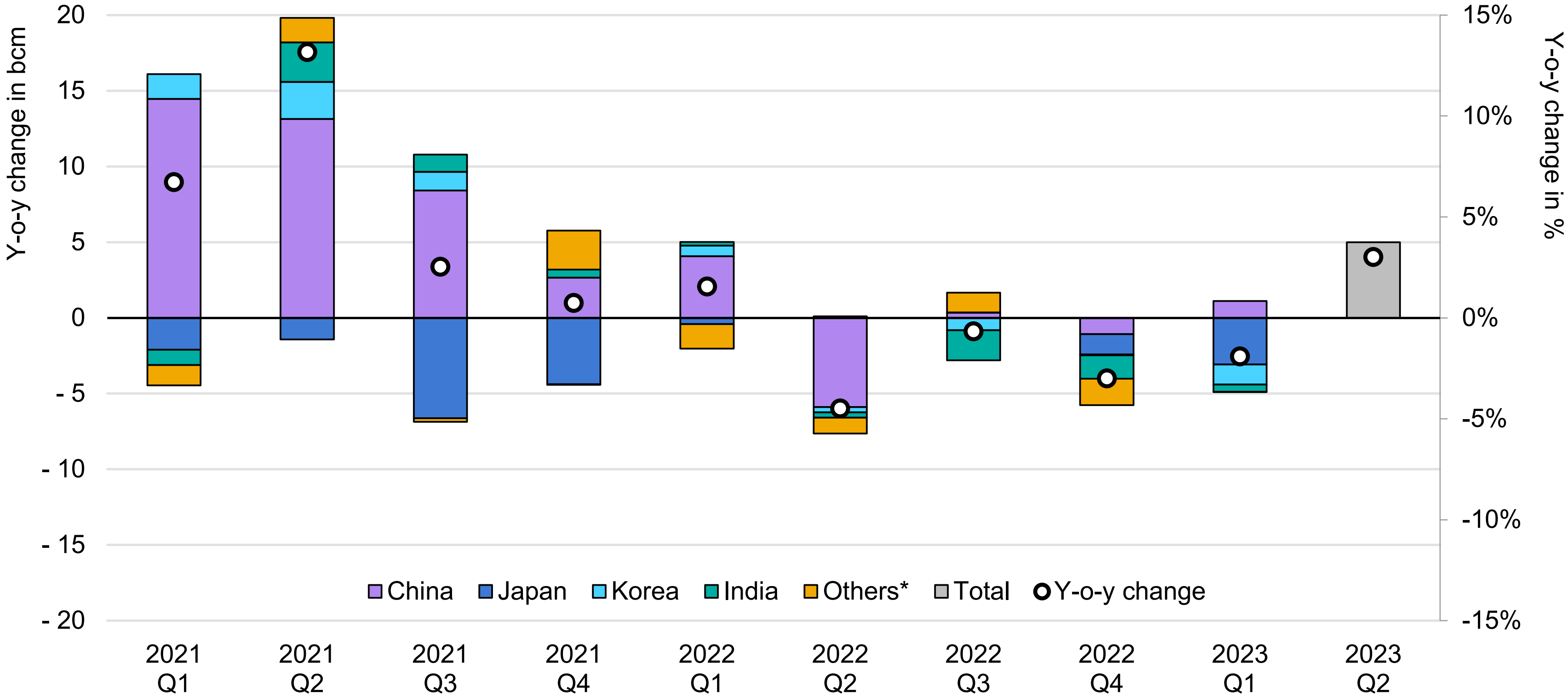
Korea's gas consumption in the first four months of 2023 was 6% lower than in the same period in 2022. According to data from Korea Energy Economics Institute (KEEI), the country saw a significant decrease in city gas demand, considered to have largely been due to a warm winter driving down space heating requirements. Gas demand for power generation declined by 4% y-o-y in the first three months of 2023 amid improving nuclear availability. For the full year of 2023, Korea's gas demand is expected to decrease by approximately 4% amid higher nuclear power generation and the expansion of renewables. In 2024 we expect gas consumption to decrease by 1%.

India's gas consumption decreased by 2% y-o-y in the first five months of 2023, following the 5% y-o-y decline observed in 2022. The fertiliser sector maintained its dominant share at 32%, followed by city gas (21%), power generation (15%), refining (7%) and the petrochemical sector (5%). Growth in India's gas demand was driven by the recovery of the fertiliser sector, up by 0.7 bcm (up 13% y-o-y). This growth follows the start-up of two new urea production facilities at Sindri and Barauni in eastern India, as well as the softening of global LNG prices since the beginning of the year. India's natural gas demand is expected to increase by 5% for 2023, primarily driven by higher gas use in industry and for power.

Emerging Asia's gas consumption increased by an estimated 3% y-o-y in the first quarter 2023, with demand growth supported by lower LNG spot prices. **Thailand**, the region's largest gas consumer, recorded 3% y-o-y growth during Q1 2023, following a 10% drop in gas use in 2022 as a whole. This recovery was mostly concentrated in the power sector and the domestic energy industry. In **Indonesia** gas demand expanded by 4% y-o-y in the first four months of 2023, led by industry and the power sector. In **Malaysia** natural gas production rose by 1% y-o-y in the first four months of 2023, while LNG exports rose by 5% y-o-y, suggesting an estimated 1% y-o-y growth in domestic gas consumption. **Bangladesh** and **Pakistan** increased their LNG imports by 0.5% and 10% y-o-y in the first four months of 2023, respectively. This indicates a gradual recovery in the two countries' gas demand, driven by lower gas prices and higher gas use in industry and especially in the power sector. Bangladesh and Pakistan are highly dependent on imported LNG and both countries experienced severe power outages in the spring of 2023, due to erratic weather conditions and difficulties in paying for fuel imports. In 2023 and 2024 gas demand in emerging Asia is projected to increase by a modest 2% and 3% respectively, fuelled by growing economic activity and power demand.

China and emerging Asia returned to demand growth in the first half of 2023

Estimated quarterly change in gas demand, selected Asian markets, 2021-2023



* Others comprise Indonesia, Malaysia, the Philippines, Singapore and Thailand.

Sources: IEA analysis based on CQPGX (2023), Nanbin Observation; EPPO (2023), Energy Statistics; ICIS (2023), ICIS LNG Edge; JODI (2023), Gas World Database; Korea Energy Economics Institute (2023), Monthly Energy Statistics; Ministry of Economy, Trade and Industry of Japan (2023), METI Statistics; PPAC (2023), Gas Consumption.

US natural gas production continues to expand in 2023, principally driven by higher gas output from shale plays

Dry natural gas production in the United States increased by an estimated 5.5% (or close to 30 bcm) y-o-y in the first half of 2023, with the average daily output above 100 bcf (or 2.8 bcm/d) during the period. This strong growth was principally met by additional gas supply from shale plays. Dry gas production in the **Permian Basin** increased by an estimated 15% (or close to 10 bcm) y-o-y in H1 2023, accounting for over 35% of incremental gas output in the United States. This production boost was supported by steady drilling activity, with an average of 471 new wells drilled per month in Q1 2023, representing a 17% increase compared with 2022. Similarly, well completions experienced an increase of more than 15% y-o-y over the same period.

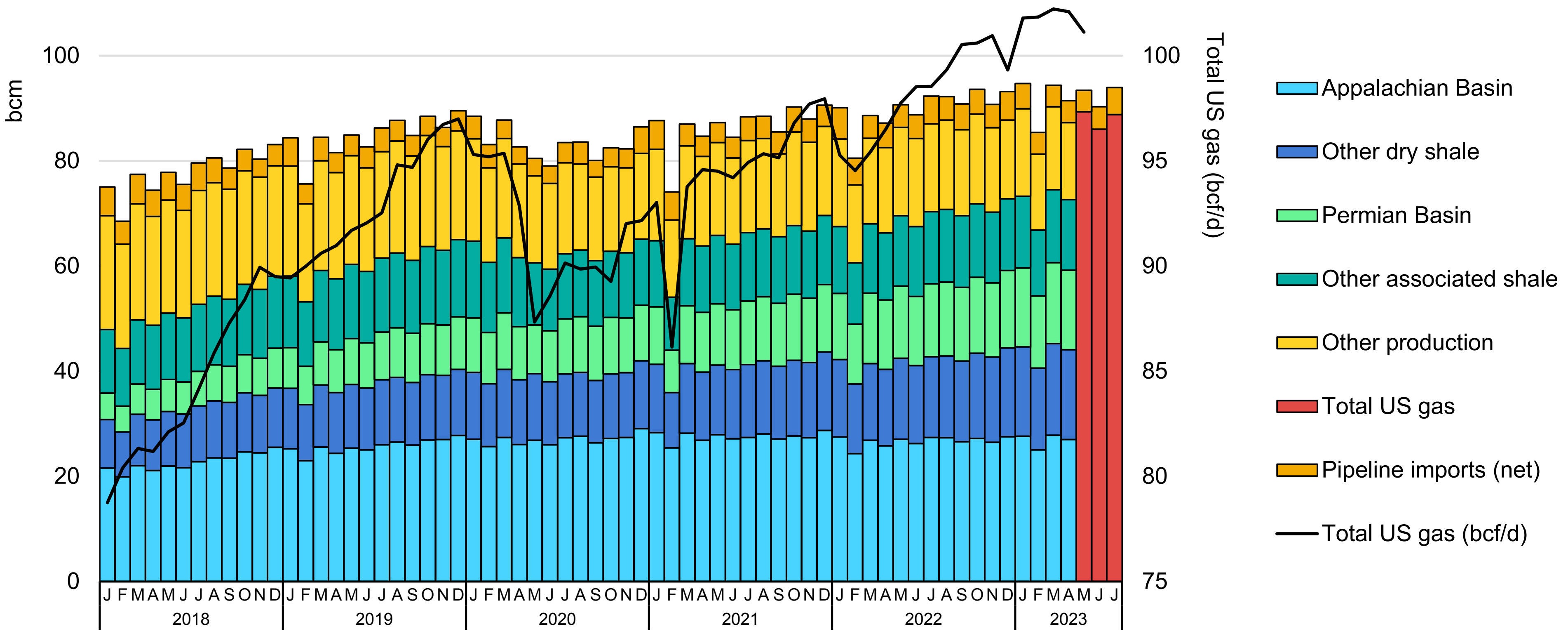
The **Haynesville shale gas play** in north-eastern Texas and north-western Louisiana was the second largest source of incremental gas supply in H1 2023. Dry gas output rose by close to 20% (or 10 bcm) compared with the same period in 2022. Daily output reached an all-time high of 0.45 bcm/d in April 2023. Drilling activity reports show how elevated Henry Hub prices in 2022 provided a supportive economic environment for new well development in the region, with a 48% increase y-o-y in 2022 resulting in a monthly average of 71 wells. 2022 also saw an increase of 22% in the well completion rate. In May 2023 the expansion of the Acadian Haynesville Extension pipeline was completed, adding 4 bcm/yr of exit capacity from the Haynesville play to the US Gulf coast.

In contrast, dry gas production in the **Appalachian Basin** – the largest source of US gas supply with a share of over 30% in 2022 – contracted by an estimated 0.5% (or 1 bcm) y-o-y in H1 2023. This was primarily driven by the Utica shale, where gas production dropped by close to 8% y-o-y in Q1 2023, while output increased marginally in the Marcellus play. Lower domestic demand together with relatively high inventory levels reduced the call on Appalachian gas producers. In addition, midstream constraints are making it difficult to increase supplies to demand centres, as long-haul interstate pipelines were already running close to nameplate capacity in 2022. The Mountain Valley Pipeline is expected to be commissioned by the end of 2023/early 2024 and would add 20 bcm/yr of transmission capacity from north-western West Virginia to southern Virginia.

We **forecast** natural gas production in the United States to continue to increase, albeit at a slower pace compared with previous years amid lower domestic demand and limited LNG export capacity additions. We expect dry gas production to grow by 2% in 2023 and by less than 1% in 2024.

US natural gas production rose to above the 100 bcf/d mark in the first half of 2023

Gas production by type, United States, 2018-2023



Sources: IEA analysis based on EIA (2023), Natural Gas Data; Natural Gas Weekly Update.

A new baseload: LNG accounted for close to 40% of Europe's gas consumption in H1 2023

Europe's total gas supply dropped by 13% y-o-y (or 38 bcm) in H1 2023, largely driven by lower Russian piped gas deliveries. In this context, **LNG continued to gain market share** and accounted for almost 40% of Europe's gas consumption in H1 2023 – a share similar to Russia's before its invasion of Ukraine. Meanwhile, the share of OECD Europe's gas demand met by Russian piped gas stood at below 10% during the first half of the year.

Russian piped gas exports to OECD Europe fell by an estimated 65% y-o-y (or 38 bcm) in H1 2023. The profile of flows to the European Union stayed relatively stable at an average of 60 mcm/d, representing a decline of over 75% (or 36 bcm) compared with H1 2022. Exports to Türkiye fell by an estimated 20% y-o-y. Russia's LNG exports to Europe rose by 5% y-o-y (or 0.5 bcm). According to shipping data, Belgium, France and Spain accounted for almost 80% of Europe's total LNG imports from Russia in H1 2023.

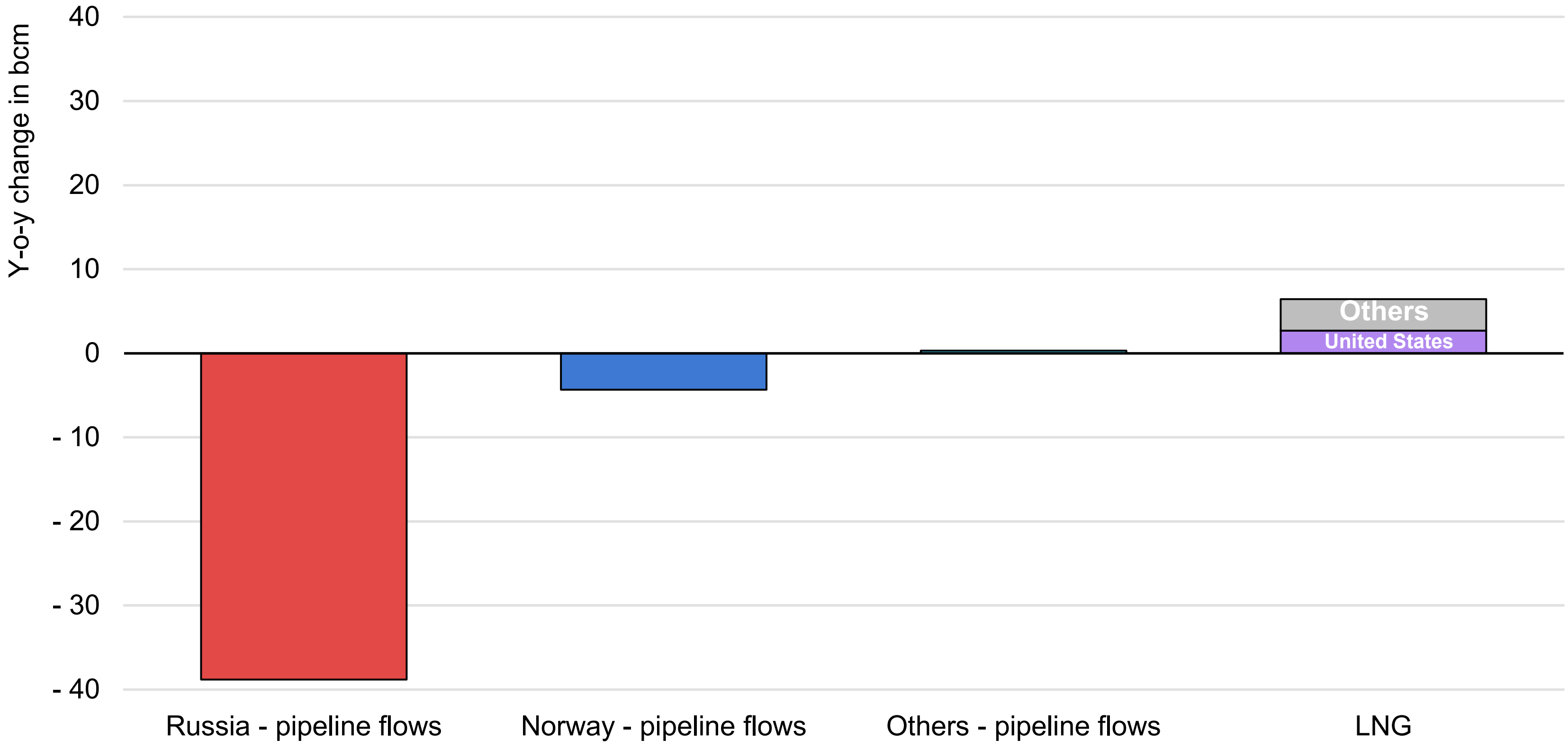
Norway's piped gas supplies to the rest of Europe declined by 7.5% y-o-y (or over 4 bcm) in H1 2023 amid a higher level of planned maintenance and unplanned outages. Norwegian pipeline deliveries to the European Union fell by 2.5%, while exports to the United Kingdom fell by around over 23% (or 3.2 bcm). **Non-Norwegian domestic production** fell by an estimated 10% y-o-y (or close to 4 bcm) in the first five months of 2023. This was largely driven by lower gas output in the Netherlands amid the continued phase-out of the Groningen field. Pipeline gas deliveries from **North Africa** declined by 5% y-o-y (or 0.8 bcm), with flows to Iberia falling by 18% (or 0.8 bcm) and remaining broadly flat to Italy. Gas supplies from **Azerbaijan** via the Trans Adriatic Pipeline rose by 4% y-o-y (or 0.2 bcm) in H1 2023.

Europe's **LNG imports** rose by over 8% y-o-y (or 6.5 bcm) in H1 2023. LNG flows from the United States increased by 7% y-o-y (or close to 3 bcm) to account for over 40% of incremental LNG supply into Europe. This further reinforced the United States' position as Europe's leading LNG supplier, providing 47% of the region's total LNG imports and meeting over 15% of its gas demand.

The profile of Russian piped gas supplies remains a major uncertainty over the **forecast period**. Assuming that flows to the European Union continue at their H1 levels, deliveries of Russian piped gas to OECD Europe would drop by more than 50% (or 42 bcm) in 2023 compared with 2022. LNG imports are expected to remain broadly flat in 2023 compared with last year. Following the increase in H1 2023, OECD Europe's LNG inflows are projected to decline for the rest of the year, reflecting lower injection needs and a continuing decline in European gas consumption. However, a colder than average Q4 could lead to higher LNG import needs. This forecast assumes that Russian piped gas deliveries stabilise at their 2023 levels in 2024, while LNG imports increase by 3%.

LNG continued to substitute Russian piped gas in Europe's supply mix in H1 2023

Y-o-y change in European natural gas imports and deliveries from Norway, H1 2023 vs H1 2022



Sources: IEA analysis based on ENTSOG (2023), Transparency Platform; Eurostat (2023), Energy Statistics; Gas Transmission System Operator of Ukraine (2023), Transparency Platform; ICIS (2023), ICIS LNG Edge; JODI (2023), Gas World Database.

Global LNG trade grew by 3% in first half of 2023, primarily supported by the United States

In the first half of 2023, global LNG trade expanded by 3% y-o-y (or 9 bcm), supported by higher supply from the United States, Norway and Qatar. Over the same period, LNG demand increased by 3% y-o-y (or 9 bcm), mainly due to Europe (up by 8% y-o-y or 6.6 bcm) and the Asia Pacific region (up by 2% y-o-y or 3 bcm).

From a supply perspective, this growth was driven by North America and the Asia Pacific region, which respectively saw a 7% (or 3.8 bcm) and 3% (or 2.7 bcm) y-o-y increase in their LNG output. The United States, Norway and Qatar were the main contributors to this expansion**.** In the **United States** higher y-o-y output was primarily driven by the continued ramp-up of Calcasieu Pass and the return of the Freeport LNG export terminal to full service after a fire-induced outage in June 2022. The resumption of production at the Hammerfest LNG terminal in **Norway** contributed 2.1 bcm to global supply growth. In **Australia** higher output from the Prelude floating LNG (FLNG) and the Wheatstone terminal supported 2.6% (or 1.38 bcm) y-o-y growth in the country's LNG exports in the first half of 2023. Additional y-o-y growth in LNG supply was driven by Qatar, the continued ramp-up of Mozambique's Coral South FLNG, Indonesia and Algeria.

From a demand perspective, Europe continued to lead LNG demand growth in the first half of 2023. The region's net LNG imports rose by 8% y-o-y (or 6.6 bcm), largely driven by higher LNG inflows to the Netherlands, Germany and Italy. In contrast, LNG flows to France dropped by 14% (or 2.3 bcm) in the first half of 2023 amid widespread strike action in April and May. Higher LNG supplies to Europe were facilitated by the commercial start-up of several new floating storage and regasification units (FSRUs) in Europe. Germany commissioned its first three FSRUs in less than a year, representing a total regasification capacity of 20 bcm/yr. In the Netherlands, Gasunie commissioned the Eemshaven FSRU in October 2022, with a regasification capacity 8 bcm/yr. In Finland, Gasgrid's Inkoo FSRU was commissioned in January 2023 with a regasification capacity of 5 bcm/yr.

LNG imports into the **Asia Pacific** region increased by a modest 2% y-o-y (or 3 bcm) in the first half of 2023. This was primarily driven by China. After more than 13 months of year-on-year declines, China's net LNG imports started to recover in March 2023 and grew by 10.6% y-o-y (or 4.4 bcm) in the first half of 2023. New regasification terminals are due to come online by the end of the year, adding a further 20 bcm/yr to the existing capacity of 140 bcm/yr. Thailand's LNG imports grew by a strong 30% y-o-y (or 1.8 bcm), largely supported by the country's declining domestic production. India's LNG imports remained broadly stable (down by a slight 0.3 bcm) compared with the first half of 2022. In April the country commissioned the Dhamra LNG import terminal (7 bcm/yr), which adds more than 10% to India's existing regasification capacity. This is India's seventh LNG import facility and the first on the east coast. We expect LNG demand in India to remain flat in 2023, as offshore gas production by Reliance Industries Ltd, India's largest company by market value, reduces the need to import LNG.

