Gas Market Report, Q2-2023

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Abstract

Pressure on the European and global gas markets has eased since the beginning of 2023 due to favourable weather conditions and timely policy actions. By the end of Q1 2023 European hub and Asian spot liquefied natural gas (LNG) prices had fallen below their summer 2021 levels, albeit remaining well above their historic averages. The steep decline in natural gas demand reduced the need for storage withdrawals in Europe and the United States over the 2022/23 winter. As a result, storage sites closed the heating season[1] with inventory levels standing well above their five-year average. This is expected to reduce injection demand during the summer of 2023, and potentially ease market fundamentals.

The improved outlook for gas markets in 2023 is no guarantee against future volatility and should not be a distraction from measures to mitigate potential risks. Global gas supply is set to remain tight in 2023 and the global balance is subject to an unusually wide range of uncertainties. These include adverse weather factors, such as a dry summer or a cold Q4, lower availability of LNG and the possibility of a further decline in Russian pipeline gas deliveries to the European Union.

This new issue of the quarterly *Gas Market Report* provides an overview of recent gas market developments during the 2022/23 heating season, with a forecast for 2023.

[1] The heating season (or gas winter) in the markets of the Northern Hemisphere refers to the period between 1 October and 31 March.

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Executive summary

A gradual rebalancing of natural gas markets

Global gas markets moved towards a gradual rebalancing over the 2022/23 heating season, following the supply shock sparked by Russia's invasion of Ukraine in February 2022. Spot gas prices across the key northeast Asian, North American and European markets dropped by close to 70% between mid-December and the end of the first quarter of 2023, while storage sites ended the heating season well above their five-year averages.

The reduced market strains and relatively well stocked storage sites ahead of the summer are reasons for cautious optimism for supply security. However, this confluence of factors should not distract from the further measures needed to mitigate potential risks that could quickly renew market tensions and price volatility.

The European and global gas markets suffered a major supply shock in 2022 when Russia sharply reduced its pipeline gas deliveries to the European Union – by 80% over the course of the year – and triggered a global energy crisis. Russia's steep gas supply cuts led to a reconfiguration of global LNG flows, drove up natural gas prices to all-time highs both in Asia and Europe and necessitated a readjustment in gas demand.

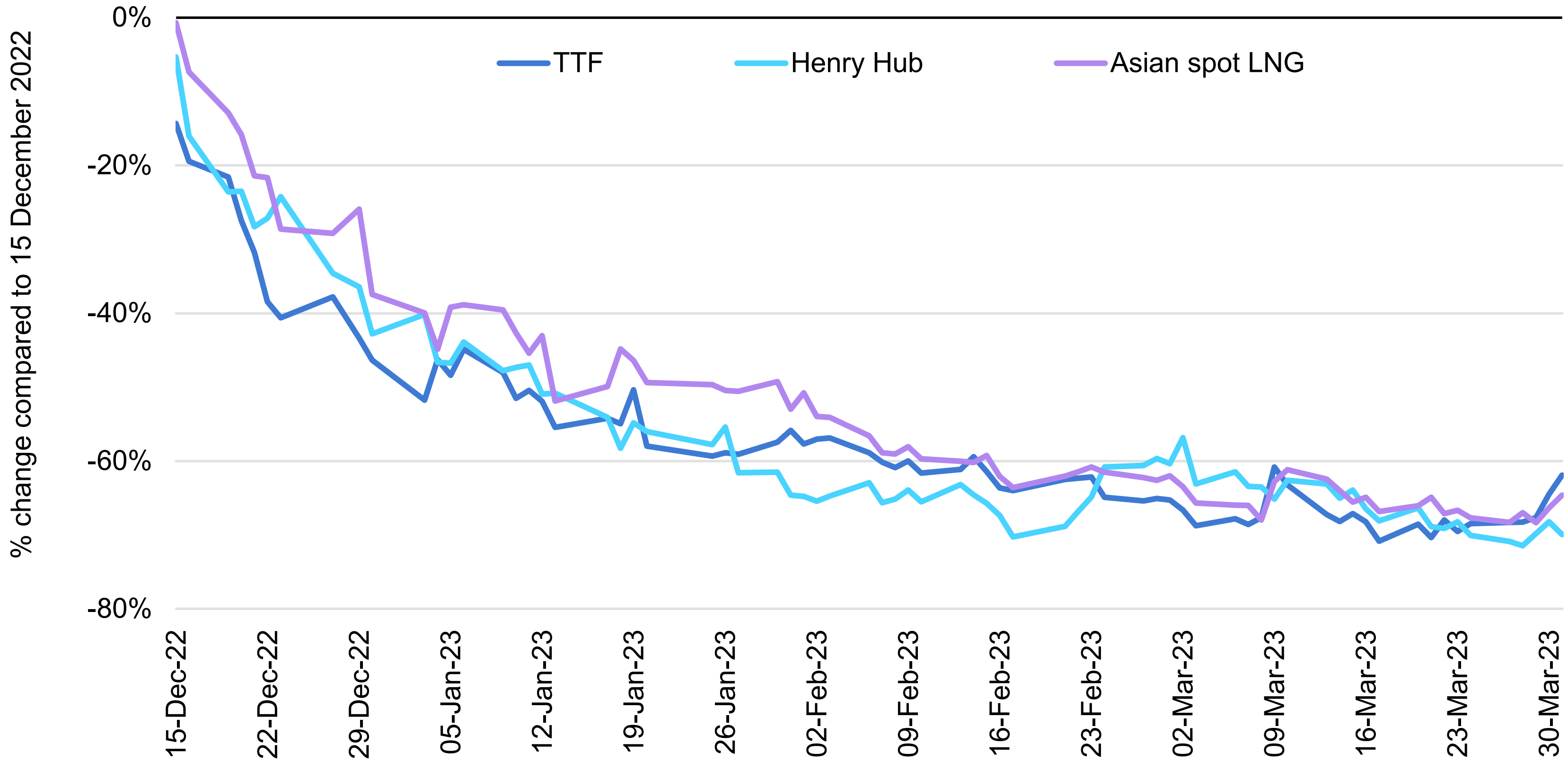
The latest estimates indicate that global gas consumption fell by 1.5% in 2022 – similar to the drop experienced in 2020 following the first wave of Covid-19 lockdowns. The bulk of demand reduction was concentrated in the key European and Asian import markets. The sharp increase in gas prices supported gas-to-coal switching dynamics in the power sector and depressed gas use in energy-intensive industries. Enhanced energy efficiency measures and the continued deployment of renewables reduced gas demand in a structural manner.

The strong decline in gas demand continued into the early months of 2023 due to favourable weather conditions and timely policy actions. Natural gas consumption in advanced economies in Europe fell by an estimated 55 billion cubic metres (bcm) year-on-year during the 2022/23 heating season – its steepest drop in absolute terms for any winter season on record.

The steep decline in natural gas demand reduced the need for storage withdrawals in Europe and the United States over the 2022/23 winter. In the European Union, storage injections equal to only half of the level seen in summer 2022 would be enough to reach the EU target of filling storages to 90% by the start of the 2023/24 heating season. Lower injection demand over summer 2023 could potentially contribute to a further easing of market fundamentals.

Market tensions have moderated significantly since mid-December 2022

Evolution of key regional key gas markets since 15 December 2022



Sources: IEA analysis based on CME (2023), Henry Hub Natural Gas Futures Quotes, CME (2023), Dutch TTF Natural Gas Month Futures Settlements; ICIS (2023), ICIS LNG Edge.

Global gas supply is set to remain tight in 2023 amid lower Russian pipeline gas deliveries to Europe

Global LNG supply is forecast to increase by a mere 4% (or over 20 bcm) in 2023. This would not be sufficient to offset the expected reduction in Russia's piped gas supplies to Europe.

The United States is projected to account for over half of the global supply increase in 2023 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, which returned to full service at the end of the first quarter of 2023. In addition to the United States, LNG supply from Africa and South and Central America is projected to increase by close to 10 bcm amid improving feed gas availability and the ramping up of the Coral South and Congo floating LNG plants. By contrast, Russia's LNG output is expected to decline. Sakhalin-II LNG's project operator announced in February 2023 that the plant will move away from the "peak load" strategy it has been pursuing in the last few years, while production from YAMAL LNG is expected to decline by 5% year-on-year in 2023.

The level of Russian pipeline gas supplies is a major uncertainty for the remainder of 2023. If flows to the European Union continue at the levels seen in the first quarter, Russian piped gas deliveries to advanced economies in Europe would drop by 45% (or over 35 bcm) in 2023 compared with 2022. Following a 90 bcm drop in Russian gas production in 2022, lower exports and muted domestic demand are expected to further reduce Russia's output by over 50 bcm in 2023, adding to the challenges facing the Russian gas industry.

Global gas demand is expected to remain broadly flat in 2023

Global gas demand is expected to remain flat in 2023, with higher demand in Asia Pacific and the Middle East offsetting the expected declines in Europe and North America. In Asia, gas demand is projected to increase by close to 3%, with China and India as the main drivers. Gas demand in China is forecast to increase by over 6% in 2023, supported by a recovery in economic activity and potentially higher gas use in industry. In the Middle East, gas demand is forecast to increase by 2%, driven by Iran and Saudi Arabia. Gas demand in advanced economies in Europe is projected to decline by 5% as rapidly expanding renewables weigh on gas-fired generation. After strong growth in 2022, gas demand in North America is expected to decline by 2% as a result of lower gas use for space heating, power generation and industry.

China gradually recovers its appetite for LNG, although imports are set to remain below their 2021 levels

China's LNG imports declined by an unprecedented 20% in 2022, enabling higher LNG deliveries to the European market. China's LNG import growth recovered to double-digit growth in March 2023, supported by higher domestic gas demand. The country's LNG inflows are expected to increase by 10-15% compared with 2022 while remaining below their 2021 levels.

LNG became effectively a new baseload supply for Europe, accounting for two-third of the region's imports and meeting around one-third of its gas demand through the 2022/23 winter season. After strong growth in Q1 2023, **OECD Europe's LNG imports are expected to decline for the remainder of the year** amidst lower injection needs and a continued decline in European gas consumption.

Grounds for cautious optimism

Pressure on the European and global gas markets has eased since the beginning of 2023 due to favourable weather conditions and timely policy actions. The improved outlook for gas markets in 2023 is no guarantee against future volatility and should not be a distraction from measures to mitigate potential risks.

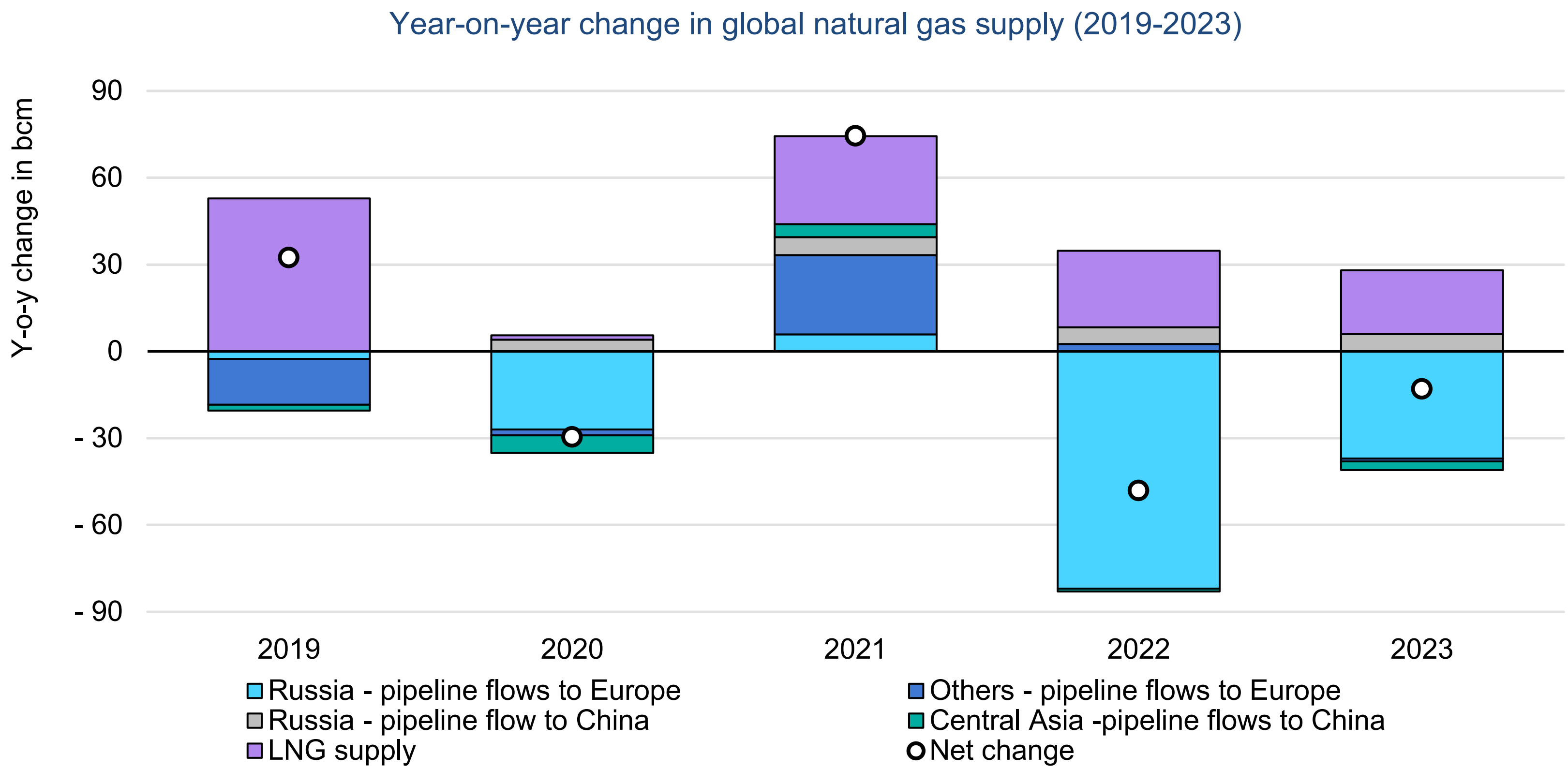
Global gas supply is set to remain tight in 2023, and the global balance is subject to an unusually wide range of uncertainties. The risks include adverse weather factors, such as a dry summer or colder-than-usual end of the year, lower availability of LNG, and the possibility of a further decline in Russian pipeline gas deliveries to Europe. These factors could easily renew market tensions and price volatility.

As a result, there is a continued need to reduce gas demand in a structural manner through improved energy efficiency measures, accelerated deployment of renewables and heat pumps, as well as behavioural changes. Short-terms options to enhance gas supply and optimise the use of gas infrastructure should be promoted, including via the reduction of methane leaks and gas flaring.

