Gas Market Report, Q2-2024

Including *Global Gas Review 2023*

INTERNATIONAL ENERGY AGENCY

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Abstract

Natural gas markets remained relatively calm over the 2023/24 Northern Hemisphere winter. Asian and European spot gas prices fell to pre-crisis levels in Q1 2024, while in the United States Henry Hub prices plummeted to multi-decade lows. Improving supply fundamentals together with high storage levels and unseasonably mild weather kept natural gas markets stable over the 2023/24 heating season[1]. While the 2023/24 gas winter was milder on average, it was accompanied by severe cold spells and gas demand spikes, which highlighted the importance of gas supply flexibility for energy security.

After rebalancing in 2023, natural gas markets are expected to return to stronger demand growth in 2024, primarily driven by the industrial and power sectors in the fast-growing economies of Asia. The continued expansion of renewables and improving nuclear availability are likely to weigh on gas-fired power generation in mature markets. High storage levels could contribute to the further easing of market fundamentals over the 2024 summer.

Geopolitical tensions represent the greatest risk to the short-term outlook. LNG trade has halted across the Red Sea since the start of the year, while Russia's ongoing attacks on energy infrastructure including storage persist. In this context, security of supply for natural gas remains a key aspect of energy policy making and the risks related to our outlook highlight the need to strengthen international co-operation, including in assessing and implementing flexibility options along gas and LNG value chains.

This edition of the quarterly *Gas Market Report* by the International Energy Agency (IEA) provides a thorough review of market developments over the 2023/24 heating season and a short-term outlook for 2024. As part of the IEA's *Low-Emissions Gases Work Programme*, the report includes a section on policy and regulatory developments aiming to stimulate demand for biomethane, low-emissions hydrogen and e-methane.

[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 mild winter kept natural gas markets stable through the 2023/24 heating season

Following the gas supply shock of 2022, natural gas markets moved towards a gradual rebalancing in 2023 and remained relatively calm over the 2023/24 Northern Hemisphere winter. Unseasonably mild winter weather conditions, together with improving supply fundamantals kept natural gas markets stable. Asian and European spot gas prices fell to pre-crisis levels in Q1 2024 and in the United States Henry Hub prices plummeted to multi-decade lows. While the 2023/24 winter was milder on average, it was accompanied by several cold spells and gas demand spikes, which highlighted the importance of gas supply flexibility for energy security. This forecast expects natural gas demand to increase by 2.3% in 2024, primarily driven by fast-growing Asian markets.

Unseasonably mild weather limited natural gas demand growth over the 2023/24 winter

Natural gas consumption increased by an estimated 2%, or almost 40 billion cubic metres, year-on-year (y-o-y) during the 2023/24 winter in the markets covered in the current Quarterly Gas Report. Demand growth was largely supported by higher gas use in the power and industrial sectors, while an unseasonably mild winter depressed space heating requirements in the key markets of the Northern Hemisphere. In the United States, residential and commercial gas demand dropped by almost 8% y-o-y, while in Europe it declined by an estimated 2% compared to the already very low levels of the 2022/23 winter.

Severe cold spells led to record-breaking demand spikes across Northern Hemisphere markets

Despite being an unusually mild winter on average, the 2023/24 heating season witnessed several cold spells, which resulted in record-breaking demand spikes across key markets in the Northern Hemisphere. In the United States, Winter Storm Heather drove natural gas use to an all-time high of almost 4 bcm a day on 16 January 2024 - about 30% above the daily demand average over the December– February period. In Europe, daily gas demand surged by almost 40% in only six days to an estimated 2.5 bcm a day in early January. Colder weather coincided with lower wind power output, increasing demand for both space heating requirements and gas-to-power demand. In Russia, a two-week cold spell in January led to several demand spikes, with gas demand surging to 1.78 bcm on 12 January 2024, its highest level on record. China faced several cold snaps over the 2023/24 winter season, with gas demand rising to an all-time high of 1.42 bcm a day in mid-December 2023. The cold spell drove up transmission pipeline utilisation rates to above 90% of capacity for the first time.

These events highlight the critical importance of gas supply flexibility for energy security, including in markets which are increasingly reliant on weather-sensitive renewable power generation, while using gas-fired power plants as a back-up option.

Asian and European gas prices dropped to below pre-crisis levels in Q1 2024

Unseasonably mild weather coincided with improving supply fundamentals over the 2023/24 winter season. Higher LNG production, up by 3% y-o-y, together with stronger piped gas deliveries to Europe and China further eased market fundamentals. This in turn provided downward pressure on Asian and European spot prices, which dropped below pre-crisis levels in Q1 2024. In the United States, the continued production growth combined with weak demand depressed natural gas prices to their lowest March average in more than three decades.

Softer prices supported higher natural gas consumption in the industrial sectors. First estimates suggest that the combined industrial gas demand in China, Europe, India and the United States, which accounts for more than half of global industrial gas use, increased by close to 8% y-o-y. Industrial gas demand in Europe is showing signs of recovery with preliminary data indicating an increase of around 15% y-o-y through the 2023/24 winter, albeit remaining 10% below its 2020/21 levels.

High storage levels could contribute to the further easing of market fundamentals over the 2024 summer

Storage sites closed the 2023/24 heating season well-above their five-year average both in Europe and the United States. In the European Union (EU), storage sites were 58% full at the end of March, with inventories standing 45% above their five-year average. Storage injections 35% below their five-year average would suffice to reach the EU's 90% fill level target by the start of the 2024/25 winter. Lower injection demand over the summer 2024 could contribute to a further easing of market fundamentals.

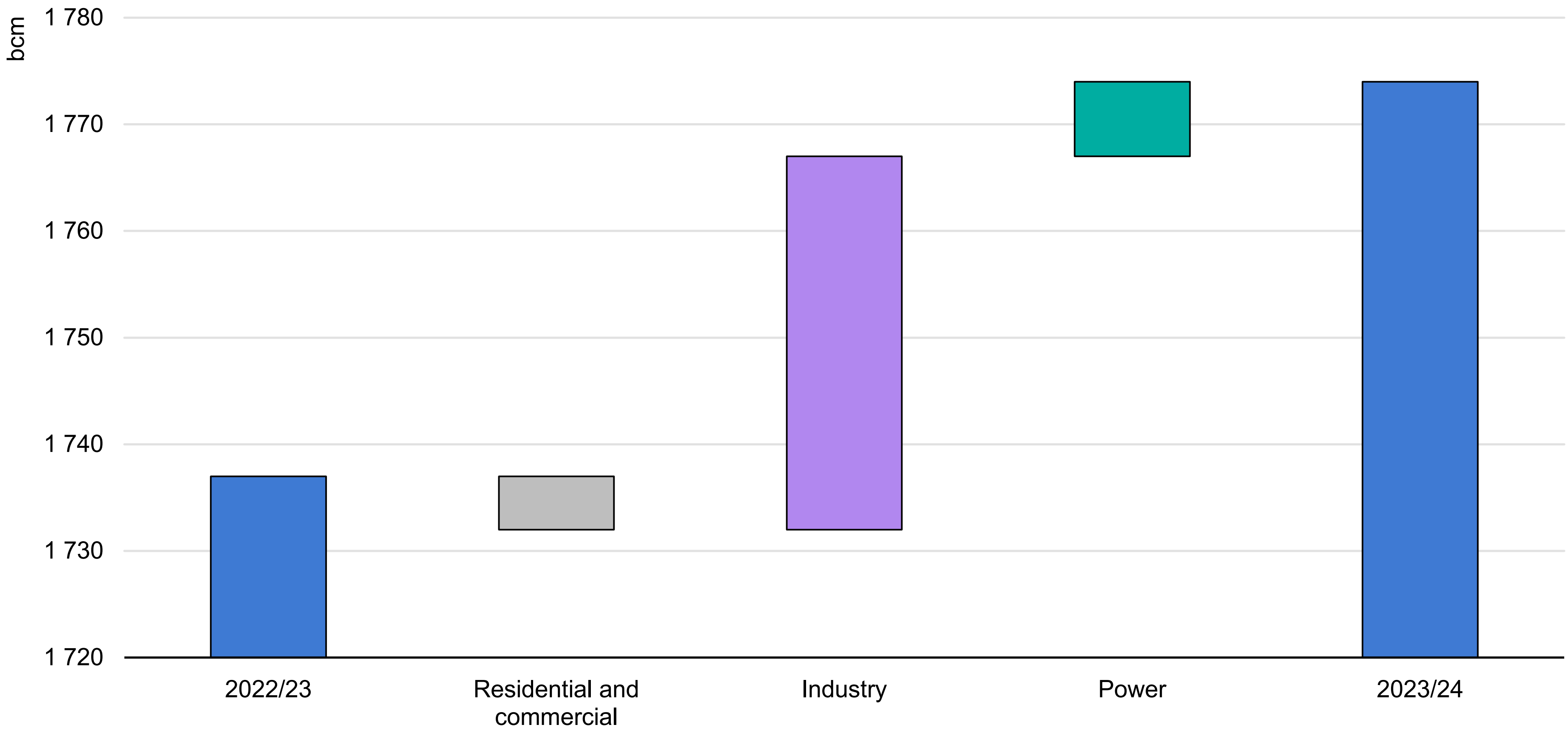
Geopoltical tensions could distort the short-term market outlook

Global gas demand is forecast to grow by 2.3% in 2024, revised down from 2.5% following a mild Q1. Demand growth is expected to be concentrated in fast-growing Asian markets. Industry emerges as the primary driver of growth, followed by residential and commercial sectors. Gas-to-power demand is forecast to increase only marginally, as higher gas burn in the Asia-Pacific region, North America and the Middle East is expected to be partly offset by the continued reductions in Europe. Lower hydro availability in China, India and Central and South America, could increase the call on gas-fired power plants.

Demand growth in key markets in Asia and Europe will be capped by the limited increase in global LNG supply, which is expected to grow by a mere 3%. However, this forecast comes with an unusually wide range of uncertainty. Potential start-up delays at new liquefaction plants, a tense geopolitical context, worsening feedgas issues at legacy projects and shipping constraints all represent downward risks to the current outlook.

Gas demand growth remained subdued through the 2023/24 heating season amidst mild winter weather conditions

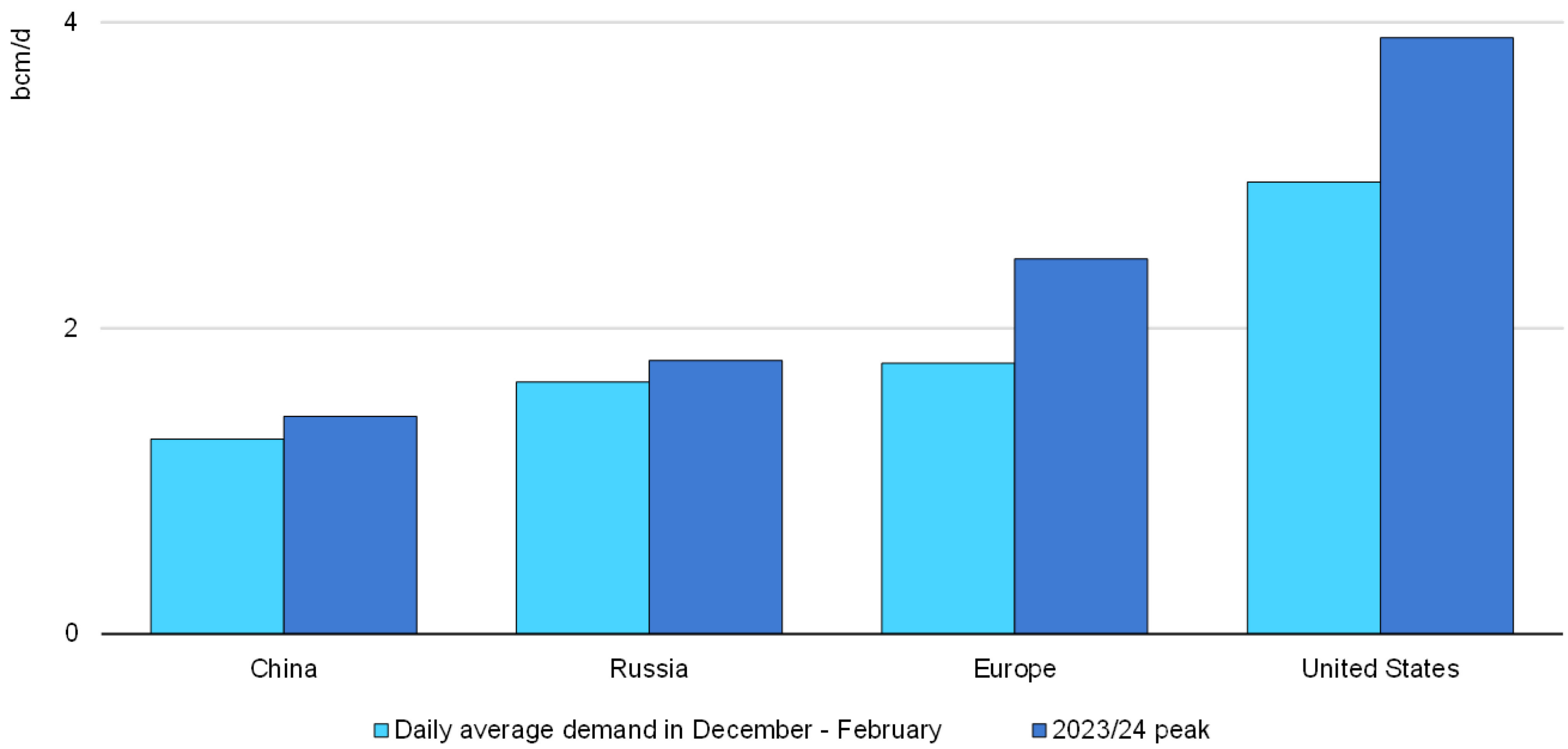
Estimated year-on-year change in natural gas demand in selected markets* over the 2023/24 heating season



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

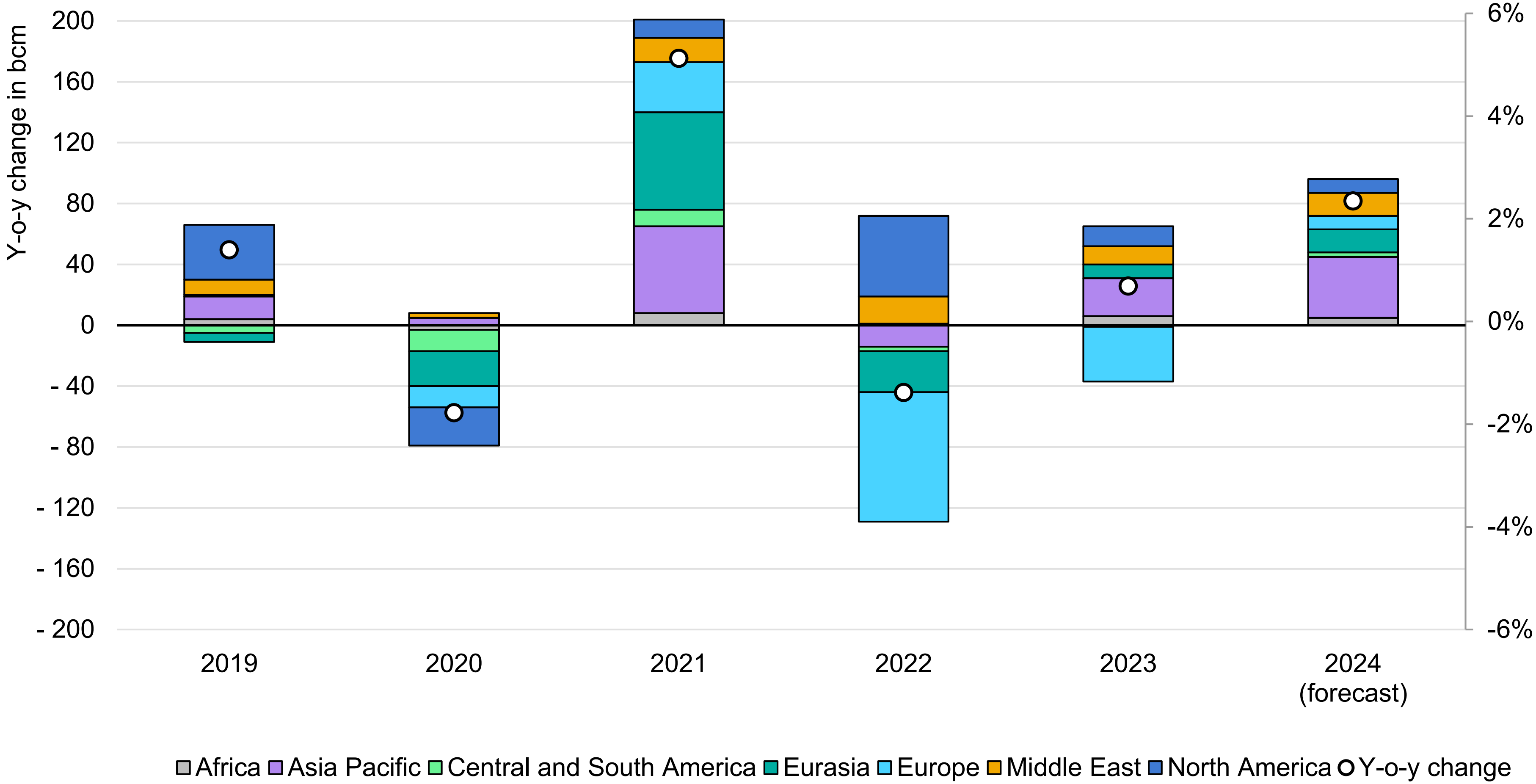
A winter of peaks: cold spells drove-up natural gas demand to all-time highs in several markets through the 2023/24 heating season

Daily average and peak natural gas demand across key gas markets during the 2023/24 winter



Asian markets are expected to drive gas demand growth in 2024

Year-on-year change in natural gas demand by region, 2019 – 2024



Gas market update

Unseasonably mild weather weighed on natural gas demand growth over the 2023/24 winter

Following the contraction in 2022, global gas demand returned to growth in H2 2023 amid a lower price environment and improving supply fundamentals. This trend continued during the October 2023-March 2024 period, which marks the heating season in the northern hemisphere. Higher LNG production (up by 3% y-o-y), together with stronger piped gas deliveries to Europe and China, further eased supply fundamentals and supported demand growth.