Asian spot LNG prices moderated significantly from the beginning of 2023 to trade at an average of USD 10/MBtu in Q2 2023, below the price range of oil-indexed LNG contracts. This encouraged South Asian buyers to come back to spot markets via tenders, especially as demand for electricity in the region has risen in the wake of heat waves in spring 2023. For instance, Bangladesh saw the rate of its LNG buy tenders awarded rise from less than 30% in 2022 to 85% so far in 2023. However, the country delayed payments for both long-term and spot LNG cargoes, following a depreciating currency and broader financial difficulties. Delayed payments could impact future interest in its spot tenders or raise the premiums for supplying into the country due to higher financial risk. For the time being, Bangladesh's state-owned company Petrobangla has secured LNG imports by signing an SPA with QatarEnergy Trading (1.1 bcm/yr for 15 years from 2026).

In contrast, Japan LNG imports declined by 12% (or 6 bcm) in the first half of 2023, amid improving nuclear availability, lower electricity demand and high LNG stocks. Japan’s LNG imports in May fell to the lowest in more than 20 years at 5.5 bcm (down by 28% y-o-y), as efforts to save energy and boost nuclear power reduced gas demand.

In addition to existing LNG importers, **Hong Kong, Viet Nam and the Philippines** all become first-time LNG buyers this year. The world’s largest FSRU arrived in **Hong Kong** in April 2023 to serve the city’s first LNG import terminal. The terminal has a regasification capacity of 5.5 bcm/yr and is scheduled to start operations in mid-2023. In **Viet Nam,** Thi Vai LNG terminal (1.36 bcm/yr) received its commissioning cargo in early July from Bontang. Regasified LNG will primarily supply two gas-fired power plants with a combined capacity of 1.5 GW currently being built in the neighbouring province of Dong Nai. **The Philippines** started importing LNG in April 2023 with the commissioning of its first LNG import facility, located in Batangas Bay (7 bcm/yr). The country’s LNG import needs are set to increase amid falling domestic production. However, neither Viet Nam nor the Philippines had secured a long-term LNG supply contract as of June 2023.

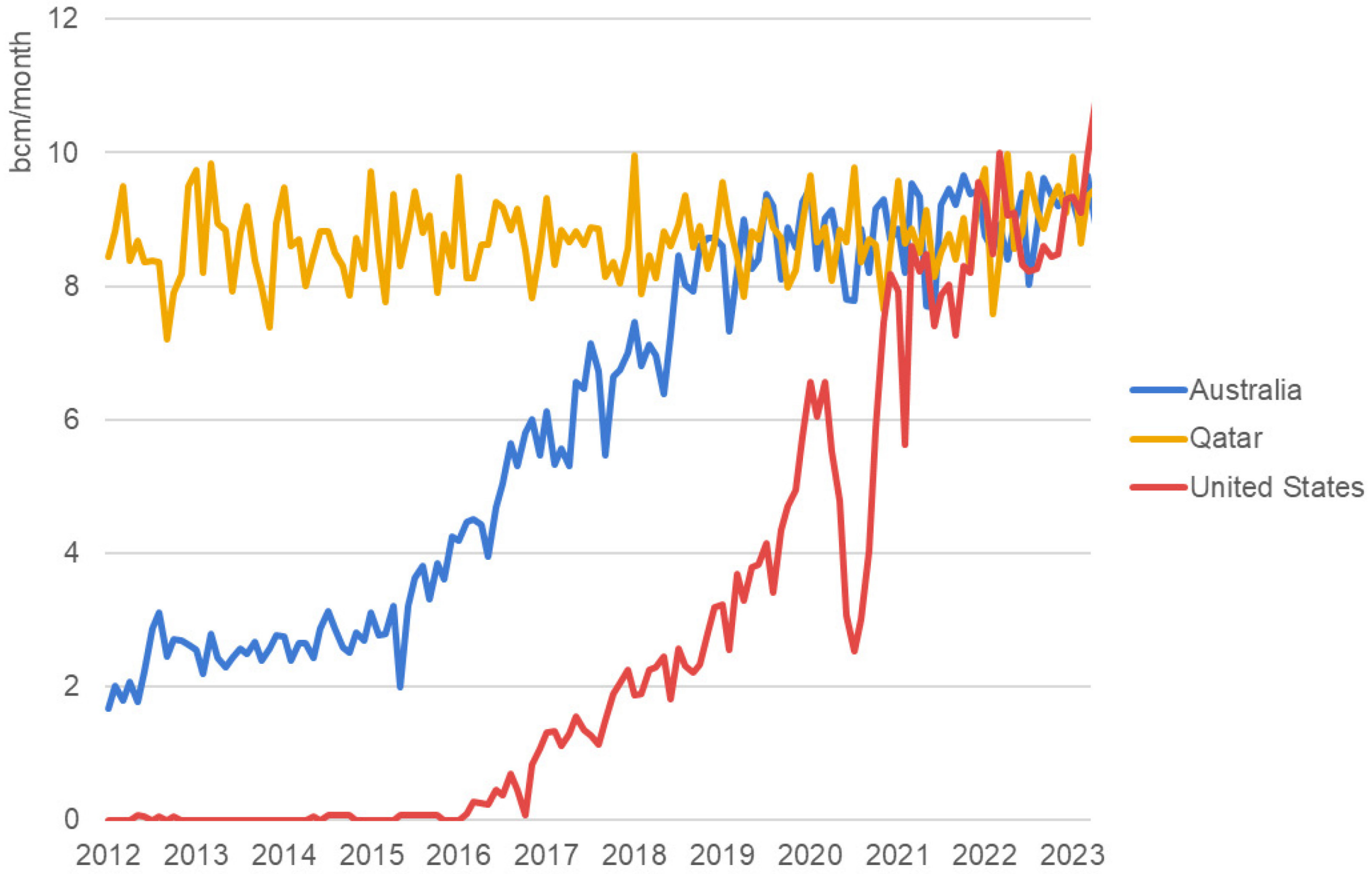
LNG imports in **Central and South America** recovered in Q2, up 24% (or 1 bcm) y-o-y, following a 27% (or 1 bcm) y-o-y decline in Q1. Overall, in the first half of 2023, LNG imports rose slightly by 2% (or 0.2 bcm) y-o-y, mainly driven by higher imports into Argentina (up 88% or 0.8 bcm) for power production. In contrast, hydroelectric production improved significantly this year in Brazil, which saw its LNG imports fall by 80% (or 1.7 bcm) year-on-year in the first half of 2023, with no deliveries until the end of April.

For the full year of 2023 we forecast global LNG trade to increase by 4% (or 22 bcm). The United States alone is expected to contribute half of the incremental LNG supply and become the world's largest LNG exporter. This growth will be supported primarily by the ramping up of the Calcasieu Pass LNG terminal and the restart of Freeport LNG. Additional supply is expected from improved feed gas availability in Algeria and Trinidad and Tobago, and the ramp-up of Coral South FLNG in Mozambique. Demand growth is set to be largely driven by Asia. China's LNG imports are expected to increase by 15% over 2022 levels, while remaining below their record levels of 2021, and heavily dependent on growth in domestic production and pipeline imports from Central Asia and from Russia with the planned ramp-up of the "Power of Siberia 1" pipeline. After strong growth in Q1 2023, OECD Europe's LNG imports are expected to decline in the second half of 2023 amid lower injection needs and a continued decline in European gas consumption.

In 2024 global LNG trade growth is expected to moderate to 4% (or 24 bcm) – well below the 8% average growth rate experienced between 2017 and 2021. Below-average LNG liquefaction capacity additions are expected to prolong tight supply conditions into 2024. Incremental LNG supply is anticipated to be driven primarily by the gradual start-up of new LNG liquefaction plants in North America (Plaquemines LNG Phase 1, Golden Pass LNG Train 1, Fast LNG Altamira), the ramp-up of Tangguh Train 3 in Indonesia and the start-up of Grand Tortue Ameyim off Senegal and Mauritania. Russia's Arctic LNG 2 Train 1 is expected to start operations at the end of 2023, although uncertainties remain around its ramp-up schedule and initial utilisation rates. LNG demand in 2024 is expected to be driven by Asia and Europe, with the two regions competing for limited supply. Asian LNG imports are projected to increase by 6% in 2024, primarily supported by China's procurement through its growing portfolio of long-term import contracts. LNG inflows into Europe are forecast to increase by 3%, driven by a moderate recovery in the region's gas demand.

The United States is expected to become the world's largest LNG supplier in 2023

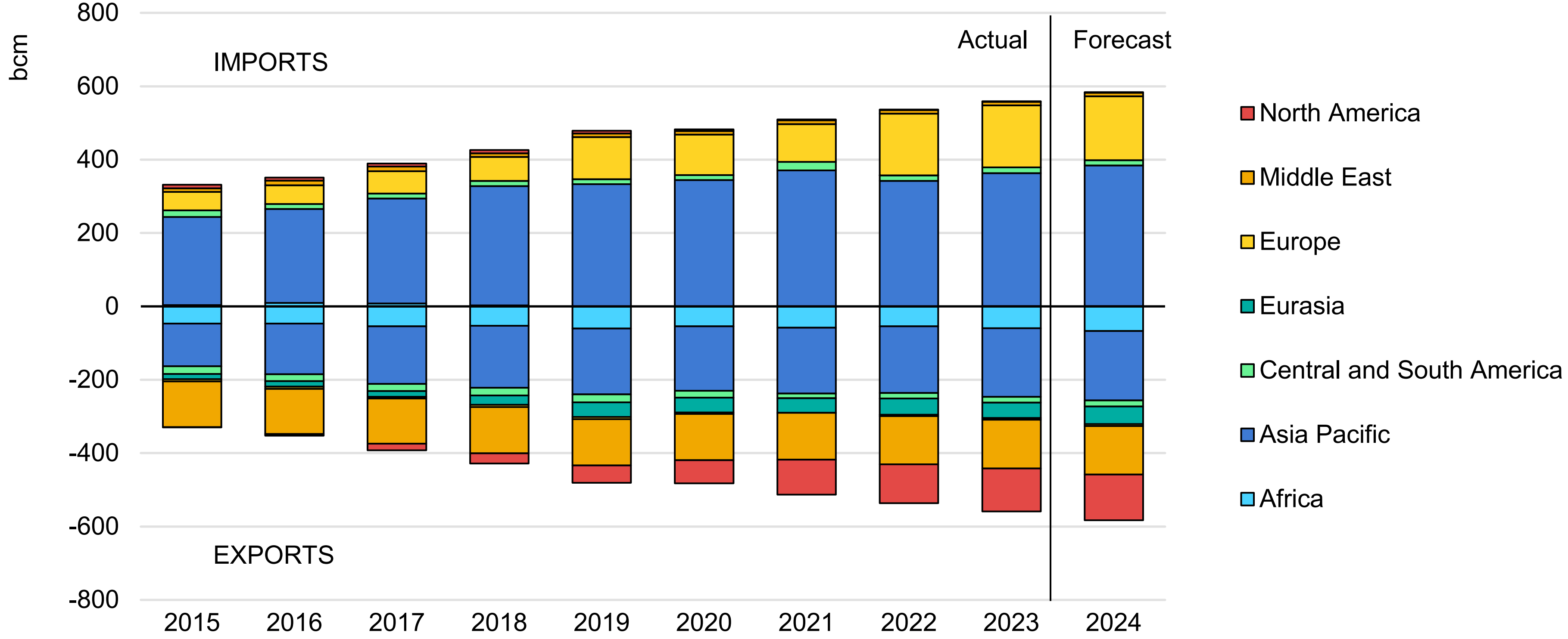
Monthly LNG exports from Australia, Qatar and the United States, 2012-2023



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Global LNG market growth is expected to moderate to 4% in 2024

LNG imports and exports by region, 2015-2024



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Asian spot LNG and European hub prices fell to a two-year low in Q2 2023

Subdued demand, together with high storage levels and improving supply fundamentals, continued to put **downward pressure** on natural gas prices across key gas markets in Q2 2023. Asian spot LNG and European hub prices traded below the estimated average price of oil-indexed LNG contracts during Q2 and had dropped to a two-year low by the end of May 2023.

In **Europe**, TTF spot prices declined by 34% on the quarter to an average of USD 11/MBtu, standing 63% below last year's levels. Strong LNG inflow, together with high inventory levels and continued demand reduction, put strong downward pressure on European hub prices. By the end of May, TTF month-ahead prices had dropped to below USD 8/MBtu – their lowest level in two years. TTF's premium over NBP narrowed to USD 0.7/MBtu in Q2 2023 from USD 10/MBtu in the same period last year. North-western Europe's increasing LNG regasification capacity and lower storage injection needs eased congestion along the EU-UK interconnectors, which in turn tightened the TTF-NBP price spread.

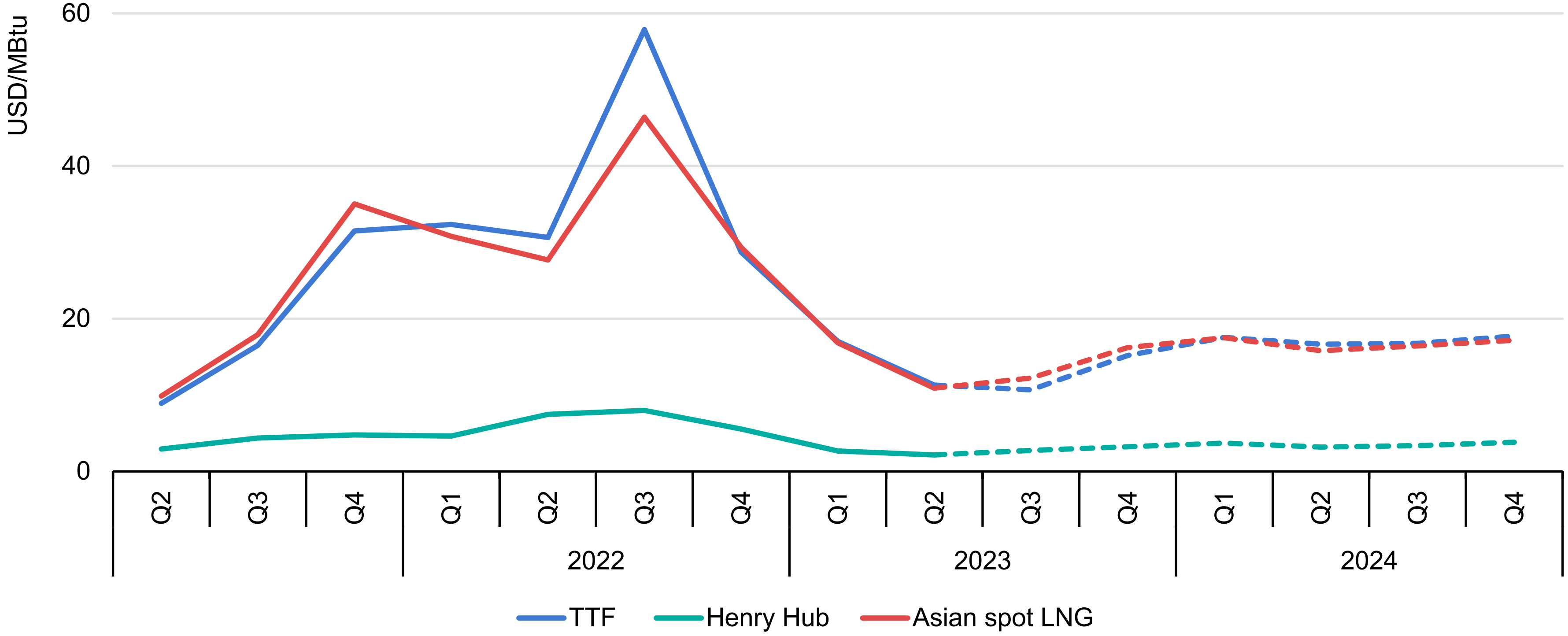
Asian spot LNG followed a similar trajectory to European hub prices. Spot LNG prices in Asia declined by 35% from Q1 to an average of USD 11/MBtu in Q2 2023 – down by 60% compared with the same period last year. Less competition from Europe, subdued demand and improving LNG availability weighed on prices. By the end of May, Asian spot LNG prices had recovered their premium over European hub prices for the first time since Q1 2022, averaging USD 0.7/MBtu above TTF month-ahead prices in June. If Asian spot LNG prices maintain their premium, LNG inflows into Europe could decline in the second half of 2023.

In the **United States**, Henry Hub prices declined by 15% on the quarter to an average of USD 2.2/MBtu in Q2 2023 – their lowest Q2 level since 2020. Strong growth in domestic production combined with lower gas demand and above-average storage levels put downward pressure on gas prices.

According to forward curves as of the end of June 2023, TTF is set to average at just above USD 13.5/MBtu in 2023, with Asian spot LNG averaging at USD 14/MBtu and Henry Hub averaging USD 2.7/MBtu. Asian spot LNG prices are expected to have an average premium over TTF of USD 1.3/MBtu during the second half of 2023. Natural gas prices could strengthen again in 2024 amid tighter supply-demand fundamentals. Forward curves indicate that TTF prices are expected to increase by 25% to average over USD 17/MBtu in 2024, while Asian spot LNG rises by 20% to stay just below USD 17/MBtu. TTF regains its premium over Asian spot LNG prices to an average of USD 0.5/MBtu, allowing for a stronger pull of LNG towards the European market. In the United States, Henry Hub prices are expected to rise by 30% to USD 3.5/MBtu on tighter supply-demand fundamentals.

Asian spot LNG prices are expected to trade above TTF during the second half of 2023

Main spot and forward natural gas prices, 2020-2024*



* Future prices are based on forward curves as of the end of June 2023 and do not represent a price forecast.

Sources: IEA analysis based on CME (2023), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements; LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; ICIS (2023), ICIS LNG Edge; Powernext (2023), Spot Market Data.

Gas storage levels remained well above their historic average in Q2 2023

Storage sites opened the 2023 injection season[1] with inventory levels standing well above their historic averages, as lower gas demand depressed withdrawal rates over the 2022/23 winter. **Storage injections displayed a varied pattern in Q2 2023**: while the United States experienced above-average storage build-up, injections in the European Union slowed compared with previous years, albeit remaining sufficient to keep the bloc well on track to reach its 90% fill target by 1 November 2023.

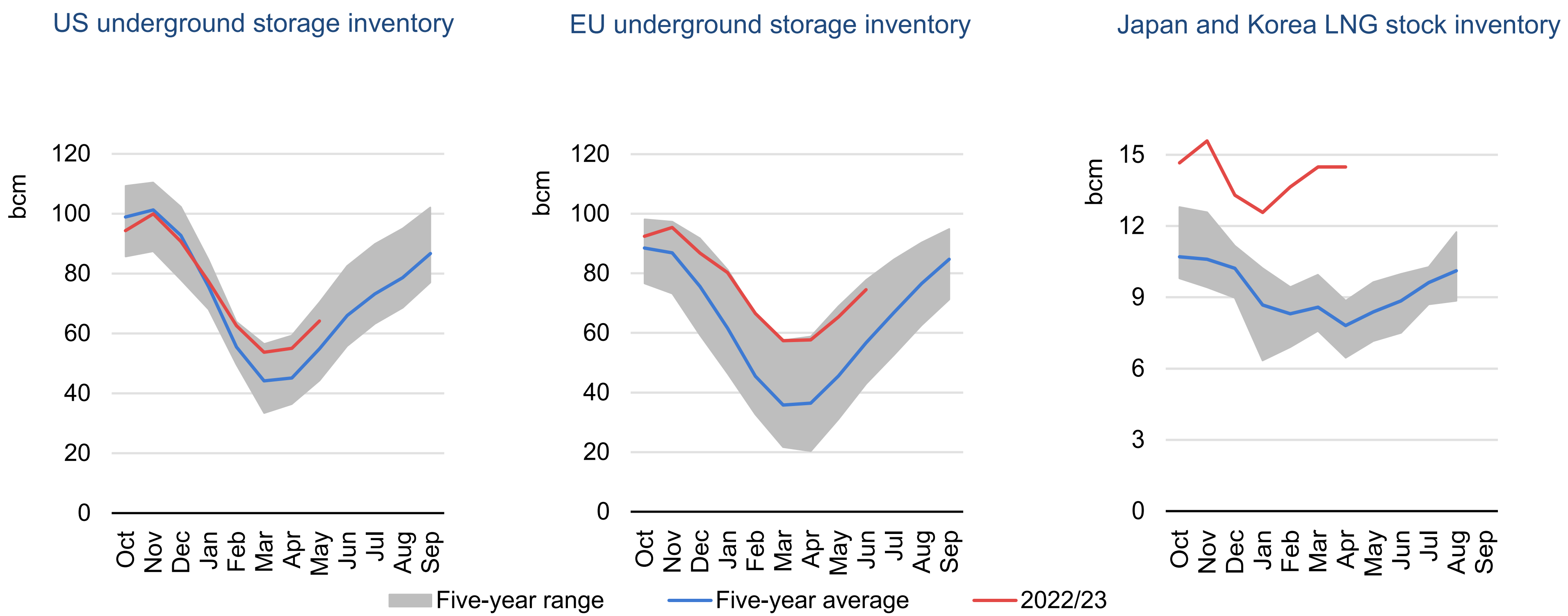
In the **European Union**, as a consequence of below-average net withdrawals, storage sites closed the 2022/23 heating season 55% full and with inventory levels standing 67% (or 22 bcm) above their five-year average. Lower primary gas supply (domestic production and imports) led to a slower storage build-up over the first half of the gas summer. Net injections fell 20% (or 5.5 bcm) below their five-year average to a total of 22 bcm in Q2 2023. While slower injection rates moderated the European Union's storage surplus, inventory levels still stood 27% (or 16.5 bcm) above their five-year average at the end of the Q2. Consequently, EU inventory levels reached 77% of their working storage capacity at the end of June. Assuming that storage injections continue at the average rate observed since mid-April, EU storage sites would reach 90% fill levels by early August and could be filled close to 100% of their working capacity by mid-September. In **Ukraine** gas inventory levels at the end of March 2023 were estimated at 9 bcm, rising to 10.5 bcm by the end of Q2. Ukraine has a target to build up gas storage levels of 14 bcm by the start of the 2023/24 heating season.

In the **United States** storage sites opened the 2023 injection season 43% full, standing almost 20% (or 8 bcm) above their five-year average. Strong growth in domestic gas production allowed for a more robust storage build-up in the first half of the gas summer. Net injections in Q2 were 7% (or 1.9 bcm) above their five-year average and totalled 29 bcm. Consequently, US storages sites were 67% full by the end of June, standing 15% (or 10 bcm) above their five-year average. If injections return to their five-year average, storage will be over 90% full by the beginning of November, which typically marks the start of the heating season in the United States.

