Gas Market Report

Q2-2021

Abstract

After a record drop in global demand of about 75 billion cubic metres (bcm) in 2020, natural gas markets experienced significant supply-demand tensions in the initial months of 2021. Colder-than-expected temperatures and tighter supply led to price rallies and spikes, first in Northeast Asia in January and then in North America in February.

These winter storms provided some short-term support to natural gas demand, but market fundamentals for 2021 remain fragile. Global gas demand is expected to recover to its 2019 level, but with uncertainties regarding the recovery trajectory in fast-growing markets as compared to more mature regions, while sectoral demand is subject to a variety of risk factors including a slow rebound in economic activity and fuel switching.

This new quarterly report offers a detailed review of 2020's gas supply and demand fundamentals and figures, an analysis of recent developments in global gas markets during the northern hemisphere's heating season, and an updated near-term outlook for 2021.

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Winter of our discontent

After average conditions in early winter, natural gas markets experienced severe supply-demand tensions in the opening weeks of 2021, with extremely cold temperature episodes sending spot prices to record levels. The first episode took place in Northeast Asia in January with a combination of incremental gas demand, limited storage capacity and regional liquefaction outages that pushed spot LNG prices and charter rates to unprecedented highs. This had repercussions on European markets, driving LNG away from Europe and prompting a surge in storage withdrawals and price spikes. The second happened in North America in mid-February, when extremely cold temperatures led to rising heat and electricity needs while hampering production with well freeze-offs, resulting in rolling power cuts in several US states and Mexico.

This report provides a detailed account of the events and consequences of both cold spells, addressing their immediate impacts on supply availability and market prices. These extreme events also illustrate broader energy policy and security-related realities. First, they are a useful reminder (after last year's unusually mild heating season) that winters can be cold, and that natural gas demand is particularly temperature-sensitive. Several tools are available to cope with this, such as storage, interconnectors, flexible fuel capability and diversified supply portfolios, and they played a critical role in mitigating the impacts of supply-demand tensions in both episodes. Second, that gas markets are becoming truly global, with implications for interdependence. This was illustrated by the LNG switch from Europe to Asia during the January cold spell, compensated by withdrawals from European underground storage sites. And third, that liquid and competitive markets help create short-term flexibility that is also needed to balance markets in such extreme situations. Time will tell whether the cold snaps of winter 2020/21 will have an influence on market design and regulatory policy decisions. But they do remind us that security of energy supply is never out of season.

No glorious summer in sight for 2021

While these winter storms provided some support to the rebound in heating demand, they are not sufficient to fundamentally change our view on natural gas consumption in 2021. **This forecast expects a 3.2% y-o-y increase in global gas demand**, sufficient to offset the losses of 2020, but subject to uncertainty linked to the global health and economic recovery, and to the same caveats expressed in our previous quarterly report. Most of the expected demand growth is in Asia and other fast-growing markets, whereas mature markets see a more gradual recovery, with some likely to remain below their 2019 level. Among consuming sectors, power generation remains the most challenging due to a combination of low electricity demand growth and increasing competition from renewables and cheaper alternative fossil fuels.

Out in the cold 1/2 – Northeast Asia, January 2021

In January 2021 a cold spell across Northeast Asia – coupled with reduced availability of LNG supply and logistical constraints on LNG shipping – culminated in localised fuel shortages and an unprecedented spike in spot LNG prices. While Japan, the People's Republic of China ("China") and Korea were equally exposed to cold winter weather and tightening LNG market fundamentals, local market characteristics led to different outcomes in the world's top three LNG importing countries.

Japan's electricity demand greatly exceeded the previous year in January due to the cold winter weather. At the same time only three of the country's nine restarted nuclear reactors were operational, and solar power output was also reduced due to the snow cover. The ensuing tightness in electricity markets led to record-high wholesale electricity prices, and prompted calls for electricity rationing. Local utilities, which entered the heating season with lower-than-average LNG inventories, were caught by surprise. The rush to secure cargoes propelled Asian spot LNG prices to all-time highs, while shipping bottlenecks delayed numerous deliveries.

Korea was relatively little affected by the tightening LNG fundamentals in the heating season. Despite record-high LNG spot prices in January, wholesale electricity prices remained stable within the normal historical range. LNG imports in January decreased by 1% y-o-y according to shipping data, while nuclear generation was up by 18% y-o-y in January.

In China, rising heating demand – combined with a strong economic recovery – pushed y-o-y gas demand growth to 23% in January. Pipeline gas deliveries were only sufficient to cover a fraction of the increase, so it was largely left to LNG to meet record levels of demand. LNG imports rose by a whopping 38% in January, but this was not enough to avoid sporadic gas supply curtailments to non-prioritised sectors. Local market tightness was evident in trucked LNG prices, which in some cities reached CNY 10 000/tonne (USD 28/MBtu), a level not seen since the 2017/18 winter gas shortage.

Europe played a critical balancing role during the Northeast Asian cold spell. In contrast to the first half of 2020, when Europe was absorbing surplus LNG, the widening spread between Asian spot LNG and European hub prices drew LNG cargoes away from Europe, with LNG imports falling by close to 40% y-o-y between mid-December and mid-January. Lower LNG inflow was compensated in Europe by ramping-up pipeline imports and by strong storage draws, which more than doubled compared to last year. **Prices experienced a short-lived spike in Spain**, soaring to a record of USD 18.54/MBtu on 7 January, amidst a particularly harsh cold spell and following an LNG cargo reloading on 6 January. Prices returned to their seasonal norms within days on improved gas supply conditions.

Out in the cold 2/2 – North America, February 2021

Winter storms hit the North American region in mid-February 2021, causing extremely cold temperatures across parts of Canada, the United States and Mexico. These resulted in a sharp increase in heating needs, with heating degree days reaching 279 in the United States for the week ending 18 February, some 40% above average conditions. US gas demand increased by 23% during these seven days, driven by additional needs in the residential sector (up 37%) and for power generation (up 20%). At the same time, gas production capacity was hampered by well freeze-offs and reduced capacity at gas processing plants, with weekly dry gas output plunging 15%. Southern US production areas were more affected due to the predominance of associated gas production (the presence of liquids making it more prone to freeze-offs) and where winter insulation of infrastructure is less common.

Texas, the largest gas-producing US state, was particularly hit. Local production almost halved, falling by 45% during the week of the storm. This happened while local electricity and gas demand jumped – space heating is predominantly based on electricity, which in turns relies on gas for over half of its generation. The lack of gas supply, together with low wind and reduced availability of coal-fired generation, led to electricity supply unavailability and rotating power cuts that affected 4 million customers. The Electric Reliability Council of Texas (ERCOT) shed load up to the equivalent of 35% of forecasted demand during the week of the storm. Upstream underperformance resulted in reduced linepack, which, together with power supply issues at certain compressor stations, further limited the deliverability of natural gas. Over 30 pipelines issued force majeure notices and/or operational flow orders.

Alternative supply sources provided some support to US demand, such as Canadian pipeline imports and withdrawals from underground gas storage, which both jumped (up 23% and 43% w-o-w respectively). US pipeline exports dropped by 14% w-o-w, which caused power shortages in northern Mexico. Spot prices on local hubs all surged during the storms; Texas' Waha reached over USD 200/MBtu and Houston Ship Channel climbed to USD 400/MBtu, while Oklahoma's OGT spiked to an all-time gas price record of USD 1 192/MBtu on 17 February. Benchmark Henry Hub in neighbouring Louisiana reached an 18-year record of USD 23.60/MBtu, suffering less from shortages than Texas. Other US hubs also experienced spikes, such as Chicago Citygate at close to USD 130/MBtu and California's SoCal Citygate at over USD 140/MBtu. These high prices were short-lived, as rising temperatures helped bring production back online and reduced heating demand, which both returned to pre-storm levels by the end of February.

Global Gas Review 2020

Gas markets showed resilience in 2020 despite an unprecedented energy demand shock

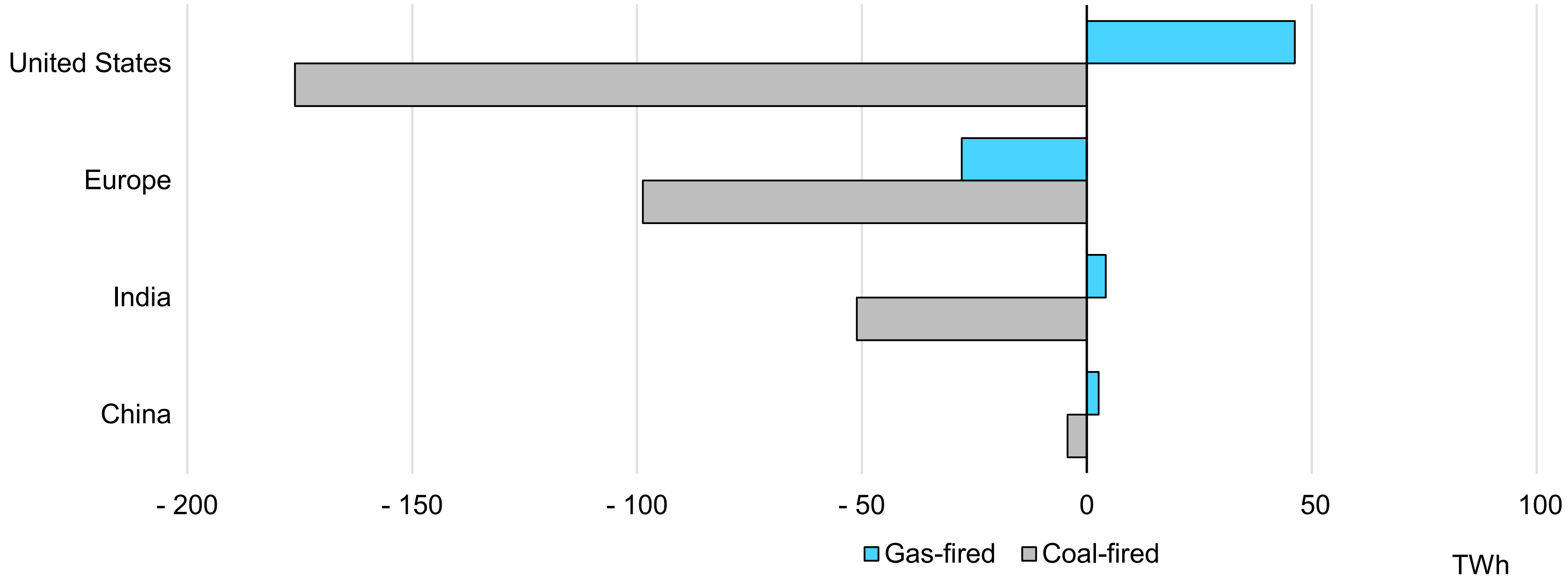
Global natural gas consumption declined by an estimated 75 bcm (or 1.9% y-o-y) in 2020. We have revised this from our previous estimate of a 2.5% y-o-y drop, due to colder-than-expected temperatures in the northern hemisphere in December and data updates from emerging markets. As a result, 2020 would remain the year with the largest ever recorded drop in gas demand in absolute terms, but would be on a par with 2009 in relative terms. Natural gas demand proved to be relatively resilient despite an exceptionally mild Q1 followed by the widespread impact of the Covid-19 pandemic – global energy demand declined by an estimated 4%, principally dragged down by oil and coal, which declined by a respective 9% and 4% y-o-y.

Part of this resilience can be explained by fuel switching in power generation. The IEA Global Energy Review highlights that **coal-to-gas switching led to a 58 Mt reduction in CO_2 emissions from the power sector in 2020.** Gas prices dropping to multi-decade lows across all major gas-consuming regions improved the cost-competitiveness of gas-fired power generation, triggering coal-to-gas switching. The most visible impact was in the United States, where gas-fired generation increased by close to 3% while coal-fired generation fell by 19%. In Europe, gas consumption partially recovered over the second half of 2020 from a 10% drop in H1, thanks to lower nuclear availability and switching from hard coal and lignite. In Asia, gas-fired generation posted slight increases in China, India and Korea, and limited decline in Japan. However, and in spite of these favourable factors, power generation was the most significantly affected sector in 2020 and accounted for almost half of the y-o-y decline in gas demand, with an estimated drop of close to 35 bcm compared to 2019.

On the supply side, almost all regions were affected by production cuts, with the main exporters being the most affected. Eurasia, faced with declines in both domestic and export markets, accounted alone for over 40% of the total fall in gas production in 2020. Interregional trade was instrumental in managing the supply adjustment from the demand shock observed in the first half of 2020. Long-distance and interregional pipeline trade was negatively affected, with a contraction in trade flows of about 40 bcm (or down 15% y-o-y), principally due to lower European imports (down about 30 bcm). Global LNG trade managed to maintain positive growth, albeit at a meagre 1.4% y-o-y increase (or 1% net of reloads), far from the double-digit annual growth rates observed in previous years.

Coal-to-gas switching reduced CO_2 emissions from power generation by 58 Mt in 2020

Estimate of y-o-y change in coal- and gas-fired power generation, 2019-2020



Sources: IEA analysis based on China Electricity Council (2021), Monthly Statistics of China Power Industry; EIA (2021), Hourly Electric Grid Monitor; ENTSOE (2021), Transparency Platform; EPIAS (2021), Transparency Platform; Eurostat (2021), Net Electricity Generation by Type of Fuel; National Bureau of Statistics of China (2021); National Power Portal of India (2021), Monthly Reports.

North American markets accounted for one-third of 2020's fall in global gas demand

Natural gas demand in North America fell by about 2.2% y-o-y in 2020 (or close to 25 bcm), accounting for about a third of the net decline in global gas demand.

Gas consumption in the **United States** fell by about 2% y-o-y in 2020. Gas burn for power generation grew by 2.7% despite power demand declining by about 3%, triggered by abundant domestic gas supply and low prices. This mitigated the double impact of a mild first quarter and Covid-19-related loss of economic activity. The residential and commercial sector was the most affected, gas demand dropping by 8.6%, while in the industrial sector it declined by 1.9%.

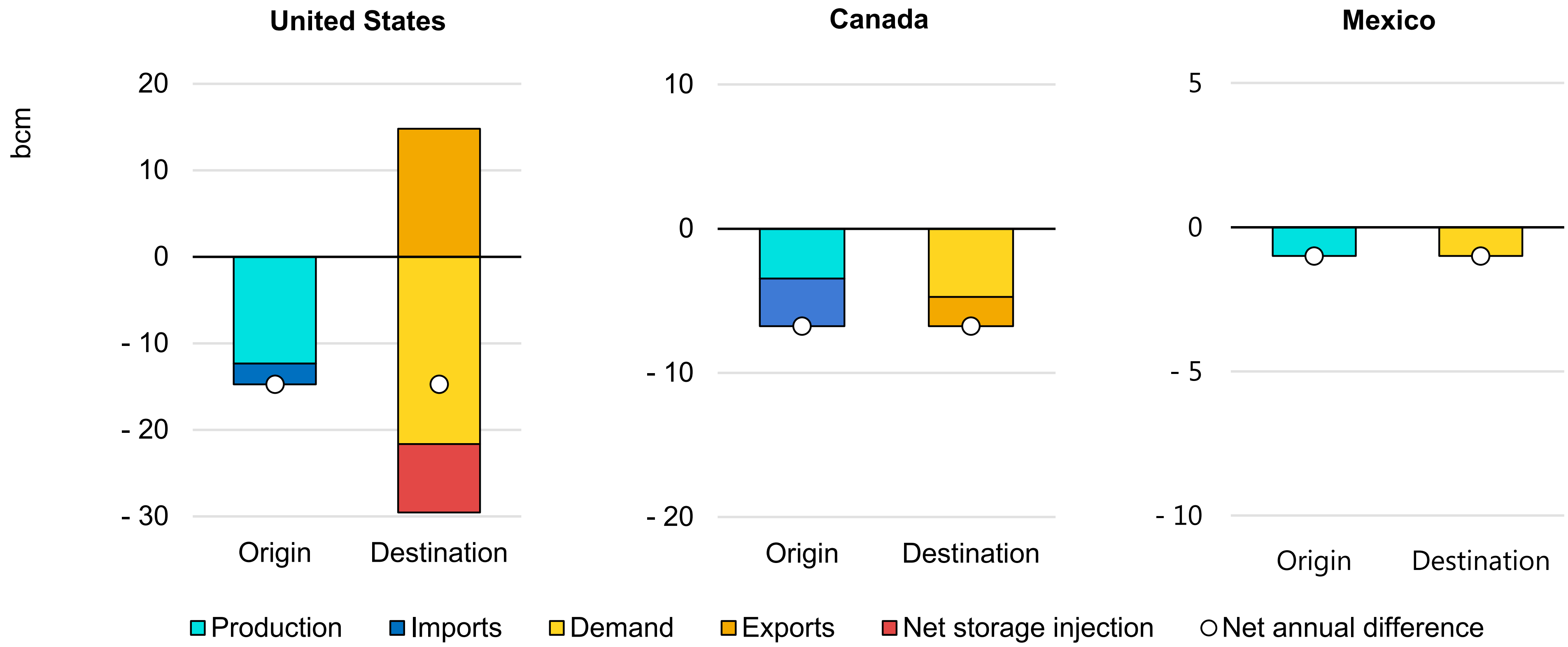
US dry gas production was proportionally less affected, with a 1.6% y-o-y decline, in spite of a plunge in drilling activity causing a 50% drop in the gas rig count. Production levels were sustained in the Appalachian Basin, the largest contributor to dry shale gas production, thanks to productivity improvements and the completion of previously drilled but uncompleted wells. Additional demand came from the contribution of growing LNG exports (up 16 bcm in 2020 or a 34% annual increase), changes in the pipeline trade balance (with lower imports from Canada and higher exports to Mexico), and a net increase in underground storage inventory.

Canada's natural gas consumption declined by an estimated 4%, with demand from industrial and other large consumers (including power generation, which accounts for two-thirds of total consumption) falling by 2.5%. Meanwhile, residential, commercial and other small consumers saw their consumption decline by almost 7%. Canadian natural gas production suffered from the combined effects of lower domestic demand and reduced pipeline exports to the United States, leading to an estimated 2% decline in domestic production.

After the major impact of Covid-19 in the second quarter, gas consumption in **Mexico** recovered during the second half of 2020, principally due to the power generation sector. Apparent natural gas consumption fell by an estimated 1% y-o-y in 2020, while domestic gas production (which covers about one-third of supply) decreased by over 2% y-o-y, in line with consumption. Total imports thus remained relatively stable, but with a switch from LNG to pipeline imports from the United States.

Rising exports helped US production partially mitigate lower domestic demand, while Canadian production was affected by both lower domestic needs and exports

Natural gas balance y-o-y differentials for North American markets, 2019-2020



Sources: IEA analysis based on EIA (2021), Natural Gas Data, Natural Gas Weekly Update; IEA (2021), Monthly Gas Data Service; SENER (2021), Dry Gas Distribution; Statistics Canada (2021), Canadian Monthly Natural Gas Distribution.

The Asia Pacific region saw growing demand in 2020, but production decreased by 1%

Consumption in the Asia Pacific region increased by 0.5% in 2020, which is remarkable given the demand declines seen in most other regions amid the Covid-19 crisis. But it is still a far cry from the 5% average growth in the 2015-2019 period. The continued expansion of demand was due to relatively healthy growth in China, which more than offset declining consumption elsewhere. Production fell by 1% as low prices, CAPEX cuts and mature field declines hit production levels in Indonesia, India, Thailand and Malaysia. This was only partially compensated by strong production growth in China (and modest growth in Australia). Net imports into the region increased by 5% (or 10 bcm), met entirely with additional LNG, while pipeline gas imports decreased by 5%.

