Gas Market Report Q4-2021

including *Global Gas Security Review 2021*

INTERNATIONAL ENERGY AGENCY

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Abstract

Winter 2021/22 opens with record high seasonal gas prices, as the combination of a strong recovery in demand, extreme weather events and unplanned supply outages have led to tighter markets. Such tensions are a reminder that security of supply remains a major topic for gas markets, only a year after a record drop in demand and oversupplied markets.

The succession of market events over the past year further illustrates the critical role flexibility plays in ensuring security and continuity of supply. Flexible liquefied natural gas trade – alongside other major components of the gas flexibility toolbox such as interconnectors and storage capacity – has been and remains instrumental to adjusting to sharp and unexpected demand swings (both up and down). Delivering flexible and yet secure supply is likely to become more complex for systems in transition as they switch to low-carbon gas to reach net zero emission objectives. Regulators should therefore adopt a prudent and scalable approach to market design to ensure security of supply in a transitioning gas system.

This new quarterly report includes a review of gas security in light of recent supply-related developments, and an analysis of short-term gas market evolution to 2022.

Table of contents

Global Gas Security Review 2021

Main findings

This sixth issue of the *Global Gas Security Review* shows that security of supply remains a central topic for gas markets, as the combination of recovering economic activity, lower liquefied natural gas (LNG) availability and a succession of severe weather events has put the global gas system under strong pressure and sent market prices to new highs. The prospect of further recovery has prompted the gradual return of contracting activity and investment decisions in 2021 that would ensure sufficient medium-term supply, while the need for a transition to low-carbon gases opens new challenges for longer-term security of supply.

Gas prices rallied as market fundamentals tightened on strong demand and unexpected supply bottlenecks

Gas year 2021/22 opened on October 1st with record-high spot gas prices in Europe and Asia and lower-than-average storage inventory levels for the coming heating season. The tightening of gas markets over the past months results from a combination of robust demand growth as economies recover from 2020 lockdowns, a succession of extreme weather episodes that have generated additional gas consumption, and tighter-than-expected supply as a series of outages hampered gas production and export capacity.

High natural gas prices have also ripple effects on electricity markets, pushing prices up and driving fuel substitution in favour of coal and oil, thus also impacting higher levels of emissions of CO2 and local pollution.

The IEA is closely monitoring global gas market developments and issued a statement in late September as part of its constant dialogue with stakeholders on security of energy supply.

Cold winter and dry summer put immense pressure on the gas supply system

Last January's cold weather in Northeast Asia – coupled with reduced LNG availability – led to localised fuel shortages and an unprecedented spike in spot LNG prices. This was followed in February by winter storm Uri that hit North America, with extremely cold temperatures leading to higher heat and electricity needs and well freeze-offs hampering production, resulting in rolling power cuts in several US states and Mexico. Over the following months, several hydro-rich power markets, including Brazil, California and Turkey, faced severe droughts that led to higher reliance on gas-fired power generation and further tightened the summer gas market.

This succession of events highlights the interdependence between natural gas and electricity security of supply – a link that appears to be stronger than ever. The IEA's new Electricity Security Event Scale rating, published in its latest Electricity Market Report, shows that recent weather events triggered power outages in a number of markets where availability of gas supply was also an issue. The Texas power crisis of February was assigned the highest ranking on the scale – the largest US gas-producing state and where the fuel plays a dominant role in power generation.

LNG trade has continued to be a strong source of flexibility against the backdrop of demand volatility, although capacity outages were high during 2020 and have remained so in 2021, contributing to market tension and price fluctuations.

Underground gas storage capacity played a central role in providing trans-regional flexibility during the January cold snap, meeting Europe's additional needs while enabling arbitrage of LNG cargoes to Asia. This episode also emphasised the lack of storage capacity in major Asian markets and their resulting dependence on imported flexibility; additional measures to enhance storage development and management have been announced in Japan, Korea and China since then.

LNG contracting is recovering slowly

While flexible LNG trade was a key contributor to adjusting to the sharp demand decline and recovery in 2020, LNG contracting activity has tended to show a higher share of fixed-destination, long-term deals than in previous years. This can be partially attributed to lower activity from portfolio players, as well as to a motivation to limit risk in an exceptionally volatile price environment.

LNG contracting activity shrank by almost 30% year-on-year (y-o-y) in 2020 (or 45% compared to its 2018 peak), while activity during 2021 to date shows some potential for recovery. Final investment decisions (FIDs) were also down from their 2019 record high, with one North American project sanctioned in 2020, plus Qatar's major expansion plan confirmed in early 2021. These new investments, added to the wave of FIDs taken before 2020, should therefore prove sufficient to satisfy additional LNG demand in the coming years.

The transition to low-carbon gases results in new security of supply challenges

Reaching a net zero emissions objective by 2050 implies the extensive deployment of low-carbon gases in order to decarbonise the current gas system. This deployment must be supported by policies enacted in the short to medium term to prepare for such a massive transition for gas systems and industry. In this regard, policy makers should take into consideration new security of supply challenges that are likely to emerge in this transition.

Future gas systems will be more complex and decentralised, and will entail bidirectional networks. Keeping harmonised quality standards is likely to become more difficult due to the diversity of low-carbon gas supply sources and the current absence of hydrogen blending threshold harmonisation for the transition period. The potential to deliver flexibility could be constrained by the operational specifications of low-carbon gas production. Regulators should therefore adopt a prudent and scalable market design approach to ensure security of supply in a transitioning gas system.

Review of recent gas security-related events

January 2021: Cold spell in Northeast Asia

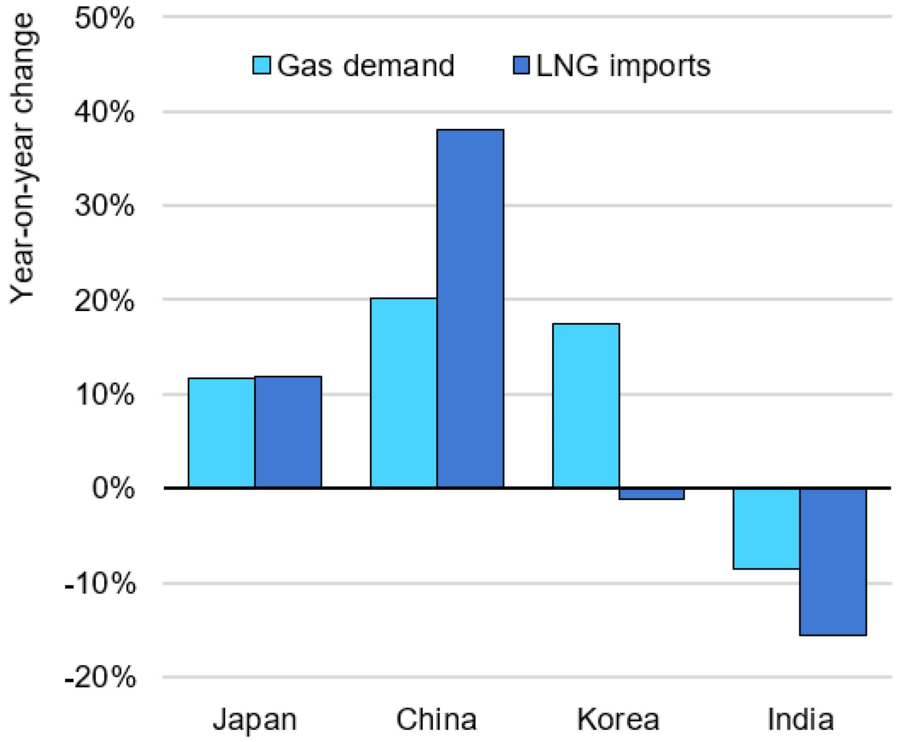
The winter crisis in Northeast Asia led to record high LNG prices and repercussions across Asia

In January 2021 cold winter weather in Northeast Asia – coupled with reduced availability of LNG supply and logistical constraints on LNG shipping – led to localised fuel shortages and an unprecedented spike in Asian spot LNG prices.

Japan, China and Korea were equally exposed to cold temperatures and tightening LNG market fundamentals, but local market characteristics led to different outcomes in the world's three biggest LNG importing countries. Japan experienced sharp electricity price spikes and a few buyers paid record high prices for emergency LNG supplies, but power cuts were avoided in the end. China faced localised gas shortages and saw the highest trucked LNG prices since the 2017/18 winter gas shortages in some parts of the country. Meanwhile, Korea weathered the January episode without disruption thanks to the country's ample gas-fired generating capacity and LNG stocks during the cold spell.

The Northeast Asian winter freeze also had repercussions beyond the immediate region, affecting importers across South and Southeast Asia as well. Price-sensitive buyers in India, Pakistan and Bangladesh were forced to cut their LNG imports as spot prices reached record levels. Meanwhile, some importers in Southeast Asia dispatched reloaded cargoes for the first time, thus providing an unexpected source of emergency supply for Northeast Asia amid the crisis.

Change in natural gas consumption and LNG imports in selected Asian countries, January 2021



Sources: IEA analysis based on ICIS (2021), ICIS LNG Edge; JODI (2021), Gas World Database; CQPGX (2021), Nanbin Observation; Korea Energy Economics Institute (2021), Monthly Energy Statistics; PPAC (2021), Gas Consumption.

Japan: Local electricity market tightness and global LNG bottlenecks push prices to record levels

Japan was the epicentre of the January gas supply crunch, as colder than average temperatures boosted electricity and heating demand at a time when LNG stocks were low and the availability of surplus generation capacity was limited.

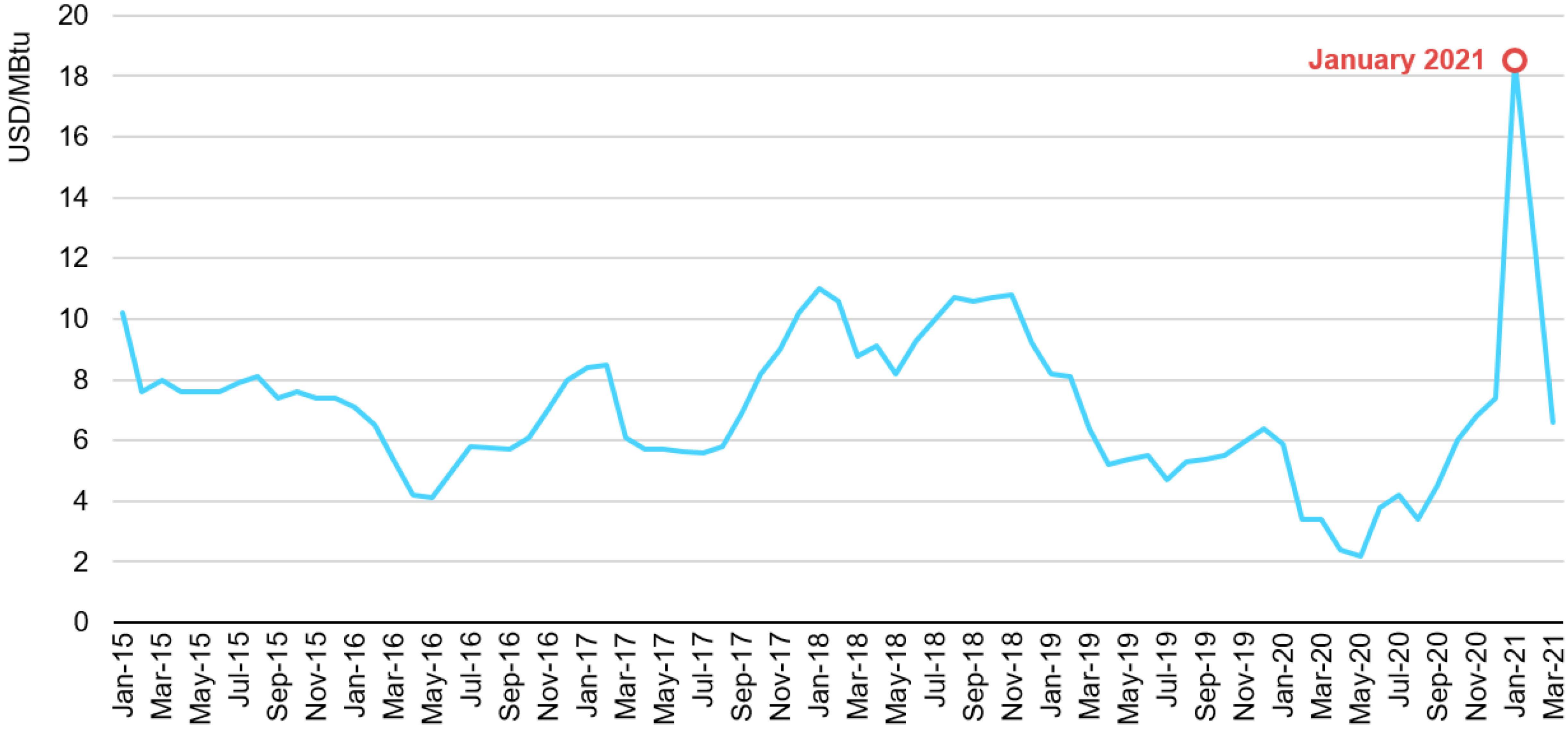
In early January, temperatures in northern and western Japan were 2-4°C lower than the seasonal average, and electricity demand accordingly jumped by 14% y-o-y in the first half of the month. Hydropower output fell (with load factors reported in the mid-20s compared to 40% year-round utilisation in 2019) and nuclear generation was down by nearly 50% y-o-y in January. Only three of the nine restarted reactors (Genkai 3, Sendai 1 and Sendai 2) operated throughout the cold spell and another (Ohi 4) restarted in mid-January. Unexpected outages at a number of coal-fired power plants reduced thermal capacity at the height of the crisis. The Ministry of Economy, Trade and Industry (METI) also highlighted the closure of 10 GW of oil-fired backup capacity in the 2014-2019 period as a contributing factor to the tight power market conditions. Wholesale electricity prices jumped to record high levels (exceeding JPY 200/kWh) in mid-January and prompted calls to conserve electricity. Power cuts were avoided, but reserve margins eroded in some regions to as low as 3% during the depths of the crisis.