Preliminary data suggest that natural gas demand increased by 2% (or almost 40 bcm) y-o-y in the markets covered by this market update, [2] primarily driven by Asia, Eurasia and Central and South America. Demand growth was largely supported by higher gas use in the industrial and power sectors, while an unseasonably mild winter depressed gas consumption in the residential and commercial sectors in Europe and North America.

In North America natural gas demand remained broadly flat on the year over the 2023/24 heating season. While gas-fired power generation continued to expand strongly, these gains were more than offset by the steep decline in demand seen in the residential and commercial sectors amid unseasonably mild weather conditions. Despite subdued demand, natural gas output rose by an estimated 3% y-o-y in the United States. Continued production growth combined with weak demand depressed natural gas prices, which fell to decade lows in Q1 2024. In Central and South America the heatwaves of the southern hemisphere summer increased the call on gas-fired power plants amid higher cooling demand and lower hydro availability. Initial data suggest that gas demand in the region increased by 3% y-o-y. This growth was largely driven by Brazil, with the country's gas-fired power generation surging by 15% y-o-y over the October 2023-March 2024 period.

Natural gas demand in Asia increased by an estimated 6% y-o-y (or 25 bcm) over the October 2023-March 2024 period. China continues to drive the region's gas demand growth, with the country's gas consumption rising by 9% (or over 18 bcm) y-o-y, amid higher gas use across all end-use sectors. Lower natural gas prices continued to stimulate gas demand in India, with gas use in industry rising by an impressive 15% y-o-y during the October 2023-February 2024 period. Natural gas demand continued to decline in the mature markets of the region (Japan and Korea) amid improving nuclear availability.

Natural gas consumption in OECD Europe fell by 1% (or 3 bcm) y-o-y during the 2023/24 heating season. The strong expansion of renewables together with improving nuclear availability reduced gas-fired power generation, while mild winter weather depressed gas use in the residential and commercial sectors. Natural gas consumption

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

in industry continued to recover over the heating season, benefiting from improving gas supply availability and a lower price environment.

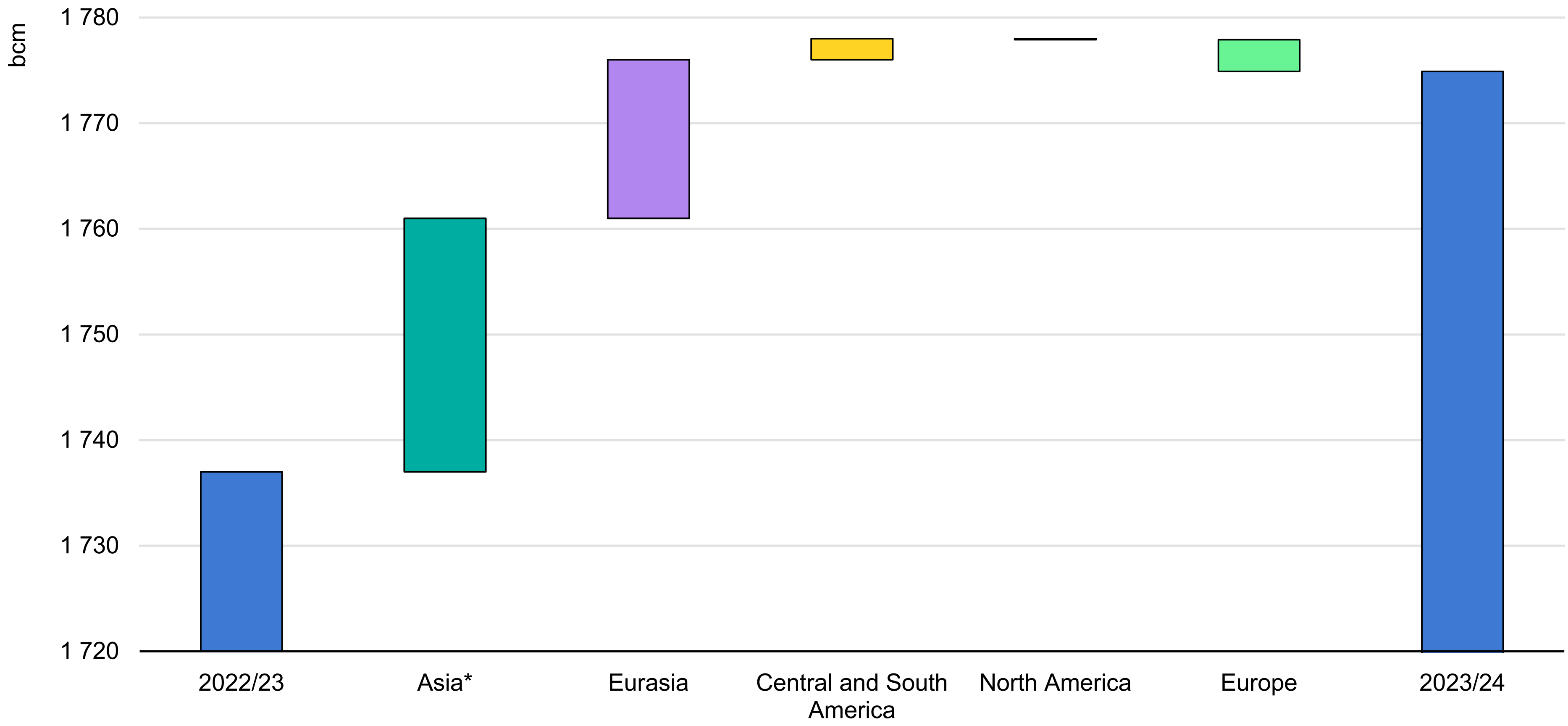
In Eurasia natural gas demand rose by an estimated 4% y-o-y during the 2023/24 heating season. A colder winter supported higher space heating requirements, while lower nuclear availability in Russia increased the call on gas-fired power plants. Russia's natural gas production increased by 7% (or 20 bcm) y-o-y over the October 2023-February 2024 period. This growth was partly driven by stronger piped gas exports, including to China, Europe and Central Asia, as well as higher LNG supplies and rising domestic demand. The country faced several cold spells. On 12 January 2024 domestic gas demand surged to 1.78 bcm – its highest level on record. In Central Asia natural gas production increased marginally amid higher output in Kazakhstan and Turkmenistan, while Uzbekistan recorded a drop of 8% (or 1.7 bcm) y-o-y during the period October 2023-February 2024. In Azerbaijan natural gas production rose by 3% during the same period, supported by higher gas exports and stronger domestic demand.

Global gas demand is forecast to grow by 2.3% in 2024. We anticipate growth being capped in import markets by the limited increase in global LNG supply, which is expected to expand by a mere 3% (or 16 bcm). Industry is expected to account for around 45% of incremental gas demand in 2024. This is partly supported by continuing economic expansion in the fast-growing Asian markets, as well as recovery in Europe's industrial gas demand – albeit remaining well below its pre-crisis levels. Following an unseasonably mild Q1 in Europe and North America, natural gas demand in the residential and commercial sectors is expected to increase by 2.3% globally in 2024, assuming average weather conditions in Q4. Gas demand in the power sector is forecast to increase only marginally, as higher gas burn in the fast-growing Asian markets and the gas-rich countries of Africa, the Middle East and North America is partially offset by the expected declines in Europe.

Gas demand in the Asia Pacific region is expected to expand by over 4% compared to 2023, supported by industrial activity and higher gas use in the power sector. Hence, the Asia Pacific region is expected to account for more than 40% of incremental gas demand in 2024. Gas consumption in North America is projected to increase by less than 1% in 2024 and by just 2% in Central and South America. In Europe natural gas demand is forecast to grow by less than 2%, remaining almost 20% below its 2021 levels. While gas use in industry and for space heating is expected to recover, gas-fired generation is set to decline further. Combined gas demand in the gas-rich markets of Africa and the Middle East is forecast to increase by close to 3%. Eurasian gas demand is projected to grow by near 2.5% amid higher demand in industry and the residential and commercial sectors.

Asia drove natural gas demand growth during the 2023/24 northern hemisphere winter

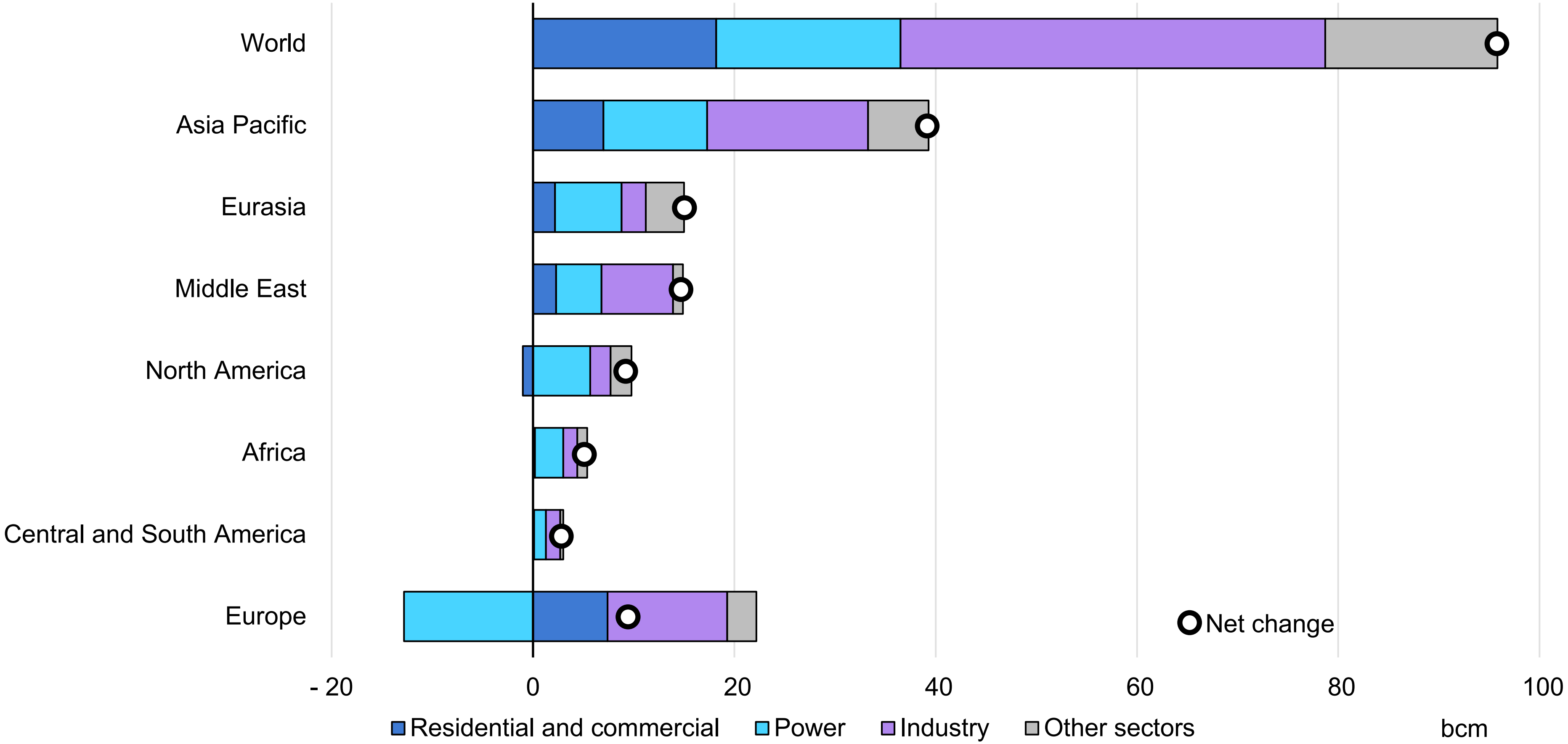
Estimated y-o-y change in natural gas demand, key regions, October 2023-March 2024



* Bangladesh, People's Republic of China, India, Indonesia, Japan, Korea, Malaysia, Pakistan, Philippines, Singapore and Thailand.

Industry is expected to account for nearly 45% of incremental gas demand in 2024

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



North American gas demand declined marginally during the 2023/24 heating season

Natural gas consumption in North America remained broadly flat over the 2023/24 heating season. While gas-fired power generation continued to expand strongly, these gains were almost entirely offset by unseasonably mild weather conditions, which weighed on space heating requirements both in Canada and the United States.

In the United States natural gas consumption dropped by an estimated 0.4% (or 2 bcm) y-o-y over the 2023/24 winter. While overall natural gas demand declined during the heating season, winter storm Heather drove up natural gas use to an all-time high of over 3.9 bcm/d on 16 January 2024. This highlights the crucial importance of gas supply flexibility to the broader energy system. On average, heating degree days were down by 6% compared to the 2022/23 winter period, which reduced space heating requirements. First estimates indicate that gas demand in the residential and commercial sectors declined by around 7.5% (or 13 bcm) y-o-y. Heating intensity in the residential and commercial sectors marginally declined, which suggests that non-weather-related factors (including energy efficiency and electrification of heat) might have also contributed to the lower gas use in buildings.

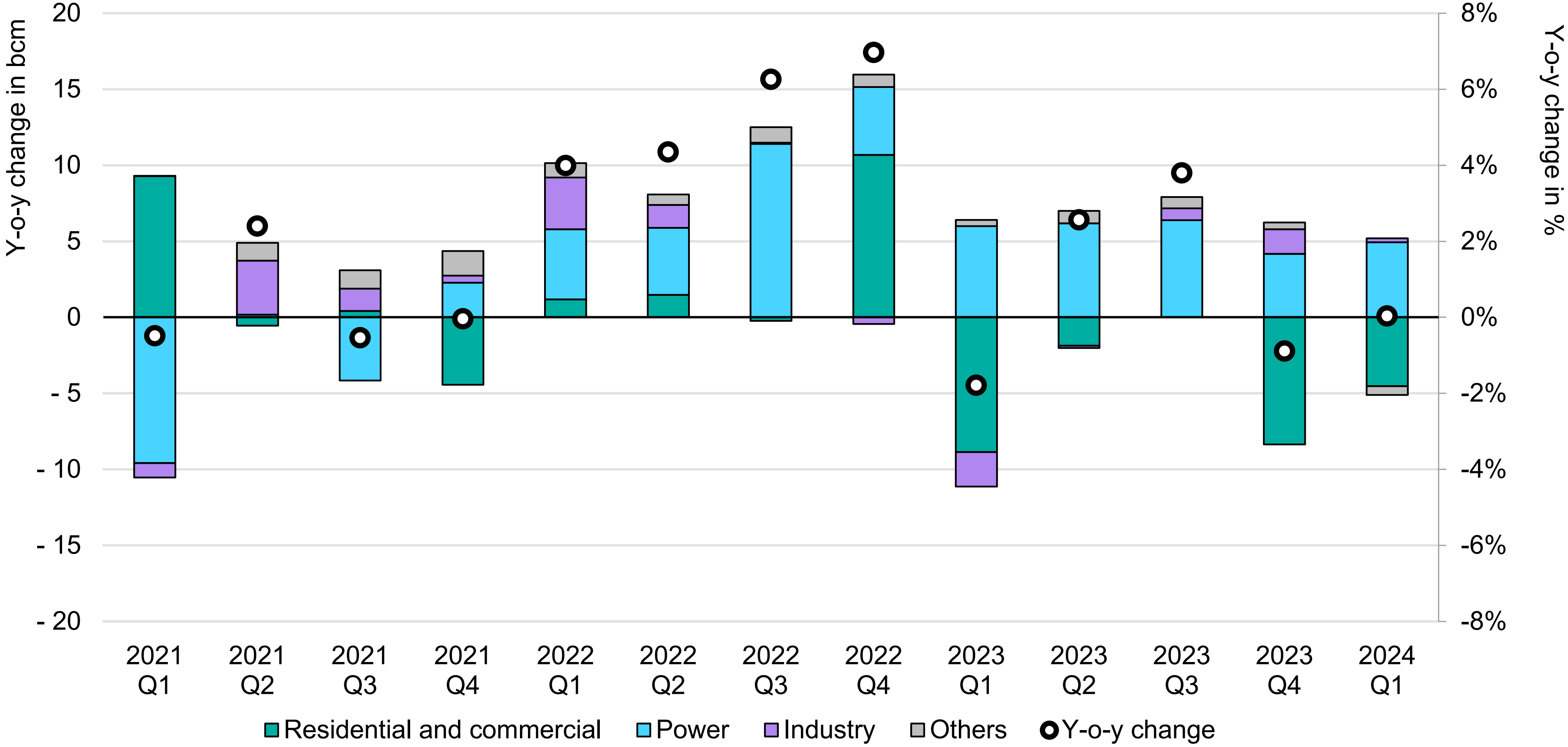
In contrast, gas burn in the power sector continued to expand and rose by close to 6% (or 9 bcm) compared to the 2022/23 heating season. This strong growth was primarily supported by coal-to-gas switching, while electricity demand rose by a marginal 1% y-o-y. The steep decline in gas prices (down 40% y-o-y) increased the cost-competitiveness of gas-fired generation vis-à-vis coal-fired power plants, which saw their production plummeting by 9% y-o-y. Hence, the share of natural gas in power generation rose from 39% over the 2022/23 winter to near 41% in the 2023/24 heating season. Natural gas demand in industry grew by an estimated 1.5% (or 2 bcm) y-o-y, although remaining below its 2021/22 levels.