Japan's gas consumption declined by 4.5% in 2020. The negative effects of Covid-19 on industrial and commercial activity, which were strongest in May, continued to weigh on gas demand throughout the year. However, an unexpected cold spell – combined with low nuclear and solar availability – provided a boost to gas demand in December, mitigating the overall drop in 2020.

Korea's gas demand registered a 2% increase in 2020. After a sharp drop in Q2 due to Covid-19, gas consumption rapidly recovered in the remainder of the year. Increased gas burn in the power sector reflected temporary nuclear outages in Q3 and the government-mandated shutdown of 16 coal-fired plants in December. Some coal-to-gas switching also occurred in 2020 thanks to low spot LNG prices in Q2 and Q3. A cold winter bolstered gas consumption further in Q4.

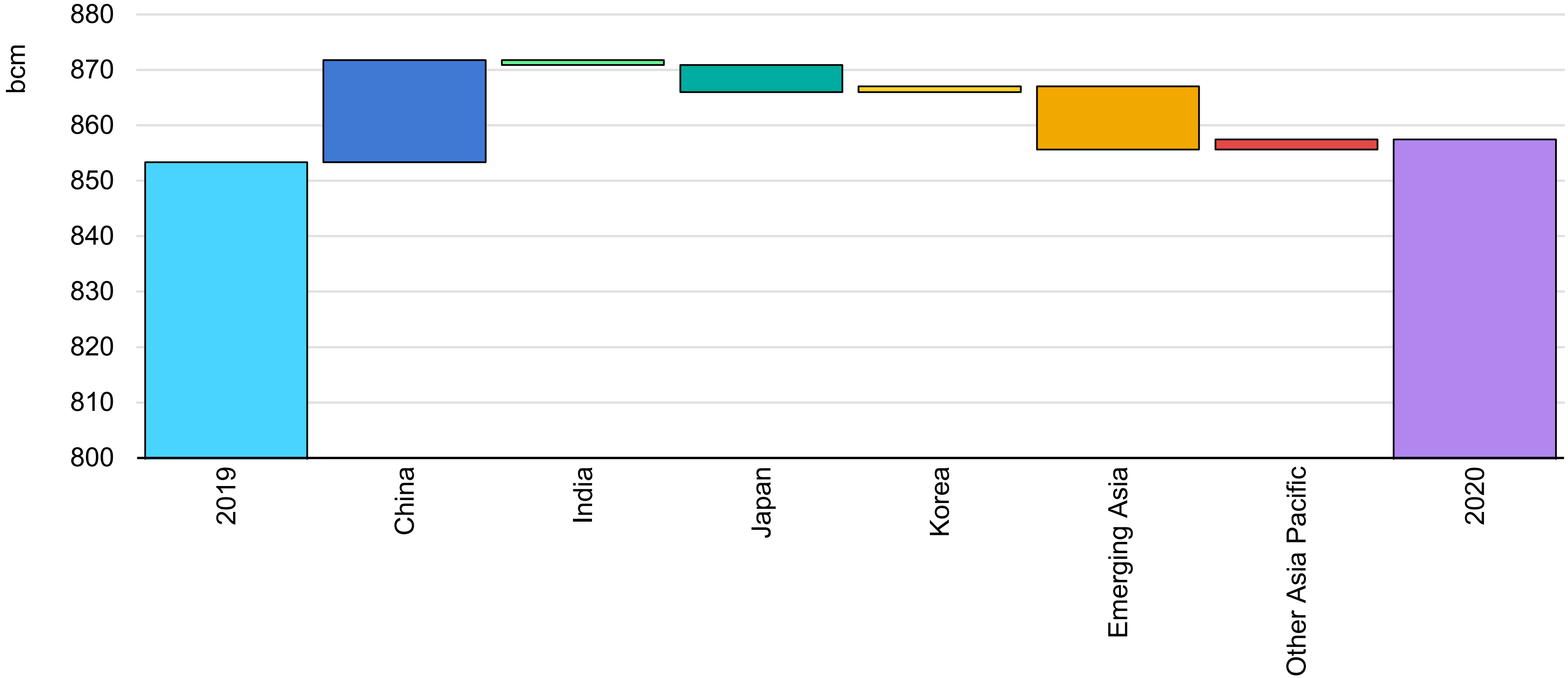
China's natural gas consumption increased by 6% in 2020 as the Covid-19-induced slump in Q1 gave way to an accelerating economic recovery in the rest of the year. Colder-than-average winter weather gave an additional boost to residential demand in Q4. Production grew by 9% and reached 189 bcm in 2020 as China's state-owned energy majors responded to government orders to prioritise domestic supply growth. About a quarter of incremental production came from shale developments. Natural gas imports rose by 5%, with LNG growing by 12% as opposed to pipeline gas imports, which registered a 5% decline.

India's gas demand shrank by 1.4% in 2020 as Covid-19-related restrictions hit gas use in the city gas sector especially hard, while consumption in industry remained resilient. Domestic production fell by 11% as operators struggled to maintain output at mature fields in the face of poor production economics in a low-price environment. LNG imports increased by 15% thanks in part to the inauguration of the Mundra LNG terminal in February 2020.

Total consumption in **Emerging Asia** decreased by an estimated 5% in 2020, but LNG imports grew by 1% as production declines continued in several major legacy producers across the region.

Asia Pacific demand growth was solely driven by China in 2020

Natural gas consumption in Asia Pacific



Note: Emerging Asia includes Bangladesh, Indonesia, Malaysia, Myanmar, Pakistan, the Philippines, Singapore, Thailand and Viet Nam.

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

Eurasia accounted for over 40% of the drop in global gas production in 2020…

Natural gas production in Eurasia declined by 6% y-o-y in 2020, as the region's gas industry faced the double impact of lower domestic demand (down by over 4%) and exports (down by 10%). Eurasia alone accounted for over 40% of the drop in global gas production in 2020.

Russian Federation's ("Russia") natural gas production fell by 6.5% y-o-y. Approximately **80% of this reduction was concentrated in the first half of the year**, when production was down by 10% y-o-y amidst an unseasonably mild winter season and plummeting exports to Europe. **The decline in production moderated to 2.5% in the second half of the year**, driven by recovery in domestic demand and export flows returning close to previous years' levels by the end of 2020. As such, the country's production grew by close to 25% in Q4 compared to Q2, **a seasonal swing almost three times larger than in 2019**. This was supported by Russia's giant swing fields, including Zapolyarnoe, which accounted for over 20% of the production increase between Q2 and Q4. **Russia's extra-regional export flows declined by over 10% y-o-y in 2020.** This was entirely driven by **lower net pipeline exports to Europe**, falling by close to 15% in 2020 compared to the year before. **Pipeline deliveries to China** via the Power of Siberia pipeline totalled 4.1 bcm in 2020, below the initially scheduled 5 bcm. **LNG exports** rose by close to 3%, with both Sakhalin-II and Yamal LNG ramping up exports. **Domestic demand** fell by an estimated 5% y-o-y, largely due to lower gas-to-power demand, as thermal generation declined by over 9% y-o-y in 2020.

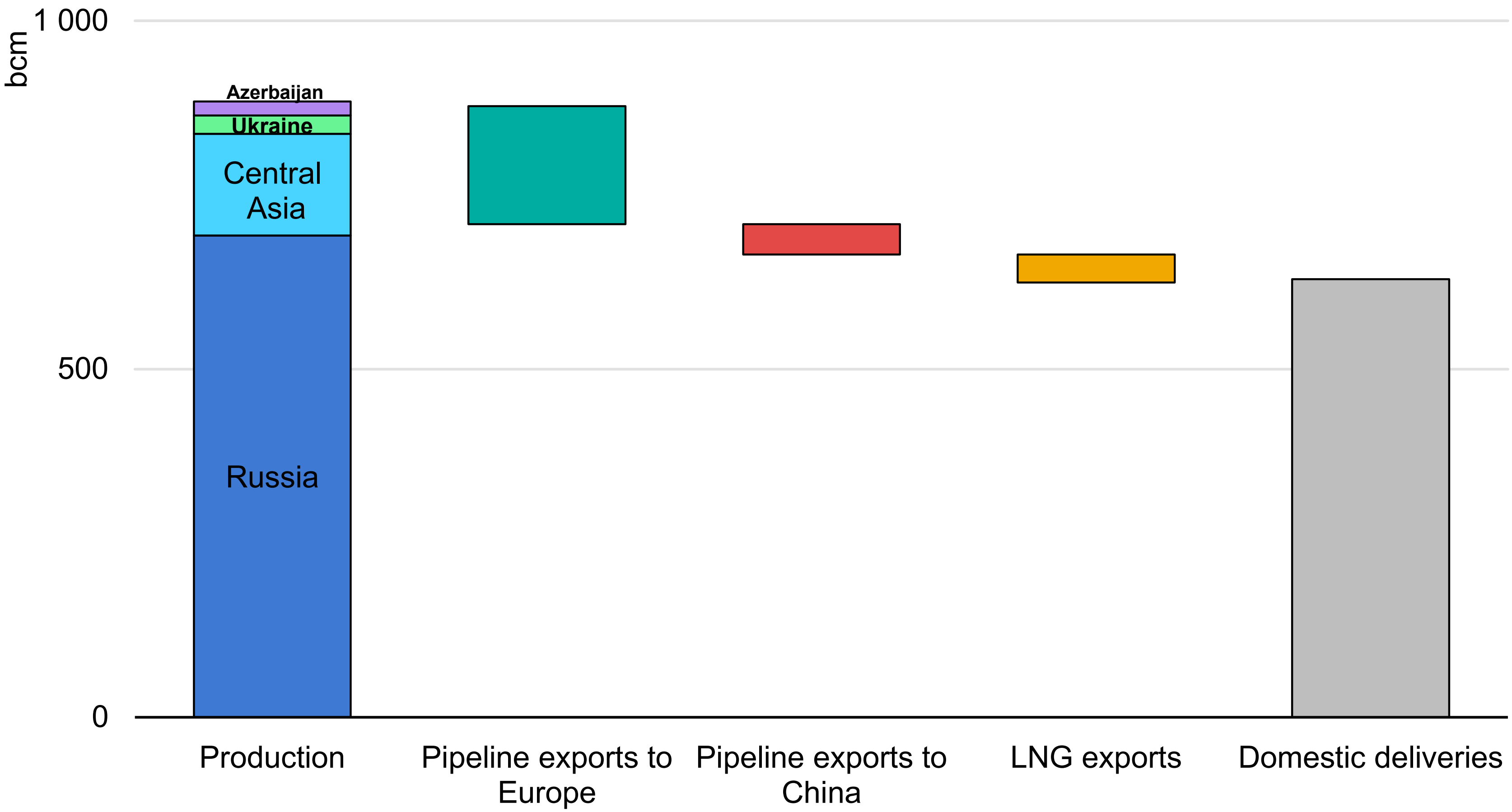
In **Central Asia** gas production decreased by close to 5% y-o-y. This was largely driven by lower exports, as the region's pipeline supplies to China fell by 13**%** y-o-y to below 40 bcm. Turkmenistan alone accounted for over three-quarters of the net drop. Whilst Kazakh and Turkmen gas production remained stable, gas output in Uzbekistan plummeted by over 16% y-o-y to reach its lowest level since 1996.

In **Azerbaijan** gas production rose by over 6% y-o-y to reach 26 bcm in 2020. This was largely driven by the rapid ramp-up of pipeline exports via the TANAP pipeline. Azerbaijani gas exports to Turkey increased by an impressive 21% y-o-y (or 2 bcm), supported by higher production at the Shah Deniz-II field.

Natural gas production in **Ukraine declined** by 2% y-o-y to 20 bcm in 2020. However, gas consumption rose by 3% y-o-y to 30 bcm. This was primarily driven by higher gas-to-power demand, which rose more than twofold. **Belarus**'s pipeline imports from Russia decreased by 7.4% y-o-y in 2020, as domestic consumption declined on lower gas burn in the power sector and lower demand in the residential and commercial sectors.

…with exports dropping by close to 10% despite the start of new export corridors

Eurasia's gas production, extra-regional exports and estimated deliveries to the domestic market in 2020



Sources: IEA analysis based on Bureau of National Statistics of Kazakhstan (2021), Statistics of Industry; ENTSOG (2021), Transparency Platform; Eurostat (2021), Imports of Natural Gas by Partner Country – Monthly Data; General Administration of Customs of People's Republic of China (2021), Customs Statistics; ICIS (2021), ICIS LNG Edge; State Committee of the Republic of Uzbekistan on Statistics (2021), Press Releases; Media reports (2021), Interfax, Neftegaz.

European gas markets in 2020: Balancing between demand shocks and recovery

European gas consumption proved to be rather resilient in the face of the unprecedented macroeconomic shock caused by the Covid-19-induced lockdowns, **falling by 2.8%** y-o-y in 2020. **Gas-to-power** demand fell by 3% y-o-y and **accounted for 40% of the net drop**, while distribution network-related consumption declined by 2.5% y-o-y and demand from industrial consumers decreased by close to 4% y-o-y.

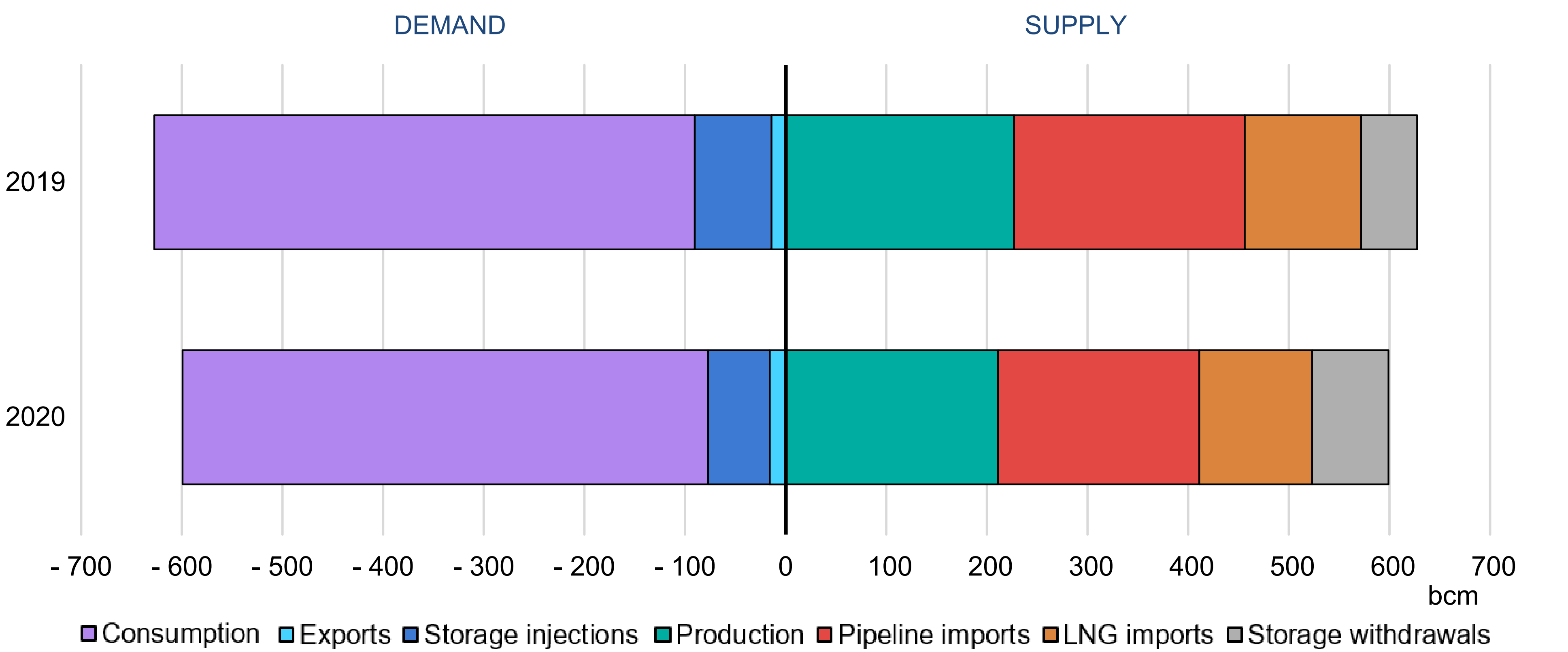
European gas markets faced an unprecedented demand shock during the first half of 2020. Gas demand plummeted by over 7% y-o-y, due to a combination of mild temperatures in Q1 and the Covid-19-induced lockdowns in Q2. The impact was particularly felt in gas-to-power demand, which plummeted by 15% y-o-y in Q2. European gas demand started to recover in June and rose by 1% y-o-y in Q3 2020. This was largely driven by gas-fired power generation, rising by 5% y-o-y despite the decline in electricity consumption and rising renewables output. In Q4, European gas demand increased by 2.5% y-o-y, despite the restrictive measures imposed amid a second wave of the pandemic. Gas consumption was supported by higher space heating demand in the residential sector and an increase of over 2% in gas-fired power generation. European domestic gas production fell by 8% y-o-y. The Netherlands alone accounted for half of the decline, as output from the giant Groningen field almost halved. Norwegian natural gas production remained resilient, declining by a mere 1% y-o-y in 2020. Following a drop close to 7% y-o-y in H1 2020, gas output rose by more than 5% in the second half of the year.

European gas imports fell by close to 10% y-o-y in 2020. Both LNG and pipeline imports were affected, falling by 3% and 12% respectively. **European LNG imports rose by 20% y-o-y in H1 2020**, as Europe absorbed two-thirds of the global incremental LNG supply, amid lower-than-expected demand in Asia. This put downward pressure on pipeline imports, which plummeted by close to 20% y-o-y. **LNG imports into Europe started to decline in June** and fell more than 20% y-o-y in the second half of 2020. This in turn **supported the recovery of pipeline gas supplies** through the second half of the year. Imports from **North Africa** increased by 25% y-o-y, and **Russian pipeline flows** had recovered close to 2019 levels by the end of the year.

Storage movements reduced Europe's import requirements in 2020 by close to 30 bcm. Storage levels above the five-year average at the start of the heating season depressed injection needs, which fell by 20% y-o-y, while withdrawals rose by 34% y-o-y. Storage withdrawals were particularly strong in Q4, rising more than twofold compared to 2019. **Pipeline exports to Ukraine rose by 12%** to 16 bcm in 2020. This was facilitated by **virtual reverse flows**, accounting for 45% of total exports.

European gas consumption fell by 3% in 2020, weighing on both pipeline and LNG imports

European natural gas supply-demand balance, 2019-2020



Sources: IEA analysis based on ENTSOG (2021), Transparency Platform; Eurostat (2021), Energy Statistics; GIE (2021), AGSI+ Database; ICIS (2021), ICIS LNG Edge.

Middle Eastern production and consumption increased; net exports registered minor declines

Gas consumption in the Middle East increased by 0.8% in 2020 as growth in Iran, Israel and Saudi Arabia outweighed declines in the United Arab Emirates, Qatar and Kuwait. Production was 0.5% higher and net exports 0.6% lower than in 2019. Higher pipeline gas deliveries from Israel to Egypt were offset by lower pipeline gas exports from Iran to Turkey. LNG trade saw a small decline in 2020 due to lower imports into Jordan and reduced exports from Oman.