In **Japan** and **Korea**, closing LNG stocks stood 85% (or 6.5 bcm) above their five-year average in April 2023. The LNG stocks of Japan's largest power generation companies stood at 2.1 Mt (3.1 bcm) at end of June 2023, 15% above their five-year average.

[1] The injection season (or gas summer) in the markets of the Northern Hemisphere refers to the period between 1 April and 30 September.

EU and US storage sites closed Q2 2023 with 77% and 64% fill levels, respectively



Sources: IEA analysis based on EIA (2023), Weekly Working Gas In Underground Storage; GIE (2023), AGSI+ Database; IEA (2023), Monthly Gas Data Service.

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 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 50% between 2016 and 2022, 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 over 46% in 2022, largely driven by the expansion of US LNG. Pricing terms are becoming more diverse, with the share of oil-indexed LNG export contracts declining from over 71% in 2016 to 59% in 2022, replaced by hub indexation and hybrid pricing formulae.

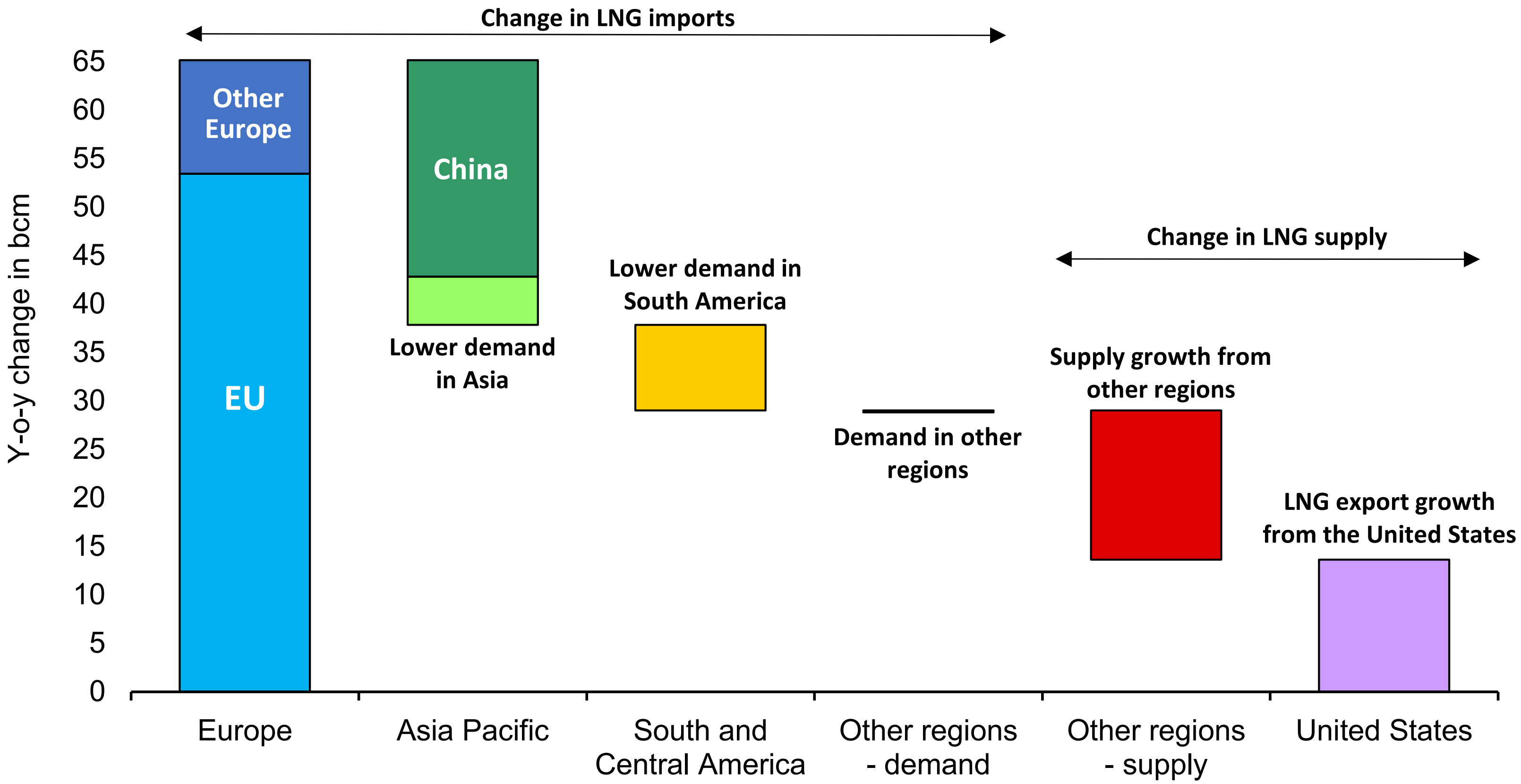
In addition to traditional suppliers, the role of portfolio players in LNG trade has increased significantly in recent years: their procurement contracts' share of total LNG contracts in force rose from 26% in 2016 to over 41% in 2022. Portfolio players are key enablers of short-term supply flexibility, facilitated by their net open positions and commercial ability to resell long-term LNG supply to customers on a short-term or spot basis.

The growing flexibility and liquidity of the global LNG market was crucial in the response to the gas supply shock of 2022 – Russia's steep cuts to its piped gas supplies to the European Union totalled almost 80 bcm, equating to close to 15% of global LNG trade and leading to a profound reconfiguration of global LNG flows. While European LNG imports increased by 60% (or close to 65 bcm) in 2022, Asian LNG imports declined by 7%, primarily driven by lower inflows to China, which saw an unprecedented drop of 20% in its LNG procurements. The United States alone accounted for two-thirds of the incremental LNG deliveries to Europe. The destination flexibility in the contractual structures underpinning US LNG supply was instrumental in enabling these higher LNG flows.

Without this strong LNG inflow, the European market would have been left in a significantly more vulnerable position ahead of the 2022/23 heating season, with an increased risk of gas supply disruption. In contrast, price-sensitive buyers with high exposure to the spot market faced a deterioration in the security of their gas and electricity supply in 2022, with rotating power cuts introduced in Bangladesh and Pakistan amid the inadequacy of gas supplies.

Flexible LNG played a key role in maintaining gas supply security in Europe in 2022

Y-o-y change in global LNG exports and imports by key region, 2021-2022



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Close to 90 bcm/yr of LNG liquefaction capacity sanctioned since Russia's invasion of Ukraine

After a record year for FIDs in 2019, with almost 100 bcm/yr of new liquefaction capacity sanctioned, 2020 saw only one project reaching FID (Energía Costa Azul in Mexico), with a capacity of 4 bcm/yr. The steep decline in LNG liquefaction investment in 2020 reflected the uncertainties created by the Covid-19 pandemic and falling oil and gas prices. 2021 marked a return to LNG investment: two projects with a total capacity of 52 bcm/yr reached FID. Qatar sanctioned its 45 bcm/yr expansion project in February – the largest FID in the history of LNG. In Australia, Woodside Petroleum took FID on the Pluto LNG Train 2 project (7 bcm/yr) in November 2021.

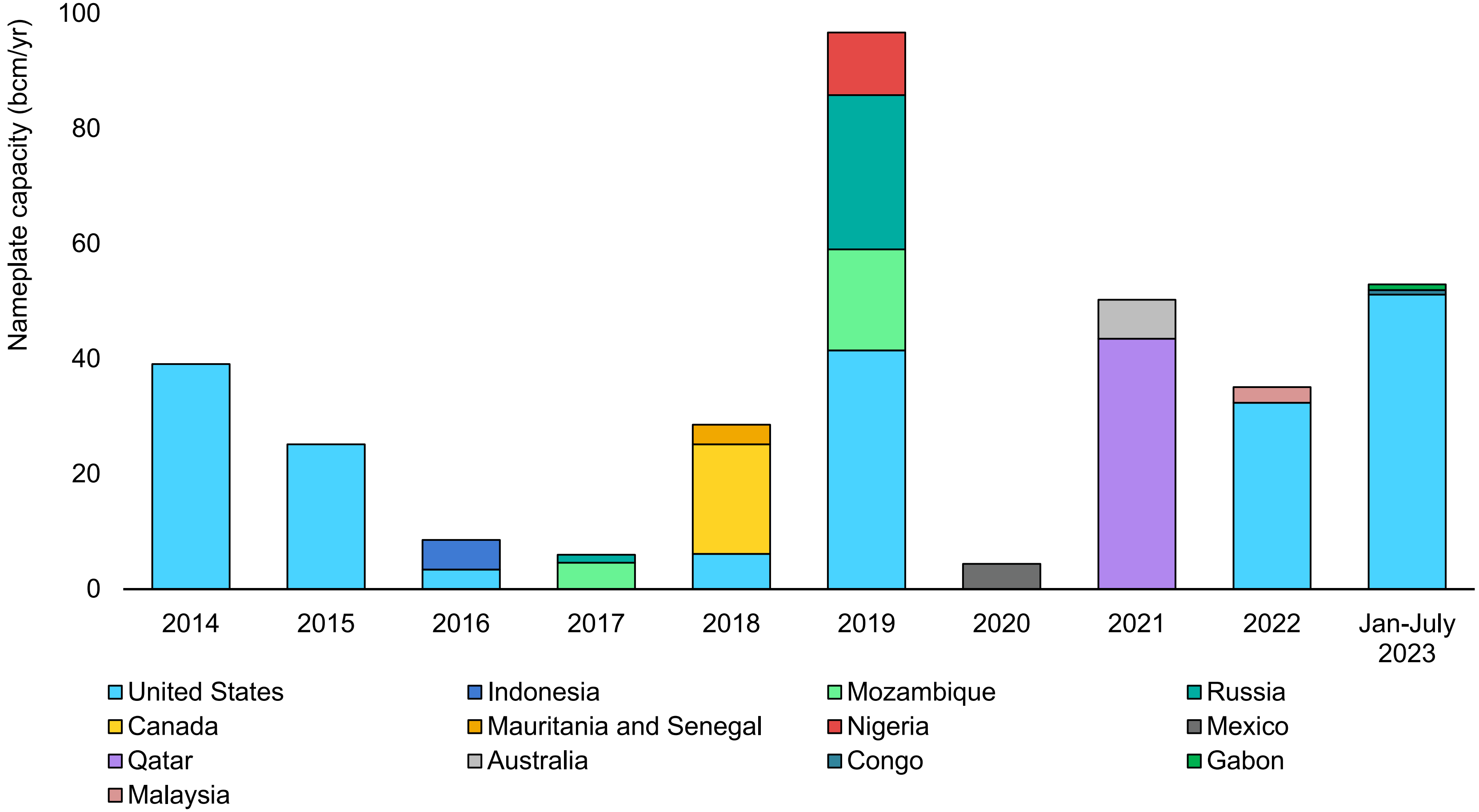
Since Russia's invasion of Ukraine in February 2022, close to 90 bcm/yr of LNG liquefaction capacity has been approved, with the United States alone accounting for 95% of the new FIDs. In May 2022 the first phase of the Plaquemines LNG project (18 bcm/yr) received FID. The project developers plan a phased start-up, which could signify first LNG by the end of 2024 and the start of commercial operations by mid-2025. The Corpus Christi Phase 3 expansion project (14 bcm/yr) was sanctioned in June 2022 and it is expected to come online by the end of 2025. In addition, one floating LNG (FLNG) project in Malaysia (ZLNG Sabah) reached FID in December 2022, with a capacity of 2.7 bcm/yr.

In the first half of 2023 over 50 bcm/yr of LNG liquefaction capacity was sanctioned and/or started construction. The Plaquemines Phase 2 project (9 bcm/yr) reached FID in March 2023, with first LNG expected by 2025. Port Arthur LNG Phase 1 (18 bcm/yr) announced FID in March 2023. The project consists of two trains with a target for commercial operations of 2027 and 2028. The Rio Grande LNG phase 1 project (24 bcm) reached FID in July 2023. The project consists of three trains, with first LNG expected in 2027. In addition to these large-scale projects, the Congo FLNG project was launched in April 2023. The first FLNG plant (0.8 bcm/yr) is set to begin production in 2023. The project could be expanded to 4 bcm/yr by 2025 with the installation of a second FLNG. Offshore at Altamira in Mexico, an initial FLNG production unit is set to be deployed by July or August 2023 with a capacity of 1.9 bcm/yr. According to the project developer, additional FLNG units are to be installed during 2024, scaling total liquefaction capacity up to 5.5 bcm/yr. In Gabon, the Cap Lopez FLNG project (1 bcm/yr) reached FID in February with first LNG expected by 2026. Qatar awarded an engineering, procurement, and construction contract for its North Field South (NFS) expansion project (22 bcm/yr) in May 2023, although no FID has been announced yet.

Together with Qatar's NFS, projects that reached FID or began construction would add close to 250 bcm/yr of liquefaction capacity to 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.

The United States alone accounted for 90% of the LNG FIDs sanctioned in 2022-H1 2023

FIDs for new LNG liquefaction capacity, 2014-2023



Sources: IEA analysis based on various public statements.

North America remained the largest source of new LNG export contracts in 2022

In 2022, 60 bcm/yr of newly signed contracts were concluded with post-FID projects, including portfolio players' contracts. This represents a 23% decline in contracting activity compared with 2021. However, when pre-FID contracts are considered, the total contracted volume in 2022 rises to just over 100 bcm/yr, an increase of 20% compared with the total volumes contracted in 2021. More than 70% of the total contracted volume in 2022 originated from North America and the Middle East.

On the export side, North America continued to dominate the LNG contracting landscape, accounting for around half (or 30 bcm/yr) of the volumes contracted in 2022. The second largest source of newly signed contracts was the Middle East, with a share of 20% (or 11 bcm/yr). Portfolio players accounted for 15% (or 9 bcm/yr) of the LNG supply contracts signed in 2022, well below the 32% average during 2016-2020. The Asia Pacific region's export share increased from 3% in 2021 to 12% in 2022, primarily supported by new LNG export contracts signed with producers in Australia and Brunei.

When pre-FID contracts are considered, North America's dominance is even more pronounced, with the region accounting for 70% (or 70 bcm/yr) of all the volumes contracted in 2022. This is reflective of the strong pipeline of LNG projects that are at various stages of development in the United States and need long-term offtake agreements to reach FID.

On the import side, portfolio players led contracting activity to account for around 40% (or 24 bcm/yr) of the volumes signed in 2022. In terms of regions, Asia continues to dominate the contracting landscape with a 37% share (or 22 bcm/yr) of new volumes contracted in 2022. China alone accounted for 21% of the contracts signed in 2022. European buyers increased their LNG contracting activity in 2022 in the aftermath of Russia's invasion of Ukraine. The volume of LNG contracted by Europe rose from 4 bcm/yr in 2021 to close to 15 bcm/yr in 2022, its highest level in the last five years. Hence, Europe's share of post-FID LNG contracts rose from 5% in 2021 to 24% in 2022. When pre-FID contracts are considered, Europe's share remains rather limited, accounting for 20% of the total volumes contracted in 2022.

In contrast, portfolio players' share of the total contracted volumes (pre-FID contracts included) rose from 17% in 2021 to over 40% in 2022, highlighting their key role in bridging the gap between certain buyers' reluctance to sign long-term contracts and the sellers' imperative to secure long-term contracts before sanctioning new projects. Notably, over 70% of the import contracts signed by portfolio players are associated with North American LNG projects.

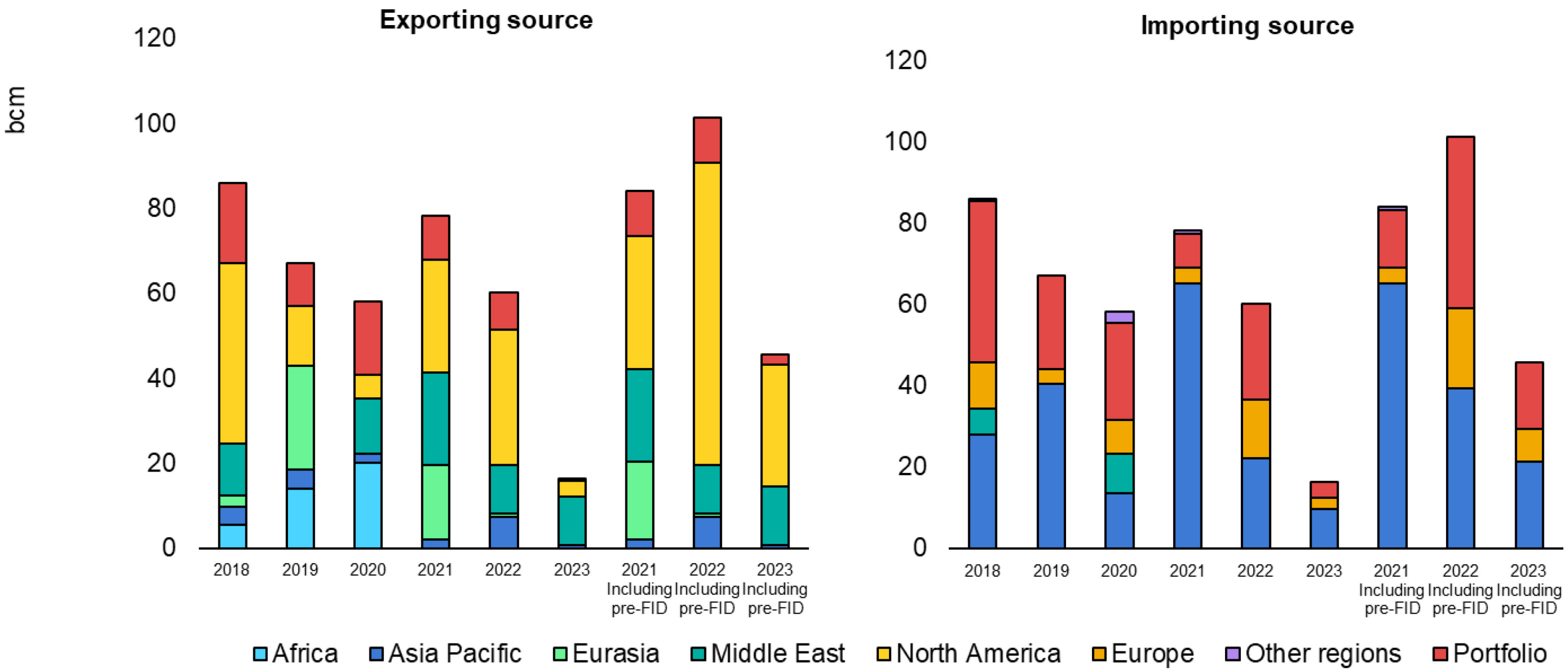
In the first half of 2023, 16 bcm/yr of firm contracts were concluded, representing a decline of 10% compared with the same period in 2022. When pre-FID contracts are included, the total volume of contracts rises to 45 bcm/yr – almost 10% higher than the total volumes contracted in the first half of 2022. The slowdown in contracting activity is partly reflective of the limited uncontracted capacity available (both at existing LNG liquefaction plants and projects that are under construction or have reached FID), as well as the uncertainties related to the long-term future of natural gas.

On the export side, contracting activity was dominated by the Middle East, accounting for 70% (or 11 bcm/yr) of the contracted volumes. This has been largely driven by the renewal of offtake agreements with Oman. North America accounted for 23% (or 4 bcm/yr) of the new, firm export contracts. However, when pre-FID agreements are considered, North America's share rises to 63% of the total volumes contracted in the year to date.

On the import side Asian buyers continue to play a dominant role, accounting for 60% (or 10 bcm/yr) of the firm volumes contracted in the first half of 2023, with China alone concluding 8 bcm/yr of offtake agreements. Europe accounted for 17% (or 3 bcm/yr) of the contracts signed in the year to date, with most of the offtake agreements signed with projects in North America and the Middle East. Portfolio players' share stood at 24% (or 4 bcm/yr) of the firm contracts concluded in the first half of 2023. When pre-FID contracts are included, their share rises to 36% of the total volumes contracted in the year to date. The majority of the portfolio offtake contracts were signed with North American projects. Asian buyers accounted for 46% of the total volumes contracted in the first half of 2023, with the bulk of them destined for China. In contrast, European buyers accounted for just 18%. The relatively small share of European buyers might reflect the uncertainties surrounding the future of natural gas in Europe.

Portfolio players and Asian buyers continue to lead LNG contracting activity on the import side

Volume of contracts concluded in each year split by exporting and importing source, 2018-2023



Notes: Contracted volumes used for the analysis are associated with confirmed export projects that have taken FID. 2023 represents volumes signed by the end of June 2023. “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 (2023), ICIS LNG Edge.

Long-term agreements continue to dominate the contracting landscape

LNG contracting activity in 2022 indicates a trend towards longer contract durations, a stronger interest in large contracts and an increase in the number of destination-flexible contracts.

Long-term agreements (with a duration of over 10 years) have dominated the contracting landscape since 2018. In 2021 they accounted for 84% of contracted volumes and for 88% in 2022, their highest share in the last three years. This high share was driven by Asian buyers, which accounted for 42% of contracted long-term volumes; China alone was responsible for 23%. Agreements with a medium-term duration (between five and ten years) accounted for 12% of the volumes contracted last year, with portfolio players acting as offtakers. In the first half of 2023, the share of long-term contracts stood at 78%, with portfolio players acting as offtakers for some of them. The strong price volatility seen in 2022 and growing supply uncertainty could have reminded both buyers and sellers of the importance of long-term contracts to secure a stable price outlook and reduce short-term price variability.