In Canada natural gas demand remained broadly flat compared to the 2022/23 heating season. Similarly to the United States, unseasonably mild weather conditions weighed on gas use in the residential and commercial sectors, which declined by 10% y-o-y during October 2023-January 2024. Combined gas demand in the industrial and power sectors rose by 7% y-o-y during the same period, largely supported by stronger gas-fired generation at the expense of coal-fired power plants. In Mexico natural gas consumption grew by an estimated 5% (or 3 bcm) y-o-y during October 2023-March 2024, amid the continued expansion of gas-fired power generation.

Following a mild Q1, natural gas demand in North America is forecast to increase by less than 1% in 2024 as a whole. The power sector is expected to drive this growth, with a low gas price environment supporting coal-to-gas switching. Gas demand in industry is expected to decline marginally amid a weak macro-economic environment.

Lower space heating demand weighed on gas use in the United States over the 2023/24 winter

Estimated y-o-y change in quarterly natural gas demand, United States, 2021-2023



Sources: IEA analysis based on EIA (2024), Natural Gas Consumption; Natural Gas Weekly Update.

Natural gas demand in Central and South America returned to growth in H2 2023

Following a decline of 1% in 2022, natural gas consumption in Central and South America remained broadly flat in 2023. While gas demand contracted by around 2% (or 1 bcm) y-o-y in H1 2023, this decline was almost entirely offset by the demand growth recorded in H2 2023. Preliminary data indicate that the region's natural gas consumption increased by 3% y-o-y over the October 2023-March 2024 period, primarily supported by higher gas burn in the power sector.

In Argentina – the region's largest gas market – natural gas consumption fell by 1% in 2023. Gas demand in the residential and commercial sectors declined by 3.5% (or 0.4 bcm) y-o-y. The decline was entirely concentrated during the southern hemisphere winter season (April-September), when milder weather conditions weighed on space heating requirements. In contrast, gas demand in industry rose by more than 4% (or 0.5 bcm) y-o-y in 2023. Gas burn in the power sector declined by 2% (or 0.3 bcm) y-o-y in 2023, amid strong growth in hydropower output.

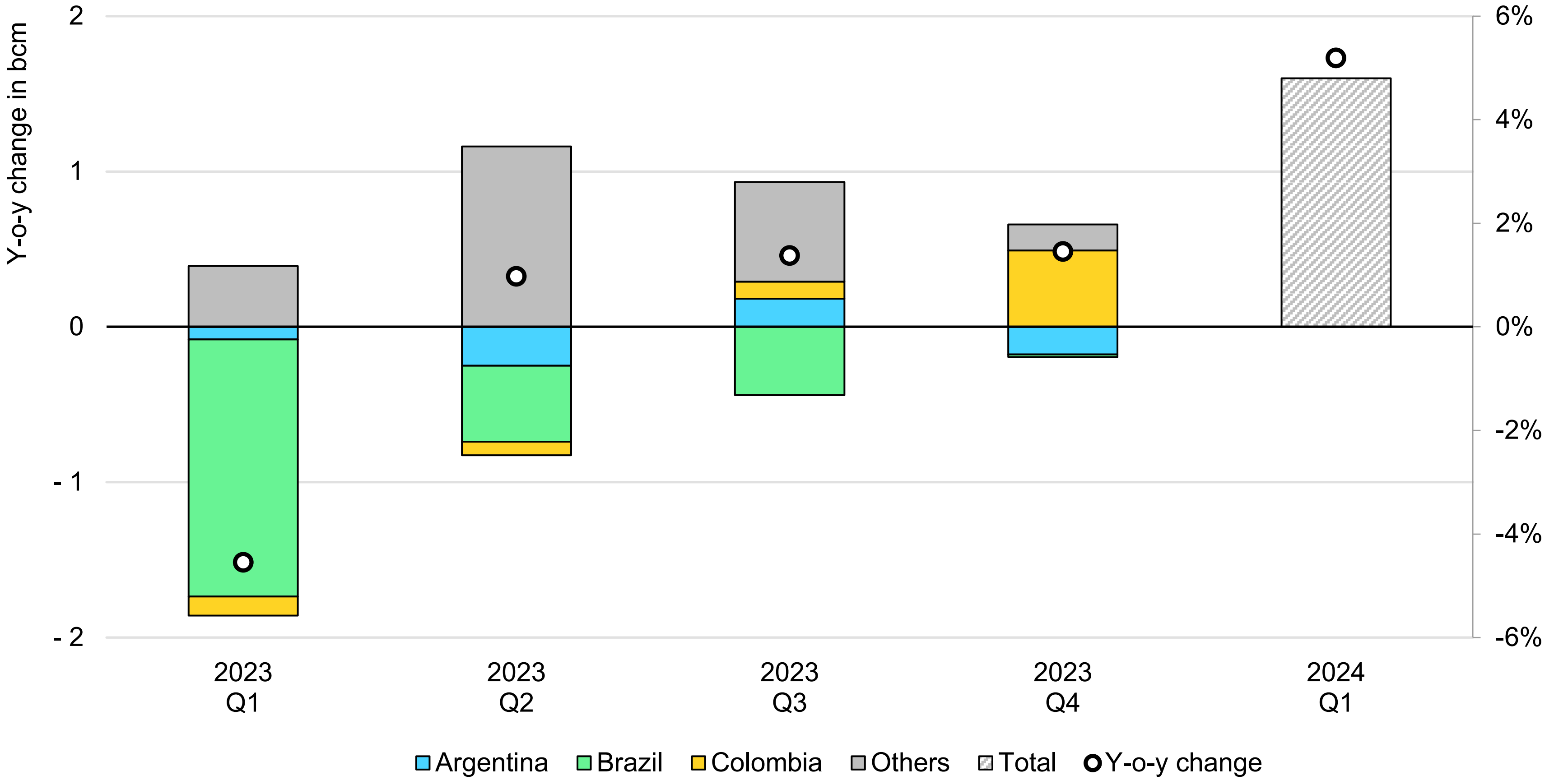
Natural gas consumption in Brazil fell by an estimated 9% (or 2.5 bcm) in 2023. Healthy hydro availability (up by 1%) and the continued expansion of wind and solar reduced the call on gas-fired power plants, with their output tumbling by 20% y-o-y in 2023. The decline in gas-fired generation was largely concentrated in the periods of higher hydro availability (Q1 and August-October). Lower hydropower output in April-June led to a temporary increase in gas-fired generation, while the heatwave in November-December drove up gas-fired power generation by 32% y-o-y on higher cooling demand. These episodes highlight the back-up role of gas-fired power plants in Brazil's electricity system. Due to lower gas demand, Brazil reduced its piped gas imports from Bolivia by 11% (or 0.65 bcm), while its LNG inflows dropped by 55% (or 1.65 bcm) in 2023. Initial data indicate that Brazil's gas demand grew by near 15% y-o-y in Q1 2024 amid stronger gas burn in the power sector.

In Trinidad and Tobago natural gas consumption declined by 3% (or 0.5 bcm) y-o-y in 2023, amid lower gas-to-power demand (down by 1%) and reduced gas use in industry (down by 4%). In Venezuela observed gas consumption grew by 3.5% (or 0.6 bcm) 2023. Colombia's gas consumption rose by 4% (or 0.8 bcm) in 2023 amid stronger gas-fired generation (up by 20%). Gas demand grew by 25% y-o-y in Q1 2024, primarily driven by the surge in gas-fired power generation amid a sizzling heatwave and lower hydro availability. Gas demand grew strongly in Central America and the markets of the Caribbean Sea. Their combined LNG imports surged by 35% in 2023.

This forecast expects natural gas demand in Central and South America to increase by 2% in 2024. A dry summer, which supported stronger gas-fired power generation, and the industrial sector are expected to provide room for natural gas demand growth.

Heatwaves drove up natural gas demand in Central and South America in summer 2023/24

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



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.

Natural gas demand in Asia continued to expand over the 2023/24 heating season

Natural gas demand in Asia returned to growth in 2023 and expanded by an estimated 6% y-o-y during the 2023/24 winter season of the northern hemisphere. This growth was largely driven by a strong increase in gas demand in China, India and emerging Asian markets. Natural gas demand continued to decline in the mature markets of the region (Japan and Korea) amid improving nuclear availability. Gas demand in Asia is forecast to increase by 4% in 2024, accounting for about 40% of incremental gas demand globally.

Building on full-year 2023 dynamics, China's natural gas market continued to gain momentum over the winter 2023/24 period, driven partially by weather, but also by the effects of economic recovery and more fundamental trends. Winter demand is estimated to have grown by over 9% y-o-y, reaching record monthly demand levels in December and January. While on the whole not colder than average, the 2023/24 winter period brought about a series of cold snaps that tested the Chinese gas market. An early cold wave in the north spurred authorities to start district heating slightly earlier than usual in November. By mid-December a cold snap that swept across multiple Chinese provinces lifted heating demand, leading to record daily peak demand for both gas and power. As a result of the cold wave, transmission pipeline utilisation rates reportedly reached above 90% of national capacity for the first time, highlighting the infrastructure stakes associated with an evolving role for gas in the energy mix and the increasing weather sensitivity of gas demand.

City gas demand was up by about 9% over the winter period, partially reflecting weather patterns, but also the growing penetration of natural gas in residential heating. Although the rate of expansion of distribution-level pipelines and gas connections has slowed in recent years, natural gas demand has continued to grow in residential and commercial applications. As this trend continues and the weather sensitivity of gas demand evolves – through both direct consumption and gas-fired power demand – transmission and distribution network resilience will gain increasing importance.

Power sector gas demand also surpassed previously recorded highs over the winter months, driven up by higher electricity demand and relatively flat nuclear output. Aided by the fall in global gas prices, Chinese industrial gas demand maintained strong year-on-year growth over the winter months, as recovery combined with new outright demand. However, as China emerges from the rebound phase after the 2022 gas price crunch and the overall economic context remains tempered, gas demand growth in industry is set to ease slightly through the rest of the year compared to the recovery in 2023.

Despite robust gas demand this past winter, the Chinese gas market remained well supplied and balanced. Domestic gas production was up by about 4% over the period, thanks to growth in both conventional and unconventional production. Pipeline gas imports were up by about 17%, with a continued ramp-up in Russian deliveries through the Power of Siberia pipeline and a recovery in imports from Central Asia after a strong dip in the previous winter due to simultaneous cold spells in Central Asian countries. In addition to strong domestic production and pipeline imports, Chinese LNG imports grew by 20% as new term supply contracts have come into force.

China's gas demand is forecast to grow by nearly 7% in 2024 (slightly less than in 2023), as all sectors maintain relatively robust momentum. Industry remains the primary driver of incremental demand, although the turnout of economic fundamentals will be key in driving sectoral dynamics. Residential and commercial gas demand is set to grow by close to 7% after strong first quarter demand, growing distribution-level connections and healthy commercial activity. Power sector gas burn is also expected to grow by over 7%, as electricity demand growth pushes up overall power generation.

Japan's gas demand in October 2023 to February 2024 declined by 6% (or 2 bcm) y-o-y. Unseasonably mild weather conditions reduced space heating requirements and weighed on gas demand in the residential and commercial sectors. Furthermore, stronger nuclear and increased renewable electricity generation reduced gas demand in the power sector. In October 2023 to January 2024 industrial demand fell by 6%, and residential and commercial demand by 4% compared to the same period in 2022/23. Total gas demand in 2024 is forecast to decrease by 1% (or 1 bcm) compared with the year before. The main reasons are the restart of nuclear power plants and the continued increase in renewable energy generation. Nuclear power generation increased by 50% in 2023 compared with 2022, and is expected to increase further in 2024 on the planned restart of Shimane 2 and Onagawa 2. Nuclear power generation increased by 16% in Q1 2024 y-o-y. Government subsidies on electricity and gas bills are scheduled to end in May 2024. After they end, awareness of the cost reductions available from saving energy could increase and contribute to reducing demand, especially in the residential and commercial sectors.

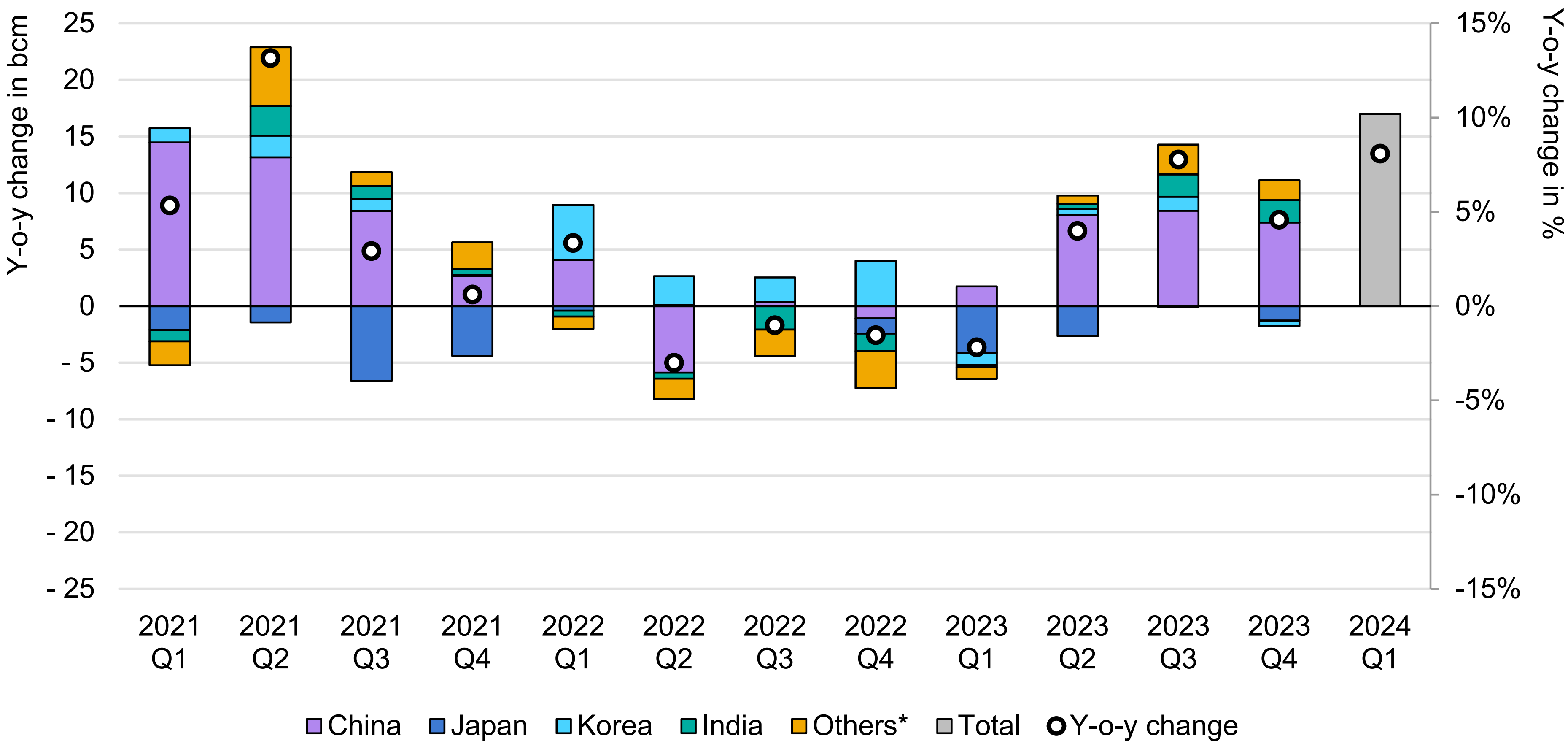
Gas demand in Korea declined by 1% (or 0.3 bcm) y-o-y in October 2023 to January 2024, primarily driven by the power sector and the city gas segments. Higher nuclear and renewable power generation weighed on gas-fired power generation. The Shin Hanul 1 nuclear power reactor started commercial operations in December 2022. Furthermore, warmer weather during this period contributed to the decrease in gas demand in the residential and commercial sectors. Gas demand in 2024 is projected to decline by 3% (or 1.5 bcm), primarily driven by the power sector. In April 2024 Shin Hanul 2 has started commercial operation. Furthermore, Saeul 3 is scheduled to start commercial operation in 2024 according to information from Korea Hydro & Nuclear Power Co. In addition, renewable electricity generation is expected to expand. Industrial gas demand is forecast to increase marginally, while residential and commercial demand is assumed to remain close to its 2023 levels.

