Gas Market Report

Q1-2021

Abstract

Global gas demand fell by an estimated 2.5% or 100 billion cubic metres (bcm) in 2020 – its largest drop on record. Amid this slowdown, gas demand for power generation remained resilient owing to fuel switching, while the whole supply chain showed strong flexibility in adjusting to demand variations. Gas trade globalisation progressed with increasing liquidity, while prices experienced historical lows and extreme volatility. The Covid-19 crisis and a well-supplied market put investment on hold, whereas gas market reforms and clean gas policy initiatives gained momentum in major consuming markets.

2021 opens with price rallies in Asia and Europe as rising winter demand tightened supply, but the price spikes are not expected to last beyond the short-term cold snaps given that market fundamentals for 2021 remain fragile. Global gas demand is expected to recover its 2019 level but with uncertainties regarding the recovery trajectory of fast-growing markets compared with more mature regions. Sectoral demand, on the other hand, is subject to a variety of risk factors including fuel switching, slow industrial rebound or milder weather.

This new quarterly report offers a detailed analysis of recent developments in global gas markets and the near-term outlook, and includes an overview of the main market highlights for 2020.

Table of contents

Winter has come, yet gas demand recovery remains fragile for 2021

After an unprecedented drop in natural gas demand 2020 closed with a rapid recovery in gas prices as a rise in winter demand tightened supply. A similar pattern held in the first weeks of 2021 with cold snaps bumping gas prices in Europe to their high winter levels and spot LNG prices in Asia broke historical records. This tight market episode was driven by short-term factors, whereas the fundamentals remain uncertain and potentially challenging for global gas demand recovery in 2021.

Global gas markets experienced their largest recorded drop in 2020, with an estimated 2.5% year-on-year (y-o-y) decrease in consumption (about 100 bcm). This was triggered by exceptionally mild weather in the early months and the onslaught of the Covid-19 panademic; impacts were concentrated in the first-half of the year which saw a 4% y-o-y decline in global gas demand. Progressive recovery was observed in Q3 as lockdown measures eased, seasonal electricity demand pushed up demand along with competitive gas prices. However, the beginning of the heating season in the northern hemisphere was less supportive with very mild temperatures in Europe and North America in October and November.

A cold open to 2021

Colder temperatures in December 2020 marked the start of a gas price rally amid tightening LNG supply. Spot LNG prices in Asia more than tripled to above USD 30/MBtu by the start of January 2021, with some cargoes reportedly awarded close to USD 40/MBtu; breaking the record price levels in the aftermath of the Fukushima nuclear accident in 2011. Rather than a single event, the recent spike reflects a combination of supply and demand factors. LNG demand in northeast Asia increased 10% y-o-y between mid-December 2020 and early January 2021 due to colder than average winter temperatures, exacerbated by lower nuclear availability in Japan and limits on coal-fired generation in Korea. The rise in LNG demand in Asia coincided with a number of outages at regional liquefaction plants, which increased the call on more remote suppliers. Longer voyages and congestion at the Panama Canal spiked spot charter rates to historical highs of more than USD 230 000/day – reportedly one prompt vessel was contracted at USD 350 000/day.These price spikes are not expected to last beyond the short-term cold wave, as market fundamentals for 2021 remain fragile.

Under pressure

This forecast expects global natural gas demand to grow 2.8% in 2021 (about 110 bcm), slightly above the 2020 decline, thus **enabling a recovery to the 2019 level.** This is a far cry from the 7.5% y-o-y post-2009 financial crisis rebound observed in 2010. This projection comes with two main caveats:

- All regions are not equal when it comes to gas market recovery. Mature markets bore the brunt of demand drop in 2020, while emerging markets will be the main drivers of demand growth in 2021. Fast-growing markets in Africa, Asia, Central and South America and the Middle East are projected to account for about 70% of global demand growth in 2021. Mature markets are likely to see a more gradual recovery though some may remain below their 2019 demand levels.
- The sectoral pillars of growth are all subject to major uncertainties. Gas burn in power generation is expected to be hampered by slow electricity demand growth and increasing inter-fuel competition as gas prices recover from their 2020 lows. Gas consumption in the industry is strongly dependent on economic recovery, especially for Asia's export-driven industries. Residential demand received support from cold temperatures so far, but would be negatively impacted in case of a return to milder weather conditions.

Global gas demand recovery in 2021 is uncertain. Demand is subject to a variety of risk factors including fuel switching, slow industrial rebound and mild weather which can moderate consumption.

Gas market highlights 2020

Gas demand for power generation was resilient thanks to fuel switching

Natural gas use in power generation fell an estimated 2% y-o-y worldwide in 2020. This is in line with total electricity demand and despite that output from renewables was up 6.6%. Cheap and abundant supply favoured gas in the merit order at the expense of coal in several markets.

Abundant US production supported an increase in gas-fired power generation in North America. In the United States, gas-fired generation increased 3% in 2020 while overall electricity output was down 2% and coal's share plummeted by 19%. In late July, gas reached a record share of 45% of electricity generation in the United States. In Mexico, total electricity output was lower than in 2019 for the first three-quarters of 2020, but gas-fired generation increased slightly at the expense of liquid fuels and coal.

In Europe, gas-fired power generation rose through the second-half of 2020. Following a steep decline of more than 10% in the first-half, gas-fired power generation rose by over 4% y-o-y in the third-quarter (Q3), despite a 4% fall in electricity consumption. This was partly driven by lower nuclear availability due to plant retirements, maintenance work, unexpected outages amid low river levels (for cooling purposes) and optimisation of fuel usage. Gas benefited from the combination of low prices and a sharp recovery in carbon prices through Q3 2020, while coal-fired generation fell by more than 8% in Q3. Despite the recovery in gas prices to above 2019 levels, gas-fired power generation rose 2.5% y-o-y in Q4, while power output from coal- and lignite-fired plants fell by close to 7%. This was primarily driven by Turkey, where gas-fired power generation increased 50% due to depressed hydro availability and environmental restrictions on lignite-fired plants.

Fuel switching trends are more mixed in other regions. In **Asia**, the People's Republic of China (hereafter "China") saw a 2% y-o-y increase in gas-fired generation for the first eleven months of 2020, while electricity demand was up 2% and coal declined slightly. Gas-fired generation in India increased 9% in 2020 thanks to cheap LNG spot prices, while coal declined 5%. Falling oil-linked LNG prices provided tougher competition for coal in Japan's power sector. Coal-to-gas switching continued throughout the year in Korea, with record gas burn in September.

In the **Russian Federation** (hereafter "Russia"), thermal power generation fell 10% y-o-y in the January-October period, squeezed by a 3.7% drop in electricity demand and a 12% increase in hydropower output. Coal-fired power generation fell more than 13%, while gas-fired power generation decreased approximately 10%.

Thermal generation also fell in **South America** on favourable hydro conditions combined with lower electricity demand. Gas-fired generation dropped 11% y-o-y in Brazil and 6% in Argentina over the first eight months of 2020.

In the **Middle East**, the squeeze on associated gas availability resulting from oil production cuts coincided with peak electricity demand in the northern hemisphere summer. This led to a resurgence of oil use in power generation in some key oil and gas-producing countries.

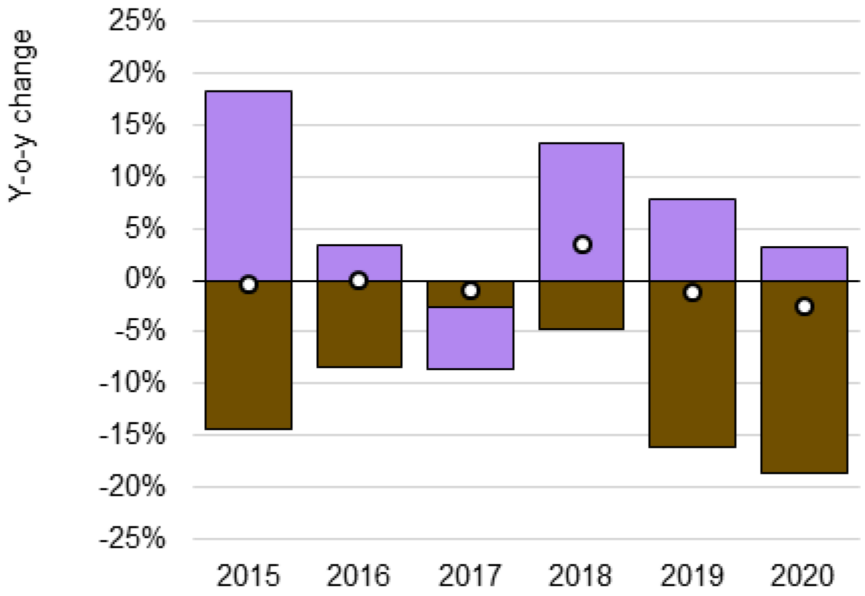
Limited prospects for increased gas-fired power generation in 2021, but policy measures provide longer term support in emerging Asian markets

Prospects for increased use of gas in power generation may be limited in 2021 in some regions, particularly in mature markets. This reflects the expanding contribution of renewables to the power mix. As well, fuel price projections suggest less competitiveness for natural gas and consequently a potential rebound of coal in electricity generation in the United States.

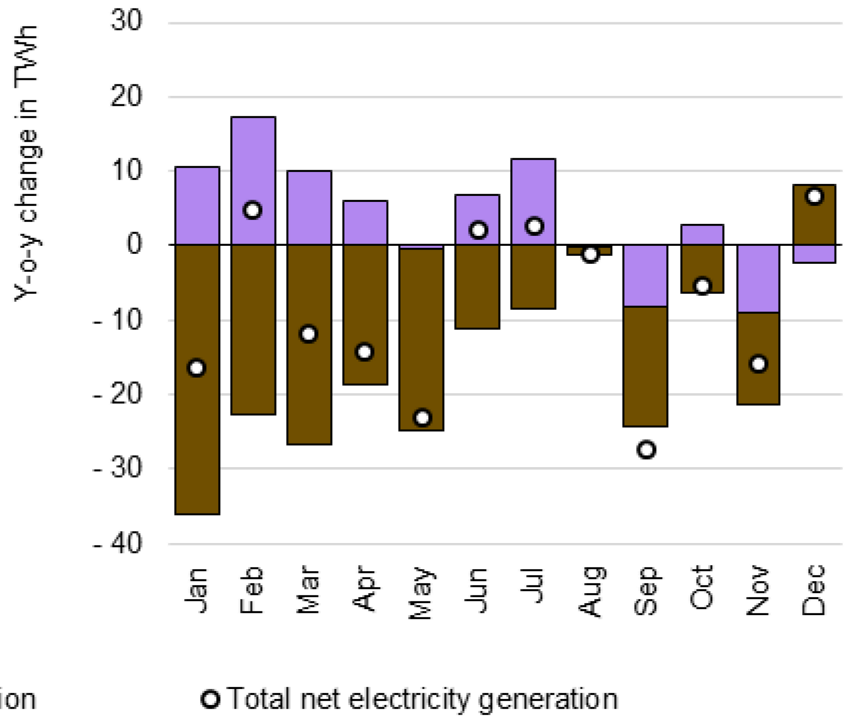
Prospects for more use of gas in power generation are favourable in Asia. They are fuelled by policies that support gas and LNG in power programmes and that limit development of coal-fired generation, principally in South Asian and Southeast Asian economies. Recent announcements are noted in Bangladesh, Viet Nam, Thailand, Myanmar and the Philippines.

Gas-fired generation in the United States rose as total electricity demand fell and coal-fired generation plummeted in 2020

Annual electricity generation in the United States, 2015-2020



Monthly electricity generation in the United States, 2020



Sources: IEA analysis based on EIA (2020), *Electric Power Monthly*, *US Electric System Operating Data*.

Gas value chain demonstrated strong supply flexibility

Long-distance and inter-regional gas pipeline trade bore the brunt of the supply adjustment in the face of lower demand with an estimated 15% (40 bcm) y-o-y contraction in trade flows. A steep fall in pipeline exports moderated as from June, supported by increased demand and lower LNG inflow. North African flows rose 8% through the second-half of 2020, while Russian flows returned to 2019 levels in Q4.

Pipeline imports to **Europe** decreased by 13% (30 bcm), primarily due to lower inflows from Russia and North Africa. This compares with a decline of 13% (28 bcm) in 2009, when European gas demand was depressed by the financial crisis. Pipeline flows fell 22% y-o-y in the first five months of 2020, at a time when flexible LNG was increasingly diverted to Europe amid subdued demand in Asia. This highlights the **crucial balancing role of Europe in the global gas market.**

In **Asia**, China decreased its import flows from Central Asia by 14% (6 bcm) y-o-y in the first eleven months of 2020, with Turkmenistan accounting for three-quarters of the reduction.This supported China's strategy to increase spot LNG purchases and accommodate the gradual ramp up of the Power of Siberia pipeline (reaching 4.1 bcm in 2020).

Global LNG supply proved its flexibility in the face of market oversupply, which hit its peak during the summer months of 2020. Global LNG exports fell by 22% between January and June 2020 – much steeper than the 5-7% seasonal swing normally observed during this period. The United States, which emerged as the world's largest swing supplier of LNG in 2020, accounted for a third of the downward adjustment in global LNG exports. A wide range of other producers – including Malaysia, Oman, Trinidad, Egypt and Indonesia – also responded to the pandemic-induced drop in demand with supply curtailments. The second-half of 2020 saw a sharp recovery as LNG export volumes gained momentum in Q4.

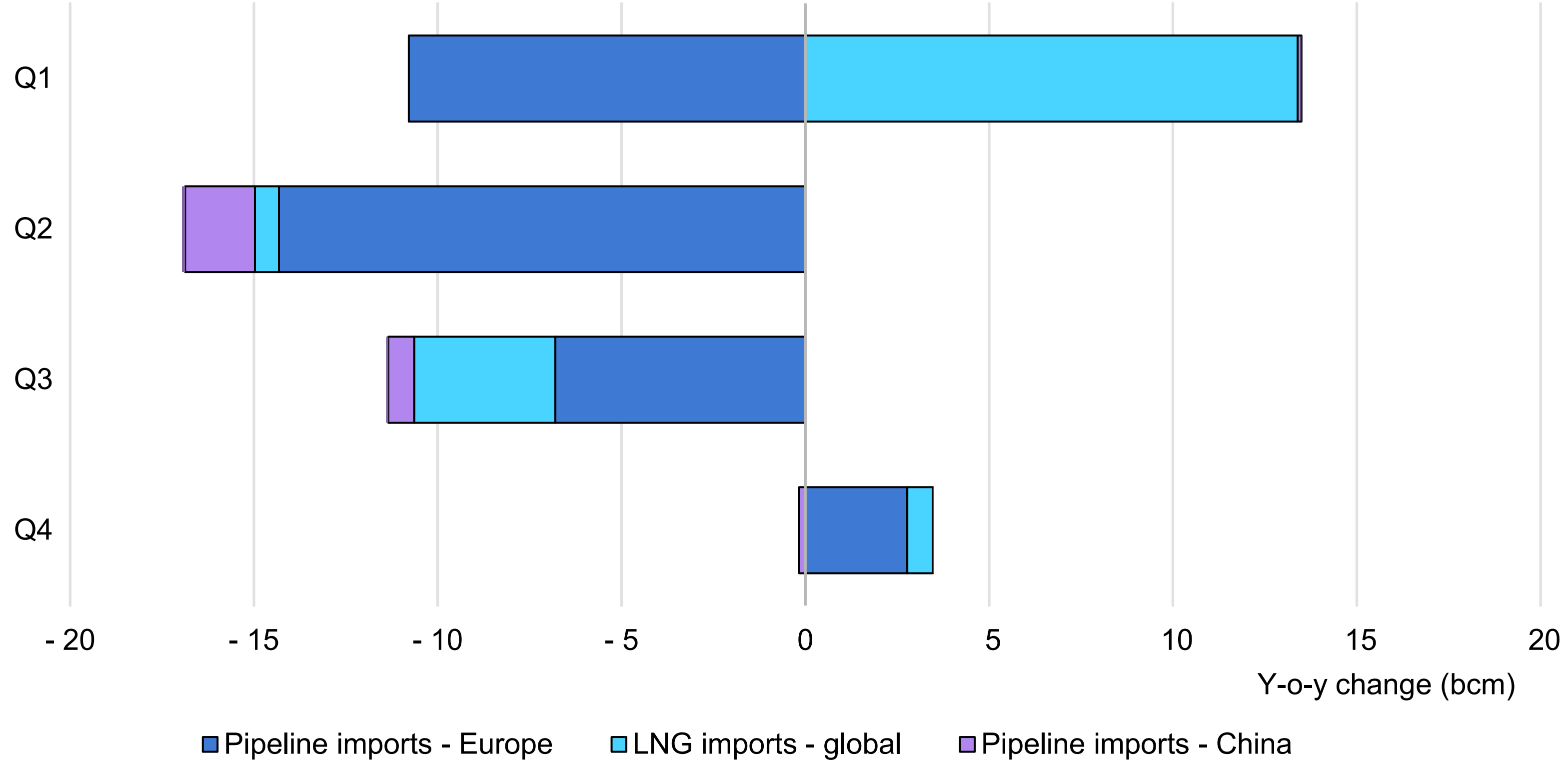
Between June and December, global LNG supply increased by 25%. US LNG output fully recovered and ran at record levels by the end of 2020, but the rest of the world – led by Russia, Australia, Malaysia, Egypt and Oman – also posted strong gains, together accounting for half of the net increase in LNG exports over the June to December period.

LNG tanker fleet helped balance a heavily oversupplied market

LNG floating storage volumes remained at elevated levels during the first three-quarters of 2020, and, at times, absorbed more than 10% of monthly LNG trade in Q2. In Q4, LNG floating storage levels were relatively subdued and below the average of the previous year. The shift reflects the simultaneous tightening of global gas and LNG shipping markets from September. As demand picked up in Asia, regional price spreads widened and long-distance trade expanded quickly. US cargo cancellations, which previously kept the LNG shipping market relatively loose, all but disappeared by the end of 2020. Daily spot LNG charter rates rose above the USD 100 000 mark by the end of October and approached USD 200 000 as the year drew to a close. The monthly cost of floating LNG storage increased more than fivefold between June and December 2020 from less than USD 0.3/MBtu to more than USD 1.3/MBtu. The steep tightening of inter-month price spreads diminished the economic incentive to keep LNG on the water for longer than necessary during much of Q4.