Power utilities entered the heating season with lower than average LNG inventories and scrambled to procure additional cargoes from the spot LNG market. LNG imports jumped by 12% y-o-y and 12% month-on-month (m-o-m) in January, but a combination of unplanned outages in Australia, longer shipping distances from marginal producers in the United States and congestion on the Panama Canal prevented even more cargoes from reaching Japan in a timely manner. A small number of distressed buyers in the worst-affected regions of Japan paid record high prices for individual LNG cargoes, which contributed to the surge in Asian spot LNG price benchmarks to all-time high levels in January. The average spot LNG import price in Japan reported by METI also reached a record level in January (USD 18.5/MBtu).

In the aftermath of the unprecedented electricity and gas price spikes, METI launched a two-month investigation into the circumstances leading up to the domestic energy market tightness in January. Based on the preliminary findings, the ministry is planning to implement a number of short-term measures to shore up supply security. These include new LNG procurement guidelines and regular monitoring of LNG stocks held by power utilities, which were not systematically tracked or disclosed prior to the January crisis.

Japanese buyers pay record high prices for spot LNG in January 2021

Average import price of spot LNG in Japan, 2015-2021



Source: METI (2021), Spot LNG Price Statistics.

China: Record high LNG imports alleviate gas supply shortages amid the cold spell

In China, 2021 started with multi-decade temperature lows in the northern part of the country and Beijing recorded the coldest temperatures since 1966 during the second week of January. The boost to heating demand amid the cold blast added to already strong industrial and power demand due to the ongoing economic recovery. These together pushed January's gas demand growth rate to more than 20% y-o-y, its highest reading since 2018.

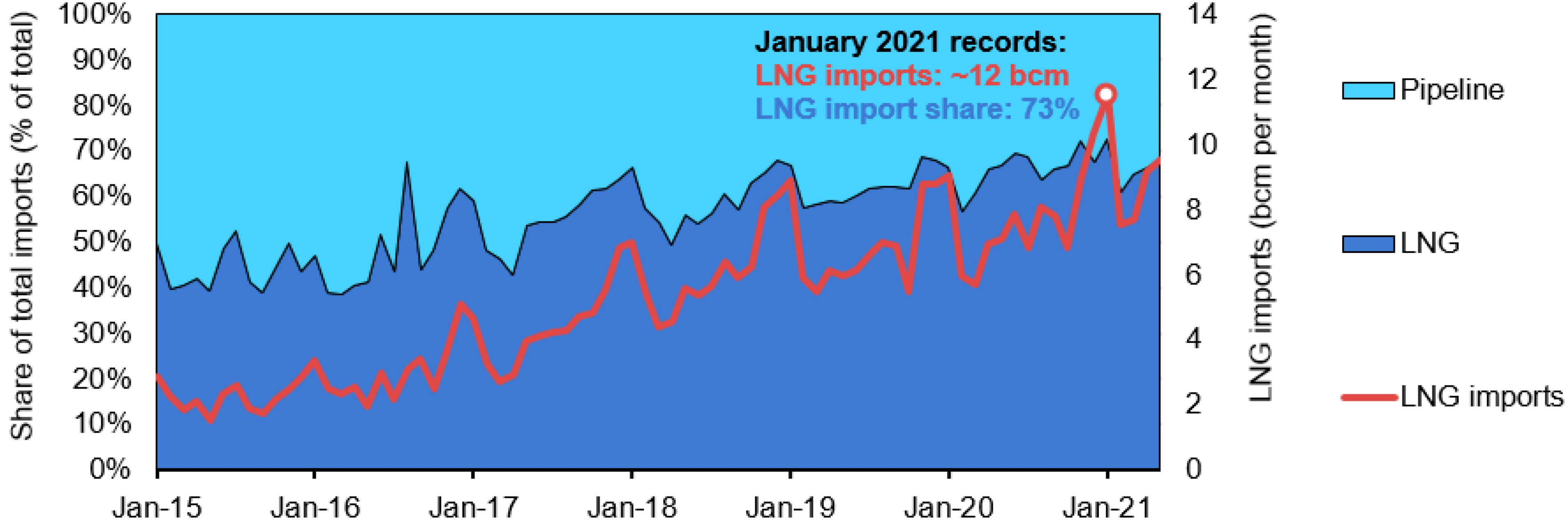
Domestic gas production remained strong, with output during January and February combined growing by 11% on the same months in 2020 according to the National Bureau of Statistics. But this was only sufficient to cover a fraction of the surge in demand. Pipeline gas deliveries were down by 5% y-o-y (and 12% m-o-m) in January, driven by a 12% y-o-y (7% m-o-m) decline in Central Asian shipments due to a combination of peak winter demand in the exporting countries and technical issues limiting outflows from the region. Therefore, it was largely left to LNG to fill the supply gap during the January cold spell; LNG imports jumped by a remarkable 38% y-o-y and reached the highest monthly level on record (at close to 12 bcm). The share of LNG in China's natural gas import mix also reached an all-time high of 73% in January.

However, even this dramatic rise in LNG inflows was not enough to avoid localised fuel shortages and gas supply curtailments, which mainly affected non-prioritised sectors, including industrial users with interruptible contracts. The gas supply situation was exacerbated by icy conditions on major roads and waterways, which hindered truck-based LNG deliveries and port operations in parts of northern China. City gas distributors also reportedly underestimated gas demand and did not contract enough additional volumes with upstream producers ahead of the winter, relying instead on spot market procurement and truck-based LNG, which was difficult and expensive to come by. The price of LNG delivered by truck at times exceeded CNY 10 000/tonne (USD 28/MBtu) in the most-affected regions, a price level not seen since the 2017/18 winter gas shortage.

The gas shortfall this winter once again underlined the relative lack of seasonal storage in China. The working gas capacity of China's underground gas storage facilities was estimated at between 14 bcm and 16 bcm at the end of 2020, which is less than 5% of total consumption and well below the level of other mature gas markets with a similar seasonal profile to China's. Recognising the importance of the issue, the State Council issued a statement at the height of the January cold spell promising to accelerate the development of natural gas storage facilities.

Chinese LNG imports broke new monthly records in January 2021

Share of LNG in total gas imports and LNG import volume in China, 2015-2021



Sources: IEA analysis based on China Customs (2021), Statistics; National Bureau of Statistics (2021), Monthly Data.

Korea: no disruption during the January 2021 winter energy crisis

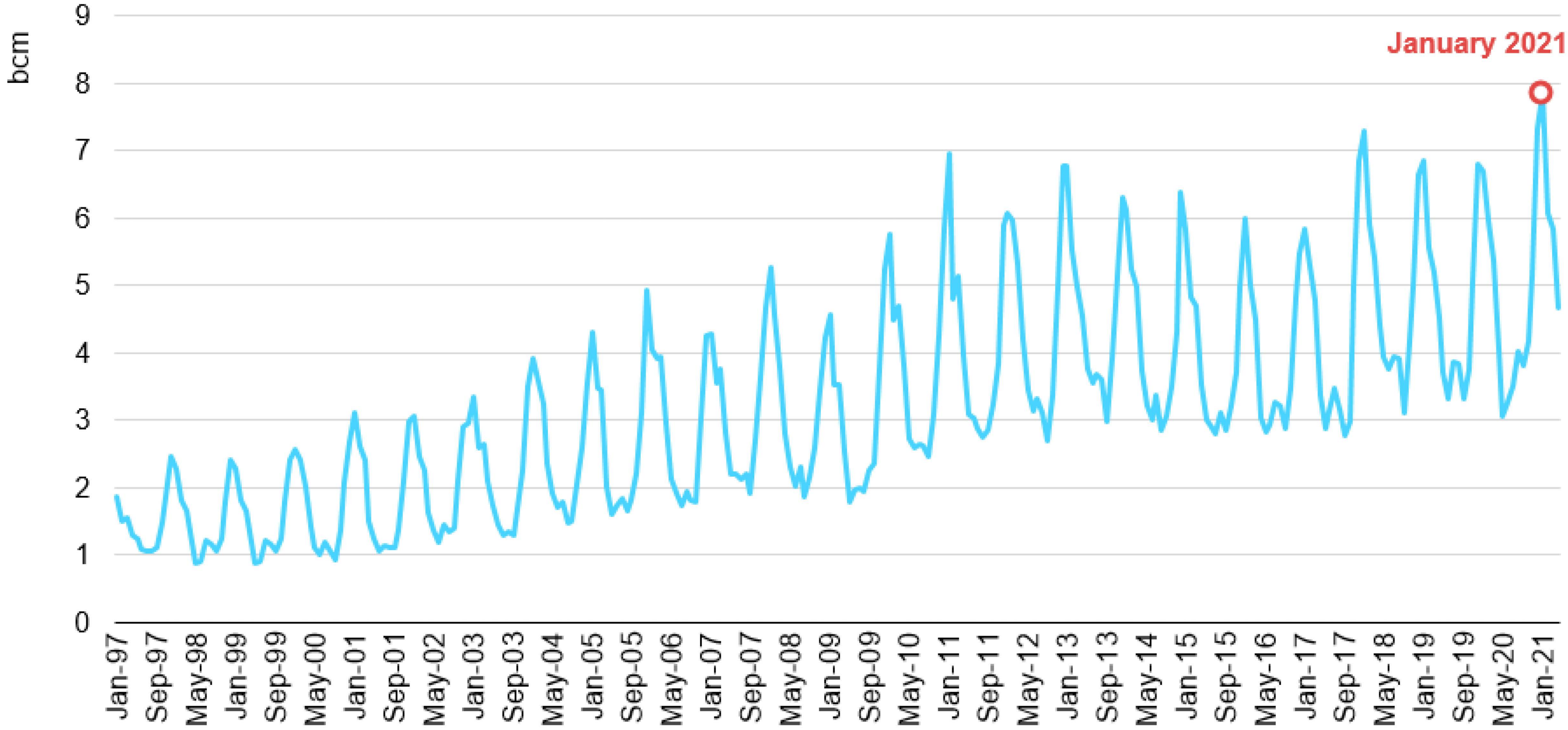
Korea weathered the January cold spell without noticeable disruption to its natural gas supplies. Average temperatures in January 2021 fell by 2°C from the previous month and 4°C from the previous year, which boosted heating degree days by 11% m-o-m and 25% y-o-y. The resulting rise in heating and heating-related electricity demand had to be largely met with natural gas as nuclear generation was limited by regular maintenance at five of the country's 24 reactors during the cold snap, and coal-fired electricity generation was constrained by the government-mandated shutdown of several coal-fired plants between December and February to reduce air pollution.

Gas demand jumped by 17.5% y-o-y in January to the highest monthly level on record, a 7% m-o-m increase from an already strong December. The January increase was driven by power generation (up by 13% y-o-y), district heating (up 17%) and the city gas segment (up 23%), which includes residential and commercial users as well as small industries in Korea. Increased gas demand in January was largely met with the drawdown of LNG stocks, which dropped by half (or 2 bcm) from the previous month to the lowest level in three years. LNG imports recorded a much smaller monthly increase in January (estimated at 0.2-0.6 bcm by various sources), followed by a sharper 1 bcm m-o-m rise in February, likely from delayed deliveries dispatched during the cold spell in January. LNG imports in January and February combined were up by 8% y-o-y. As the January demand spike had already subsided, record high LNG imports in February were largely used to replenish stocks. Wholesale electricity rates remained stable within the normal historical range despite the record high spot LNG prices in January. This is partly thanks to Korea's ample generating capacity (with reserve margins staying close to 10% even during the January peak) and partly due to the country's gas and power market structure. KOGAS, the leading LNG importer, uses a pricing formula with limited pass-through of sudden price spikes to local utilities, while wholesale electricity markets are dominated by a single buyer, KEPCO.

Korea has introduced several emergency response measures in recent years to enhance gas supply security during crises. These include LNG stockholding obligations for KOGAS, demand restraint measures, fuel switching contracts and mandatory procurement of alternative fuels for cogeneration plants. In the aftermath of the January crisis, the Korean Ministry of Trade, Industry and Energy (MOTIE) decided to further increase mandatory LNG stocks from seven to nine days of total demand, and exclude heel volumes from the calculation of LNG stocks (which is equivalent to an additional 5% increase in emergency reserves). The higher storage requirement, which is intended to ensure gas supply security during unexpected cold spells and heatwaves, will be phased in from October 2021.

Cold snap in January 2021 pushed monthly gas demand to all-time high levels in Korea

Monthly natural gas consumption in Korea, 1997-2021



Source: Korea Energy Economics Institute (2021), Monthly Energy Statistics.

Emerging Asia: Priced out of spot LNG trade during the winter price spikes

The supply crunch in Northeast Asia had broader repercussions across LNG importing countries in South and Southeast Asia.