According to the Petroleum Planning & Analysis Cell, India's primary natural gas supply (including net domestic production and LNG imports) increased by 16% y-o-y between October 2023 and February 2024. This strong growth in supply reflects growing demand for natural gas across all sectors. The increase in consumption was mainly driven by the oil refining sector (up by more than 70% y-o-y) and industry (up by over 15% y-o-y). In 2024 India is expected to see an increase in LNG imports due to the decline in spot LNG prices. However, this growth could be tempered by the increase in domestic gas production from ONGC's Krishna-Godavari field. Following an announcement by Prime Minister Narendra Modi in January 2024, the USD 67 billion investment plan for developing India's natural gas supply chain is set to maintain its momentum over the coming years. India's natural gas consumption in 2024 is projected to increase by over 7%.

Emerging Asia's gas consumption increased by an estimated 5% y-o-y in the period October 2023-February 2024, with lower LNG prices supporting demand growth in the region's price-sensitive end-use sectors. Natural gas consumption in Thailand grew by an impressive 12% (or 2 bcm) y-o-y. This was primarily driven by soaring gas-to-power demand, which increased by 18% (or 1.7 bcm) y-o-y during October 2023-February 2024. Industrial gas demand remained broadly flat, while gas use in the transport sector fell by 12% (or 0.1 bcm) y-o-y during the same period. Estimated natural gas demand in Bangladesh and Pakistan remained broadly flat compared to the October 2022-February 2023 period. The strong increase in LNG imports (up by almost 20% y-o-y) was sufficient to offset the decline in domestic production, although it was not enough to support demand growth. Tight gas supplies weighed on Pakistan's gas-fired power generation, which dropped by 12% y-o-y during October 2023-February 2024. Indonesia's gas demand grew by 2.5% (or 0.4 bcm) y-o-y during October 2023-February 2024, primarily supported by the power and industrial sectors. In Malaysia natural gas demand increased by an estimated 6.5% (or 1 bcm) y-o-y during October 2023-February 2024, supported by a strong growth in domestic production of near 7% y-o-y during this period. Natural gas demand in emerging Asia is forecast to increase by close to 4% in 2024, primarily driven by the power and industrial sectors.

China and India continue to drive Asia' natural gas demand growth

Estimated y-o-y change in quarterly natural gas demand, selected Asian markets, 2021-2024



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

Sources: IEA analysis based on ICIS (2024), ICIS LNG Edge; CQPGX (2024), Nanbin Observation; JODI (2024), Gas World Database; PPAC (2024), Gas Consumption; EPPO (2024), Energy Statistics, Korea Energy Economics Institute (2024), Monthly Energy Statistics, Ministry of Economy, Trade and Industry of Japan (2024), METI Statistics.

Mild weather, strong renewable output weighed on European gas demand in 2023/24 winter…

Natural gas consumption in OECD Europe fell by 1% (or 3 bcm) y-o-y during the 2023/24 heating season. The power sector remained the most important driver behind lower gas demand, as the strong expansion of renewables together with improving nuclear availability reduced the call on gas-fired power plants. Mild winter weather limited gas demand in the residential and commercial sectors. In contrast, gas use in the industrial sector continued to recover, supported by the lower price environment.

Distribution network-related demand fell by an estimated 2% (or 3 bcm) y-o-y in the 2023/24 winter season. While the short-lived cold spell in January 2024 provided a temporary boost for gas demand, unseasonably mild weather conditions during the remainder of the winter weighed on space heating requirements in buildings. Heating degree days declined by 5% compared to the previous winter season. Preliminary data suggest that the heating intensity (gas use per heating degree day) increased marginally compared to the 2022/23 winter. This potentially indicates that the gas-saving measures undertaken in the previous two heating seasons are wearing off. This also highlights the importance of doubling down on energy efficiency measures, supporting the electrification of heat and continuing awareness-raising campaigns on the responsible use of energy and natural gas.

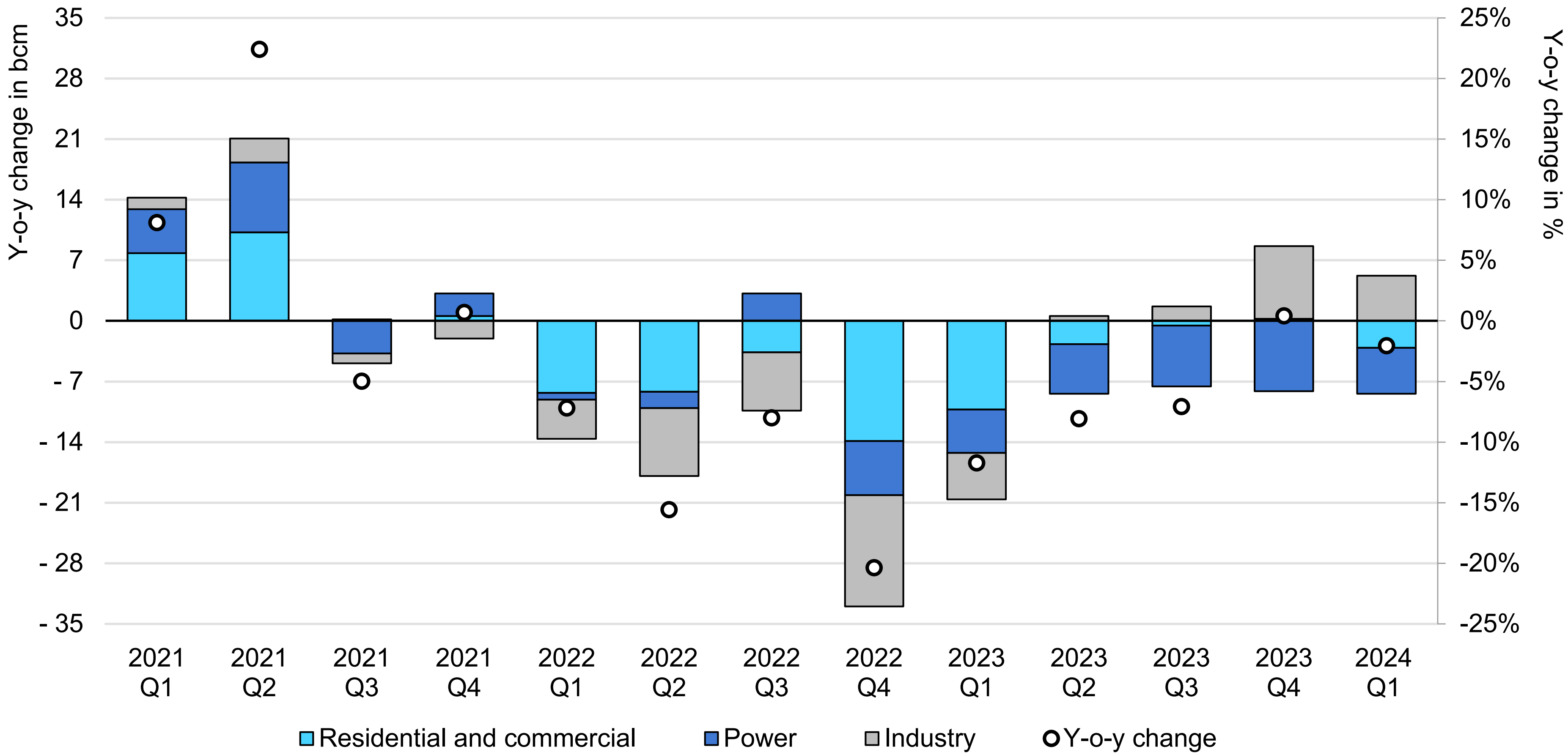
Gas-to-power demand plummeted by 18% (or 13 bcm) y-o-y in the 2023/24 winter season. This steep decline was primarily driven by the strong increase in renewable electricity generation, which increased by an estimated 22% (or 140 TWh) y-o-y on the back of higher wind and hydropower output. In addition, improving nuclear availability (up by 5%) further weighed on overall fossil-based thermal power generation, which declined by close to 20% y-o-y during the heating season. Without the strong increase in renewable and nuclear power output, Europe’s gas balance would have been significantly tighter during the 2023/24 winter.

Natural gas consumption in industry continued to recover in the heating season, benefiting from improving gas supply availability and a lower price environment. Preliminary data indicate that gas use in industry increased by 15% (or 13 bcm) y-o-y in the 2023/24 winter – albeit remaining 10% below its 2020/21 levels. Industrial gas consumption increased by an estimated 15% y-o-y in Belgium, 3% in Italy, 15% in the Netherlands and 13% in Spain during the 2023/24 heating season.

This forecast expects natural gas demand in OECD Europe to increase by less than 2% in 2024. Gas burn in the power sector is forecast to drop by almost 10% amid improving nuclear availability in France and the rapid expansion of renewables. Gas demand in the residential and commercial sectors is expected to increase marginally compared to 2023 following a mild Q1. Gas use in industry is forecast to continue its recovery, albeit fragile and largely dependent on the evolution of prices.

…while industrial gas demand continued its recovery

Estimated y-o-y change in quarterly natural gas demand, OECD Europe, 2022-2024



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

Bearish price dynamics are set to lead to a decline in overall US dry gas production in 2024

Winter 2023/24 is set to have been a transitional period for US dry natural gas production. After full-year production growth of around 4% in 2023 and an all-time monthly production high in December 2023, US production growth tapered significantly in early 2024, setting the market up for an expected y-o-y decline in production for full-year 2024.

In late 2023 US dry gas production bucked the trend of slowing growth that had been in place since the start of the year, thanks in part to decreasing y-o-y losses in Appalachian output in Q4. December recorded exceptional growth, with overall production up by around 6% y-o-y, compared to an average of around just 3% y-o-y in the previous six-month period. This led to record monthly output in December, topping off a record year for US natural gas production. In early 2024 production growth slowed significantly, averaging just 2% y-o-y for the whole of the first quarter as a result of a combination of factors. A spell of extreme cold weather in January led to well freeze-offs in what is becoming a recurrent wintertime event in the US market. While the downside effects on production were milder in 2024 than during winter storm Uri in January 2021, the Permian and Haynesville plays reportedly recorded temporary production declines of around 3 Bcf/d and 2 Bcf/d, respectively.

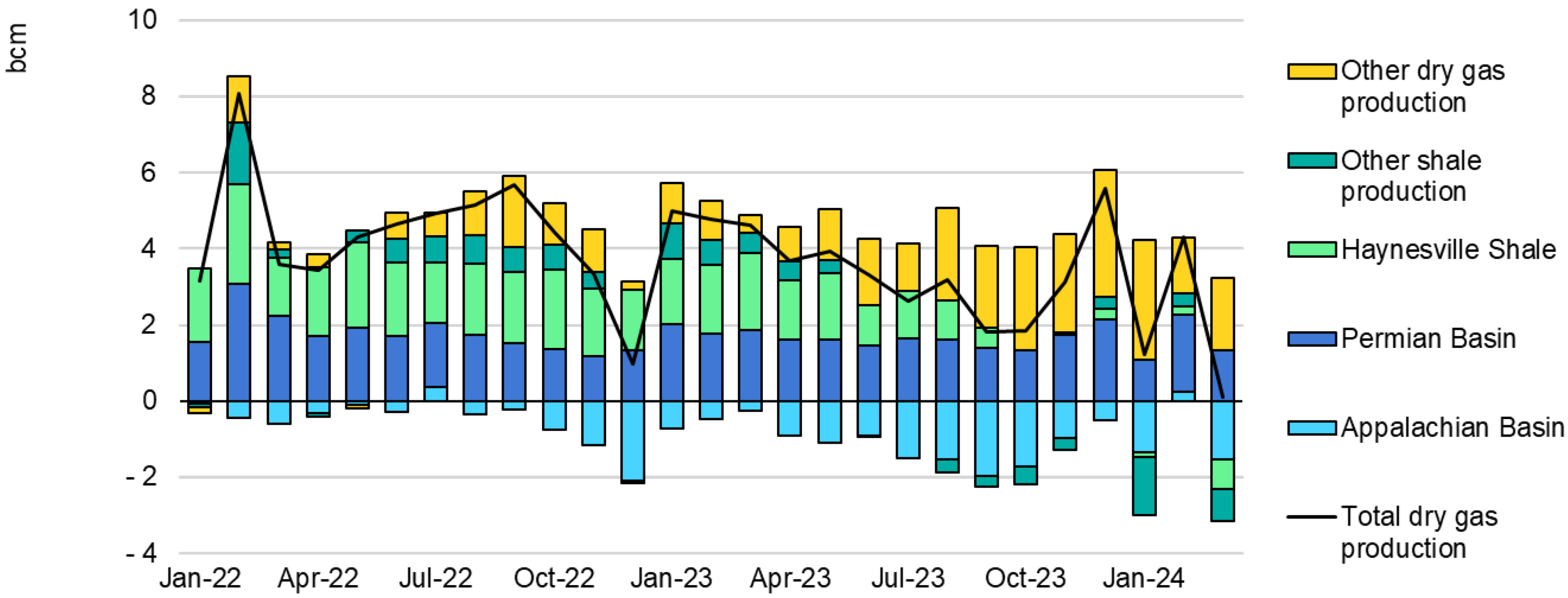
Ultimately, the supply-side pinch was short-lived and had only a temporary upward impact on prices. Henry Hub fell steeply in February and March, reaching a multi-decade monthly low of USD 1.49/MBtu in March 2024. The bearish price environment contributed to the overall slowing of US gas production growth through to the end of the winter season, although monthly production remained slightly up y-o-y. Following months of holding out in the hope of more bullish fundamentals in 2024, a number of gas producers announced a cooling of drilling activity and cutbacks to overall upstream capital expenditure in a sign that the market is expected to remain well balanced through the rest of the year.

US storage sites closed the heating season with inventory levels standing 40% above their five-year average, as continued production growth and subdued demand weighed on storage draws. With lower storage injection needs during summer and only moderate growth in feedgas demand for LNG exports, the US market is expected to see overall dry gas production fall during the rest of the year, leading to a net y-o-y decline in gas production of around 1% in 2024.

While relatively high oil prices should help keep Permian associated gas production up in 2024, output in other basins is expected to remain relatively flat. A further delay in Mountain Valley Pipeline operations from Q1 2024 to late Q2 2024 – with the planned start date originally in late 2023 – is expected to restrain takeaway capacity from the Appalachian Basin, effectively putting a cap on potential output growth.

US dry gas production growth slowed significantly over the winter period

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



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

Europe's LNG imports declined over the 2023/24 heating season amid stronger pipeline flows

OECD Europe's primary natural gas supply fell by an estimated 4% (or 10 bcm) y-o-y over the 2023/24 winter, amid lower gas demand and high storage levels. Stronger pipeline flows reduced the share of LNG in Europe's total primary gas supply from 38% during 2022/23 winter to 34% over the 2023/24 heating season.