Supply flexibility at play during the Covid-19 crisis

Inter-regional natural gas trade, 2020 relative to 2019



Sources: IEA analysis based on ENTSOG (2021), *Transparency Platform*; Eurostat (2021), *Imports of natural gas by partner country - monthly data*; China Customs Office (2021), General Administration of Customs of People's Republic of China (2021), *Customs Statistics;* ICIS (2021), *ICIS LNG Edge*.

An increasingly liquid global gas market is emerging…

The global gas market continued to gain in depth and liquidity in 2020 despite shrinking demand. This reflects expanding volumes of LNG traded on the spot market and a substantial rise in volumes traded on regional gas hubs.

LNG volumes traded on spot and short-term basis continued to rise in 2020. Preliminary shipping data suggest an increase close to 8% to account for 37% of global LNG trade – its highest share on record. Short-term volumes were driven up by higher net selling positions of portfolio players and uncontracted commission cargoes. In contrast, the share of volumes traded under long-term contracts has been declining and was further depressed due to cargo cancellations through the third-quarter.

The United States continued to be the largest source of flexible LNG, with a 20% share of spot and short-term volumes, which account for over half of incremental supply of spot and short-term LNG. This is largely driven by the ramp up of new liquefaction facilities, including Cameron Train 2 and 3, and Elba Island.

China and India remained the world's largest buyers of short-term and spot LNG, with respective market shares of 20% and 11%. Buyers in China were particularly keen to benefit from the low spot prices through 2020 and increased purchases more than 50% y-o-y under short-term contracts and spot LNG, which offset more expensive sources of supply, including piped imports from Central Asia. China alone accounted for 40% of gross growth in spot and short-term LNG trading.

In **Europe**, Turkey increased purchases of short-term and spot LNG more than 50%, largely at the expense of piped imports from Iran and Russia, especially during the first-half of 2020.

Traded volumes on all major regional gas hubs increased. This highlights the increased appetite of market players to hedge positions along the forward curve.

In the United States, volumes traded on the Henry Hub in 2020 rose by more than 15% y-o-y.

In Europe, gas traded on the region's major hubs expanded 13% y-o-y in the first eleven months of 2020, largely driven by the 19% volume increase on the TTF hub in the Netherlands**.** TTF's share in total European gas trade rose from 66% to over 70%, further cementing its position as Europe's leading gas hub. Yet, volumes traded on the TTF are more than ten-fold lower than the US Henry Hub volumes traded on the NYMEX. Another important development in Europe has been the increasing share of volume traded on exchanges, from one-third in 2019 to 38% in 2020, which typically offer more standardised products, rather than via brokerages.

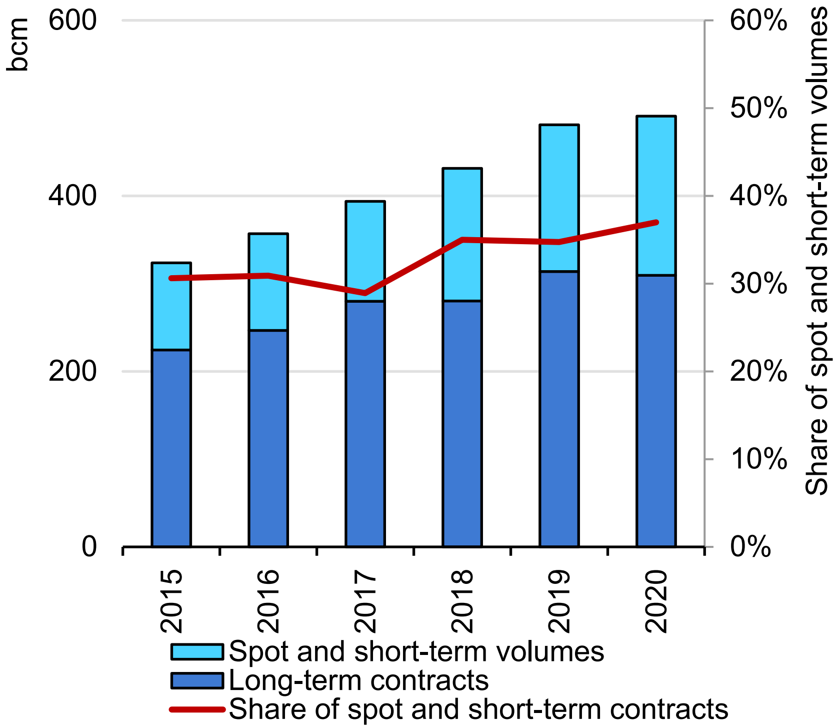
In Asia, trading in ICE JKM derivatives continued to increase in 2020, jumping almost 60% y-o-y.This shows growing interest from market participants to diversify price risk management strategies along the continued trend of LNG commoditisation.

Marketing strategies of traditional players may evolve towards increased focus on the short-term, amid the expanding liquidity of global and regional gas markets. **Gazprom sales via auctions** (for intra-annual deliveries) increased by 30% in 2020 compared to 2019, representing more than 10% of its exports to Europe. In November 2020, Qatar Petroleum announced the establishment of its trading arm, **QP Trading,** with a mandate to build a globally diversified portfolio and manage price risk exposure via physical and derivatives trading.

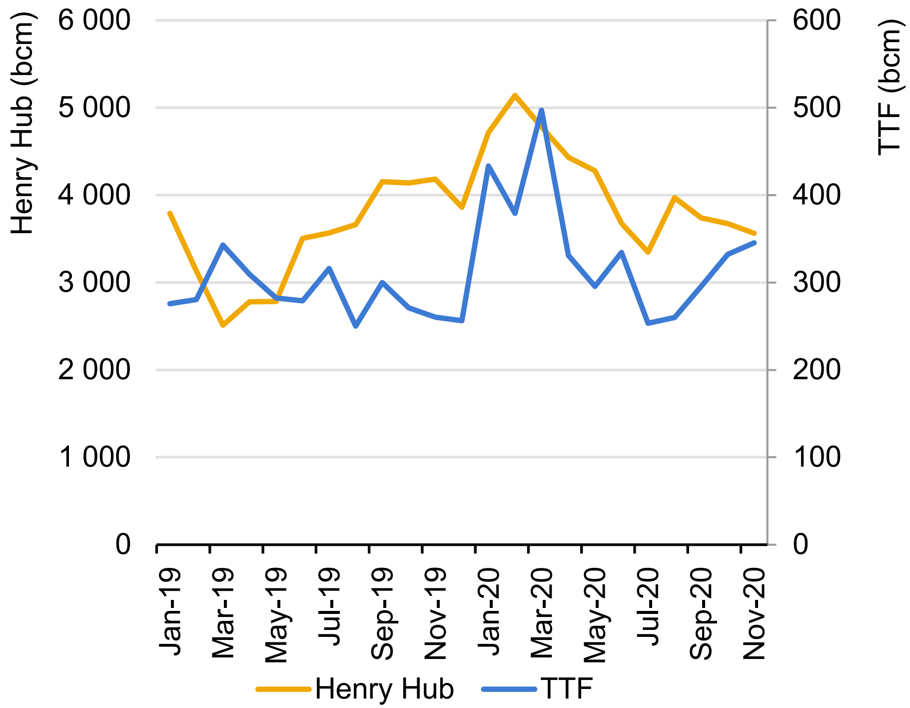
Carbon-neutral LNG continued to gain traction, with at least seven carbon-offset cargoes delivered in 2020. Singapore's Pavilion held the world's first LNG tender that included a bidder's obligation to quantify greenhouse gas emissions associated with each LNG cargo.The tender was won by QP Trading, which signed a ten-year production sharing agreement in November 2020.

...with LNG traded on spot and short-term basis reaching new highs

Spot and short-term LNG volumes in total trade, 2015-2020



Traded volumes on Henry Hub and TTF, 2019-2020



Sources: IEA analysis based on ICIS (2021), *ICIS LNG Edge*; GTS (2021), *TTF Development*; CME (2021), *NYMEX/COMEX Exchange ADV Report – Monthly Report*.

Gas price roller coaster: historical lows, steep recovery and high volatility…

It was a roller coaster ride for regional gas benchmark prices in 2020. Prices collapsed in all major gas consuming regions in the face of sharp drops in demand. By late May, day-ahead prices on the TTF hub fell below USD 1/MBtu and LNG spot prices in Asia dropped below USD 2/MBtu, both historic lows. In the United States, trades on the Henry Hub averaged USD 1.8/MBtu over the first-half of 2020 – the lowest price for this period since 1995.

Conversely, gas benchmarks recorded strong gains through the third-quarter. Prices rose to above 2019 levels by the start of the heating season. Increases in demand and supply adjustments along the gas value chain drove the recovery. TTF prices almost quadrupled through Q3 and traded almost 25% higher y-o-y in Q4. LNG spot prices in Asia followed a similar price trajectory, climbing above last year's levels in Q4. Despite the recovery, the annual average of TTF (USD 3.2/MBtu) and Asian (USD 4.2/MBtu) spot prices were historic lows. Price gains at Henry Hub were largely driven by rising LNG exports and lower production through the last quarter 2020, allowing the North American benchmark to return to 2019 price levels. Henry Hub prices averaged USD 2/MBtu in 2020, the lowest price level since 1995.

Large price swings had wide seasonal spreads and high volatility reflecting unprecedented market uncertainty that prevailed through the year. Month-ahead volatility on both Henry Hub and TTF averaged 65% – the second-highest level for both since 2008.

Oil-indexed LNG prices recorded heavy losses through the second-half of 2020, unlike the spot indices. The oil-premium (i.e. the estimated difference between oil-indexed and spot prices) started to gradually disappear after reaching a high of USD 7/MBtu in May and effectively turned negative by October – for the first time since September 2018. Oil-indexed LNG pricing dominates in the Asia Pacific market, where the average LNG import price in China, Japan and Korea fell by close to 40% y-o-y between September and November to an average of USD 5.6/MBtu, despite strong gains in spot prices.

Rising volumes of LNG supplies that are destination flexible increase liquidity of the global gas market and are underpinned by increased affiliation with regional gas hubs. This means that gas prices in a given market are becoming increasingly sensitive (and responsive) to the supply-demand fundamentals prevailing in regions beyond their immediate geographical reach.

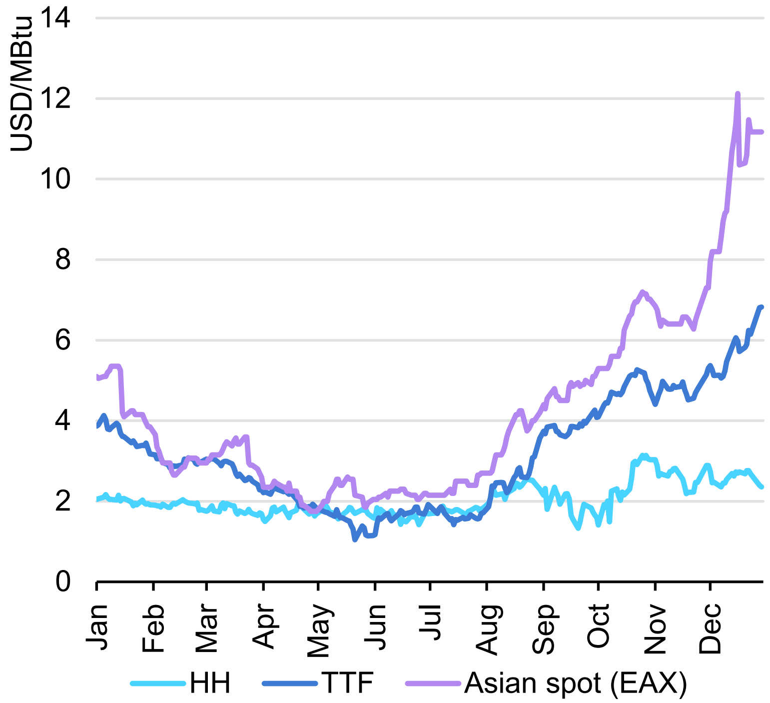
The correlation between TTF and Asian LNG spot prices increased from 0.86 in 2019 to close to 0.95 in 2020 – the highest annual level on record.The correlation was particularly strong through the second-half of 2020 driven by improving market conditions both in Asia and Europe, and more active competition for LNG cargoes. Most importantly**, the correlation between Henry Hub and TTF, and Henry Hub and Asian spot prices continued to increase** to reach 0.81 and 0.76 respectively from relatively low levels just two years ago. The rapid ramp up of US LNG exports – rising more than threefold since 2017 – underscores the increasing linkages between Henry Hub and other regional indices.

In contrast, the correlation between oil and natural gas prices stayed well below the 0.6-0.7 annual averages experienced between 2012 and 2016, when oil prices had a stronger influence on Asian and European spot prices.

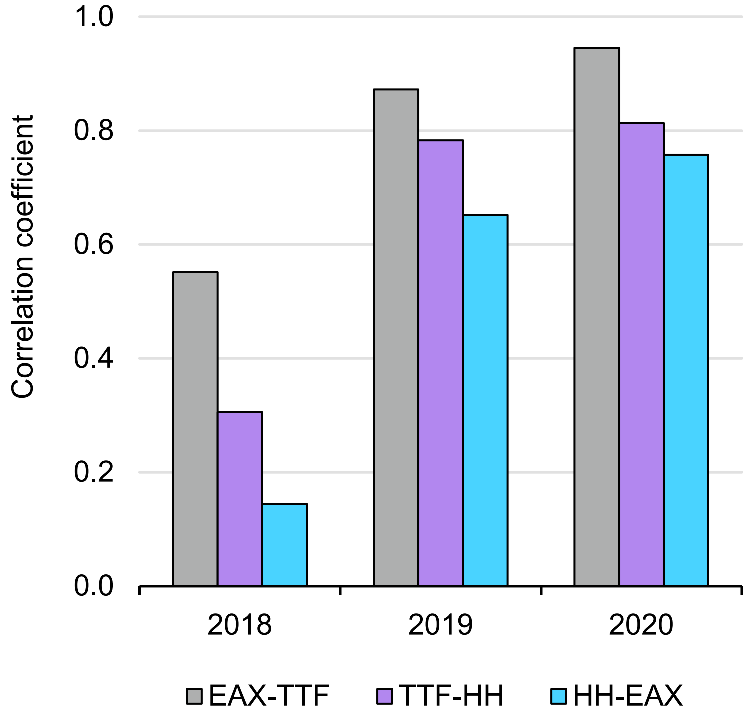
The high correlation between regional natural gas prices in 2020 could be diminished by tightening of the global gas market or unexpected regional supply-demand shocks. However, the mechanisms underpinning the rising liquidity of global gas trade – flexible LNG volumes and marketing strategies evolving toward optionality – are likely to be sustained and continue to support the expanding influence of regional gas hubs over time.

… hides the strengthening linkages of regional gas benchmarks

Natural gas spot prices, 2020



Correlation of key regional gas prices, 2018-2020



Note: HH = Henry Hub; TTF = Title Transfer Facility; EAX = East Asia Index.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Covid-related market uncertainty puts LNG supply investment on ice while investment in shipping and receiving capacity is robust

The demand uncertainty related to the global pandemic and a historic oil market downturn put the brakes on new investment in liquefaction capacity and upstream gas exploration in 2020. However, LNG vessel orders and investment in LNG regasification projects continued at a healthy clip.

Investment in new liquefaction projects stalled in 2020. After a record year for new final investment decisions (FIDs) in 2019, when nearly 100 bcm of new liquefaction capacity was approved, new FIDs in 2020 were limited to a single train development (the 3.4 bcm Energía Costa Azul project in Mexico).This marks the biggest annual drop in liquefaction project approvals in LNG market history. This investment standstill was due to a combination of excess supply and low global gas price benchmarks, widespread capex cuts by the major national and international oil companies, uncertainty about future LNG demand related to the economic impacts of the pandemic, and a lack of buyer appetite for long-term LNG contracts. The collapse of investment activity raises concerns about long-term supply availability.