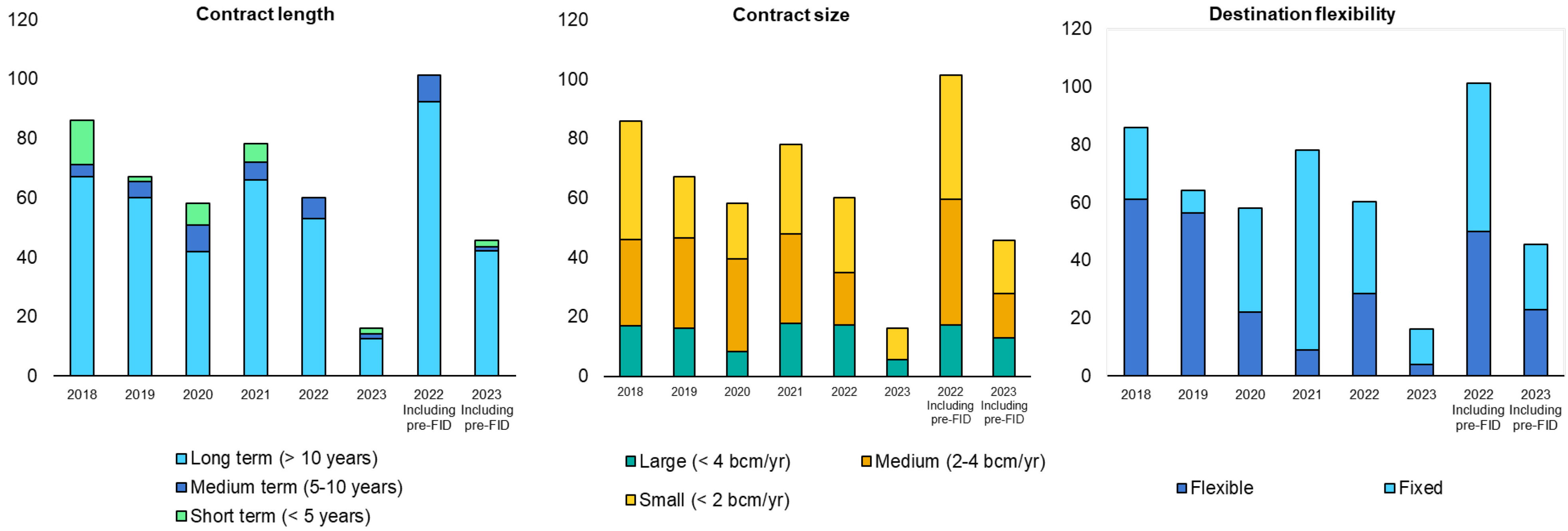
In volume terms, large contracts (over 4 bcm/yr) accounted for 30% of contracted volumes in 2022 – their highest share since the IEA Global Gas Security Review started tracking LNG contracting trends in 2015. This relatively high share of large contracts is underpinned by three SPAs, two where portfolio players acted as offtakers and a major contract signed between QatarEnergy and China's Sinopec.

Medium-sized contracts (2-4 bcm/yr) accounted for 30% and small contracts (< 2 bcm/yr) for 40% of the total volumes contracted in 2022. In H1 2023 small contracts were the majority, potentially indicating that buyers are withholding from signing up for large volumes amid future market uncertainties.

The share of destination-fixed volumes in newly signed contracts averaged 78% during 2020 and 2021, representing a sharp increase from just 22% during 2018 and 2019, when new FIDs in the United States supported more flexible contractual structures. In 2022 the share of destination-free contracts rose compared with 2020 and 2021, accounting for around half of the newly contracted volumes. Around 75% of destination-flexible contracts were associated with North American projects. The bulk of destination-flexible volumes were contracted by portfolio players (75%) and European buyers (25%). In contrast, the majority of destination-fixed volumes were contracted by Asian buyers. China accounted for 40% of the destination-fixed contracts concluded in 2022. In H1 2023 the share of destination-fixed contracts rose to 76%, primarily supported by the contractual preferences of Asian buyers. Despite the recent increase in destination-fixed contracts, the share of destination-free volumes in total contracted volumes is set to increase over the medium term due to the continued expiry of legacy contracts with destination clauses.

Destination-flexible contracts accounted for half of the volumes contracted in 2022

Volume of contracts concluded in each year, split by contractual element, 2018-2023



Note: 2023 represents volumes signed by the end of June 2023. Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Portfolio players: Key enablers of market flexibility and liquidity

Portfolio players have an important role in meeting buyers' growing need for flexibility in volume and destination. They procure a mix of LNG supplies from various origins and resell to customers according to their requirements via term and spot contracts.

The role of portfolio players has grown significantly in recent years: by volume, the share of their procurement contracts among all LNG contracts in force rose from 26% in 2016 to over 40% in 2021 and stayed at similar levels in 2022. This increase was underpinned by particularly strong contracting activity between 2016 and 2020, when portfolio players accounted for 34% of the total purchase contracts signed. Their share declined to 9% in 2021, before rebounding to 38% of the total offtake agreements concluded in 2022. The average length of new purchase contracts concluded by portfolio players increased from 5 years in 2017 to over 15 years in 2022. The share of large contracts (more than 4 bcm/yr) rose from 30% in 2018 to account for over 50% concluded by portfolio players in 2022.

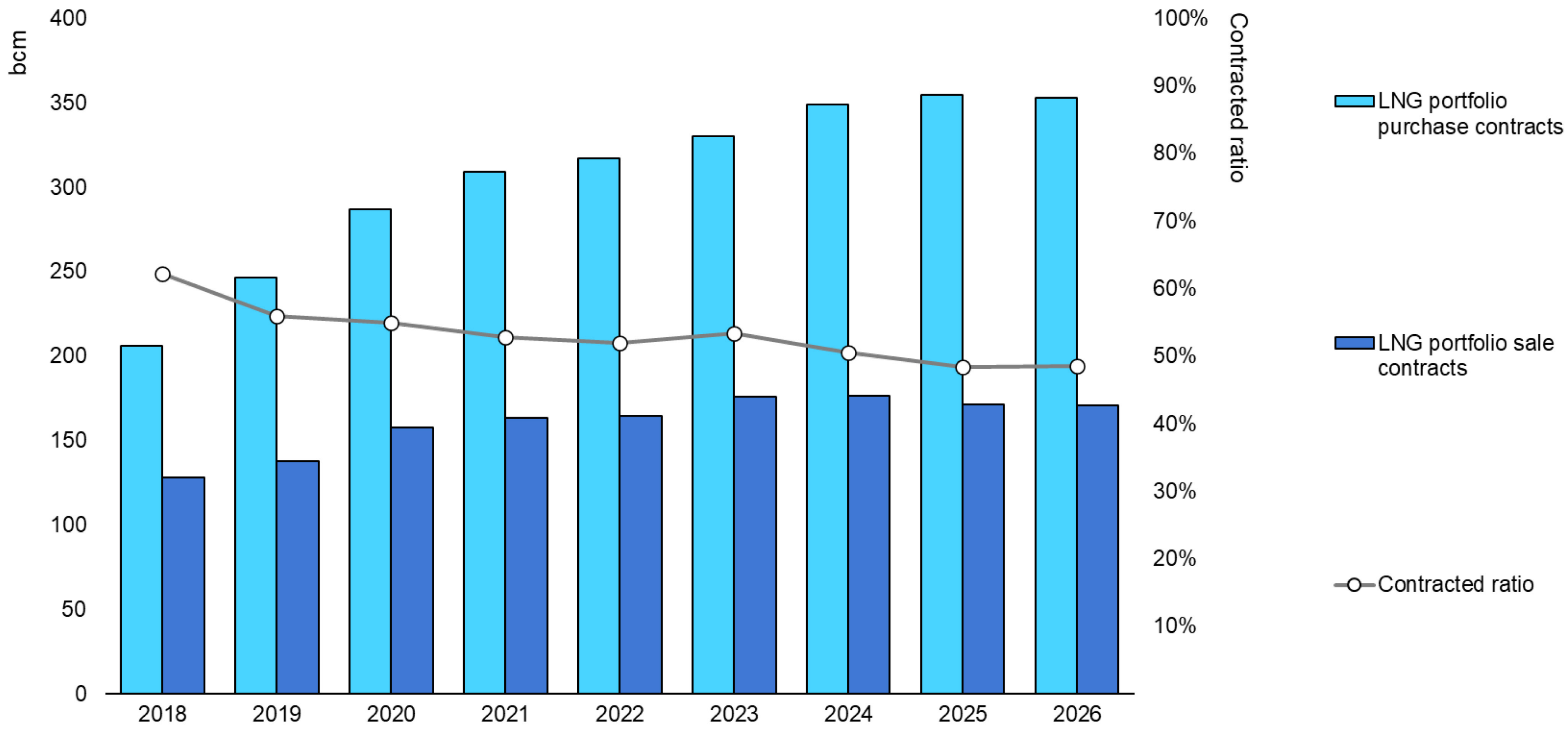
The volume of sale contracts signed by portfolio players fell to 18 bcm/yr 2021 and below 10 bcm/yr in 2022 – a sharp decline from the 22 bcm/yr average between 2016 and 2020. Consequently, the proportion of sale contracts signed by portfolio players has fallen from 50% of total volumes contracted in 2017 to just 14% in 2022. Portfolio players remained largely absent from new sale contracts in the first half of 2023. This might be reflective of their preference under current market conditions to sell their LNG volumes on the spot market rather to sign term contracts.

The portfolio players' contracted ratio – sales offtake as a percentage of purchase obligations, a metric of relative exposure to certain types of market risk – declined to 52% in 2022 from 71% in 2017. This means that the share of their purchase obligations not covered by term sale contracts – or their net open position – increased from 29% to 48% between 2017 and 2022. Based on existing contracts, their net open position is set to increase to an average of close to 50% between 2023 and 2026. The growing net position of portfolio players allows them to play a more active role in the short-term market by increasing their spot sales and benefit from the arbitrage opportunities arising from regional price differentials.

Portfolio players played a crucial role in supplying flexible LNG to the European Union amid the steep fall in Russian piped supplies from the beginning of the 2021/22 heating season. Preliminary shipping data indicate that portfolio players accounted for around half of incremental LNG supply into the European Union in 2022. The supply flexibility they provide is expected to remain a key contributor to gas supply security amid the energy crisis triggered by Russia's invasion of Ukraine.

Portfolio players' net open position is set to widen further over the medium term

LNG portfolio players' contractual position and contracted ratio, 2018-2026



Note: This graph represents the volumes signed by the end of June 2023.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Contracted volumes are set to increase marginally over the medium term

Based on firm contracts, the volume of total active contracts (including portfolio contracts) is expected to increase by about 10% between 2022 and 2026. This represents a marked slowdown compared with the 2017-2021 period, when contracted volumes surged by close to 40%. This slower increase in active contracts is reflective of lower LNG liquefaction capacity additions over the 2022-2025 period and Qatar's strategy of developing new liquefaction capacity without securing long-term contracts in advance.

On the export side, North America accounts for the bulk of additional active contracts, with its volumes increasing by 60% between 2022 and 2026. In contrast, active LNG contracts sourced from Africa, the Middle East and Central and South America are set to decline by 17%, 7% and 92% respectively upon expiry. Consequently, the share of the North America in total active contracts is set to increase from 18% in 2022 to 26% by 2026, making it the largest source of active contracts ahead of the Middle East and the Asia Pacific region.

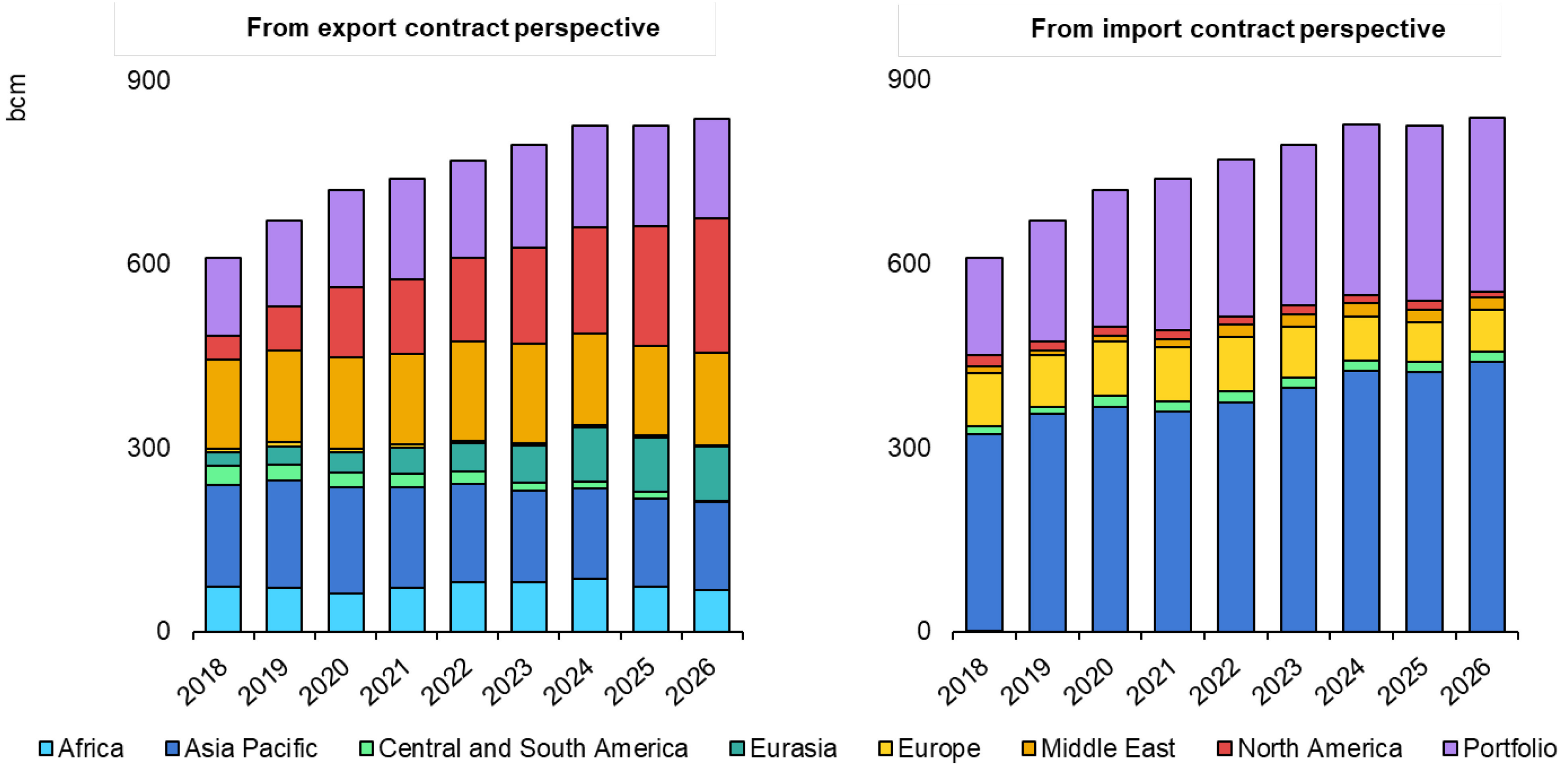
On the import side, the Asia Pacific region's share remains broadly stable to 2026, accounting for more than half of import contracts. Notably, China's LNG import contract volumes are set to increase by around 70% between 2022 and 2026, solidifying the country's position as the largest holder of firm import contracts. In contrast, contracted volumes going to traditional Asian buyers, including Japan and Korea, are decreasing gradually. Europe's LNG import contracts are set to decline by over 20% by 2026 compared with their 2022 levels, leaving the region at a greater exposure to spot market dynamics.

Despite the recent increase in new destination-fixed contracts, the share of destination-flexible volumes in primary[2] LNG export contracts is set to rise from 34% in 2016 to 58% by 2026 as older destination-fixed contracts expire. The growing share of destination-free contracts, together with uncontracted capacity, is expected to further increase the flexibility and liquidity of the global LNG market over the medium term. Nevertheless, in the current market context, where there is increasingly strong competition for LNG between Europe and Asia, it is possible that destination-fixed contracts will continue to gain traction. If sustained, this trend could weigh on the evolving liquidity and flexibility of the global LNG market.

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

North America is set to become the world's largest source of active LNG export contracts

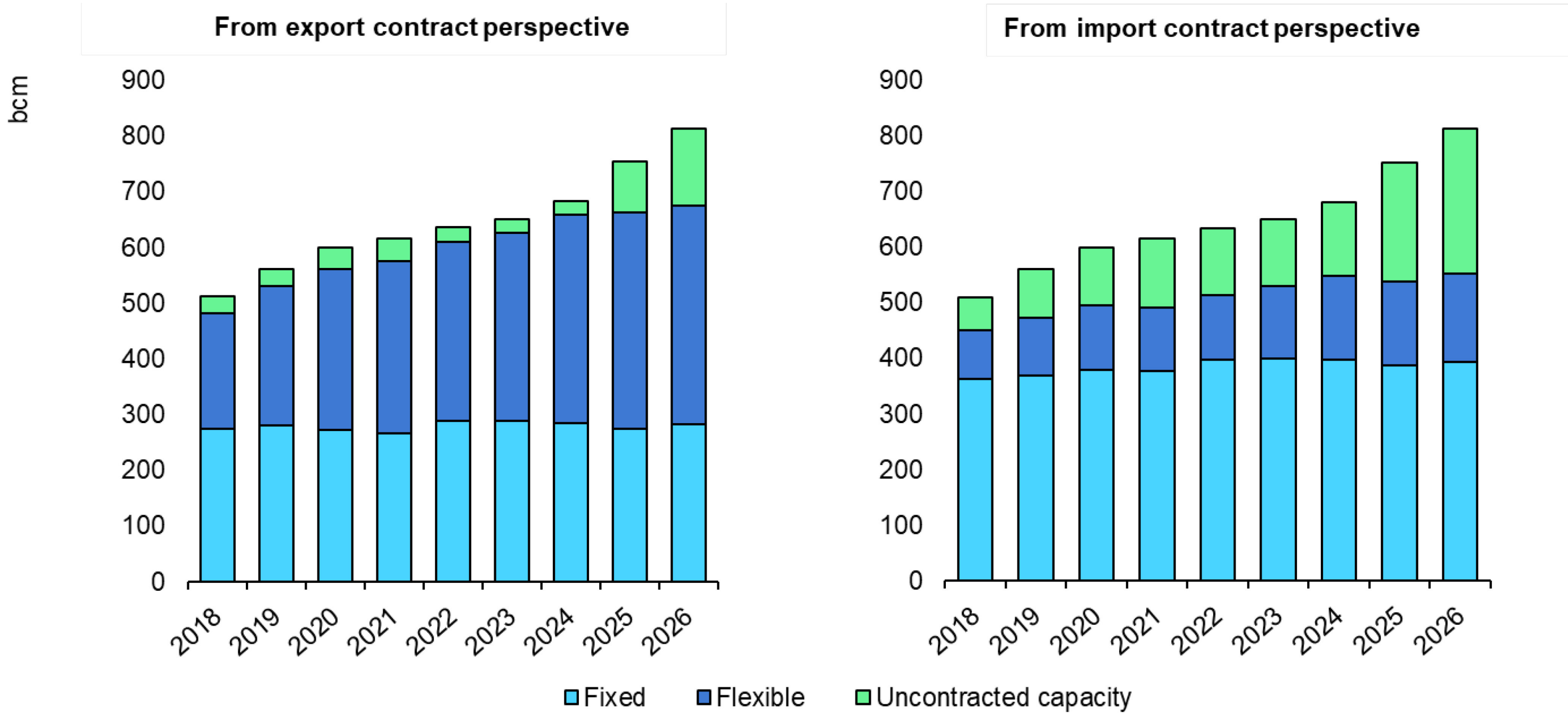
Total active LNG contracts, 2018-2026



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Destination-flexible contracts and uncontracted capacity expand over the medium term

LNG supply capacity by destination flexibility (excluding portfolio contracts), 2018-2026



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Contract expiry creates new marketing opportunities in the medium term

Approximately 150 bcm of active LNG contracts are set to expire between 2023 and 2026, followed by an additional 120 bcm between 2026 and 2030.

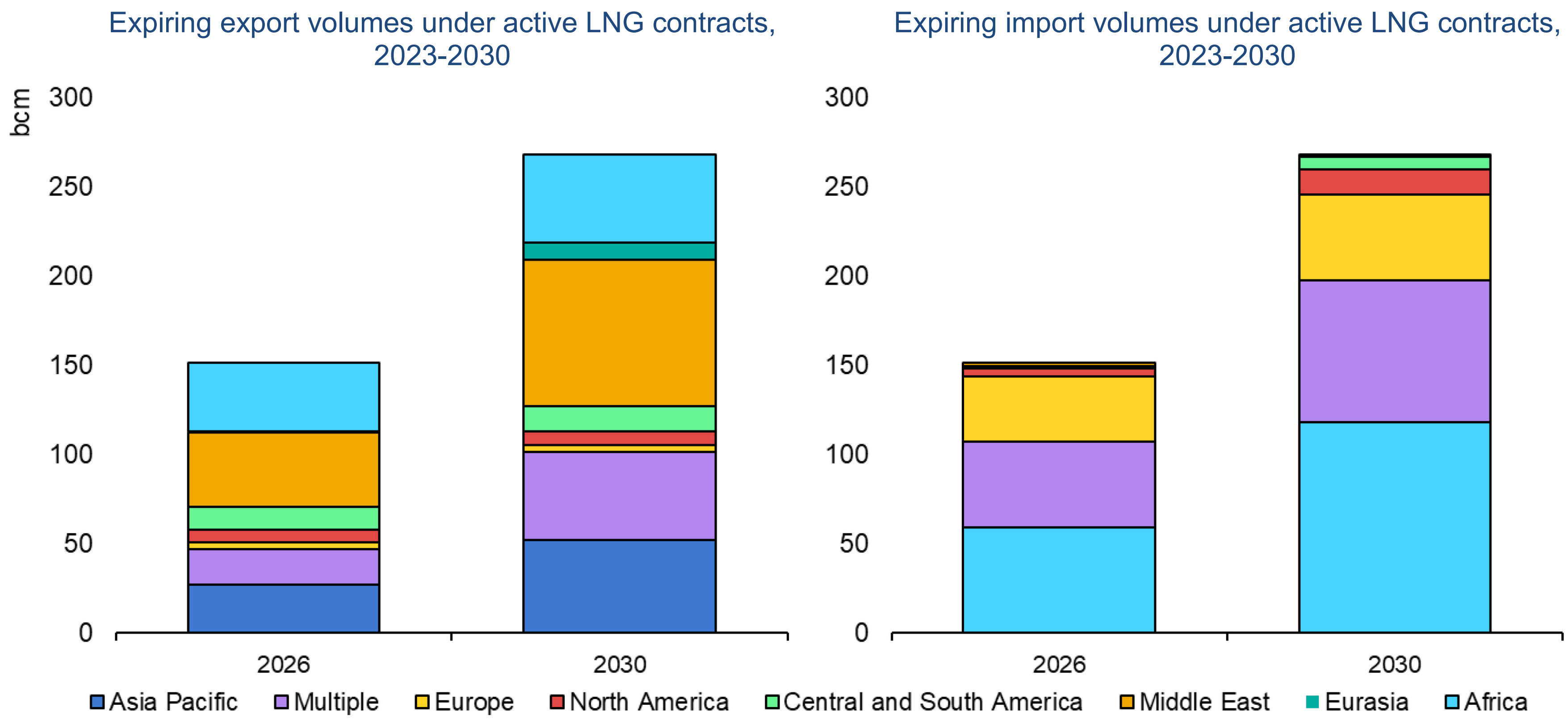
On the seller side, the Middle East and the Africa are expected to experience the greatest contract turnover in the medium term. Of the total volume of export contracts expiring by 2026, they account for 28% (over 40 bcm) and 25% (close to 40 bcm) respectively. The Asia Pacific region has around 27 bcm of contracts expiring during the same period. Contract renewals and newly signed contracts are only partially offsetting the expiry of legacy contracts. Consequently, the Middle East is expected to see its firm contracted volumes decline by 7% (or 12 bcm) between 2023 and 2026, while Africa sees a drop of 17% (or 14 bcm) over the same period. The Asia Pacific region's total active contracts are set to decline by 3% (or 4 bcm) by 2026. Contracts with multiple sources fall by 20 bcm between 2023 and 2026, but new contracts from portfolio players are exceeding the expired contract volumes to result in a net increase of 4 bcm over the 2022 level.