Europe's LNG imports declined by 12% (or 11.5 bcm) y-o-y in 2023/24. The continued declined in demand together with high inventory levels and stronger piped gas deliveries kept European hub prices below Asian spot LNG prices through 2023/24 winter. Platts JKM averaged at a premium of near USD 1.5/MBtu compared to TTF over the 2023/24 heating season, which incentivised flexible LNG cargos to favour Asian markets instead of Europe. Despite lower inflows, LNG remained Europe's dominant primary source of gas supply with a share of 34% and effectively acting as a baseload. LNG flows from the United States rose by 5% (or 2 bcm). This further reinforced the position of the United States as Europe's largest LNG supplier, accounting for over half of Europe's LNG imports over the 2023/24 heating season. Russian LNG inflows rose by 1% y-o-y and remains highly concentrated. Belgium, France and Spain accounted for 80% of Europe's total LNG imports from Russia during the 2023/24 gas winter.

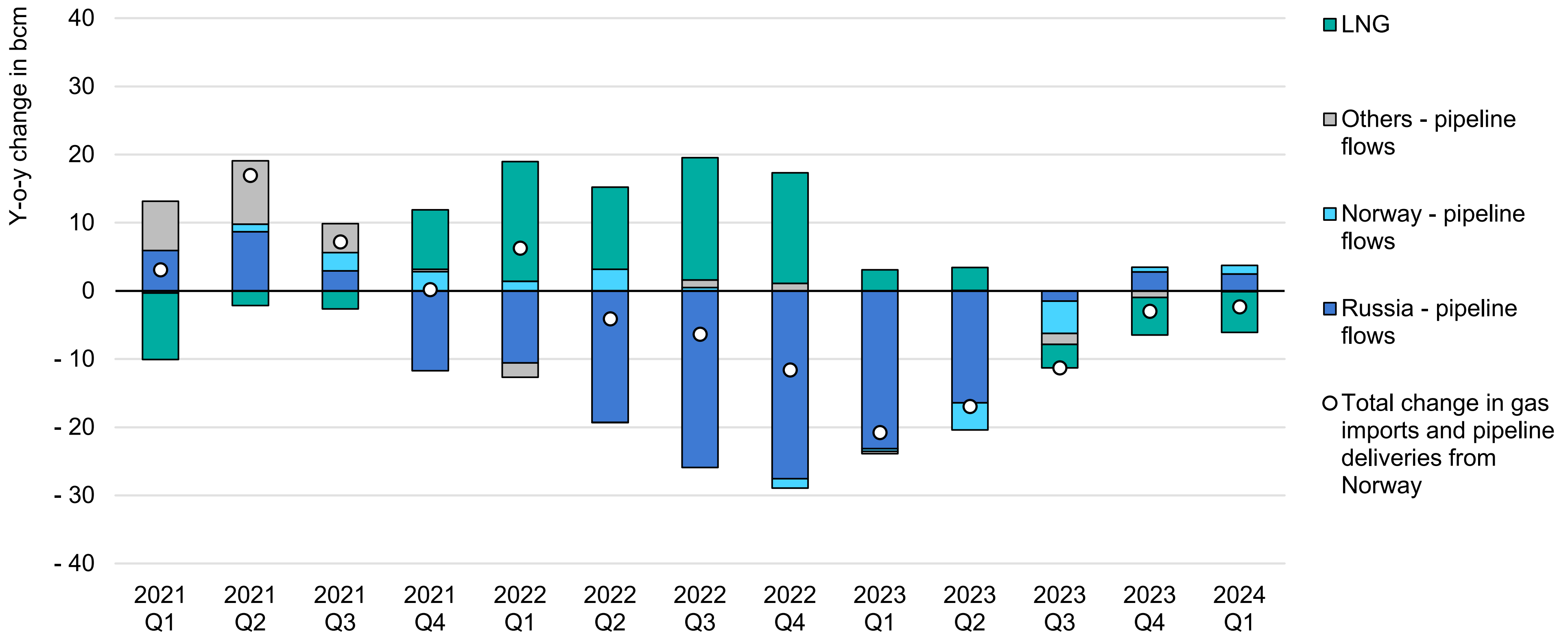
Norway's piped gas deliveries to the rest of Europe increased by 3% (or 2 bcm) compared to the 2022/23 heating season amidst a lower level of maintenance works. Norwegian pipeline supplies to the European Union rose by 2%, while exports to the United Kingdom increased by 8% y-o-y. Non-Norwegian domestic production fell by 12% (or 4 bcm) y-o-y during October 2023 – February 2024. The Netherlands and the United Kingdom accounted for over 95% of this decline, as the closure of the Groningen field and the continued output reduction from aging gas fields in the North Sea is weighing on production levels. In Denmark, the Tyra gas field started to flow first gas at the end of Q1 2024. The field was in redevelopment since September 2019 and is expected to ramp-up production to 2.8 bcm/y.

Russia's piped gas supplies increased by an esimated 25% (or 5 bcm) y-o-y through the 2023/24 winter season -albeit remaining 70% below their levels during the 2020/21 gas winter. Deliveries to the European Union increased by 9% (or 1 bcm). Exports to Türkiye rose by 50% y-o-y through October 2023 – February 2024. Despite this increase, the share of Russian piped gas in Europe's gas demand remained below 10% over the 2023/24 gas winter. Pipeline gas deliveries from North Africa and Azerbaijan remained broadly flat compared to the previous heating season.

This forecast assumes that Russian piped gas supplies to OECD Europe will remain close to their 2023 levels in 2024 -albeit their profile remains a major uncertainty. LNG imports are expected to decline marginally amid high inventory levels and stronger piped gas deliveries.

Russia's piped gas deliveries to Europe rose over the 2023/24 winter season, albeit remaining well-below their historic levels

Y-o-y change in quarterly European natural gas imports and deliveries from Norway, 2021 – 2024



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

The global LNG market remained balanced amid continued expansion during winter 2023/24

The global LNG market remained robust and relatively well balanced over the 2023/24 northern hemisphere winter. Cumulative traded volumes over the October-March period grew by about 3% y-o-y, or by 9 bcm, thanks to the ramp-up of production at liquefaction projects that came online in 2023 as well as to improved utilisation at a number of existing plants. On the demand side, the market was driven by emerging Asia, counterbalancing significant declines in Europe and mature Asia.

2023 brought very few new liquefaction projects to market. As such, incremental LNG supply over the winter period was the result of the final ramp-up effects from what little new capacity was brought online, and utilisation improvements at existing plants following important outages over the past 12-18 months.

The United States led the charge on the supply side this winter, with the return of Freeport LNG – after a fire kept the facility offline from mid-2022 into much of Q1 2023 – and improved output at facilities including Sabine Pass and Calcasieu Pass. Despite a further two-month outage at Freeport's third train in Q1 2024, overall US LNG exports grew by 14% y-o-y, adding nearly 8 bcm to global LNG supply over the full winter. This accounted for close to half of gross incremental supply over this period.

Three key markets in Africa accounted for a further 25% of gross supply growth. Mozambique's Coral South FLNG reached full capacity during H2 2023 after starting operations in late 2022, making the country the second-largest contributor to incremental supply this past winter. Both Algeria and Nigeria also showed improved output at existing plants. In Algeria the recovery was likely helped by upstream fields brought online in 2023, although LNG exports tailed off from Q3 2023 highs. Incremental Nigerian exports since the start of 2024 are clearly linked to an improving security context for key upstream and feedgas delivery infrastructure in the Niger Delta. Still, force majeure remains in place at the Nigeria LNG facility and utilisation rates have averaged only around 70% since the start of the year.

The extra 4.2 bcm of supply from these three markets (Mozambique, Algeria and Nigeria) was more than offset by losses in Egypt. Despite a return to LNG exports in Q4 2023 – driven by the recovery of pipeline gas imports from Israel following a steep curtailment in October 2023 – Egyptian exports for the entire winter were down by 80% (5 bcm) on previous-year volumes, as domestic production trended downward in 2023 and remained well below recent historical levels. As a result of these diverging dynamics on the continent, LNG supply from Africa was down by 5% (over 1 bcm) y-o-y in the winter period.

The majority of the remaining gross supply downside came from Qatar, whose exports fell by approximately 2.5 bcm y-o-y over the winter period, as favourable weather across a number of regions kept peak global demand in check.

Regional and country divergence was significant on the demand side as well during the winter period, notably across the emerging–mature regional market divide. European LNG imports fell by 12% (11.5 bcm) y-o-y, although EU imports fell less drastically. The United Kingdom and Türkiye both took in far lower volumes than in the previous winter period. In the former, strong renewables generation pared back power sector gas burn, in turn weakening demand for LNG. In the latter, higher pipeline imports and relatively flat domestic demand weighed on LNG imports. In the European Union, Germany, the Netherlands and Finland drove most of the gross upside, while France, Spain and Greece reduced their imports. Overall, EU LNG imports fell by about 2% (1 bcm), thanks to relatively mild winter weather and robust pipeline gas imports.

In Asia, Japan and Korea also reduced their LNG intake as mild weather reduced heating demand (particularly in Korea) and nuclear restarts in 2023 led to lower thermal generation requirements. Together, their LNG imports fell by nearly 3%, or over 2 bcm.

In contrast, all other Pacific Basin importing markets easily absorbed the extra LNG volumes on the market, as gas demand growth in the region continued and lower global gas prices made spot LNG cargos more accessible than over the previous 18-month period. China, India and Thailand together accounted for over 80% of the gross increase in Asia Pacific imports, and for nearly 60% of the gross increase in imports globally.

Chinese LNG imports grew by 20%, or 9 bcm, accounting for one-third of the gross upside in global LNG imports, as gas demand grew across all sectors and new term supply contracts started delivering. However, while winter 2023/24 LNG import growth surpassed full-year 2023 growth, Chinese import volumes were only about 3% higher than in winter 2020/21.

India was the second-largest LNG import growth market globally by volume, growing by 33% and taking in an extra 4 bcm y-o-y. The lower spot price environment led to a notable increase in overall spot tenders for the purchase of LNG cargos, with three to four times more tenders in winter 2023/24 than in the previous winter. These tenders also had a higher success rate, particularly since October 2023. With lower prices, the improved competitiveness of gas in certain industries has driven a greater appetite for LNG imports.

The lower LNG price environment also drove higher spot purchasing in Thailand, where LNG imports grew by over 40%, or 2.3 bcm. Winter period buying echoed dynamics in place since Q2 2023, as higher LNG imports went hand in hand with a notable jump in electricity demand and power sector gas burn. LNG imports in the rest of the Asia Pacific region grew by about 12% (over 3 bcm) overall, with notable growth in Bangladesh (24%) and Singapore (48%).

The Caribbean and Central and South America also took in more LNG, growing by about 44% (2 bcm) y-o-y as weather conditions reduced hydropower availability in late 2023 in key markets like Brazil. El Niño weather patterns also led to drought conditions in

Colombia, where hydropower output was down and increased power sector gas burn drove up LNG imports sevenfold.

We forecast global LNG trade growing by 3% (about 16 bcm) in 2024, a slightly lower increase than previously expected in the Q1 2024 Gas Market Report, as project delays, outages and operational risks have developed. While the global market was relatively well balanced in Q1 2024 and is set to remain so through the rest of the year, a degree of supply-side uncertainty continues to hover over the market.

North America, the Russian Federation (hereafter, "Russia"). and Africa are expected to make up the vast majority of LNG supply growth in 2024, as new projects come online and utilisation rates recover after reduced operations at a number of key plants. In the United States, the return to full operations at Freeport LNG is set to add to exports, although partial outages in Q1 that extended into Q2 have slightly reduced the full-year upside for the plant. Robust utilisation rates at existing projects and a start to Plaquemines LNG exports in late 2024 provide further export growth. In Mexico, the start-up of Altamira – which relies on US feedgas – in second quarter 2024 could add about 1 bcm to global supply in 2024. Although the project does not yet have US approval to export to non-FTA markets, targeting FTA countries will allow it to ramp up its production. Overall, North American LNG exports are set to increase by about 5%, or nearly 6 bcm.

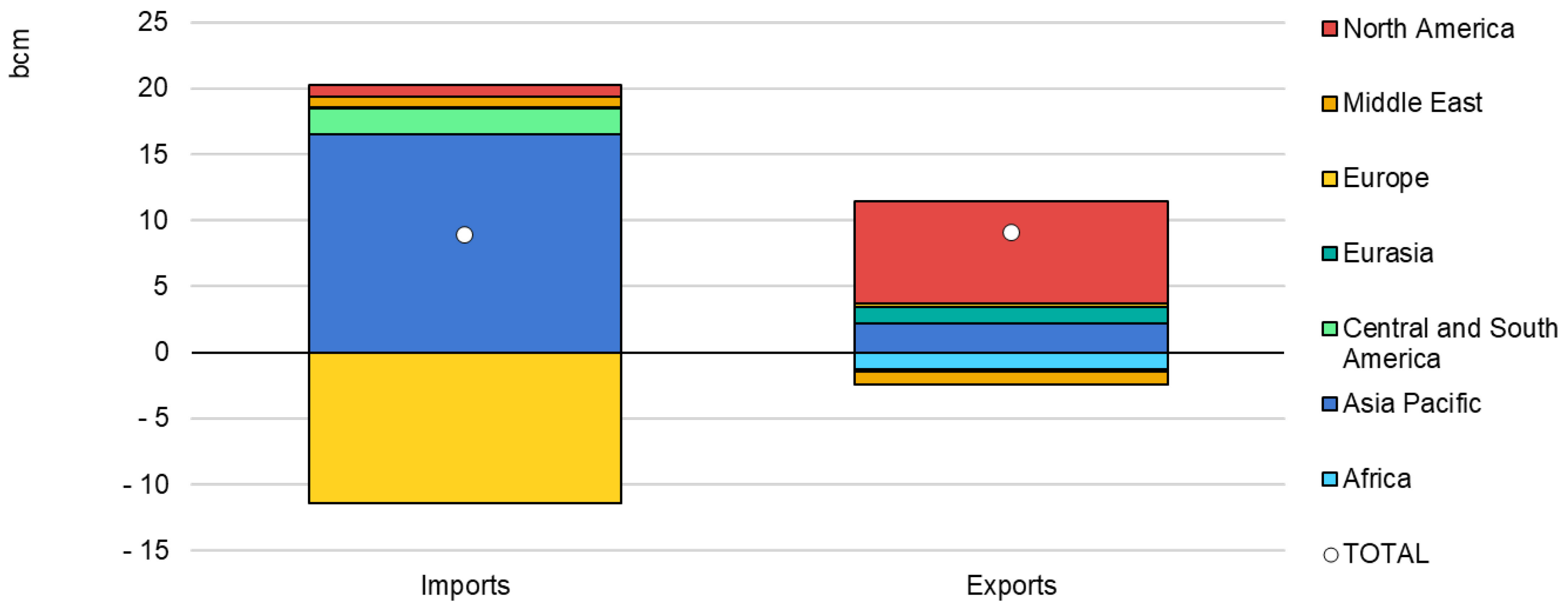
Russian LNG exports are set to rise in 2024, thanks to recovery from long maintenance outages at Sakhalin-2 and Yamal LNG in 2023, and despite a highly uncertain outlook for Arctic LNG 2 train 1. US sanctions on Arctic LNG 2 led Novatek, the primary project sponsor, to declare force majeure in December 2023 to a number of its clients regarding future LNG deliveries. Subsequently, TotalEnergies, also a shareholder in the project, declared force majeure in January 2024 on volumes from the project. In late March 2024 Novatek announced it had shut down production at the facility, notably following difficulties in securing tankers to export volumes.

Africa is expected to drive about 15% of supply growth in 2024, or around 2 bcm, with the ramp-up of exports from Congo LNG and Greater Tortue FLNG (despite a delay in start-up to Q4). The improving security and feedgas context in the Niger Delta should also lead to improved utilisation rates at Nigeria LNG. However, a deteriorating domestic balance in Egypt is expected to lead to a sharp drop in LNG exports from the country.

On the demand side, Asia – and particularly China and India – continue to lead LNG import growth in 2024, as overall gas demand remains robust and the low price environment encourages more spot buying. Price-sensitive markets like Bangladesh and Pakistan are also set to capitalise on the reduction in prices from last year's levels. European LNG import levels will be a key factor in the availability of volumes for some of the most price-sensitive markets in the Pacific Basin. Based on relatively stable gas demand, robust pipeline gas imports and record end-of-winter storage fill levels, European LNG imports are expected to decrease by about 3% y-o-y in 2024.

The fall in winter European LNG imports helped compensate for strong Asian buying in a context of low incremental LNG supply

Y-o-y change in winter period LNG imports and exports by region, winter 2023/24 vs winter 2022/23



Notes: Winter period refers to the northern hemisphere winter and spans October to March.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

The impact of Red Sea disruption and Panama Canal congestion is limited for now, with easing expected following the rainy season, shipping optimisation and new LNG supply in 2024

During the winter of 2023/24 in the northern hemisphere, LNG flows were affected by severe congestion in two of the world's most strategic maritime shipping choke points, the Panama and Suez canals, which had a notable impact on the dynamics of the global LNG market.