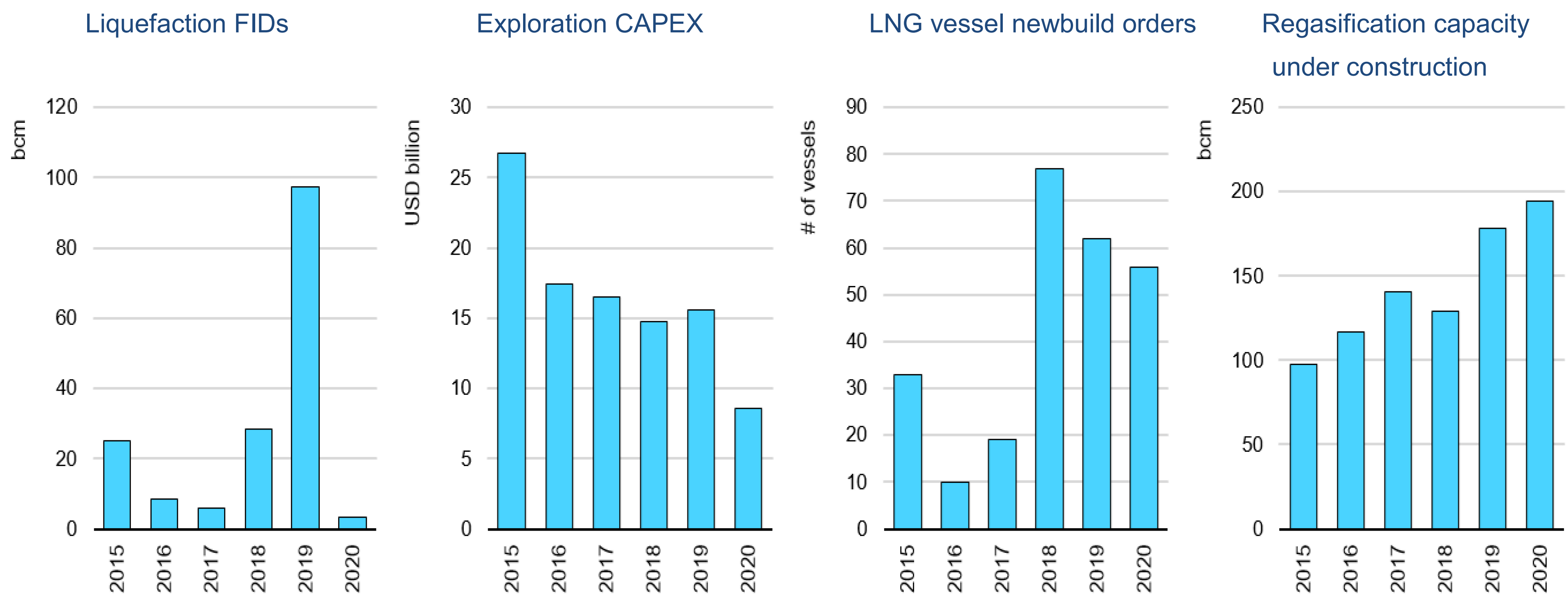
Key development milestones, though not a FID, were reached in 2020 for Qatar Petroleum's 64 bcm LNG expansion project, which could delay concerns of a post-2025 market tightening by several years. Nonetheless, LNG capacity outages in 2020 indicate that supply availability cannot be taken for granted even in a seemingly well-supplied market. For a brief period in Q3 2020, for example, as much as 10% of global liquefaction capacity went offline due to unplanned outages (while another 3% of total capacity was offline for planned maintenance), which contributed to a sudden LNG market tightening in the second-half of 2020.

Spending on gas exploration declined in 2020 amid fresh uncertainties related to the global pandemic and its economic repercussions. The drop in gas exploration is a structural trend, which has been fuelled by abundant unconventional resources (especially in the United States), concerns about stranded asset risk and monetisation challenges in a crowded marketplace for pre-FID LNG projects. Exploration capex for prospective gas plays in 2020 hit the lowest level in at least two decades.

Orders for LNG carrier vessels held up relatively well. After a lacklustre period in Q1-Q3 2020, order activity rebounded sharply in Q4 as the LNG shipping market tightened and spot charter rates skyrocketed. Fleet operators ordered more than 50 new LNG carriers in 2020, about 40% more than the global five-year average, but well below the levels seen in the bumper years of 2018 (77 orders) and 2019 (69 orders). The order book could soon receive another boost as Qatar Petroleum recently announced that it had booked more than 100 slots at one Chinese and several Korean shipyards to meet the vessel requirements of its LNG expansion project. If fully executed, the plan would be the largest shipbuilding programme in the history of LNG.

Investment in new LNG import capacity remained relatively strong in 2020. At the end of 2020, about 194 bcm of regasification capacity was under construction, a 9% increase from the end of 2019. FIDs on as many as eight new regasification projects sustained a robust project pipeline throughout 2020. However, construction delays due to Covid-19 and project-specific issues pushed some anticipated project completions to 2021, which also contributed to the high level of under construction capacity in 2020. Nearly two-thirds of new regasification capacity under development is located in growth markets in Asia, where new infrastructure is required to accommodate increasing gas demand.

Investment activity indicators



Sources: IEA analysis based on Rystad Energy (2021), *Gas Market Analytics*; ICIS (2021), *ICIS LNG Edge;* GIIGNL (2021), *Annual Report.*

Gas market reforms and clean gas policy initiatives take off in 2020

Reforms to open gas markets gained momentum in 2020. This progress can deliver benefits to economies as they recover from the pandemic and its economic consequences. The development of liquid wholesale gas markets typically fosters competition among suppliers, improves allocation efficiency and ensures transparent price discovery.

In **Brazil**, the Novo Mercado de Gas programme was officially launched in July 2019 to establish an open and competitive gas market. Petrobras, the country's formerly vertically integrated oil and gas company, reached a settlement agreement with the anti-trust regulator, CADE, to fully divest its participation in gas pipeline networks and to guarantee effective third-party access to its infrastructure, including LNG regasification terminals and import pipelines. In August 2020, a proposed new law to further solidify the foundations of a competitive gas market with an entry-exit system, full third-party access to gas infrastructure and a prohibition on vertical integration was approved by the lower house of Brazil's parliament. In December 2020, the upper house rescinded the bill with amendments to the lower house for final approval.

China launched its new national pipeline company, PipeChina, on 30 September 2020. It marks a significant step towards improved third-party access, better network integration and lower transmission tariffs. The reform may increase market competition, stimulate investment across the natural gas value chain and reduce the cost of gas to end-users. PipeChina has consolidated most of the long-distance gas pipelines as well as six regasification terminals and three underground storage sites that were previously controlled by China's three state-owned energy majors (PetroChina, Sinopec and CNOOC). The formation of PipeChina follows earlier reforms in July 2019, which removed the remaining ownership restrictions for foreign investors in China's upstream and downstream gas sector.

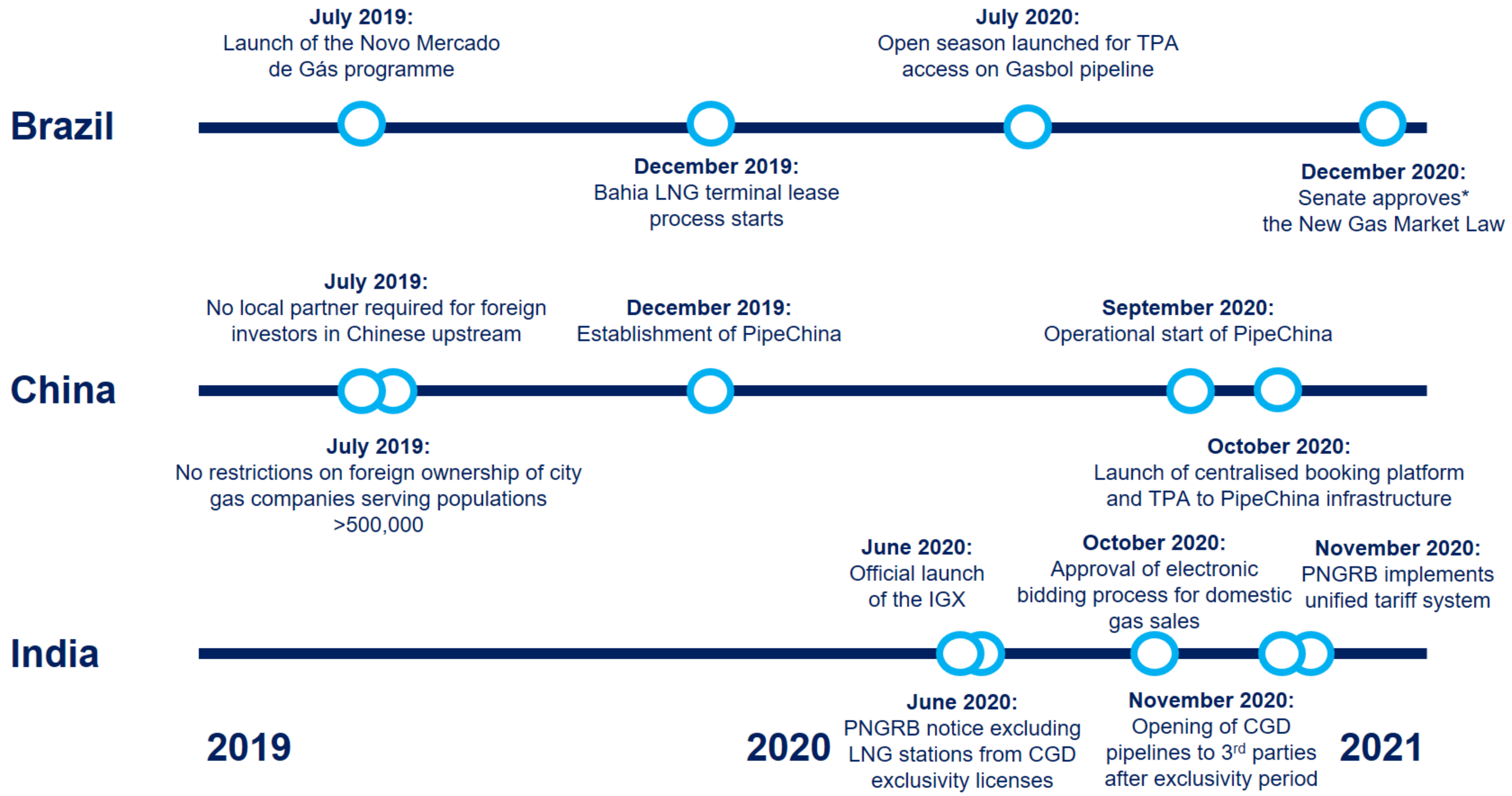
India launched the Indian Gas Exchange (IGX) in June 2020, which is authorised to operate as a regulated gas exchange for 25 years. This represents a significant step towards transparent market-based gas pricing, although traded volumes were negligible in the second-half of 2020. The national government enacted reforms to rationalise gas pipeline tariffs (by transitioning to a unified tariff structure from the previous distance-based system) and eased rules to set up LNG fuelling stations. It also approved the creation of an electronic bidding platform where producers will be able to offer their output at market-based prices. India's gas market regulator extended third-party access to city gas distribution pipelines as exclusivity periods (which run for a minimum of five years) expire. However, CNG stations were excluded from third-party access provisions.

Clean gas policy initiatives

Low-carbon hydrogen is garnering increased attention and a number of countries have announced related targets and strategies. Japan and Korea established hydrogen roadmaps in 2019. The European Union's hydrogen strategy set out in July 2020 aims to produce 1 Mt of green hydrogen by 2024 and 10 Mt by 2030. France, Germany, Spain and Netherlands have also launched hydrogen strategies. In Canada, Alberta's Natural Gas Vision foresees large-scale hydrogen production from natural gas with carbon capture, utilisation and storage by 2030. Canada's federal government hydrogen strategy set out in December 2020 highlights the potential of clean hydrogen to meet 6% of the country's energy end-use by 2030 and to expand to 30% by 2050. Chile's hydrogen strategy targets 5 GW of electrolysers by 2025.

The European Commission put forward a **methane strategy** in October 2020. It focuses both on reducing methane emissions in the European Union and addressing methane emissions associated with supply chains linked to the European Union. Legislative proposals including on measurement, reporting and verification for all energy-related methane emissions are planned for 2021.

Timelines for gas market reform are accelerating



TPA = third-party access; PNGRB = Petroleum and Natural Gas Regulatory Board; IGX = Indian Gas Exchange; CGD = City Gas Distribution.

**The Senate approved the gas bill with amendments, reverting it to the lower house for final decision.*

Gas market update and short-term forecast

Gas demand faces uncertainty

Global natural gas demand is expected to recover in 2021 from an unprecedented drop in 2020. Yet the prospect of a prolonged economic impact related to the Covid-19 pandemic heightens uncertainty about the pace and trajectory of growth.

The largest ever recorded drop in gas consumption occurred in 2020, about 2.5% (an estimated 100 bcm) **lower than in 2019**. This compares with a decline of about 65 bcm in 2009 from 2008 related to the financial crisis. Close to 85% of the decline in 2020 is from mature markets across Europe, Eurasia, North America and Asia. Contributing factors include: exceptionally mild temperatures in Q1 affecting heating needs; lockdowns in Q2 related to the pandemic that curbed gas use for power generation and in the commercial sector; slow economic recovery in the second-half of the year and a resurgent wave of Covid-related restrictions in the last months of 2020.

Power generation was the most significantly affected sector in 2020. It accounted for almost half of the y-o-y decline in gas demand with an estimated drop of over 40 bcm, even though coal-to-gas switching for power generation occurred in the United States and Europe, and marginally in Asia. Gas demand in the residential and commercial sector was principally impacted by above-average temperatures in the early months of the year across the northern hemisphere dampening heating requirements.This resulted in an estimated y-o-y decline of over 30 bcm, about a third of the global demand decline. Gas use by industrial customers and the energy sector appear to have been less impacted, with each dropping by close to 15 bcm over the year.

Heading towards an asymmetric (and fragile) recovery

Global natural gas demand is projected to increase by 2.8% in 2021 (about 110 bcm), thus reaching slightly above its 2019 level. However, this masks differences in the pace of growth among regions, sectors and markets. Fast-growing markets in Asia, Africa and the Middle East are projected to see increased gas demand in 2021 while mature markets may experience a more gradual recovery, and some may not reach their 2019 level in 2021.

Industrial sector demand is expected to take the lead with close to 40 bcm (3.9%) y-o-y growth, principally driven by markets in Asia, as global output and trade volumes recover in 2021. (The IMF's *World Economic Outlook* in October 2020 projects growth of 5.2% in global output and 8.3% in trade volume in 2021.)

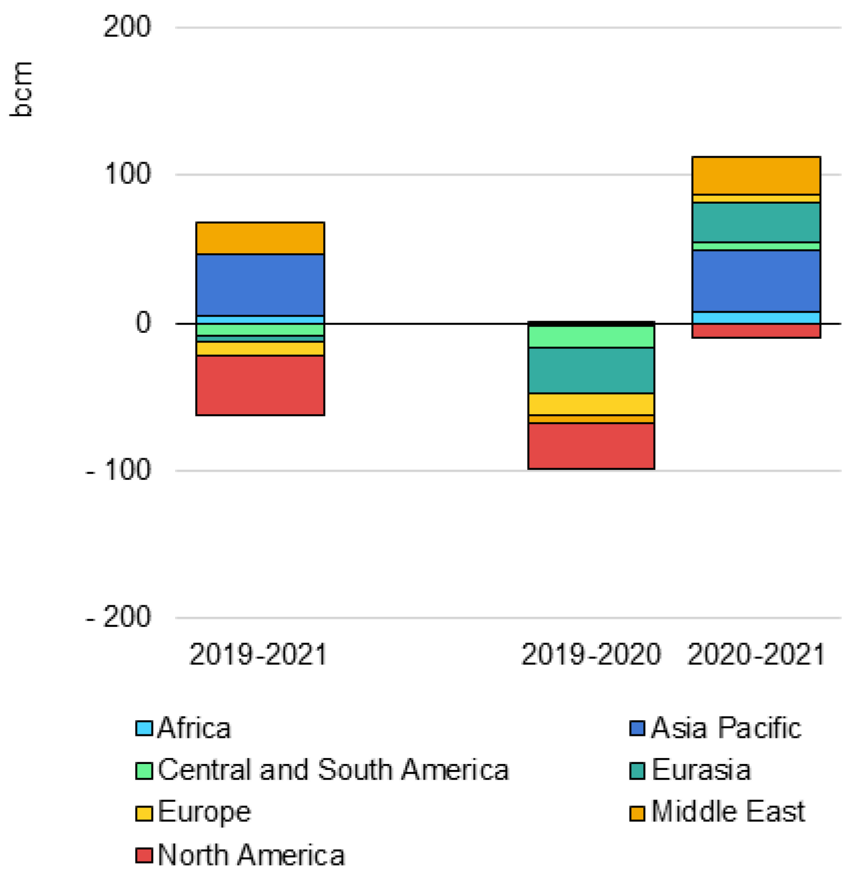
Residential and commercial gas demand is assumed to regain around 30 bcm (3.6%) based on a return to average seasonal temperatures, as forecast in the seasonal outlooks of the US National Weather Service (NWS) and the European Centre for Medium-Range Weather Forecasts.

Gas demand in the power generation sector is projected to only partially recover in 2021 with a 30 bcm (1.7%) increase, owing to a combination of low electricity demand growth and tougher competition in mature markets related to the expansion of renewables, the prospect of an increase in coal use in the United States and nuclear resarts in Japan.

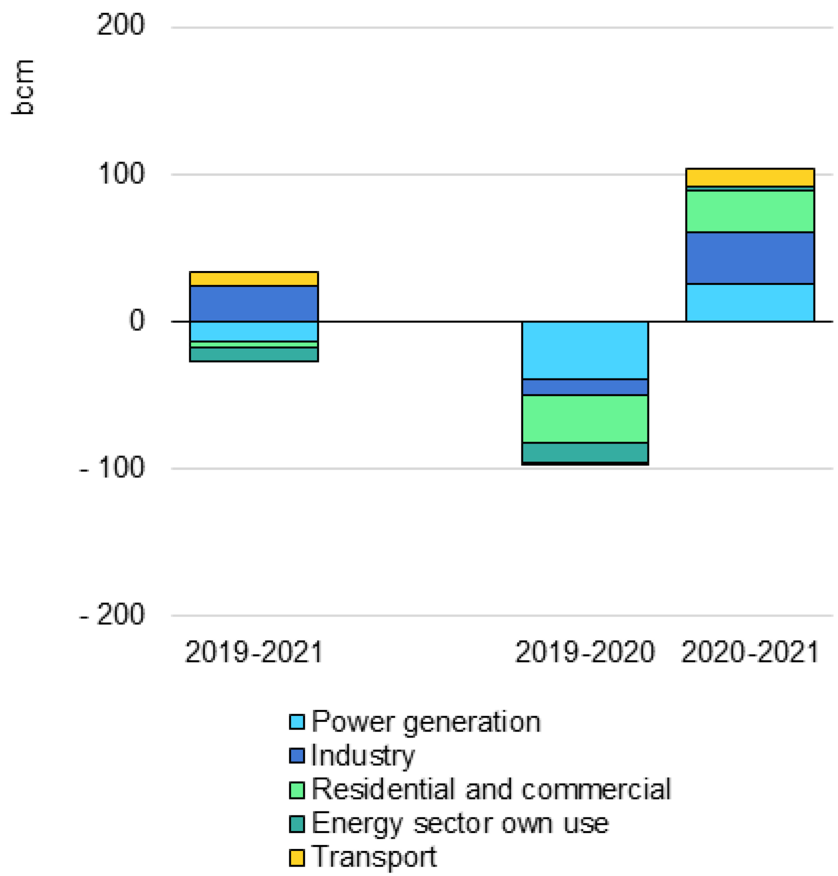
Global gas demand recovery therefore is fragile. It is subject to a range of uncertainties and risks from delayed industrial rebound, mild temperatures and stronger fuel competition in power generation that could lead to lower demand for natural gas in 2021.