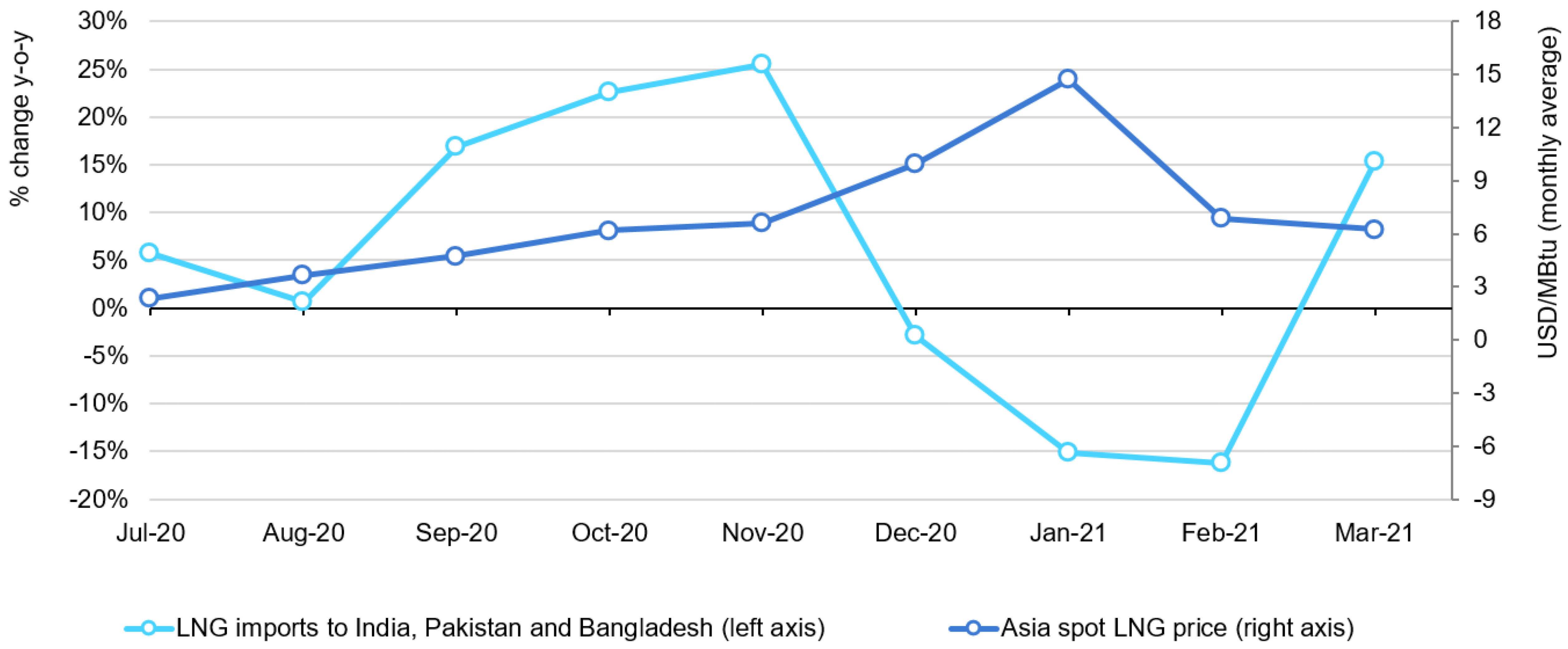
Record high spot LNG prices dented demand in price-sensitive markets across the region. India, Pakistan and Bangladesh all recorded sharp year-on-year declines in LNG imports in January (which were down by 15%, 5% and 32%, respectively). Buyers in each of these countries left several spot LNG tenders unawarded due to astronomical bid prices during the winter price spikes. In turn, this contributed to gas shortages – and a mix of demand destruction and fuel switching away from gas – in both Pakistan and Bangladesh. Price-sensitive natural gas users in India (especially in the refining and petrochemical sectors) reportedly switched from imported LNG to liquid fuels, and monthly gas burn in the power sector was down by 10% in January 2021 from the average of the previous six months while coal-fired generation rebounded sharply in early 2021.

Meanwhile, Southeast Asia – where winter is a low season due to a lack of heating demand – emerged as an unexpected source of emergency supply for Northeast Asia. In January 2021 both Indonesia and Thailand completed their first-ever LNG re-exports. The Arun terminal in Indonesia, which was converted from an export terminal to a regasification plant in 2014, sent its first reloaded cargo to China, while the Map Ta Phut facility in Thailand re-exported its first cargo to the Tokyo Bay area of Japan. Developing LNG reloading infrastructure in Thailand has been part of the government's broader ambition to turn the country into an international LNG trading hub. Singapore, an established reloading hub in the region, also re-exported record volumes of LNG between December and March; all reload cargoes from Singapore during this period were delivered to China.

Enhanced reloading capabilities in Southeast Asia are a welcome development that enables importers with no winter peak demand to take advantage of high spot LNG prices during the season, while also helping to ease localised fuel shortages at times of unexpected cold spells in the northern parts of Asia.

Price sensitivity in emerging Asia on display during the January 2021 price spikes

LNG imports to India, Pakistan and Bangladesh and spot LNG prices in Asia, July 2020-June 2021



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

February 2021: Winter storm in North America

The deep freeze in Texas revealed the many interdependencies between gas and power systems…

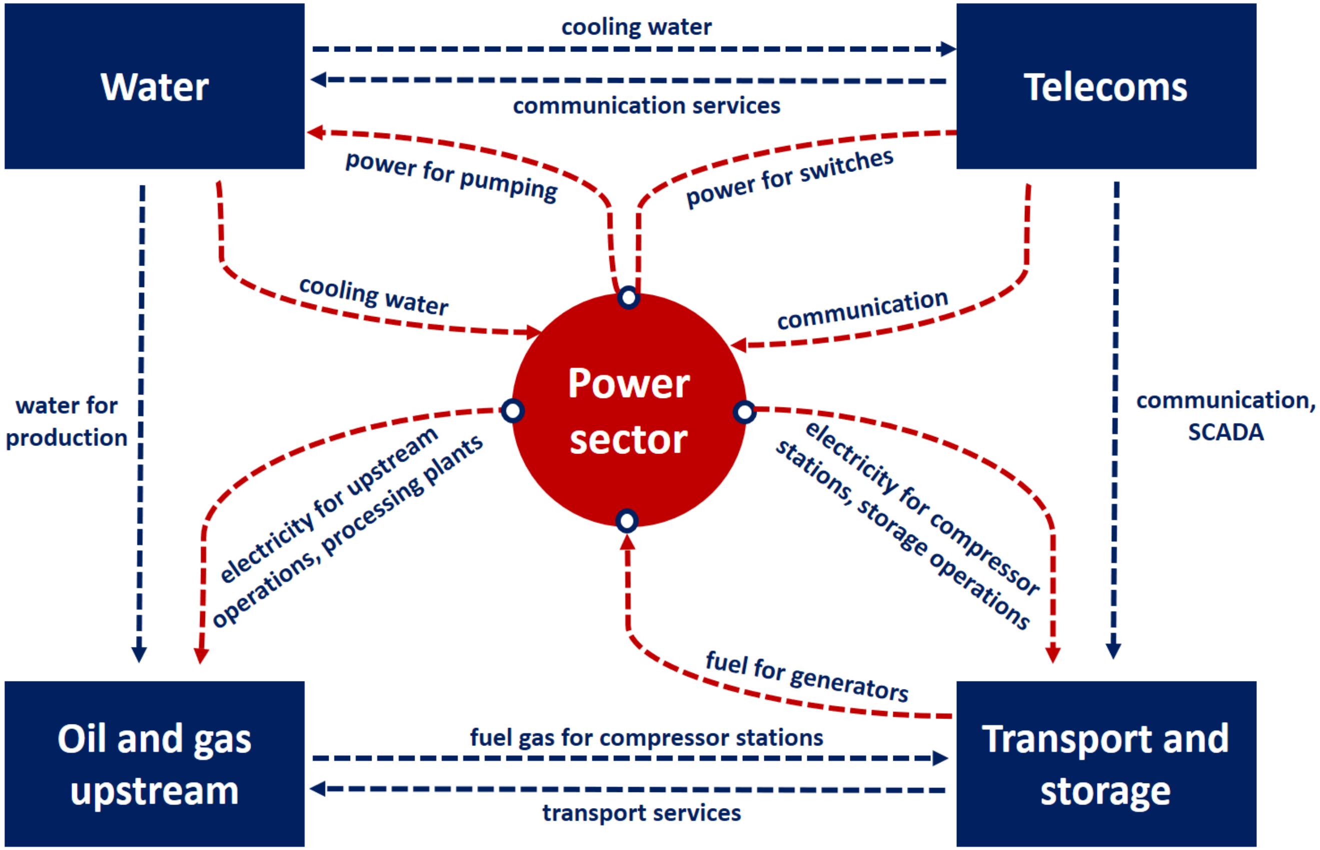
The United States was hit by one of the most severe winter storms in its history between 13 and 17 February 2021. As described by the National Weather Service, Storm Uri was caused by an upper-level polar vortex dropping from the North Pole and lingering over southern central Canada, which allowed cold arctic air to gradually spill southward into Texas (and further down to northern Mexico). Based on historical data from the National Oceanic and Atmospheric Administration, heating degree days during the gas storage week ending 18 February reached 280 – their highest level since December 1983.[1]

Storm Uri had devastating impacts on the South Central region of the United States. In Texas over 100 fatalities have been linked to the storm, while initial damage estimates are in the range of USD 80-130 billion in direct and indirect economic losses. The storm caused **severe disruption to energy supplies**: the exceptionally cold weather drove up electricity and natural gas demand at a time when freezing temperatures hampered supply from the gas system and power plants. As the system operator, the Electric Reliability Council of Texas (ERCOT) introduced rotating power cuts between 15 and 19 February.

Over 4.5 million customers (~11 million people, or 40% of all customers) in Texas were without power and nearly 12 million Texans faced water restrictions at the height of the crisis. **The insatiable demand drove up electricity and natural gas prices to historical highs**. Electricity spot prices hit their market cap of USD 9 000/MWh. Natural gas prices at local Texan hubs rose to triple digits, while the OGT hub in neighbouring Oklahoma soared to a record of USD 1 250/MBtu at the height of the crisis. **The February crisis in Texas highlighted the multiple interdependencies that exist between the power and gas supply systems.** The steep drop in natural gas production due to wellhead freeze-offs resulted in fuel supply limitations to power plants, while the start of rotating power cuts on 15 February exacerbated gas supply issues as some critical natural gas infrastructure faced power cuts as well. **The rotating power cuts in Texas**, the US state with the most abundant energy resources, are **a stark reminder that security of energy supply cannot be taken for granted**. It must remain a top priority for policy makers and requires a holistic approach, taking into account the multitude of interdependencies existing across the energy system.

[1] As per the reporting of the US Energy Information Administration (EIA), a gas storage week ends on Friday.

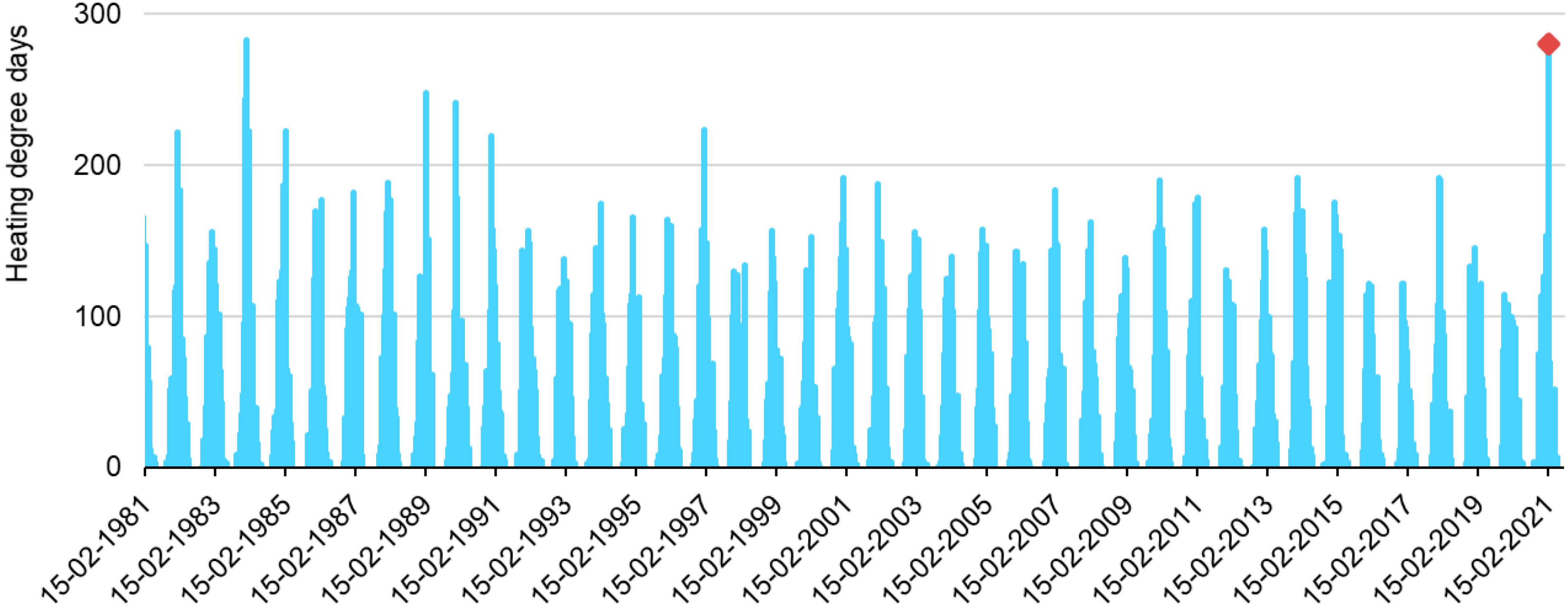
… and the need for a holistic approach to energy security taking into account the central role of the power system



Note: SCADA = supervisory control and data acquisition; this is a system that transmits via telecommunication networks the information and data necessary for the operation of oil and gas pipelines.

Storm Uri brought a cold spell to Texas not seen in decades…

Heating degree days in Texas by gas storage week (January 1981-July 2021)



Source: IEA analysis based on National Oceanic and Atmospheric Administration (2021), Heating Degree Days.