E-methane: A gas fit for net zero?

Beyond the immediate security of supply concerns, there is a clear and urgent need for policy makers and the private sector to promote effective ways to decarbonise gas supply. E-methane is interchangeable with natural gas and would limit the need for retrofitting existing natural gas plants and networks while enhancing system and seasonal flexibility. As part of the IEA's Low-Emission Gas Work Programme, this quarterly edition of the *Gas Market Report* provides an in-depth overview of the developments related to e-methane. E-methane's high production costs require further technological development and policy support, including through closer dialogue between future producers and consumers.

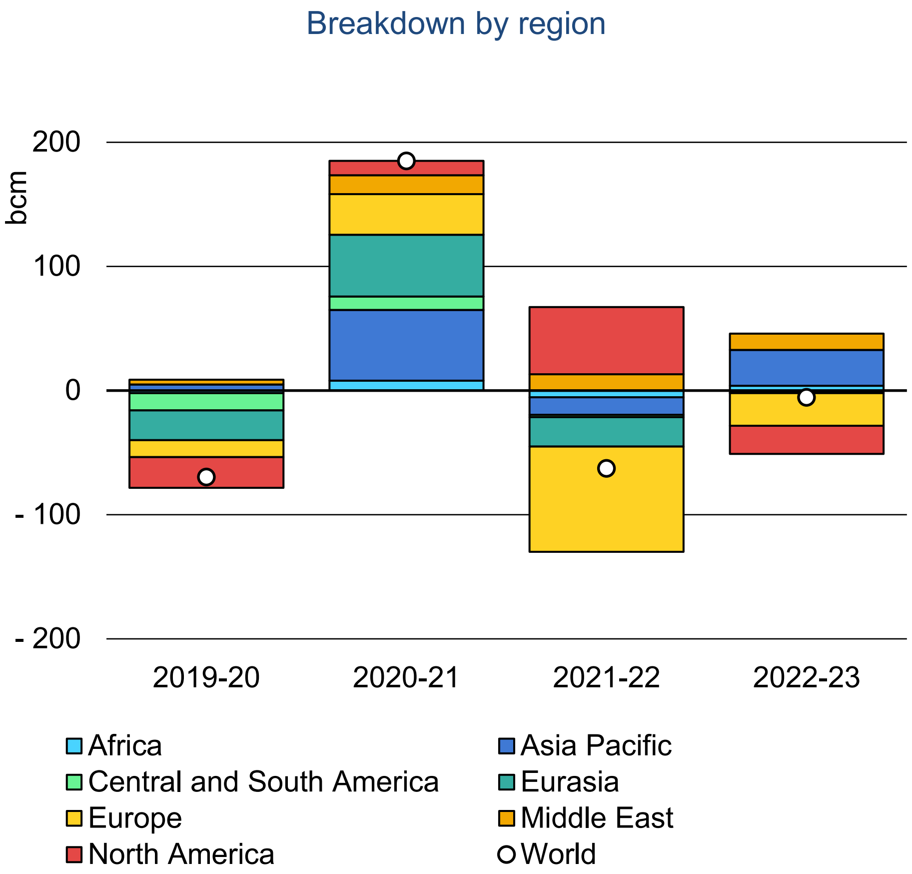
Global gas supply is set to remain tight in 2023

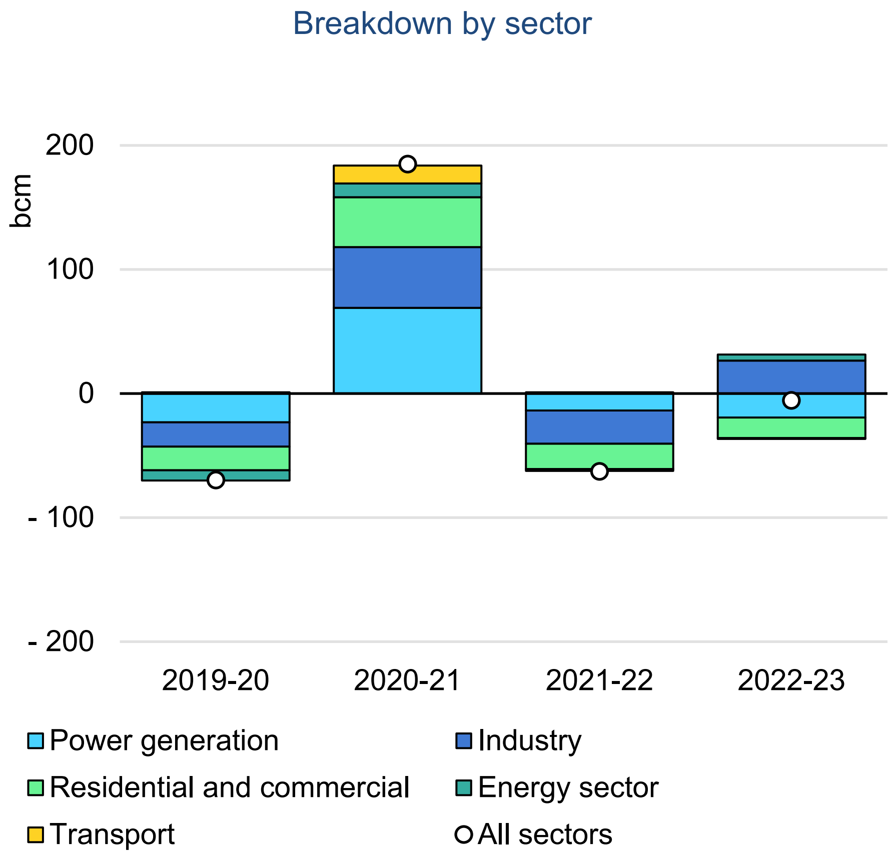


Sources: IEA analysis based on ENTSOG (2023), Transparency Platform; Eurostat (2023), Energy Statistics; General Administration of Customs of People's Republic of China (2023), Customs Statistics; ICIS (2023), ICIS LNG Edge; JODI (2023), Gas World Database.

Global gas growth turned negative in 2022, flat and uncertain for 2023

Change in global natural gas demand per calendar year, 2020-2023





Gas market update and short-term forecast

Gas demand increased in North America during the winter, but is expected to contract in 2023

During the winter season of 2022/23 the **United States** saw an estimated 0.6% year-on-year (y-o-y) increase in its consumption of natural gas. As temperatures plummeted in December, the end of the year saw a dramatic rise in the demand for natural gas for commercial and residential heating. The first quarter of 2023, however, saw a significant reversal, with mild temperatures nearly reversing the increase in demand over the previous year's winter season. Overall, natural gas consumption saw a 5.3% rise in 2022, driven by the use of natural gas for power generation. This was stimulated by the need for cooling, which can be attributed to high temperatures during the summer months.

Furthermore, the retirement of coal-fired power plants and relatively high coal prices, along with lower than average coal stocks, caused coal consumption for power generation to decrease, leading to a switch in favour of natural gas for electricity generation. This resulted in natural gas accounting for 38.0% of the power mix on average during the winter period, or a 3 percentage point increase over the previous winter, while coal fell to 18.4%, a drop of 2.5 percentage points.

In addition, abnormally low temperatures – especially during the arctic front that swept across the country in late December causing heavy rain and snow – greatly added to the rise in the use of natural gas for residential and commercial heating. In stark contrast, January saw unseasonably mild temperatures, setting new records for the warmest month, offsetting the trend.

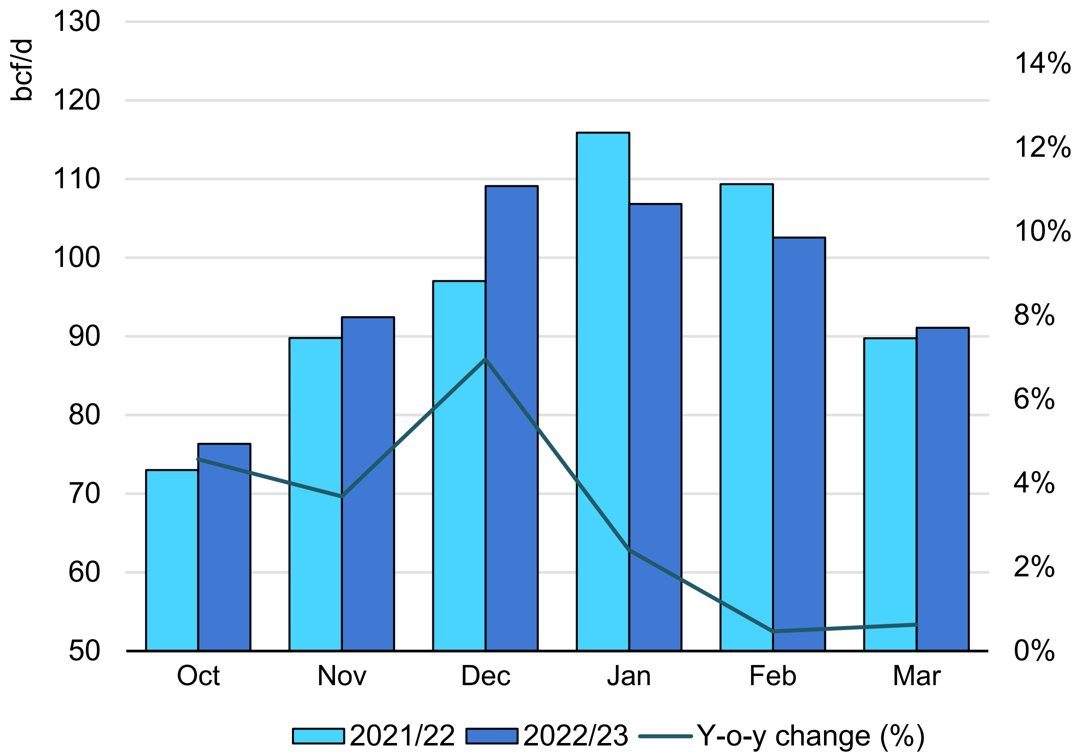
The industrial sector experienced a 2.1% decrease in natural gas consumption during winter 2022/23 relative to winter 2021/22, albeit at a relatively stable rate.

Gas consumption in **Canada** increased by close to 7% in 2022. Both wholesale customers (large industry and power generators) and residential and commercial customers contributed to this growth. The switch away from coal in the power generation mix has been gradually pushing demand for natural gas upwards. The winter season started with a rise in residential and commercial natural gas consumption (up 7.5% y-o-y in Q4 2022) due to lower than average temperatures, but this trend could potentially be counteracted in the first quarter of 2023 as temperatures were higher than average. **Mexico**'s apparent natural gas consumption remained stable y-o-y during the period from October 2021 to January 2022.

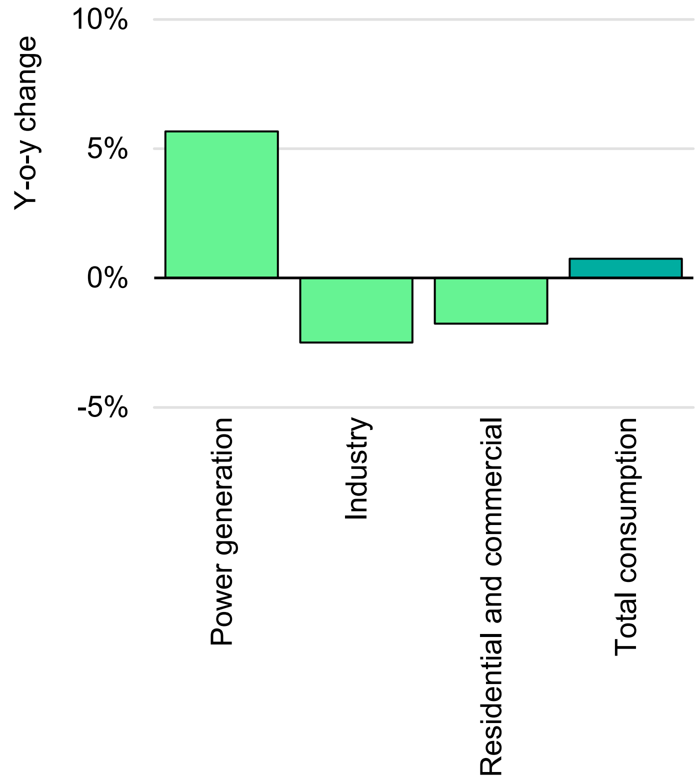
North American gas consumption is expected to decrease by about 2.9% in 2023. In the United States, slower economic growth is set to depress gas demand in industry, while an unseasonably mild Q1 reduced gas use in the residential and commercial sectors, weighing on the outlook for the full year. The economic slowdown coupled with the strong expansion of renewables is set to reduce the call on gas-fired power plants, although continued coal-to-gas switching could moderate the overall decline in gas demand for power generation.

Growth in US gas consumption during the past winter was sustained by power generation and heating needs during cold weather in Q4

Monthly natural gas consumption, United States, winter 2021/22 and 2022/23



Gas consumption by sector, United States, winter 2022/23 relative to winter 2021/22



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

Gas consumption saw a limited decline in Central and South America in 2022, and is expected to stabilise in 2023

Natural gas consumption in the Central and South America region is estimated to have fallen by close to 1.5% in 2022, primarily due to lower need for gas for power generation in Brazil after record droughts in 2021. It is expected to stabilise in 2023 with a limited decline of less than 1% as higher hydro availability (as of the end of Q1) further reduces gas for power needs, partly compensated by limited growth among industrial consumers.