Global gas demand is expected to recover in 2021, yet with notable variations

Gas demand growth by region, 2019-2021



Gas demand growth by sector, 2019-2021



Gas demand in the United States is projected to decline in 2021 as gas-fired power generation faces increased competition from expanding renewables and cheaper coal

Natural gas consumption in the **United States** declined by an estimated 2.6% in 2020. While demand had been on a recovery path from June to October 2020, an exceptionally mild November erased these gains, followed by lower demand in December compared with 2019. Natural gas demand rose slightly over Q3 (increasing 0.2% y-o-y), mainly due to a 3.5% y-o-y increase in July with a strong increase in gas-fired power generation (close to 8%) related to high temperatures and cooling demand, whereas consumption was down in both August and September (-1.4% and -2% y-o-y respectively). Q4 started on a rising trend for demand, with a 2.4% y-o-y increase in October, principally driven by the residential and power generation sectors. November was particularly mild and ranked as the fourth-warmest ever recorded by the NWS. This precipitated in a drop in natural gas demand for the residential sector (preliminary weekly data show a 25% y-o-y decline) as well as for power generation, where the combination of lower electricity demand and an increase in wind and solar output led to a 9% y-o-y drop in gas use. This resulted in an estimated 13% y-o-y decline for November. The return of colder temperatures in the first days of December resulted in an increase in gas heating demand, partly compensated by a decline in gas use for power generation due to increasing competition with coal.

In **Canada** gas demand decreased by 6% y-o-y in the first three-quarters of 2020. This reflects lower than usual heating demand, reduced industrial activity and less gas-fired power generation. Pipeline imports decreased by 4.3% y-o-y during the first three-quarters of 2020, totalling almost 19 bcm, while pipeline exports to the United States decreased by close to 5 bcm over the same period, a 8.3% reduction from 2019.

Mexico's apparent natural gas consumption fell by an estimated 2% y-o-y during the first ten months of 2020.This reflects lower industrial activity and decreased electricity consumption. Domestic gas production reported by the Secretaría de Energía decreased by almost 2% y-o-y from January to October, while pipeline imports from the United States increased by 6% over the same period, at the expense of both domestic production and LNG imports, which fell by 65%.

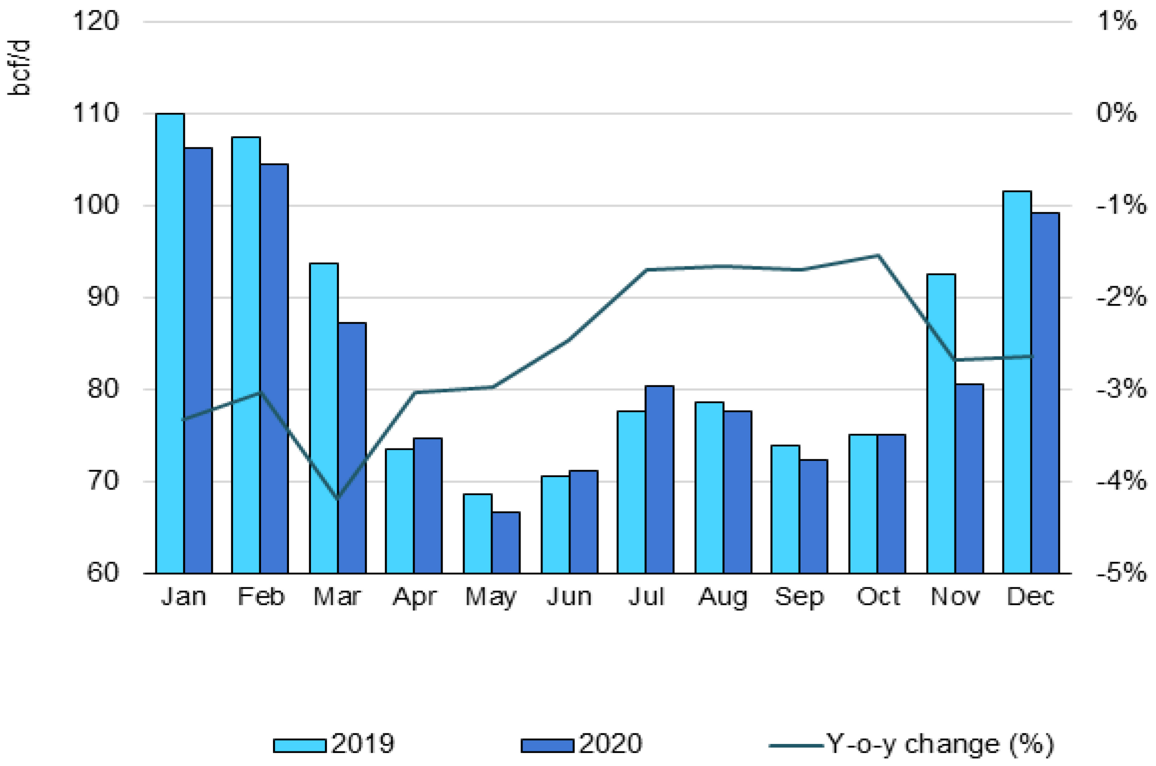
Flick of the switch: gas-fired power generation in the United States loses ground in 2021

Abundant and cheap domestic production remained a key driver behind the US natural gas demand resilience throughout 2020. It enabled gas-fired power generation to increase an estimated 3% in spite of lower electricity demand. Yet, a progressive decline in US gas production pushed prices up.This is likely to put pressure on the competitiveness of gas in power generation in 2021.The IEA *Electricity Market Report* highlights that the combination of limited electricity demand growth and ongoing expansion of renewables capacity put a ceiling on thermal generation. As well, at the current forward prices, coal could make a comeback in 2021 at the expense of gas in the United States, preliminary data show that it increased 8 Twh y-o-y in December 2020.

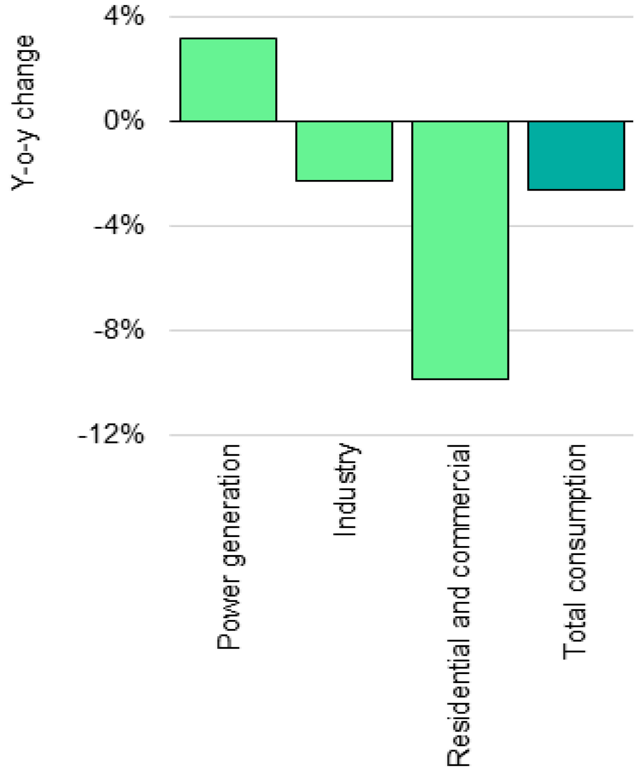
US gas consumption is projected to decline by 2% y-o-y in 2021 as demand for power generation falls (-8%) and offsets modest increases in other sectors. Residential and commercial demand is projected to partly recover from the 2019/20 warm winter with a 3% y-o-y increase (after an 8% fall in 2020) as the NWS forecasts a combination of cooler than average temperatures in the north and milder than average in the south for Q1 2021. Gas demand from the industry sector is expected to rise a modest 1% in 2021 after a 2% decline in 2020.

Natural gas consumption in the United States declined by an estimated 2.6% in 2020

Gas consumption by month in the United States, 2019 and 2020



Gas consumption by sector in the United States, 2020 relative to 2019

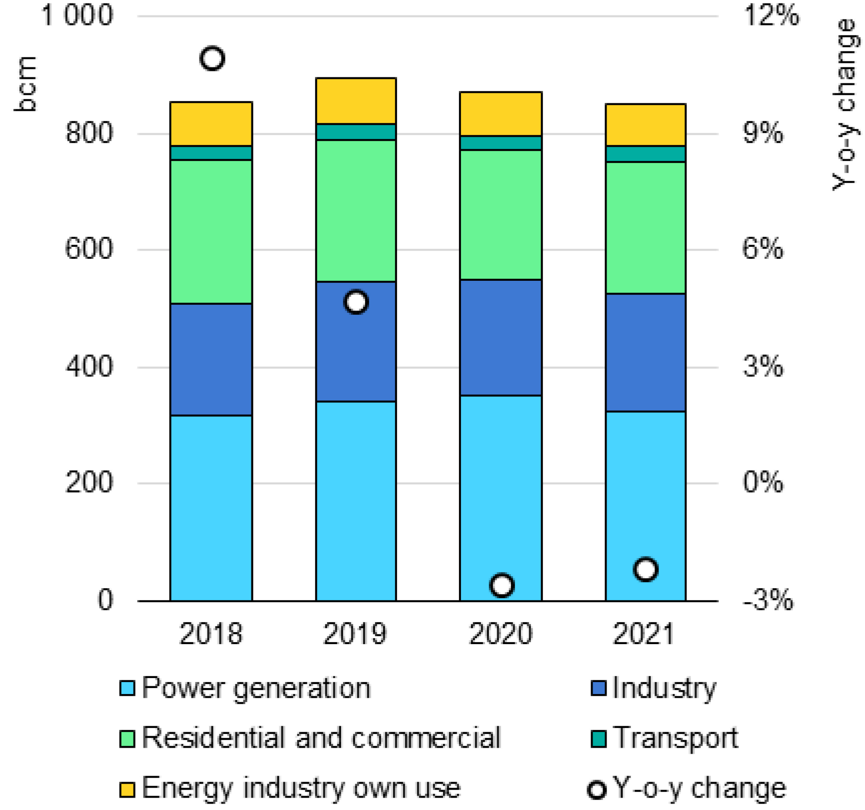


Note: bcf/d = billion cubic feet per day.

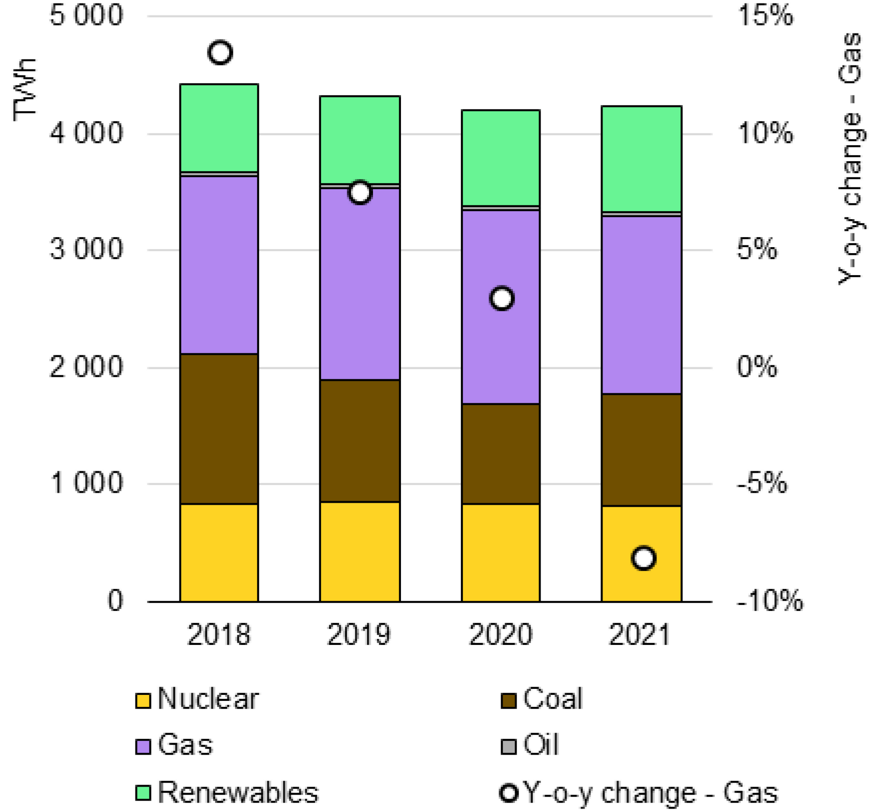
Sources: IEA analysis based on EIA (2021), Natural Gas Consumption; Natural gas weekly update; US Electric System Operating Data.

Gas demand in the United States is projected to decline 2% in 2021 as it loses share in the power mix on higher prices and increasing renewables

Natural gas demand by sector in the United States, 2018-2021



Power generation by source in the United States, 2018-2021



Sources: IEA analysis based on EIA (2021), *Natural Gas Consumption; Natural gas weekly update; US Electric System Operating Data*; IEA (2020), *Electricity Market Report.*

Gas demand in Europe: towards a fragile recovery

Gas demand in Europe proved to be rather resilient in the wake of the unprecedented macroeconomic shock related to the Covid-induced lockdowns. Estimates suggest that **gas demand in Europe fell by close to 3% in 2020.**

Gas markets in Europe faced a perfect storm through the first-half of 2020 with gas consumption plummeting by over 7% y-o-y, due to a combination of mild winter temperatures in Q1 and pandemic-related lockdowns through Q2. European gas demand started to recover in June and rose by 2% y-o-y in Q3 driven by increased coal-to-gas switching in the power sector.

European gas consumption rose by an estimated 3% y-o-y in Q4 2020 despite restrictive measures imposed amid another wave of the pandemic. Several factors explain the resilience of natural gas demand and why it was not impacted similarly as during the lockdowns in Q2:

- The confinement measures imposed across Europe in Q4 were less restrictive and disruptive for economic and industrial activities.
- Companies were able to adapt more quickly and smoothly to the (re)-introduction of regulatory measures related to social distancing and teleworking.
- The bulk of natural gas is consumed during Q4 for space heating in the residential and commercial sector is typically more sensitive to weather conditions and depends less on economic activity.

Heating degree days in Q4 2020 edged 3% above 2019 levels across Europe's main gas consuming regions.This pushed higher space heating demand requirements in the residential sector and outpaced some of the demand lost due to the temporary closure of commercial establishments. Overall, gas distribution network consumption rose by an estimated 4% y-o-y in Q4.

Gas demand for power generation in Europe rose 2.5% in Q4.This was primarily driven by a 50% increase in gas-fired power generation in Turkey reflecting lower hydro availability and environmental restrictions imposed on lignite-fired power plants. In contrast, demand for gas for power generation in the European Union and the United Kingdom fell by 3%.This reflects a combination of higher renewables output, restarts of nuclear power capacity and reduced cost-competitiveness of gas-fired power plants (due to a sharp recovery in gas prices through the second-half of 2020).

Preliminary data suggest that gas demand in industries in some markets has been less affected, e.g. up 2% in Italy, flat in France and down 1.5% in Spain.

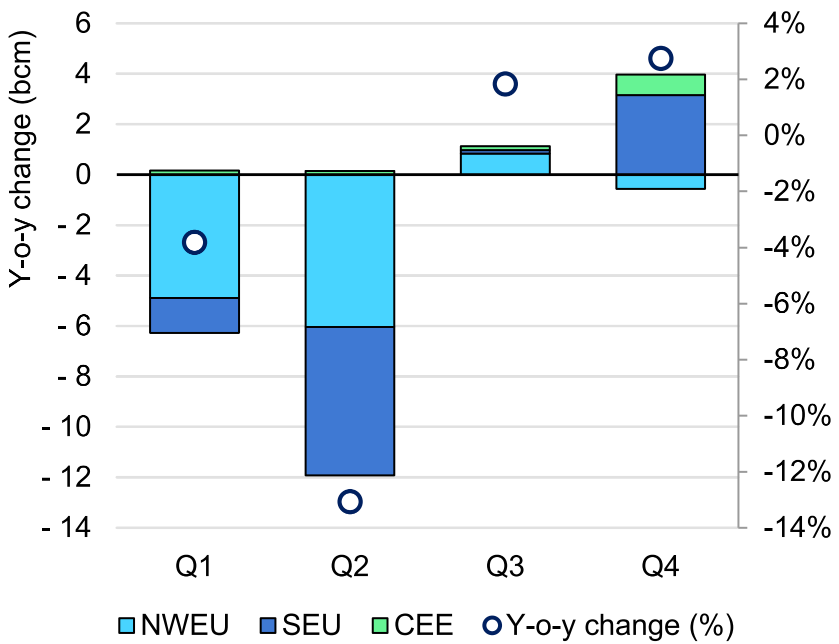
Prospects for 2021: a fragile recovery

Gas demand in Europe is projected to increase by 2% in 2021, though not to reach pre-pandemic levels. Forecast for a return to average heating requirements through the winter season and a gradual recovery of industrial and commercial activity drive the expected uptick in gas demand.