…driving up electricity and natural gas demand on higher space heating requirements

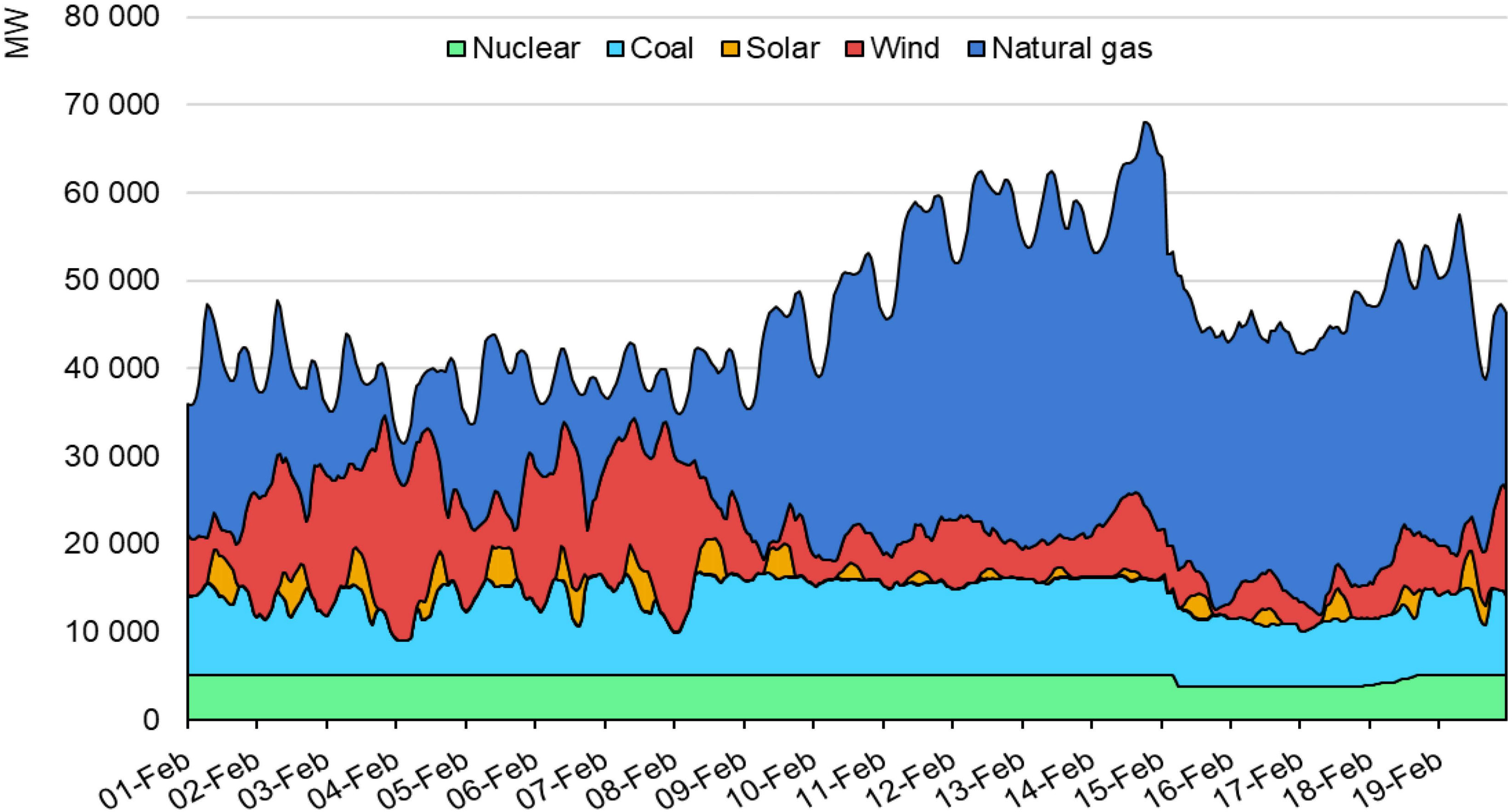
The cold spell brought by Storm Uri resulted in a sharp increase in electricity and natural gas demand in Texas, almost entirely driven by higher space heating requirements. The temperature sensitivity of gas and power demand is high in Texas, especially at very cold temperatures due to the widespread use of electricity for space heating. Notably, there is a **strong interplay between electric space heating and gas-fired power generation in Texas:** over 60% of homes use electricity as their primary heating source and over half of electricity is generated from natural gas.

Natural gas demand more than doubled between 8 and 15 February in Texas. Residential and commercial consumers contributed to approximately one-third of the demand surge, while the power sector accounted for almost half. According to the Railroad Commission of Texas, natural gas supply was largely uninterrupted to Texan residents, with over 99% of customers connected to natural gas receiving service during the storm. **Driven by higher space heating requirements, electricity demand surged by 55% between 8 and 14 February.** Gas-fired power plants accounted for 95% of the gross generation increase, with their output almost tripling during this period to account for 57% of total generation. Gas-based generation was also compensating for lower wind output, which was down by 30% as a result of blade icing and low wind speeds. **During the same period, natural gas production in Texas started to rapidly decline**, primarily as a result of wellhead freeze-offs. As highlighted by the University of Texas at Austin, unit-specific data indicate that certain thermal power plants started to derate capacity as early as 10 February due to insufficient fuel supply (in most cases natural gas). While demand continued to increase, **some of the large generators began to go offline on 13-14 February**, due to a combination of frozen components at power generation sites and/or fuel supply issues.

Considering the deteriorating frequency of the grid, **ERCOT** called a Stage 3 emergency **on 15 February** at 01:20 CST and **began rolling power cuts,** which affected over 4.5 million customers. Electricity spot prices hit their market cap of USD 9 000/MWh. The cumulative generation capacity forced out during the event totalled 46.25 GW. The availability of coal-fired capacity fell by up to 6 GW and nuclear capacity by around 1 GW, while wind averaged at 3 GW, about half its seasonal average. However, gas-fired power generation was the most affected, with 27 GW of capacity unavailable. According to ERCOT, the cumulative **gas generation derated exclusively due to fuel supply issues amounted to 9.3 GW.** Rotating **power cuts lasted until 19 February**, when improving weather and gas supply conditions allowed normal operating conditions to resume.

Surge in electricity demand combined with weather-related power generation outages led to rotating power cuts in Texas

Generation by fuel type in ERCOT territory, 01-20 February 2021



Source: IEA analysis based on US EIA (2021), Hourly Grid Monitor.

The natural gas system faced several outages along the supply chain…

Natural gas production in Texas fell by 46% (or 300 mcm/d) between 8 and 17 February – the equivalent of over 50 GW of gas-fired power generation. **Half of the production drop occurred before the start of the rotating power cuts** and was mainly due to wellhead freeze-offs, reported across key production regions.

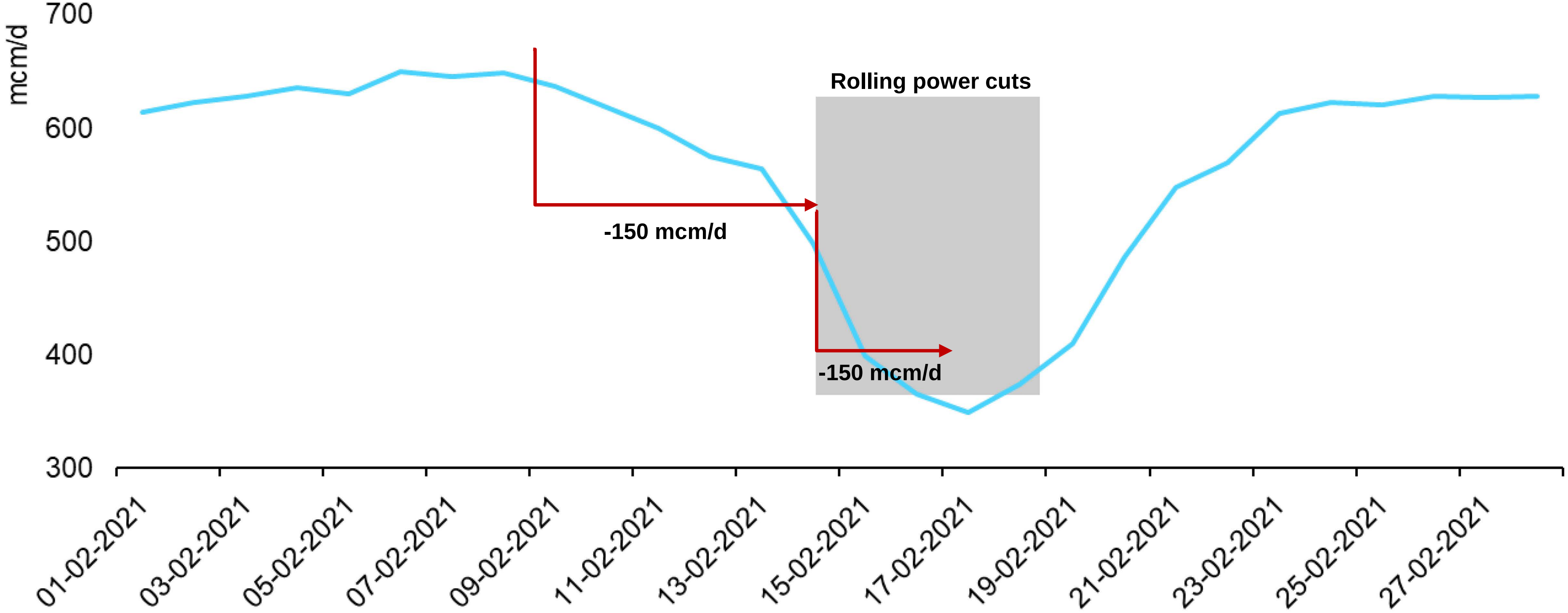
Freeze-offs typically occur when water produced alongside raw natural gas crystallises due to low temperatures and blocks off the producing well and/or the natural gas gathering lines. Given the rare occurrence of cold spells and freezing temperatures in Texas, **operators rarely winterise wellheads, gathering lines and processing facilities** and as such are more prone to suffer from freeze-offs during extremely cold weather. In addition, in recent years Texan production has increasingly been driven by shale plays with a higher liquids-to-gas ratio. **Wet gas has a naturally higher risk of freeze-offs than dry gas production**, especially if it is not winterised fully. This was well **demonstrated in the Permian Basin**, where gas output plummeted by over 40% between 8 and 14 February and accounted for over 95% of the total production drop in Texas.

The estimated cost of winterisation can vary considerably according to the type of facility, the degree of cold weather protection that is required, gas flow rates and pressures, and other factors. In 2011 the Gas Technology Institute estimated the equipment cost of **full-scale winterisation** (including chemical injection pumps, flow line insulation, methanol tank and small hut to protect equipment) at over USD 34 000 per well, with operating costs close to USD 7 000 for the winter season. **Basic winterisation**, including simple installation of a methanol injection system for use during cold spells, is estimated at USD 3 000 per well. Considering that Texas has over 100 000 wells, the overall investment required would be in the range of USD 0.3-3.4 billion if all the wells were winterised.

In the second half of the crisis, the power cuts – which were partly caused by the disruption of gas supply to power plants – exacerbated the steep drop in dry gas output at natural gas production facilities, which fell by 150 mcm/d between 15 and 17 February. In addition, power cuts to processing facilities and compressor stations further reduced the deliverability of the overall gas system. When **ERCOT deployed its emergency response programme** on 15 February, cutting power to customers enrolled on the programme, **several critical gas facilities were reportedly affected**. Including gas supply infrastructure on the list of critical load customers would help to ensure that those facilities retain power during rolling power cuts.

…with half of the decline in Texan gas production occurring before the start of the power cuts

Natural gas production in Texas, 01-28 February 2021



Sources: IEA analysis based on Bloomberg.

Upstream underperformance and power cuts put additional stress on the gas system

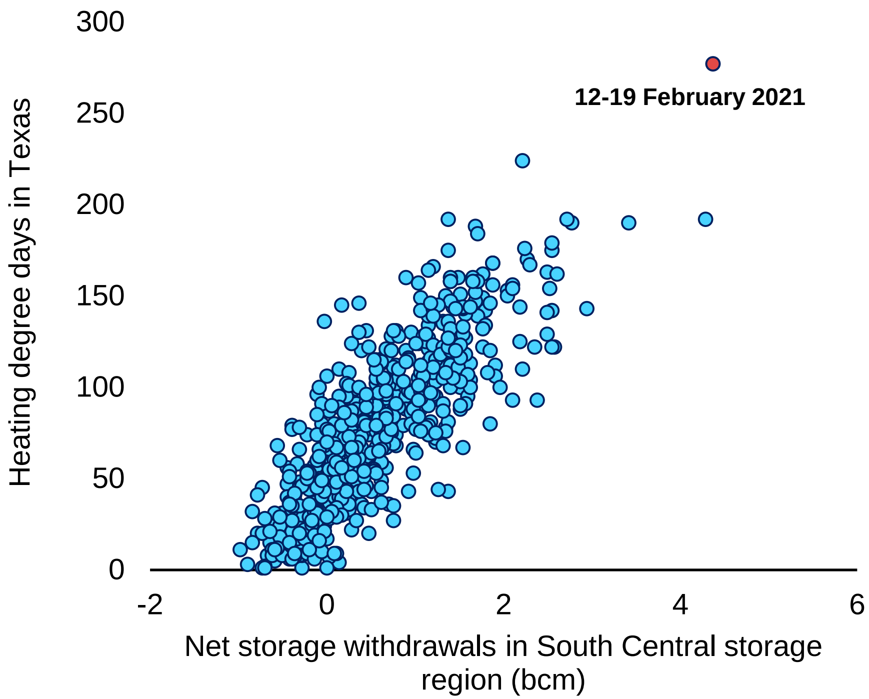
Upstream underperformance together with power cuts had a direct impact on midstream infrastructure. Lower supplies resulted in a thinner linepack, which reduced the short-term balancing capabilities of pipeline operators. Over 30 gas pipelines declared force majeure and/or issued operational flow orders, effectively limiting incremental gas supplies to customers. The short gas system propelled **gas prices** to historical highs on regional hubs: Katy and Waha in Texas rose to triple digits, while OGT in Oklahoma soared to USD 1 250/MBtu. Spot prices on the more liquid Henry Hub rose to USD 23.86/MBtu, the highest real price level since 2003.