The Yemen-based Houthi group began targeting commercial ships transiting through the Red Sea in November 2023. In response, in December 2023 the US-led coalition, Operation Prosperity Guardian, aimed to secure the waterways and counter Houthi aggression. However, the heightened security risks, including ship attacks in the Red Sea and Gulf of Aden, have led major shipping companies to reroute their vessels around South Africa's Cape of Good Hope. Even though no LNG carriers have been targeted so far, the situation has affected LNG flows due to the increased risks and rerouting of LNG vessels. The halt in the transit of LNG tankers through the Red Sea and Suez Canal from January 2024 has led to a notable increase in fuel expenses and regional insurance costs. According to the Suez Canal authority, between 10% and 12% of the total volume of world trade in goods and 8% of global LNG flows transited through the Suez Canal in 2023. This reduction in ship transits has significantly affected Egypt's economy. The Suez Canal, which accounts for almost 8% of the Egyptian government's income, has seen its revenue drop by approximately 50% since the start of the year.

Meanwhile, the Panama Canal continues to face droughts. Restrictions on ship transits are leading to increased traffic congestion and delays. In 2023 the Panama Canal Authority almost halved traffic on the waterway to save water from the depleted reservoirs used to fill the canal's huge locks. The authority recently confirmed that the restrictions would be maintained until the start of the rainy season, expected from April. Until then, only 24 transits are permitted daily, compared with the usual 38 to 40, and normal levels of activity may not return until 2025. In turn, the auction system set up to allow shippers to request priority passage is increasing both costs and unpredictability.

The situation underscores the vulnerability of critical shipping routes to geopolitical tensions. These bottlenecks through the Suez and Panama canals are leading to a return to a more regional pattern of physical LNG flows. LNG from the United States typically lands in Europe and Central and South America, while Asian buyers mainly source LNG from closer producers, such as Qatar and Australia. During the winter of 2023/24 in the northern hemisphere, Europe experienced a 12% y-o-y drop in its LNG imports, while Asia saw a 10% y-o-y increase. As a result, and despite the congestion affecting the Panama and Suez canals, the share of US LNG in

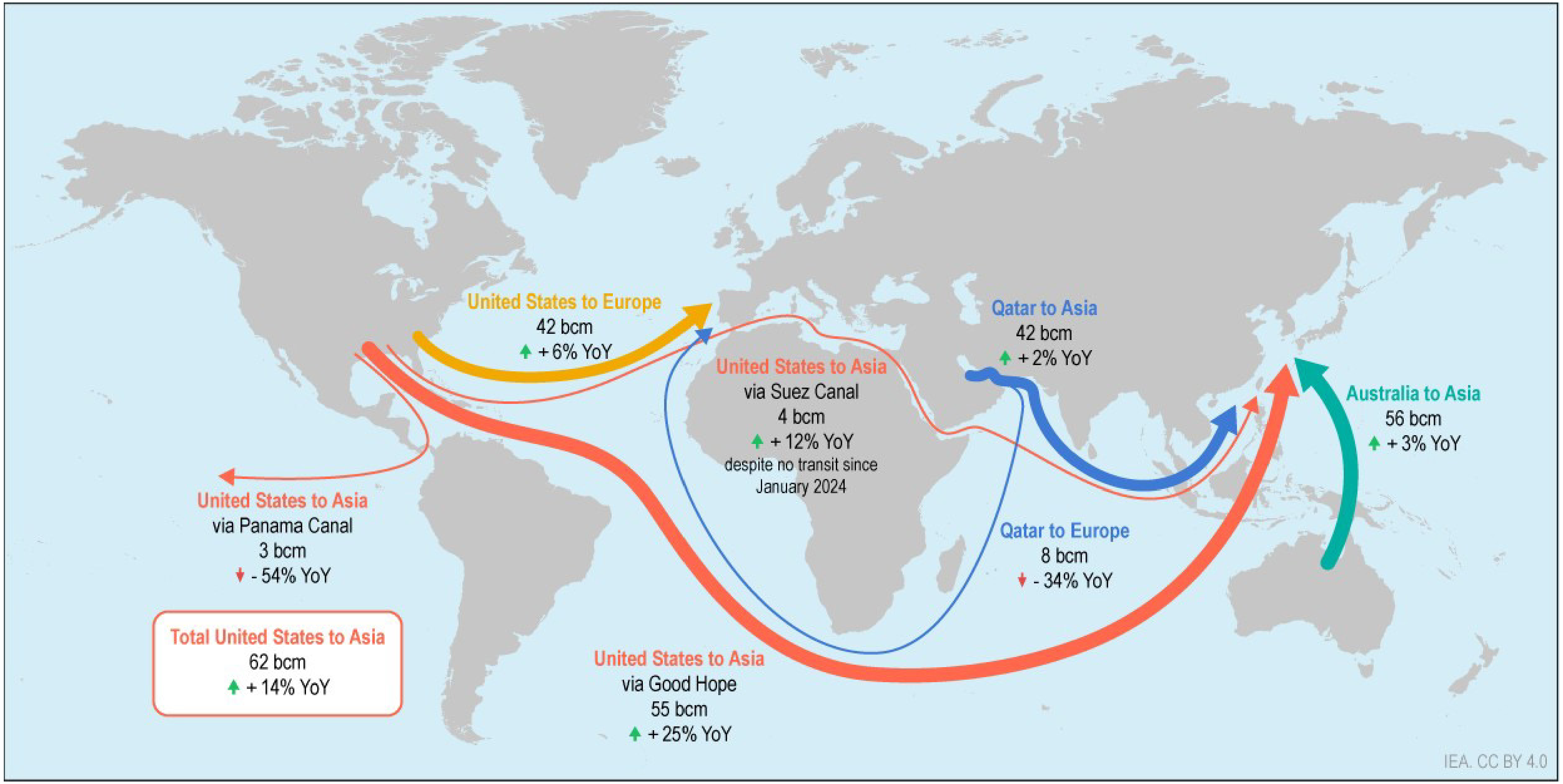
Asian LNG imports increased by 14% in the northern hemisphere winter of 2023/24 compared with the winter of 2022/23. This means that most of the LNG cargos from the United States that physically delivered to Asian markets (i.e. excluding commercial swaps) transited via the Cape of Good Hope. This alternative route extends the one-way voyage by around ten days compared with transit via the Panama Canal, depending on both the loading point and the precise destination.

On another front, the extended shipping routes resulting from the halt in Red Sea transits and the restricted transits through the Panama Canal may have an impact on the International Maritime Organization (IMO) Carbon Intensity Indicator (CII) assessment, currently ongoing. These extended journeys result in higher fuel consumption and, consequently, greater carbon emissions. The IMO CII evaluates the carbon efficiency of ships by measuring CO_2 emissions per ton-mile of cargo transported. The CII considers factors such as fuel type (i.e. LNG, heavy fuel oil) and operational practices.

To date, the effect of these shipping constraints is not visible on spot LNG freight rates, which are at their lowest since 2020, contrary to what is currently observed in oil tanker freight rates. If congestion were to persist, it could reduce LNG shipping capacity and thus put upward pressure on LNG spot charter rates, ultimately resulting in higher LNG supply costs.

Red Sea disruption and Panama bottleneck make LNG flows more regional, but also mean longer voyages

LNG Flow Dynamics: winters 2023-24 vs 2022-23



Notes: Winter period refers to the northern hemisphere winter and spans October to March. This map represents the main LNG flows only and should not be considered exhaustive. Numbers in *bcm* indicate winter 2023-24 flow volumes and arrow thickness corresponds to flow volumes.
Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Asian and European spot gas prices fell below their pre-crisis levels in Q1 2024

Natural gas prices declined across all key markets in Q1 2024 compared to the previous quarter amid unseasonably mild weather conditions, healthy supply and high inventory levels.

In Europe, TTF spot prices fell by 32% on the quarter to an average of USD 8.7/MBtu in Q1 2024 – their lowest quarterly average since Q1 2021. Continued declines in demand together with strong Norwegian piped gas flows, healthy LNG availability and high storage levels weighed on natural gas prices. While TTF prices fell by almost 50% on the year, they remained 55% above their 2016-20 Q1 averages. All-time high storage levels limited short-term price variability. Historical volatility in TTF month-ahead prices averaged 55% in Q1 2024, 70% and 40% below the volatility displayed during the same period in 2022 and 2023, respectively. TTF's premium over NBP narrowed from USD 0.6/MBtu in Q1 2023 to USD 0.07/MBtu in Q1 2024. Consequently, flows from the United Kingdom to continental Europe fell by 90% y-o-y in Q1 2024.

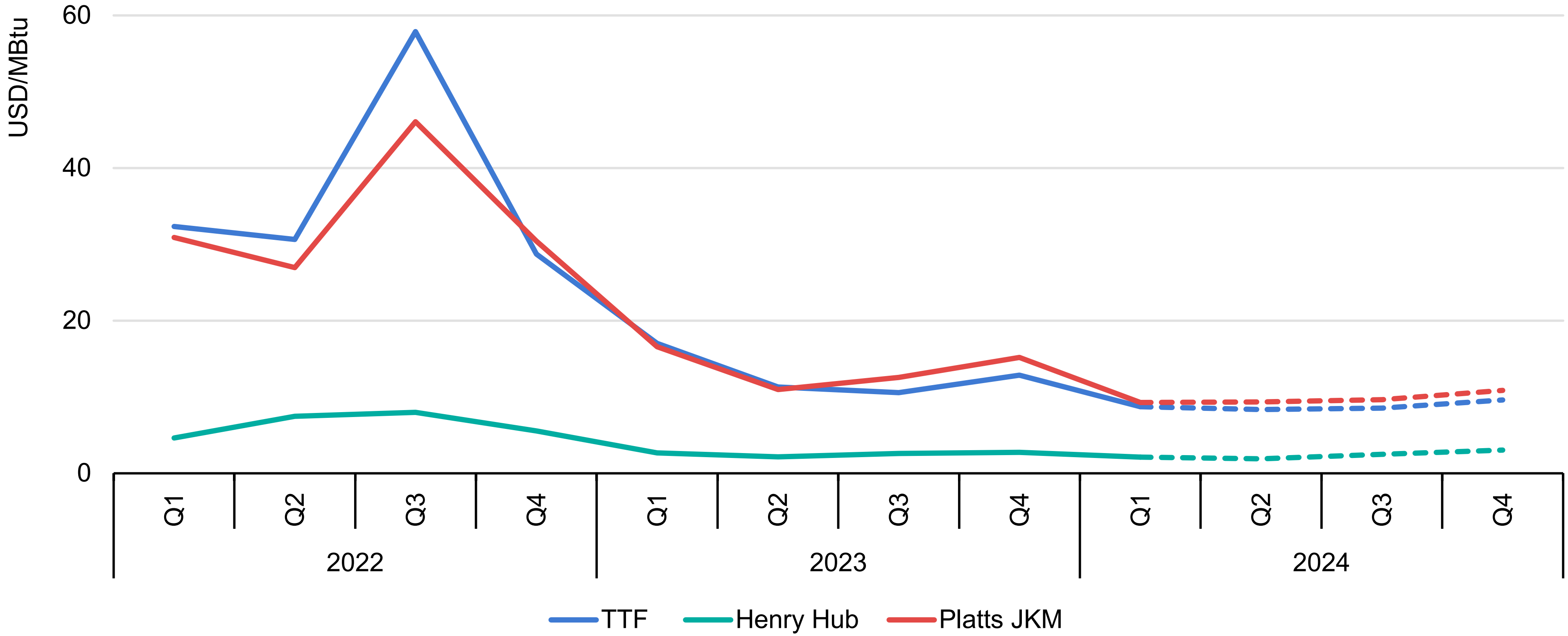
In Asia, Platts JKM prices followed a similar trajectory and declined by almost 40% on the quarter to an average of USD 9.3/MBtu in Q1 2024 –their lowest quarterly average since Q4 2020. Lower competition with Europe for spot LNG cargos, together with mild winter weather in Northeast Asia and improving nuclear availability in Japan, depressed spot LNG prices to USD 2-3/MBtu below the estimated range of oil-indexed LNG prices in Q1 2024. The premium of Asian spot LNG prices over TTF narrowed from USD 2.3/MBtu in Q4 2023 to USD 0.6/MBtu in Q1 2024, as the Red Sea crisis incentivised stronger Middle Eastern LNG flows towards Asia. Overall, Platts JKM prices averaged USD 1.5/MBtu above TTF during the 2023/24 heating season, driving LNG cargos away from Europe. While Asia's LNG imports grew by 9% y-o-y, Europe's declined by 12% y-o-y during the 2023/24 winter.

In the United States, Henry Hub prices fell by 22% on the quarter to average USD 2.1/MBtu in Q1 2024 – their lowest Q1 level since 2020. Winter storm Heather supported a short-lived surge in natural gas prices, with Henry Hub rising to USD 13.1/MBtu on 12 January 2024 – its highest daily level since February 2021. Unseasonably mild winter weather together with strong natural gas production and high inventory levels weighed on Henry Hub prices during the remainder of the heating season. In March 2024 Henry Hub prices dropped to an average of USD 1.49/MBtu, their lowest March price level since 1992.

Forward curves as of beginning of April 2024 suggest that TTF is set to average 30% below its 2023 levels in 2024 at just below USD 9/MBtu. According to forward curves, JKM prices should retain their premium over European hub prices in 2024, with JKM averaging USD 1/MBtu above TTF. This provides an incentive for higher LNG flows towards Asian markets. Based on forward curves, Henry Hub prices in the United States are set to decline by 5% amid easing market fundamentals and average USD 2.4/MBtu.

Asian spot LNG prices are expected to retain their premium over TTF in 2024

Main spot and forward natural gas prices, 2022-2024



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

Subdued demand weighed on gas storage withdrawals over the 2023/24 winter

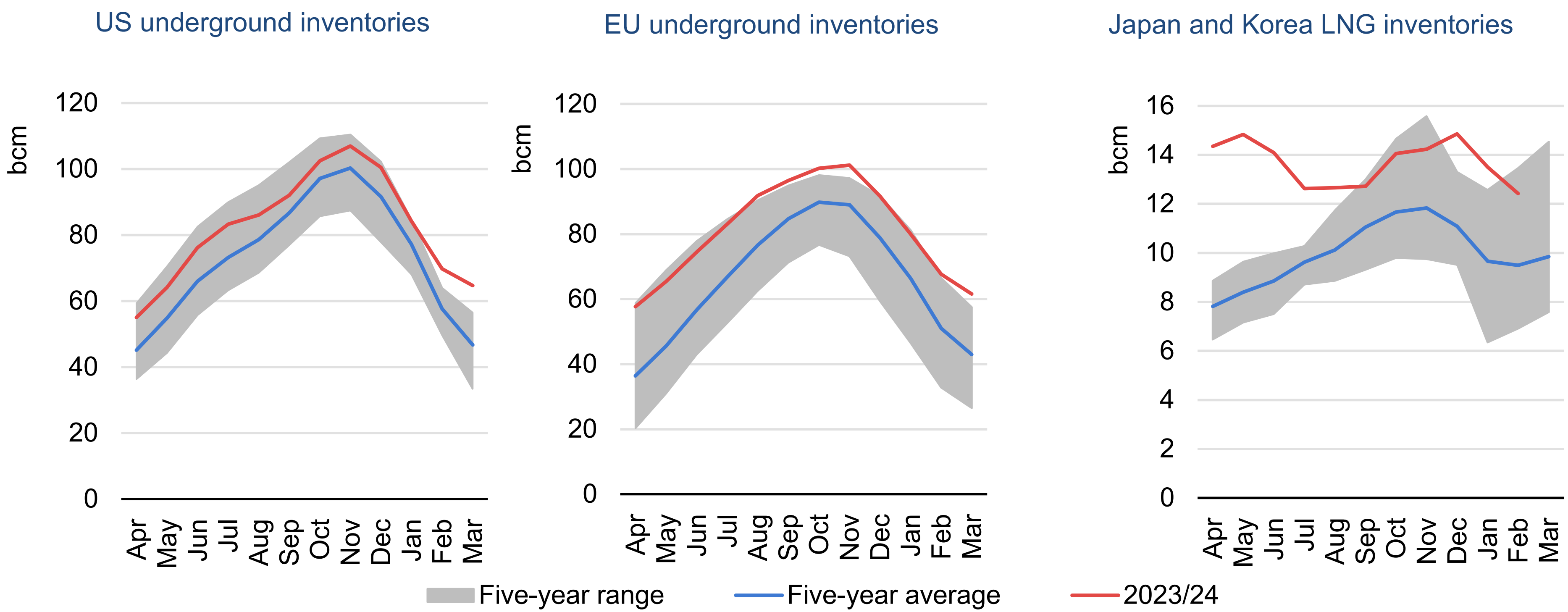
Lower natural gas demand depressed storage withdrawals in the Europe Union and the United States during the 2023/24 winter. Storage sites closed the heating season with inventory levels standing well above their five-year average. This is expected to reduce injection demand over the 2024 summer, which could potentially further ease market fundamentals.