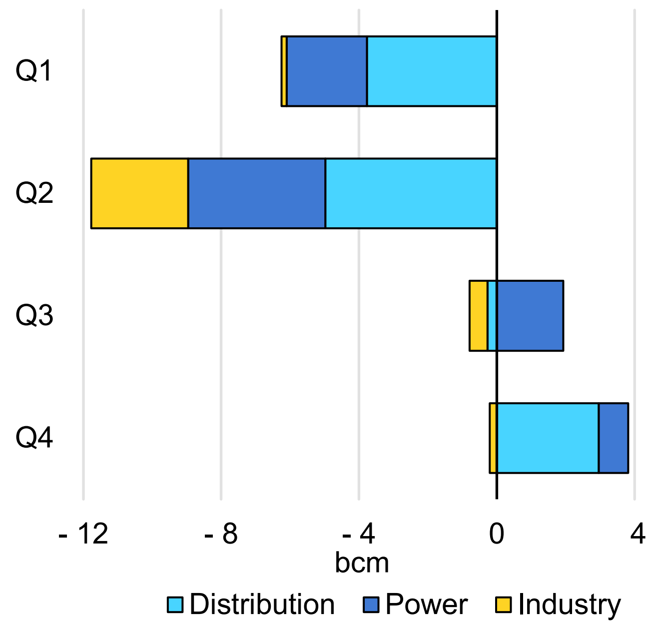
Gas-fired power generation in Europe is projected to decline by 1% in 2021. Electricity demand is expected to increase and to be met by a 5% increase in nuclear generation and a 4% boost in output from renewables.This implies that the portion of the generation mix from fossil fuel sources (gas, coal, lignite) is projected to shrink by 1%. A projected sharp recovery in gas prices, increasing by twofold y-o-y (per forward curves at the beginning of 2021) would diminish the competitive advantage of gas-fired power plants *vis-à-vis* coal-fired generation.

Overall gas demand in Europe was down 3% in 2020 with huge drops in the first-half moderated by increased demand in the second-half

Gas demand by region in Europe, 2020 relative to 2019



Gas demand by sector in Europe, 2020 relative to 2019

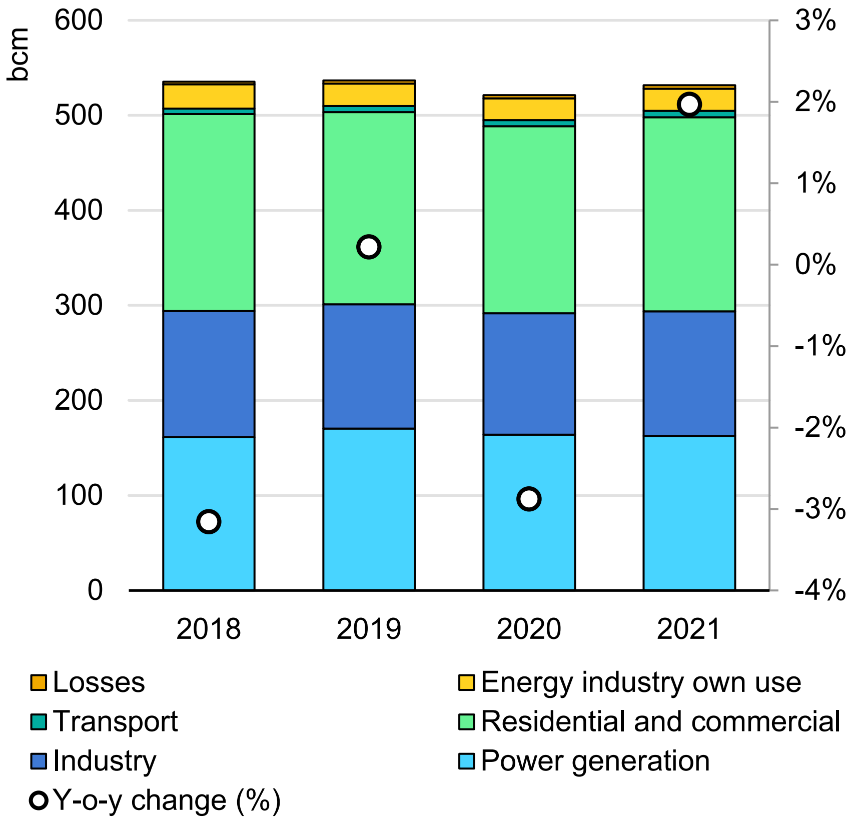


Notes: NWEU = Northwest Europe; SEU = South Europe, CEE = Central and Eastern Europe. Distribution represents demand from consumers connected to a distribution network.

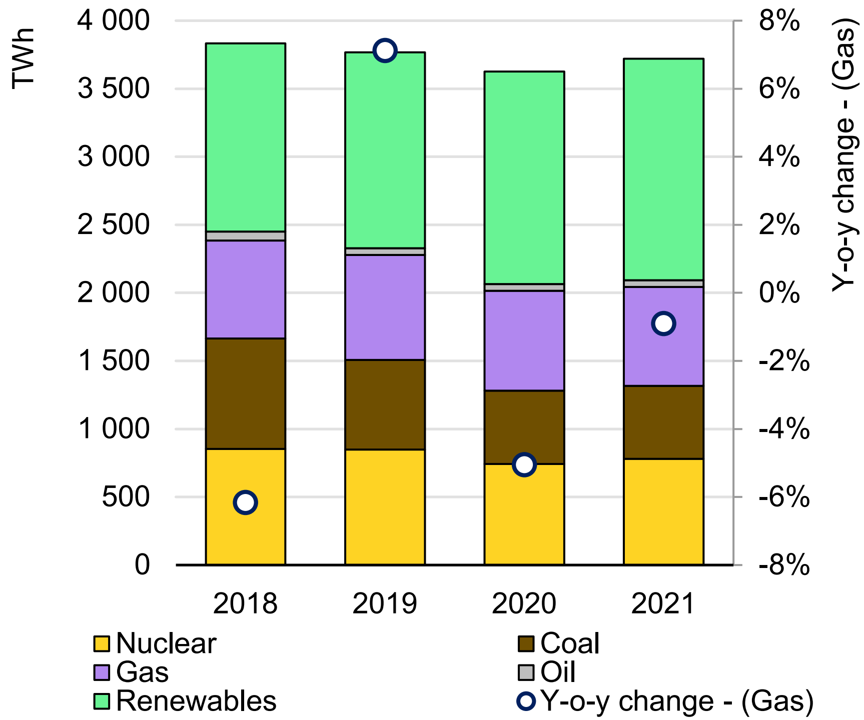
Sources: IEA analysis based on ENTSOE (2021), *Transparency Platform*; ENTSOG (2021), *Transparency Platform*; Gaspool (2021), *Consumption Data*; NCG (2021), *Consumption Data*; EPIAS (2021), *Transparency Platform*.

Gas demand in Europe in 2021 is expected to remain below pre-crisis levels

Gas demand by sector in Europe, 2018-2021



Power generation by source in Europe, 2018-2021



Sources: IEA analysis based on ENTSOE (2021), Transparency Platform; ENTSOG (2021), Transparency Platform; Gaspool (2021), Consumption Data; NCG (2021), Consumption Data; EPIAS (2021), Transparency Platform; IEA (2020), Electricity Market Report.

Gas demand in Asia picked up in the second-half of 2020 with an expected rebound in 2021

Gas demand in Asia saw steep declines in the first-half of 2020. Demand rallied in the second-half with year-on-year rates increasing in most Asian economies. Colder than average winter temperatures and a host of country-specific factors boosted Asian gas demand further in Q4 2020. Gas demand in 2021 is projected to see a strong rebound in most of the key growth markets in Asia.

Gas demand in **China** is estimated to have risen 5% in 2020, though the trend was not consistent over the year. China was the first country to emerge from a Covid-19-induced gas demand drop in the early spring with gradual recovery in Q2 that accelerated in the second-half of 2020. For the January-October period, the National Development and Reform Commission reported a 5% y-o-y increase in consumption while market sources estimated 3% for that period.

City gas distribution was the principal driver of gas demand growth throughout the year, due in part to new residential connections. In the second-half of 2020, gas demand was also up in the power generation, industrial and chemical sectors. An early onset of winter in October and a cold spell in December accelerated gas demand in the residential and commercial sector. In Q4 industrial production and trade were stronger than expected and pushed up gas consumption even further.

Gas demand in China is projected to increase by more than 8% in 2021 on the back of strong economic recovery. In addition, this outlook is supported by ongoing expansion of natural gas use by residential and commercial consumers and market reforms that will increase market competition and lower end-user prices.

These reforms showed early indications of bearing fruit in the second-half of 2020. PipeChina, the new national pipeline company, established a central booking platform and offered access to its infrastructure assets to third-parties just days after its formal launch on 30 September. Also notable in the second-half of 2020 was China's announcement of a net-zero emissions target by 2060, which will be favourable to gas demand growth in the medium term.

India's economy was hit hard by a prolonged Covid-19 epidemic in 2020. With a strict nationwide lockdown in the early phase, gas demand dropped a massive 27% y-o-y in April and was lacklustre in Q2-Q3 reflecting slow economic recovery and delays in key gas infrastructure projects. Gas demand picked up in October with a 4% y-o-y increase, but slowed again in November rising only 1% y-o-y. In the January-October period gas consumption was down 1.1% y-o-y.

India's refining and fertiliser sub-sectors remained relatively unscathed during the pandemic and registered healthy gas consumption growth rates over most of the year. Gas demand for power generation picked up from Q3, but turned negative again in November. In the January to November period, negative y-o-y growth rates for gas demand were reported in the city gas sector (i.e. gas-based transport, small industries, and residential and commercial users), power generation and petrochemicals. The pace of recovery in Q4 indicated that overall gas demand growth in 2020 is expected to be slightly negative.

India's gas demand is projected to rebound sharply and increase by 10% in 2021, driven by strong economic recovery and new infrastructure projects. However, further project delays, lower than forecast GDP growth and a challenging outlook for domestic gas production present significant downside risks to the outlook for 2021.

Total gas demand in **Japan** is estimated to decline 5% y-o-y for 2020. In May it reached a low point with a decline of 11% y-o-y as Covid-induced impacts hit commercial and industrial activity particularly hard.

The impacts of the Covid-19 pandemic have been prolonged in Japan; total gas consumption was down 5% y-o-y in the first ten months of 2020. Volumes of city gas sales plummeted 27% for commercial use and 16% for industrial use in Q2, though the y-o-y consumption decline in both sectors moderated to 10% in Q3 according to the Ministry of Economy, Trade and Industry. In Q3-Q4, gas use for power generation increased due to the shutdown of several nuclear reactors for periodic inspections. Colder than average winter temperatures likely boosted residential and power sector gas demand in Q4.

In 2021, total gas demand in **Japan** is projected to decrease by 4% y-o-y. A boost in gas demand from a gradual economic recovery will be more than offset by lower demand in the power sector as nuclear capacity is restarted. Notable policy developments that affect the long-term outlook for gas demand include Japan's announcement of a net-zero emissions target by 2050 and that its sixth Strategic Energy Plan is due to be finalised in fiscal year 2021; it will shape the LNG strategy of the world's largest LNG importer in the decade ahead.

Total gas demand in **Korea** is estimated to have increased 1% y-o-y in 2020. Demand fell sharply in Q2 related to the pandemic, but thanks to rapid containment of the virus spread, gas consumption expanded by 1% y-o-y in the first ten months of 2020.

From January to September, consumption in Korea's city gas segment decreased by 6.6% y-o-y while gas demand for power generation increased 2.6% y-o-y, which mitigated the overall decline. Gas use for power rose in Q3 as some nuclear plants were offline due to typhoons, as well as some coal-to-gas switching. Some nuclear capacity restarted in Q4 but cold winter weather and a government mandated shutdown of some 16 coal-fired power plants from December underpinned increased gas consumption in Q4.

In 2021, total gas consumption in Korea is projected to increase by 2% y-o-y, mainly driven by economic recovery and continued coal-to-gas switching in power generation.

Total gas demand in **Bangladesh** is estimated to be broadly flat for 2020. Gas consumption fell by a third compared to pre-Covid levels in April due to the effects of a nationwide lockdown, but demand recovered gradually to pre-pandemic levels by September.

In 2021, total gas demand in Bangladesh is projected to increase 6% y-o-y. This increase is underpinned by a sharp rebound in economic activity and the recent debottlenecking of LNG import terminals. Bangladesh purchased its first spot LNG cargo in September 2020, having previously relied exclusively on deliveries from Qatar and Oman under long-term contracts.

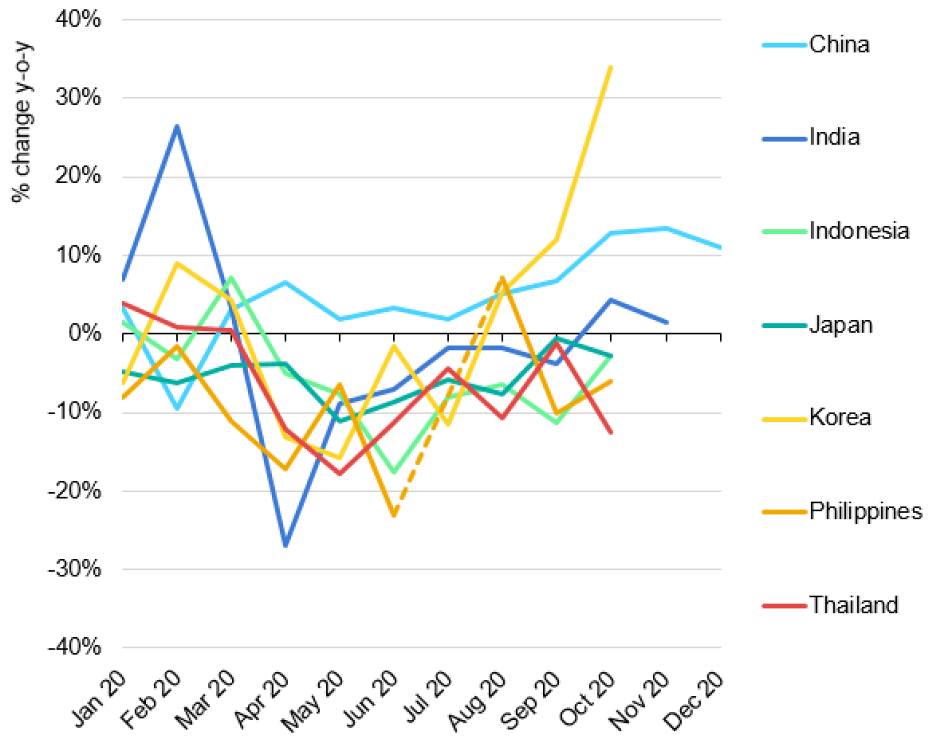
Gas demand in **Thailand** registered a sharp 18% y-o-y decline in May 2020 due to Covid-related impacts. While a gradual recovery trend started in June, total gas consumption in the January-October period decreased about 7% y-o-y. Total gas consumption is not expected to recover to pre-Covid levels before the second-half of 2021.

Gas demand in **Indonesia** dropped 18% y-o-y in June 2020 due to the economic fallout from Covid-19. Indonesia's economy lapsed into recession in Q3 for the first time since the late 1990s. Total gas consumption in the January-October period decreased about 5% y-o-y. Demand picked up into Q4 albeit at a slow pace. In 2021, total gas consumption is projected to increase 3% y-o-y, mainly driven by gas-fired power generation.

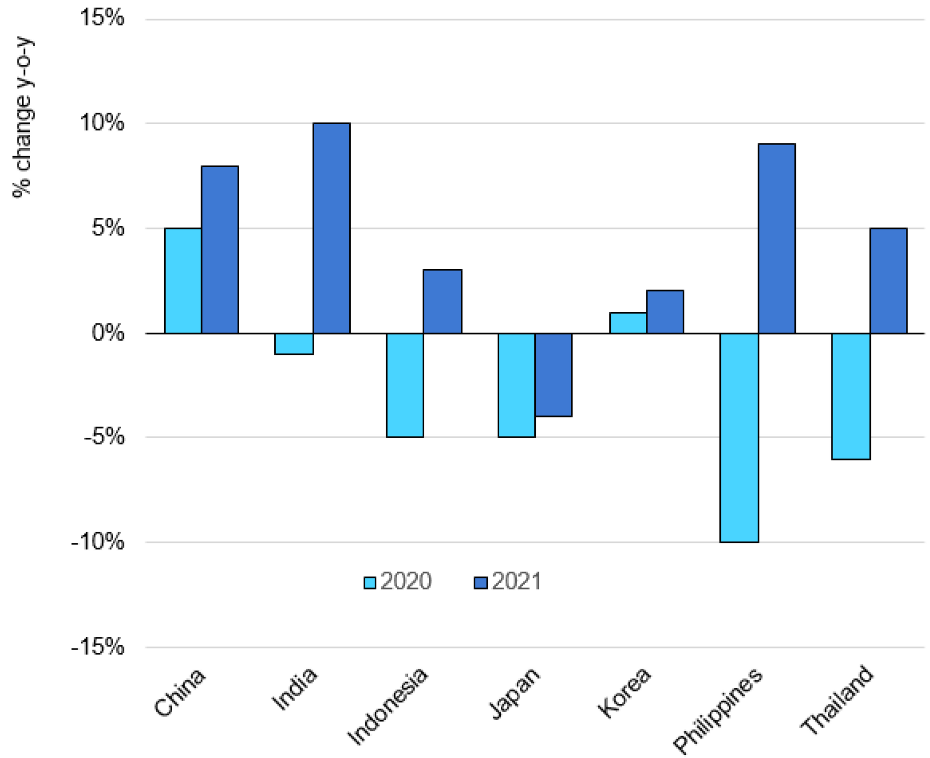
Gas demand in the **Philippines** decreased 12% y-o-y during the first-half of 2020 and is expected to decline by 10% for the year as a whole due to pandemic-induced impacts. In 2021, total gas consumption is projected to increase 9% y-o-y as the economy gradually recovers.

Gas demand in most Asian economies show positive growth in the second-half of 2020 or in 2021

Monthly gas demand in selected Asian countries, 2020



Gas demand in selected Asian countries, 2020 and 2021



Note: Dashed line indicates unavailable data for the Philippines.
Sources: IEA analysis based on CQPGX (2021), Nanbin Observation; IEA (2021), Monthly Gas Data Service; JODI (2021), Gas World Database; PPAC (2021), Gas Consumption; EPPO (2021), Energy Statistics.