Saudi Arabia, which has no international gas trade, saw its domestic consumption and production increase by an estimated 1.5% in 2020. Gas supply to the power sector remained stable, while gas use in industry is likely to have increased as the ramp-up of the 26 bcm Fadhili gas processing plant to full capacity by May 2020 more than offset the decrease in associated gas production after last year's OPEC+ oil production cuts.

Iran's natural gas consumption increased by an estimated 3% in 2020, with most of the growth from the power generation and residential sectors. Partial official data indicates that the expansion may have been higher than our estimate. Production is estimated to have increased by 2% due to the ongoing development of the South Pars field. Net exports are likely to have fallen by 2-3 bcm, as deliveries to Turkey dropped in Q2 due to a pipeline explosion and exports to Iraq were temporarily cut back in December 2020 as a result of payment disputes.

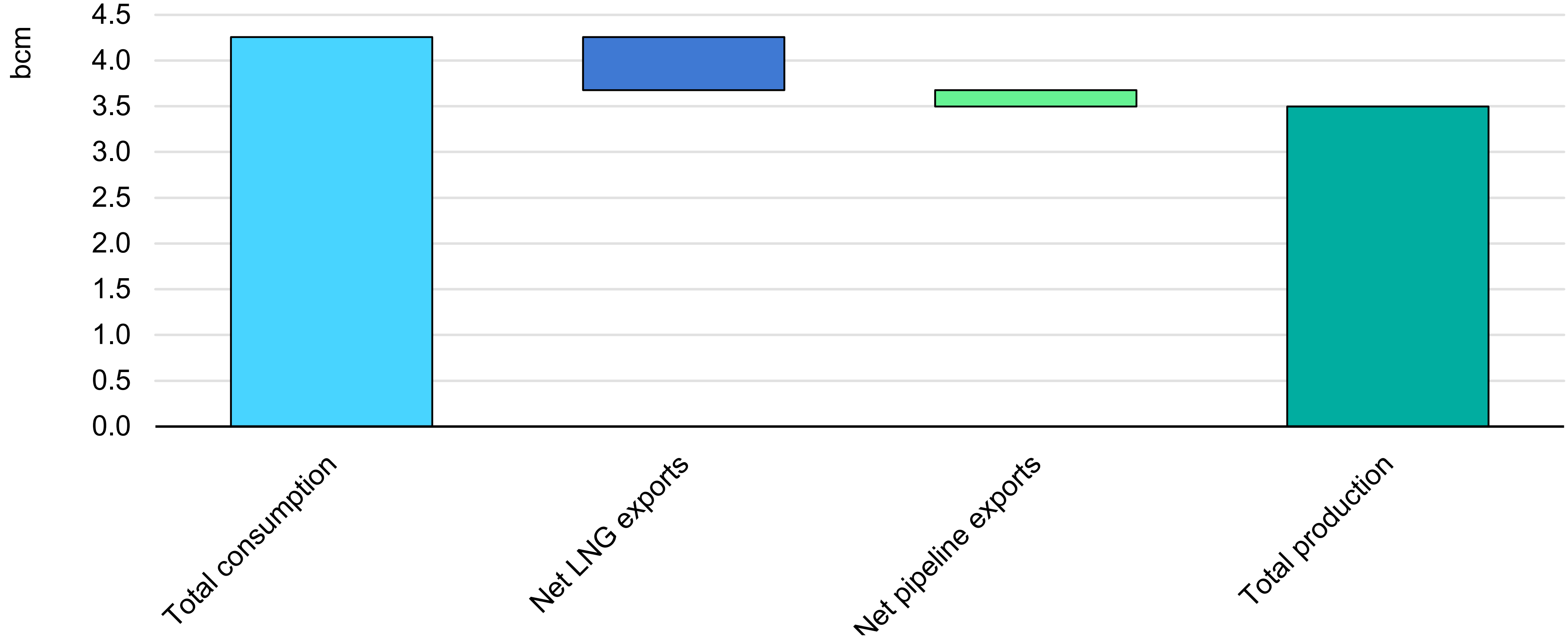
Qatar's gas consumption decreased by 2.5% in 2020, mainly due to lower industrial and power generation needs. Production in 2020 was slightly lower than in the previous year, while LNG exports increased by 0.4% as Qatar Petroleum leveraged its low-cost LNG supply to gain further market share in a challenging price environment. Deliveries via the Dolphin pipeline to the United Arab Emirates and Oman remained stable at 20 bcm.

Israel's gas consumption was up by an estimated 5% in 2020 due to growing gas burn in the power generation sector. Total gas production was up by more than a third thanks to the giant Leviathan field, which started commercial production at the end of 2019. LNG imports remained stable at below 1 bcm, while pipeline gas exports rose almost sevenfold as deliveries to both Jordan and Egypt ramped up significantly.

The United Arab Emirates experienced a 4% drop in total gas consumption, caused entirely by the power sector. Gas-fired generation was squeezed by lower electricity demand as well as growing renewable output, the start-up of the first 1.4 GW unit at the Barakah nuclear plant and the grid connection of the first 600 MW coal-fired block at the Hassyan plant in Dubai. Production decreased by 5% due to lower associated gas production following the OPEC+ supply cuts. Pipeline gas imports from Qatar remained stable, while net LNG exports declined by 4% in 2020.

Middle Eastern demand growth continued, albeit at a slow pace, met mainly by growing production within the region

Change in natural gas demand and supply in the Middle East, 2019-2020



Sources: IEA analysis based on ICIS (2021), ICIS LNG Edge; Cedigaz (2021), Annual Trade Statistics; Middle East Economic Survey (2021), MEES Archives; IEA (2021), Monthly Gas Data Service; JODI (2021), Gas World Database.

Natural gas demand in Africa remained almost stable with less than 1% y-o-y decline

Natural gas demand in Africa was relatively stable in 2020, with a limited decline estimated at 0.6% y-o-y, principally due to the positive contributions of Nigeria and Algeria. Lower exports weighed on production, which declined by about 3%.

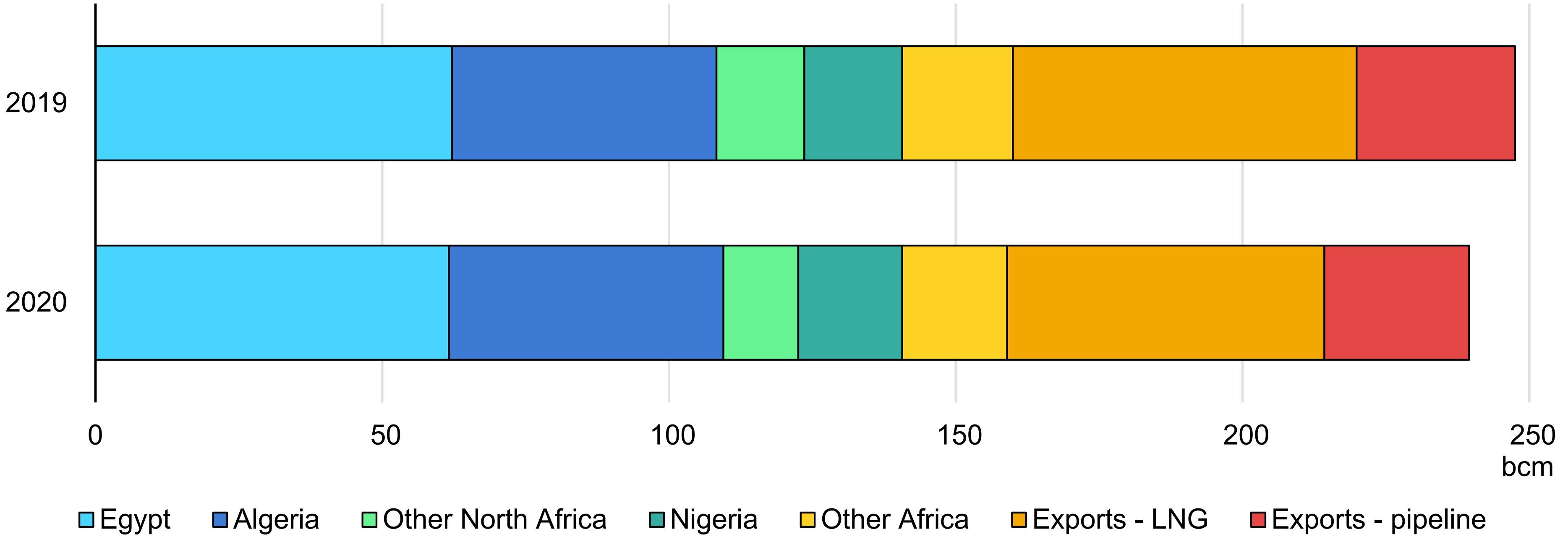
After a decline in the second quarter of 2020, **Egypt**'s monthly natural gas demand recovered to its 2019 level in September, and thus remained almost stable in 2020 with an estimated 1% annual fall compared to 2019. This was mainly driven by recovery in electricity consumption, which accounts for 60% of total gas use. This was in spite of a 19% increase in electricity tariffs in July as part of the country's plan to phase out electricity subsidies by 2022. In contrast, the rebound in domestic production remained subdued due to lower LNG exports (down 60% y-o-y at less than 2 bcm), which resulted in an estimated 9% y-o-y decline in Egyptian gas production for 2020.

Algeria's Ministry of Energy reported a 1% decline in gas production in 2020, while exports fell by 8% – pipeline flows to Europe were strongly affected in the first half of 2020, but managed a recovery over the second half of the year to reach a total of 21 bcm, 5% below their 2019 level. Meanwhile, LNG exports declined by 13% y-o-y to 14 bcm. Algeria's resulting apparent consumption thus increased by about 4%. The country's gas system is constrained by a combination of declining gas production from the legacy Hassi R'Mel complex (whose net output is falling further due to growing reinjection needs to maintain reservoir pressure) and strong growth in domestic demand, mainly driven by the power generation sector – which entirely relies on gas-fired capacity. Other North African markets also experienced negative growth in 2020 – **Libya**'s pipeline exports to Italy dropped to a decade low of 4 bcm (down 24% y-o-y), and gas consumption was reported as down by 5% in **Tunisia,** while electricity demand in **Morocco** (the main driver of gas consumption) fell by 3%.

Nigeria, the region's largest LNG exporter, had stable exports at close to 28 bcm in 2020, while domestic consumption reportedly increased by 6% y-o-y. The Nigerian government had declared 2020 to be the "Year of Gas", with a range of policy reforms such as: the implementation of the Nigeria Gas Transportation Network Code to define the contractual framework for transporting gas; the rollout of the National Gas Expansion Programme to stimulate domestic gas demand and oil-to-gas substitution in transport; and the Petroleum Industry Bill, which includes new provisions for gas aggregators and introduces penalties for flaring. Other West African countries actively prepared for domestic gas development in 2020, such as **Senegal** with its enactment of a new Gas Law to monitor future domestic production, and the confirmation of **Ghana**'s Tema LNG terminal, due to start operations in 2021. In both countries natural gas is set to replace heavy fuel oil for power generation.

Africa's natural gas production declined by an estimated 3% y-o-y in 2020 on lower exports

Natural gas production in Africa by domestic and export market destination, 2019-2020



Sources: IEA analysis based on ENTSOG (2021), Transparency Platform; GECF (2020), Annual Statistical Bulletin; ICIS (2021), ICIS LNG Edge; JODI (2021), Gas Database; Ministry of Industry, Energy and Mines of Tunisia (2021), Newspage; Morocco Energy Observatory (2021), Electricity Sales; Radio Algérie (2020), Interview with Abdelmadjid Attar, Minister for Energy.

Central and South America’s gas demand and production fell by 9% y-o-y in 2020

Regional gas consumption declined by 9% y-o-y in 2020, principally due to double-digit percentage falls in Venezuela and gas exporting countries. **Production fell by a similar 9%** on a combination of lower domestic demand and LNG exports.

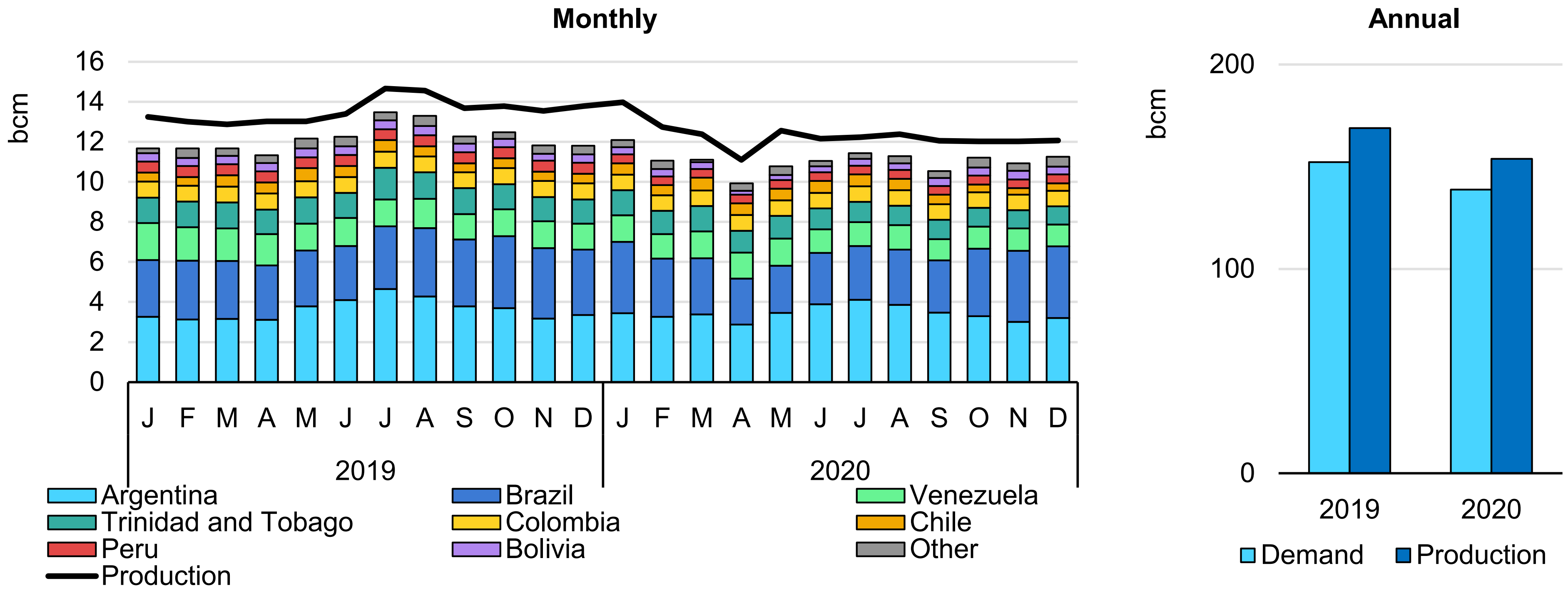
Gas demand in **Argentina**, the region’s largest consumer, fell by an estimated 5% y-o-y in 2020 with a 5% decline in gas-fired power generation and 4% fall in industrial consumption, partly compensated by higher residential demand (up 0.5%) due to the impact of colder temperatures and confinement measures during the southern hemisphere winter months. Domestic gas production declined by close to 9% y-o-y, and ended the year with December’s output 24% below the country’s peak production level in mid-2019. The government launched a four-year Gas Plan in December 2020 to support domestic supply, under which production volumes are contracted at an average price of USD 3.50/MBtu – above the average lifting costs of existing assets and enabling domestic supply to be secured below the level of pipeline and LNG import prices. The lifting of lockdown and these price incentives at the end of the year favoured a rebound in drilling activity in the Neuquén Basin’s Vaca Muerta play, with the monthly count of fracking operations rising by 40% between November and January.

Brazil experienced an estimated 6% y-o-y decline in gas demand in 2020. The industrial sector, the country’s largest consumer of gas, was relatively resilient with a 2% drop, while power generation (which accounts for a third of total gas demand) fell by close to 10%. The energy sector‘s own consumption increased by 4% on higher oil and gas output. Brazil’s gross natural gas production increased by 4.3% y-o-y to reach a record of 46.6 bcm in 2020, thanks to the development of pre-salt associated gas. This increase in production led to higher reinjection and lower LNG and pipeline imports to meet lower domestic demand needs. The New Gas Act, which aims to establish an open and competitive gas market, was approved by the lower house of Brazil’s parliament in August 2020. The New Gas Law received presidential approval on 8 April 2021.

Venezuela reported a 17% y-o-y drop in gas consumption in the first eight months of 2020 – most of its gas production is associated with oil, which collapsed from 0.87 mb/d in 2019 to 0.53 mb/d in 2020. Gas exporting countries were all strongly affected: **Bolivia** managed to keep its pipeline exports stable (even rising close to 3% y-o-y) but reported a 20% drop in domestic consumption, while **Trinidad and Tobago**’s LNG exports and gas demand declined by 19% and 15% respectively. **Peru**’s production declined by 11% according to Perupetro’s reporting, while its LNG exports remained stable. Gas demand in **Central America**, which is principally driven by power generation needs, was also significantly affected, with a 12% y-o-y decline in LNG imports in 2020.

Gas demand in July, the month of highest consumption in Central and South America, fell by 15% between 2019 and 2020

Natural gas balance, Central and South America, 2019-2020



Sources: IEA analysis based on ANP (2021), Boletim Mensal da Produção de Petróleo e Gás Natural; ICIS (2021), ICIS LNG Edge; IEA (2021), Monthly Gas Data Service; JODI (2021), Gas Database; MME (2021), Boletim Mensal de Acompanhamento da Industria de Gás Natural; Perupetro (2021), Reporte de Produccion Fiscalizada de Gas Natural a Nivel Nacional.

Global LNG trade grew by 1.4% in 2020, showing resilience despite the impacts of Covid-19

The global LNG trade grew by 1.4% in 2020 (1% net of reloads), showing resilience in a context of declining gas consumption. While this positive growth rate is a far cry from the double-digit annual growth observed since 2016, it is nonetheless a sign of resilience in the market given that global gas demand was down by 1.9%.

LNG trade increased by 11% y-o-y globally in Q1, despite lower imports into Covid-19-struck Northeast Asian markets, as cargoes markedly switched to Europe, which saw LNG imports in Q1 increase by 26% y-o-y. Between Q2 and Q3, with the pandemic hitting the global economy, total trade volumes reversed to register declines of 1% in Q2 and 4% in Q3. Asia's trade volume increased by 8% in Q4, supported by colder-than-expected temperatures in Northeast Asia, while imports to Europe fell by 30%, resulting in total LNG trade decreasing by 1% y-o-y in Q4.