Natural gas storage played a critical role in meeting gas demand during the crisis. Storage withdrawals in the South Central region (of which Texas is part) hit over 4.3 bcm between 12 and 19 February, their highest level on record since at least 1994. Withdrawals from Texan storage sites surged by an estimated 75% between 8 and 15 February. Nevertheless, certain **storage sites experienced such rapid drawdown** that their volumes of working gas and pressure levels were significantly reduced, leading to curtailed operations at some, while others experienced power cuts (e.g. Tres Palacios). Flow data from Platts suggest that storage withdrawal rates declined in the second half of the crisis, by over 50% between 15 and 17 February. Adding further storage working capacity, especially in the form of fast-cycling salt caverns, can significantly improve the midstream deliverability of gas systems. It is notable that **the storage-to-consumption ratio in Texas has deteriorated over the past decade:** while the state's gas consumption increased by over one-third, working gas storage capacity rose by less than 10%.

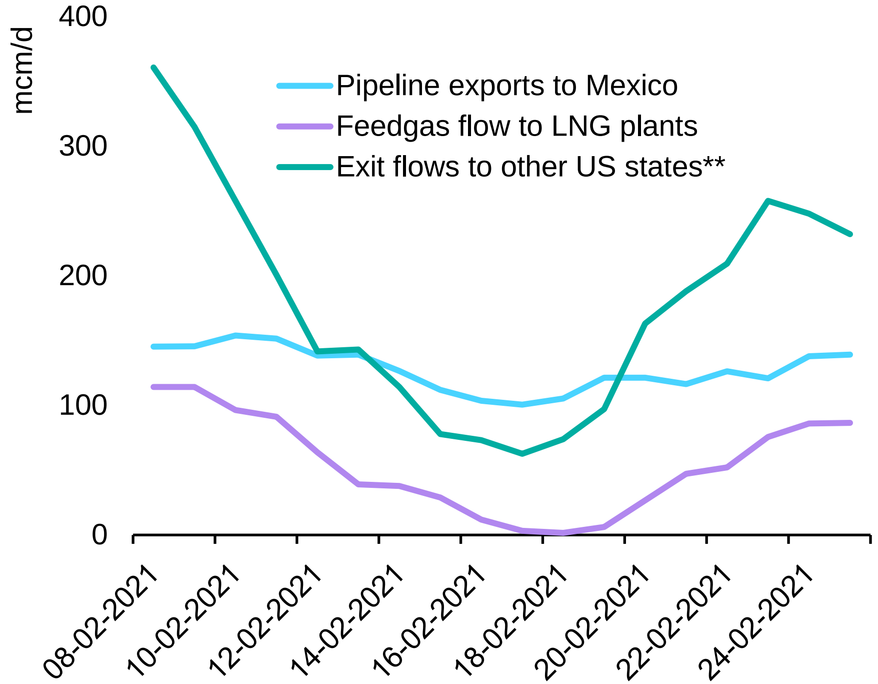
Export flows from Texas plummeted during the crisis**,** as high spot prices constrained spot volumes. In addition, following a mandate from the state governor, the Railroad Commission of Texas issued a notice to operators to prioritise gas sales to state power generators and limit flows out of Texas until 21 February. The steep reduction in exports to **Mexico** contributed to widespread outages there, affecting over 4 million customers in the northern part of the country. Feedgas flows to **Texan LNG export** facilities had dropped to close to zero by 18 February from over 110 mcm/d before the crisis. **Exit flows** to other US states also fell, mainly through the MidCon pipeline system and via the Southwest and Southeast pipeline corridors. State **imports** remained limited, with ~30 mcm/d flowing from south Louisiana through the crisis. **The gas system remained short until 18/19 February.** Improving weather conditions, optimisation of gas flows and resuming power supplies allowed a rebalancing of the gas system, which in turn allowed the power system to return to normal operating conditions.

Storage withdrawals and optimisation of gas flows could not avoid a short gas system

South Central* weekly storage withdrawals vs Texas heating degree days (1994-2021)



Natural gas exit flows from Texas (08-25 February)



* Data on storage withdrawals from before 2010 are based on the US EIA “producing region”, which includes New Mexico. Data since 2010 exclude New Mexico from the definition of the South Central region.

** Exit flows to other US states include flows via the MidCon pipeline system and via the Southwest and Southeast pipeline corridors.

Sources: IEA analysis based on Energy Information Administration (2021), Weekly working gas in underground storage; National Oceanic and Atmospheric Administration (2021), Heating Degree Days; S&P Global Platts (2021), North American Natural Gas Analytics Service.

Droughts across hydro-rich power markets increase call on flexible gas

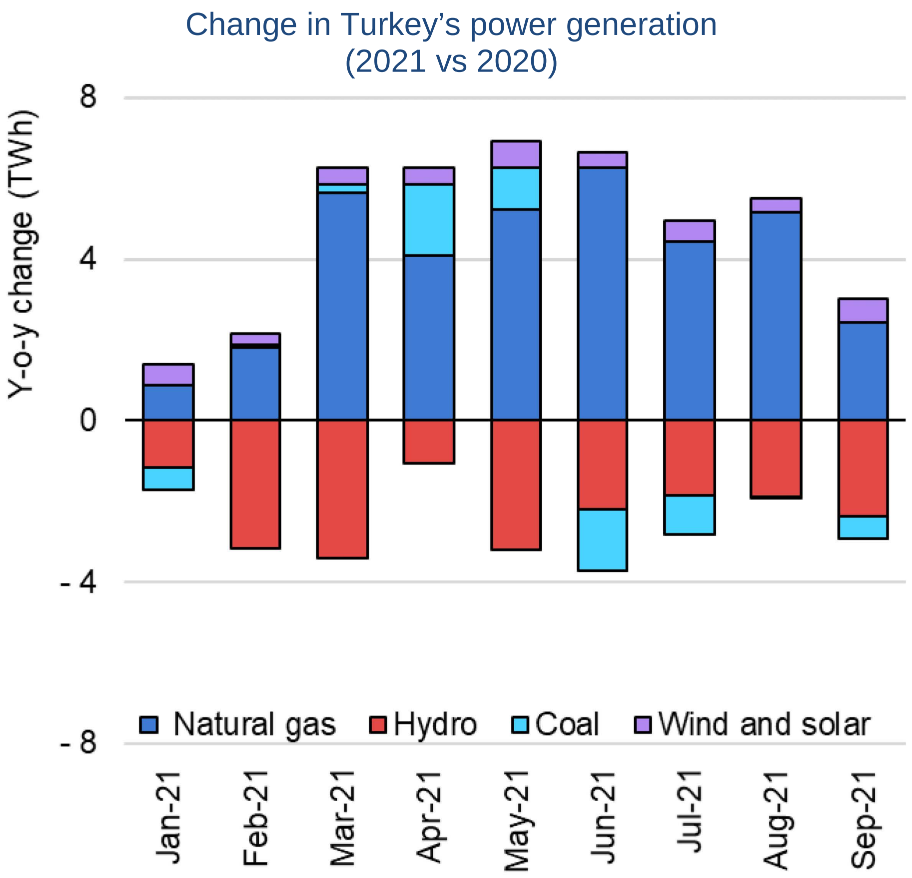
In Turkey gas-fired power generation surged amid plummeting hydro generation and strong electricity demand growth

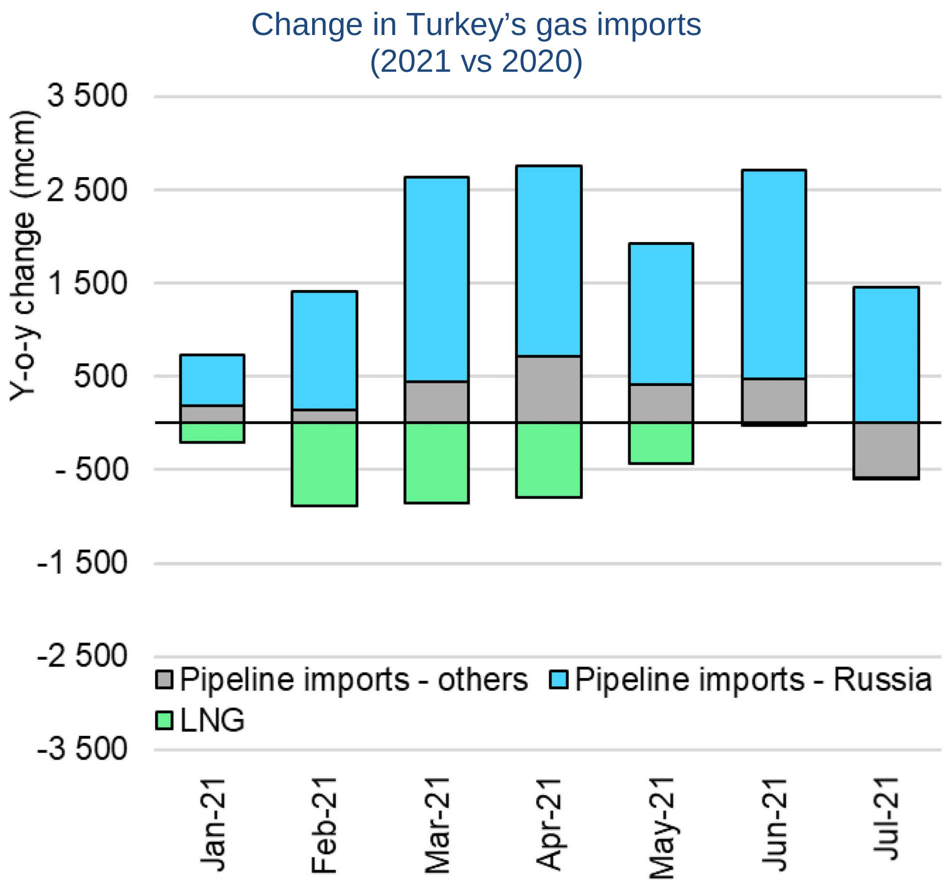
Turkey's electricity consumption rose by a remarkable 13% y-o-y during the first nine months of 2021, largely driven by a recovery in economic activity and higher cooling demand in the summer when the country faced several heatwaves. Electricity demand rose by 23% y-o-y in August, with daily electricity consumption climbing to historical highs, to reach 1.15 TWh on 4 August 2021.

This strong demand growth coincided with severe drought and plummeting hydropower generation. Turkey's hydro output has accounted for 25% of total power generation on average during the past three decades, while experiencing significant variation between 16% and 46% depending on precipitation and water reservoir levels. Low rainfall levels during 2021 weighed both on dammed and river-based hydro generation, which plummeted by 31% and 33% y-o-y respectively in Q1-3 2021, translating into a drop of 20 TWh in absolute terms. Consequently, hydro's share of the Turkish power mix shrank to 20% from last year's 31% during the same period. A temporary shortfall in hydro output led to countrywide rotating power cuts on 2 August, which lasted for over an hour. By mid-August the average active level of Turkey's five largest dams was under 25% of capacity, falling to close to 20% by mid-September and further tightening the country's power market. Low hydro output, combined with strong recovery in electricity demand, created additional market space for thermal generation, most of which was captured by gas-fired power plants, almost doubling their output compared to last year during Q1-3 2021. By mid-September gas-fired power plants accounted for close to 45% of Turkey's power output. In contrast, coal-based generation remained flat y-o-y during Q1-3 and fell by 7% y-o-y in Q3, due to the deteriorating competitive position of imported coal.

Driven by strong gas-to-power demand and economic recovery, Turkey's gas consumption rose by over 25% y-o-y during Q1-3 2021. LNG imports fell by 34% y-o-y during the same period as a result of the widening price differential between Asian and European spot prices. In this context, Turkey's spare pipeline import capacity and diversified import portfolio have been instrumental in ensuring adequate natural gas supplies to the country. Pipeline deliveries – enabled by spare capacity and flexible contractual terms – ramped up to fill the widening gap between supply and demand. Recovery has been strongest for Russian deliveries, via both Blue Stream and TurkStream pipeline systems, which more than doubled compared to last year during Q1-3 2021.

Flexible pipeline supplies ramped up amid the surge in Turkey's gas-fired power generation





Sources: IEA analysis based on EPIAS (2021), Transparency Platform; Eurostat (2021), Imports of Natural Gas by Partner Country – Monthly Data.

Brazil's gas-fired power generation soared to new records in Q3 2021 amid the country's worst drought in nearly a century…

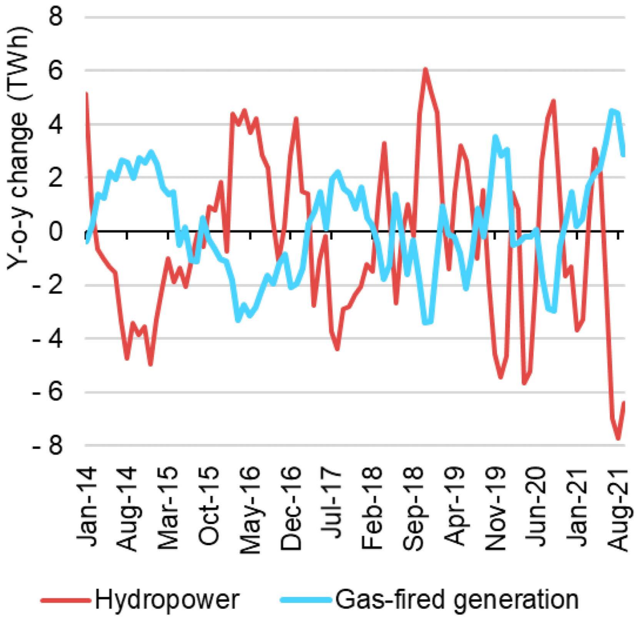
Brazil's electricity consumption increased by close to 10% y-o-y in the first 9 months of 2021, supported by economic recovery and colder than average southern hemisphere winter temperatures during Q3 2021. This strong growth in electricity consumption coincided with the country's worst drought in over 90 years. Low rainfall in the Southeast and Centre West regions weighed on Brazil's hydropower output, which typically accounts for over two-thirds of the country's power supply.