Natural gas production in the United States slows in 2020 and 2021 – a first for two consecutive years since the mid-2000s

Natural gas production in the **United States** registered its lowest monthly level of 75.5 bcm in June 2020. It showed some gains in July and August, but dropped to 76.3 bcm in September.This reflects a combination of lower electricity demand and curtailment of LNG exports due to hurricanes in the Gulf of Mexico. US monthly natural gas output was flat at around 78 bcm during Q4 in spite of lower domestic demand, as well as net pipeline imports from Canada which stabilised over Q4, and increased in the last weeks of December, after a 8.3% decline y-o-y during the first nine months of 2020. Exports provided support to US gas production in the last months of 2020, especially LNG output which at 8.5 bcm in December broke February's record 7.3 bcm and more than doubled from September's output (3.4 bcm). In addition, pipeline flows to Mexico increased 4% y-o-y in Q4. While exports increased in late 2020, **US gas production in Q4 was slightly below its average of the first nine months, resulting in negative growth estimated at - 2.2% for 2020 y-o-y**.

Associated gas output from oil-driven shale basins, which dropped 13% in January-June due to oil production declines, were stable over the second-half 2020. The Permian Basin – one of the largest sources of associated gas and accounting for close to 15% of gas production in the United States – produced on average 10.3 bcm per month over the second-half of 2020, close to its record of 10.5 bcm in March 2020. But short-term output was extremely variable, especially in November with strong changes in weather conditions. This led to high price volatility on the Permian's Waha Hub, which fell negative briefly in early November and traded at close price parity to Henry Hub in December. Lower oil production also impacted gas output from conventional fields.This basin, which accounted for about a quarter of total US gas production in 2019, declined by close to 13% y-o-y in 2020.

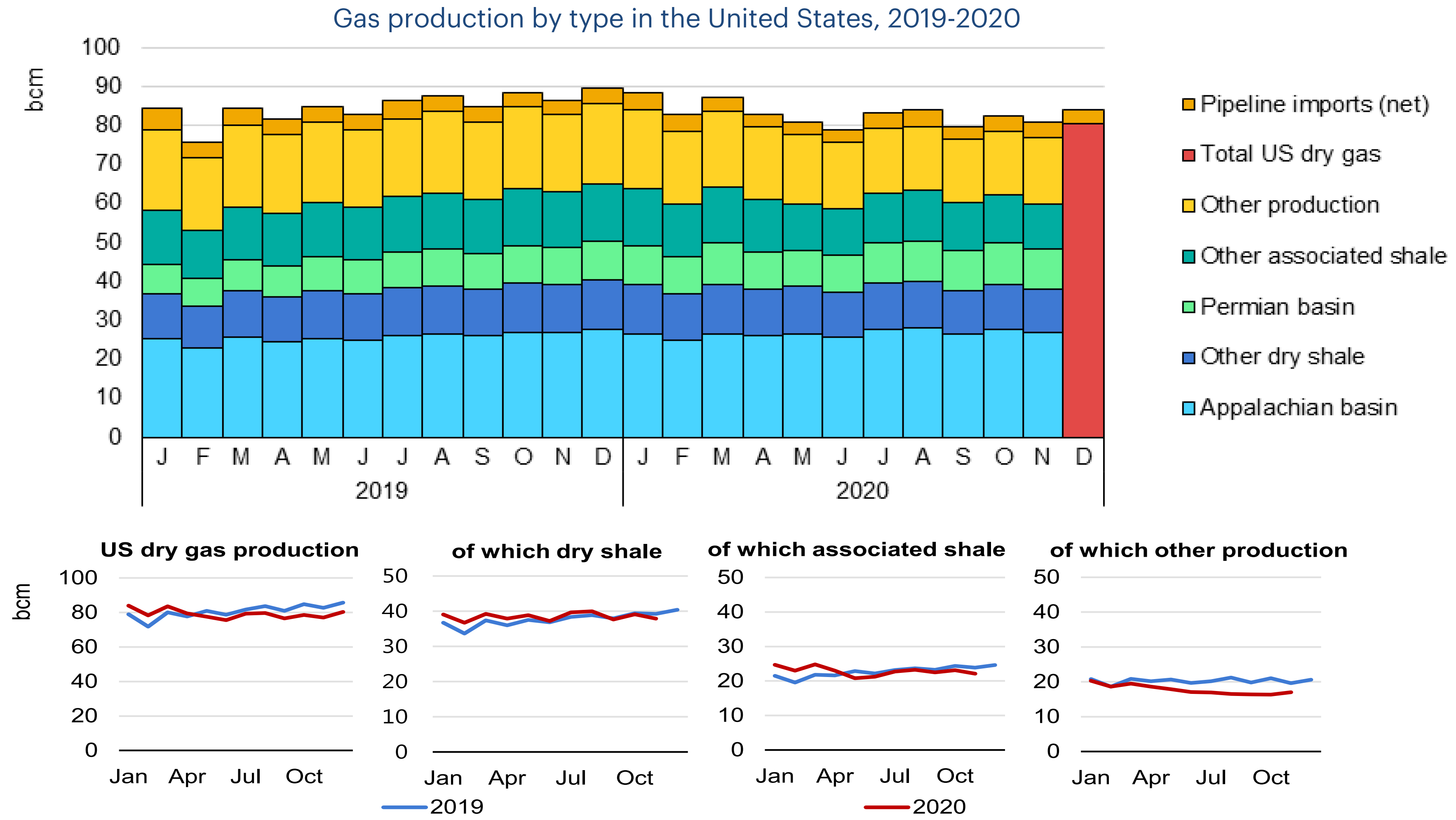
Dry shale gas plays have recovered to pre-pandemic production levels, with monthly averages of almost 40 bcm over the second-half of 2020.

Production reached record highs in the last months of the year in the Appalachian Basin – the largest contributor to dry shale gas production. This production level was sustained even with reduced drilling activity thanks to productivity improvements and the completion of previously drilled but uncompleted wells with a monthly average of 61 new wells drilled for 70 completed over the year's second-half.The Haynesville play also experienced limited decline even with lower drilling activity, with a monthly average of 35 new wells drilled and 33 completed.

Prospects for US gas production in 2021 are intertwined with oil production

Dry shale gas production in the United States increased an estimated 2% in 2020. For 2021, production is projected to continue on this trend as a steady rate of drilled but uncompleted wells in the Appalachian Basin underpins gas output in spite of low drilling activity. If natural gas prices recover in the coming months, it could spur new drilling activity.The IEA's *Oil Market Report* projects US crude oil output to decline from 11.3 mb/d in 2020 to 11.1 mb/d in 2021. Lower light tight oil output results in a proportional decline in associated shale gas production. Natural gas output from conventional fields (both dry and associated) is also likely to decline on a combination of the oil production adjustment and continuing depletion for the most mature assets. The expected growth from dry shale gas basins is not sufficient to offset declines from other sources, resulting in **an estimated 2% decline in gas production in the United States in 2021. This would be the first time US output declines for two consecutive years since 2005** which marked the take-off of its wide-scale development of shale gas production.

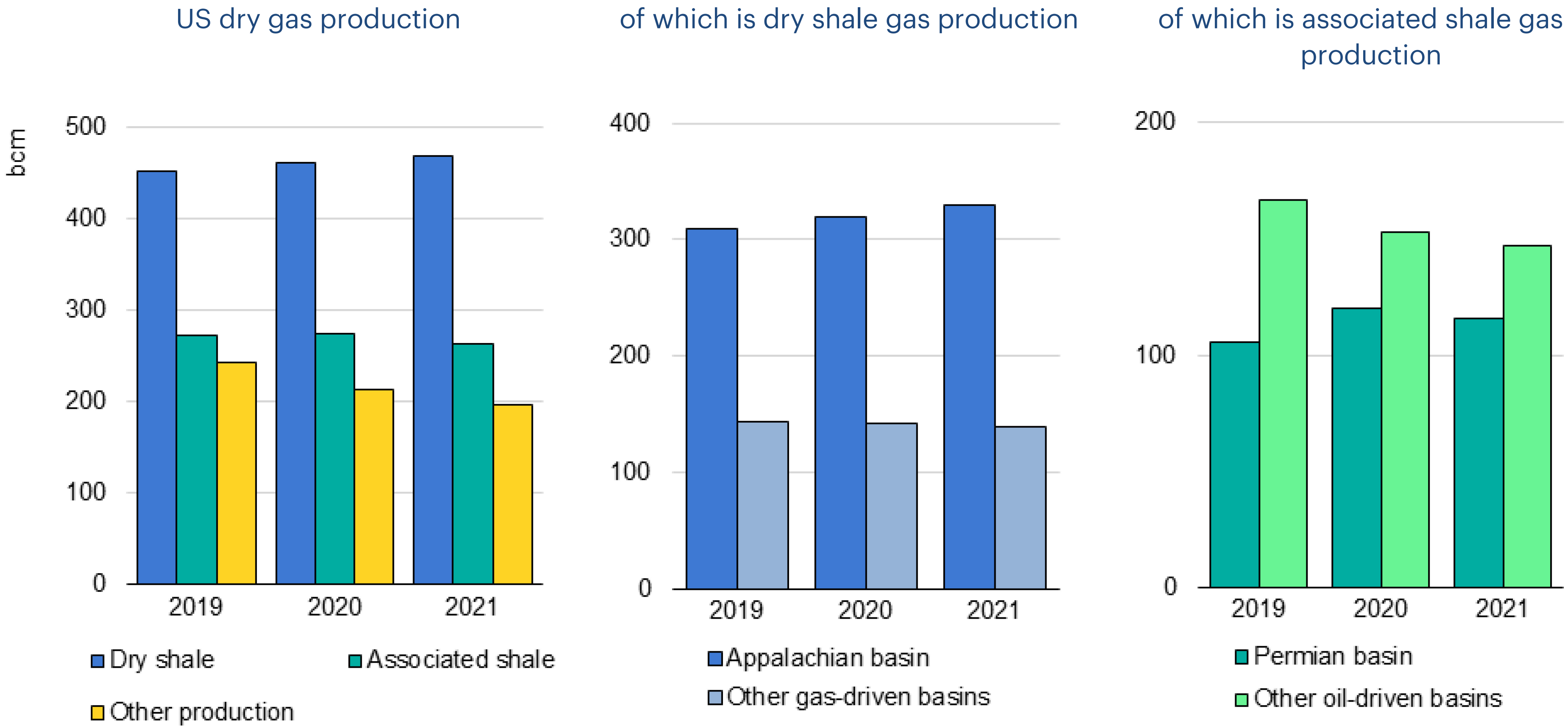
US gas production flattened in late 2020 despite record output from dry shale plays



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

Gas output in the United States fell 2.2% in 2020 and is projected to contract 2% y-o-y in 2021

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.*

Gas production in Eurasia: is there light at the end of the pipe?

Eurasia was the hardest hit gas-producing region in 2020, accounting for approximately 40% of the global reduction in natural gas output. Preliminary data suggests that the region's gas production decreased by over 6% (over 50 bcm) y-o-y in 2020. This reflects a drop in domestic consumption of 5% and extra-regional exports plummeting by close to 10% y-o-y, even with the start-up of new export corridors. Approximately three-quarters of this decline was during the first-half of 2020, reflecting an unseasonably mild winter in Q1 followed by the panademic-induced lockdowns through Q2, which depressed both domestic and export demand. The intra- and inter-annual flexibility mechanisms incorporated in pipeline gas supply agreements allowed buyers, both in Europe and China, to reduce pipeline imports from Eurasia, which fell 20% y-o-y in Q2. In this sense, **Eurasia played a crucial role in balancing the global gas market by absorbing the majority of the demand shock.**

Russia alone accounted for over 80% of the gross decline in the region's gas output. Gas production in Russia plummeted by close to 10% (38 bcm) in the first-half 2020.This steep drop in output moderated over the second-half of the year for an overall decrease of less than 3% y-o-y. Increased output reflected an uptick in domestic consumption with recovering economic activity as well as export demand.

Pipeline deliveries from Russia to Europe (net of virtual reverse flows via Ukraine) plummeted by one-fifth over Q1-Q3, before ramping up close to 2019 levels in Q4 2020. This moderated contraction in pipeline exports to 15% for 2020. The rebound in flows from Russia to Turkey was particularly notable, more than doubling in the September-November period compared with 2019. Pipeline deliveries to China via the Power of Siberia pipeline started in December 2019 and totalled 4.1 bcm in 2020, below the initially scheduled 5 bcm. LNG exports from Russia rose 3% y-o-y. LNG exports were lower through Q2 and Q3 (-1.7% y-o-y), but rose 5% y-o-y in Q4, with both Sakhalin-II and YAMAL LNG ramping up exports.

Unlike the gradual recovery in Russian gas exports, **pipeline flows from Central Asia to China were subdued** with a 15% decline y-o-y in the June-November period. Even though gas demand in China was recovering, the pipeline supplies faced stiff competition from LNG.

Gas production in **Azerbaijan** increased by over 6% y-o-y in the first eleven months of 2020. Its **gas exports to Turkey expanded by an impressive 25% over the first eight months of 2020,** as gas flows through the TANAP pipeline continued to ramp up. Azeri deliveries grew at a more moderate rate of 6% y-o-y in the September-October period, amid increasing competition from Russian gas.

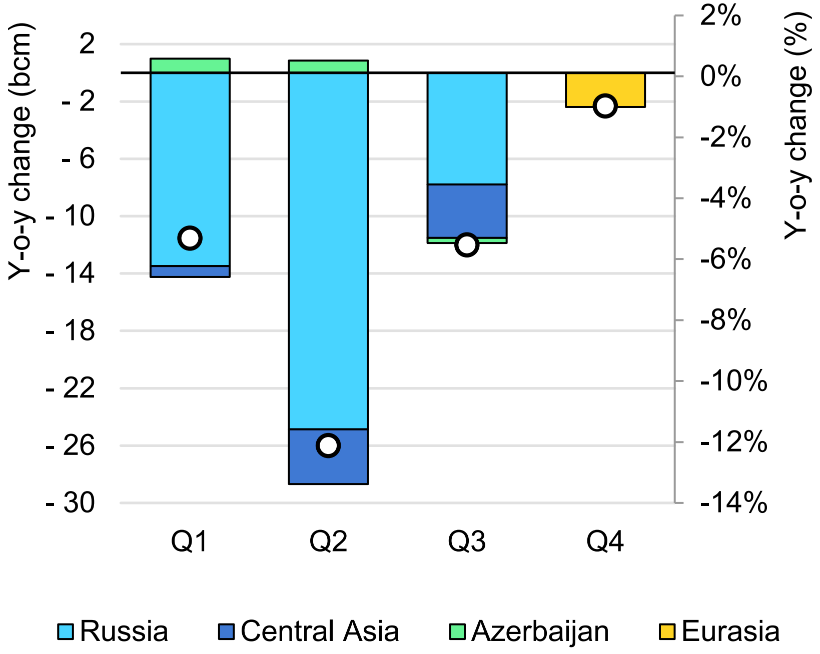
Prospects for 2021: rocky road to recovery

Gas production in the Eurasia region is projected to increase close to 6 % in 2021. Its overall gas output is expected to remain below 2019 levels reflecting slow growth in domestic demand and an outlook that economic activity does not return to pre-crisis levels before 2022.

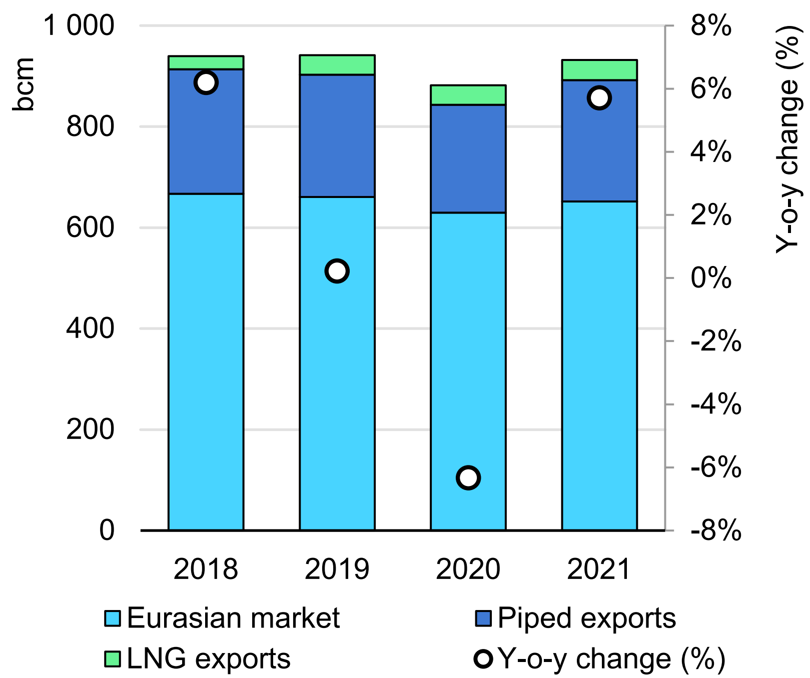
Exports from the region are expected to recover close to pre-crisis levels in 2021, partly boosted by the ramp up of flows via new export corridors. Russian gas supplies to China via the Power of Siberia pipeline are projected to increase to 10 bcm. Completion of the mid-section of the China-Russia East gas pipeline system in December 2020 will allow larger offtake and channel Russian gas deliveries to the Beijing-Tianjin-Hebei region. In Europe, the TAP pipeline started commercial operation in November 2020. Exports from the Shah Deniz II field in Azerbaijan to the European Union are expected to increase in a 4-6 bcm range in 2021. LNG exports from Russia are expected to increase by about 1 bcm, boosted by the start-up of Train 4 at Yamal LNG in Q1 2021. Exports via the traditional pipeline corridors from Russia to Europe and from Central Asia to China are expected to increase by close to 10%.