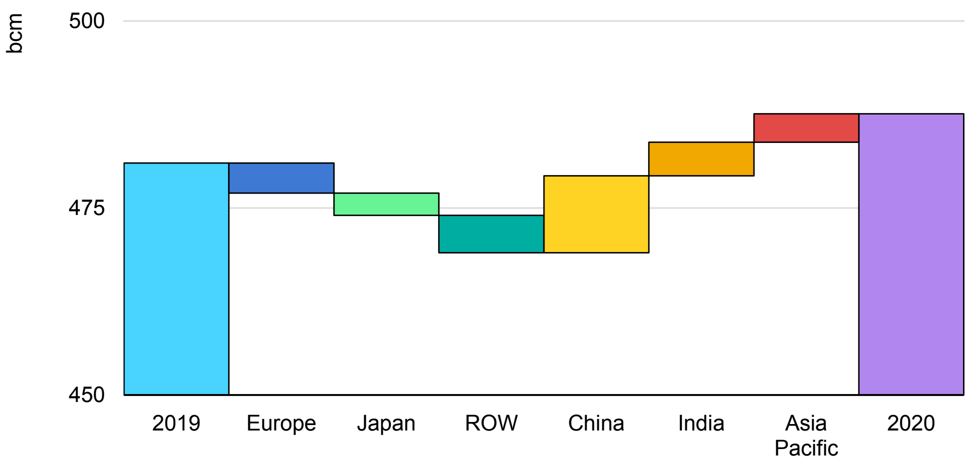
Asia accounted for all the increase in LNG trade, keeping a leading 71% share of global imports. This was mainly driven by China (up 12%) and India (up 15%). In addition, Thailand (up 18%) showed strong growth, while Japan (down 3%), Indonesia (down 31%) and Pakistan (down 9%) experienced declines. Korea’s imports remained almost flat. LNG trade to regions other than Asia declined by 4%. For example, Europe’s imports were down 3%, as dramatic declines in Q4 offset the increased volumes in Q1. Myanmar and Croatia joined the group of LNG importing countries and received their first LNG cargoes in June 2020 and January 2021 respectively.

The United States was the largest source of growth on the supply side, accounting for 70% of the total increase. Qatar, Australia, Russia and the United States remain the leading exporters of LNG, accounting altogether for two-thirds of supply. US LNG exports surged by 34% y-o-y despite 170 cargoes being cancelled in 2020, and supplied most of the incremental demand in Northeast Asia between December 2020 and January 2021. Exports increased by between zero and 3% in the three other major exporting countries. Other suppliers experienced substantial declines, such as Egypt (down 57%), Trinidad and Tobago (down 20%), Algeria (down 13%) and Malaysia (down 8%). Liquefaction capacity outages were elevated for much of 2020. This contributed to the tightening of the global LNG market. For a brief period in the second half of the year as much as 13% of global LNG export capacity was taken offline for planned or unplanned maintenance.

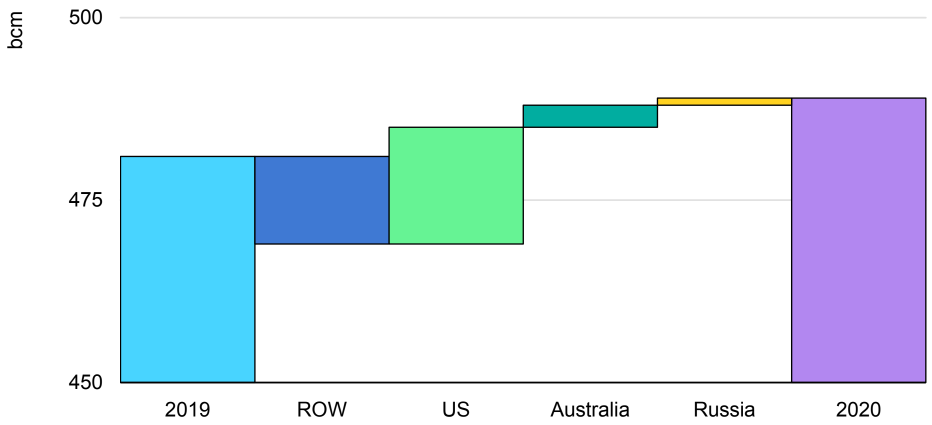
LNG volumes traded on a spot or short-term basis continued to rise in 2020. Preliminary shipping data suggest an increase of 6%, to account for 37% of the global LNG trade – its highest share on record. Short-term volumes were driven up by the higher net selling positions of portfolio players and uncontracted commission cargoes.

LNG demand increased in 2020, driven by Asian markets and principally supplied by growing US exports

LNG import growth in 2020



LNG export growth in 2020



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

Natural gas prices averaged multi-decade lows during 2020…

Regional natural gas prices closely reflected the rapidly changing dynamics of the global gas market in 2020. The steep drop in gas consumption through the first half of the year led to a collapse in prices, which plummeted to decade lows across all major gas-consuming regions in Q2. In Europe, TTF had fallen below the USD 1.00/MBtu mark by the end of May, while Asian LNG spot prices traded at below USD 2.00/MBtu at the beginning of June – historical lows in both cases. In the United States, Henry Hub averaged below USD 1.80/MBtu in H1, its lowest level since 1995.

Asian and European gas prices then recorded strong gains during H2 2020, recovering well above their 2019 levels in Q4. This was partly driven by tightening LNG supply due to a combination of planned and unplanned outages, as well as recovering gas demand in both Asia and Europe. The combination of a cold spell, low nuclear availability in Japan and outages at regional liquefaction plants led to a price rally in Asian LNG spot prices at the end of 2020, climbing to an historical high of over USD 30/MBtu in the first half of January 2021. Despite the strong gains recorded in H2 2020, both TTF and Asian LNG spot prices averaged record lows in 2020, at USD 3.20/MBtu and USD 4.20/MBtu respectively. Henry Hub averaged USD 2.00/MBtu in 2020, its lowest level since 1995.

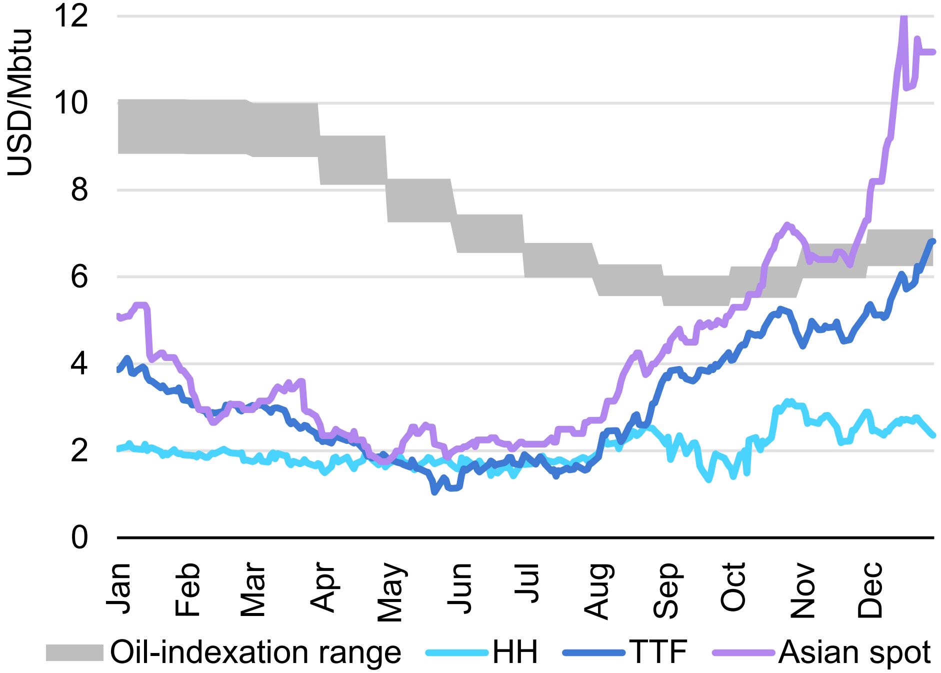
Spot charter rates closely followed the price fluctuations in Asian and European spot gas prices. Following a dip below USD 30 000/day during the summer months (or one-third below their five-year average), charter rates had risen sixfold by the end of Q4 2020 and closed the year well above their 2019 levels in both the Atlantic and Pacific basins.

In contrast with spot indices, oil-indexed LNG prices weakened y-o-y throughout H2 2020, as oil prices, which averaged below USD 40/barrel between March and December, filtered through the price-setting reference period of the contracts. Reflecting the dominance of oil-indexation in Asian LNG markets, the estimated drop of 30-40% in oil-indexed LNG prices had a significant impact on their import prices.

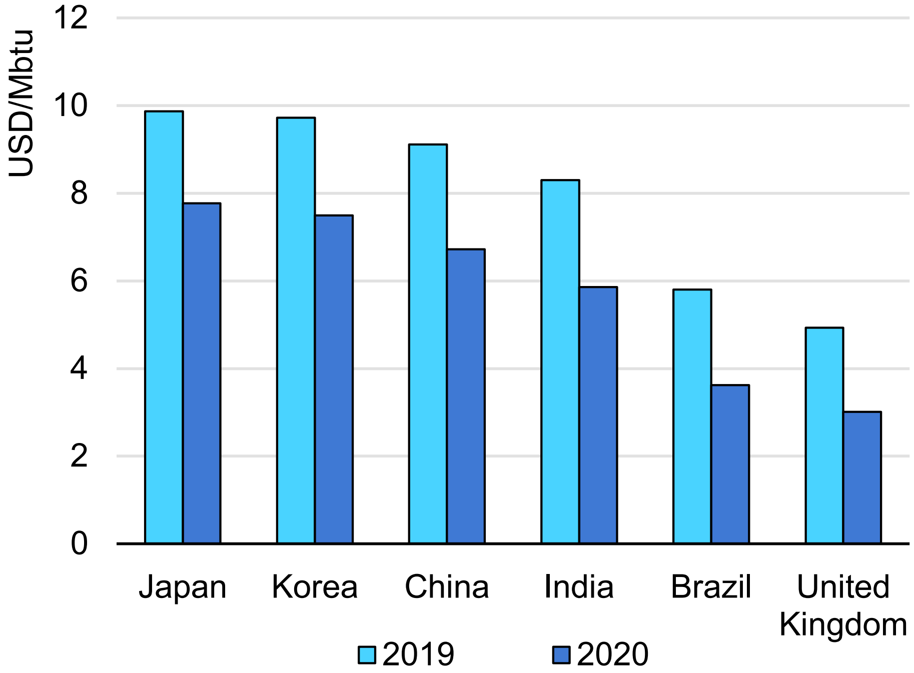
The combination of low spot gas prices and oil-indexed LNG prices has benefited LNG importers across all regions. LNG import prices have fallen by close to 40% y-o-y in the United Kingdom and Brazil. In Asia, China and India – who have a higher exposure to spot procurement – benefited the most, with their LNG import prices falling by 26% and 29% y-o-y respectively. Japan and Korea have recorded import price drops of 21% and 23% y-o-y respectively and displayed significantly higher price stability compared to other importers.

…with the low price environment benefiting LNG importers across all regions

Selected natural gas price indices in 2020



Estimated LNG import prices (2019-2020)



Note: HH = Henry Hub.

Sources: IEA analysis based on EIA (2021), Henry Hub Natural Gas Spot Price; ICIS (2021), ICIS LNG Edge; General Administration of Customs of People's Republic of China (2021), Customs Statistics; Ministry of Commerce and Industry of India (2021), Trade Statistics; Powernext (2021), Spot Market Data; Korea Customs Service (2021), Trade Statistics; Statistics of Japan (2021), Trade Statistics; UK Trade Info (2021), Trade Statistics.

Gas market update and short-term forecast

Global gas demand: Back on track?

2021 is anticipated to see a 3.2% y-o-y increase in global gas demand (about 125 bcm). On this basis the recovery would offset losses seen in 2020 and even result in some net growth above 2019 levels. However, as mentioned in our previous quarterly report, this is likely to be a fragile and rather asymmetric recovery, as sectors and regions that have suffered the largest losses may not see the biggest gains. Moreover, the prospect of a prolonged impact of the pandemic on the global economy adds further uncertainty to the pace of short-term gas demand growth.

Consumption in the **industrial sector**, which remained resilient in 2020 with an estimated 1.2% annual decline, is expected to take the lead in 2021 with 5.4% y-o-y growth (close to 55 bcm). China, India and emerging Asian markets are set to be the main drivers behind this increase. Higher gas demand from industrial buyers hinges on a consumption rebound in both these large Asian economies and their main export markets. The IMF World Economic Outlook in April 2021 projects annual growth of 6% in global output and 8.4% in trade volume.

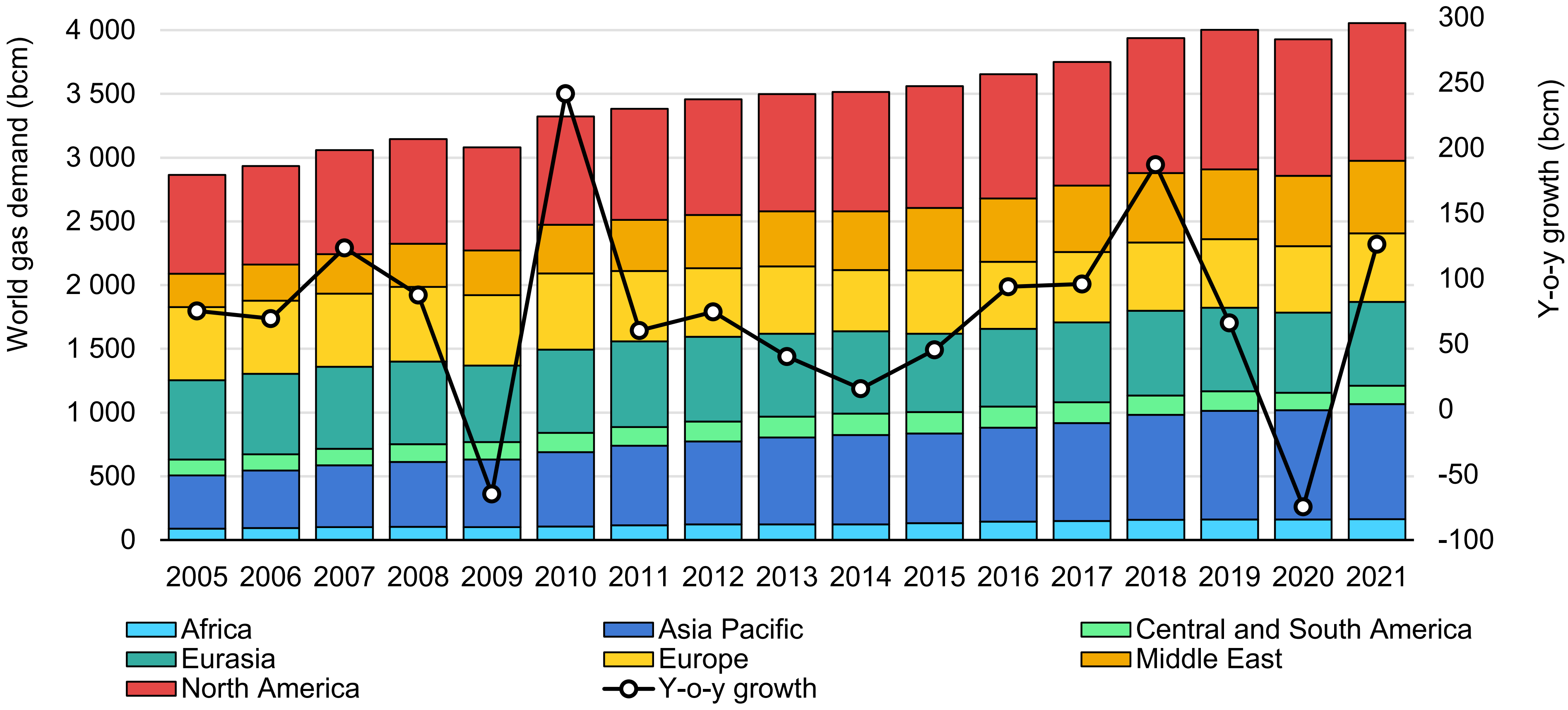
Gas demand from the **power generation sector** is facing a more challenging environment. Gas consumption for power generation was already the most affected segment in 2020, accounting for an estimated 45% of the total annual decline, despite favourable fuel-switching dynamics in North America and Europe. 2021 is expected to see limited growth in electricity demand, strong competition from increasing renewable capacity and lower cost-competitiveness against coal as natural gas prices recover from their 2020 lows. This forecast therefore expects a 1.2% increase in natural gas for power burn in 2021, not sufficient to offset the estimated 2.1% y-o-y drop seen in 2020.

A cold start to 2021 provided support for heating demand after a tough year for gas demand in the **residential and commercial sectors,** which fell by 2.4% y-o-y in 2020. This reflected the joint impacts of unusually mild winter temperatures for residential and widespread lockdowns for commercial. The return to more average winter temperatures and retail activity, together with the expansion of gas connections in China, support a strong 4.9% anticipated increase in gas demand for 2021.

Although gas demand is expected to recover globally, regional disparities remain, with the most mature markets in Europe, Eurasia, North America and Asia seeing slower growth – with only partial recovery for some. Meanwhile, faster-growing economies in Asia, the Middle East and Africa are projected to go beyond simply bridging the 2020 gap in 2021.

Global gas demand is expected to grow by 125 bcm in 2021 after a record drop in 2020

Evolution of global gas demand, 2005-2021



North American 2020/21 winter gas consumption remained below 2019/20 despite cold snaps; US power generation hampers the region's gas demand recovery in 2021

Natural gas consumption in the **United States** declined by an estimated 3.8% y-o-y during the past heating season (October 2020 to March 2021 inclusive) in spite of cold temperatures driving up heating demand. The decline reflected gas-fired electricity generation losing ground on higher fuel prices (gas burn for power generation was down 7.5% y-o-y over the winter). Gas consumption by industrial customers remained stable and comparable by volume with the previous winter. Wide temperature variations remained the main driver of gas demand over the heating season.

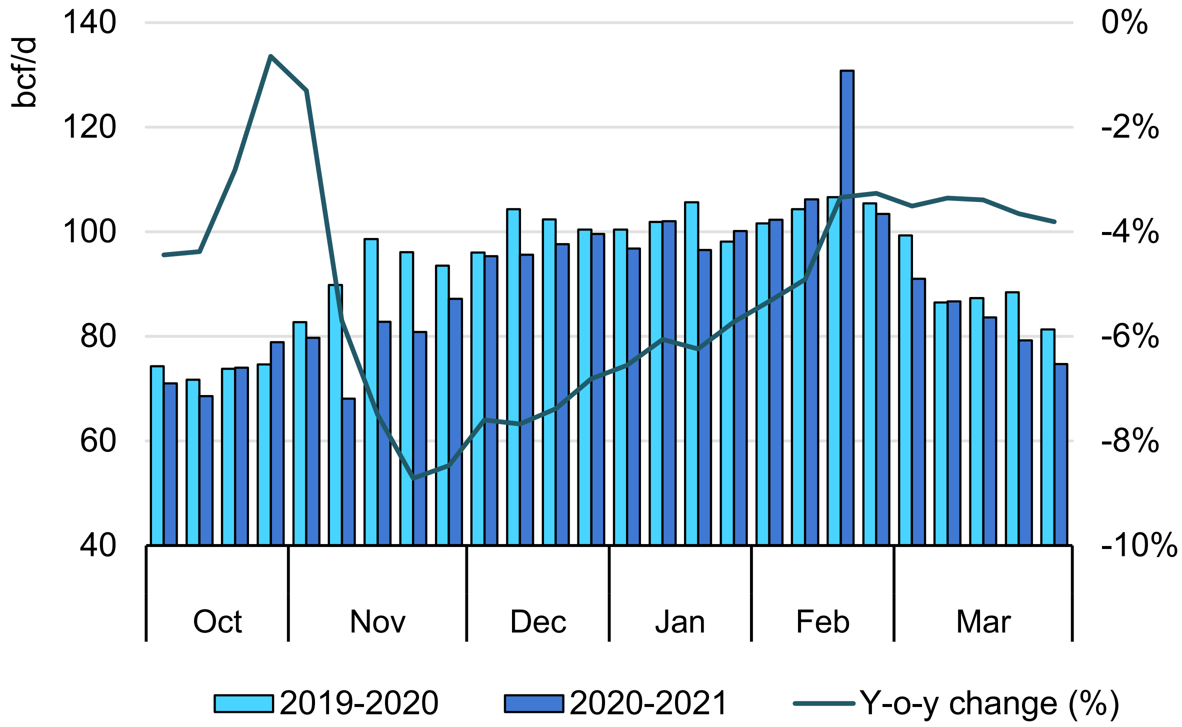
In the third quarter of 2020, average weather conditions in October were followed by an exceptionally mild November that erased most of the recovery made over the summer. The advent of colder temperatures in December pushed monthly residential demand slightly above its 2019 level, while gas-fired generation was hampered by recovering prices, declining 5% y-o-y against a 2% increase in electricity demand and an 8% rebound in coal-fired generation. The first quarter of 2021 was marked by colder weather, culminating in mid-February with extremely low temperatures leading to rising heat and electricity needs while also hampering gas production with well freeze-offs, resulting in rolling power cuts in several US states and a drop in gas exports to Mexico. US gas demand fell in March (down 4% y-o-y) on lower use for power generation and milder temperatures.