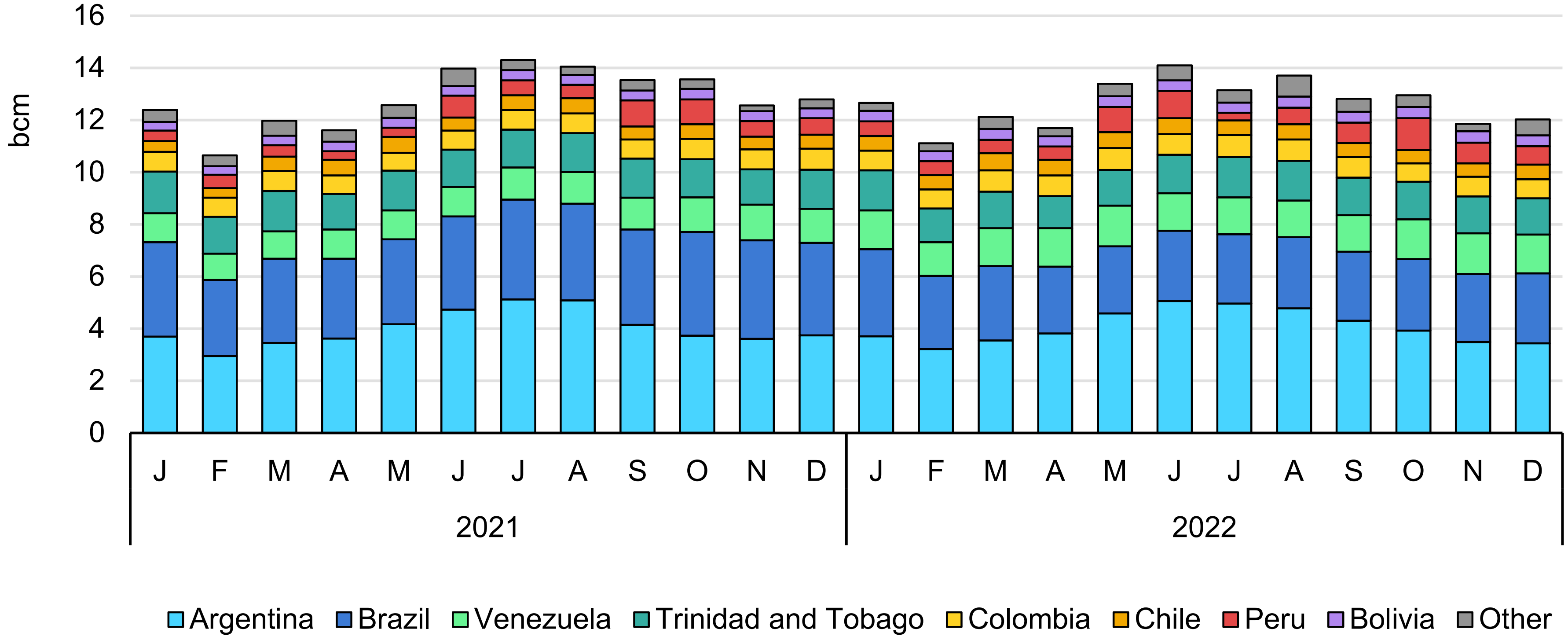
Argentina's gas consumption declined by about 2% y-o-y in the fourth quarter of 2022 after registering a 3% increase in the first nine months of the year, as demand growth from the industrial sector turned negative in the final months of 2022. The power generation sector, which accounts for close to 30% of total gas consumption, experienced an 11% decline in 2022 due to modest growth in electricity demand and a rebound in hydro generation from the low levels of 2021. This was partly offset by increases from the industrial sector (up by 6%) and the residential and commercial sector (up by 3%), which account for a quarter of total gas demand each. Domestic production grew by 3% in 2022, supported by a 14% increase in the Vaca Muerta shale basin in Neuquén province, which contributed to a 26% reduction in natural gas imports.

The decline in gas use in **Brazil** further accelerated in Q4 2022 with a 29% y-o-y slide, as gas burn for power generation dropped by close to 70% on strong hydro recovery. Gas consumption for the whole of 2022 declined by an estimated 22% y-o-y, dragged down by a steep 61% drop in gas use for power generation, while demand from industry and retail customers increased by 7% and 5% respectively. Operational data show that hydroelectricity increased by 4.2 TWh y-o-y (up 4%) in the first quarter of 2023 against only 2.6 TWh (up 2%) for total electricity generation, resulting in an estimated 6 TWh drop in gas-fired generation (down 62%).

Gas production in **Trinidad and Tobago** increased by 4% in 2022 while LNG exports recovered by 19% y-o-y, leading to an estimated decline in domestic consumption of close to 3%. Apparent gas consumption grew by 10% in **Central America and the Caribbean** in 2022, and LNG imports almost doubled during the October 2022 to February 2023 period, supported by strong increases in Jamaica and Panama. **Bolivia**, **Chile** and **Peru** reported a 10% increase in their respective gas demand in 2022. **Colombia** saw its gas consumption increase by 5% over the same period, although early 2023 data show a 6% y-o-y decline for the first two months of the year.

Declines in gas demand in Argentina and Brazil in 2022 were almost balanced by growth in other Central and South American markets

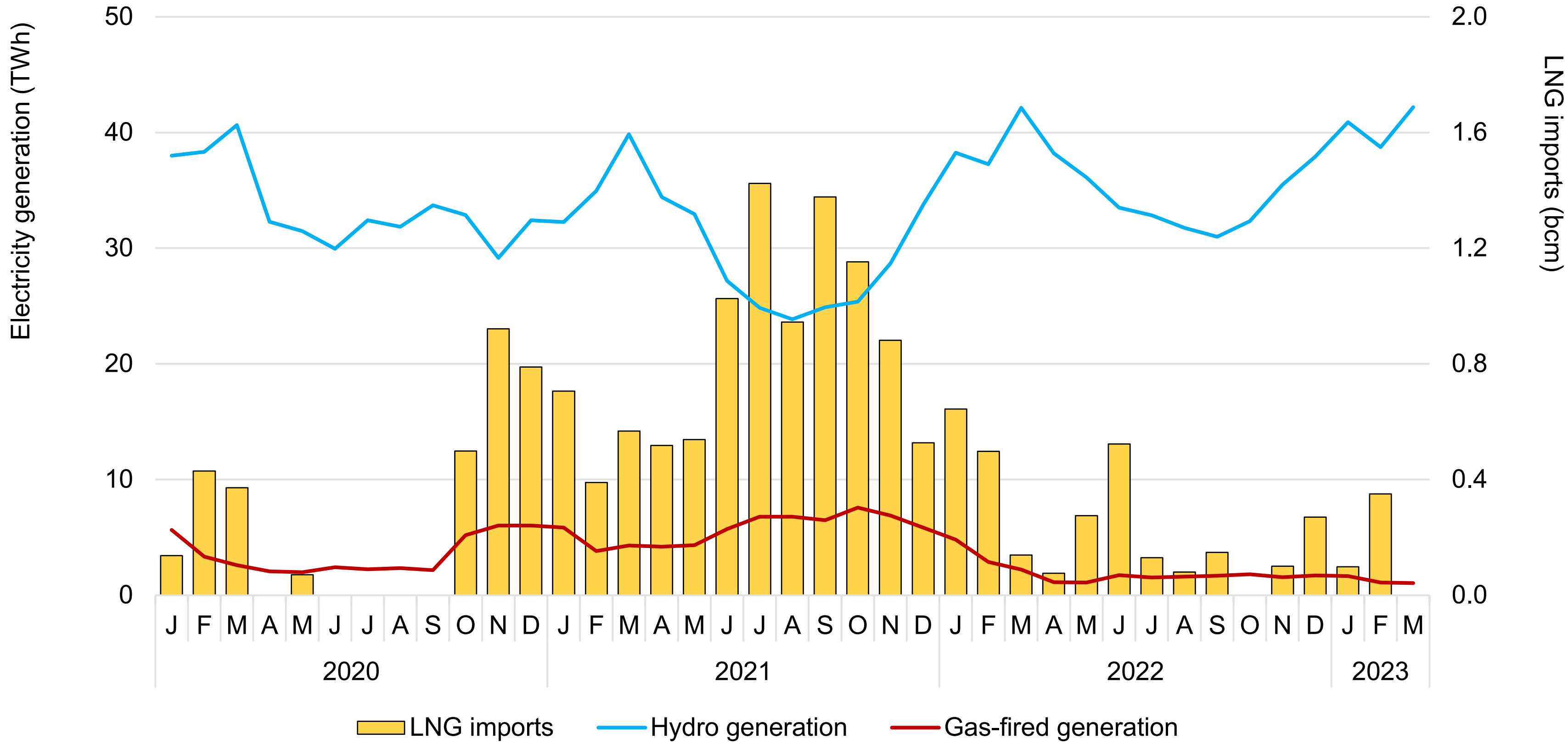
Monthly natural gas consumption, Central and South America, 2021-2022



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.

Gas use for power generation remains low in Brazil in Q1 2023 on strong hydro availability and limited electricity demand growth

Monthly hydro and gas-fired electricity production and LNG imports, Brazil, 2020-2023



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 a record 55 bcm during the 2022/23 heating season

Natural gas consumption in OECD Europe fell by an estimated 16% (or 55 bcm) y-o-y during the 2022/23 heating season – its steepest drop in absolute terms for any winter season in our records. High gas prices continued to weigh on gas use in industry, while milder weather conditions – together with energy saving measures – depressed distribution network-related demand and gas burn in the power sector.

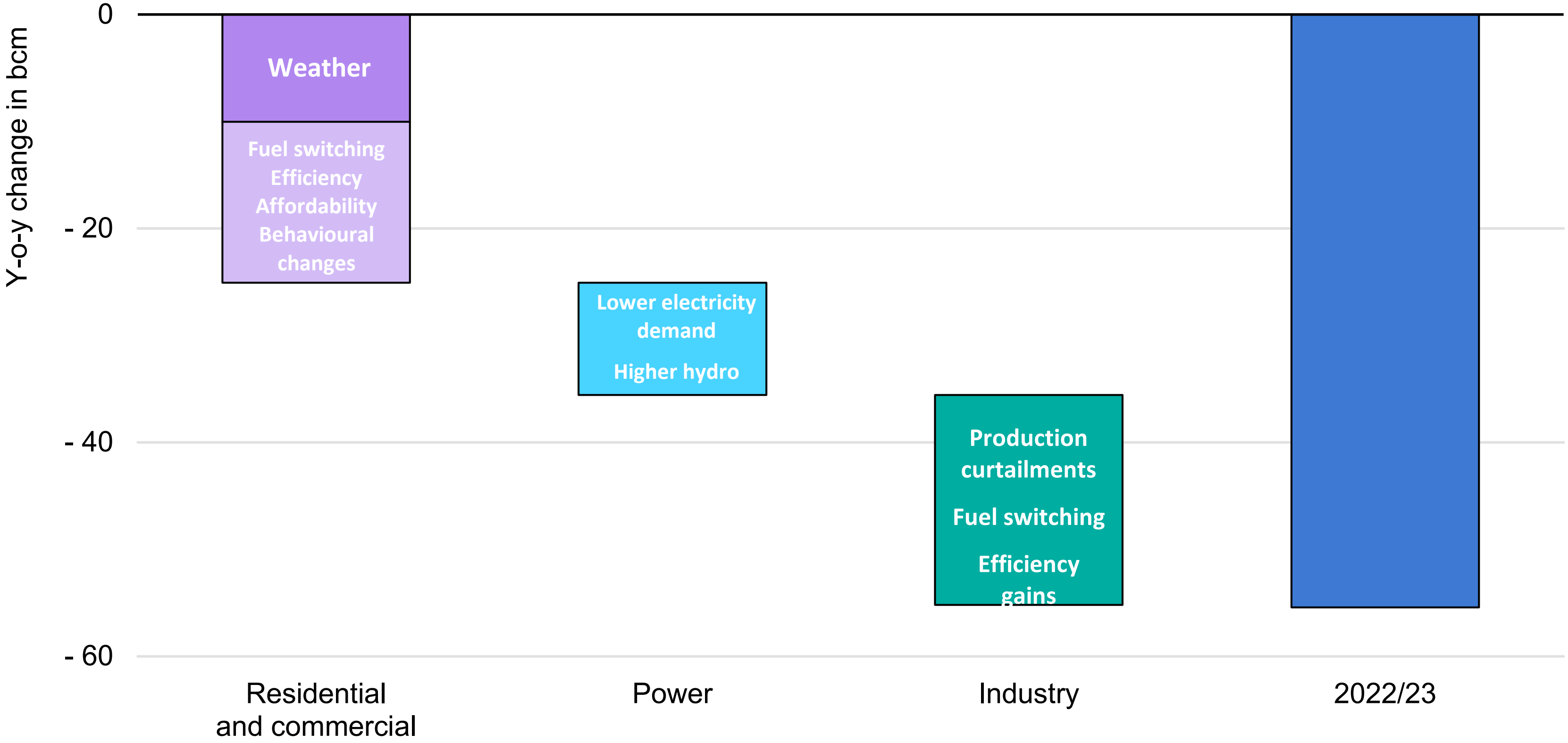
Distribution network-related demand fell by 16% (or 25 bcm) y-o-y during the 2022/23 winter season, accounting for around 45% of the total reduction in OECD Europe's gas consumption. Heating degree days stood 7% below their 2021/22 levels, weighing on space heating requirements in the residential and commercial sectors. Notably, unseasonably mild temperatures in October and the first half of November delayed the start of the European heating season by almost a month. Nevertheless, weather-related factors explain only 40% of the demand decline experienced in the residential and commercial sectors. Gas-saving measures enacted in public buildings (such as mandatory temperature controls), fuel-switching in rural households (including to biomass, fuel oil and waste), the installation of heat pumps, efficiency gains and behavioural changes all played a critical role in reducing distribution network-related demand. Rising affordability issues also contributed to lower gas use in households. The share of people unable to heat their homes in the European Union stood at 6.9% in 2021. This situation is expected to have significantly worsened during the 2022/23 winter season.

Gas burn for power generation declined by an estimated 12% (10 bcm) y-o-y during the 2022/23 heating season. This was largely driven by lower electricity consumption, which fell by close to 7% (90 TWh), its largest drop in absolute terms for any winter season in our records. Milder weather, energy saving measures and lower electricity use in industry were the main drivers behind this sharp decline. Gas demand in industry fell by close to 20% (20 bcm) y-o-y during the winter season, with high prices leading to continued fuel-switching and reduced operating rates in the most gas-intensive industries. The steep drop in gas prices in Q1 2023 supported gas use in industry, which increased by an estimated 20% compared with Q4 2022.

OECD Europe's gas demand is forecast to decline by 5% in 2023. This is largely driven by lower gas burn in the power sector, down by close to 15% amid rapidly expanding renewables. Gas use in industry is expected to recover by close to 5% as lower gas prices enable demand recovery in the second half of the year. Considering the declines seen in Q1, demand in the residential and commercial sectors is expected to fall by 4% in 2023.

Mild weather, energy saving measures and lower gas use in industry weighed on gas demand

Estimated y-o-y change in gas demand by sector, OECD Europe, 2021/22 heating season vs 2022/23 heating season



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 came under pressure in 2022; recovery in 2023 is expected to be modest

Asia's gas consumption experienced an unprecedented slowdown of 2% in 2022 because of high LNG prices, Covid-related disruption in the People's Republic of China (hereafter "China") and mild weather for most of the year in Northeast Asia. This trend was confirmed in January 2023 with a decrease of 2% y-o-y. Asian gas demand is projected to return to modest growth of around 3% in 2023 due to the lifting of China's zero-Covid policy, an assumption of normalising weather and the modest recovery of gas consumption in India and emerging Asia after steep declines in 2022.