On the buyer side, the Asia Pacific region, which is the largest holder of contracted purchase volumes, is expected to account for almost 40% (close to 60 bcm) of expired contracts by 2026, followed by multiple destination contracts with a share of 33% (or 48 bcm) and Europe with a share of 24% (or 37 bcm). Nevertheless, new contracts (primarily with China) together with contract renewals will keep the Asia Pacific region's total active contracts slightly above their 2022 levels to the end of 2026. In contrast, Europe's total active contracts are set to shrink by 22% between 2022 and 2026.

The expiry of legacy contracts creates an opportunity for market participants to align contract terms more closely with buyers' and sellers' requirements in the years ahead, including on pricing mechanisms and contracting period.

While LNG contracting has historically been dominated by oil indexation, the adoption of more flexible contractual approaches, such as gas-to-gas indexation, hybrid formulae and hub pricing, has continued to gain ground in recent years. Based on available information, it is estimated that the share of oil-indexed LNG export contracts fell from over 71% in 2016 to 59% in 2022. This has been largely supported by the expansion of LNG export capacity in the United States, with most of the supply contracts indexed to Henry Hub. Based on the firm LNG export contracts in place, the share of gas-to-gas indexation is set to increase from 41% in 2022 to close to 45% by 2026.

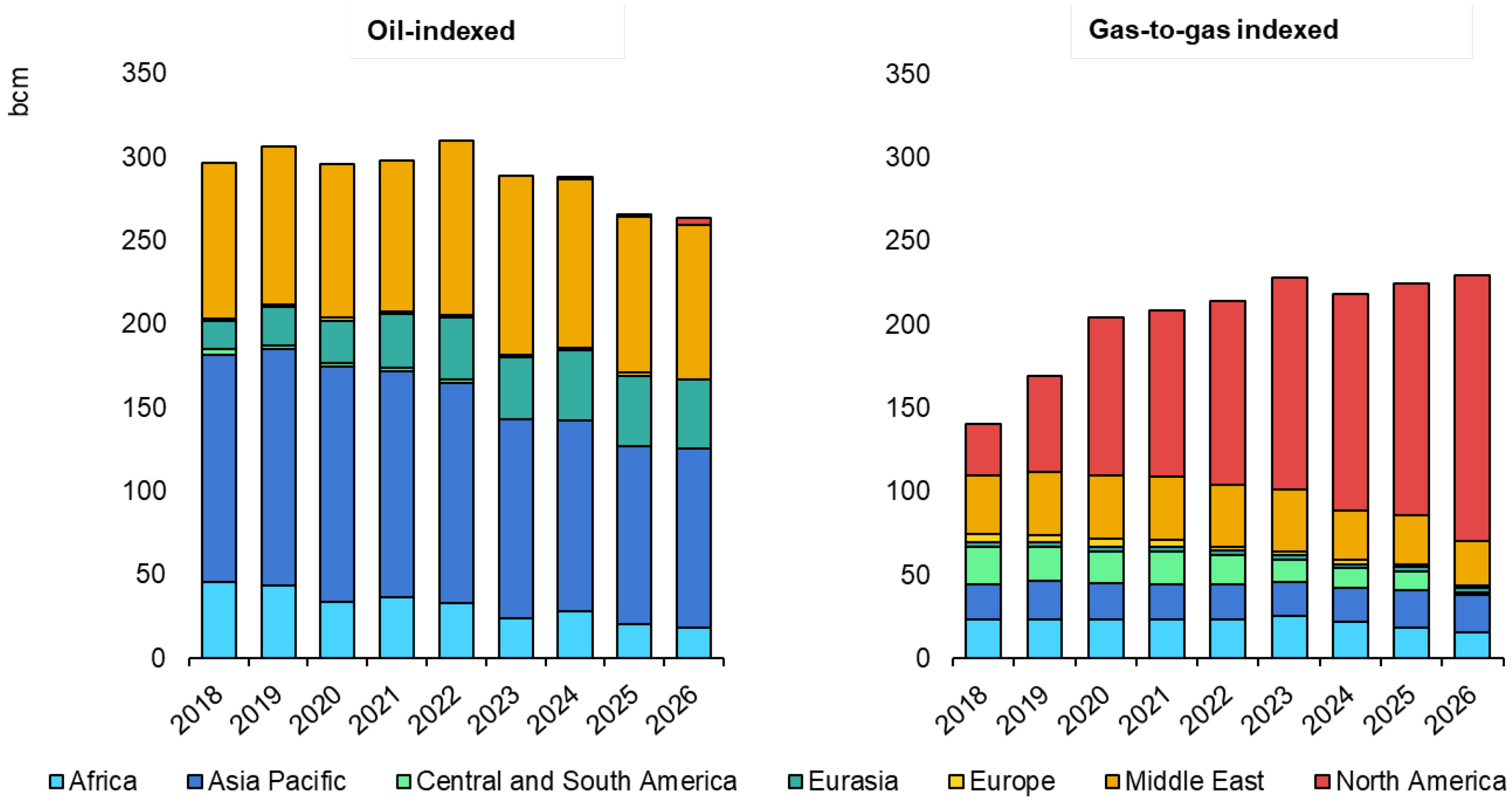
Around 150 bcm of LNG contracts are set to expire by 2026 and over 250 bcm by 2030



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

On the export side, North America is driving growth in the number of gas-to-gas indexed contracts

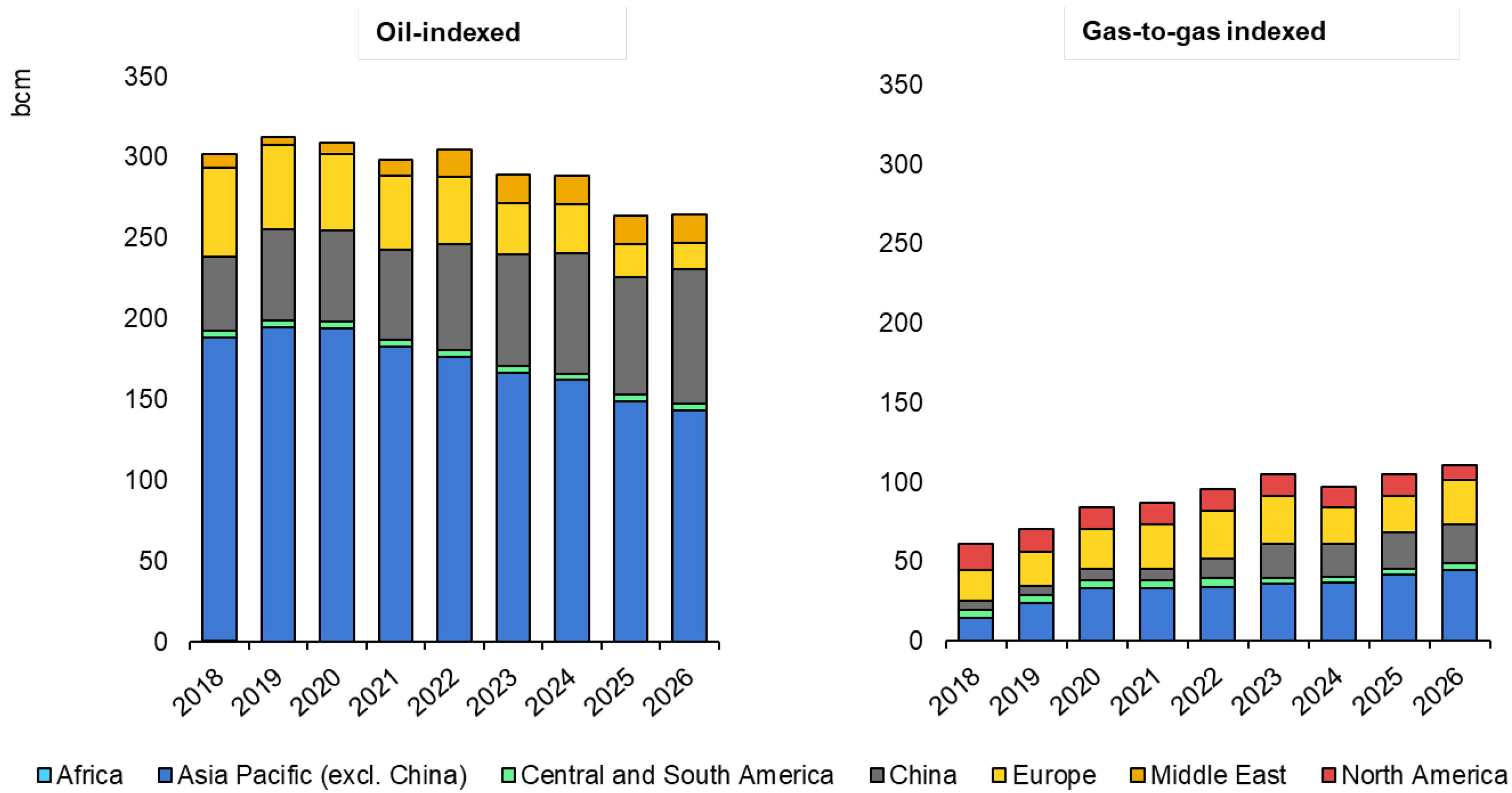
LNG export contract volumes with oil-indexed and gas-to-gas pricing, by region and country, 2018-2026



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Oil-linked pricing remains dominant in import contracts

LNG import contract volumes with oil-indexed and gas-to-gas pricing, by region and country, 2018-2026



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Spotlight on natural gas storage

The 2022 gas supply shock put natural gas storage in the spotlight

The **global energy crisis** triggered by Russia's invasion of Ukraine put the spotlight on natural gas storage and its regulation. Natural gas storage plays a key role in meeting **seasonal demand swings** and ensuring gas supply adequacy in markets with cold and temperate climates. For instance, storage withdrawals met over 40% of EU gas demand during the coldest winter days in early December 2022 and late January 2023. In addition, the **short-term deliverability** provided by fast-cycling storage sites (such as salt and rock caverns) is crucial to meet the fluctuating needs of the power sector through the year, especially in markets where coal-fired generation is being phased out and reliance on gas-fired power plants (and hence on natural gas) is increasing.

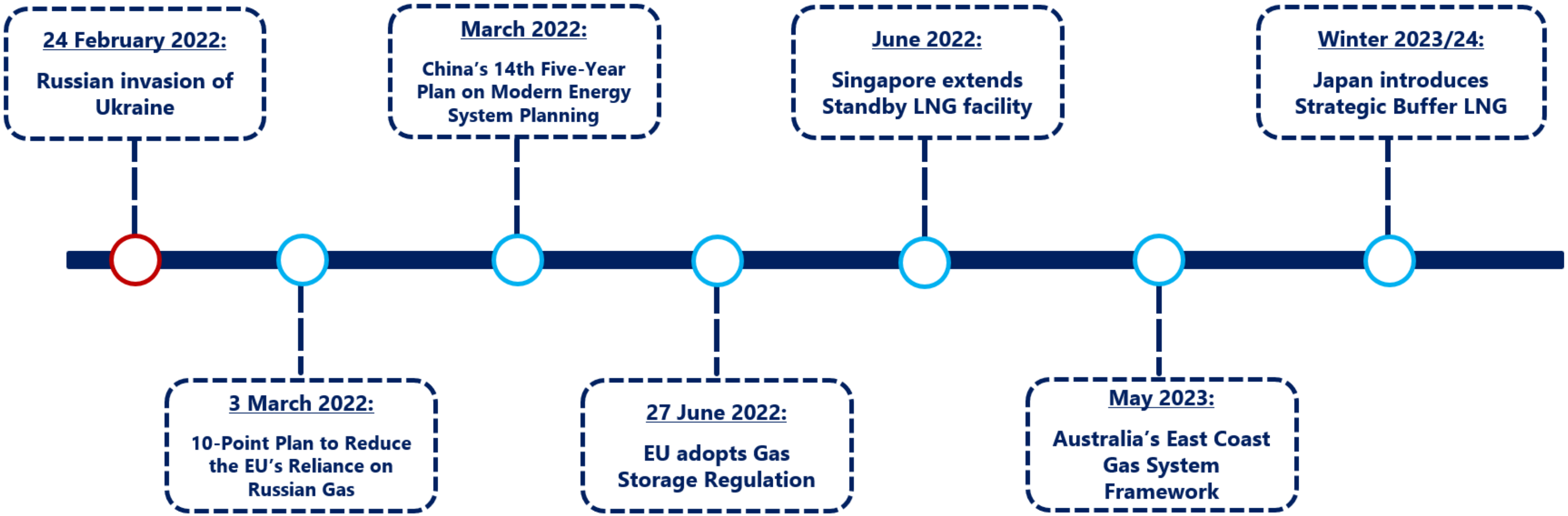
While storage sites are not the only providers of gas supply flexibility, practical experience shows that they are typically the **most reactive in instances of supply and demand shocks**. Bringing additional volumes of LNG to the market usually takes at least several days; piped imports can be ramped up more quickly, but there is usually a limit in volumetric terms. In contrast, storage sites are typically located close to demand centres and hence are readily available to meet additional demand or to make up for lost supplies. Storage can therefore provide a significant **security buffer** to the gas and wider energy system.

Since Russia's invasion of Ukraine, more stringent storage regulations have been adopted across key natural gas markets.

The **European Union** adopted a new Gas Storage Regulation at the end of June 2022 with a target storage fill level of 80% of capacity before the winter of 2022/23, and 90% ahead of all following winter periods. **Singapore** introduced a standby LNG facility at the end of 2021 and in June 2022 the Energy Market Authority extended it until 31 March 2023 to address the risk of gas supply disruptions. In **Australia** the East Coast Gas System Framework was implemented in May 2023 in response to the significant challenges experienced across east coast gas markets. In **Japan**, METI is due to launch the Strategic Buffer LNG ahead of the 2023/24 winter.

In an increasingly globalised gas market, storage regulations can have extra-regional implications. This calls for closer international dialogue and improved transparency on storage regulations. The International Energy Agency carried out a **survey** on natural gas storage and its evolving regulatory frameworks across the members of the Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security. The task force provides a platform for data and information exchange among its members to further enhance transparency on natural gas markets. Over 20 countries and entities, representing 70% of global gas storage capacity (underground and LNG storage combined), responded to the survey on natural gas storage. A summary of the survey is provided in the annex to this chapter.

Key natural gas storage policies and regulations initiated since February 2022



Global natural gas and LNG storage capacity is set to expand by 10% in the next five years

Global natural gas and LNG storage capacity in import markets is expected to expand by 10% (or 45 bcm) during the 2023-2028 period, largely supported by projects in China, Europe and Eurasia. **Underground gas storage** (UGS) capacity is set to grow by over 35 bcm, with porous reservoirs (aquifers and depleted fields) accounting for more than 75% of total UGS capacity additions. **LNG storage** capacity associated with regasification terminals is expected to increase by close to 10 bcm over the forecast period.

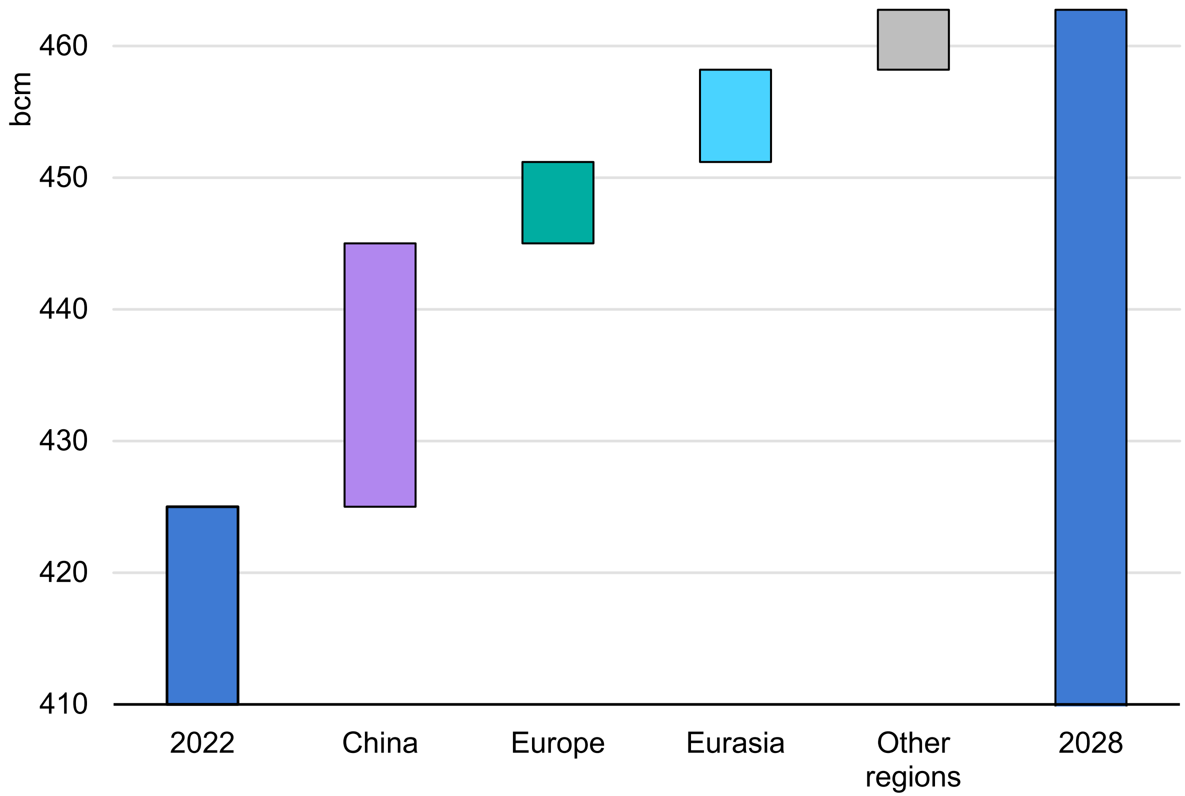
China is expected to lead gas and LNG storage development in the medium term. In March 2022 China released its 14th Five-Year Plan for a Modern Energy System, which sets a target to more than double the country's gas and LNG storage capacity to reach 55-60 bcm by 2025. At the end of 2022 China's working gas capacity was estimated to be 18 bcm, accounting for just 5% of the country's annual consumption, well below the level in mature markets. Based on projects under development, China could add 20 bcm of UGS capacity in the coming years, **accounting for more than half of the increase globally**. In addition, China has around 7 bcm of LNG storage capacity, with 5 bcm currently under construction.

Europe's UGS capacity is set to increase over the forecast period, largely driven by **Türkiye**. The Silviri storage site was expanded from 3.2 bcm to 4.6 bcm by the end of 2022 and the Tuz Gölü (salt cavern) storage facility is set to increase its working capacity from 1.2 bcm to 5.4 bcm by the end of 2023. In **Poland** the capacity of UGS Strachocina is due to increase from 0.36 bcm to 0.46 bcm from the start of the 2023/24 winter season. In addition, UGS Wierzchowice is set to be expanded from 1.3 bcm to 2.1 bcm by 2025. In **Bulgaria** the working capacity of the Chiren storage site is set to almost double from the current 0.55 bcm to 1 bcm by 2024. In **Romania** the Bilciuresti storage site will be enhanced, increasing its storage capacity from 1.31 bcm to 1.42 bcm and its daily withdrawal capacity from 14 mcm/d up to 20 mcm/d by 2027. In the **United Kingdom** the Rough gas storage facility was reopened ahead of the 2022/23 heating season with a capacity of 0.85 bcm, representing just 25% of its pre-closure capacity in 2017. The working capacity of Rough is set to increase by 0.2-0.25 bcm ahead of the 2023/24 winter season. **New FSRUs** and the reopening of the El Musel LNG terminal in Spain are set to add over 1 bcm of LNG storage capacity during 2023-2025.

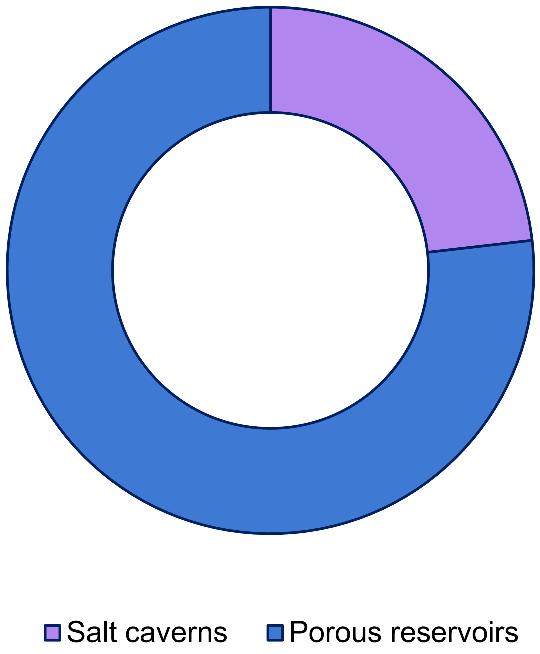
In **Eurasia** underground storage developments are driven by Russia, with the country targeting an increase in its daily withdrawal capacity from 0.84 bcm in 2022/23 to 1 bcm. Storage additions are expected to be limited in other regions, with projects being developed in **Australia**, **Brazil** and **Iran**. **LNG storage capacity additions** outside China and Europe are expected to be driven by Korea, emerging markets in Asia, and Kuwait (in association with the giant Al-Zour LNG import terminal).

China alone is expected to account for half of UGS capacity additions by 2028

Expected UGS capacity additions in key gas markets, 2022-2028



Expected UGS capacity additions by type, 2022-2028



Sources: IEA analysis based on various company and news reports.