Gas production in Eurasia is not expected to return to pre-crisis levels in 2021, despite recovering export levels

Gas production in Eurasia, 2020 relative to 2019



Natural gas supply in Eurasia for domestic and export markets, 2018-2021



Sources: IEA analysis based on ENTSOG (2021), *Transparency Platform*; Eurostat (2021), *Imports of natural gas by partner country - monthly data*; China Customs Office (2021), General Administration of Customs of People's Republic of China (2021), *Customs Statistics*.

Gas supply in Europe: balance between pipelines and LNG

European gas imports fell close to 10% (more than 30 bcm) in 2020 – a drop larger than in 2009 in the aftermath of the financial crisis. Both LNG and pipeline imports were impacted, falling 3% and 13% respectively, although displaying very different dynamics over the year.

Europe played a crucial role in balancing the global gas market in the first five months of 2020. It absorbed two-thirds of incremental LNG supply amid weaker than expected demand in Asia. A strong LNG influx put downward pressure on pipeline supplies, which fell over 20% y-o-y in the first-half of 2020. **LNG imports to Europe tapered from June** responding to the collapse of the trans-Atlantic price spread and the gradual recovery of the regional price spread between Asian spot LNG and TTF. Consequently, LNG imports to Europe fell more than 20% y-o-y in the second-half of 2020.

Pipeline suppliers ramping up

LNG imports in Europe plummeted more than 30% y-o-y in Q4 2020. European LNG imports fell to 112 bcm, just 3% below their record levels in 2019 as the price spread with Asian spot LNG continued to widen to a six-year high average of USD 4/MBtu in December. Qatar maintained its top position while the United States overtook Russia as the second-largest LNG supplier to Europe.

Traditional gas suppliers via pipelines benefited from lower LNG imports through the second-half of 2020:

- Exports from **North Africa** increased 25% y-o-y, largely driven by higher flows from Algeria to Italy via the Transmed pipeline (up almost 80%).
- Net exports from **Russia** were down more than 15% y-o-y in Q3 (partly due to the rise of reverse flows in Ukraine), but recovered close to 2019 levels over Q4. This has been partly driven by the strong growth in deliveries to Turkey, which more than doubled compared to 2019 during the September-November period.

Pipeline deliveries from Norway remained resilient in 2020, falling a mere 0.1% for the year boosted by an increase of more than 8% y-o-y during the second-half of the year.

Indigenous production in the rest of Europe fell an estimated 14% in the first eleven months of 2020, primarily on rapidly declining production in the Netherlands (down 25% y-o-y).

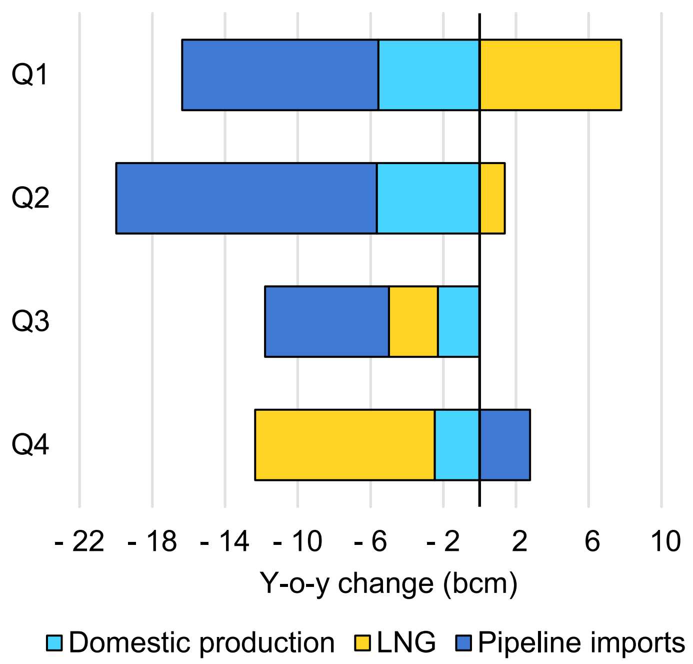
Expanding market for gas suppliers to Europe

Europe's import requirements are projected to increase 6% in 2021. This is driven by recovery in gas demand (2% y-o-y) and continuing decline in domestic gas production (other than Norway).

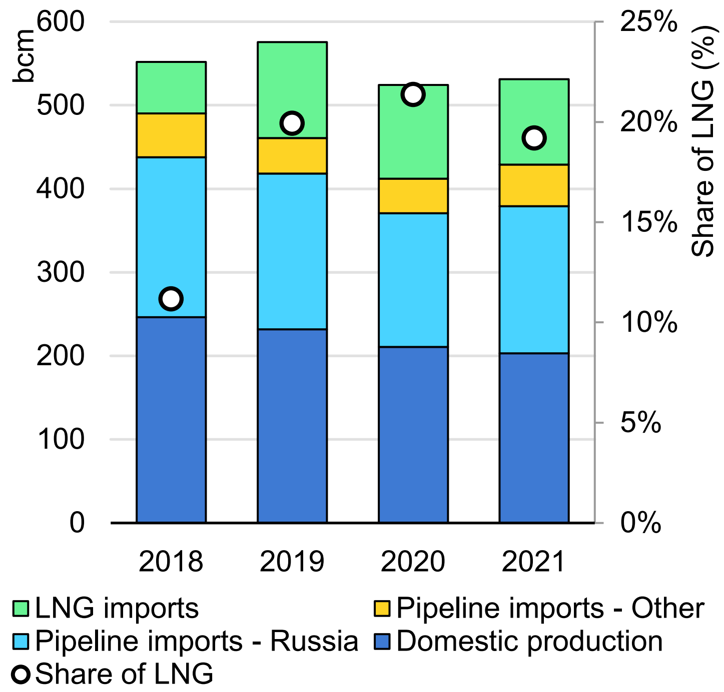
In 2021, this expanding gas market **will benefit both traditional pipeline suppliers** (recovering by close to 10%) **and sustain strong LNG imports,** just below their record-breaking levels of 2019 and accounting for over one-fifth of total gas supply. With the commercial start of the TAP pipeline in mid-November, first deliveries of Azerbaijani natural gas reached Greece and Bulgaria via the Nea Mesimvria interconnection point, and in Italy via the Melendugno interconnection point on 31 December 2020. Azerbaijani gas supplies to the European Union are set to gradually ramp up by an initial 4-6 bcm in 2021.The Krk LNG terminal in Croatia started commercial operations on 1 January 2021 with the arrival of the first LNG cargo from Cove Point in the United States.

Imports are set to rebound to pre-crisis levels in Europe

Gas supply by source in Europe, 2020 relative to 2019



Gas supply by source in Europe, 2018-2021



Sources: IEA analysis based on ENTSOG (2021), *Transparency Platform;* EPIAS (2021), *Transparency Platform*; Eurostat (2021), *Energy;* ICIS (2021), *ICIS LNG Edge.*

LNG trade expands in 2020-2021, albeit at a relatively slow pace

Global LNG trade (net of re-exports) **expanded 2% in 2020**. This is notable recognising that global gas consumption was down 2.5%, though very low relative to the 10% average annual growth rate in the previous three years.

The sharp slowdown in 2020 was due to a significant demand shock related to the pandemic, which prompted buyers to cancel or defer LNG shipments, especially during the summer months. After a strong Q1, when traded volumes increased by 11% y-o-y, LNG flows dropped 1% in Q2 and 3% in Q3 before recovering at 1% y-o-y rate in Q4. The end of 2020 and the beginning of 2021 brought a sharp increase in Asian LNG demand. LNG imports to northeast Asia increased by 10% y-o-y between mid-December and early January due to colder than average winter temperatures, further exacerbated by lower nuclear availability in Japan, limits on coal-fired generation in Korea, and reduced pipeline gas flows from Central Asia to China.

In 2021, global LNG trade is projected to increase by a modest 3%, as the recovery of pipeline gas flows will present headwinds to LNG demand.

LNG import growth in 2020 was led by China, up 12%, **and India**, up 15%. LNG imports into the rest of Asia were largely flat, with declines in Japan (-3%), Indonesia (-31%) and Pakistan (-5%) largely offset by continued growth in Thailand (+18%), Bangladesh (+19%), Chinese Taipei (+8%) and other Asian importers. Europe acted as the market of last resort and recorded a sharp 16% y-o-y increase of LNG inflows in the first-half of 2020. But its market balancing role was reversed and imports dropped 22% y-o-y in the second-half, resulting in a 3% drop for the year as whole. LNG imports in the rest of the world were down 8% in 2020, mainly driven by a sharp decline in Mexico due to increased pipline gas imports from the United States.

In 2021, growing LNG imports will be driven by the Asia Pacific region, which will increase LNG inflows by 6%. European LNG imports are also expected to remain high, though likely below the levels seen in 2019 and 2020.

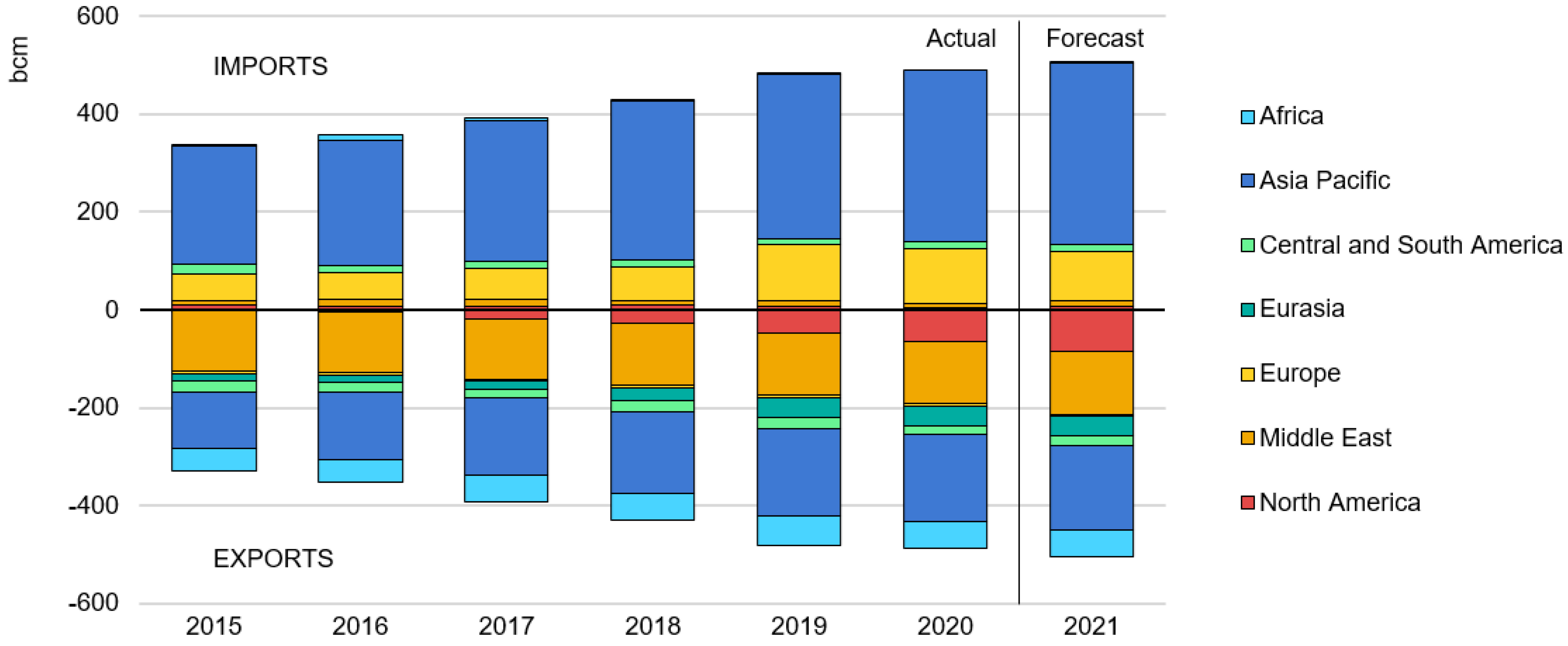
North America led global LNG export growth in 2020 with a 35% y-o-y (17 bcm) increase in export volumes. The negative impact of widespread cargo cancellations and capacity shut-ins at US terminals during Q2 and Q3, which was further compounded by extensive outages in the second-half of 2020, was more than offset by a 40% expansion of US liquefaction capacity over the year.

Qatar, Russia and Australia increased their LNG exports in 2020. However, legacy exporters – especially those with a high spot market exposure or contracts allowing for same-year cargo deferrals – saw their export volumes drop. The biggest declines occurred in Trinidad and Tobago, Egypt, Algeria, Malaysia and Indonesia. A fire at Hammerfest LNG, Norway's only liquefaction plant, in late September brought the country's entire LNG production to a halt for the rest of the year.

In 2021, North America will continue to lead the expansion of global LNG exports with a projected 33% increase in output. The rest of the world will see an overall decrease in LNG exports. Continuing declines in the Asia Pacific region, largely driven by Malaysia, will be only partially offset by smaller increases in Africa, and Central and South America.

Asia Pacific leads LNG import growth and North America leads LNG export growth in 2020-2021

LNG imports and exports by region, 2015-2021



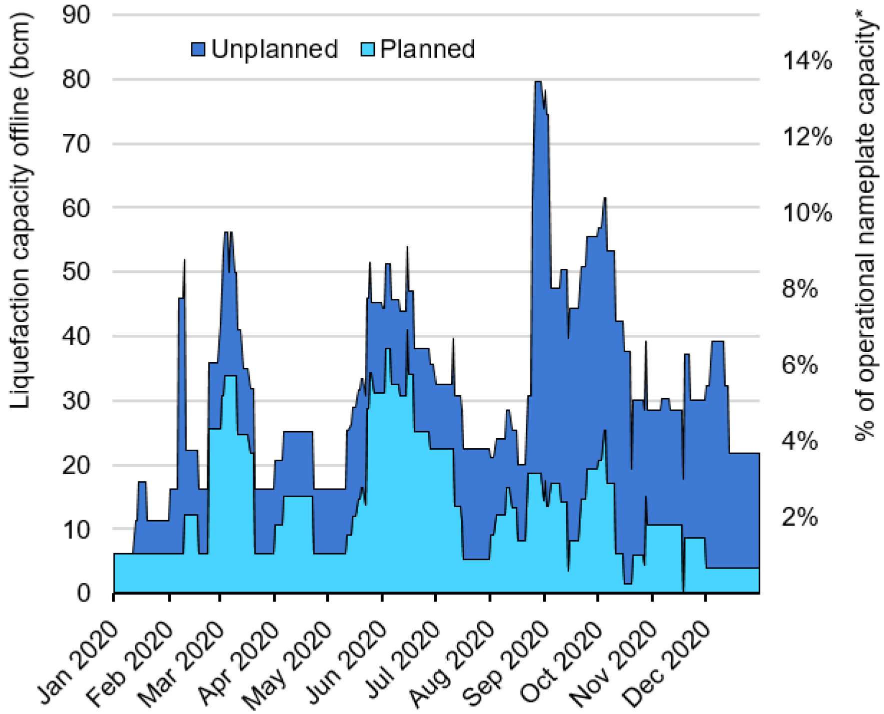
Source: IEA analysis based on ICIS (2021), [ICIS LNG Edge.](#)

Global LNG market was beset by widespread liquefaction capacity outages in 2020

Liquefaction capacity outages were elevated for much of 2020. This contributed significantly to the tightening of the global LNG market in the second-half of the year. For a brief period in Q3 as much as 13% of global LNG export capacity was taken offline for planned or unplanned maintenance, equivalent to more than the entire export capacity of the United States at the beginning of 2020. Outages between February and August were due partly to normal seasonal inspections during the shoulder season and partly to the rise in LNG cargo cancellations and deferrals amid a historic LNG market oversupply, which prompted some facilities to carry out extended maintenance on their shut-in liquefaction trains. The sharp increase in offline capacity between late August and November was mainly driven by a series of unforeseen events which impacted plant operations in Australia, Norway, Qatar and the United States.

In the United States, Hurricane Laura in late August briefly knocked the Sabine Pass facility offline and resulted in a sustained outage at the Cameron LNG facility. Six weeks later, Hurricane Delta again forced the Cameron plant offline, this time only briefly. In late October, Freeport LNG's Train 1 sustained a compressor fire and was down for repairs for three weeks. In Australia, regular maintenance at Gorgon LNG's Train 2 in May revealed cracks at the plant's heat exchangers, which prompted the operator to extend maintenance on Train 2 through November and to schedule staged repairs at the plant's other two trains that will last well into 2021. Australia's Prelude floating LNG facility was offline between February 2020 and January 2021 due to electrical and safety-related issues. The Wheatstone LNG facility encountered supply availability issues in December when the offshore platform feeding the terminal was temporarily shut down due to safety concerns. In Norway, the Hammerfest LNG plant suffered fire damage in late September and will remain out of service until Q4 2021. In Qatar, Train 4 at the Ras Laffan plant shut for unplanned maintenance due to a compressor issue in November that lasted for nearly a month.