China's gas consumption decreased by 1-2% in 2022, depending on the source of the data (from the Chongqing Petroleum and Gas Exchange or from the NDRC). In 2023 natural gas demand decreased by 4% y-o-y in January and increased again by 4% y-o-y in February. For the first two months of 2023 natural gas demand globally decreased very slightly by 0.1%. This drop in demand in the first two months of 2023 was led by industry, with a 9% decrease y-o-y, and the power sector, with a 6% decrease y-o-y. China's coal imports reached record levels during the first quarter of 2023; this trend may continue throughout the year supported by the extension of the provisional "zero" import tax policy until the end of 2023 as part of Beijing safeguarding its energy security. The largest coal ports in China are located on the east coast, where some of China's largest LNG import terminals are based. Power producers and large industrial plants in the area can switch between coal and natural gas for their energy generation needs to achieve the most cost-effective production. The decrease in gas use for power generation is also explained by the record growth in the share of renewable energy in the electricity mix. The city gas segment recovered in January and February 2023, with a 7% increase y-o-y due to the resumption of economic activity post reopening. In 2023 China's gas consumption is expected to rebound by 5-7%, led by the industrial sector, although the rate is highly uncertain. 2023's demand increase is fuelled by the expected recovery of economic activity following the easing of Covid-19 lockdown restrictions. Fresh LNG procurement is expected to be sluggish due to the combined effect of the introduction of newly signed long-term LNG purchase contracts, increased domestic production and pipeline gas imports.

India's gas consumption declined by 6% in 2022 as soaring prices squeezed gas demand for power generation (down 24% y-o-y) and refining (down 30% y-o-y), and from the petrochemicals sector (down 32% y-o-y). City gas demand was broadly flat, while consumption in the fertiliser segment and other end uses (which include agriculture, upstream operations and other industries) saw modest expansion during 2022, although not enough to compensate for the steep declines in the more price-sensitive sectors of the economy. India's LNG imports dropped by 17% in 2022, the steepest fall on record and the first decline covering two consecutive years in India's two-decade history as an LNG importer. Price-driven fuel-switching played the leading role in suppressing LNG demand, but a modest 3% increase in domestic production also contributed to the decrease in LNG inflows. In January 2023 natural gas demand in India increased by 14% y-o-y, with a significant increase in the city gas sector (up 70% y-o-y) and the recovery of the fertiliser sector (up 13% y-o-y) along with the power sector (up 5%) amid lower gas prices. In 2023 total gas consumption is expected to increase by 4% thanks to a modest recovery in power sector gas use and continuing – albeit slow – growth in the industrial and city gas sectors.

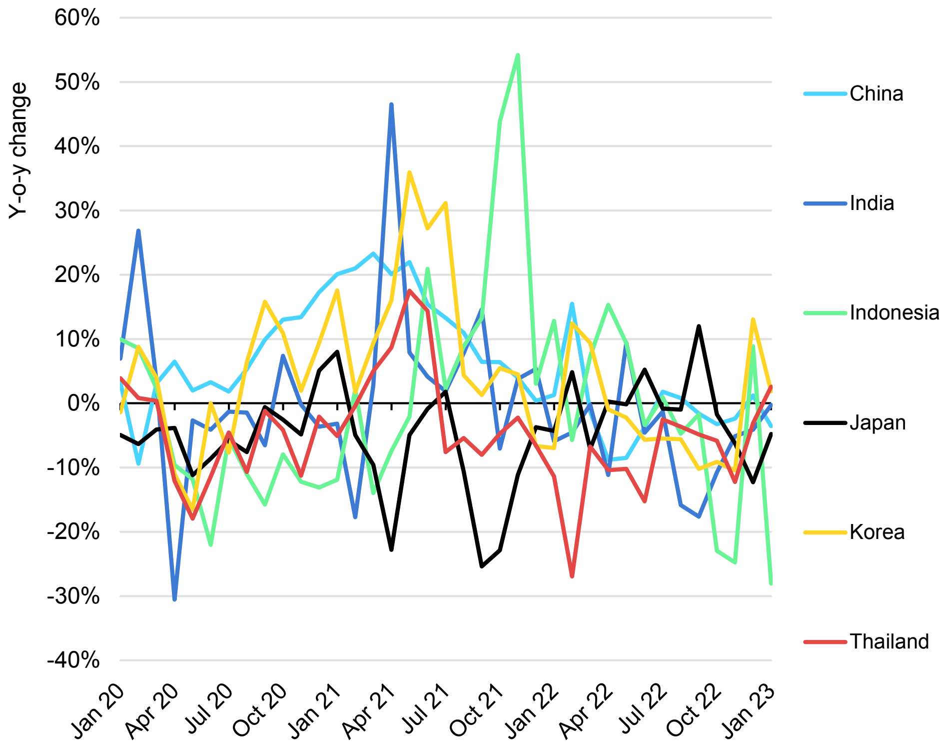
Japan's gas consumption decreased by 1% in 2022, with declines in power generation partially offset by increases in other sectors such as commerce and industry. City gas sales for commercial and industrial use increased by 7% and 3% respectively, according to data from METI. Total electricity demand rose by 1% y-o-y, despite a sharp 15% y-o-y reduction in nuclear generation due to the shutdown of reactors requiring periodic or special inspection. Thermal generation from gas and coal, which account for a combined share of more than 65% of the Japanese electricity mix, compensated for this loss. In 2023 Japan's gas consumption is expected to decrease by 3%, driven by the power sector, as growing nuclear and renewables reduce the need for gas-fired electricity. The increase in nuclear output is due to the improved operating rate of plants in production and the restart of others.

Korea's gas consumption decreased by almost 1% in 2022, a reversal from the robust growth of 10% in 2021. Healthy growth in the industrial, district heating and city gas segments only partially offset the decrease in gas use for power generation. Gas demand for power generation decreased by more than 3% due to the high output from nuclear, renewable and coal-fired generation. This trend is projected to continue in 2023 as total gas demand is set to decrease by 2%. Growing gas use in the industrial and city gas sectors is expected to offset only partially the decline in gas demand for power generation, driven by the start-up of new coal-fired generation and additional nuclear output, such as from Shin Hanul 1 and 2.

Emerging Asia's gas consumption dropped by 4% in 2022, as high import prices combined with falling domestic supply from some of the region's legacy producers put pressure on demand. Thailand, the region's biggest gas consumer, recorded a 10% y-o-y drop in its gas use in 2022, with most of the decline concentrated in the power sector and the domestic energy industry. Indonesia, the number two consumer in emerging Asia, saw an overall 2% y-o-y decrease in 2022. Y-o-y readings turned mostly negative from mid-2022 in emerging Asia, and gas demand fell by 12% in the period July to November 2022 (with power and industry both contributing to the decline), a sharp contrast to the 6% y-o-y growth recorded in H1 2022. Gas demand was also severely curtailed in Pakistan and Bangladesh, with a combination of power cuts and switching to alternative fuels as spot LNG became practically unaffordable for the two South Asian importers. In 2022 LNG imports into Pakistan and Bangladesh dropped by 18% and 17% respectively, the sharpest annual decline in both countries' brief history as LNG importers. In 2023 emerging Asia's gas consumption is projected to increase by a modest 2%, fuelled by growing economic activity and power demand.

Widespread declines in demand in Asia during 2022 are set to be followed by an uneven recovery in 2023

Monthly gas demand, selected Asian countries, 2020-2023



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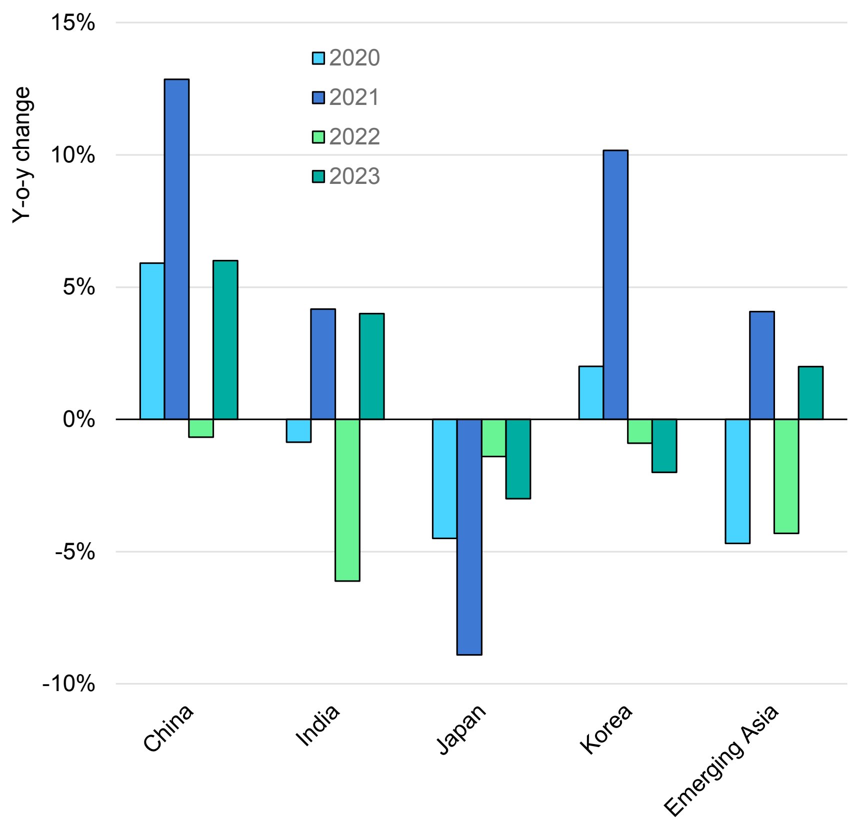


Sources: IEA analysis based on ICIS (2023), ICIS LNG Edge; CQPGX (2023), Nanbin Observation; JODI (2023), Gas World Database; PPAC (2023), Gas Consumption; EPPO (2023), Energy Statistics, Korea Energy Economics Institute (2023), Monthly Energy Statistics, Ministry of Economy, Trade and Industry of Japan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

US natural gas output maintains its growth, driven by Permian oil-driven production

US dry gas production increased by an estimated 4% y-o-y during October 2022 to March 2023, reaching an average daily level of 100 bcf in the first quarter of 2023 (or a 5.7% y-o-y increase).

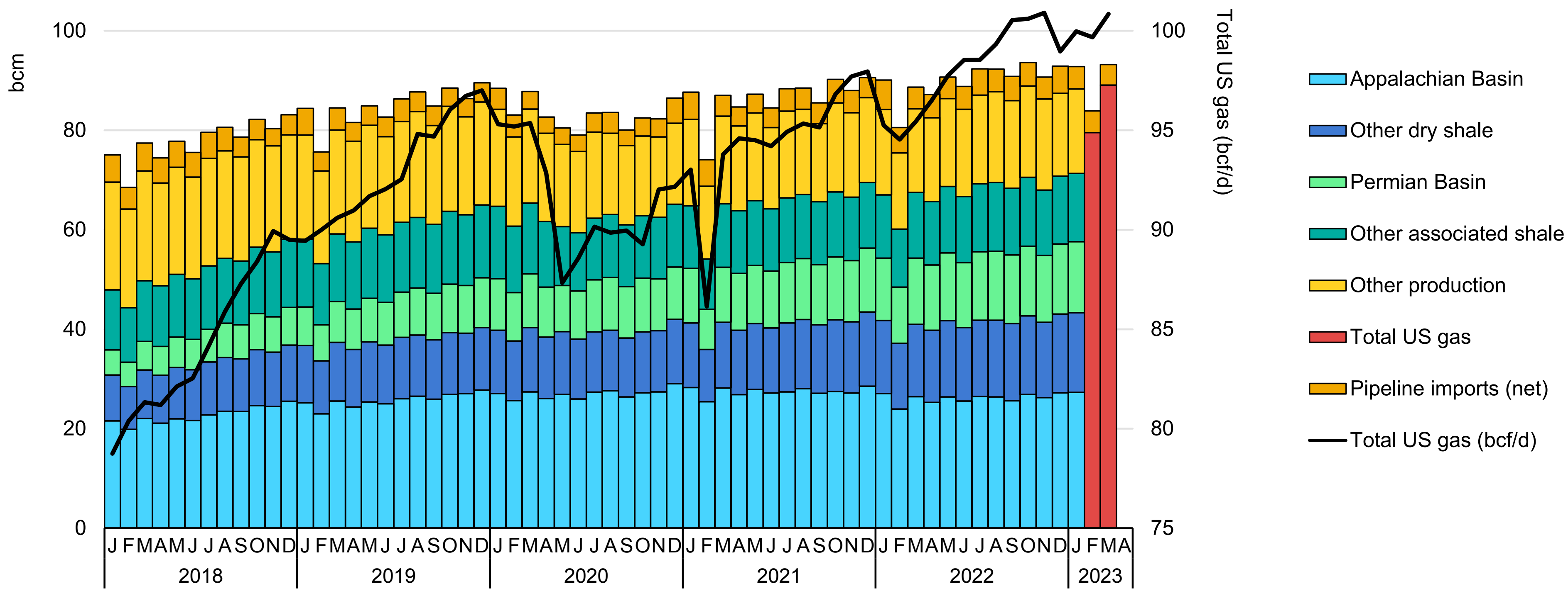
This increase was primarily led by associated production from oil-driven shale plays, which increased by close to 8% y-o-y during October to January. Output from the Permian Basin, the largest oil-driven shale play, grew by close to 11% y-o-y over the same period. This has been supported by strong drilling activity, with an average of close to 430 new wells drilled per month in the Permian during October to January, or a 33% y-o-y increase, whereas completion rates increased by only 4% y-o-y over the same period, to a monthly average of 435 wells. January 2023 marked the highest level of drilling activity in the Permian since March 2020, with 437 new wells drilled. Additional associated shale gas growth principally came from the Eagle Ford play, which experienced a 10% increase in output in the October to January period. The Mississippian and Woodford plays have shown similar growth rates, albeit with lower production volumes, while the Bakken and Niobrara had limited growth, and the Fayetteville play experienced a 20% slide.

By comparison, natural gas output from gas-driven shale plays was close to stable with a meagre 1.1% y-o-y increase during October to January. The Appalachian Basin, the leading source of natural gas, accounting for about 31% of total US production, experienced a 2.5% y-o-y decline during this period. According to quarterly statistics from the Pennsylvania Independent Fiscal Office, gas production in the Pennsylvanian part of the Appalachian Basin dropped by 5% y-o-y in the fourth quarter of 2022, while the number of wells drilled declined by close to 12% over the same period. Other gas-driven shale basins provided more support, with a close to 8% y-o-y increase in the period October to January, driven by the Haynesville play, which recorded strong 14% growth y-o-y over the same period. Drilling activity in the Haynesville increased by 45% y-o-y, with an average of 75 new wells drilled per month, while the completion rate grew by 67% to an average of 64 wells completed.