In **Canada** gas demand slightly decreased by 1% y-o-y in the fourth quarter of 2020, principally due to lower retail sales (down 6%), while wholesale customers in power generation and industry saw their consumption increase by 3%. Gas demand in January was stable at slightly below January 2020, whereas several provinces reported record daily consumption levels in early February as temperatures fell sharply. US production constraints led to a jump in Canadian pipeline exports, which increased by 22% compared to February 2020 – and were still up by 13% y-o-y in March. **Mexico**'s apparent natural gas consumption remained stable y-o-y during the October to January period. In mid-February, Mexico turned to LNG to compensate for lower pipeline imports, but was still faced with supply cuts to wholesale customers.

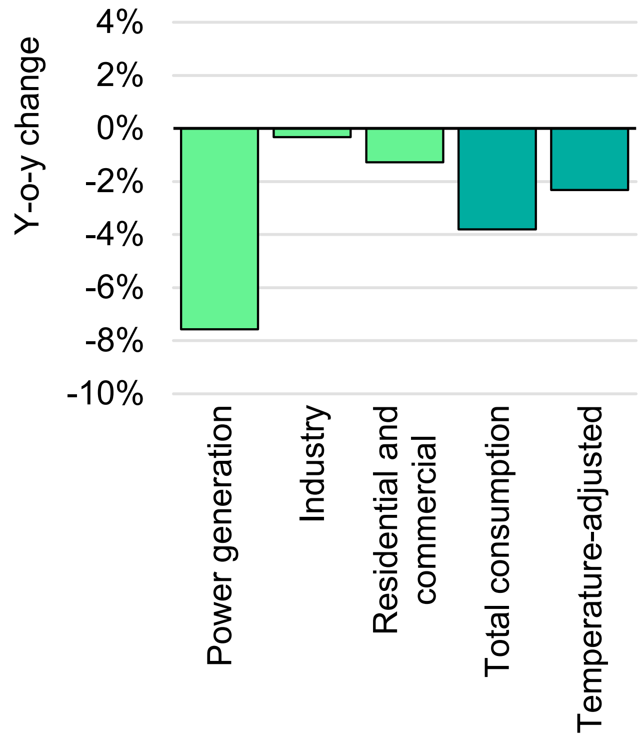
This forecast expects power generation to play a central role in North American gas demand trends for 2021 – downward in the United States and Mexico on a mix of limited electricity demand growth, growing renewable capacity and rising gas prices, and upward in Canada principally thanks to coal-to-gas conversions in Alberta. Other sectors are set to progressively return to their 2019 levels on a combination of industrial recovery and a return to average temperatures. As a result, North American gas demand would be almost stable in 2021, with an annual increase of less than 1%.

February's extreme temperatures were not sufficient to compensate for an exceptionally mild November, leading to a 3.8% y-o-y decline in US winter gas demand

Weekly natural gas consumption in the United States, winter 2019/20 and 2020/21



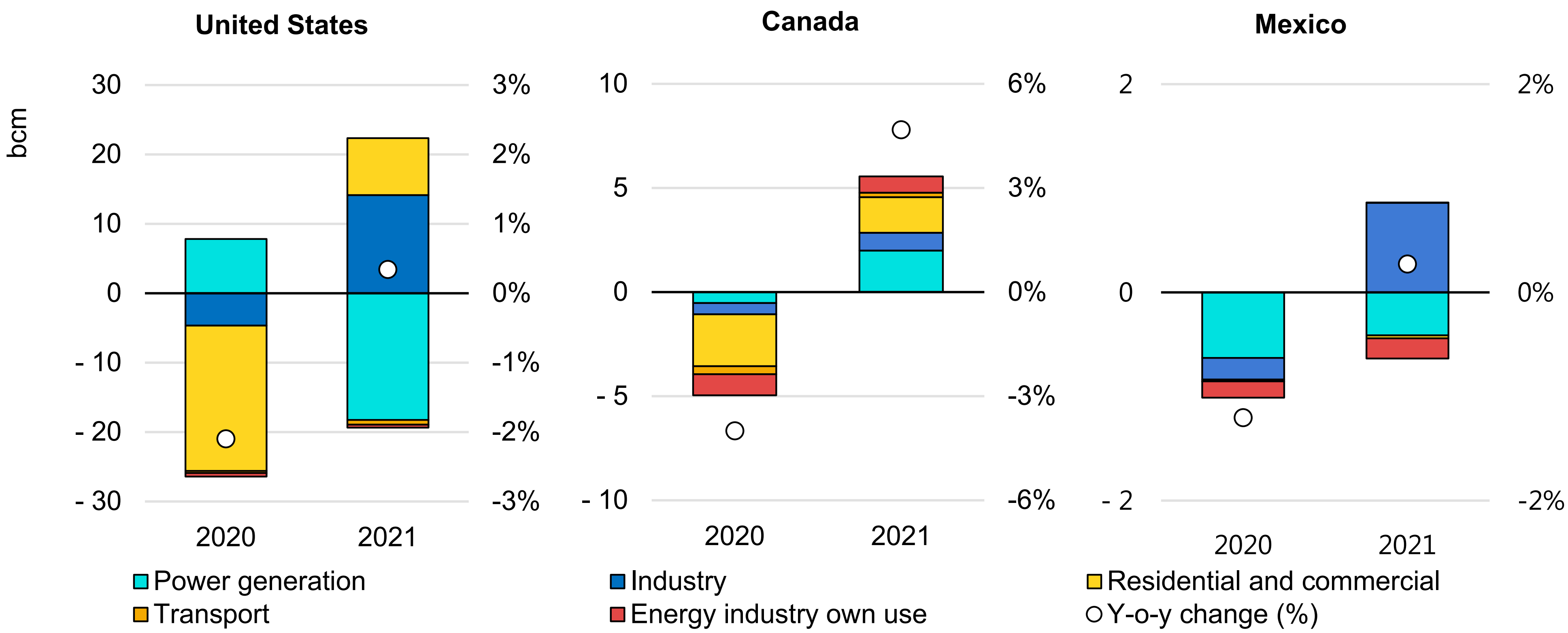
Gas consumption by sector in the United States, winter 2020/21 relative to 2019/20



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

In 2021 gas for power is expected to drag demand down in Mexico and the United States, and to drive recovery in Canada

Change in North American gas demand on previous year by country and sector



Sources: IEA analysis based on EIA (2021), Natural Gas Data, Natural Gas Weekly Update; IEA (2021), Monthly Gas Data Service; SENER (2021), Dry Gas Distribution; Statistics Canada (2021), Canadian Monthly Natural Gas Distribution.

Turn the heat on: European gas demand recorded strong gains on colder winter temperatures...

European gas consumption rose by over 5% y-o-y during the 2020/21 heating season, driven by colder winter temperatures, a higher gas burn in the power sector and a gradual recovery in gas demand in industry.

Heating degree days averaged 10% higher compared to the 2019/20 heating season across Europe's main gas-consuming regions. **Distribution network consumption increased by an estimated 6% y-o-y**, supported by the higher space heating requirements in the residential sector. Demand growth was particularly strong during January and February, which faced **several cold spells**. The sharp drop in temperatures during the first half of February, together with lower wind generation, propelled European daily gas demand to a high of 2.4 bcm/day on 12 February, topping the daily gas consumption levels seen during the "Beast from East" of March 2018. **The sharp increase in demand did not lead to price spikes**, as supply remained stable, supported by a combination of larger storage withdrawals, a ramp-up in pipeline supplies and greater LNG send-out.

Gas-to-power demand increased by an estimated 4% y-o-y during the 2020/21 heating season. The **decline in nuclear power output** (down 2% y-o-y), together with **lower wind generation** (down 6% y-o-y), created additional market space for thermal generation, most of which was captured by gas-fired power plants.

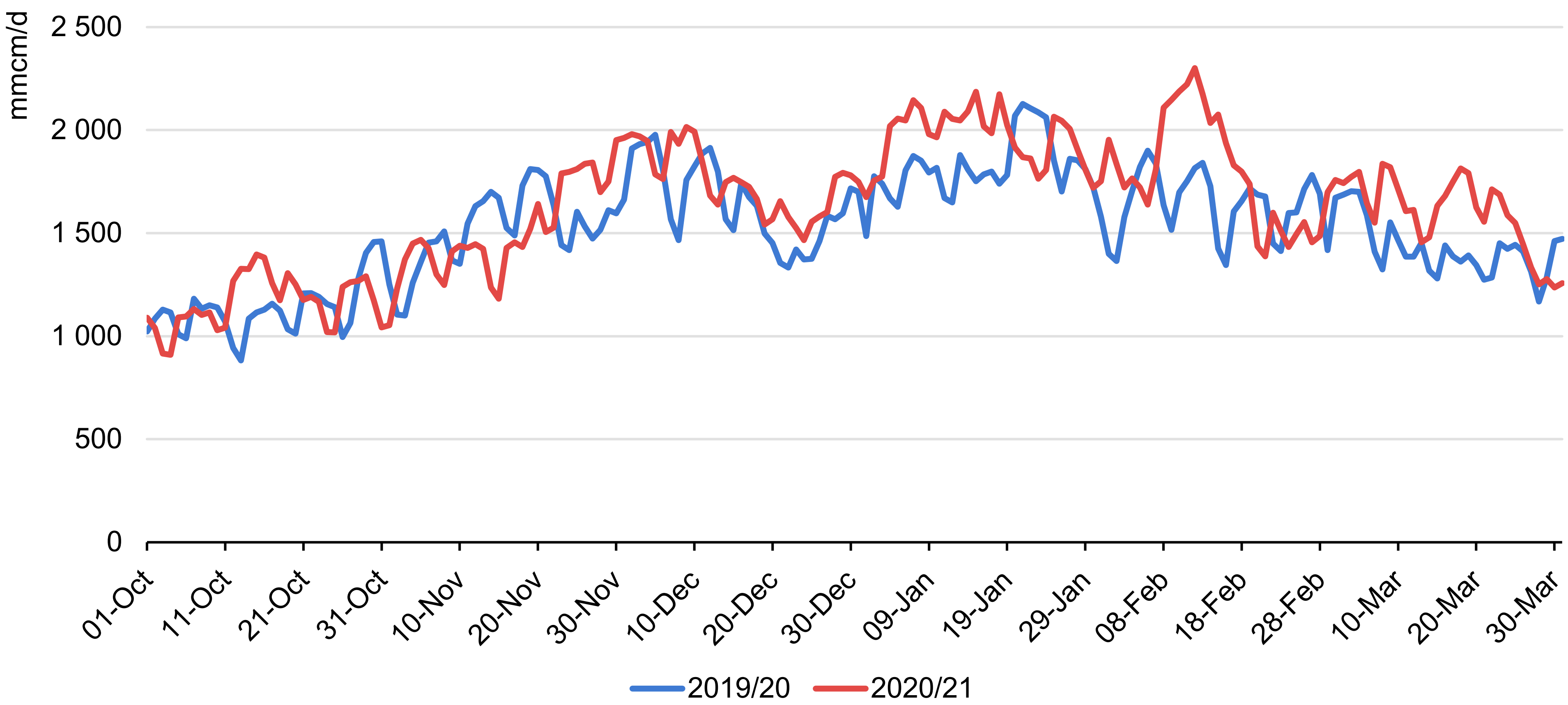
Coal- and lignite-fired generation remained subdued, and increased by a mere 1% y-o-y. **Turkey accounted for the majority of incremental gas-to-power demand in Europe,** with its gas-fired power output increasing by 55% y-o-y driven by lower coal- and lignite-fired generation (down by 5.5% y-o-y) and plummeting hydro availability (down 29% y-o-y). **Germany was the second-largest contributor to additional gas burn** in the power sector, where lower wind power generation (down 18% y-o-y) together with a drop in nuclear output (down 10% y-o-y) supported both gas-fired power plants (up 15% y-o-y), and coal- and lignite-fired generation (up 18% y-o-y).

Gas demand from industry remained resilient in major economies during the heating season, increasing by 3% y-o-y in Italy and averaging at pre-crisis levels in France, whilst down by 3% in both Belgium and Italy. Industrial gas demand was particularly strong in Turkey, where it rose by 12% y-o-y during the period October-January.

Following strong growth in Q1, **European gas demand is expected to increase by 3% in 2021**, recovering to its pre-crisis levels. The sharp increase in carbon prices is expected to support **additional gas burn in the power sector through the summer**, while industrial gas demand is expected to continue its recovery amid improving economic conditions.

…with consumption increasing by 4% during the 2020/21 heating season

Estimated daily gas consumption in Europe during the heating season (2019/20 and 2020/21)



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

Asia's recovery in gas demand remained uneven last winter; 2021 growth expected to be 5%

Asia's gas demand recovery showed a mixed picture last heating season. Northeast Asian economies saw strong y-o-y increases between December and February, driven by colder-than-average temperatures, nuclear maintenance in Japan and limits on coal-fired generation in Korea, while a number of emerging economies in South and Southeast Asia saw their gas consumption decline amid record-high spot LNG prices.

In 2021 total gas consumption in Asia is expected to grow by 5% thanks to a strong rebound in economic activity and expanding gas infrastructure across the region. China accounts for 56% of the net demand growth in Asia, followed by India with a 14% share. A group of emerging Asian economies together make up 28% of the net demand increase, while expected declines in Japan are completely offset by consumption growth in the rest of Asia.

China's gas consumption registered double-digit y-o-y growth rates throughout the last heating season, driven by a robust recovery in the industrial sector, new residential connections and high heating demand. Total consumption increased by 15% y-o-y in Q4 2020 and growth was especially strong during the cold spell in December and January, when y-o-y rates were up by 17% and 20% respectively. Monthly gas consumption (at nearly 40 bcm) reached an all-time high in December. Gas use in February was up by 21% y-o-y due to the low base in February 2020 (when China's Covid-19 epidemic was at its peak), but demand in February was actually 28% lower than January as warmer temperatures and the Lunar New Year holiday moderated consumption.

In 2021 total gas demand is projected to increase by 8% in China, fuelled by strong GDP growth, continuing coal-to-gas conversions and expanding gas infrastructure. The industrial sector remains the primary growth driver, accounting for nearly 40% of China's demand expansion due to ongoing coal-to-gas conversions and recovering industrial activity. Power generation contributes about a quarter of the 2021 growth thanks to the continuing expansion of the gas-fired generation fleet. Residential and commercial users make up more than a fifth of the net demand growth, driven by new grid connections (and further boosted by a cold start to the year).

India saw a reversal of a tentative recovery that started in October 2020, and consumption growth rates registered y-o-y declines of 5%, 9% and 12% in December, January and February respectively. Falling demand was largely due to the steep rise in Asian spot LNG prices, which prompted price-sensitive users – especially in the refining and petrochemicals sector – to curtail gas consumption. In 2021 demand is set to rebound sharply and increase by 10% on the back of a strong economic recovery, new gas connections, improving infrastructure, growing domestic supply and a supportive policy environment. Nearly two-thirds of the net demand growth is expected to come from industrial users, while new city gas connections and growing compressed natural gas (CNG) consumption in the transport sector will account for the remaining increase. Barring a collapse in spot LNG prices in the rest of 2021, power sector gas consumption is likely to decrease from last year's elevated levels.

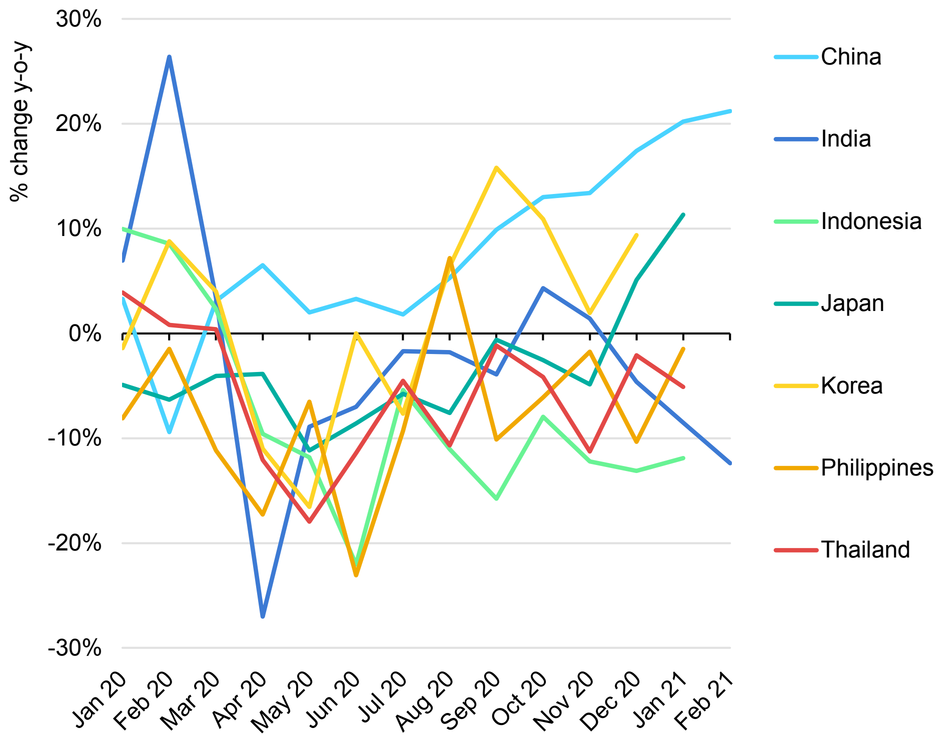
Japan's gas demand was relatively sluggish at the start of the heating season, posting negative y-o-y growth rates in both October and November, but demand received a strong boost in December and January when a cold blast – coupled with low nuclear and solar availability – increased gas use in the power sector. Gas consumption in December was up by 5% y-o-y, and LNG imports registered a 14% y-o-y increase in the period between December 2020 and February 2021. Despite the strong start to the year, gas demand in 2021 as a whole is projected to decrease by 3% as nuclear restarts and Japan's second state of emergency from January present headwinds to consumption growth in the remainder of the year.