The European Union and its member states introduced mandatory fill targets in 2022

The European Union has just over 100 bcm of UGS capacity, accounting for 25% of the bloc's natural gas consumption in 2021. In addition, it has approximately 5 bcm of LNG storage capacity. Storage plays a key role in meeting EU member states' **seasonal swing in gas demand** and ensuring gas supply security during the winter season.

In the aftermath of Russia's invasion of Ukraine, the **new EU Gas Storage Regulation** was urgently developed and entered into force on 1 July 2022. The regulation provided that UGS on member states' territory must be filled to at least 80% capacity before the winter of 2022/23 and to 90% before subsequent winter periods. The regulation turned out to be key in achieving a 95% fill level by 1 November 2022.

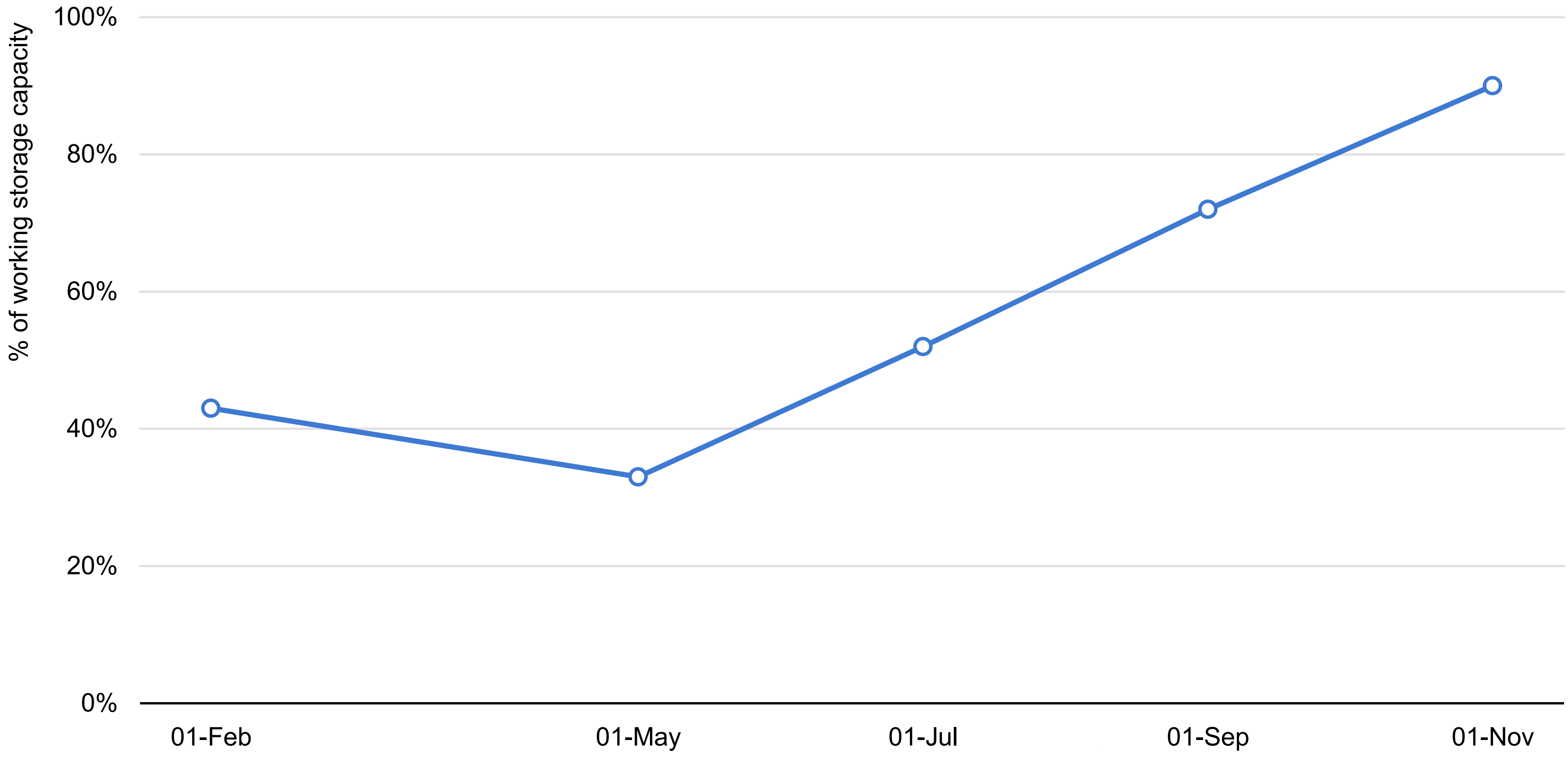
Each year as of 2023 member states with UGS facilities submit to the European Commission a so-called "filling trajectory" with **intermediate targets**. The Commission then analyses the situation and adopts an Implementing Regulation laying down the intermediate storage filing targets that member states need **to meet in order to reach the 90% storage target**. The filling trajectories are subject to a margin of five percentage points and are monitored by the national authorities, while member states are free to set a higher filling target. If there is substantial and sustained deviation from the filling trajectory or from the filling target, the Commission can take effective measures to avoid security of gas supply problems. The regulation allows member states to partially meet the storage targets by **counting stocks of LNG** or alternative fuels. In member states with very large storage capacity compared to their domestic gas consumption, the filling obligation for UGS stocks is limited to a volume corresponding to 35% of the average annual gas consumption in that member state over the past five years. Member states that do **not have storage facilities on their territory** should store 15% of their annual domestic gas consumption in stocks located in other member states and thus ensure they have access to them. This mechanism strengthens the security of their gas supply while sharing the financial burden.

The regulation also provides for **compulsory certification** of all UGS site operators by the authorities of the member states concerned. The aim of this certification is to avoid the potential risk of external influence on critical storage infrastructure, which could jeopardise the security of the European Union's energy supply and other essential security interests. A fast-track certification procedure is applied to storage sites with a capacity above 3.5 TWh that were filled at levels below the EU average in 2020 and 2021.

Storage capacity filling obligations will come to an end on 31 December 2025, but operator certification obligations will continue to apply beyond that date.

The EU's new storage regulation sets a UGS fill target level of 90% by 1 November

Indicative filling trajectory targets in the European Union after 2022



Source: IEA analysis based on European Commission (2022), Document 52022PC0135.

Japan is set to introduce the Strategic Buffer LNG ahead of the 2023/24 winter season

Japan has **no large-scale UGS facilities** due to the particular topography of the country. The country has approximately 190 **LNG storage** tanks, with a combined nominal tank capacity of around 9.6 million tonnes (or 13 bcm). It should be noted, however, that the entire capacity of LNG tanks cannot be used for storage due to physical constraints and other factors. Hence, the storage capacity available to the market is somewhat lower than the declared nameplate capacity. Power and gas utilities, which are the main LNG users, hold their own commercial inventories equal to approximately 10 days to 2 weeks of demand.

Considering that LNG can be stored only for a limited time (due to the ageing of LNG),[3] Japan follows a strategy of securing “reserves” and “buffers” **not only through physical storage**, but also through a number of other mechanisms, relying on the flexibility options available along the LNG value chain.

In response to the natural gas crisis unfolding in 2022, **Japan reinforced its policies relating to gas supply security**. In this context, a public–private liaison conference was held last year to discuss LNG procurement, develop a framework for interoperator flexibility, and require LNG users to systematically and steadily secure inventories, especially during the winter months when demand is high. In addition, regular monitoring of LNG inventory levels held by power utilities is conducted in accordance with guidelines prepared by the government.

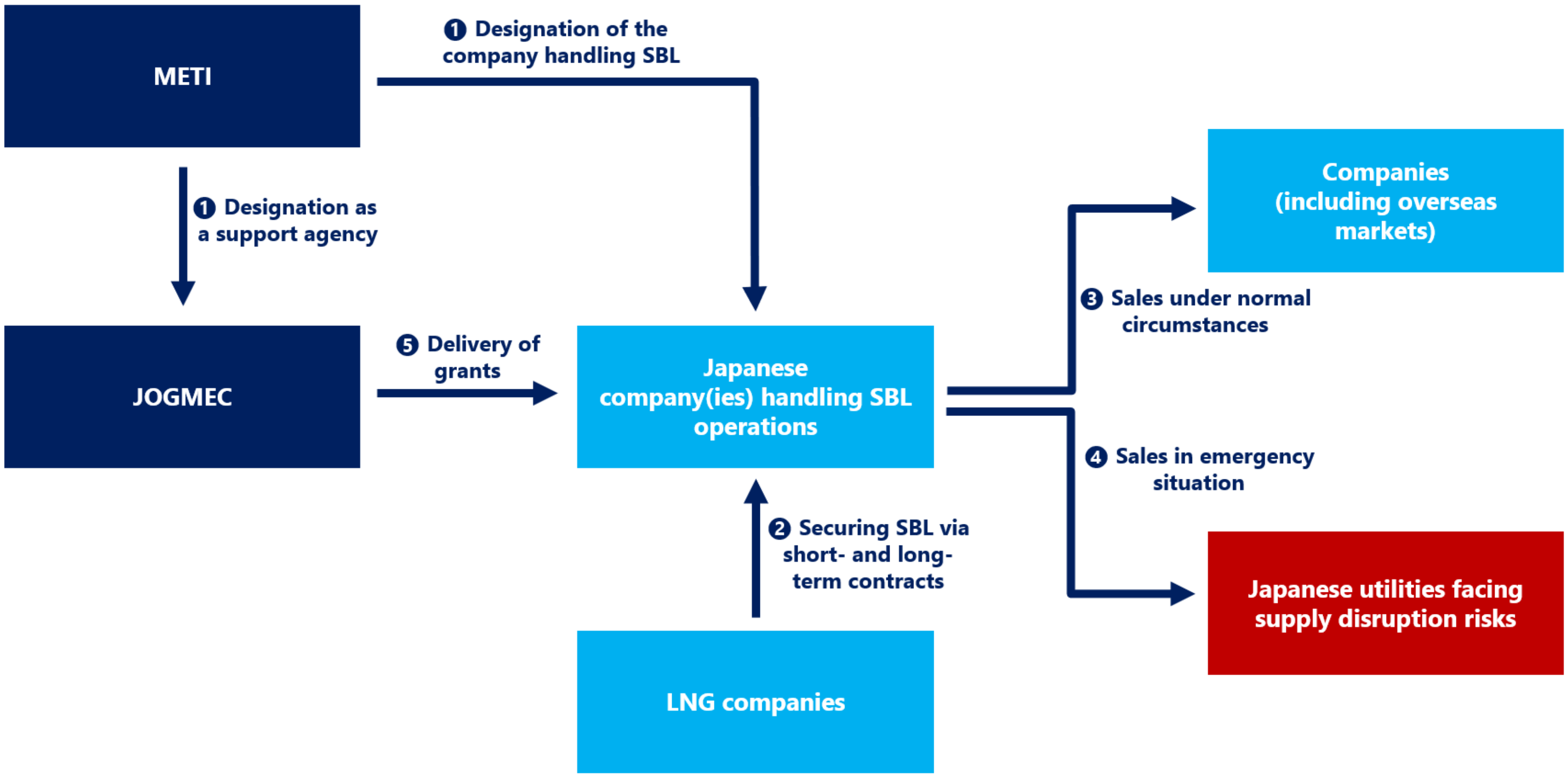
Japan has designated natural gas as a critical product that requires a stable supply under the Economic Security Promotion Act that was enacted in 2022. Under this new law, METI is to launch the **Strategic Buffer LNG** (SBL) ahead of the 2023/24 winter season. Under this system, METI will designate private operators with high LNG procurement capacity as companies authorised to handle SBL operations. In the event of a contingency that would hinder LNG supply, the government will instruct the designated companies to sell their LNG cargoes to utilities in Japan facing the risk of supply disruption. The government will compensate the certified operator for any losses caused by the instructed trade.

Furthermore, Japan has secured substantial LNG reserves by using **public finance to acquire interests in overseas projects**. Japan considers that the use of public finance to acquire LNG concessions and secure LNG under long-term contracts with flexible destinations can be a beneficial mechanism for countries that, like Japan, are not rich in natural resources, have low energy self-sufficiency rates and do not have oil majors.

[3] Due to the boil-off of lighter molecules (methane and nitrogen), the composition of stored LNG changes over time. The phenomenon is referred as the ageing (or weathering) of LNG.

The Strategic Buffer LNG provides a new LNG security framework with close co-operation from the private sector

Simplified scheme of the functioning of Japan's SBL



Note: JOGMEC = Japan Oil, Gas and Metals National Corporation.

Source: IEA analysis based on METI.

Australia implemented the East Coast Gas System Framework in May 2023

Australia has approximately 280 PJ (or 7.5 bcm) of natural gas storage. Over 95% of the country's storage capacity is in UGS sites, with over 70% of it located in the east coast market.

The country's storage capacity is expected to increase in the coming years. The Iona UGS site operator, Lochard Energy, has informed the Australian Energy Market Operator (AEMO) of a planned upgrade to Iona's storage capacity prior to the 2024 southern winter. This upgrade (known as the Heytesbury Underground Storage Project) will increase the working capacity of the **Iona storage site** from 23.5 PJ (0.6 bcm) to 28 PJ (0.7 bcm) and its withdrawal capacity from 520 TJ/d (13 mcm/d) to 570 TJ/d (14 mcm/d). In addition, the **Golden Beach Gas Production and Storage project** (offshore site east of Melbourne) is currently being considered. Subject to FID, the project is aiming to supply gas into the domestic market from H1 2025. The storage phase of the project is planned to commence in 2026, with a capacity of 12.5 PJ (0.3 bcm) of gas and with an initial withdrawal capacity of 250 TJ/d (6 mcm/d).

Considering the **significant challenges experienced across Australia's east coast gas markets** during the 2022 southern hemisphere winter, Australian federal, state and territory energy ministers agreed to take a range of actions aimed at supporting a more secure, resilient and flexible gas market on the east coast. They include:

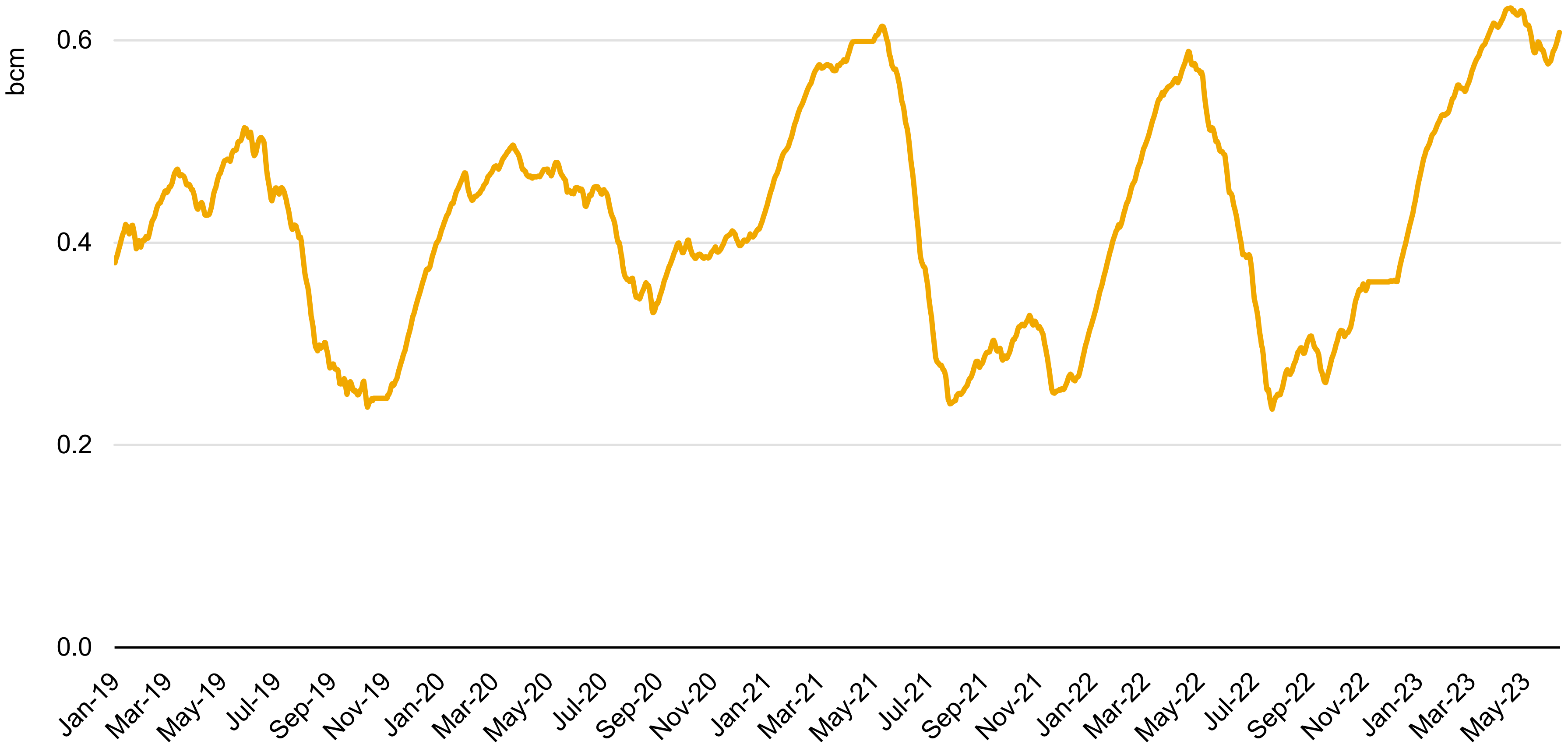
- The **East Coast Gas System Framework**, extending AEMO's power to better manage gas supply adequacy and reliability risks ahead of the 2023 southern hemisphere winter.
- An agreement to examine options to implement a **third-party access regime** for storage infrastructure.

The **East Coast Gas System Framework**, implemented in May 2023, provides AEMO with the power to exercise direction or trading functions to manage supply adequacy and reliability risks. The exercise of these powers may include, for example, directing a storage service provider to inject or withdraw gas from a storage facility, or for AEMO to purchase services provided by a storage provider. These powers are intended to be deployed as a last resort and AEMO's ability to exercise these powers is constrained in a number of ways – for example, prior to issuing a direction, AEMO must generally provide industry with time to mitigate risk.

In addition, under new rules implemented in December 2022, AEMO is required to contract any uncontracted capacity in the **Dandenong LNG storage facility** (0.015 bcm) ahead of winter through the period 2023-2025.

Storage is a key contributor to supply flexibility during the southern hemisphere winter

Inventory levels at the Iona UGS facility, 2019-2023



Source: IEA analysis based on AEMO (2023), Gas Bulletin Board.

Annex: Natural gas storage capacity and regulatory frameworks in selected markets*

Country	Total storage capacity (bcm)	Strategic storage (bcm)	New capacity (bcm)	Regulatory framework
Austria	9 bcm (UGS)	1.8 bcm (UGS)	-	System operators are required to connect all UGS facilities within the country to the Austrian gas network and offer gas storage capacity to the market, with non-compliance resulting in the loss of the right to operate the facility. The legal basis for the Austrian strategic gas reserve (SGR) was implemented in April 2022. The entity in charge of the procurement of the SGR is the gas distribution area manager. The purchase (two tenders in 2022) was financed from the federal budget. The SGR can only be released by ordinance of the energy minister to tackle an imminent or existing disruption of energy supply or in case of an obligation to provide solidarity pursuant to Art. 13 of Regulation (EU) 2017/1938.
Australia	7 bcm (UGS) 0.06 bcm (LNG)		0.11 bcm (UGS by 2024)	The East Coast Gas System Framework, implemented in May 2023, gives AEMO the authority to direct gas storage providers and purchase their services to ensure supply adequacy. For further details please refer to the Australia section of this chapter.
Belgium	0.7 bcm (UGS) 0.3 bcm (LNG)	-	-	Gas storage regulation is based on non-discriminatory third-party access, transparency and a regulated tariff. In the course of 2022, regulated documents were amended to account for filling targets and trajectories, in line with the provisions of security of supply regulation (EU) 2017/1938. Belgian gas law modification to allow sales below the regulated tariff was agreed upon before the start of the 2022 gas crisis.
Canada	27 bcm (UGS) 0.32 bcm (LNG)	-	-	Natural gas storage is regulated by provincial governments, which have largely chosen to deregulate their gas markets to enable gas market participants to acquire, sell and store gas in ways that best suit their commercial needs. Canada's federal government does not regulate natural gas storage. There are no government support mechanisms to ensure natural gas storage fill levels in Canada. Canada's integrated and liquid gas markets have served to adequately fill gas storage before each winter heating season.
Czech Republic	4 bcm (UGS)	0.23 bcm (UGS)	-	Booking of storage capacity is conducted through electronic auctions, with operators publishing regular auctions on their electronic booking platforms. Since 2022 the Czech Republic has adopted new regulations and rules, i.e. removal of transmission tariffs for entry/exit at interconnection points to gas storage sites, and an obligation on gas traders to use booked gas storage capacity (use-it-or-lose-it rule) accompanied by the right of a gas trader to withdraw from storage contracts in force within two months of the implementation of the rule. The country also introduced new reporting obligations for unused storage capacity and compulsory gas withdrawal during extraordinary gas emergencies, while the core of the gas storage regulation remains unchanged. In 2022 the government subsidised gas stocks through premiums paid to gas traders for storing gas in their

Country	Total storage capacity (bcm)	Strategic storage (bcm)	New capacity (bcm)	Regulatory framework
				facilities, and transmission tariff discounts at interconnection points to gas storage are still in effect in 2023. No additional support mechanisms were introduced.
Denmark	0.9 bcm (UGS)	-	-	The Danish gas network operator Energinet is in charge of buying emergency gas and meeting filling requirements. It buys emergency gas to ensure supplies to customers in case of a declaration of an emergency. Furthermore, Energinet buys filling requirements from actors who have bought capacity in Danish storage facilities. Under this mechanism, Energinet purchases a service from commercial gas companies to hold a certain amount in storage. Energinet together with the authorities can decide when to release this gas from storage (when encountering severe consumer supply issues).
Finland	0.14 bcm (LNG)	-	-	The government imposes stockholding obligations on companies. Companies must store annually by 1 April the amount of natural gas or LNG that corresponds to one-quarter of the amount of their usage, retailing or reselling of natural gas or LNG during the previous calendar year. As part of the implementation of the EU Gas Storage Regulation, the legislation on compulsory storage was temporarily amended. During the winters of 2022/23-2024/25, companies that 1) use natural gas from a usage point connected to transmission network; or 2) retail natural gas to end users via the transmission network, are obliged to store gas so that the requirements of the regulation are met at a national level.
France	12 bcm (UGS) 0.75 bcm (LNG)	-	-	In 2018 the government implemented a regulation on essential UGS facilities to enable the build-up of gas stocks before the beginning of winter. Essential storage sites are regulated by the French energy regulatory agency (CRE). Essential storage capacity is sold to gas suppliers through an auction system in which all gas suppliers are allowed to participate. The cost of essential gas storage facilities are partially covered by transmission tariffs if auction revenues are insufficient. A new mechanism was introduced in 2022 to secure the filling of essential storage sites, even in the event of the collapse of a major gas supplier. The authorities define a minimal filling trajectory. In the case that storage fill lags the defined minimal filling trajectory during the filling season, storage operators are responsible for buying gas to constitute the missing stocks. The associated costs are covered by the government budget. This new mechanism was not activated in 2022.
Germany	22.5 bcm (UGS) 0.27 bcm (LNG)	-	2.4 bcm (UGS with uncertain timeline) 0.3 bcm (LNG by 2024)	Since 2022 the German Energy Act has set mandatory storage level requirements (90% by 1 Nov). Strategic storage-based options and Trading Hub Europe ensure the market-based filling of storage facilities. The government stimulates the market-based filling of storage facilities by tendering strategic storage-based options. Furthermore, storage capacity is taken from non-compliant storage users (that do not fill their capacity as required) and the injection of gas into this storage is ensure by the market area manager Trading Hub Europe.