Hydro output remained close to last year's levels in the first five months of the year, driving down water reservoir levels, which had fallen 17% below their five-year average by end of May. At the beginning of June, Brazil's National Water Agency declared a "critical situation" for water resources in the Paraná River basin (home to key water reservoirs) until November 2021. Hydro generation plummeted by 23% (or 20 TWh) y-o-y in Q3. Water reservoir levels continued to draw down, falling to 30% below their five-year average by mid-September. The country's grid operator started taking submissions for the voluntary rationing of power from large consumers in September. Thermal power output almost doubled in the first nine months of 2021 compared to last year, providing backup to Brazil's power system amid the strong increase in electricity demand and low hydro output. This was largely supported by the strong increase in gas-fired generation, which rose to its highest level on record in Q3.

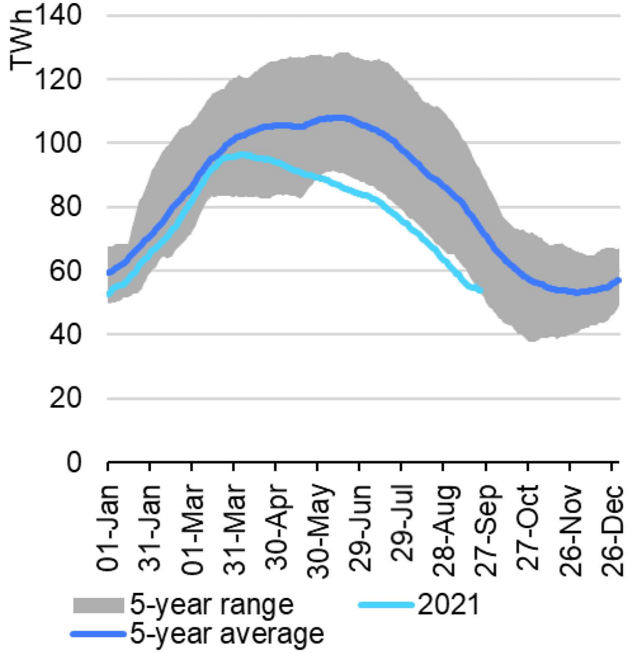
As a result of soaring gas-fired generation, combined with economic recovery and higher space heating requirements in the southern part of Brazil (which faced a cold spell in Q3), natural gas consumption increased by an estimated 20% in the first eight months of 2021. Given that Brazil has no underground gas storage, gas supply flexibility was ensured through a combination of higher domestic output, ramped-up pipeline imports and mainly via higher spot LNG imports. Brazil's domestic production rose by close to 5% y-o-y during the same period, mainly driven by higher output of associated gas. In mid-June Petrobras announced measures to raise domestic production, leading to a marked increase in July, while maintenance at the Mexilhao gas field and on the Rota 1 pipeline weighed on domestic output in the second half of August. Pipeline imports from Bolivia through the GASBOL pipeline increased by 7% y-o-y. LNG imports covered most of the incremental supply, rising more than sevenfold to a record of 7 bcm in Q1-3 2021. Brazil's spare regasification capacity and an increasingly liquid global LNG market enabled the redirection of LNG cargoes to Brazil. Destination-flexible US LNG accounted for nearly 95% of additional LNG supplies to Brazil.

…with flexible US LNG imports providing most of the incremental gas supply

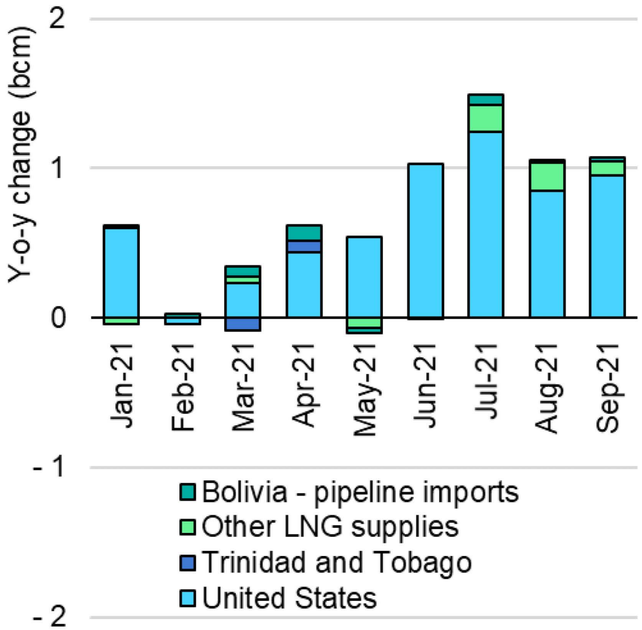
Change in hydro and gas-fired power generation (2014-2021)



Hydro reservoir levels in Brazil (2015-2021)



Brazil's LNG and pipeline imports (2021 vs 2020)



Sources: IEA analysis based on ANP (2021), Painéis Dinâmicos da ANP; ICIS (2021), ICIS LNG Edge; ONS (2021), Dados Históricos da Operação.

Historic drought in California drove up gas-fired power generation…

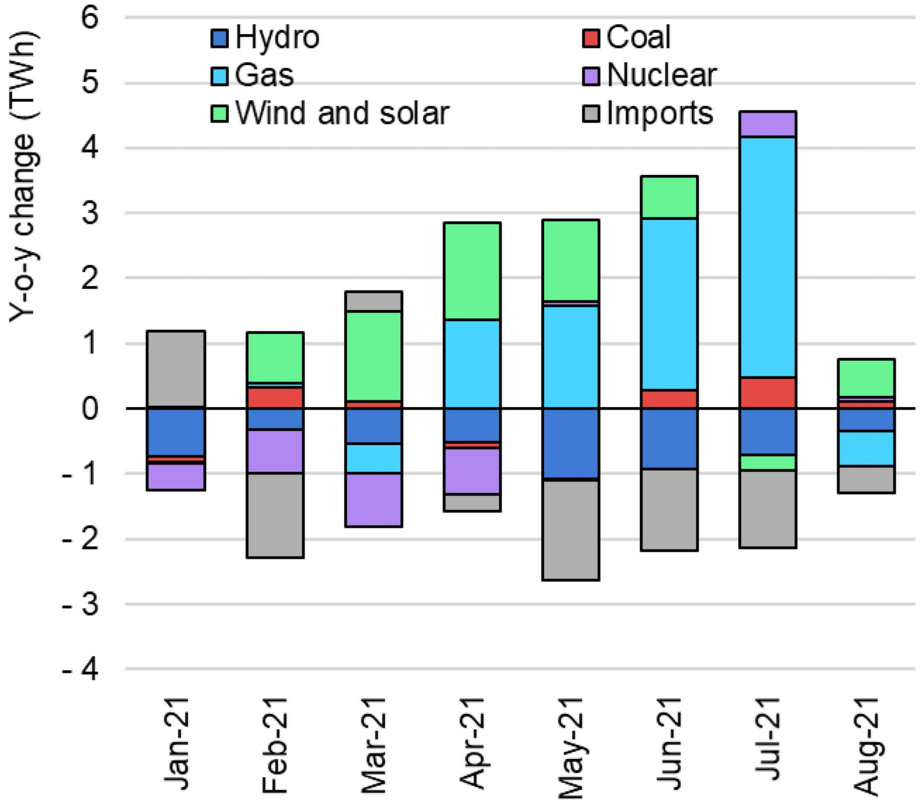
California's grid-sourced electricity consumption rose by 3% (or 2 TWh) y-o-y through the summer season (from June to August), supported by economic recovery and sporadic heatwaves driving up cooling demand. Recovery in electricity demand coincided with a historic drought in the western part of the United States, with California being one of the most affected states. By the beginning of August 2021 almost half of California's territory was classified under exceptional drought by the US Drought Monitor.

During the past decade hydro has accounted on average for 15% of California's summer power mix and plays a key role in the daily balancing of the power system. Because of severe droughts, hydro output fell by 36% (or 2 TWh) y-o-y through the summer of 2021 and by around 60% when compared to the same period in 2019. By the beginning of August, California's fourth largest hydropower plant, the Edward Hyatt, had been shut down due to low water levels, further tightening California's summer power market. Electricity imports declined by 17% y-o-y as the Northwest power region faced similar droughts and a steep decline in its hydropower output. Wind and solar, which together account for over 25% of California's power mix, grew by 6% (or 1 TWh) y-o-y. Nuclear increased by an impressive 10% (or 0.5 TWh), although not sufficient to fill the widening gap between electricity demand and supply. Thermal generation ramped up to provide backup on lower hydro output and declining electricity imports. Gas-fired power plants accounted for 90% of incremental thermal generation, with their output rising by 6 TWh y-o-y. Higher gas-to-power demand, together with economic recovery, drove up California's gas consumption by close to 10% during the summer of 2021.

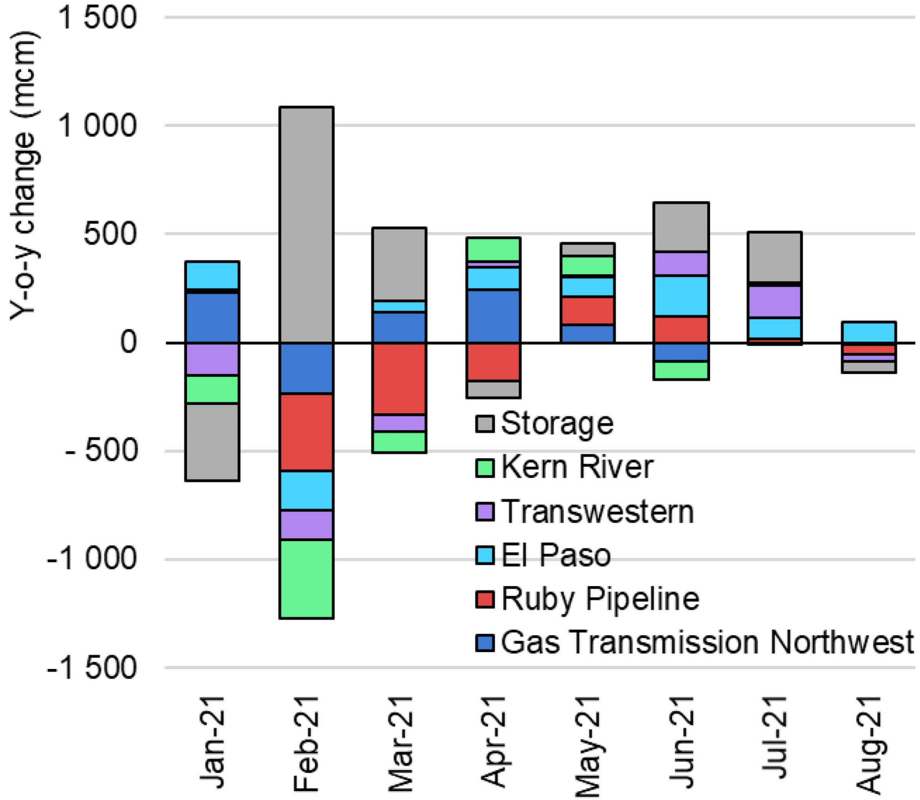
Pipeline supplies from Canada and other US states account for over 90% of California's natural gas supply. Imports from Canada declined slightly in the summer due to higher demand in the Northwest region of the United States. The widening price differential between Texan and Californian gas hubs incentivised strong gas inflow from Texas, enabled by spare pipeline capacity. Deliveries via the El Paso and Transwestern pipelines rose by over 15% y-o-y during the summer, despite outages on El Paso. In the same period gas flows via the Ruby Pipeline from Wyoming rose by 8%. Storage movements played a crucial role in balancing the gas market: net injections to underground gas storage sites more than halved y-o-y, leaving additional volumes to the market. Gas supply flexibility enabled higher deliveries to gas-fired power plants, which in turn provided essential backup to the power system through the summer. In mid-September, the Department of Energy approved a request by California's electric grid operator to dispatch more than 200 MW of natural gas-fired generation capacity beyond permitted levels to compensate for projected shortfalls in power supply.

…leading to higher pipeline inflows and storage optimisation

Change in California's power generation (2021 vs 2020)



Change in California's pipeline inflows and storage movements (2021 vs 2020)



Sources: IEA analysis based on Bloomberg (2021); EIA (2021), Hourly Grid Monitor; PGE (2021), Pipe ranger; SoCalGas (2021), Envoy.

LNG contracting and availability update

Update on LNG market flexibility metrics

This chapter focuses on the most recent LNG contracting trends, analysing LNG supply availability, seller and buyer behaviour, and the evolution of destination flexibility in LNG contracts. This analysis is based on the contractual positions of exporters and importers and their actual traded volumes, using the IEA internal LNG contract database.

The IEA tracks metrics of market flexibility, liquidity and supply security. Since the first issue of the *Global Gas Security Review* in 2016, the LNG market has become increasingly liquid and global: both buyers and sellers (including onselling buyers) are more numerous and diverse, supply contracts are more flexible and provide more optionality, total traded volumes have increased and pricing is diversifying. New trends such as tendering have emerged, providing additional short-term flexibility.

Flexibility at play in times of Covid-19

LNG trade was a major contributor to global natural gas supply flexibility in the first half of 2020 in the face of an unprecedented fall in demand. Monthly LNG trade flows declined by 21% between January and June 2020, adjusting to lower demand.