Total US natural gas production increased by 3.7% in 2022, but this is expected to slow in 2023 due to a combination of continued conservative upstream spending, cost inflation, limited export outlets and an expected decline in domestic demand. This forecast expects US dry gas output to increase by about 2% in 2023, principally supported by associated gas production, while pure gas shale plays are expected to see only limited growth.

US natural gas production remained close to the record 100 bcf/d mark during Q1 2023

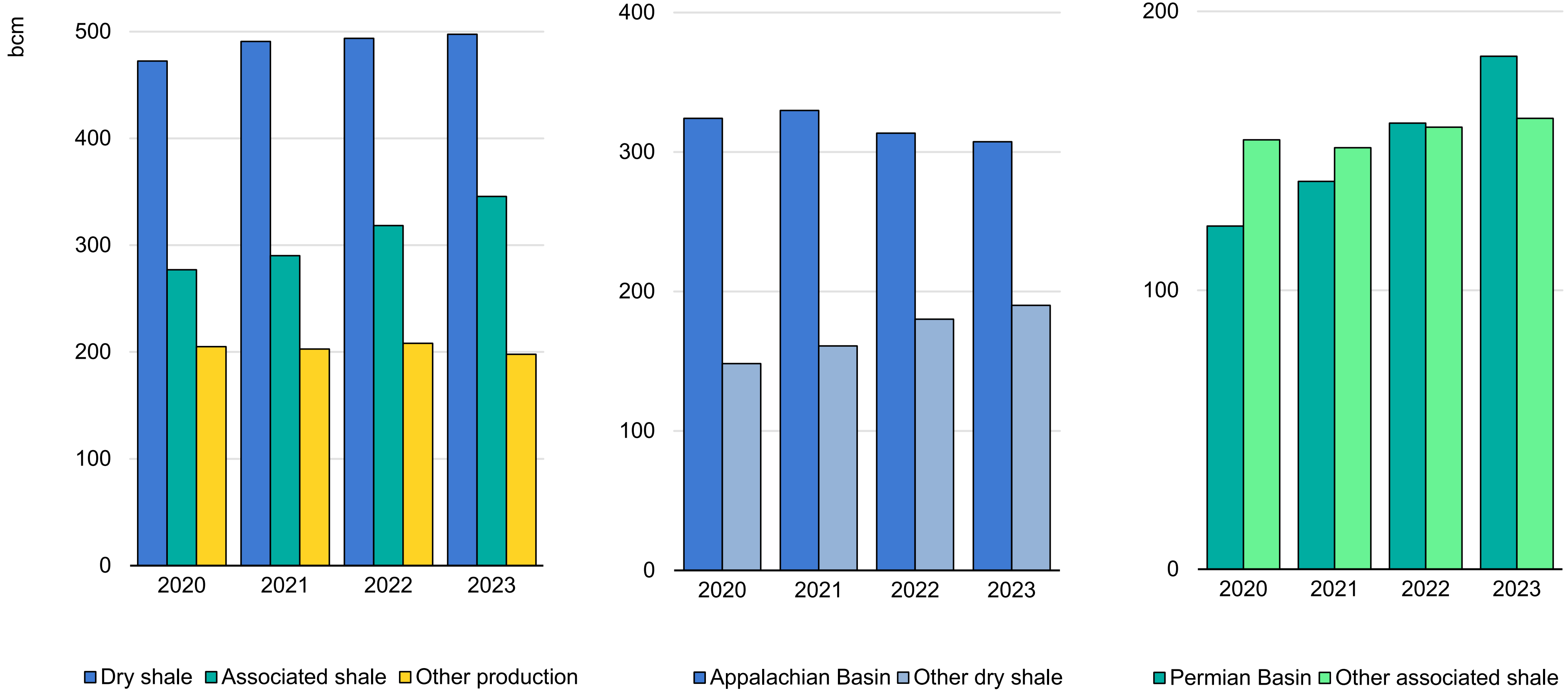
Gas production by type, United States, 2018-2023



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

US natural gas production keeps growing in 2023, but at a slower pace

Dry gas production by main source, United States, 2020-2023



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

LNG became a baseload supply for Europe…

While the share of OECD Europe's gas demand met by Russian piped gas fell to well below 10% in the 2022/23 heating season, LNG effectively became a baseload supply for Europe, meeting over one-third of the region's gas demand over the winter.

Russian piped gas exports to OECD Europe fell by an estimated 70% (or 50 bcm) y-o-y during the 2022/23 heating season. While deliveries to Türkiye declined by close to 30% y-o-y, gas flows to the European Union plummeted by over 80%, translating into a drop of 47 bcm compared to the previous heating season. In contrast, the Russian Federation's (hereafter "Russia") LNG exports to the European Union rose by 5% (or 0.5 bcm) compared to the 2021/22 winter period. Altogether, the share of the European Union's total gas demand met by Russian gas is estimated to have dropped to just 10%, while the share met by Russian piped gas is now well below 10%.

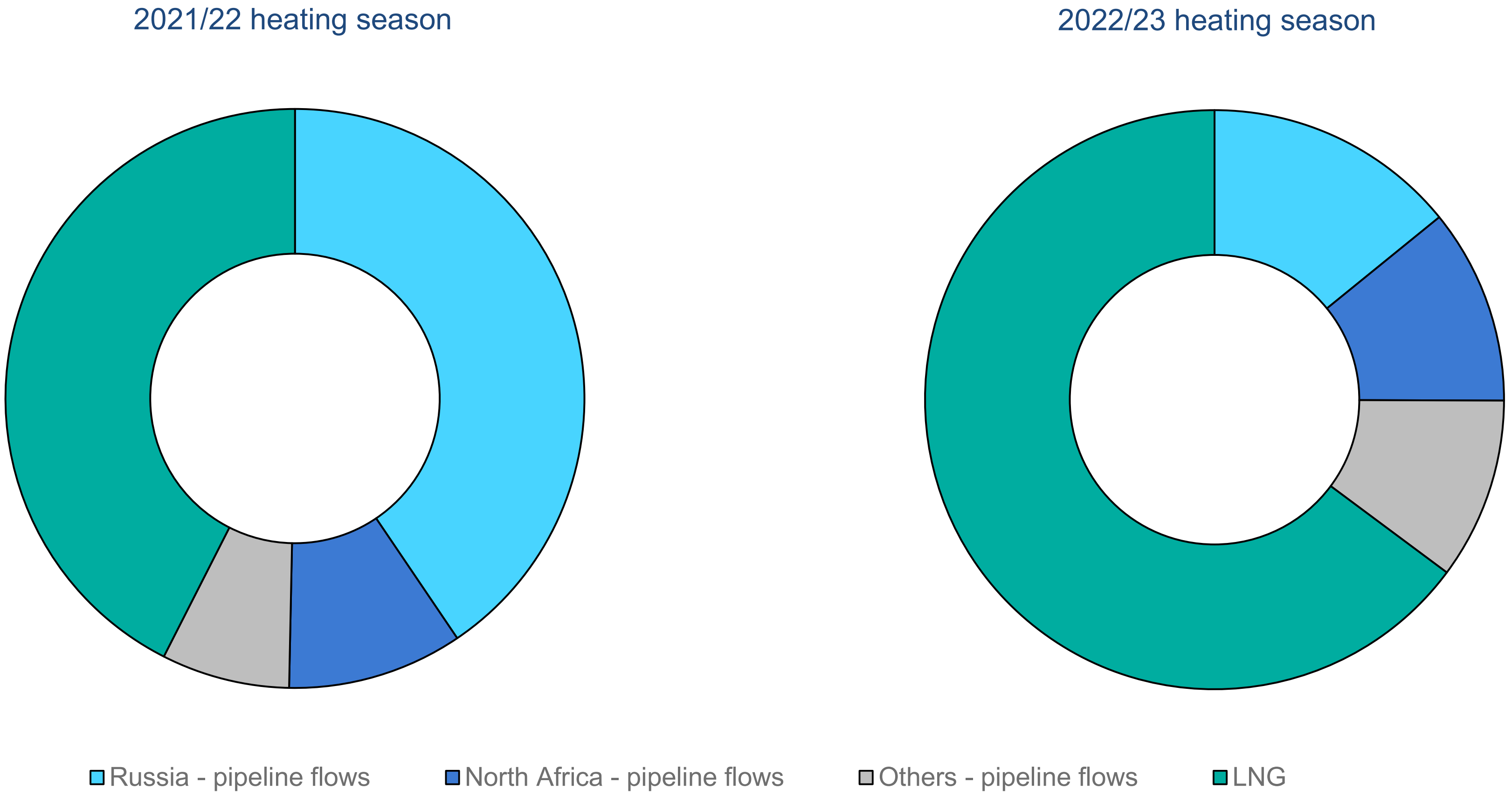
Norway's piped gas supplies to the rest of Europe declined by 4% (or 2.5 bcm) y-o-y during the 2022/23 heating season amid a higher level of planned maintenance and unplanned outages. Norwegian pipeline deliveries to the European Union rose by 2% (or 0.8 bcm), while exports to the United Kingdom fell by around 18% (or 3 bcm). Non-Norwegian domestic production fell by an estimated 5% (or 1.8 bcm) y-o-y during October 2022-February 2023. This was largely driven by lower gas output in the Netherlands, reflecting the continued phase-out of the Groningen field. Pipeline gas deliveries from North Africa declined by 8% (or 1.4 bcm) y-o-y, with flows to Iberia falling by 25% (or 1.3 bcm) and remaining broadly flat to Italy. Gas supplies from Azerbaijan via the Trans Adriatic Pipeline rose by 15% (or 0.8 bcm) compared to the previous heating season.

LNG imports rose by over 25% (or 20 bcm) y-o-y to reach a record 94 bcm during the 2022/23 heating season. LNG flows from the United States increased by 30% (or almost 10 bcm) y-o-y to account for over 45% of incremental LNG supply into Europe. This further reinforced the position of the United States as Europe's largest supplier, accounting for over 40% of the region's total LNG imports and meeting almost 15% of its gas demand. Qatar increased its gas deliveries by 15% (or 1.5 bcm), primarily supported by higher supplies to Belgium, France, Italy and Poland.

The profile of Russian piped gas supplies remains a major uncertainty for the remainder of 2023. Assuming that flows to the European Union continue at their Q1 levels, Russian piped gas deliveries to OECD Europe would drop by 45% (or over 35 bcm) in 2023 compared with 2022. LNG imports are expected to remain broadly flat compared to last year. Following a strong increase in Q1 2023, OECD Europe's LNG inflows are expected to decline through the remainder of the year amidst lower injection needs and a continued decline in European gas consumption.

…accounting for two-thirds of imports during the 2022/23 heating season

OECD Europe's natural gas imports by pipeline and LNG



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

Global LNG demand moderated in Q1 while remaining strong in Europe

In Q1 2023 global LNG imports (net of re-exports) expanded by an estimated 2% y-o-y.

LNG imports into the **Asia Pacific** region increased slightly compared with Q1 2022, up by 0.5% (or 0.4 bcm). The greatest y-o-y declines during the first quarter in volume terms occurred in Japan (down by 2 bcm or 7% y-o-y), India (down by 0.6 bcm or 9% y-o-y), and China (down by 0.3 bcm or 1.4% y-o-y). In contrast, LNG imports increased in South Korea (up by 1.5 bcm or 8% y-o-y), Thailand (up by 0.5 bcm or 18% y-o-y), Singapore (up by 0.4 bcm or 40% y-o-y) and Chinese Taipei (up by 0.3 bcm or 5% y-o-y). LNG imports into Pakistan and Bangladesh remained stable compared with Q1 2022.

After months of year-on-year declines in China's LNG imports (net of re-exports), volumes rebounded in February, up by 2% on the same month in 2022 according to ICIS LNG Edge. This was the first time that monthly Chinese LNG imports recorded a year-on-year increase since December 2021. This rebound seemed to be confirmed in March as net LNG imports increased by 11% y-o-y.

Although they remained well above historical averages, Asian LNG spot prices fell significantly in Q1 2023 from the record levels reached in the summer of 2022. In the first quarter of 2023 the average JKM spot price was around USD 18/MBtu, compared with USD 30/MBtu in the first quarter of 2022 and having reached USD 70/MBtu at the peak in August 2022. In March 2023 spot LNG prices in Northeast Asia averaged at USD 13/MBtu, encouraging South Asian buyers to return to spot markets via tenders.

Meanwhile, **Europe**'s net LNG imports rose by 8% (or 3.5 bcm) y-o-y in Q1 2023 as the continent continued to offset declining Russian pipeline gas supplies, mainly by increasing LNG imports and taking advantage of low gas price levels not seen since August 2021. However, LNG inflows into France dropped by 23% y-o-y in Q1 (or 2 bcm) and by 55% y-o-y in March alone, due to a strike at French LNG terminals. Strikes at Dunkerque LNG brought send-out from the terminal to a minimum, closed the jetty for vessel operations and prevented truck loading for 11 days in March. Disruption due to strikes at Fos Cavaou, Fos Tonkin and Montoir-de-Bretagne LNG import terminals started on 7 March and these strikes were extended until 14 April at the time of writing. France accounts for around 12% (or 26 Mt/yr) of Europe's total regasification capacity. It became the largest importer of LNG in Europe in 2022, with its LNG imports more than doubling on the previous year. The work stoppages at French LNG terminals have caused vessels to divert to other European ports, mainly to the United Kingdom and Spain, but also to the Netherlands, Türkiye and Greece. Based on ICIS data and analysis, we estimate the total loss of LNG deliveries to France to be between 1 bcm and 1.5 bcm for the month of March

2023. As a result, France has been forced to lean on its storage inventories. Data from Gas Infrastructure Europe show that French underground storage facilities were 28% full at the end of March, the lowest fill level among European countries, where the average was 56%.