Country	Total storage capacity (bcm)	Strategic storage (bcm)	New capacity (bcm)	Regulatory framework
Hungary	6.5 bcm (UGS)	1.9 bcm	-	The Act on Gas Supply sets an obligation on wholesale gas suppliers responsible for the supply of residential consumers to store a certain amount of their customers' consumption. For instances of gas supply disruption, there is also a regulation requiring the establishment, maintenance and utilisation of strategic gas stocks, which are held by a Central Stockholding Entity (HUSA). UGS on Hungary's territory must be filled to at least 80% of its capacity before the winter of 2022/23 and to 90% before the following winter periods, with specific intermediate targets for 2022. The filling obligation for underground stocks is limited to a volume corresponding to 35% of the average annual gas consumption over the last five years (about 3.1 bcm).
Italy	17.5 bcm (UGS) 0.36 bcm (LNG)	4.2 bcm (UGS)	0.2 bcm (LNG) (by 2024)	UGS operators' revenues are regulated by the National Regulatory Authority for Energy (ARERA) and the capacity allocation mechanism is decided by the Ministry of Environment and Energy Security, which issues a decree every year. Third-party access is allowed and each operator has to refer to the Storage Code (supervised by ARERA), which regulates all storage activities. In 2022 the government introduced temporary measures to guarantee 90% inventory levels by the start of the 2022/23 heating season. This included "contracts for difference" and introduced the designation of a "last resort storage filler" (GSE).
Japan	< 13 bcm (LNG)	-	-	Japan has designated natural gas as a critical product that requires a stable supply under the Economic Security Promotion Act. Under this new law the Strategic Buffer LNG will be launched ahead of the 2023/24 winter. For further details please refer to the Japan section of this chapter.
Korea	7.8 bcm (LNG)	-	2.5 bcm (LNG)	Businesses importing LNG for self-consumption are required to possess stocks corresponding to 30 days of planned natural gas consumption, while LNG wholesalers are required to possess a stockpile of LNG based on the average LNG consumption of the corresponding seasons in the two previous years, equivalent to nine days of consumption. No changes have been introduced since the 2022 gas crisis.
Netherlands	13 bcm (UGS) 0.4 bcm (LNG)	-	-	The regime for negotiated third-party access is implemented through the Dutch Gas Act. Measures regarding safe operation of storage sites and permitting for gas storage sites are implemented through the Dutch Mining Act. A support scheme compensates, if necessary, any negative summer–winter spread. No subsidy had to be paid in 2022. The state-owned company Energie Beheer Nederland (EBN) has the task of filling the gas storage site at Bergermeer with a certain amount of gas in the instance that this is not done by market participants.
New Zealand	0.2 bcm (UGS)	-	-	Gas storage regulation is not separated from the regulation of other subsurface and production assets. Gas storage is based on commercial arrangements between gas industry participants.

Country	Total storage capacity (bcm)	Strategic storage (bcm)	New capacity (bcm)	Regulatory framework
Poland	3.3 bcm (UGS) 0.18 bcm (LNG)		0.1 bcm (UGS by 2024) 0.1 bcm (LNG by 2024) 0.8 bcm (UGS by 2025)	Mandatory stocks are maintained by the Government Agency for Strategic Reserves, by entities trading natural gas with foreign countries and entities importing natural gas into Poland for their own needs. During the declaration of a state of emergency, the gas system operator, in co-operation with the entities obliged to maintain mandatory stocks, are required to take measures to ensure the proper functioning of the gas system. The transmission system operator releases mandatory stocks in the quantities necessary to balance the gas system. The volume of the mandatory stock is 1.34 bcm. In addition, the transmission system operator purchases balancing gas stocks, which are stored in UGS facilities. The reserves held for storage purposes are not to be used for system balancing purpose in non-emergency situations.
Portugal	0.35 bcm (UGS) 0.23 bcm (LNG)	-	0.05 bcm (UGS by 2028) 0.05 bcm (UGS by 2029)	Decree-Law No. 62/2020 of 28 August 2020 established the organisation and operation of the national gas system. It places the obligation on suppliers in the market regime and last-resort suppliers to maintain security reserves to guarantee supply to their customers. Ministerial Order No. 59/2022 of 28 January 2022 defines the minimum security reserves of all non-interruptible consumption. It establishes that these reserves must correspond to 45 days of average annual consumption of protected customers and 16 days of consumption equivalent to the maximum capacity of non-interruptible CCGT. It also establishes the obligation to create and maintain an additional reserve during the period from 1 October to 31 March of the following year (maximum 0.06 bcm).
Spain	3.1 bcm (UGS) 1.85 (LNG)		0.17 bcm (LNG by 2023)	All suppliers with natural gas end users must maintain a certain level of security stocks in UGS, proportional to the amount of natural gas each supplier sells to its respective end users, and expressed in equivalent days of demand. Each supplier must maintain a total of 27.5 days of equivalent demand split between: 1) 10 days of strategic stocks; 2) 10 days of minimum operational stock of the system; and 3) 7.5 days of minimum operational stock of the user. In addition, from 1 November to 31 March the "Winter Action Plan" applies, which requires shippers to increase their LNG storage to reach staggered filling milestones with a maximum on 1 January reaching a target of 5.5 days of their contracted capacity at the entry points to the transmission system. Suppliers who are obliged to maintain minimum security stocks do not have to bid in the auction for the sale of storage capacity, but rather it is assigned to them directly. Therefore, they only have to pay the storage toll. From 1 April 2022 to 31 March 2024 contracted storage capacity in excess of 20 days of capacity booked at the entry points to the transmission system will not pay the storage fee (only injection and withdrawal tariffs). The public budget will transfer EUR 23 million/year to the gas system as compensation.

Country	Total storage capacity (bcm)	Strategic storage (bcm)	New capacity (bcm)	Regulatory framework
Sweden	0.01 bcm (UGS) 0.03 bcm (LNG)			There is no strategic gas storage or regulatory framework apart from EU legislation on securing supply to protected customers. There will from June 2023 be a requirement that the gas operators responsible for system balancing also take on responsibility for ensuring sufficient gas storage filling, should the gas transmission system operator demand it. The gas system operators responsible for balancing should be able to have their costs for obligatory filling reimbursed through network tariffs.
Switzerland	-	-	-	The gas sector must guarantee that 15% of annual average Swiss gas consumption is stored in available gas storage (in the European Union) by 1 November 2023.
Türkiye	5.8 bcm (UGS) 0.4 bcm (LNG)	-	4.8 bcm (UGS by 2023)	Under the Natural Gas Market Law, the Energy Market Regulatory Authority (EMRA) determines the level of gas that importers are required to store relative to the amount of their annually imported gas, up to 20% of the total.
United Kingdom	2.3 bcm (UGS) 0.7 bcm (LNG)	-	-	The energy regulator in Great Britain, Ofgem, is responsible for ensuring compliance with the requirements of the Third Internal Energy Package, as transposed into domestic legislation, relating to gas storage. This includes ensuring compliance with third-party access arrangements and unbundling. There is no strategic gas storage in the United Kingdom nor any government support mechanisms available for gas storage filling.
United States	130 bcm (UGS) 2.5 bcm (LNG)*	-	-	The US government neither holds strategic reserves of natural gas nor places a minimum natural gas stockholding obligation on industry.

* The information provided in this annex is based on the survey carried out by the International Energy Agency among members of the Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security.

System integration of low-emission gases

Low-emission gases play a key role in the pathways to net zero emissions by 2050

The decarbonisation of gas and the broader energy system will require the deployment and scale-up of low-emission gases. Low-emission gas streams include biomethane, low-emission hydrogen, e-methane, and natural gas subject to carbon capture, utilisation and storage (CCUS) both at the production and at the end-use stage. In recognition of the growing interest of member, association and non-member countries in low-carbon gases, the IEA Secretariat developed a **Low-Emission Gases Work Programme** (LEGWP) to provide regular market analysis, including on the evolving network integration and supply flexibility of low-emission gases.

As highlighted in the IEA's Global Gas Security Review 2021 edition, the large-scale integration of low-carbon gases is expected to **transform existing gas systems in a number of ways:**

- **Gas supply chains become more complex** and increasingly decentralised, necessitating intimate integration between distribution and transmission networks.
- **Gas quality displays greater diversity and variability**, raising issues related to the interoperability of adjacent gas systems and the integration of methane and hydrogen networks.
- **Gas supply flexibility is altered** by the operational characteristics of low-carbon production facilities, the availability of storage options and more complex linepack management.

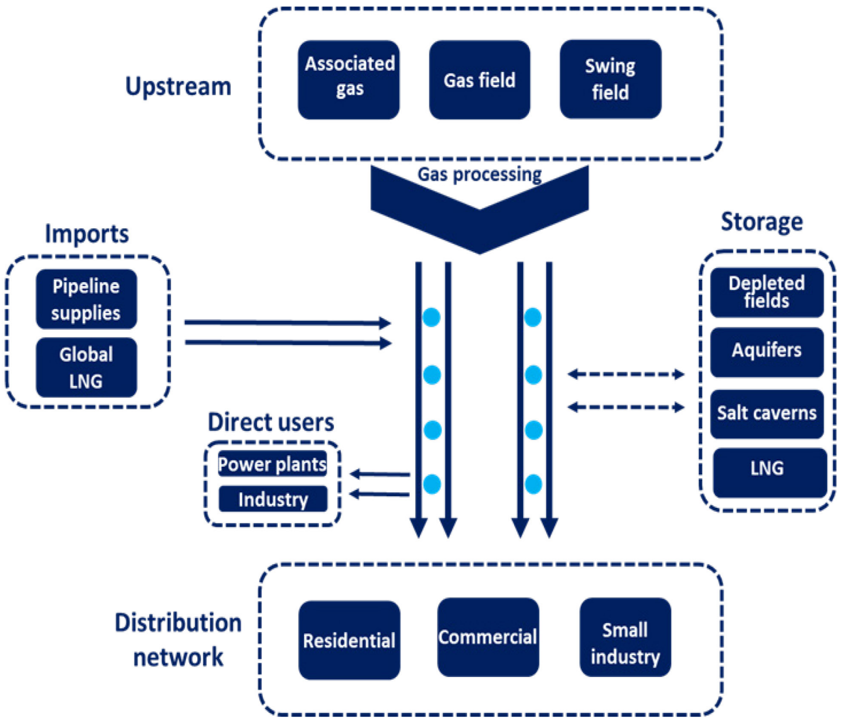
Existing natural gas infrastructure can play a key role in enabling the more rapid and cost-effective deployment of low-emission gases while facilitating their integration into the broader energy system.

In this section we focus on two key dimensions of the future integration and application of low-emission gases:

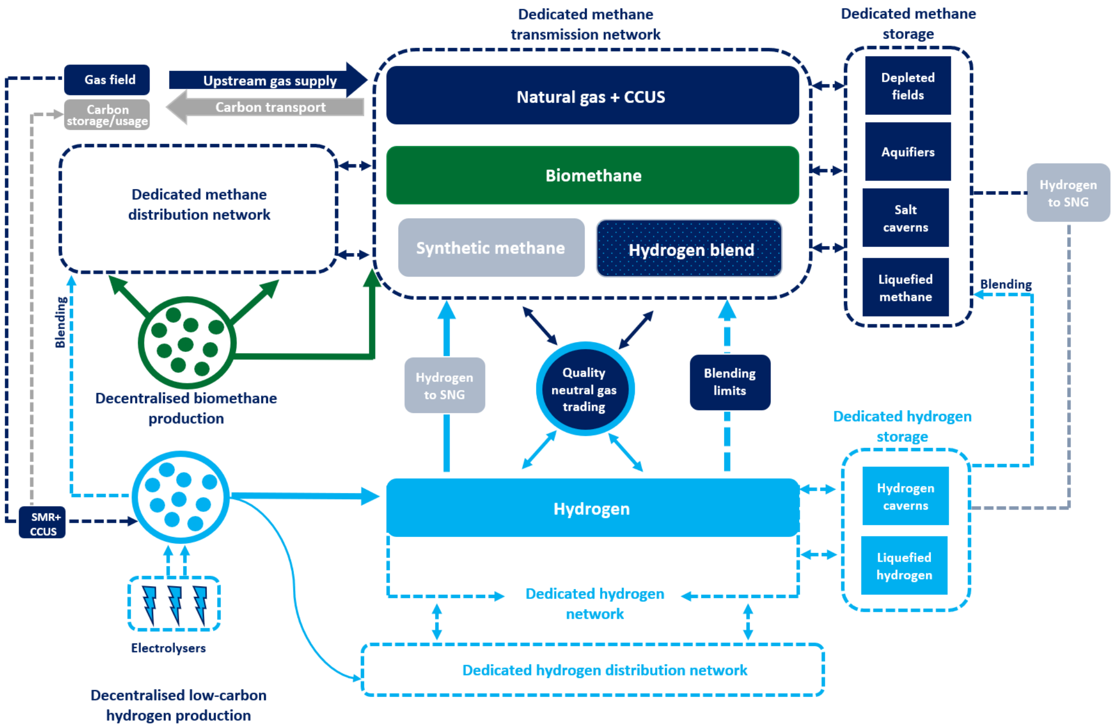
- **Large-scale storage**: low-emission gas production facilities (biogas upgraders, steam methane reformer [SMR] plants and electrolysers) have either flat or volatile supply patterns – especially when produced from variable renewables. This limited operational flexibility necessitates the development and use of large-scale storage facilities to enable low-emission gases to respond to seasonal demand swings and short-term supply–demand fluctuations.
- **Maritime transport**: international maritime transport is considered to be a hard-to-abate sector. Liquefied low-emission gases are widely acknowledged as likely to play a key role in the decarbonisation of the shipping sector in the medium to long term. In addition, the existing LNG carrier fleet could be repurposed to facilitate the transport of certain liquefied low-emission gases.

Low-emission gases naturally lead to a more complex gas system

Simplified scheme of existing natural gas value chain



Simplified scheme of low-emission gas value chains



Notes: SMR = steam methane reformer; SNG = synthetic natural gas or synthetic methane.

Underground storage plays a critical role in unleashing biomethane's full potential

Biomethane production plants display limited daily variability and seasonality as facilities typically operate close to nameplate capacity through the year. The rather minor contribution of biomethane plants to meeting the variability in overall gas demand is well demonstrated in Denmark. While biomethane accounted for 33% of total gas demand in 2022, biomethane plants alone contributed just 9% of the seasonal demand swing between summer 2022 and winter 2022/23. Moreover, the cumulative variability of daily biomethane production was less than 6% of the absolute cumulative daily variability of gas demand in 2022, indicating a proportionally lower contribution to the overall requirement for gas supply flexibility.

The production flexibility of biomethane plants could be enhanced in two ways: (1) **incentivise investment in "buffer" capacity**, although the relatively complex and rigid supply chains of raw biogas could be a limitation; and (2) provide biomethane plants with **greater access to underground storage sites**.

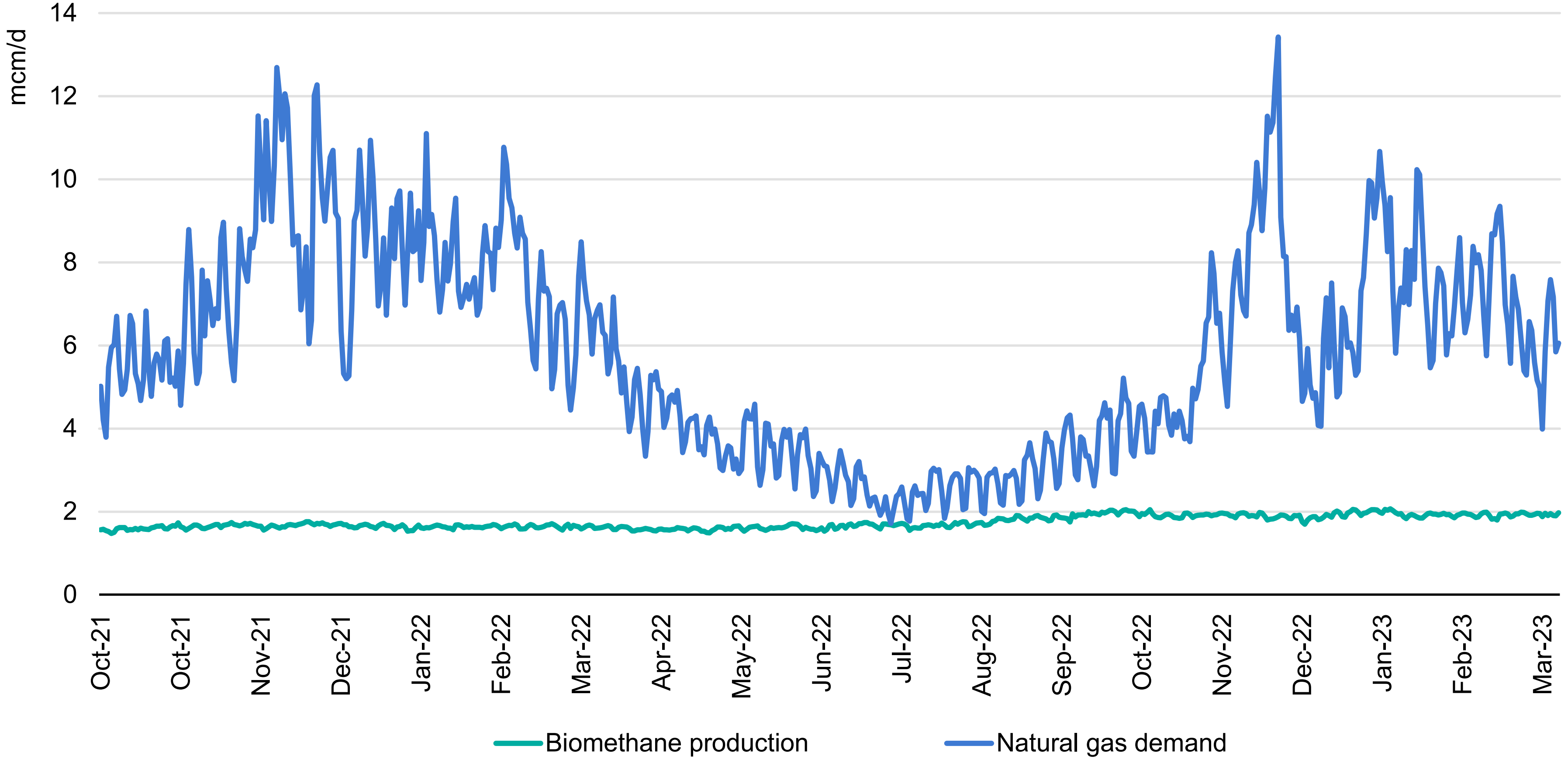
Biomethane is well-suited to being stored in underground facilities due to its physical and chemical properties being almost identical to natural gas. Nevertheless, the access of biomethane plants to underground storage sites might be limited by: (1) insufficient integration between the gas transmission and distribution systems; and (2) the oxygen content of biomethane.

In Europe almost **60% of biomethane plants are connected to the distribution grid**, while fewer than 20% feed directly into the transmission system. In contrast, underground storage facilities are typically connected to the high-pressure transmission system. **Reverse flows** from the distribution grid to the transmission network would allow low-carbon gases to access underground storage facilities. **Bidirectional compressor stations** are key to enabling closer integration between distribution and transmission systems. Currently Europe has 10 operational bidirectional compressor station, with over 20 more under construction.

In contrast with natural gas, **biomethane typically contains oxygen** (around 3 000 ppm), mainly as a consequence of the desulphurisation process during its production. Initial research indicates that this oxygen content could potentially negatively impact the effectiveness of storage in porous reservoirs and eventually lead to the disruption of storage operations (due to sulphur precipitation). Given the unique features of each underground storage site, the permissible oxygen content needs to be assessed on a case-by-case basis. The Danish Gas Technology Centre found limited corrosion risk in salt caverns, while noting the risk of microbial contamination and higher corrosion risk in aquifers. **Oxygen removal units** – at the biogas upgrader, on the gas grid or at the entrance to the storage facility – could improve the acceptance of biomethane at underground storage sites.

Biomethane production plants display limited short-term variability and seasonality

Daily natural gas demand and biomethane production in Denmark, October 2021-March 2023



Source: IEA analysis based on Energinet (2023), Energi Data Service.

The first open seasons for hydrogen storage were launched in Europe in 2023

Underground storage will be crucial for hydrogen to reach its full potential as an energy carrier and respond to the evolving flexibility requirements of a more complex energy system. Considering that low-emission hydrogen production facilities (SMR plants or electrolysers) have either flat or volatile supply patterns, storage will be critical in responding to the short-term variability of both hydrogen supply and demand. In contrast with biomethane, pure low-emission hydrogen storage in underground storage facilities will require either the repurposing of current assets or the development of new facilities suited to serving hydrogen.