Korea's gas consumption continued to recover during the heating season, increasing by 7% y-o-y in Q4 2020. This was underpinned by the government-mandated shutdown of several coal-fired power plants and cold winter temperatures in December. Early indications suggest that consumption growth remained robust in early 2021 as well. Domestic gas sales by Kogas (which excludes private company sales to power generators) increased by a remarkable 20% y-o-y in January, while LNG imports jumped by 19% y-o-y in February according to preliminary shipping data. In 2021 Korea's gas demand is expected to increase by 5%, driven by coal-to-gas substitution in the power sector. This outlook is underpinned by the temporary closure of up to 28 coal plants (around half of the total) for the month of March, following the government-mandated shutdown of up to 16 coal-fired units between December and February to reduce air pollution. The addition of 3 GW of new coal-fired capacity this year will be offset by lower utilisation of coal plants in general.

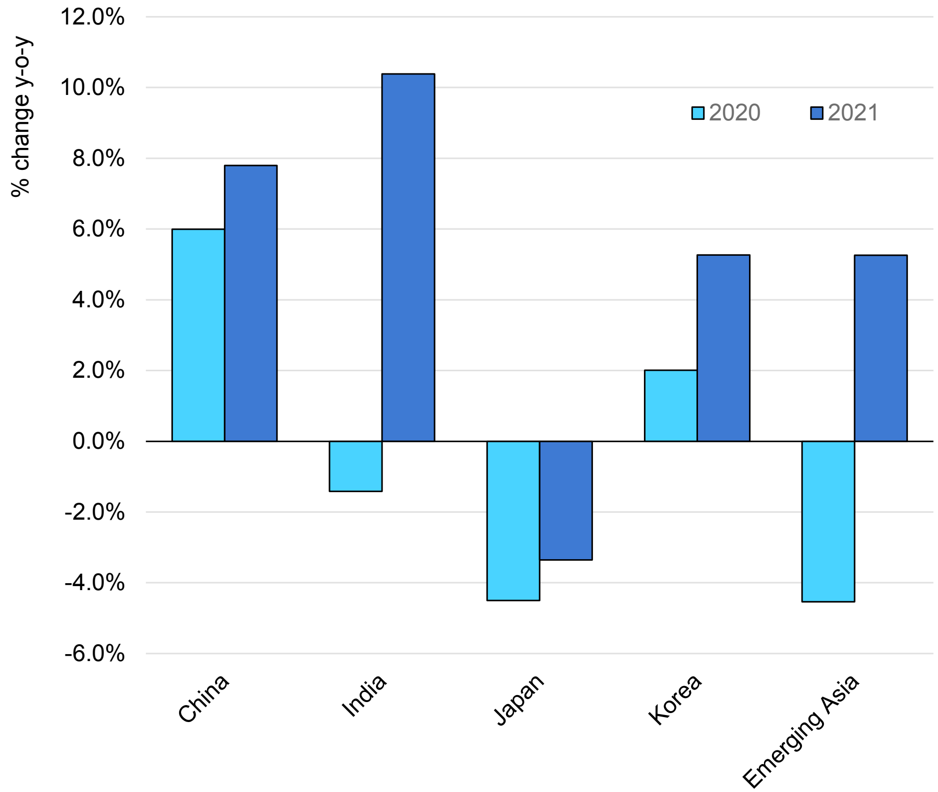
Emerging Asia's gas demand recovery remained subdued in Q4 2020 as high LNG prices dented consumption in price-sensitive markets across the region, a dynamic that continued into early 2021. Pakistan and Bangladesh, for example, experienced gas shortages as sky-high LNG prices forced both countries to cancel spot LNG tenders during the winter. In 2021 total consumption is set to increase by 5%, which is just enough to push gas use above the 2019 level across the region. This increase is supported by a rebound in economic activity and continuing strong growth in electricity demand. Small-scale LNG import terminals in Indonesia and Viet Nam, which are entering service in 2021, could unlock additional demand in these countries throughout the year.

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

Monthly gas demand in selected Asian countries



Gas demand in selected Asian countries, 2020 and 2021



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

US gas production is expected to stabilise in 2021

After three consecutive years of growth, US gas production decreased in 2020, but remained resilient compared to the decline in domestic demand – gross output was down just 1% and dry gas production fell by 1.6%. This is attributable to the net positive contribution of trade, with exports increasing by 13% y-o-y while pipeline imports from Canada declined by 7%.

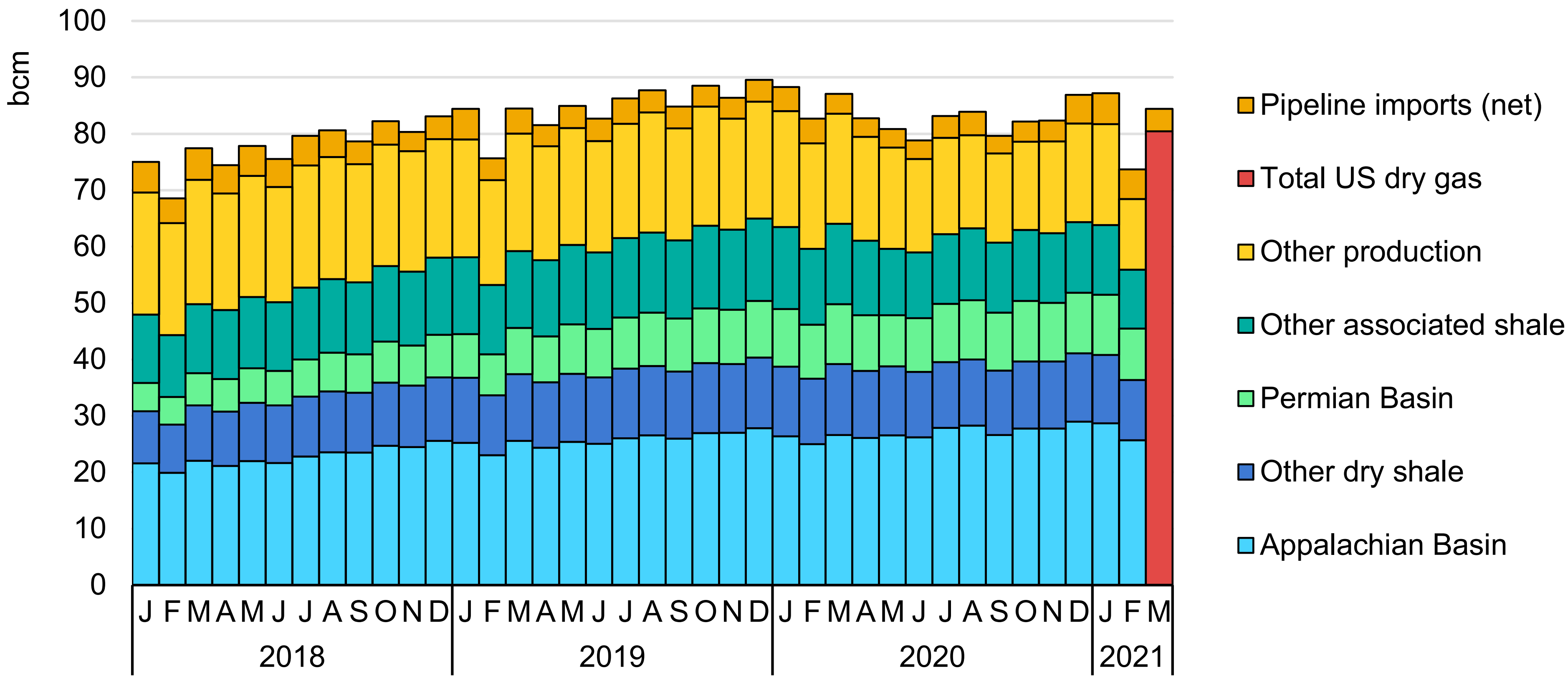
The Appalachian Basin, the main source of shale gas, which also accounts for almost 35% of total US dry gas production, saw its output grow by 4.9% y-o-y in 2020 in spite of reduced drilling activity. A monthly average of 70 new wells were drilled in 2020 against 112 in 2019. Output increased thanks to productivity gains and higher completion rates from previously drilled and uncompleted wells. The Permian Basin's oil-driven shale gas production bounced back in the second half of 2020 to reach an annual 15% increase. Both basins kept growing over the final months of 2020, reaching record levels of production in December at 29 bcm and 11 bcm respectively – their combined output accounting for almost half of total US dry gas production. Total dry gas production in January observed a slight 2% decline compared to December.

The extremely cold temperatures observed throughout North America in mid-February caused well freeze-offs that negatively affected natural gas production capacity. The South Central region was the worst affected, with gas output in Texas almost halving on 17 February compared to the previous week's average, causing shortages and rotating power cuts. The impact was less important in northern US production areas, where the proportion of liquids is lower (and hence less prone to freeze-offs) and where production infrastructure is usually winterised. Dry gas production in continental United States fell by an estimated 15% in February compared to January, reaching its lowest monthly level since February 2018.

US dry gas production is projected to stabilise in 2021 with a 0.1% decline. Dry shale gas is expected to provide limited growth, slowing from an annual increase of 3.3% in 2020 to 2.5% in 2021, thus echoing the prudent strategies outlined by Appalachian producers to keep spending flat and reduce debt. This growth will not be sufficient to offset declines from other sources. Output from the Permian and other associated shale gas plays is expected to slightly decline by about 2% in 2021, reflecting oil production forecasts in the IEA Oil Market Report: 11.3 mb/d in 2020 and 11.1 mb/d in 2021. Production from conventional gas fields is also expected to decline due to depletion and limited investment.

February freeze-offs brought US monthly dry gas production to its lowest level in three years

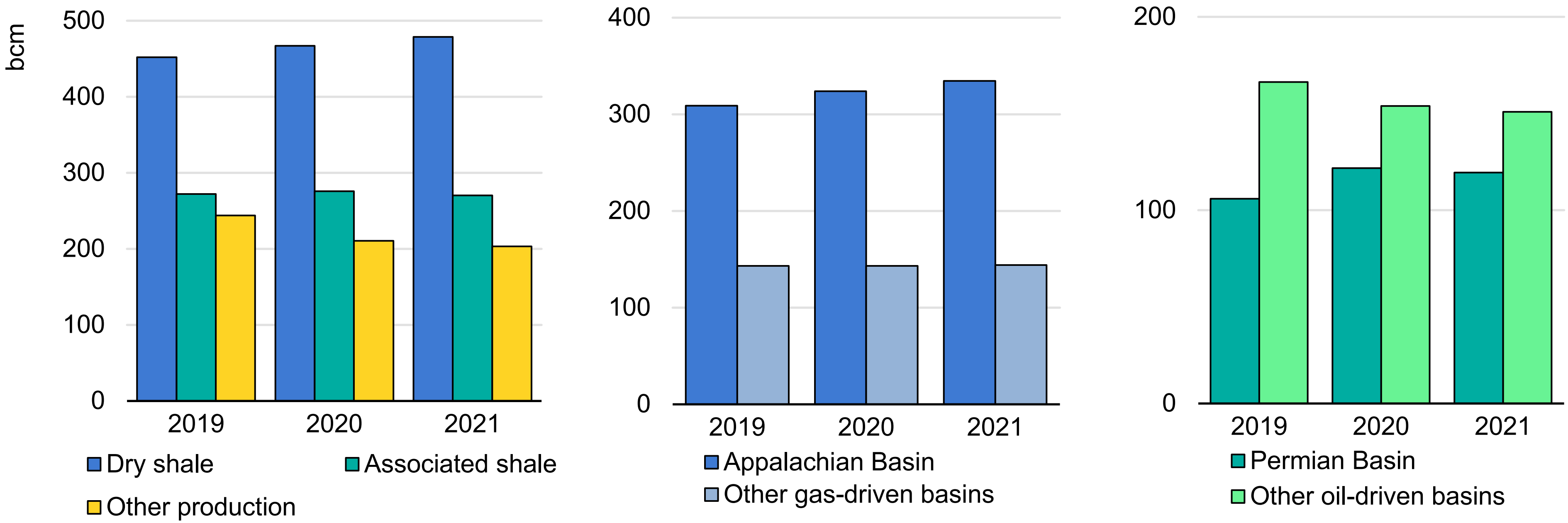
Gas production by type in the United States, 2018-2021



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

US dry gas production is projected to stabilise in 2021 after a 1.6% fall in 2020

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



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

Swings of recovery: Eurasian gas production returned to growth during the heating season…

Following the steep drop during the first half of 2020, Eurasian gas production losses moderated in the second half of the year and returned to growth in Q1 2021, largely driven by higher gas output in Azerbaijan and Russia. Overall, the region's gas production increased by a mere 2% y-o-y during the heating season.

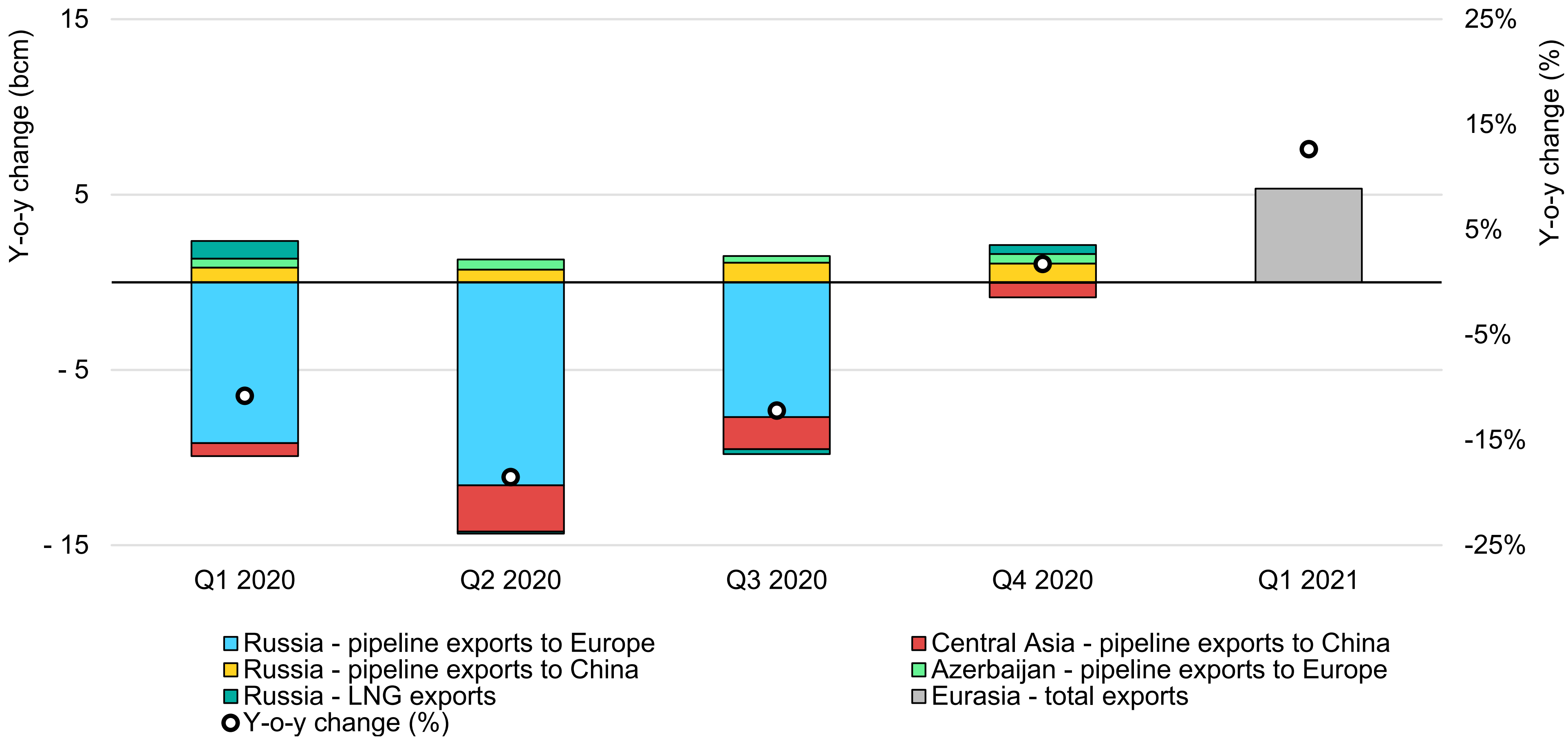
Russia's gas production grew by 2.6% (or 10 bcm) y-o-y during the 2020/21 heating season, with most of the increase concentrated in Q1 2021 (6.4% y-o-y). The recovery has been partly supported by higher exports. **Pipeline deliveries to Europe** rose by over 6% y-o-y during the heating season, with strong gains recorded in Q1 2021 (up by 18% y-o-y). Pipeline deliveries to Turkey increased particularly strongly, more than doubling in Q1 2021 compared to last year. **Exports to China** via the Power of Siberia pipeline continued to ramp up and reached close to 4 bcm during the heating season. Flows increased almost threefold in Q1 2021, in line with contractual arrangements and with most of the additional volumes going to the Beijing-Tianjin-Hebei region. **Russia's LNG exports** rose by less than 1% during the heating season, with a pronounced shift towards Asia. The widening price spread between Asian spot LNG and TTF incentivised higher exports towards the Northeast Asian market, increasing by 17% y-o-y, while flows towards Europe declined by 11% y-o-y.

Central Asian pipeline exports to China remained subdued during the heating season, down by close to 9% y-o-y in the October-February period. This was despite the strong demand increase in China during the December/January cold spell. In Uzbekistan, where gas production fell to its lowest level since 1996, electricity and gas supply cuts to the domestic market were reported over the winter. In **Azerbaijan gas production increased by 5% y-o-y** during the October-February period. This was largely driven by the ramp-up of pipeline exports via the TANAP and TAP pipeline systems, with deliveries to the European markets soaring by an impressive 40%. Exports via TAP to the European Union totalled over 1 bcm. In **Ukraine** gas production fell by 3.5% during the heating season, with February output plummeting to a 5-year low.

Eurasian gas production is expected to continue to recover, growing by over 6% y-o-y during 2021, close to 2019 levels. This would be largely supported by the ramp-up of exports via new and traditional export corridors. Pipeline exports from Russia to Europe and from Central Asia to China are expected to increase by over 10%. Exports via the Power of Siberia pipeline are set to reach 10 bcm in 2021. Azeri pipeline deliveries are set to increase by over 15%, with 8 bcm destined for Turkey and over 5 bcm for other European markets. Russian LNG exports are set to increase by about 1 bcm, with the start-up of Train 4 at Yamal LNG in Q2 2021.

…supported by the ramp-up of exports via new and traditional export corridors

Estimated change in extra-regional natural gas exports from Eurasia



Sources: IEA analysis based on ENTSOG (2021), Transparency Platform; Eurostat (2021), Imports of Natural Gas by Partner Country – Monthly Data; Gas Transmission System Operator of Ukraine (2021), Transparency Platform; General Administration of Customs of People's Republic of China (2021), Customs Statistics; ICIS (2021), ICIS LNG Edge.

European gas supplies during the heating season: LNG imports take a dip…

Despite the colder weather, LNG import flows to Europe fell by almost 30% (or 20 bcm) y-o-y during the 2020/21 heating season. Competition from pipeline imports and a greater storage draw reduced the demand for LNG. The **widening price spread** between Asian spot LNG and European hub prices have been **driving LNG cargoes away from European shores to Asia** since the beginning of September 2020. European LNG imports fell by close to 50% y-o-y **in January to their lowest level since September 2018**. Cargoes were increasingly diverted to Northeast Asia, which faced a particularly harsh cold spell when Asian LNG spot prices climbed to a record level of USD 30/MBtu. European LNG imports remained subdued in February (down 30% y-o-y), before recovering close to last year's levels in March. **Northwest Europe's LNG imports** declined the steepest, **plummeting by 37% y-o-y**, while southern and eastern European markets faced a more moderate decline of 20% y-o-y over the heating season.