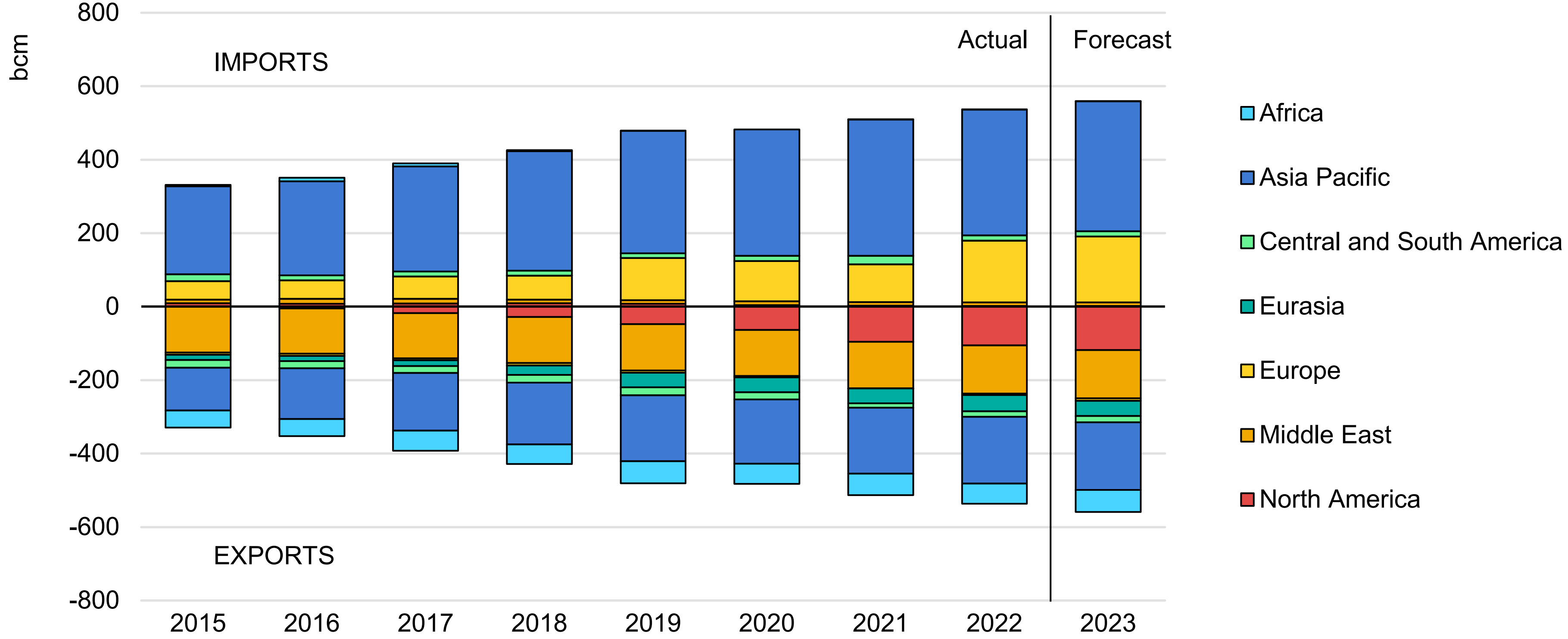
In Q1 2023 **Central and South America** experienced a sharp decline in LNG demand (down 28% y-o-y or 1 bcm), mainly due to the improved situation for hydropower generation in Brazil – which did not receive a single LNG cargo during Q1 – and the increasing share of renewables in the power mix in the Dominican Republic.

Global LNG supply was up by 2% y-o-y in Q1 2023 measured on an import basis. This was driven by the Asia Pacific region and the Middle East, which saw a year-on-year increase of 5.5% (or 2.6 bcm) and 2% (or 0.7 bcm) in their LNG outputs respectively. Qatar and Indonesia, followed by Australia and Malaysia, were the main contributors to this expansion. In contrast to the first quarter of 2022, the United States experienced a moderate 4% (or 1 bcm) decline in LNG exports, explained by the delayed and only partial restart of the Freeport LNG facility following an eight-month outage caused by a fire. LNG exports from Norway recovered from last year's first quarter with an increase of 1.5 bcm, reflecting the return to production of the Hammerfest LNG plant, which was offline between September 2020 and June 2022 following a fire. LNG exports from Russia were down by 9% (or 1 bcm) this quarter compared to the same period in 2022. Sakhalin-II LNG's project operator announced in February 2023 that the plant will move away from the "peak-load" strategy it has been pursuing in the last few years. Novatek expects YAMAL LNG production to drop by 5% year-on-year in 2023, the company's top management said at the beginning of February 2023.

In 2023 the volume of global LNG trade is set to increase by 4%. LNG supply growth will be primarily supported by the return of the Freeport LNG terminal in the United States, improving feedgas availability in Trinidad & Tobago, and the ramp-up of production at Mozambique's Coral South FLNG. Demand growth will be largely driven by Asia. China's LNG imports are expected to increase at a rate of 10-15% compared with 2022, while remaining below their 2021 levels. After strong growth in Q1 2023, OECD Europe's LNG imports are expected to decline for the remainder of the year amidst lower injection needs and a continued decline in European gas consumption.

The United States is set to drive LNG supply growth in 2023

LNG imports and exports by region, 2015-2023



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

Not feeling the heat: Gas prices moderated significantly during the 2022/23 winter

Unseasonably mild weather, lower gas demand and improving supply fundamentals weighed on spot gas prices across all key gas markets during the 2022/23 winter. By the end of Q1 2023, Asian spot LNG and European hub prices had fallen below their summer 2021 levels, albeit remaining well above their historic averages.

In Europe, Title Transfer Facility (TTF) spot prices averaged USD 23/MBtu during the 2022/23 heating season – almost 30% below the levels experienced in the previous winter. Gas prices on the TTF declined by almost 70% between mid-December 2022 and the end of March 2023. Unseasonably mild weather conditions, lower-than-expected gas use, strong LNG supply and gas inventory levels standing well above their historic averages provided strong downward pressure on European gas prices. TTF spot prices averaged USD 17/MBtu in Q1 2023, a decline of 48% on the same period the year before, although remaining more than three times the historic average of the 2016-2020 period. The TTF retained a premium of USD 2.6/MBtu above the NBP hub in the United Kingdom. This incentivised continued gas exports from the United Kingdom to the European Union over the heating season, totalling at over 7 bcm. By the end of March 2023, TTF month-ahead prices had fallen to USD 13/MBtu, their lowest level since July 2021.

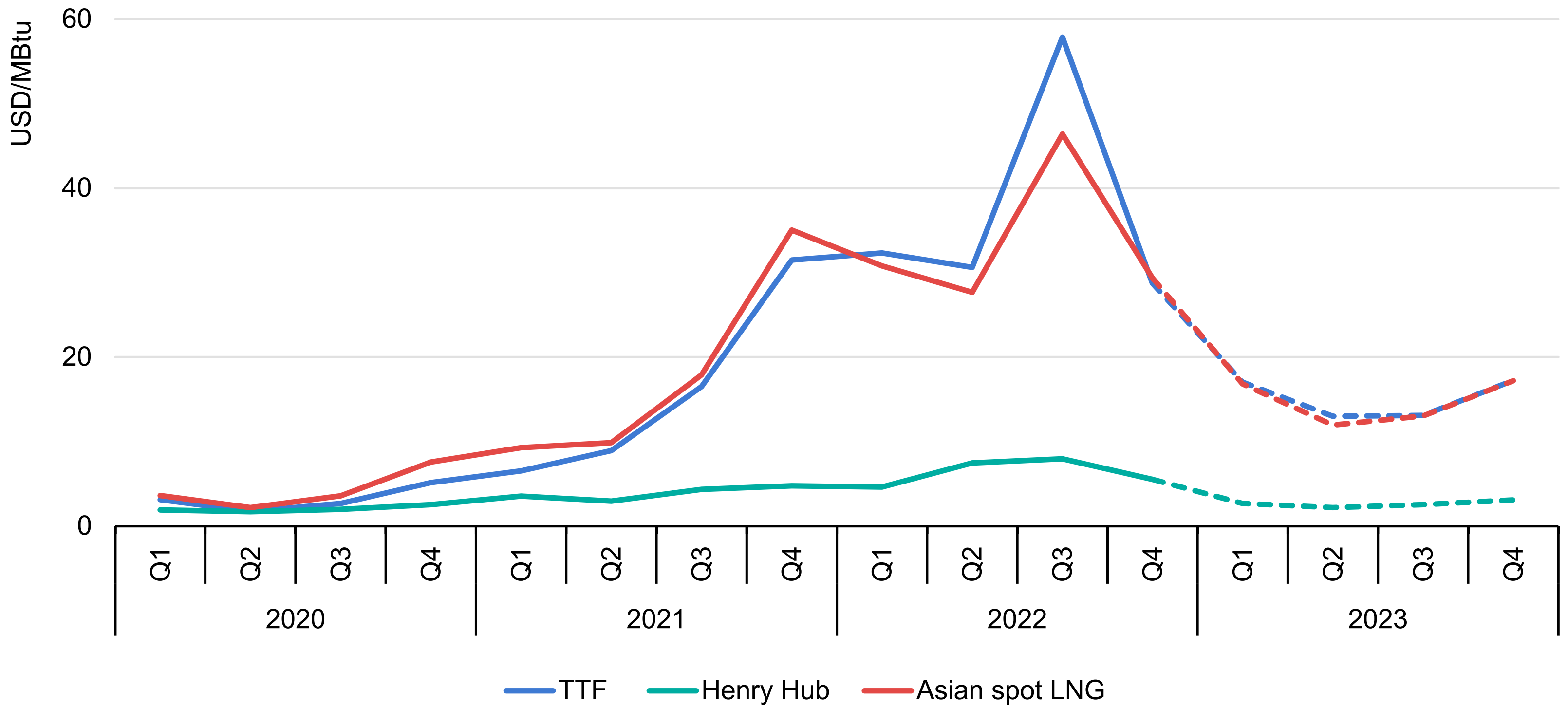
Asian spot LNG followed a similar trajectory to European hub prices, averaging USD 23/MBtu during the 2022/23 heating season – around 30% below the levels experienced in the previous winter. Less competition from Europe together with easing regional supply-demand fundamentals provided downward pressure on prices. Spot LNG prices declined by 65% from mid-December 2022, falling to almost USD 12/MBtu at the end of March 2023 – a level close to the estimated price range of oil-indexed Asian LNG.

In the United States, Henry Hub prices averaged USD 4/MBtu in the 2022/23 heating season, almost 15% below the levels experienced during the previous winter. Strong growth in domestic production combined with lower gas demand amid an unseasonably mild winter put downward pressure on gas prices. Henry Hub prices averaged USD 2.6/MBtu in Q1 2023, their lowest Q1 level since 2020.

Forward curves as of the end of April 2023 indicate that TTF is set to average USD 15/MBtu in 2023, with Asian spot LNG averaging just below USD 15/MBtu and Henry Hub averaging USD 2.6/MBtu. The price spread between TTF and Asian spot LNG is expected to tighten significantly in 2023.

Asian spot LNG and TTF prices are expected to remain above their historic averages in 2023

Main spot and forward natural gas prices, 2020-2023



Sources: IEA analysis based on CME (2023), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements; CME Group (2023), 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.

Mild winter and low gas demand depressed storage withdrawals over the 2022/23 winter season

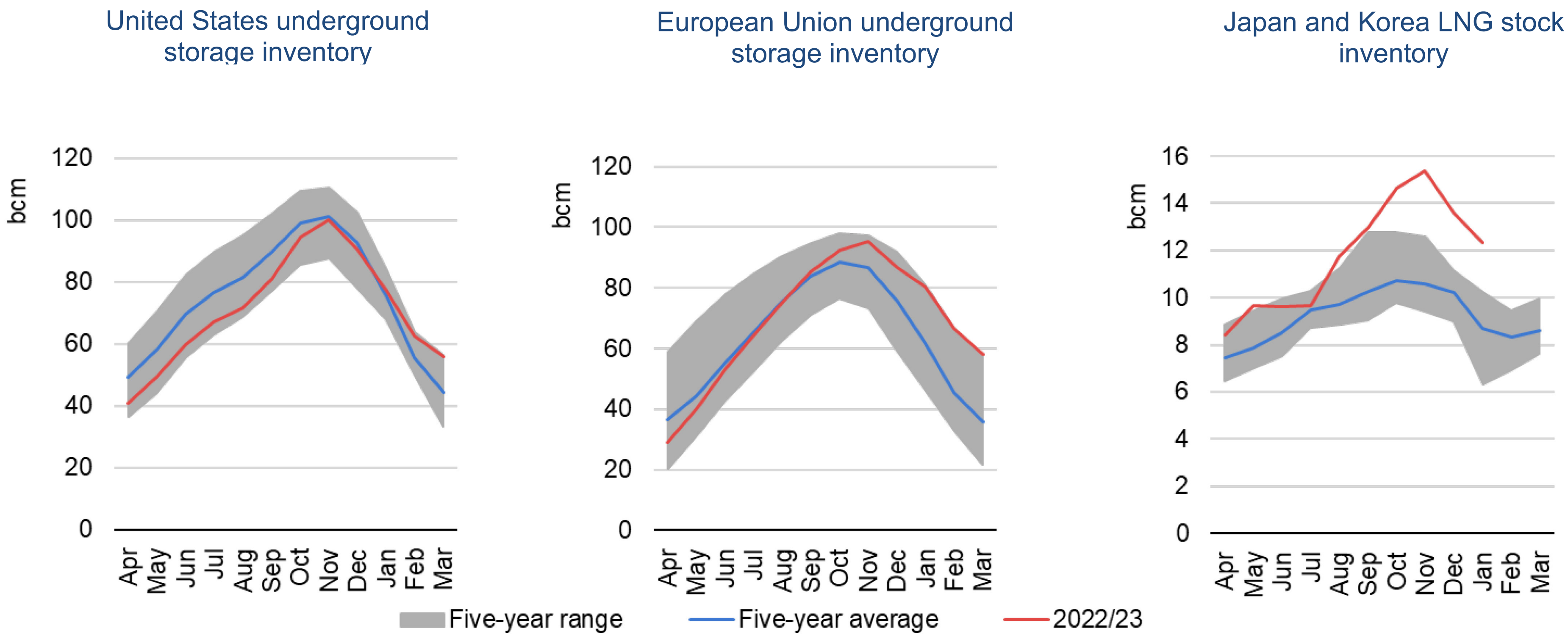
The steep decline in natural gas demand depressed storage withdrawals in Europe and the United States over the 2022/23 winter season. Storage sites closed the heating season with inventory levels standing well above their five-year average. This is expected to reduce injection demand during the summer of 2023, easing market fundamentals.