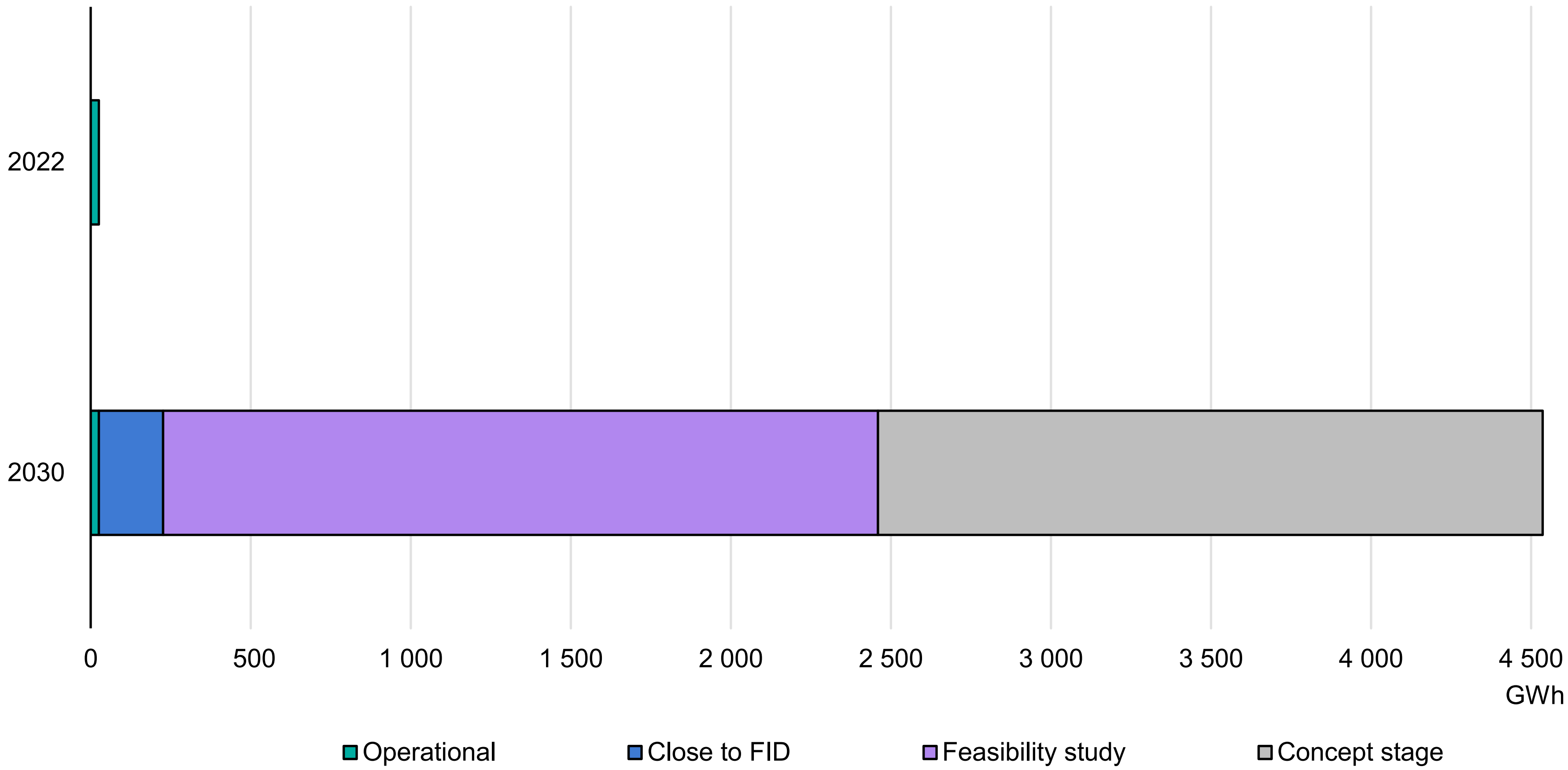
Hydrogen storage in salt caverns is a proven technology and has been used by the petrochemical industry since the early 1970s. The United Kingdom has one operational hydrogen salt cavern facility with a capacity of 25 GWh, commissioned in 1972 on Teesside. Based on public project announcements, over 4.5 TWh of underground hydrogen storage capacity could be developed in Europe by 2030 (translating into around 1.5 bcm in volumetric terms). However, none of these projects has yet reached FID, with most of them either at the conceptual phase or undergoing feasibility studies. Considering the long lead times of these projects, immediate action needs to be taken on hydrogen storage, requiring a concentrated effort among key stakeholders and policy makers.

In 2023 **several open seasons** have been launched to assess market participants' interest in underground storage capacity. Open seasons are typically divided into binding and non-binding phases. The binding phase is concluded through the conclusion of long-term capacity contracts between the project developer and market participants. The long-term capacity contract effectively functions as a risk-sharing mechanism and ensures that the project developer's initial investment costs are recovered through the payment of tariffs associated with the storage service provided. In **France**, Géométhane launched a non-binding open season from 1 February to 15 March 2023 to assess interest in hydrogen storage in two salt caverns (with a total capacity of 200 GWh) located in Manosque. No results of this non-binding open season have been disclosed to date. In **the Netherlands**, HyStock held an open season from 15 June to 14 July 2023, offering market participants the ability to reserve capacity in its A5 hydrogen salt cavern (216 GWh). The first salt cavern is expected to be commissioned in 2028.
Three additional hydrogen caverns could be developed soon after 2030, depending on market interest.

In contrast with salt caverns, there is no practical experience of storing pure hydrogen in **porous formations**. In April 2023 the Underground Sun Storage 2030 project was launched in Austria to demonstrate the storage of pure hydrogen (~4.2 GWh) in a former natural gas reservoir. Interdisciplinary technical-scientific investigations are to be carried out until 2025 to assess the initial results of hydrogen storage in the porous formations.

European hydrogen storage development will require stakeholders to make concentrated efforts

Underground hydrogen storage capacity development in Europe by 2030



Sources: IEA analysis based on project announcements.

Liquefied low-emission gases are expected to be central to decarbonising the maritime sector

International maritime transport is heavily dependent on emission-intensive oil derivatives (including very low sulphur oil, heavy fuel oil and diesel). Oil products account for 99% of the total fuel consumed in this sector today, and the industry is responsible for about 2% of global energy-related CO_2 emissions. It faces major decarbonisation challenges. With large, heavy vessels carrying cargo over long distances, it is both a hard-to-electrify and a hard-to-abate sector. Current standard marine fuels are easy to handle and store, but emit climate and local air pollutants (including CO_2, PM and NO_x). While scrubber systems and LNG could offer near-term reductions in local pollutant emissions to meet increasingly stringent regulations, it is widely recognised that other low-emission, non-fossil fuel-based fuels have a critical role to play in decarbonising the shipping sector.

The United Nations' International Maritime Organization (IMO) is the main regulatory body of the shipping industry. The IMO has set a target to reduce the carbon intensity of international shipping by 40% by 2030 and at least 50% by 2050 versus the 2008 levels. To this end, it is crucial that the IMO's ongoing work towards the adoption of a "well-to-wake" metric – which includes emissions relating to every stage in a fuel's life cycle, from production to final consumption – is successfully completed, to accurately measure the impact of fuels on climate and health. The IMO's further regulatory measures came into force in January 2023, with the introduction of two ratings: ships are required to calculate their attained Energy Efficiency eXisting ship Index (EEXI) to determine their energy efficiency, and their annual operational Carbon Intensity Indicator (CII) and associated CII rating. Carbon intensity links the GHG emissions to the amount of cargo carried over the distance travelled. The CII rating threshold will become stricter over time and will therefore determine the annual carbon reduction factor needed to ensure compliance. Each vessel will receive a grade from A (good) to E (poor). Ships with a poor grade must put a corrective action plan in place. The EEXI is based on the ship's specifications, not on its actual operating performance. EEXI is a one-off look at the technical or design efficiency of a vessel, while CII will require demonstrable reductions in operational carbon intensity.

One of the main short-term measures to comply with EEXI regulations is to reduce speed and fuel consumption, using engine power limitation or shaft power limitation. The benefits of speed reduction from an environmental point of view depend on several elements, such as the size and type of vessel, the number of annual round trips and the applicable carbon tax status. The impact of the CII is expected in 2024, as in 2023 shipowners are consolidating tracking data for each of their vessels, which will serve as the basis for the first CII A–E rating.

In addition to this international regulatory framework, individual countries may include targets for shipping in their national mitigation plans, and some regional initiatives have imposed more stringent rules and regulations. For example, in a new climate plan and for the first time ever, in 2024 the European Union will extend its emissions trading system (ETS) to cover CO_2 emissions from ships and, from 2026, two other GHGs – methane (CH_4) and nitrous oxide (N_2O). In the same spirit, the IMO is discussing a carbon tax, the revenues from which could be used to subsidise technologies or fuels to decarbonise the sector. All these regulations will have a significant impact on the design and operation of all ships. Other initiatives focus squarely on shipping fuel and aim to increase the demand for renewable and low-carbon fuels. As part of the EU's Fit-for-55 package, the FuelEU Maritime regulation promotes the use of renewable and low-carbon fuels on ships with a gross tonnage above 5 000 travelling to, from or at berth in EU ports, by setting requirements to gradually reduce the carbon intensity of marine fuels. It starts with a 2% reduction by 2025 compared with 2020 levels, reaching up to an 80% reduction by 2050.

To reduce carbon emissions and improve fuel efficiency, vessel owners and operators have several options, including:

- Operational optimisation.
- Modernisation of vessels with energy-saving technology.
- Switching to low-emission fuels.

To reach these ambitious decarbonisation targets, a combination of all these options will be needed. The following paragraphs focus on the options provided by alternative marine fuels, including liquefied biomethane (LBG), low-emission hydrogen, methanol, ammonia and liquefied e-methane (e-LNG).

Each of these fuels has its own advantages and challenges. With low NO_x, SO_x and PM emissions, **LNG** as a marine fuel meets all IMO and more stringent local emission regulations, is readily available and uses proven technology. The use of LNG requires specific engines with dedicated fuel management systems and greater fuel storage space. LNG bunkering infrastructure is developing rapidly at the world's major hubs. As a result, LNG is currently the most popular alternative fuel choice. However, uncertainties exist over future LNG prices, and upstream methane leaks and onboard methane slip are damaging to the environmental footprint of LNG from a "well-to-wheel" perspective. As they are chemically the same, LNG can be blended with or completely replaced by renewable **LBG** in the short term or by **e-LNG** (produced from low-emission hydrogen and captured carbon dioxide) in the longer term. However, the availability of feedstock, and resulting implications on cost, are of concern when it comes to meeting expected demand in the marine sector.

Thanks to its air quality benefits, **methanol** is gaining momentum because it meets current emission regulations. Moreover, it is easy to handle (it can be stored at ambient temperature and pressure) and can be used in dual fuel[4] engines. Fossil methanol is produced from natural gas. "Green" methanol, either produced from biomass

[4] Diesel/methanol or Residual Fuel Oil (RFO)/methanol.

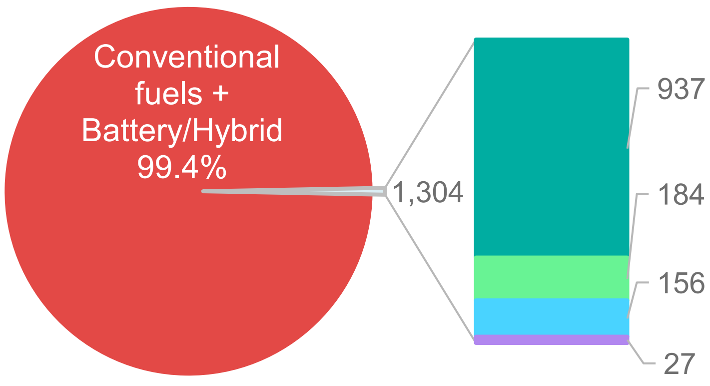
(bio methanol) or from carbon dioxide and hydrogen produced from renewable electricity (e-methanol), is becoming increasingly popular. Methanol nevertheless presents a few disadvantages, including a low volumetric energy density (around 35-40% of LNG), which has an impact on the storage system, and the absence, for the time being, of a large-scale distribution network.

Other alternative fuels, such as **low-emission ammonia** produced through the Haber-Bosch process and **low-emission hydrogen** produced through electrolysis, SMR or gasification with CCS, are emerging as long-term solutions. They are attracting significant investment into the development of technologies. Of all the options listed, these are the only two fuels that have no direct CO_2 emissions. Already produced and traded at scale, ammonia can be produced from the catalytic reaction of N_2 from air with H_2 from water. However, the current Haber-Bosch production process is highly energy intensive, ammonia has a low volumetric energy density (around half that of LNG), and it is above all corrosive and toxic. This has implications for onboard and port storage, monitoring (to ensure there are no lethal leaks) and bunkering. It also has an impact on the ships' layout (location of fuel tanks), and requires double piping, among other measures. Potentially clean and abundant, hydrogen is notoriously difficult to store safely at significant quantities. The typical solution is to store the hydrogen in a liquid form at -253°C, achieved with a complicated refrigeration system and highly sophisticated insulation. Liquid hydrogen has the worst volumetric energy density, after methanol and ammonia, with 35% of the volumetric energy density of LNG. As liquid hydrogen requires more space to store the fuel onboard, it is unsuitable for long, transoceanic trips. Lastly, liquefaction is quite energy intensive.

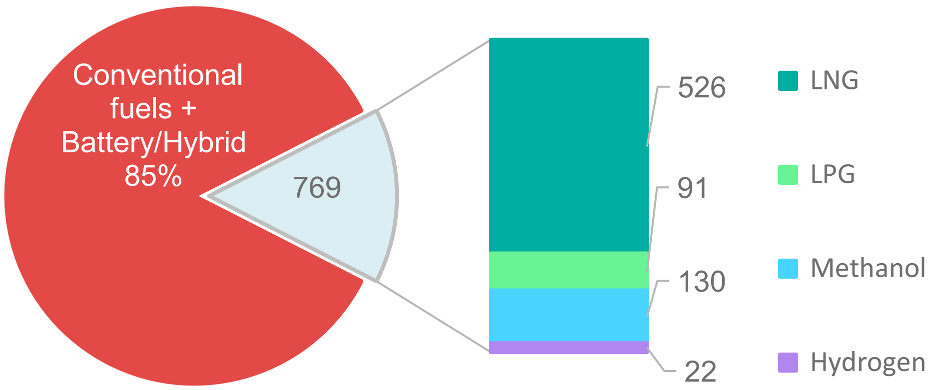
From the perspective of technological readiness, supply availability and infrastructure, LNG seems to be the most pragmatic option chosen by the industry to reduce emissions. However, the skyrocketing gas prices observed in 2022, security of supply and growing awareness about methane emissions along the whole supply chain have made other solutions, such as liquid biofuels or methanol, more attractive. Infrastructure for fuel availability at ports is an urgent concern for the maritime industry. Bunkering technologies exist for LNG and are therefore ready for LBG and, in time, for e-LNG. In contrast, there is no commercial bunkering infrastructure for ammonia or hydrogen yet, although the Global Maritime Forum recorded more than 50 ongoing ammonia demonstration projects as of May 2023, as well as almost 50 hydrogen projects. The use of ammonia and hydrogen as a marine fuel would also require the development of a whole new fleet of specialised vessels. Improvements to safety are ongoing, as seen recently on the world's very first liquid hydrogen transporter, built by Kawasaki. The potential pathways to the initial demonstration and commercialisation of ammonia and hydrogen are already underway and could materialise before 2030.

The future marine shipping market is based on multiple, more diversified fuels

World fleet,
Vessels in operation by fuel



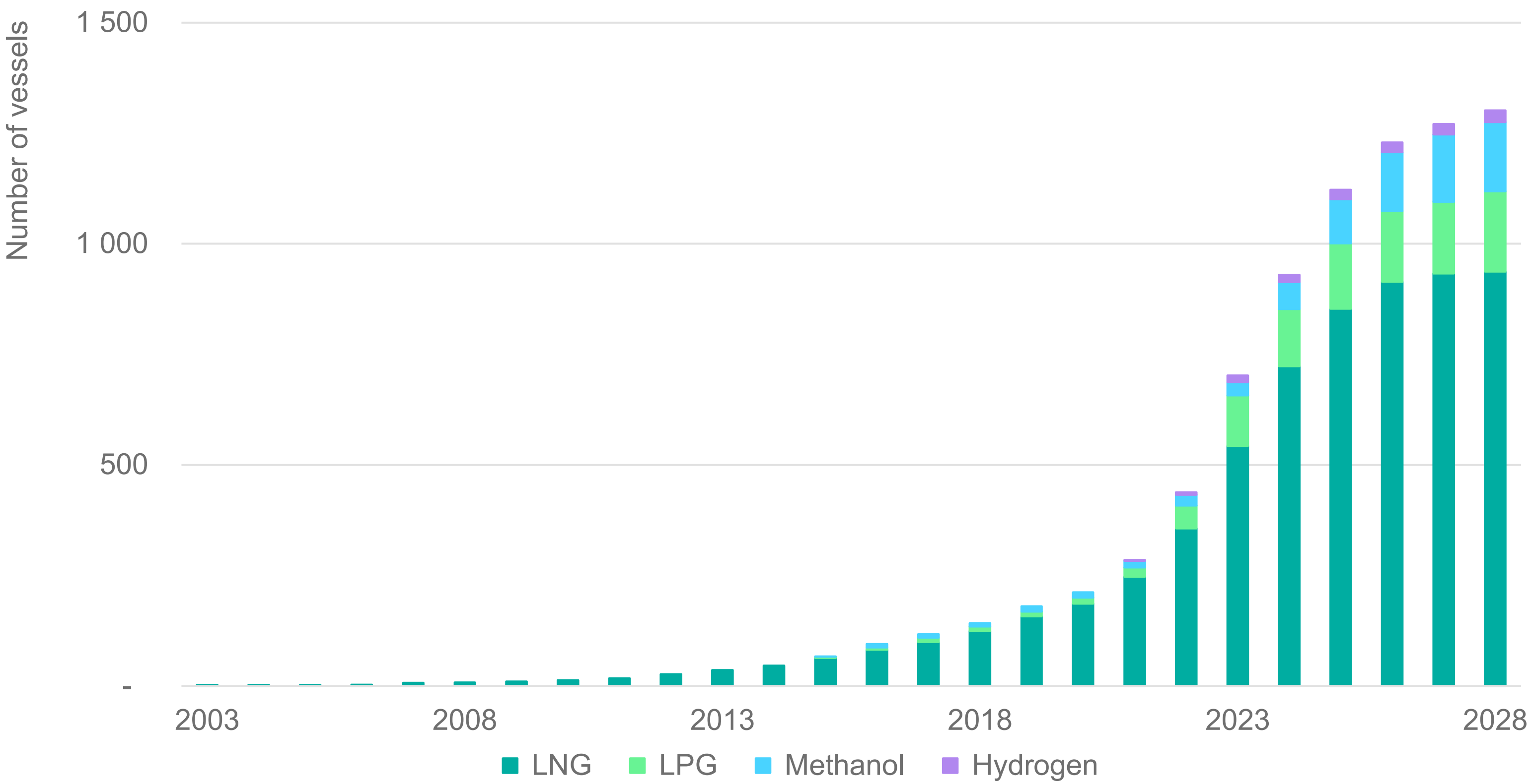
Order book
Vessels on order by fuel



Sources: IEA analysis based on DNV's Alternative Fuels Insights for the shipping industry – AFI platform data as of 9 July 2023.
Disclaimer: The positions or views stated in such document are solely those of the author and do not necessarily represent the views of DNV and/or the third-party data owner.

The number of ships running on alternative fuels on order for delivery by 2028 is rising sharply

Growth in the use of alternative fuels in the world fleet, 2003-2028



Note: LNG carriers are not included in the LNG figures.
Sources: IEA analysis based on DNV's Alternative Fuels Insights for the shipping industry – AFI platform data as of 9 July 2023.

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Annex

Summary table

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

	Consumption					Production				
	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
Africa	161	169	164	168	173	241	262	247	253	264
Asia Pacific	834	891	877	901	940	626	651	659	670	680
of which China	*325*	*367*	*364*	*387*	*414*	*189*	*205*	*218*	*229*	*240*
Central and South America	142	153	150	144	147	150	148	152	145	149
Eurasia	584	634	608	609	622	866	961	868	792	819
of which Russia	*460*	*501*	*473*	*475*	*485*	*692*	*762*	*672*	*610*	*625*
Europe	576	609	524	489	499	230	222	230	220	221
Middle East	547	562	575	588	603	669	692	713	726	744
North America	1 079	1 091	1 145	1 143	1 136	1 145	1 183	1 230	1 250	1 260
of which United States	*868*	*874*	*921*	*919*	*911*	*954*	*984*	*1020*	*1040*	*1048*
World	**3 924**	**4 109**	**4 043**	**4 042**	**4 120**	**3 927**	**4 119**	**4 099**	**4 056**	**4 137**

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

AEMO	Australian Energy Market Operator
ANP	National Petroleum Agency (Brazil)
ARERA	National Regulatory Authority for Energy (Italy)
BMC	Colombian Mercantile Exchange (Colombia)
CCGT	combined cycle gas turbine
CCUS	Carbon Capture, Utilisation and Storage
CII	Carbon Intensity Indicator
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
CQPGX	Chongqing Petroleum Exchange (the People's Republic of China)
EBN	Energie Beheer Nederland
EEXI	Energy Efficiency eXisting ship Index
EIA	Energy Information Administration (United States)
EMRA	Energy Market Regulatory Authority (Republic of Türkiye)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
EU	European Union
EUR	Euro
FID	final investment decision
FLNG	floating liquefied natural gas
FSRU	floating storage and regasification unit
GHGs	greenhouse gases
GIE	Gas Infrastructure Europe
GX	Green Transformation programme (Japan)
HH	Henry Hub
HoA	Head of Agreement
IEA	International Energy Agency
ICE	Intercontinental Exchange
ICIS	Independent Chemical Information Services
IEA	International Energy Agency
IMO	International Maritime Organization
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JPY	Japanese yen
KEEI	Korea Energy Economics Institute
LBG	liquefied biomethane
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)
NBP	National Balancing Point (United Kingdom)
NDRC	National Development and Reform Commission (the People's Republic of China)
OCCTO	Organization for Cross-regional Coordination of Transmission Operators (Japan)
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)

RFO	Residual Fuel Oil
SBL	Strategic Buffer LNG
SMR	steam methane reforming/reformer
SNG	synthetic natural gas
SPA	Sales and Purchase Agreement
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/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	cubic metres per year
Nm^3	normal cubic metre
ppm	parts per million
TWh	terawatt hour
t/yr	tonnes per year

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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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