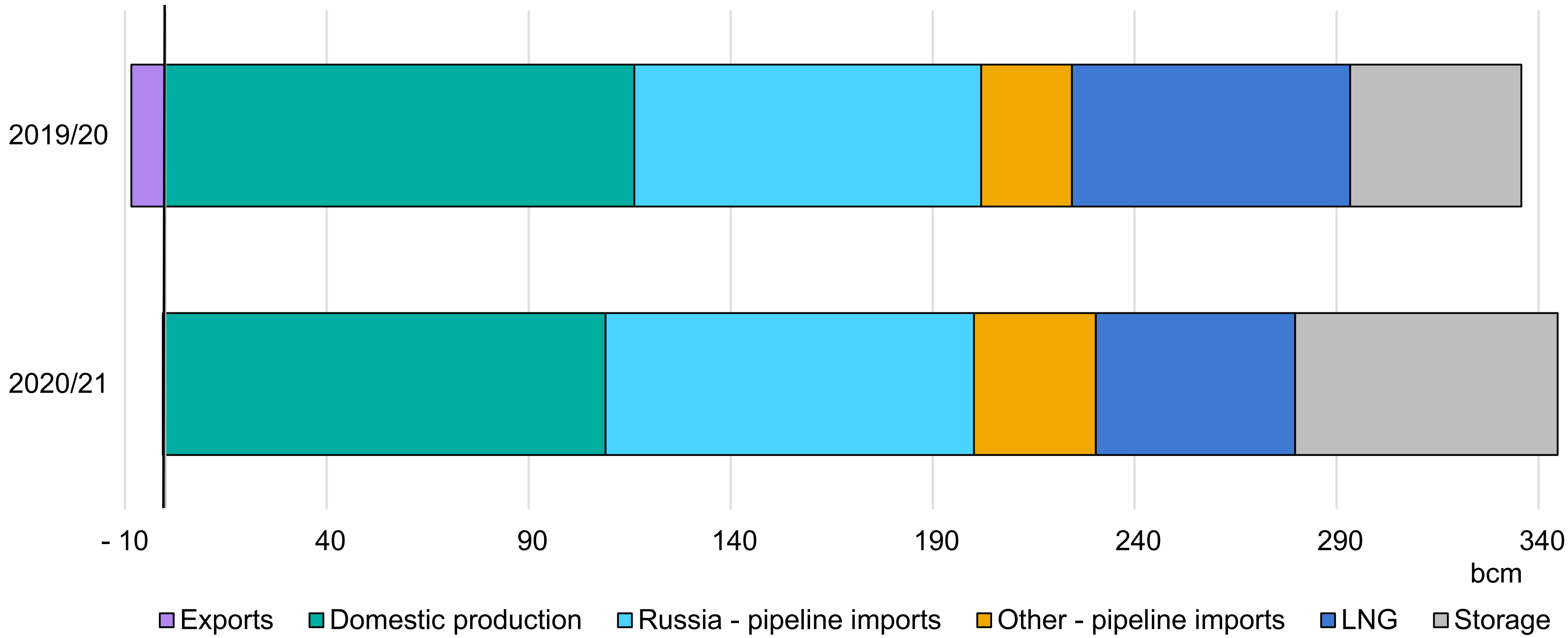
Non-Norwegian domestic production continued to decline, falling by an estimated 10% y-o-y. This was largely driven by the Netherlands, accounting for almost 40% of the net decline as a result of both lower Groningen output and lower production from its small fields. Norwegian pipeline deliveries remained broadly flat y-o-y, with lower deliveries to Germany compensated by higher flows via Emden to the Netherlands and via the Langeled pipeline to the United Kingdom.

Russian net exports to Europe had recovered to above 2019 levels by the end of 2020, and averaged 18% higher compared to last year during Q1 2021. Pipeline imports from **North Africa** rose by over 55% y-o-y during the heating season, and **Azeri gas deliveries** increased by close to 40% y-o-y during October-February as flows via the TANAP and TAP systems continued to ramp up. **Storage withdrawals** increased by over 50% y-o-y during the heating season to meet higher gas demand. They accounted for almost 20% of total supply (up from 13% during the same period last year).

Europe's gas import requirements are expected to increase by close to 10% in 2021, driven by demand recovery (3% y-o-y), lower domestic production and higher injection needs to replenish storage inventories, which stood 25 bcm lower than last year at the beginning of April 2021. Higher import requirements will benefit traditional pipeline suppliers, which are expected to recover close to their pre-crisis levels. LNG imports are projected to remain close to their 2019 record levels. Azeri deliveries are set to increase by over 15% as supplies via TAP ramp up to over 5 bcm.

…with storage and pipeline supplies ramping up deliveries to meet higher gas demand

Estimated gas supply to Europe during the heating season (2019/20 and 2020/21)



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

Global LNG trade increased by only 1% in Q1; modest 4% growth expected in 2021

In Q1 2021 global LNG trade (net of re-exports) expanded by 1% y-o-y. LNG import flows were dominated by the cold blast (and resulting price spikes) across Northeast Asia in January, which led to a 17% y-o-y jump in the combined LNG imports of China, Japan and Korea during the first quarter. Even though winter temperatures turned warmer in February, LNG inflows into the three Northeast Asian countries remained elevated in February and March, most likely as a result of delayed cargo deliveries dispatched during the cold spell. The Asia Pacific region as a whole saw a 11% y-o-y increase in LNG imports in Q1, while European imports dropped by 27% y-o-y, almost perfectly balancing the demand spike in Asia. Southeast Asia, where winter is a low season due to a lack of heating demand, also provided emergency supplies for Northeast Asia; in January Indonesia and Thailand completed their first-ever LNG re-exports to China and Japan, respectively.

LNG export growth in Q1 2021 remained subdued at 1.5% y-o-y due to ongoing capacity outages in Australia and Norway, gas supply availability issues in Trinidad and Indonesia, and a temporary disruption of LNG production at US Gulf Coast terminals during the power outages across the southern United States in February.

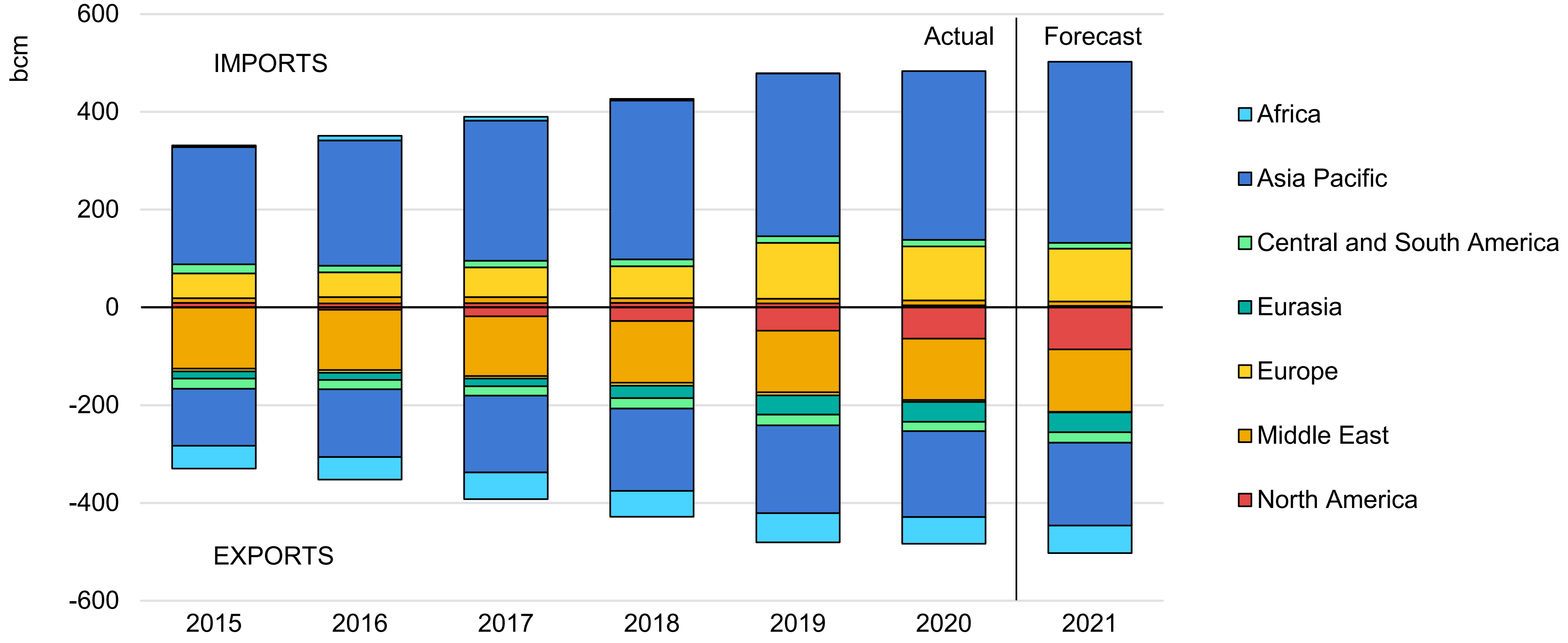
In 2021 global LNG trade is projected to expand by 4%, a slower pace relative to the 2015-2019 average annual rate of 10%. Growing pipeline gas flows and – in the case of China and India – growing domestic production will present short-term headwinds to a more rapid rebound in LNG demand.

LNG import growth is set to be driven solely by the Asia Pacific region, which is expected to see a 7% increase in LNG inflows, while all other regions are poised to see declining imports. Despite the steep drop in Q1, LNG influx into Europe is expected to remain relatively strong in 2021, albeit below the 2019 and 2020 levels. Sustained high European imports are supported by stronger injection needs, lower indigenous production and recovering demand through the summer.

North America remains the primary engine of LNG export growth in 2021. LNG output in the United States is set to increase by a third, driven by the addition of new liquefaction capacity at Corpus Christi Train 3 and the Calcasieu Pass terminal, as well as by higher utilisation of existing plants. In the rest of the world, small increases in Africa (thanks to recovering output in Egypt), Central and South America and the Middle East are more than offset by declines in Asia Pacific and Europe, the latter due to the fire-related outage at the Hammerfest LNG terminal in Norway.

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

LNG imports and exports by region, 2015-2021



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

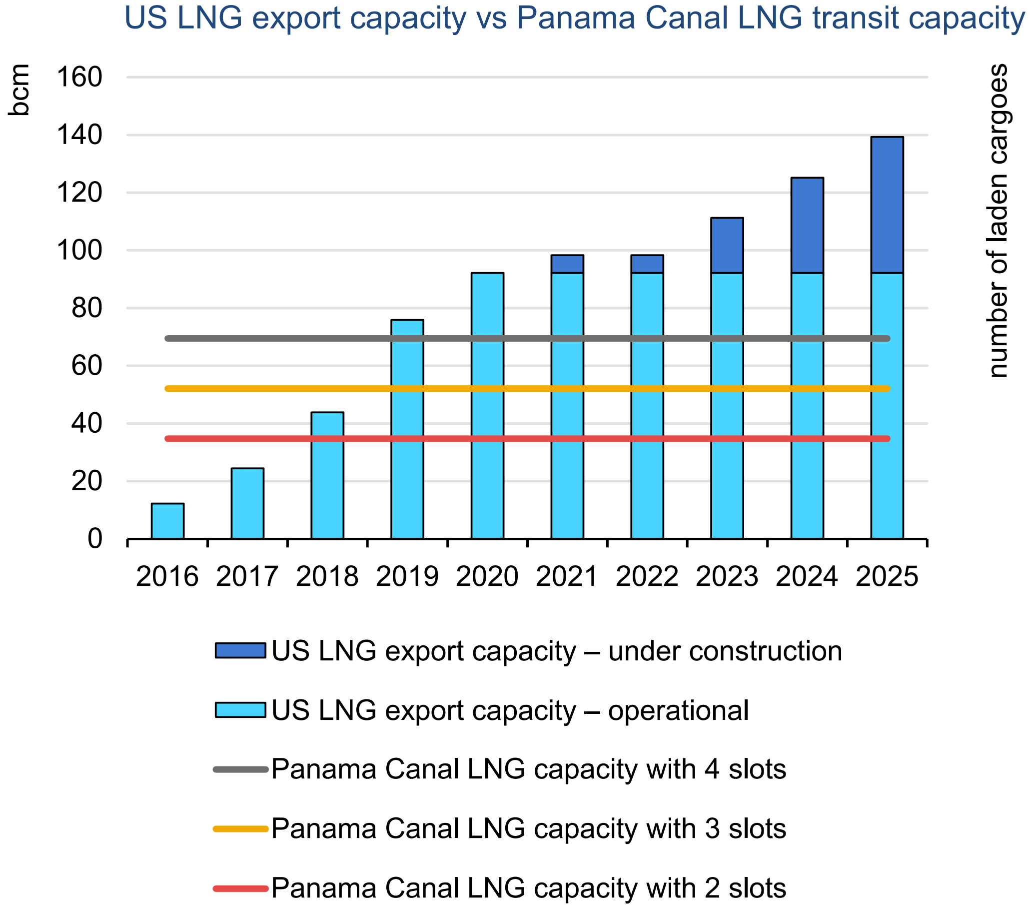
The winter energy crisis in Northeast Asia revealed capacity constraints on the Panama Canal

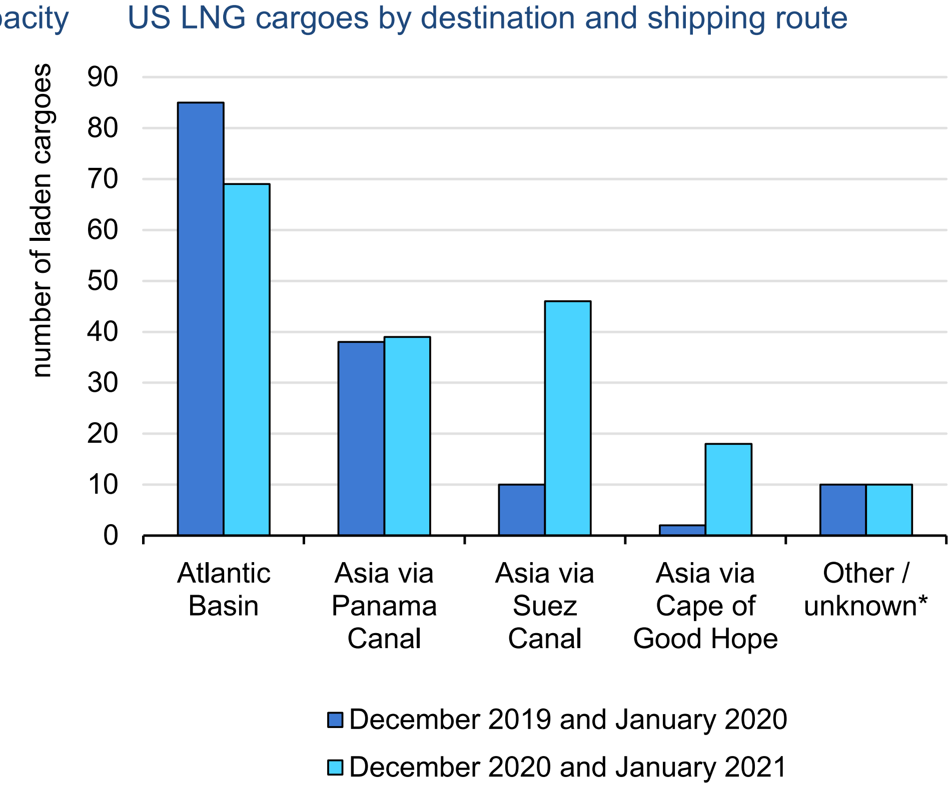
This winter illustrated – for the first time – that the Panama Canal can present a bottleneck for the global LNG trade, particularly for US LNG cargoes dispatched to Asia. During the cold spells in Northeast Asia, unscheduled spot LNG cargoes faced wait times of up to 12 days to cross the Panama Canal, or had to take longer journeys via the Suez Canal or around the Cape of Good Hope in Africa to reach buyers in Northeast Asia, who offered a steep premium to attract additional LNG amid a growing fuel shortage. The congestion on the Panama Canal contributed to the market tightness and record-high spot LNG prices in Asia, and exposed the inherent limitations of this vital LNG shipping route.

The Panama Canal Authority (PCA) currently offers only two of the eight available reservation slots per day to LNG carriers, either both for northbound transit from the Pacific to the Atlantic Basin, or one in each direction. Cruise ships and container ships take priority for the remaining spots for large *Neopanamax* vessels. The PCA has taken steps in recent years to increase throughput capacity for LNG shipments by easing navigation rules, lifting night-time restrictions and introducing an auction process for unused transit slots after last-minute cancellations. With these measures in place, the Panama Canal is occasionally able to transit three LNG carriers in a day, and on a handful of occasions (when demand from higher-priority vessel types allowed) it managed four LNG transits in a single day. At its current capacity, the canal can handle LNG flows from the United States (as well as from Trinidad, Peru and West Africa) in normal market conditions, when the majority of US cargoes remain in the Atlantic Basin, or when US terminals run significantly below capacity, as happened in the summer of 2020. However, in market conditions like the winter of 2020/21, when surging demand in Asia prompts most US LNG to flow into the Pacific Basin, the Panama Canal can only accommodate a fraction of LNG traffic in a timely manner.

Insufficient transit capacity on the Panama Canal prompted US LNG cargoes to take longer routes to Asia in December 2020 and January 2021, which led to sharp increases in US export flows via both the Suez Canal and around the Cape of Good Hope compared to the previous winter. This, in turn, boosted tonne-mile demand, propelled LNG charter rates to record highs, and lengthened the time for LNG shipments to reach buyers across Asia. If the current capacity constraints persist, the Panama Canal may become a recurring bottleneck for US LNG exports, which could exacerbate price volatility and fuel shortages in periods of regional market tightness, and lead to US cargo cancellations for logistical rather than economic reasons. US LNG offtakers reportedly had to cancel up to ten cargoes for February 2021 delivery due to limited shipping availability.

The Panama Canal could become a recurring bottleneck for US LNG, forcing exporters to take longer routes to Asia





* Other/unknown category includes cargoes shipped to Chile and Mexico via the Panama Canal or around South America, cargoes shipped to Middle East destinations via the Suez Canal (none in the sample) and cargoes with unknown route or destination.
Sources: IEA analysis based on EIA (2021), LNG Capacity Table; ICIS (2021), ICIS LNG Edge.

A volatile winter: Charter rates climbed to historical highs during the January cold spell…

LNG spot charter rates displayed strong volatility during the 2020/21 heating season: after soaring to record highs in January 2021 on high tonne-mile demand, charter rates plummeted below last year's levels at the beginning of March on improving availability of shipping capacity.

Spot charter rates opened the heating season by averaging 25% below last year's levels during October and November. This was partly driven by incremental LNG carrier capacity (up 4% y-o-y) exceeding global LNG trade growth. In addition, tonne-mile demand (tonnage of cargo multiplied by shipping distance) declined by close to 4% y-o-y, depressing further LNG charter rates.