In the **European Union** gas inventory levels had reached 95% of their working storage capacity by mid-November, standing 9% (or 8 bcm) above their five-year average. The steep drop in natural gas demand combined with continued strong LNG inflow reduced the call for storage withdrawals. Net storage withdrawals stood 38% (or 20 bcm) below their five-year average during the 2022/23 heating season and totalled 32 bcm. Altogether, net storage withdrawals met around 15% of EU gas demand over the 2022/23 heating season, compared with 20% during the previous winter. These average values hide the critical role of gas storage in ensuring gas supply adequacy during peak days: storage met over 40% of EU gas demand during the coldest winter days in early December 2022 and late January 2023. As a consequence of the below average net withdrawals, EU storage sites closed the 2022/23 heating season 55% full and with inventory levels standing 67% (or 22 bcm) above their five-year average. Hence, storage injections equal to half of last year's (around 35 bcm) would suffice to reach the European Union's 90% fill level target by the start of the 2023/24 heating season. Lower injection demand over summer 2023 could potentially contribute to an easing of market fundamentals. In **Ukraine** gas inventory levels at the end of March 2023 were estimated at 9 bcm (around 29% of working storage capacity). Ukraine has a target to build up gas storage of 15 bcm by the start of the 2023/24 heating season.

In the **United States** storage sites were 80% full at the beginning of November, well aligned with their five-year average. Unseasonably mild weather conditions combined with a strong increase in domestic production reduced storage withdrawals. Net storage withdrawals stood almost 30% (or 15 bcm) below their five-year average during October 2022-March 2023, and met approximately 7% of US gas demand during this period. As a consequence of below average draw on storage, US storage sites closed the 2022/23 heating season 43% full, standing 20% (or 12 bcm) above their five-year average.

In **Japan and Korea** closing LNG stocks stood 47% (or 4 bcm) above their five-year average in January 2023. The LNG stocks of Japan's largest power generation companies stood at 2.6 Mt (3.6 bcm) at end of March 2023, 25% above their five-year average.

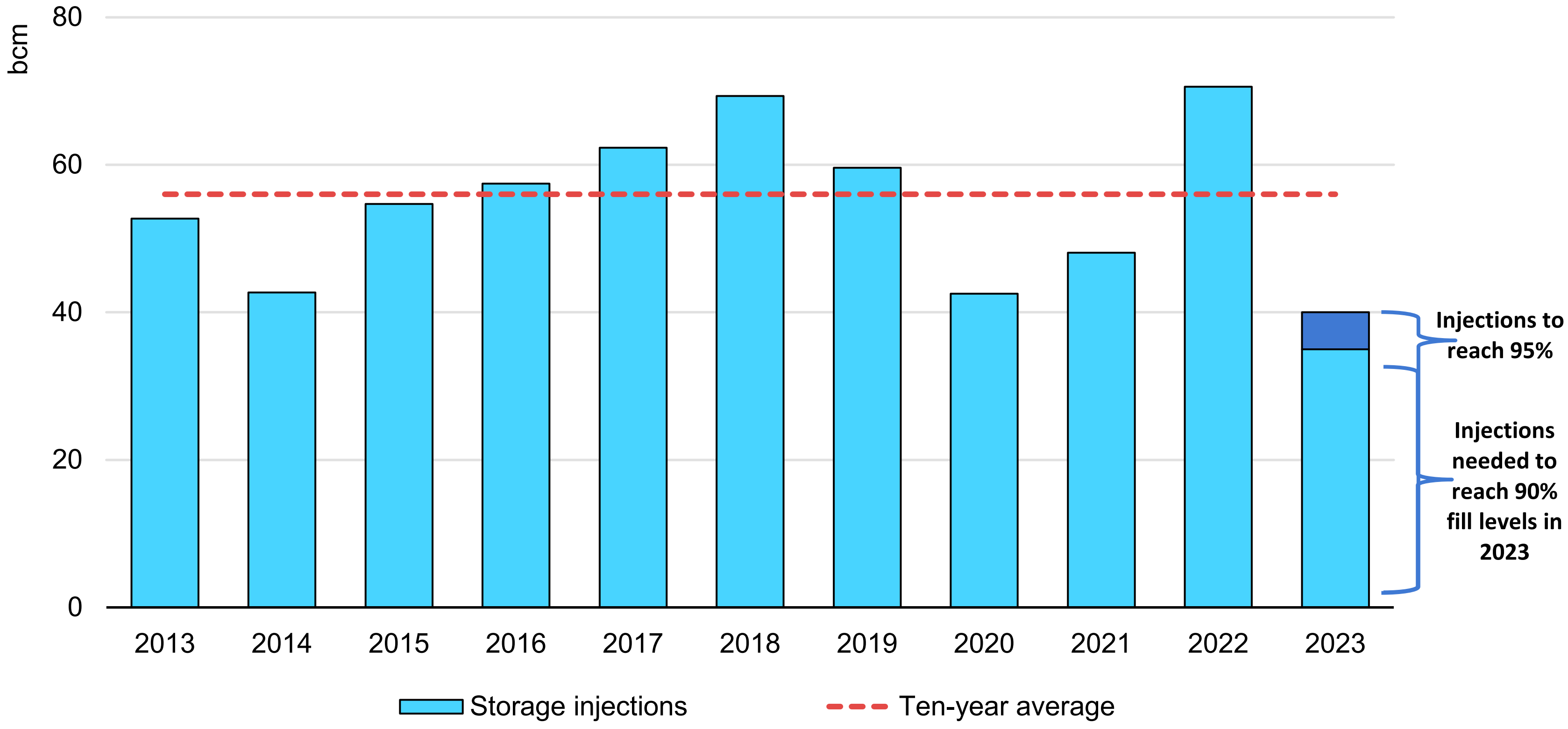
Storage levels closed the 2022/23 heating season well above their five-year average



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

In the European Union storage injections equal to half of last year's would suffice to reach 90% fill levels by the start of the 2023/24 heating season

Gas storage injections, European Union, 2013-2023



Source: IEA analysis based on GIE (2023), AGSI+ Database.

Spotlight on e-methane

E-methane: A gas fit for net zero?

Being interchangeable with natural gas, **e-methane[2] could play a significant role in decarbonising existing gas networks** without the need for retrofitting, while enhancing the seasonal and short-term flexibility of future energy systems. E-methane's high production costs require further technological development and policy support, including through closer dialogue between future producers and consumers.

E-methane is underpinned by a complex value chain…

E-methane is produced through a two-step process: low-emission electricity is converted via **electrolysis** into hydrogen, which is then reacted with a carbon source to obtain e-methane (**methanation**). Two main methanation technologies are available for demonstration:

- **Catalytic methanation** is enabled by catalysts operating at high temperature (200-700°C) and under high pressure (1-100 bar). Several demonstration projects rely on catalytic methanation, with the process having achieved a Technology Readiness Level of 7.[3] The system efficiency of catalytic methanation is around 80%.
- **Biological methanation** is carried out at comparatively low temperatures (30-70°C) and pressures. The conversion of hydrogen and CO_2 is enabled by microorganisms. This technology is not commercially available yet and is expected to have a lower efficiency compared with catalytic methanation, around 55-60%.

The overall e-methane production process presents substantial efficiency losses. Approximately half of the primary energy supplied is lost during the two-step conversion process. Moreover, its production and usage require the development of a **separate carbon value chain** and emission accounting system (to ensure its carbon neutrality). Similarly to natural gas, **e-methane can be liquefied**, which would result in an additional 10% energy loss. Liquefied e-methane could enable the development of long-distance trade routes (similar to the global LNG trade) and support the decarbonisation of maritime transport.

…resulting in high production costs

The complex value chain underpinning the production of e-methane means that **both investment costs and operational expenses are high.** Current e-methane production costs are estimated to be

[2] E-methane refers to synthetic methane produced from electrolytic hydrogen. The definition of low-emission synthetic methane used by the IEA for analytical purposes in its reports considers that any carbon inputs, e.g. from CO_2, are not from fossil fuels or process emissions. Beyond this definition, a commercial proposition for carbon-neutral e-methane could consider the use of CO_2 captured at industrial or power plants and offset through carbon credits (similar to the commercial offers of carbon-neutral LNG).

[3] Of the 11 Technology Readiness Levels (TRLs), with 1 being the lowest, TRL 7 refers to pre-commercial demonstration of a prototype.

in the range of USD 50-200/MBtu. Bringing down the cost of low-emission electricity and hydrogen production will be crucial to enhance the cost-competitiveness of e-methane.

The levelised cost of **renewables-based low-emission hydrogen** is currently in the range of USD 3-9/kg H_2 (USD 25-80/MBtu). Under the Announced Pledges Scenario (APS), renewable electrolytic hydrogen production costs could be in the range of USD 1.3-6/kg H_2 (USD 12-53 MBtu) by 2030 and USD 1-4/kg H_2 (USD 8-34 MBtu) by 2050. The strong decline in the levelised cost of low-emission hydrogen production relates to several factors, including **decreasing electrolysis and renewable technology costs**. For example, we estimated that the total cost of installing a European or American manufactured electrolyser in 2021 was about USD 1 500/kW, and that it could fall to below USD 400/kW by 2030 and to below 300/kW by 2050 in the Announced Pledges Scenario.

Considering the additional investment required in methanation systems, the efficiency losses and the expenses related to CO_2 sourcing, **e-methane production costs are substantially higher compared with low-emission hydrogen**. Depending on the carbon source, the production cost of synthetic methane can be 70-160% higher than the cost of the hydrogen used as input. The **CAPEX for catalytic methanation systems** is estimated at around USD 1000/kW. The CAPEX of methanation systems could decline to below USD 850/kW by 2030 and to around USD 500/kW by 2050. Together with the cost reductions projected for DAC and bioenergy with carbon capture (BECC), e-methane production costs could decline to a range of USD 25-110/MBtu by 2030 in the APS.

E-methane can play a key role in future market coupling

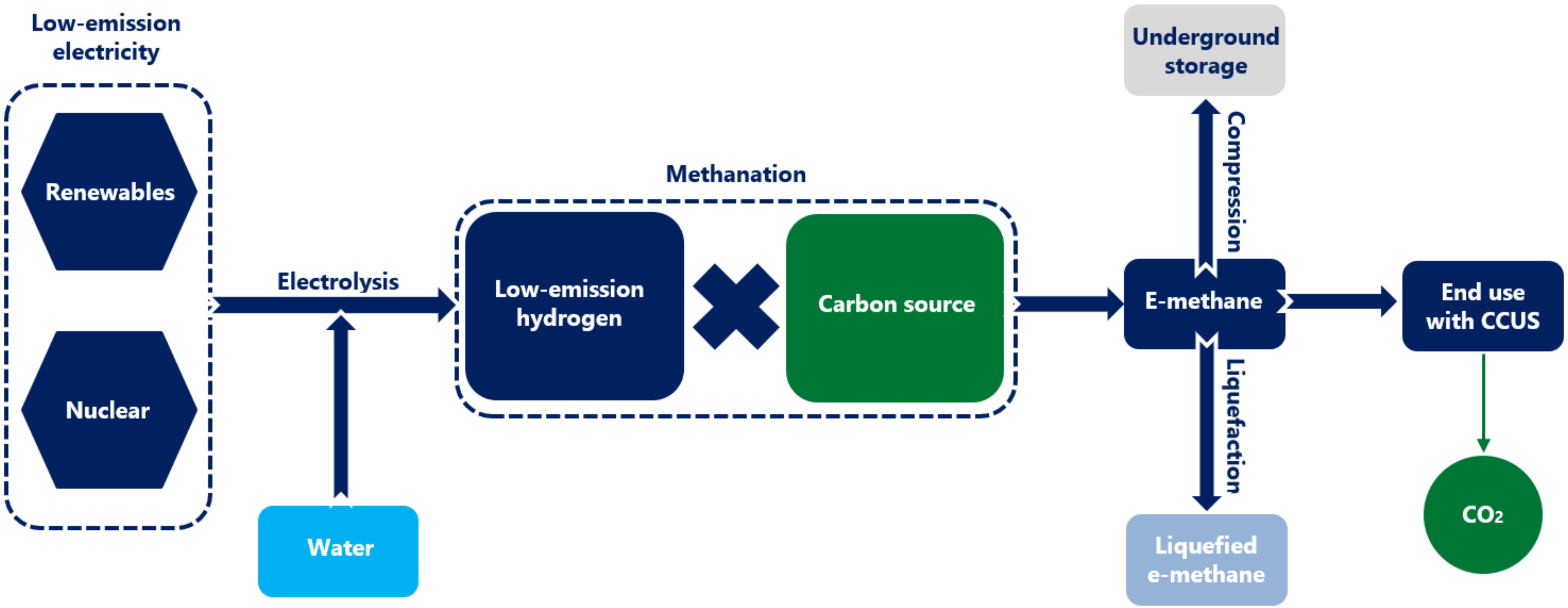
E-methane is almost identical to natural gas in its chemical and physical properties. As such, it is **suitable for use in existing gas infrastructure** including end-use appliances without requiring any substantial repurposing, unlike the case of pure hydrogen. **This could lead to significant cost savings.** E-methane could also use existing or planned LNG liquefaction and regasification infrastructure. In contrast, there are limited options to repurpose existing or planned LNG infrastructure for hydrogen service, as it would require substantial modification of most equipment – including storage tanks, which represent the majority of the investment cost of LNG import terminals. A newly constructed liquid hydrogen storage tank can be 50% more expensive than an LNG tank with a comparable volume, and the energy stored would be almost 60% lower given the lower volumetric density. Moreover, the typical foam insulation used for LNG pipelines are unsuitable for liquid hydrogen, which instead require vacuum insulation, hiking pipeline costs by five to ten times per unit of length. Liquefied e-methane could be transported via the existing LNG carrier fleet (around 600 ships with a collective value of USD 80 billion), an option not available in the case of low-emission hydrogen.

E-methane also has a **wider range of storage options** compared with hydrogen. Besides salt caverns, it could also be stored in porous formations in gaseous form (an option still being investigated for pure hydrogen) and in LNG storage tanks (an option that is unlikely to be available for pure hydrogen). Hence, e-methane could play a key role in meeting seasonal or short-term energy demand swings. In addition, synthetic methane would enable the **coupling of methane and hydrogen networks**, i.e. surplus hydrogen could be converted into synthetic methane before being injected into the methane system.

Considering the higher energy density of e-methane in gaseous form, it could have an operational advantage over hydrogen in several areas where natural gas is already widely adopted, including district heating, high-temperature industrial process and fertiliser production.