In the European Union gas inventory levels reached an all-time high of 99.6% of their working storage capacity by early November 2023, standing 13% (or 11.5 bcm) above their five-year average. The continued decline in natural gas demand combined with healthy LNG availability and strong Norwegian piped gas deliveries weighed on storage draws. Net storage withdrawals stood 20% (or 9 bcm) below their five-year average at the end of the 2023/24 heating season, and totalled 37 bcm. Altogether, net storage withdrawals met around 18% of EU gas demand in the 2023/24 heating season, up from 15% during the previous winter. As a consequence of the all-time high inventory levels at the start of November and the below-average net withdrawals, EU storage sites closed the 2023/24 heating season 58% full and with inventory levels standing 45% (or 19 bcm) above their five-year average. Hence, storage injections 35% below their five-year average (or just 32 bcm) would be sufficient to reach the European Union's 90% fill level target by the start of the 2024/25 heating season. Lower injection demand over summer 2024 could potentially contribute to a further easing of market fundamentals. In Ukraine gas inventory levels at the end of March 2024 were estimated at 7.5 bcm (just below 25% of working storage capacity). European companies injected 2.5 bcm of gas into Ukraine's underground storage sites in 2023. Ukraine could offer 10-15 bcm of gas storage capacity to European market players in 2024.

In the United States storage sites were 90% full at the beginning of November 2023, standing just 5% above their five-year average. Unseasonably mild weather conditions combined with continued growth in domestic production weighed on storage draws. Net storage withdrawals stood almost 25% (or 13 bcm) below their five-year average during November 2023-March 2024, and met more than 10% of US gas demand during this period. Storage draws surged by 70% week-on-week during winter storm Heather in mid-January 2024, highlighting the crucial role of natural gas storage in gas and energy supply security during demand and/or supply shocks. As a consequence of below-average storage draws through the overall heating season, US storage sites closed the 2023/24 winter 53% full, standing 40% (or 18 bcm) above their five-year average.

In Japan and Korea, closing LNG stocks stood 30% (or 3 bcm) above their five-year average in February 2024. The LNG stocks of Japan's largest power generation companies stood at 1.5 Mt (2 bcm) at end of March 2024, 30% below their five-year average.

Storage sites closed the 2023/24 heating season with inventory levels well above average



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

Low-emissions gases

Demand creation will be key for the scale-up of low-emissions gases

Low-emissions gases (including biomethane, low-emissions hydrogen[3] and e-methane[4]) can play a crucial role in decarbonising gas supply chains and the broader energy system. Recognising their growing importance, the International Energy Agency has developed a Low-emissions Gases Work Programme to track market developments in this area and facilitate dialogue between emerging producers and consumers.

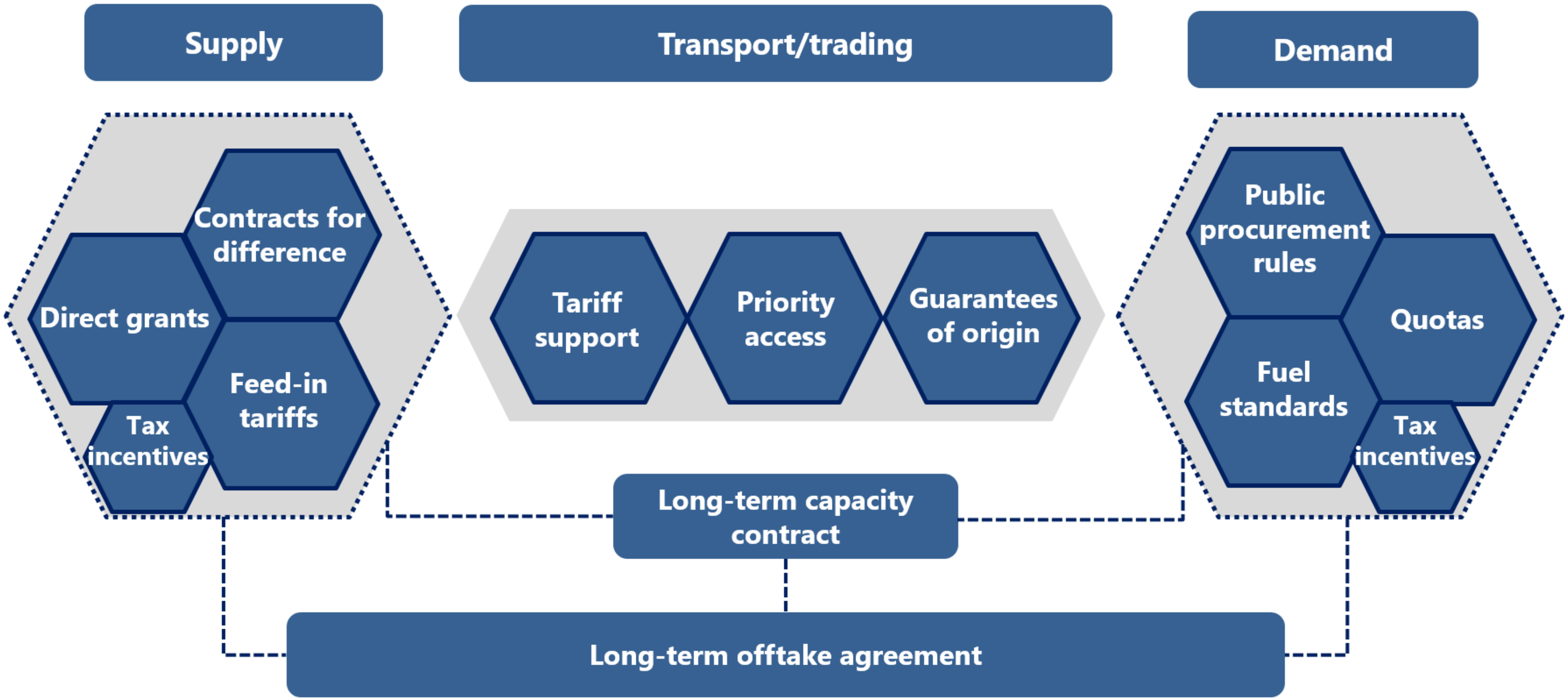
The scale-up of low-emissions gases calls for a holistic approach, with carefully designed support mechanisms targeting the entire value chain, i.e. production, transmission, distribution and end uses. Demand creation should be a key instrument to stimulate investment, including via quotas and public procurement rules. Long-term offtake agreements – similar to those used in CAPEX-intensive natural gas projects – can help to de-risk investment and improve the economic feasibility of low-emissions gas projects. This section provides an overview of policies and regulations supporting demand creation for low-emissions gases in key markets.

In respect of biomethane, a number of policies and regulations have been introduced in recent years to stimulate demand. They include the revised Renewable Fuel Standard (RFS) in the United States and India's recently adopted compressed biogas blending obligation. In the European Union, member states are setting biomethane production and demand targets in their respective National Energy and Climate Plans.

In the case of low-emissions hydrogen, the gap between production and demand targets is increasing the investment risk associated with low-emissions hydrogen projects and hinders their development. As highlighted by the IEA Global Hydrogen Review 2023, current government targets could lead to up to 14 Mt of low-emissions hydrogen demand, which is less than half the 27-35 Mt envisaged by low-emissions hydrogen production targets. A more certain outlook for low-emissions hydrogen demand would facilitate the conclusion of long-term offake agreements, which are key for project developers to take FID. In the European Union, the revised Renewable Energy Directive is set to incentivise the use of renewable hydrogen in industrial and transport sectors. In the United States, the Regional Clean Hydrogen Hubs Program aims to channel public and private investment into hydrogen ecosystems targeting both the supply and demand side. E-methane could play a key role in the decarbonisation of hard-to-abate sectors. Japan aims to increase the share of e-methane to 1% of the gas supply in existing networks by 2030, rising to 90% by 2050.

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

The development of the low-emissions gases market will require a holistic approach to support mechanisms along the entire value chain



Recent policy surges and ambitious targets are set to increase biomethane demand in the transport sector and for grid injection

For the successful integration of renewable gases, it is crucial to both foster increased demand and enhance production capacity. Demand can be supported by policy measures: governments can incentivise biomethane adoption through feed-in tariffs, tax credits and grants. From the production side, investing in infrastructure – such as anaerobic digesters, biogas plants, existing infrastructure upgrades and new distribution stations – and supporting R&D efforts are crucial to boost biomethane supply growth. Clear policies reduce market risk and attract investors.

In recent years there has been a significant surge in policies related to biomethane. This is a clear indication of the increasing recognition of the potential for biomethane to address environmental challenges and achieve sustainability goals. Governments worldwide are acknowledging the role biomethane can play in reducing greenhouse gas emissions, improving energy security and creating economic opportunities.

There is a clear trend towards incentivising the use of biomethane for transport and grid injection. While incentives for electricity generation from biogas are still relevant in some countries, such as Germany and the United Kingdom, they are gradually decreasing. This can be attributed to the increasing share of other competitive renewable sources in electricity grids.

Biomethane is finding a more useful role in the decarbonisation of other sectors. The intrinsic flexibility of biomethane makes it a promising solution for decarbonisation. It can replace conventional natural gas in existing infrastructure, including gas transmission and distribution grids, as well as underground gas storage facilities. Consequently, it can be used for the same applications as natural gas. Some countries are realising this potential and are shifting their focus towards promoting the use of biomethane in sectors other than electricity generation.

Europe is advanced in comparison to other regions in the injection of biomethane into natural gas grids. However, it is important to note that the situation can vary greatly from country to country. For instance, Denmark has an impressive 37% share of biomethane in its network as of February 2024, and France saw more than 9 TWh of biomethane injected into its network in 2023, with a 140% increase in the number of biomethane production facilities between 2020 and 2023. Conversely, countries such as Belgium, Spain and Poland remain in the early development stages.

Several regions have established targets for biomethane, including blending shares or transport targets. These targets are part of broader strategies to promote renewable energy, reduce greenhouse gas emissions and achieve sustainability goals.

In the United States, the development of biomethane has been largely driven by the transport sector and support schemes such as the RFS and California's Low Carbon Fuels Standard (LCFS). The RFS "set" rule announced in June 2023 established an ambitious aim to increase by 20% renewable natural gas (RNG) supplies in the next three years. According to the IEA Renewables 2023 report, and considering the proposed obligation volumes under the RFS, the pipeline of projects currently under development and California's targets for injected biomethane, it is expected that supplies of biogas and RNG combined will double in the next five years. This growth is set to be further facilitated by various programmes that provide generous financial support and accelerate the issuance of permits to speed up the development of RNG production infrastructure, thereby creating a favourable framework for this anticipated growth.

India introduced in November 2023 a mandate to blend 5% compressed bio-gas (CBG) into compressed natural gas (CNG) for transport and piped natural gas (PNG) for domestic use, which is expected to stimulate demand for biomethane in the city gas distribution and transport sectors. Implementation is set to start in a phased approach. The blending obligation will be progressively increased, mandating a biogas share of 1%, 3% and 4% of total CNG consumption for the fiscal years 2025/26, 2026/27 and 2027/28 respectively. From the fiscal year 2028/29 onwards the blending obligation will be set at 5%.

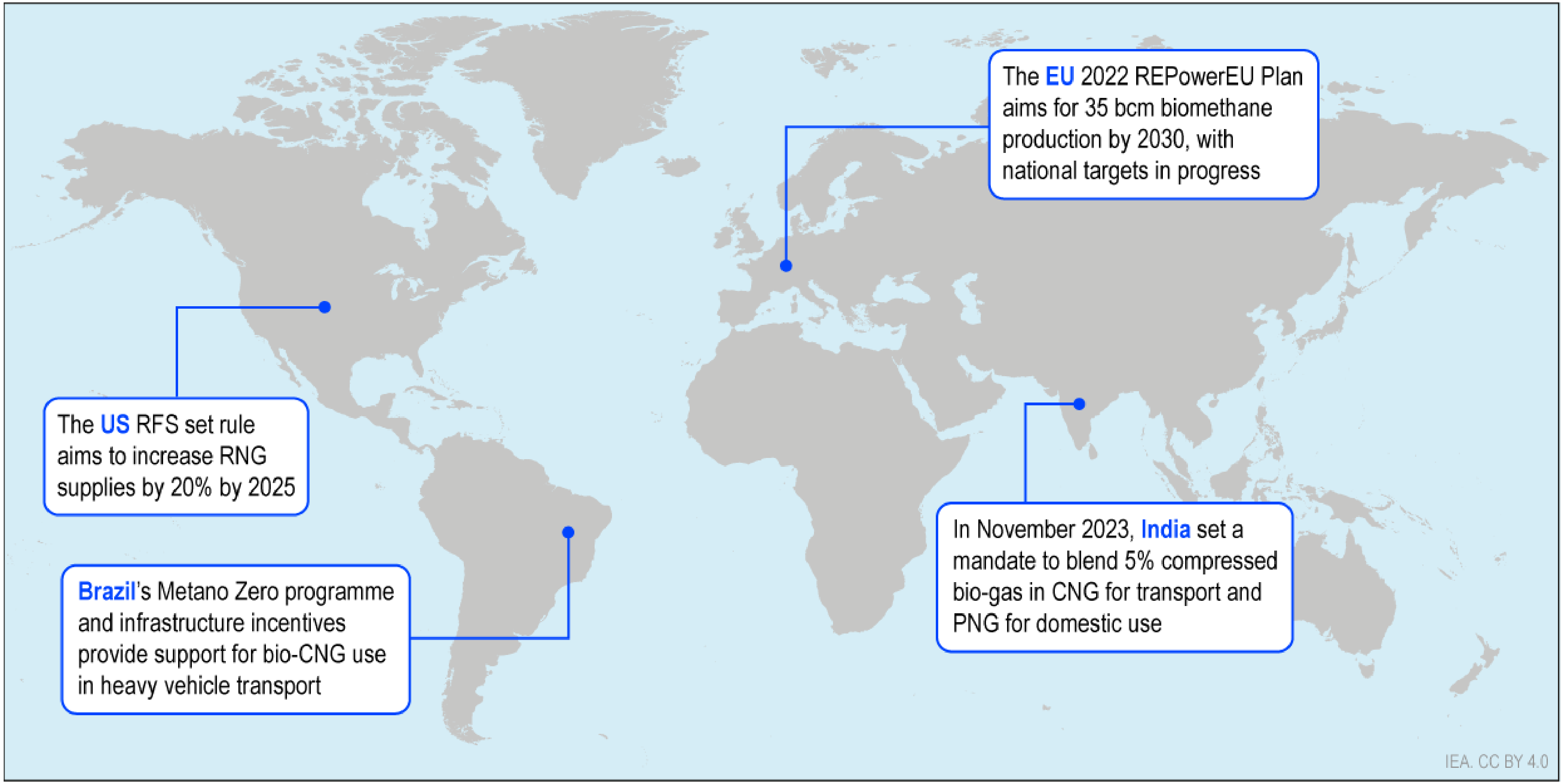
While its target does not relate solely to biomethane, but to biogas more broadly, it is nonetheless notable that China has set an ambitious target of producing 20 bcm of biogas by 2030, initially set at 30 bcm but subsequently revised downwards, as part of China's 14th Five-Year Plan.

In Brazil, the Metano Zero programme, the introduction of a carbon market and the special incentive scheme for infrastructure development (Reidi) should support the development of new biomethane production facilities and the creation of green corridors. These will have the necessary infrastructure to supply heavy-duty vehicles, where the use of bio-CNG in transport is expected to replace costly diesel imports.

In its 2022 REPowerEU plan, the European Union set a non-binding target of 35 bcm of biomethane production by 2030. Member states have initiated the process of setting national targets in their National Energy and Climate Plans. These plans are currently in draft form, but are to be finalised by July 2024.

Key regions have set biomethane targets, blending mandates or transport sector objectives

Main policies in place to drive demand for biomethane



Sources: IEA analysis based on various public announcements (release from the India's Ministry of Petroleum & Natural Gas; release from the US EPA regarding the RFS set rule; information on the Metano Zero programme on the Government of Brazil's website; release from the European Union regarding the 2022 REPowerEU plan).

Hydrogen policy attention is turning to the demand side to foster market development

Global ambitions to develop a market for low-emissions hydrogen have taken off in recent years as countries look to tackle emissions in hard-to-abate sectors. A number of countries have put forward roadmaps and targets for integrating hydrogen into their domestic energy mixes. In some cases these plans also outline the role that a given country could play in a potential global hydrogen supply chain. Identifying potential offtakers will be just as important as promoting low-emissions hydrogen production to the development of a market.