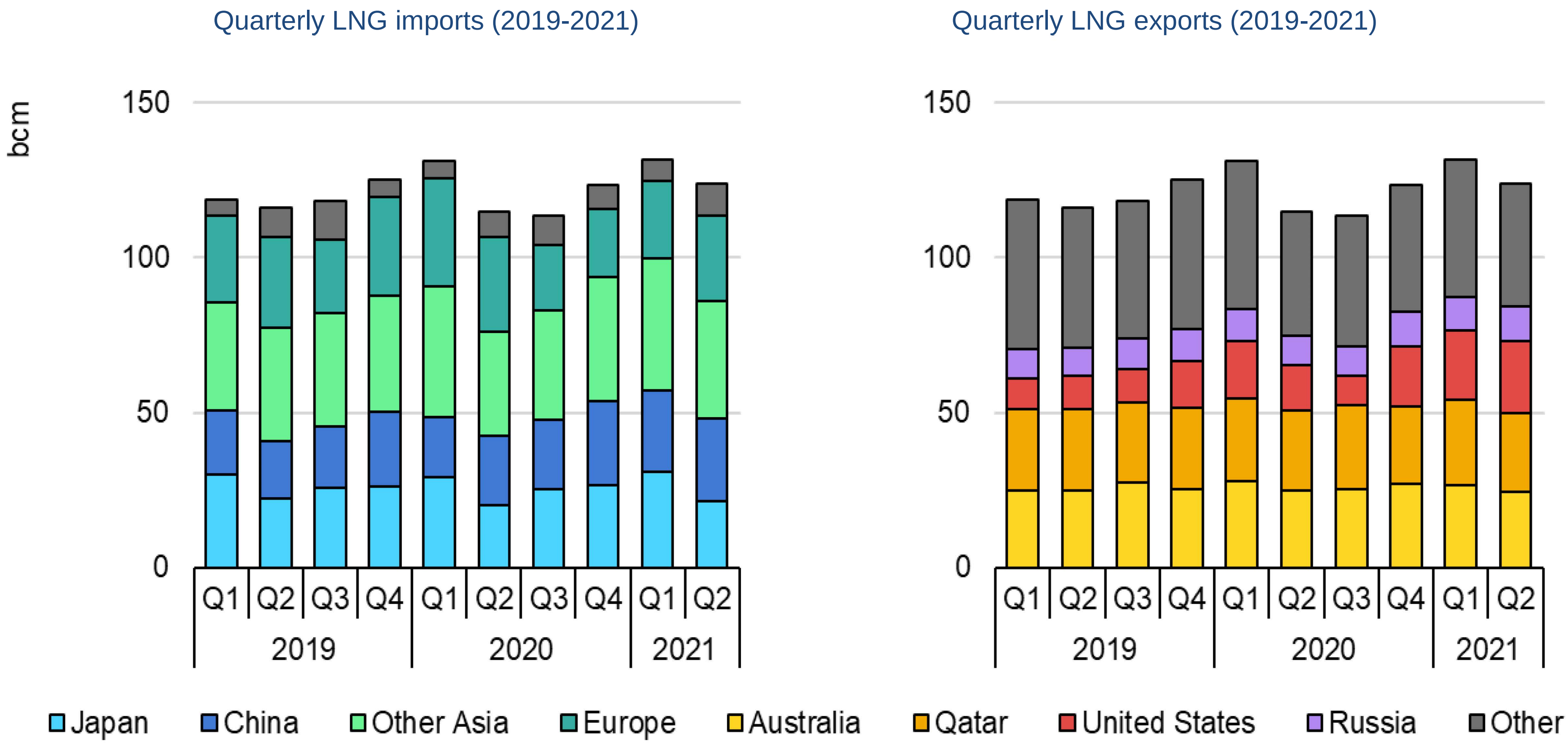
LNG trade then grew rapidly over the second half of 2020, with an 18% increase in monthly flows between July and December as the post-lockdown recovery gained momentum.

This flexibility in global LNG supply, particularly US supply, is a visible illustration of the transformation in LNG contracting and commercial terms that the *Global Gas Security Review* has been highlighting over the past five years.

Without such flexibility in LNG supply, the adjustment to the 2020 demand shock would have been less orderly, and could potentially have had a damaging effect on the commercial and contractual structures underpinning global gas trade.

The Northeast Asian cold spell of January 2021 was another test of the limits of LNG's supply flexibility. The combination of sudden demand hikes and LNG supply outages – along with logistical bottlenecks and shipping capacity constraints – pushed spot LNG prices to record levels. However, no major shortages were observed in Northeast Asian markets, thanks largely to the ability of LNG to fill the gap between surging demand and limited supply from other primary sources. At the same time, this episode underlined the fact that despite its growing flexibility, LNG short-term liquidity remains limited and timeliness is an issue.

LNG trade flexibility at work



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

FID count remains low in 2021, but with one major capacity addition

After a record year for FIDs in 2019, with over USD 65 billion committed to almost 100 bcm of new liquefaction capacity, 2020 saw only one project reaching FID (Energía Costa Azul in Mexico), with 4 bcm/y of capacity. Many projects that were on the list for a potential FID in 2020 have been postponed due to uncertainties related to the impact and repercussions of the Covid-19 pandemic. Some liquefaction projects under development were also delayed due to Covid-19, notably in Canada, Indonesia and on the maritime border between Mauritania and Senegal.

In 2019 a large proportion of capacity reached FID under the equity-lifting model. In traditional project financing, sponsors typically proceed to FID only after securing offtake for most of the project's capacity under long-term contracts with third parties. Under the equity-lifting model, project partners have access to LNG volumes proportionate to their equity stake, and projects can advance to FID before the majority of equity volumes are marketed to end users. However, the sharp drop of FIDs in 2020 showed the limitations of the equity-lifting model. It crucially depends on large CAPEX budgets and confidence in long-term market growth on the part of the major portfolio players, who were at the forefront of the previous wave of LNG FIDs.

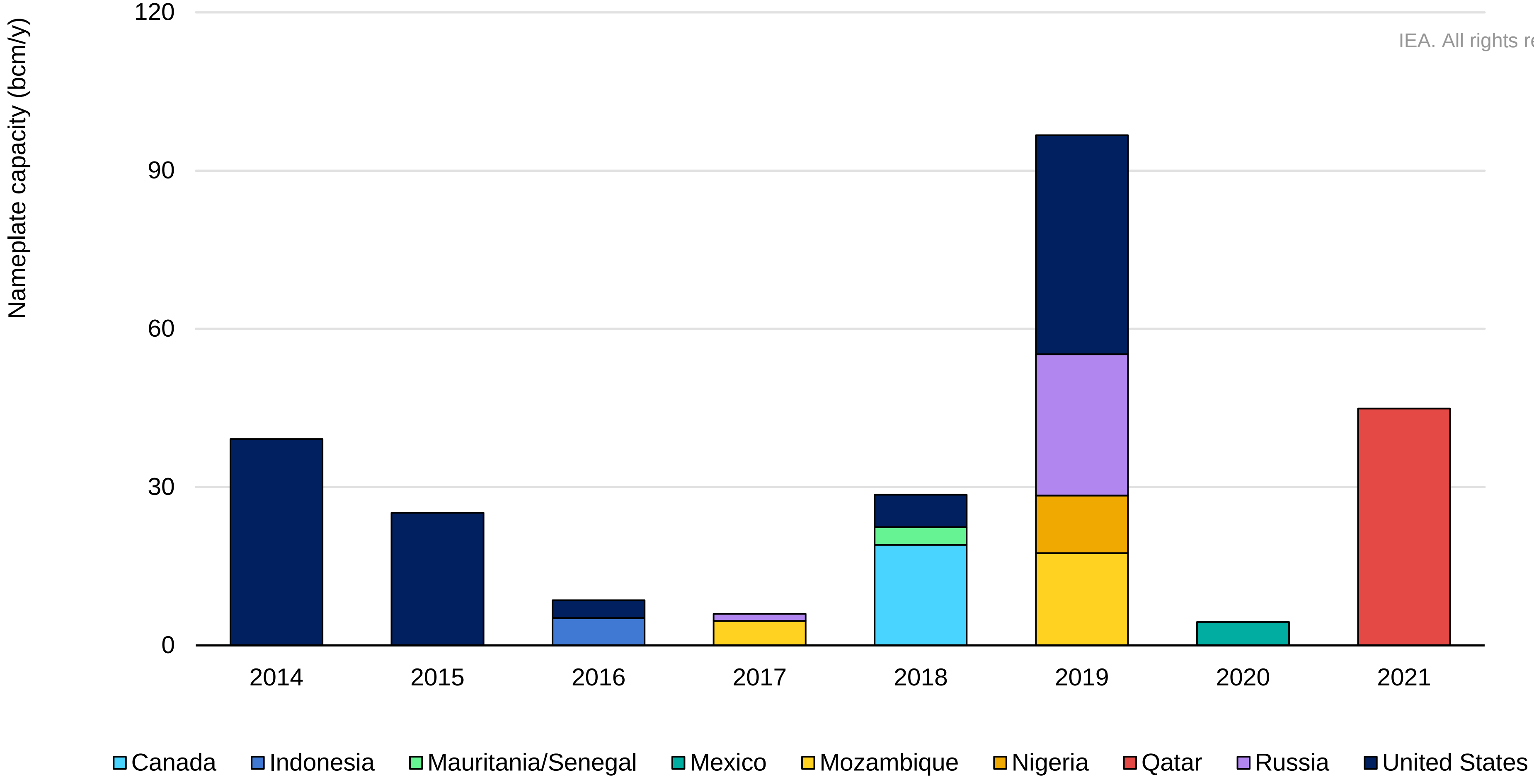
At the time of writing, only one FID has been announced in 2021. However, Qatar Petroleum's 45 bcm/y expansion project is the single largest LNG FID on record. This project will increase Qatar's LNG export capacity by 40% and is expected to cost USD 28.7 billion, making it one of the largest LNG investments of the past decade. Qatar's expansion is scheduled to start operations by the fourth quarter of 2025 at the earliest and reach full capacity by late 2026 or early 2027. Several projects are still targeting FID before the end of 2021; the majority of these are in North America.

The Energía Costa Azul project, the only FID in 2020, has the advantage of being a brownfield project (converting an existing regasification plant) and is located on the Pacific coast, which offers a shorter route to the Asian market. Qatar Petroleum's FID is an extension project that benefits from competitive upstream costs, a strategic location to serve both the Asian and European markets, and strong support from the Qatari government.

These two projects illustrate the tougher competition to sanction new projects in the face of recent CAPEX cuts. As the risks associated with the energy transition increase for the suppliers of unabated LNG, the ability to deliver low-carbon LNG could further differentiate projects in future FIDs (as was illustrated by the inclusion of a CCS facility in Qatar Petroleum's extension project).

Investment activity remains limited in 2021 by number of projects, but not by volume

FIDs for new LNG liquefaction capacity (2014-2021)



Slowdown in contracting activity lingers in 2021, with limited portfolio sourcing

Contracting activity slowed in 2020 after two years of strong activity in 2018-2019. The total volume of concluded contracts in 2020 was about 52 bcm, a 45% decrease compared to the 2018 peak of 90 bcm.

In the first eight months of 2021 about 48 bcm of contracts were concluded. The uncertainty related to the recovery from Covid-19 continues to cast a shadow over contracting activity, but it is gradually returning to pre-pandemic levels.

The notable improvement relative to 2020 is driven by export projects in Russia and Qatar. While a total of 28 contracts have been signed so far in 2021 lower than 32 contracts concluded by the same time in 2020, the average volume per contract has increased from 1.3 bcm/y during the whole of 2020 to 1.7 bcm/y in the first eight months of 2021. The share of large contracts (> 4 bcm/y) has risen from 8% in 2020 to 17% in the first eight months 2021.

The main source of new contracts has changed every year over the recent past. In 2018 North America was the leading source of newly signed contracts, accounting for 45% of the total volume. In 2019 Eurasia became the largest source with a 34% share, driven by the Arctic LNG 2 project in Russia. In 2020 portfolio players[2] dominated the contracting landscape with a 38% share of the total. Portfolio players recontracting the primary volumes that they had previously acquired from new projects enabled them to maintain a certain level of contracting activity despite the lack of new FIDs in 2020. Africa was also an important source, with a 33% share of the total volume (driven by Nigeria, and Mauritania and Senegal's project), a remarkable increase compared to the average of 8% over the past five years.

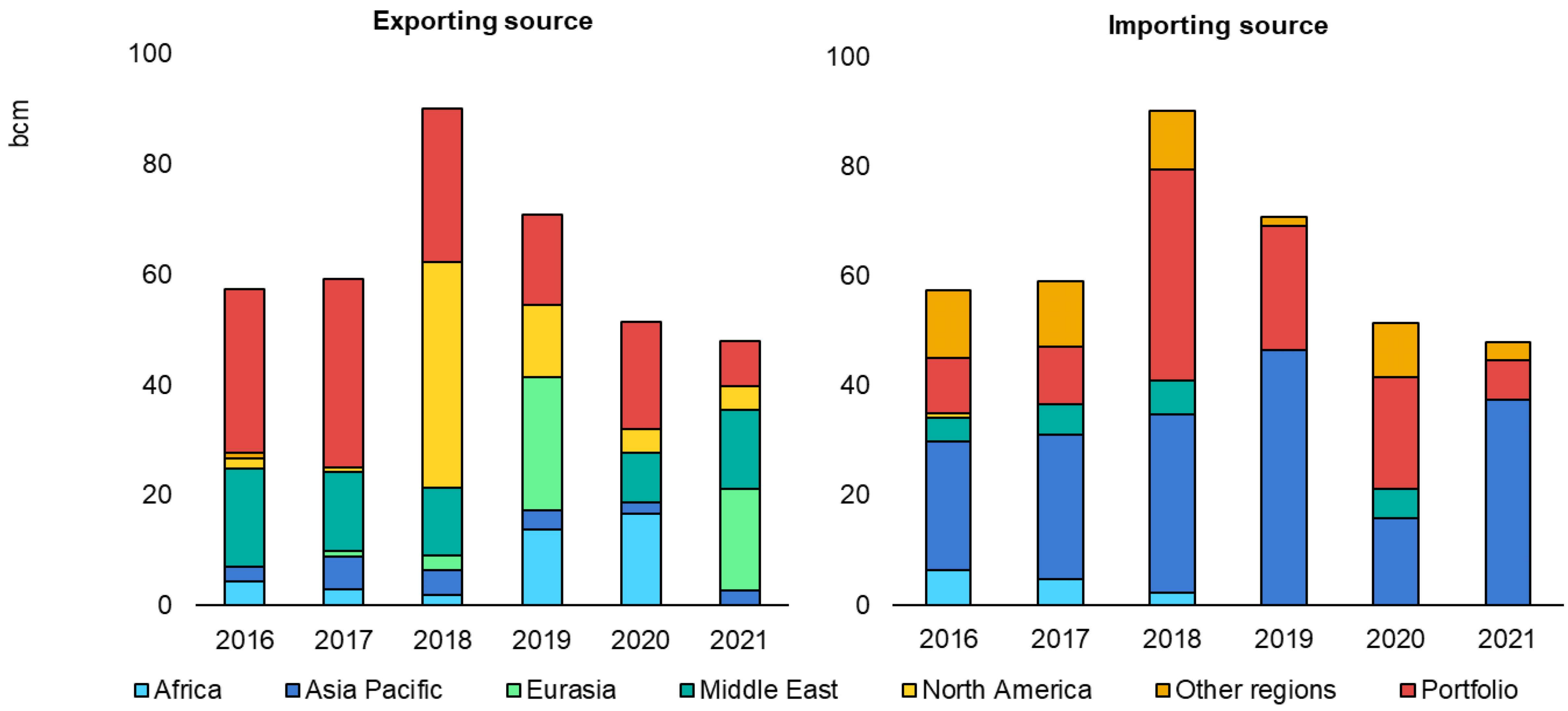
In the first eight months of 2021, two regions – Eurasia and the Middle East – have led new contracting activity. Eurasia accounted for 38% of the total thanks to the continued marketing of primary volumes from the Arctic LNG 2 project in Russia. The Middle East is the second-largest source with about 30% of total contracted volumes, thanks to Qatar Petroleum's aggressive marketing of uncommitted volumes from its existing projects.