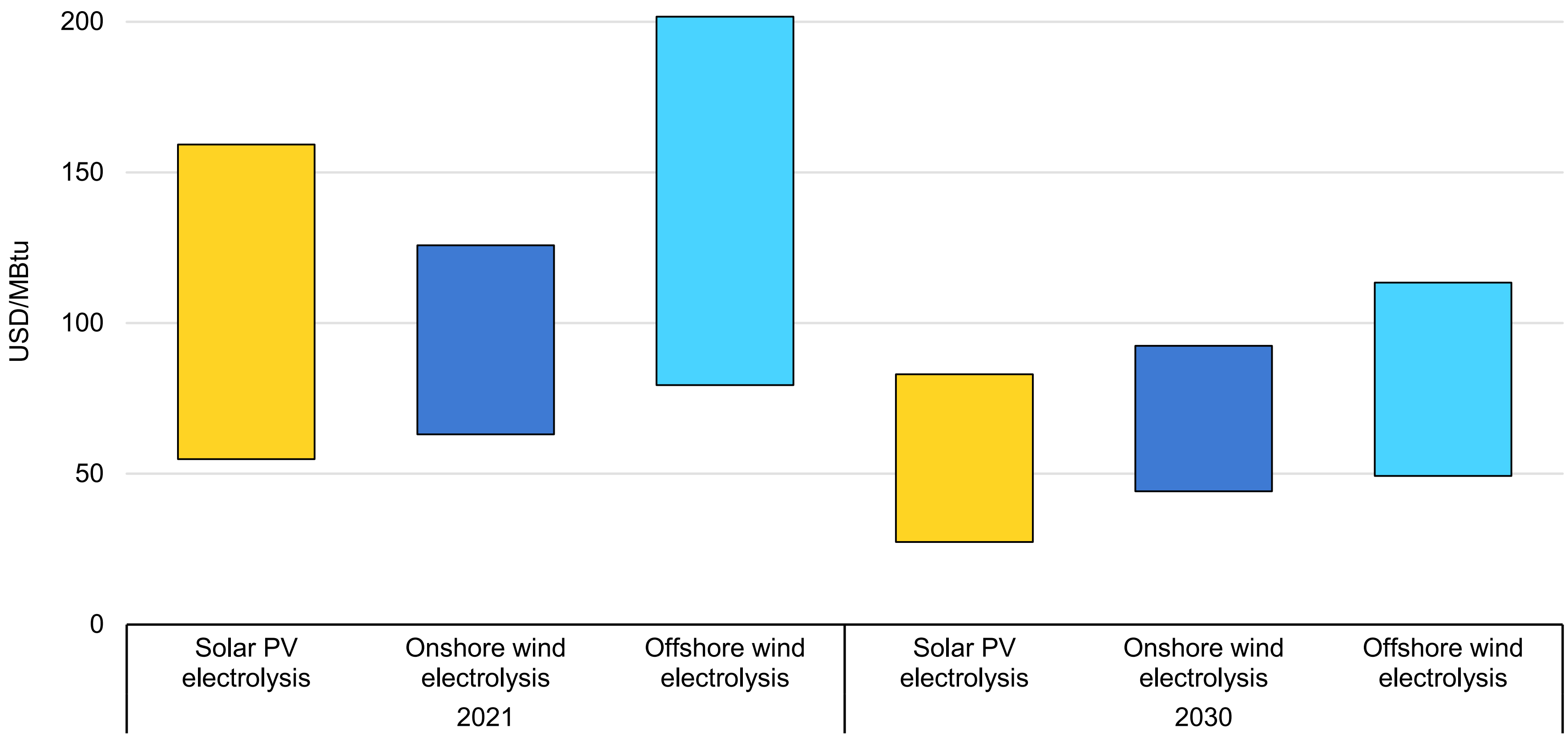
E-methane is characterised by a complex value chain with substantial efficiency losses

Simplified scheme showing e-methane production



E-methane's high production costs require further technological development and policy support

Estimated level cost of synthetic methane production, 2021 vs. 2030



Japan: A first mover in the e-methane space

Recognising the benefits of e-methane, Japan is considering methanation as a key component of its strategy to decarbonise its gas supply. The country's 6th Strategic Energy Plan set a target for synthetic methane to comprise 1% of the gas supply in existing networks by 2030, increasing to 90% by 2050. Japan aims to reduce e-methane costs to JPY 120 per normal cubic metre (Nm^3) (USD 25/MBtu) by 2030, and down further to JPY 50/Nm^3 (USD 10/MBtu) by 2050.

The country's Strategic Energy Plan aims to ramp up annual e-methane supply to 0.28 Mt (or 0.38 bcm/yr) by 2030 and 25 Mt (or 34 bcm/yr) by 2050. This amount excludes direct hydrogen, biogas and other direct uses of non-fossil fuels. The strategy highlights the importance of a closer co-operation between the various stakeholders on the supply and the demand side in decarbonising gas. To foster the development of e-methane, a **Public-Private Council for the Promotion of Methanation** was established in June 2021.

Japan funds e-methane projects through the New Energy and Industrial Technology Development Organization (NEDO). NEDO provides R&D funding and financial support for demonstration projects under their **Green Innovation (GI) Fund**. In 2017 NEDO launched a five-year programme worth JPY 1.9 billion (around USD 14 million) to research and demonstrate the viability of methanation technologies as a means to reduce emissions while continuing to use existing gas networks. Japan's **Green Transformation (GX) programme** is set to provide another major funding boost for technologies that produce low-emission hydrogen, ammonia and e-methane.

Several Japanese enterprises have embarked on e-methane production projects. Tokyo Gas started a 12.5 m^3/hr demonstration project in Yokohama in March 2022. The company has a target to produce 80 million m^3/yr of e-methane by 2030. **Osaka Gas** is developing a prototype with 0.1 m^3/hr capacity, with plans to enter the demonstration phase in 2028-2030 at 400 m^3/hr. The company has a target to produce 60 million m^3/yr of synthetic methane by 2030.

INPEX and Osaka Gas are developing Japan's largest methanation project in Nagoya. The project is expected to be launched by the second half of FY 2024/25, with production expected to ramp up to 400 m^3/hr by FY 2025/26. There are plans to increase output to 10 000 m^3/hr in the pilot phase and 60 000 m^3/hr if the project reaches the commercial phase.

Most recently, **JFE Steel Corporation** awarded **IHI Corporation** an order for the world's largest methanation system in December

2022, after being selected by the GI Fund. The plant will be able to produce 500 m^3/hr of e-methane by using 24 tonnes of CO_2 per day from exhaust gas derived from a test blast furnace. Operations are scheduled to begin in 2024.

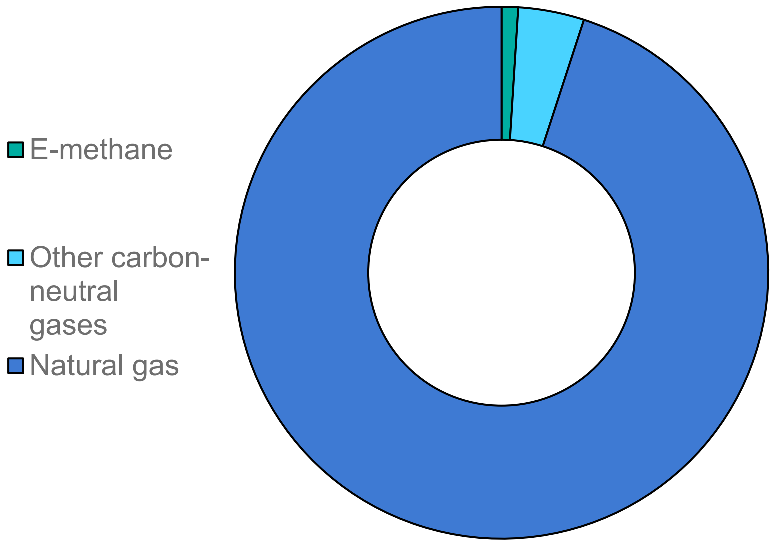
In addition to domestic demonstration projects, Japanese utilities and trading houses have started jointly exploring the feasibility of developing **e-methane supply chains** with LNG exporting countries. While **no binding agreements have been reached** yet, these recent project proposals could potentially enable 0.4 Mt/yr (or 0.55 bcm/yr) of e-methane imports into Japan by 2030. This would equate to around 0.6% of Japan's natural gas consumption in 2022.

Projects include the agreement between **Tokyo Gas, Osaka Gas, Toho Gas and Mitsubishi Corporation** to conduct a feasibility study of the production of e-methane at the Cameron LNG terminal in the United States. The companies' intention is to export 130 000 t/yr of synthetic methane by 2030. Similarly, **Osaka Gas, Tallgrass Energy and Green Plains** agreed in December 2022 to conduct a joint feasibility study on synthetic methane production. The firms aim to produce up to 200 000 t/yr of synthetic methane by 2030 and export it to Japan from the Freeport LNG export terminal in the United States. Most recently, **Osaka Gas Australia and Santos** agreed in March 2023 on pre-front end engineering and design work for a demonstration-scale project to produce e-methane from low-emission hydrogen in Australia. The two companies aim to reach a final investment decision in 2026 and export about 60 000 tonnes of e-methane annually by 2030.

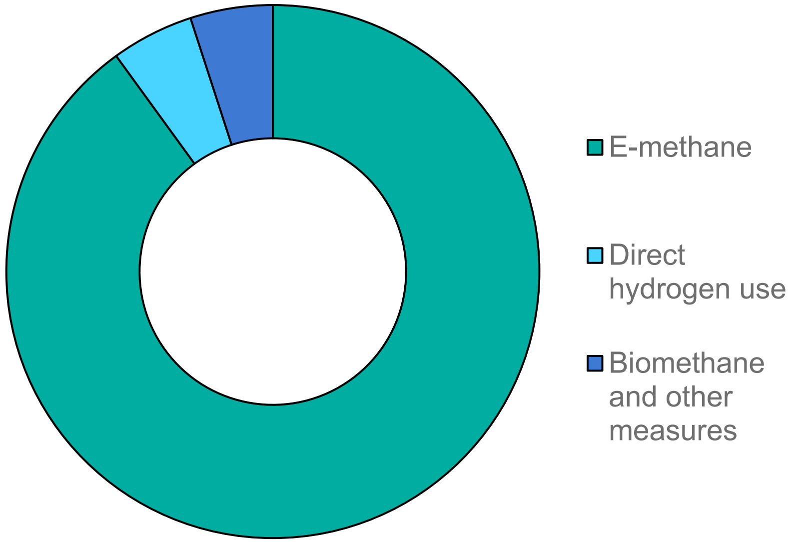
A non-exhaustive list of key international e-methane projects supported by Japanese companies is provided at the end of this section.

Japan has set a target for e-methane to meet 90% of its city gas supply by 2050

City gas consumption of gaseous fuels, 2030



City gas consumption of gaseous fuels, 2050



Source: IEA analysis based on Japan's 6th Strategic Energy Plan.

Japan is actively developing international value chains for e-methane

Companies involved	Potential import country	Year of agreement	Potential import volumes	Description of the project
Tokyo Gas, Sumitomo Corporation and Petronas	Malaysia	2021	N/A	A joint feasibility study on potential e-methane production in Malaysia. The renewable hydrogen-derived methane produced in Malaysia would be liquefied and transported to Japan in LNG carriers using existing facilities.
INPEX and Osaka Gas	N/A	2021	N/A	Study on the commercial feasibility of importing e-methane into Japan and evaluation of policies on the domestic environmental value of importing e-methane produced abroad.
JERA	United States	2021	N/K	JERA secured a grant of around USD 0.45 million from NEDO to conduct a feasibility study on producing a CO_2-free LNG from e-methane in the United States.
Osaka Gas Australia and ATCO Australia	Australia	2021	N/A	A memorandum of understanding to undertake a joint feasibility study of a methanation pilot plant for the production of e-methane.
Toyota Tsusho, Toho Gas and TotalEnergies	N/A	2022	N/A	An agreement to commence a business feasibility study of establishing hydrogen and e-methane supply chains into Japan.
Marubeni and Osaka Gas	Peru	2022	N/K	A project to study the production of e-methane in Peru and its delivery to Japan.
Tokyo Gas, Osaka Gas and Shell	N/A	2022	N/A	Separate memorandums of understanding to explore potential opportunities to accelerate decarbonisation across their respective production value chains, including via renewables-based synthetic gas.
Tokyo Gas, Osaka Gas, Toho Gas and Mitsubishi Corporation	United States	2022	0.13 Mt/yr by 2030	An agreement to conduct a feasibility study of the production of e-methane at the Cameron LNG terminal in the United States. E-methane supply could reach 0.13 Mt/yr by 2030.
Osaka Gas, Tallgrass Energy and Green Plains	United States	2022	0.2 Mt/yr by 2030	Agreement to conduct a feasibility study on synthetic methane production at the Freeport LNG export terminal in the United States.
IHI Corporation and Pertamina	Indonesia	2022	N/K	Memorandum of understanding to undertake a feasibility study on e-methane production in Indonesia. Aiming to start commercial operations by 2030.
Osaka Gas Australia and Santos	Australia	2023	0.06 Mt/yr by 2030	Pre-front end engineering and design work on a demonstration-scale project to produce e-methane from low-emission hydrogen in Australia. The two companies aim to make a final investment decision in 2026.

Notes: N/A = not applicable; N/K = not known.

Annex

Summary table

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

	Consumption					Production				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
Africa	164	161	169	164	168	252	241	262	251	262
Asia Pacific	829	834	891	877	905	630	626	651	659	666
of which China	*307*	*325*	*367*	*364*	*388*	*174*	*189*	*205*	*218*	*228*
Central and South America	156	142	153	151	149	167	150	148	152	154
Eurasia	608	584	634	610	610	921	866	961	873	820
of which Russia	*482*	*460*	*501*	*475*	*476*	*738*	*692*	*762*	*672*	*620*
Europe	590	576	609	524	498	249	230	222	230	226
Middle East	543	547	562	575	588	668	669	693	712	727
North America	1 104	1 079	1 091	1 145	1 122	1 164	1 145	1 183	1 230	1 250
of which United States	*886*	*868*	*874*	*921*	*899*	*968*	*954*	*984*	*1020*	*1040*
World	**3 993**	**3 924**	**4 109**	**4 046**	**4 041**	**4 051**	**3 927**	**4 120**	**4 108**	**4 105**

Regional and country groupings

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

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

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

Eurasia – Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, the Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

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

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain and Sweden.

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

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

North America – Canada, Mexico and the United States.

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

[2] Including Hong Kong.

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

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

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

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

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

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

Abbreviations and acronyms

ANP	National Petroleum Agency (Brazil)
BMC	Colombian Mercantile Exchange (Colombia)
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
CQPGX	Chongqing Petroleum Exchange (the People's Republic of China)
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
EU	European Union
EUR	Euro
FID	final investment decision
GIE	Gas Infrastructure Europe
GX	Green Transformation programme (Japan)
HH	Henry Hub
IEA	International Energy Agency
ICE	Intercontinental Exchange
ICIS	Independent Chemical Information Services
IEA	International Energy Agency
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JPY	Japanese yen
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
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)
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)
TTF	Title Transfer Facility (the Netherlands)
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
TWh	terawatt hour
t/yr	tonnes per year

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