The European Union is aiming for a total of 20 Mt of renewable hydrogen demand by 2030, half of which would be domestically produced and half imported. While individual member states have also put forward their own initiatives on the demand front, EU policy made a significant step forward with the revised Renewable Energy Directive (RED III), which came into effect in November 2023. The directive notably sets out requirements for the origin of hydrogen consumed across certain sectors – particularly in industry and transport – effectively supporting demand for renewable hydrogen. With RED III, EU member states have agreed that renewable fuels of non-biological origin (RFNBOs) should account for at least 42% of total hydrogen use in industry by 2030, rising to 60% by 2035. In transport, at least 1% of all fuel supplied to the sector must either fall under advanced biofuel or biogas classification, or comply with RFNBO rules, by 2025. The share rises to 5.5% by 2030, with a minimum contribution of 1% from RFNBOs.

Across the European Union, current hydrogen consumption is highly concentrated in refining and chemicals production, totalling approximately 6 Mt of demand. In the early ramp-up of low-emissions hydrogen, demand is likely to come from these sectors as they transition away from current unabated fossil fuel-derived sources of hydrogen, as well as from industrial subsectors looking to replace certain fuel streams with hydrogen.

The United States is another market where the importance of the demand side has emerged in ensuring market viability. The rolling out of the Inflation Reduction Act (IRA) includes a Clean Hydrogen Production Tax Credit, with subsidies varying according to a number of factors, notably the life cycle emissions of produced hydrogen. While lauded, such provisions have also sparked concerns that incentives may be overly skewed to the supply side, providing little clarity on the build-up of offtakers for potential supply.

In response to this, the US Department of Energy announced in mid-2023 that it was considering making available USD 1 billion in funding to develop a demand-side mechanism. Following a feedback period, it was announced in early 2024 that financing would be provided within the broader USD 8 billion Regional Clean Hydrogen Hubs Program (H2Hubs), which itself aims to channel public and private investment into hydrogen ecosystems (seven such hubs have been selected). Support under this demand mechanism could take various forms, including fixed subsidies or contracts for difference (CfDs), where a subsidy makes up for the incremental cost a consumer faces in opting for renewable hydrogen compared to another fuel.

There has also been progress in this direction at the state level. In Colorado, for example, a 2023 law provides a demand-side tax credit for the offtake of low-emissions hydrogen in certain sectors and end uses. The law targets the use of hydrogen as a feedstock in industrial processes – such as in chemicals, steel and fertiliser production – as well as in certain transport applications.

The state of California has been at the forefront of transport sector decarbonisation regulation. While policy tools have generally been technology and fuel agnostic, they have created a space for alternative fuels, including hydrogen. Key among these policies is the Advanced Clean Truck (ACT) programme, establishing minimum zero-emisions vehicle sales requirements for heavy-duty vehicle manufacturers. As the state has sought to enact stricter targets over time, other states have started to adopt similar regulations, creating significant momentum. Complementary to the ACT, California's LCFS acts directly at the fuel level, encouraging use of low-carbon options, where low-emissions hydrogen (among other options) can play a role.

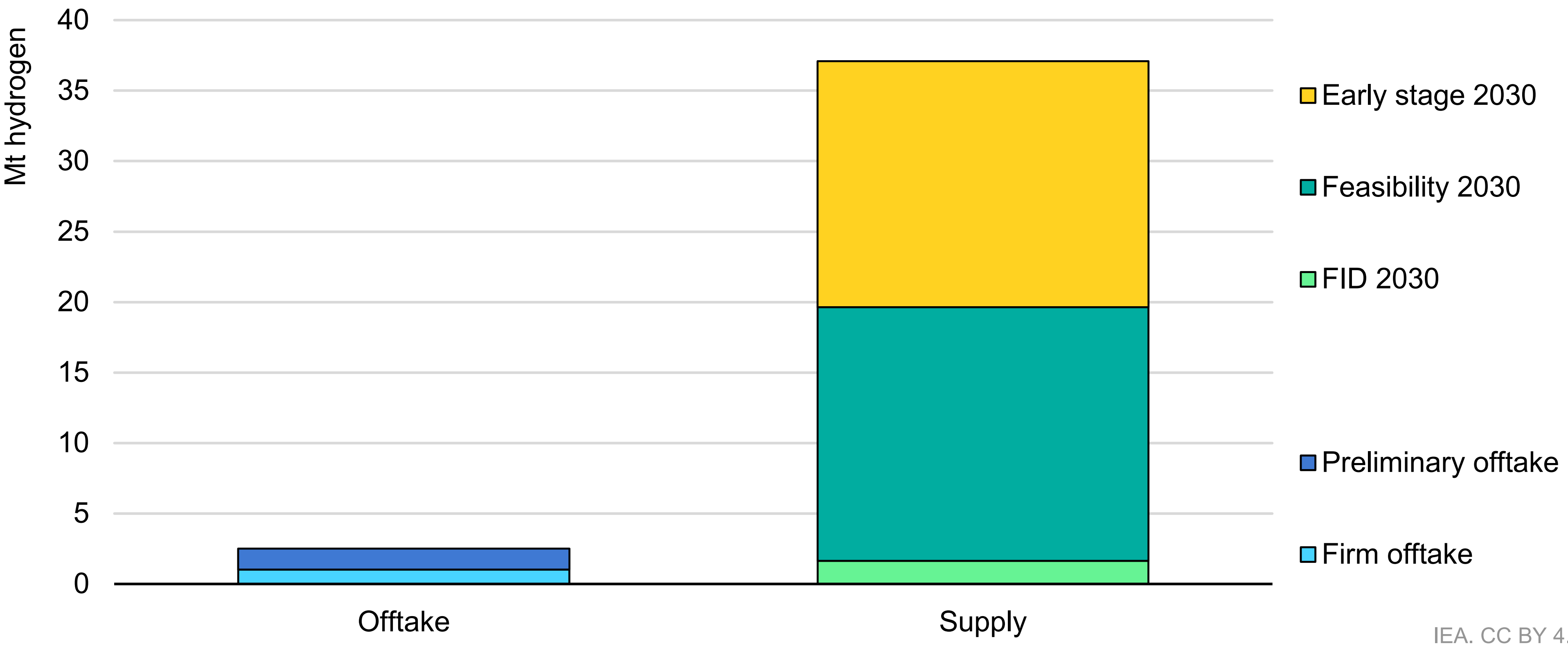
In the Pacific Basin, Japan's unique energy context means that the country has opted for a role as a key link in the hydrogen technology value chain and as a key offtaker of low-emissions hydrogen in a global supply chain. In 2023 Japan updated its Hydrogen Basic Strategy, providing more precise guidance on target end-use sectors for the consumption of hydrogen, as well as on the carbon intensity of hydrogen supply.

While under its original form the strategy called for wide-ranging use of hydrogen across all sectors, the updated document recognises more explicitly hydrogen's role in decarbonising hard-to-abate sectors, particularly those with significant heat requirements and where replacing carbon feedstocks will be necessary, as in the steel and chemicals sectors. Key to stimulating this domestic demand will be the development of industrial hydrogen clusters over the next decade, allowing for better scale-up of the hydrogen value chain from both a supply and demand perspective. In parallel to these evolutions, transport and the power sector remain segments where Japanese policy also encourages hydrogen use. Japan's strategy also puts forward more stringent carbon intensity rules around hydrogen supply, providing clearer guidance on the role for low-carbon hydrogen in the country's energy mix.

Globally, despite refocused attention in key markets on the demand side of the hydrogen equation, potential supply commitments for low-emissions hydrogen continue to significantly outweigh offtake agreements globally. Addressing this imbalance through more targeted policy and support mechanisms could prove essential in driving early development of a market for low-carbon hydrogen.

Global low-emissions hydrogen supply commitments outweigh offtake agreements to 2030

Global offtake agreements and supply commitments for low-emissions hydrogen to 2030
2021 and 2030



Sources: IEA analysis based on various public announcements.

Global actions to promote e-methane are expanding

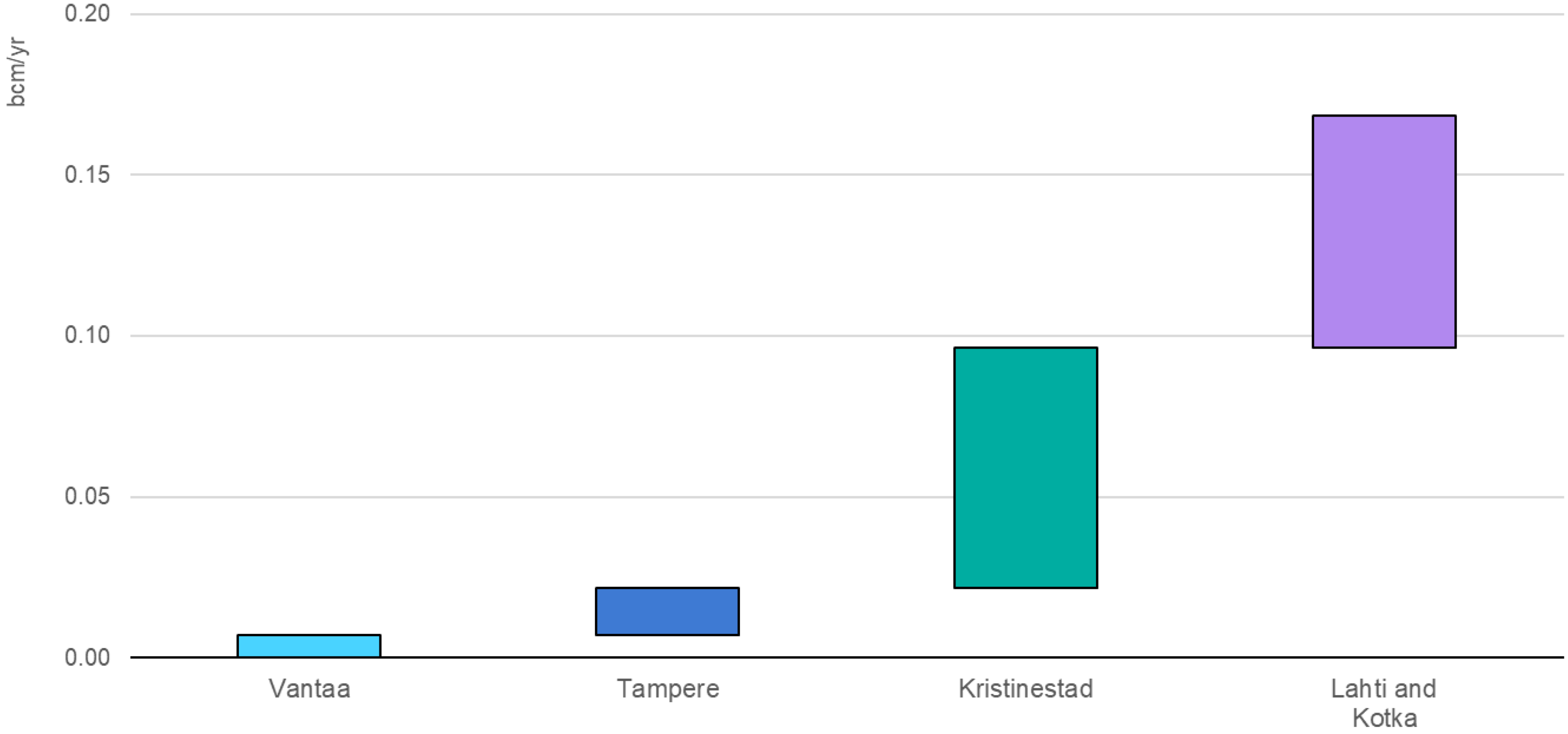
E-methane is produced by combining low-emissions hydrogen with carbon resources and has the potential to contribute to the decarbonisation of gas networks without the need for retrofitting. In March 2024 eight companies promoting e-methane (or electric natural gas [e-NG]) announced the creation of the e-NG Coalition with the aim of accelerating global deployment in a reliable, affordable and sustainable way. In January 2024 the Japan Gas Association together with 17 other companies, associations and organisations submitted an open letter to the GHG Protocol Secretariat advocating a specific update to the GHG Protocol. The aim is to reflect the environmental benefits of carbon recycled fuels, including e-methane, e-fuels and sustainable aviation fuels, in the GHG Protocol. The letter proposes the inclusion of a market-based approach and the recognition of low-carbon fuel certificates in the GHG Protocol's Scope 1 inventory.

Japanese companies are aiming to produce e-methane in the Middle East, in addition to aiming for production in the United States, Australia, South East Asia and Peru. Abu Dhabi Future Energy Company-PJSC-Masdar, INPEX, Tokyo Gas and Osaka Gas signed a collaboration agreement for a feasibility study on e-methane production in the United Arab Emirates. Tokyo Gas and Osaka Gas plan to offtake e-methane in volumes equivalent to 1% of their respective annual city gas demand in this project. Hitachi Zosen signed a memorandum of understanding with Oman LNG to co-operate on the study of commercial prospects for methanation in Oman. The collaboration aims to install methanation equipment in existing LNG plants owned by Oman LNG.

European companies are also taking steps towards e-methane production. Finland has a target to achieve carbon neutrality by 2035. Several companies are working on e-methane production in Finland, mainly to reduce CO_2 emissions in the transport and industrial sectors. P2X Solutions has a plan to produce low-emissions hydrogen and e-methane using a 20 MW electrolyser in Harjavalta. This project is expected to be operational in 2024. Gasum announced an e-methane offtake agreement with Nordic Ren-Gas from its planned e-methane production project in Tampere. This project aims to produce 160 GWh of e-methane annually using renewable electricity and biogenic carbon dioxide captured from the Tammervoima waste incineration plant, and is expected to start in 2026. Gasum also plans to purchase more e-methane from planned Nordic Ren-Gas production projects in Lahti and Kotka. The two projects are intended to produce a total of 800 GWh of e-methane per year and are expected to be operational by 2027. The e-methane produced by the two projects will be connected to the existing gas grid, with the potential for export elsewhere in Europe or liquefied for use as e-LNG. Outokumpu has signed a memorandum of understanding with Q Power to explore e-methane production for the decarbonisation of stainless steel. This project aims to explore the possibility of capturing carbon monoxide and carbon dioxide from the Outokumpu's production processes and using them as raw material to produce e-methane.

Finnish companies aim to produce e-methane to support the decarbonisation of transport and the industrial sector

Production volumes and locations of the key planned e-methane projects in Finland



Sources: IEA analysis based on various public announcements.

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	170	176	181	240	260	251	253	260
Asia Pacific	834	891	877	902	942	622	648	660	670	685
of which China	*325*	*367*	*364*	*391*	*417*	*189*	*205*	*216*	*230*	*240*
Central and South America	142	153	150	149	152	150	148	151	149	153
Eurasia	585	649	622	631	646	866	961	865	830	860
of which Russia	*461*	*516*	*487*	*495*	*507*	*692*	*762*	*672*	*638*	*670*
Europe	576	609	524	488	497	230	222	230	215	219
Middle East	546	562	580	592	607	670	692	715	725	745
North America	1 079	1 091	1 144	1 157	1 166	1 145	1 172	1 240	1 285	1 270
of which United States	*868*	*874*	*919*	*928*	*935*	*954*	*984*	*1 021*	*1 061*	*1 055*
World	**3 923**	**4 124**	**4 067**	**4 095**	**4 191**	**3 923**	**4 105**	**4 112**	**4 127**	**4 192**

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)
BIL	Bipartisan Infrastructure Law (USA)
BMC	Colombian Mercantile Exchange (Colombia)
CCUS	Carbon Capture, Utilisation and Storage
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
EPA	Environmental Protection Agency (USA)
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
ETS	EU Emissions Trading System
EU	European Union
EUR	Euro
FID	final investment decision
FSRU	floating storage and regasification unit
GHGs	greenhouse gases
GIE	Gas Infrastructure Europe
HH	Henry Hub
HoA	Head of Agreement
ICE	Intercontinental Exchange
ICIS	Independent Chemical Information Services
IEA	International Energy Agency
IMO	International Maritime Organization
IRA	Inflation Reduction Act (USA)
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JOGMEC	Japan Organization for Metals and Energy Security
JPY	Japanese yen
KOGAS	Korea Gas Corporation
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
MME	Ministry of Mines and Energy (Brazil)
MMRV	Measuring, monitoring, reporting, and verification
MoU	Memorandum of Understanding
NBP	National Balancing Point (United Kingdom)
OECD	Organisation for Economic Co-operation and Development
OSINERG	Energy Regulatory Commission (Peru)
PPAC	Petroleum Planning and Analysis Cell (India)
RSG	Responsibly sourced natural gas
SBL	Strategic Buffer LNG
TFFS	Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security
TTF	Title Transfer Facility (the Netherlands)
UGS	underground storage
UNFCCC	United Nations Framework Convention on Climate Change
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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