Planned and unplanned liquefaction capacity outages in 2020



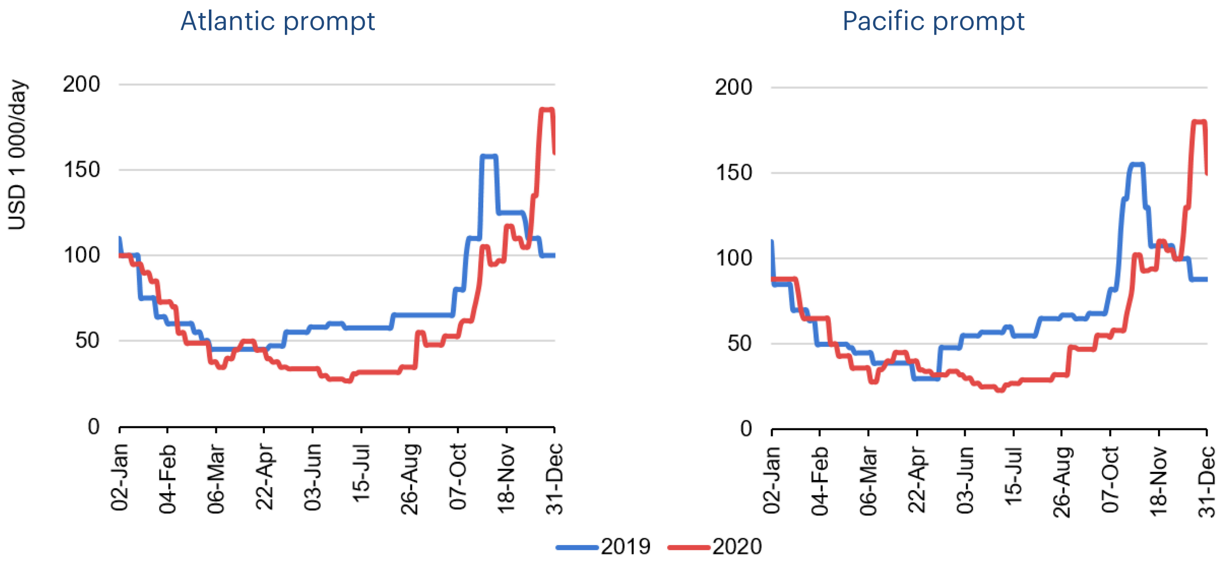
* Based on operational nameplate capacity as of December 2020.

Sources: IEA analysis based on Rystad Energy (2021), Gas Market Analytics; ICIS (2021), ICIS LNG Edge.

Charter rates in 2020: a long voyage to recovery

LNG charter rates continued to display a strong seasonal pattern in 2020 in both the Atlantic and Pacific Basins. Spot market rates for tri-fuel diesel electric LNG carriers declined fourfold from their highs in January to an average of USD 30 000/day between May and August, about one-third below their five-year average. This has been partly driven by higher LNG shipments to Europe amid subdued demand in Asia, which in turn shortened shipping distances and hence tonne-mile demand (tonnage of cargo multiplied by shipping distance). The collapse of inter-regional price spreads and the consequent cargo cancellations in the United States and other major exporters, provided further downward pressure to charter rates.The gradual recovery in LNG imports in the Asia Pacific region through the second-half of 2020 and a strong rebound in US LNG exports from October increased tonne-mile demand to above 2019 Q4 levels. In addition, congestion issues at the Panama Canal in late 2020 increased shipments from the United States to Asia around the Cape of Good Hope, leading to longer shipping distances and providing further support to spot charter rates. By the beginning of January 2021, spot charter rates climbed to historical highs at more than USD 230 000/day. Worthy of note is that in contrast with previous peaks in 2018 and 2019, the current winter peak was not driven by the build-up of floating storage, rather by the increase in tonne-mile demand.

Spot charter rates, 2019 and 2020



Notes: Prompt = chartering of up to 90 days, with delivery taken within 40 days of the transaction date. Spot charter rates are for tri-fuel diesel electric LNG carriers. Source: IEA analysis based on ICIS (2021), *ICIS LNG Edge.*

Spot gas prices are expected to recover to above 2019 levels…

Regional gas benchmark prices dropped to historic lows in the first-half of 2020, gained strongly in Q3 and exceeded 2019 levels in Q4. **Increased demand in 2021 is projected to underpin spot gas prices**, with forward curves indicating price recovery to above 2019 levels in all major gas consuming regions.

In the **United States**, Henry Hub traded 5% above 2019 levels in Q4 2020, as declining gas production and higher LNG exports (+40% y-o-y) provided upward pressure to prices despite declining domestic demand. Forward curves (as of end-2020) suggest that this price trend will continue through 2021, with **Henry Hub prices increasing by 33% y-o-y** to an annual average of USD 2.7/MBtu – its highest level since 2018.

LNG spot prices in **Asia** rose more than ten-fold from a historic low of USD 2/MBtu in late May 2020 to above USD 30/MBtu by mid-January 2021. Reportedly some cargoes were awarded at close to USD 40/MBtu, breaking the record price levels experienced in the aftermath of the Fukushima nuclear accident in 2011.This unprecedented price increase was driven by a combination of supply and demand factors.Colder than average temperatures, ongoing coal-to-gas switching in China, low nuclear availability in Japan and limits on coal-fired power generation in Korea boosted LNG import demand in northeast Asia more than 10% between mid-December 2020 and mid-January 2021. This increased demand coincided with a number of outages at regional liquefaction plants, such as Australia. This in turn increased the call on more distant suppliers, primarily from the United States which in conjunction with congestion at the Panama Canal led to longer LNG voyages and higher charter rates. Record-breaking charter rates provided additional upward pressure on spot prices. Forward curves suggest that prices above USD 10/MBtu are not expected to last beyond the current heating season. **LNG spot prices in Asia are expected to rise almost twofold y-o-y in 2021** to an average of USD 8.3 MBtu, well above 2019 levels.

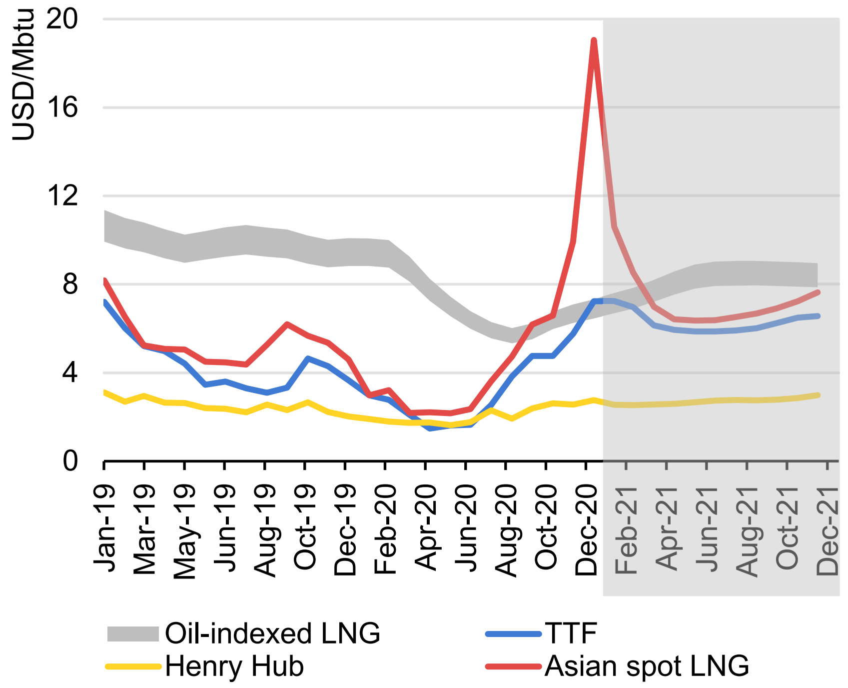
In **Europe**, TTF traded 25% above 2019 levels in Q4 2020.TTF's price gains have been partly driven by higher domestic consumption (+3% y-o-y) and to a large extent by the steep fall in LNG imports, down 30% y-o-y in Q4. LNG flows have been increasingly diverted to Asia, with the price spread between Asian spot LNG and TTF widening to an average of USD 2.4 MBtu, almost triple the spread in Q4 2019. Reduced LNG inflow to Europe combined with colder temperatures pushed TTF prices to USD 10/MBtu by mid-January 2021, their highest level since September 2018. The forward curve for 2021 suggests a continued recovery in **TTF prices rising by twofold y-o-y** to an annual average of USD 6.4/MBtu, 40% above their 2019 levels.This will be partly driven by domestic demand, projected to rise 2% y-o-y amid a return to average heating requirements through the winter season and a gradual recovery of industrial and commercial activity. Moreover, the strong gains on TTF reflect the price recovery projected in other gas importing regions, particularly in Asia.

Forward curves indicate that the **spot price spread will widen between Henry Hub with sharp recovery in Asian and European spot prices** estimated at above USD 6 /MBtu and USD 3.7/MBtu respectively in 2021, more than double the trans-Atlantic spread in 2020. The widening regional price spreads with Henry Hub mitigate risks of cargo cancellations as seen in mid-2020 and support a 33% increase in US LNG exports in 2021.The price spread between Asian spot LNG and TTF is expected to widen compared to 2019 levels, averaging close to USD 2/MBtu in 2021.

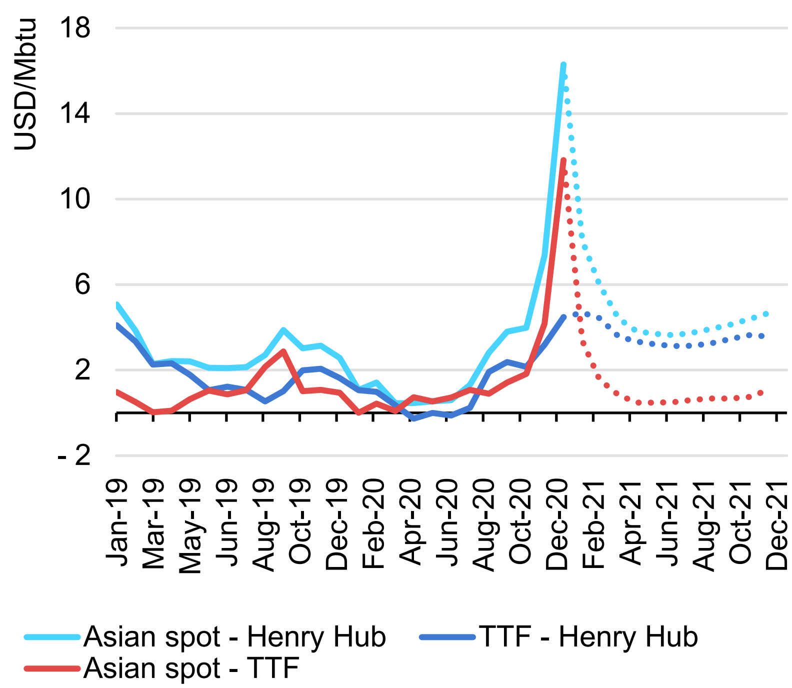
In contrast with the sharp recovery in spot benchmarks, **oil-indexed LNG prices fell an estimated 30% y-o-y in Q4 2020** and averaged 10-20% below spot prices during Q4 for the first time since 2018. Forward curves suggest that oil-indexed prices will average 25% below 2020 levels and retain their competitiveness *vis-à-vis* spot LNG in Q1 2021. **Oil-indexed LNG prices are projected to gradually recover in 2021** as oil prices rise and filter through the gas contract price formulae with a typical lag of five to six months. Oil-indexed LNG prices are expected to average close to 2019 levels in a USD 7- 8/MBtu range.

…and price spreads with Henry Hub widen to drive global LNG trade

Main spot and forward LNG prices, 2019-2021



Inter-regional price spreads, 2019-2021

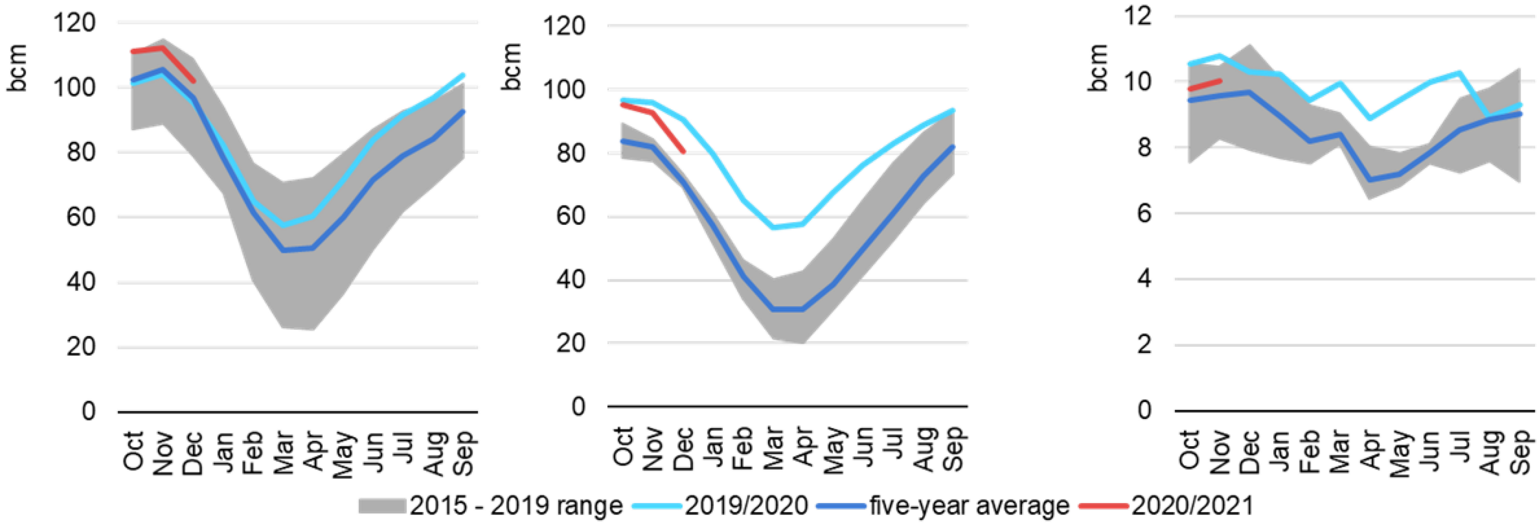


Sources: IEA analysis based on CME (2021), *Henry Hub natural gas futures quotes*; *Dutch TTF Natural Gas Month Futures Settlements; LNG Japan/Korea Marker (Platts) Futures Settlements*; EIA (2021), *Henry Hub Natural Gas Spot Price*; ICIS (2021), *ICIS LNG Edge*; Powernext (2021), *Spot market data*.

Storage: strong draws in Europe and Asia, weak withdrawals in the United States

Underground storage inventories in Europe and the United States were 11% and 5% above their respective five-year averages at the beginning of the heating season[1], despite lower injection rates during the summer season. In **Europe**, the sharp recovery in spot prices tightened the price spreads between the day-ahead and forward winter contracts through October and December from an average of USD 1.2/MBtu in 2019 to below USD 0.2/MBtu in 2020. This incentivised **higher withdrawals through Q4**, which increased more than twofold (13 bcm) compared with 2019. Consequently, European storage inventories plunged 16% below 2019 levels by the end of 2020. In the **United States**, storage withdrawals through November and December remained close to 2019 levels. 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. This was largely compensated in December, when withdrawal rates surged to well above 2019 levels amid a tighter supply-demand balance. At the beginning of 2021, US storage inventories were 5% above their five-year average, their highest level since 2016. In **Japan and Korea**, LNG storage stocks fell 7% below 2019 levels by the end of November 2020, reflecting recovering demand and rising LNG spot prices in the Asia Pacific region.

US underground storage inventor European underground storage inventory Japan and Korea LNG storage inventory



Sources: IEA analysis based on EIA (2021), *Weekly working gas in underground storage;* GIE (2021), *AGSI+ database;* IEA (2021), *Monthly Gas Data Service.*

[1] Beginning of October in Europe and beginning of November in the United States.

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	160	157	166	244	243	242	247
Asia Pacific	824	853	856	898	627	655	661	671
of which China	*283*	*307*	*322*	*349*	*160*	*174*	*189*	*199*
Central and South America	153	152	138	144	185	177	147	158
Eurasia	666	657	626	653	932	941	882	932
of which Russia	*493*	*482*	*455*	*478*	*726*	*738*	*692*	*723*
Europe	536	537	521	532	246	227	211	204
Middle East	544	547	542	568	666	679	681	704
North America	1061	1102	1070	1061	1062	1146	1135	1122
of which United States	*854*	*894*	*871*	*852*	*868*	*956*	*947*	*928*
World	**3940**	**4008**	**3910**	**4021**	**3963**	**4068**	**3959**	**4041**

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

CME	Chicago Mercantile Exchange (United States)
CNG	compressed natural gas
CNOOC	China National Offshore Oil Corporation
CQPGX	Chongqing Petroleum and Gas Exchange (China)
EIA	Energy Information Administration (United States)
ENTSO	EEuropean 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)
FID	final investment decision
GIE	Gas Infrastructure Europe
HH	Henry Hub
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)
PPAC	Petroleum Planning & Analysis Cell (India)
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
y-o-y	year-on-year

Units of measure

bcf	billion cubic feet
bcm	billion cubic metres
mb/d	million barrels per day
TWh	terawatt hour

Acknowledgements, contributors and credits

This publication has been prepared by the Gas, Coal and Power Markets Division (GCP) of the International Energy Agency (IEA). The analysis was led and co-ordinated by Jean-Baptiste Dubreuil, Senior Natural Gas Analyst. Tetsuro Hattori, Songho Jeon, Akos Losz, Gergely Molnár and Jean-Baptiste Dubreuil are the main authors. Keisuke Sadamori, Director of the IEA Energy Markets and Security (EMS) Directorate, and Peter Fraser, Head of GCP, provided expert guidance and advice.

Timely and comprehensive data from the Energy Data Centre were fundamental to the report. Special thanks go to Mathilde Daugy, Louis Chambeau and Amani Al-Saidi for their support.

The IEA Communication and Digital Office (CDO) provided production and launch support. Particular thanks to Jad Mouawad and his team: Astrid Dumond, Isabelle Nonain-Semelin, Merve Erdem, Jethro Mullen, Rob Stone and Therese Walsh. Debra Justus edited the report.

The report was made possible by assistance from SK E&S and Tokyo Gas.

The individuals and organisations that contributed to this report are not responsible for any opinion or judgement it contains. Any error or omission is the sole responsibility of the IEA.

For questions and comments, please contact GCP (gcp@iea.org).

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 8 association countries and beyond.

Please note that this publication is subject to specific restrictions that limit its use and distribution. The terms and conditions are available online at www.iea.org/t&c/

This publication and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

International Energy Agency
Website: www.iea.org

IEA member countries:
Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

IEA association countries:
Brazil
China
India
Indonesia
Morocco
Singapore
South Africa
Thailand

IEA Publications

International Energy Agency

Website: www.iea.org

Contact information: www.iea.org/about/contact

Typeset in France by IEA – January 2021

Cover design: IEA - copyright shutterstock