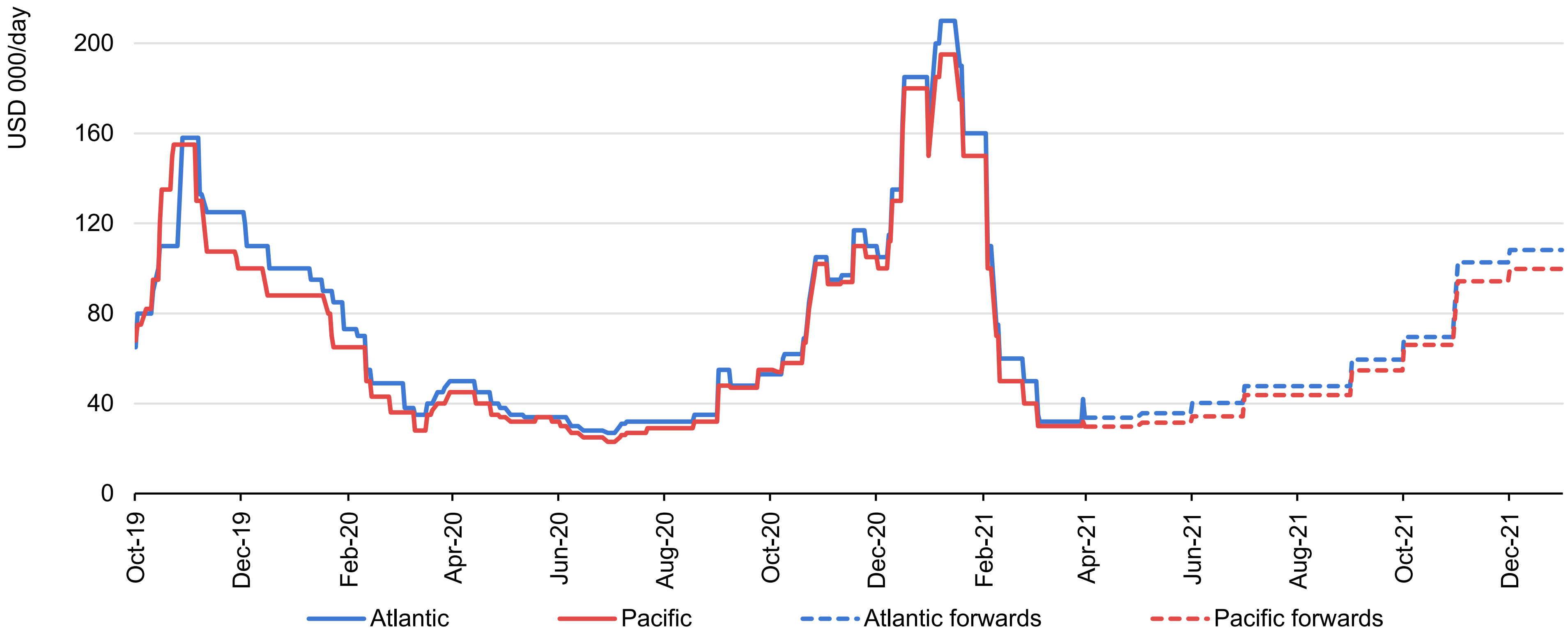
Colder winter temperatures in Northeast Asia in December and early January, together with lower nuclear availability in Japan, prompted strong LNG demand growth, with imports rising by over 12% y-o-y in January and December. The increase in demand for LNG imports in Northeast Asia **coincided with a number of outages at regional liquefaction plants** (including in Australia, Indonesia and Malaysia). This, in turn, **led to a sharp increase in LNG imports from the US to Northeast Asia**, rising more than twofold compared to the previous year during December and January. Higher LNG shipments from the US, combined with **congestion issues on the Panama Canal**, **increased tonne-mile demand** by 37% in January 2021 compared to September 2020. Consequently, **spot charter rates had climbed to historical highs** at more than USD 230 000/day by the beginning of January, with one cargo reportedly awarded at USD 350 000/day. The reduced shipping availability and high charter rates allegedly **prompted several LNG cargo cancellations** by US LNG buyers expecting deliveries in February and March.

Spot charter rates plummeted by 70% in February and fell below last year's levels in March to an average of USD 33 000/day. Lower LNG shipments from the United States to Northeast Asia – contracting to a quarter of those in January – depressed tonne-mile demand, which has fallen by 17% from its January highs according to data from Kpler. In addition, 20 new-build LNG carriers started commercial operations in Q1 2021 (against 4 in Q1 2020), further improving vessel availability and weighing on spot charter rates.

Global LNG shipping capacity is expected to increase by close to 10% y-o-y in 2021, with the delivery of an additional 30 vessels in Q2-Q4 2021. Forward curves suggest that charter rates will average above last year's levels over the summer, with higher LNG exports from the US supporting tonne-mile demand. Charter rates are set to strengthen in Q4, albeit remaining on average 15% below last year's levels on improved vessel availability.

...before plummeting below last year's levels by March 2021 on improving vessel availability

Atlantic and Pacific spot and forward charter rates (October 2019-December 2021)



Sources: IEA analysis based on ICIS (2021), ICIS LNG Edge; Spark Commodities (2021), LNG Freight Dashboard.

A winter of spikes: Spot gas prices took a wild volatility ride through the heating season…

Spot prices recorded strong gains across all main gas-consuming regions during the 2020/21 heating season, driven by tightening supply-demand fundamentals, while sporadic cold spells in Northeast Asia and the United States propelled regional spot prices to historical highs.

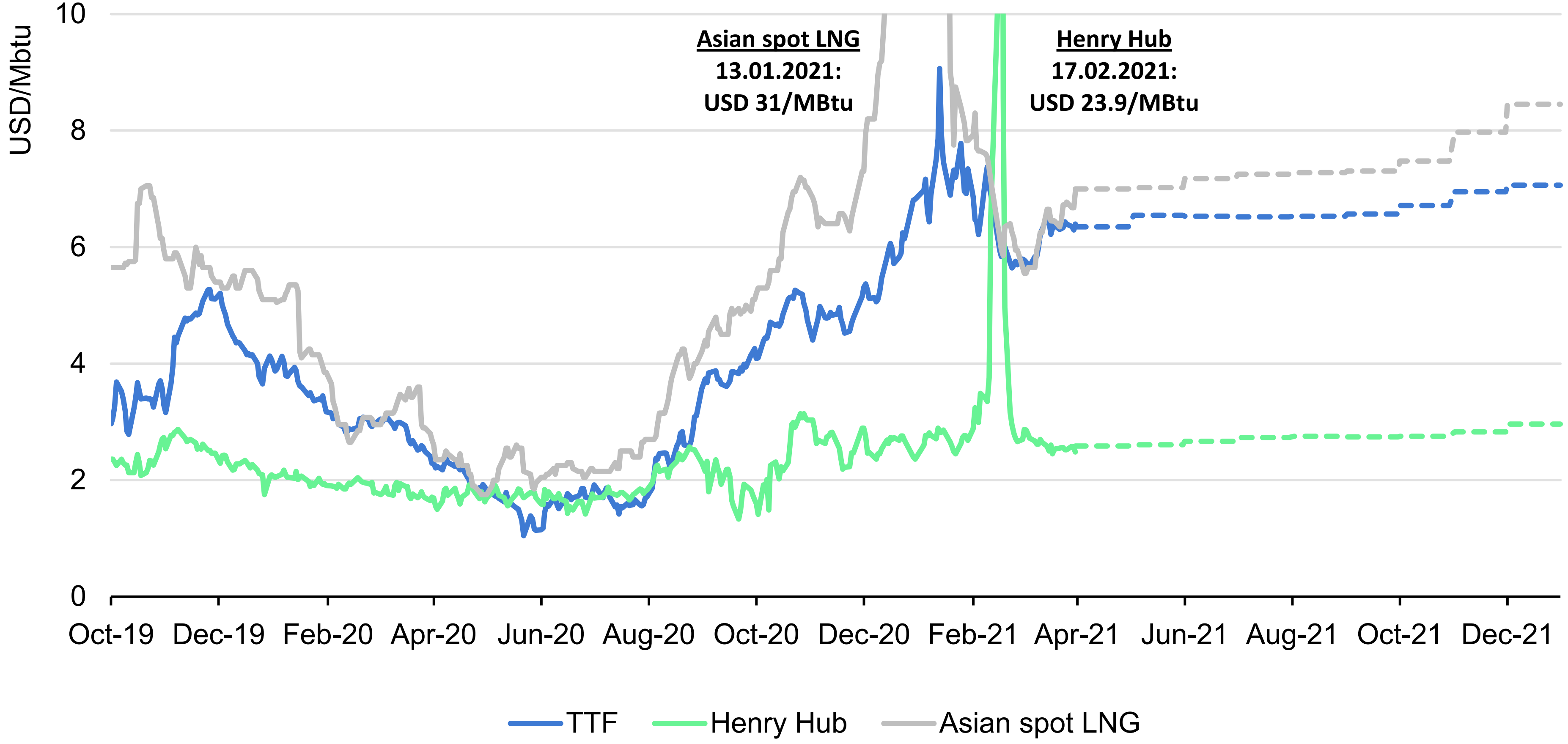
In the United States, Henry Hub prices averaged 40% above the 2019/20 heating season's price levels at USD 3.05/MBtu, as domestic production continued to fall while higher LNG exports (up by 28% y-o-y) kept gas demand resilient. The **February 2021 cold spell propelled regional hub prices to historical records**, as higher gas demand coincided with plummeting domestic production due to wellhead freeze-offs. Henry Hub averaged USD 5.49/MBtu in February 2021, its highest monthly value since February 2014. **Prices returned to their seasonal norms** on improving supply-demand fundamentals **during the second half of February**. Stable US production combined with a strong growth in LNG exports through the rest of the year are expected to support continued price recovery through the rest of 2021. Forward curves at the end of March indicate Henry Hub prices averaging 32% above last year's levels during Q2-Q4 2021.

In Asia, spot LNG prices rose by 80% compared to the 2019/20 heating season, driven by **higher LNG demand** from Northeast Asia (up by 12% y-o-y) and lower-than-expected LNG supply due to a variety of planned and unplanned **outages** at regional liquefaction plants. Tight market conditions during the **December/January cold spell** culminated in Asian spot LNG prices soaring to a record USD 30/MBtu in early January and reaching their highest monthly average since April 2014. Despite the strong growth in spot prices, **average import prices in Northeast Asia declined by 20% y-o-y** during the period between October-February, as buyers benefited from **lower oil-indexed LNG prices**. Forward curves indicate a strong recovery through the rest of the year, with LNG spot prices expected to be almost 70% above last year's levels in Q2-Q4 2021. The recovery in oil prices (up by 60% since October 2020) is set to support oil-indexed prices to above spot levels in Q2-Q3 2021.

In Europe, TTF averaged 60% above the 2019/20 heating season's price levels, supported by demand recovery (up by over 5% y-o-y) and plummeting LNG imports (down 30% y-o-y). Forward curves indicate that the recovery is set to continue through the rest of 2021, with TTF prices expected to double compared to last year's levels in Q2-Q4. **Price spreads with Asian spot LNG** are expected to remain tight through the summer – indicating a potentially higher LNG influx into Europe. Forward curves suggest a **price spread with Henry Hub** averaging close to USD 4/MBtu in Q2-Q4, limiting the risk of cargo cancellations in 2021.

…and are expected to continue their recovery through the rest of 2021

Main spot natural gas prices (October 2020-December 2021)



Sources: IEA analysis based on CME (2021), Henry Hub Natural Gas Futures Quotes; Dutch TTF Natural Gas Month Futures Settlements; CME Group (2021), LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2021), Henry Hub Natural Gas Spot Price; ICIS (2021), ICIS LNG Edge; Powernext (2021), Spot Market Data.

Gas storage inventories in Europe and the United States fell below their 5-year average levels…

Cold winter temperatures and lower primary gas supply prompted strong storage draws across the main gas-consuming regions during the 2020/21 heating season.

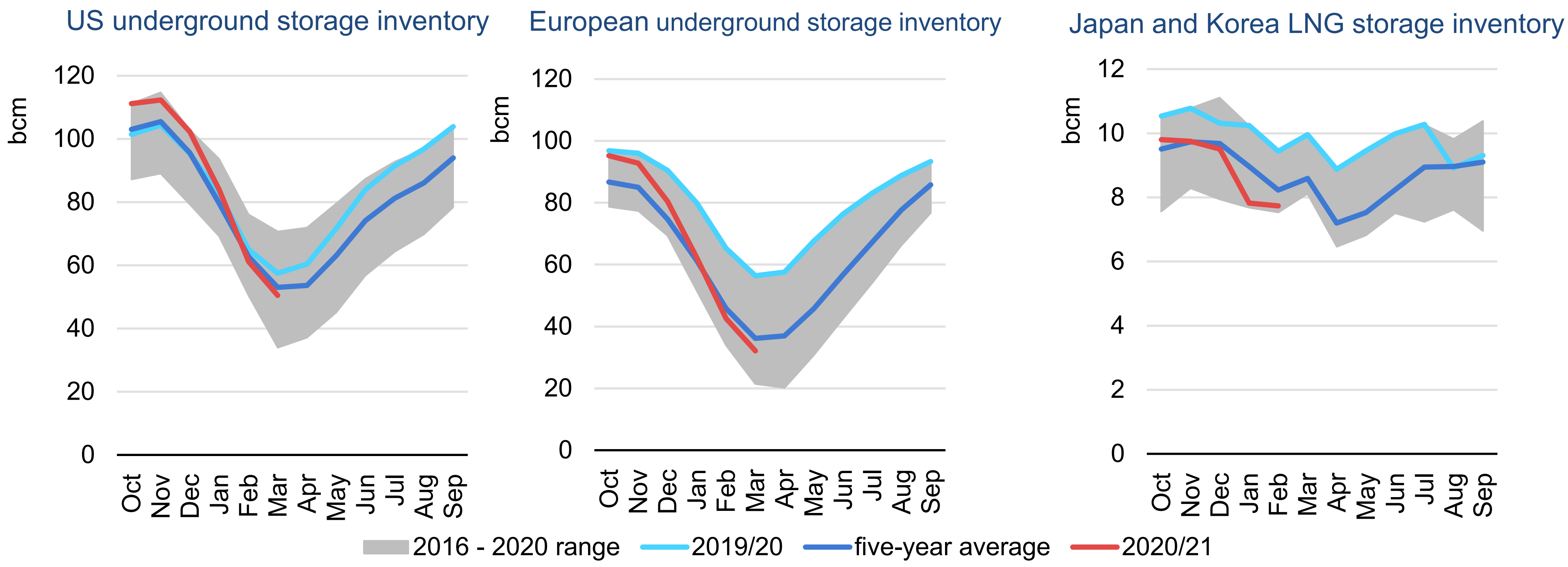
In the United States, storage sites started the gas winter in November with inventory levels 5% above their 5-year average. Mild temperatures and lower natural gas demand depressed withdrawal rates to below injection levels in November, resulting in a slight increase in working storage by the end of the month. As heating degree days edged higher, **storage draws started to gain strength in December** and remained well above the levels seen during the last heating season. **The cold spell in mid-February triggered the second-largest weekly storage withdrawal** ever reported by the EIA, with storage sites supplying 10 bcm of natural gas to the market during the week ending 19 February 2021. The sharp increase in weekly demand coincided with a steep fall in weekly dry gas production, primarily due to wellhead freeze-offs.

In these circumstances, storage facilities played a critical role in supplying the market, accounting for 38% of total gas supplies during the peak day of 15 February. Altogether, storage draws rose by 24% (or 12 bcm) y-o-y during the November-March period. **Inventory levels fell to 2% (or 1 bcm) below their 5-year average** and 11% (or 6 bcm) below their level last year by end of March 2021. **In Canada**, storage sites opened the heating season 30% above their previous year's levels. Storage **withdrawals rose by over 50% y-o-y** on colder temperatures and higher net pipeline exports to the United States. Canadian gas inventories were just 6% above last year's levels by the end of March 2021.

In Europe, gas storage sites started the heating season with inventory levels 12% above their 5-year average. Recovery in gas demand (by over 5% y-o-y) and the steep decline in LNG inflows (down by 28% y-o-y), supported higher **storage draws, soaring by 55% compared to last year** and accounting for close to 20% of total gas supply during the heating season. Consequently, European **storage inventories had fallen to 10% (or 3.7 bcm) below their 5-year average** and 44% (or 24 bcm) below last year's levels by the end of March. Low inventory levels could translate into higher gas injections through the summer of 2021, providing additional market space both for LNG and pipeline suppliers.

In Japan and Korea, LNG inventories were 7% below last year's levels in October 2020. The tight supply-demand conditions between mid-December and early January resulted in low intra-monthly storage levels. This prompted strong LNG imports during the second half of January and February (up by 16% y-o-y), which allowed LNG inventories to ramp back up to 6% below last year's levels by the end of February.

…leaving space for higher gas storage injection rates during 2021



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

Annex

Summary table

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

	Demand				Production			
	2018	2019	2020	2021	2018	2019	2020	2021
Africa	157	161	160	164	244	248	240	252
Asia Pacific	824	853	857	902	627	654	648	656
of which China	*283*	*307*	*326*	*351*	*160*	*174*	*189*	*200*
Central and South America	153	152	138	145	167	167	152	164
Eurasia	666	657	629	657	932	941	884	943
of which Russia	*493*	*482*	*458*	*482*	*726*	*738*	*692*	*742*
Europe	536	537	522	538	246	227	211	202
Middle East	544	547	551	569	666	677	680	707
North America	1061	1097	1072	1081	1062	1163	1144	1152
of which United States	*854*	*888*	*870*	*873*	*868*	*968*	*953*	*952*
World	**3940**	**4004**	**3929**	**4056**	**3944**	**4077**	**3959**	**4075**

Regional and country groupings

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

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

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

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

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

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

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

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

North America – Canada, Mexico and the United States.

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

[2] Including Hong Kong.

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

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

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

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

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

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

Abbreviations and acronyms

ANP Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (Brazil)

CAPEX capital expenditure

CME Chicago Mercantile Exchange (United States)

CNG compressed natural gas

CNY Chinese yuan

CQPGX Chongqing Petroleum and Gas Exchange (China)

EIA Energy Information Administration (United States)

ENTSOE European Network of Transmission System Operators for Electricity

ENTSOG European Network of Transmission System Operators for Gas

EPIAS Enerji Piyasaları İşletme A.Ş (Turkey)

EPPO EnergyPolicy and Planning Office (Thailand)

ERCOT Electric Reliability Council of Texas (United States)

FID final investment decision

GDP gross domestic product

GECF Gas Exporting Countries Forum

GIE Gas Infrastructure Europe

HH Henry Hub

IEA International Energy Agency

ICIS Independent Chemical Information Services

JODI Joint Oil Data Initiative

LNG liquefied natural gas

NBP National Balancing Point (United Kingdom)

NCG NetConnect Germany

NDRC National Development and Reform Commission (China)

OGT Oneok Gas Transmission (United States)

PCA Panama Canal Authority

PPAC Petroleum Planning & Analysis Cell (India)

SENER Secretaría de Energía (Mexico)

TANAP Trans-Anatolian Natural Gas Pipeline

TAP Trans-Adriatic Pipeline

TTF Title Transfer Facility (the Netherlands)

USD United States dollar

w-o-w week-on-week

y-o-y year-on-year

Units of measure

bcf billion cubic feet

bcf/d billion cubic feet per day

bcm billion cubic metres

mb/d million barrels per day

mcm/d million cubic metres per day

TWh terawatt hour

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