Portfolio volumes during the first eight months of 2021 remained relatively low, accounting for about 17% of total contracted supply, compared to the average of 40% over the past five years.

[2] Portfolio players are market players who hold both purchase and sale contracts. They often hold an equity stake in LNG facilities or purchase LNG from other sellers in multiple regions, permitting them to independently market a share of the facility production capacity to end users.

Portfolio players' contracting activity shrinks in 2021 on both the selling and the buying side

Volume of contracts concluded in each year split by exporting and importing source (2016-2021)



Notes: Contracted volumes used for the analysis are associated with confirmed export projects (that have taken FID at the time of writing). 2021 represents volumes signed through to end of August 2021. "Portfolio" volumes are contracted from a market player who may source product from one or multiple regions to fulfil contractual obligations.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Large long-term contracts with a fixed destination have made a comeback in 2020 and 2021

Contracts with a flexible destination accounted for the majority of newly signed LNG contract volumes in 2018 and 2019. In 2020, however, their share dropped to 43%, a sharp decline from the 2019 peak when 84% of contracted volumes were destination-flexible amid the wave of LNG FIDs. Portfolio players remained central to LNG contracting activity in 2020, accounting for 38% of volumes bought and 40% of volumes sold, respectively.

2021 contracting data to date show a shift back to fixed-destination volumes, which accounted for 82% of the total in the first eight months. This is due to a declining share of flexible supply sources (mainly portfolio players and US primary capacity) in contracted supply, and a corresponding rise of contracting activity in Eurasia and the Middle East. Among fixed-destination contracts, China has been the single largest destination so far in 2021 with a share of 52%.

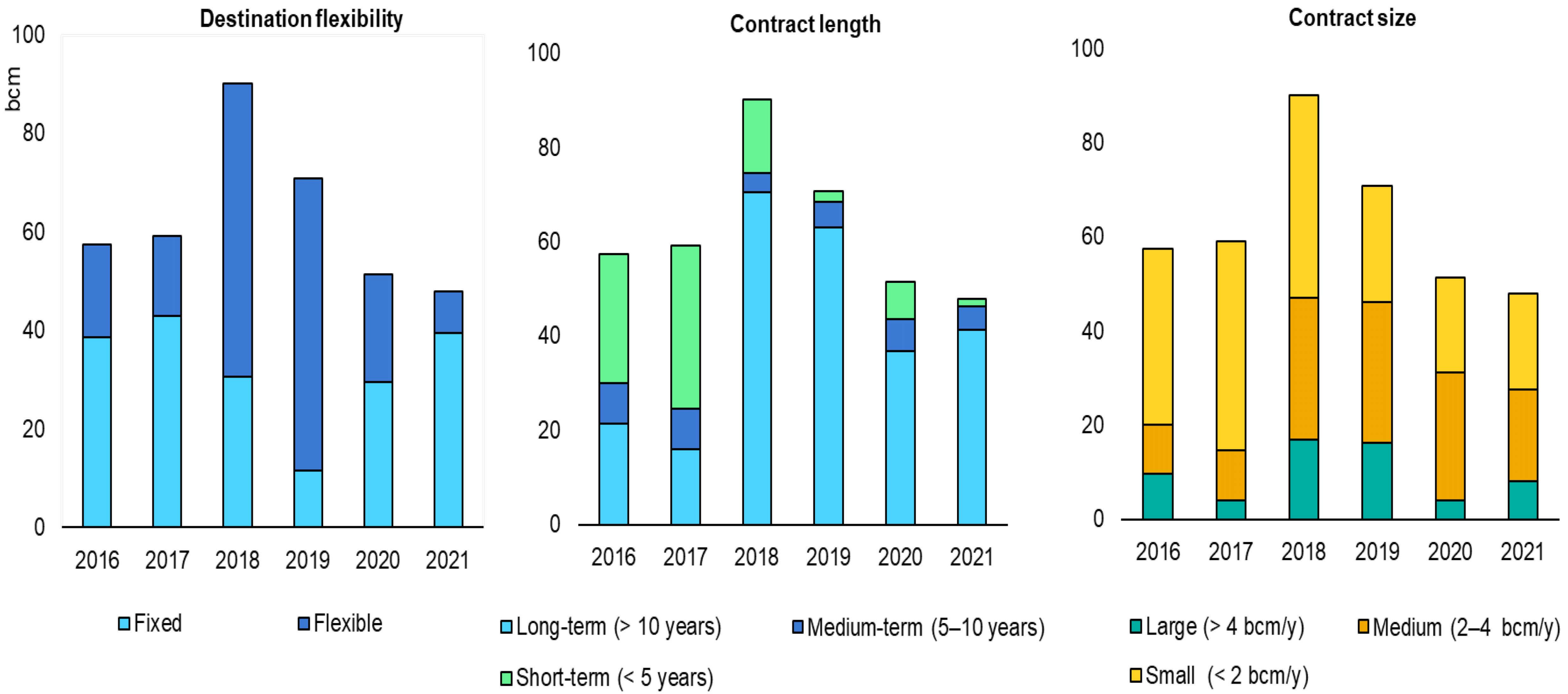
The share of long-term contracts (with durations greater than ten years) has remained high at above 70% since 2018. Long-term contracts accounted for 71% of the total in 2020 and 86% so far in 2021 – their highest share (with 2018) since the IEA's *Global Gas Security Review* started tracking LNG contracting trends in 2015. In 2021 this high share of long-term contracts has been driven by Asian buyers, which made up 82% of contracted long-term volumes. China alone accounted for half of the long-term volumes.

Such a strong appetite for longer-term contracts can at least partially be attributed to the unprecedented price volatility and price spikes we have seen in 2020 and 2021. Regional gas benchmark prices collapsed and recorded a historic low level in 2020 in the main. By contrast, spot prices recorded strong gains during the 2020/21 heating season. This could have reminded both buyers and sellers of the importance of long-term contracts to secure a stable price outlook.

Contracts of all sizes are represented in the 2021 mix. Large contracts (more than 4 bcm/y) account for almost one-fifth of contracted volumes, medium-sized contracts (2-4 bcm/y) for 40% and small contracts (< 2bcm/y) for 43%. Large contracts were almost absent in 2020, at a share of less than 10%.

A shift back to fixed-destination contracts

Volume of contracts concluded in each year split by contractual element (2016-2021 to date)



Note: 2021 represents volumes signed through to end of August 2021.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Portfolio players remain important sources of LNG market flexibility

Portfolio players have an important role in meeting buyers' growing need for flexibility in volume and destination. They procure a mix of LNG supplies from various origins, and resell to customers according to their requirements via term and spot contracts. The proportion of sale contracts signed by portfolio players has fallen from 58% by volume of LNG sold in 2017 to 38% in 2020, and only 17% so far this year.

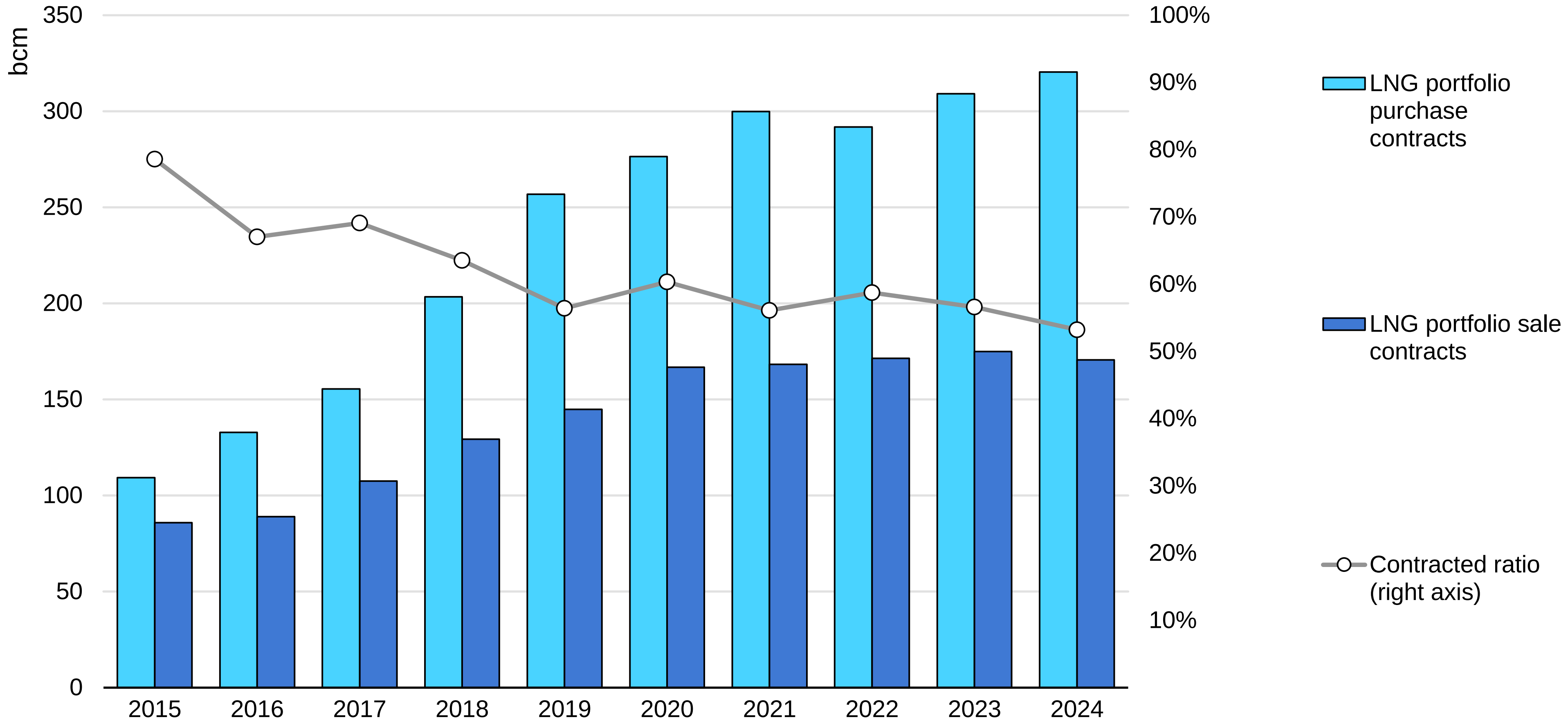
Although the proportion of all new sale contracts concluded by portfolio players has declined in recent years, the average length and contracted volume both increased at the same time. In 2020 small volume contracts (< 2 bcm/y) accounted for 68% of new sale contracts from portfolio players, compared with a 93% in 2016. Long-term contracts (> 10 years) accounted for 58% of volumes sold by portfolio players in 2020, compared with 25% in 2016.

The portfolio players' contracted ratio – sales offtake as a percentage of purchase obligations, a metric of relative exposure to certain types of market risk – was down to 60% in 2020 from 79% in 2015. This means that the share of portfolio players' purchase obligations not covered by term sale contracts – or their net open position – increased from 21% to 40% between 2015 and 2020. The evolution of this ratio reflects the strong role of portfolio players as primary buyers or equity holders in new liquefaction projects over the second half of the past decade, sometimes without back-to-back reselling contracts. Based on existing contracts, this trend is expected to continue in the coming years, as new liquefaction capacity currently under development is commissioned, pushing the contracted ratio down to 53% by 2024. Without a sharp increase in contracting activity with end users, portfolio players will continue to have greater exposure to the risks and opportunities inherent in spot LNG trading.

The existence of uncontracted volumes is beneficial for market liquidity and flexibility, but any mismatch between project development timelines and demand expectations can quickly erode this buffer. The IEA's Gas 2021 report expects medium-term LNG trade growth to be slower than in recent years. As the rate of capacity additions also decelerates, utilisation rates of liquefaction capacity are expected to stay relatively high but stable until 2024.

Portfolio players' net open position is set to widen further by 2024

Contracted volumes in natural gas purchase and sale contracts signed by portfolio players



Note: 2021 represents volumes signed through to end of August 2021.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Contract flexibility and market opportunity

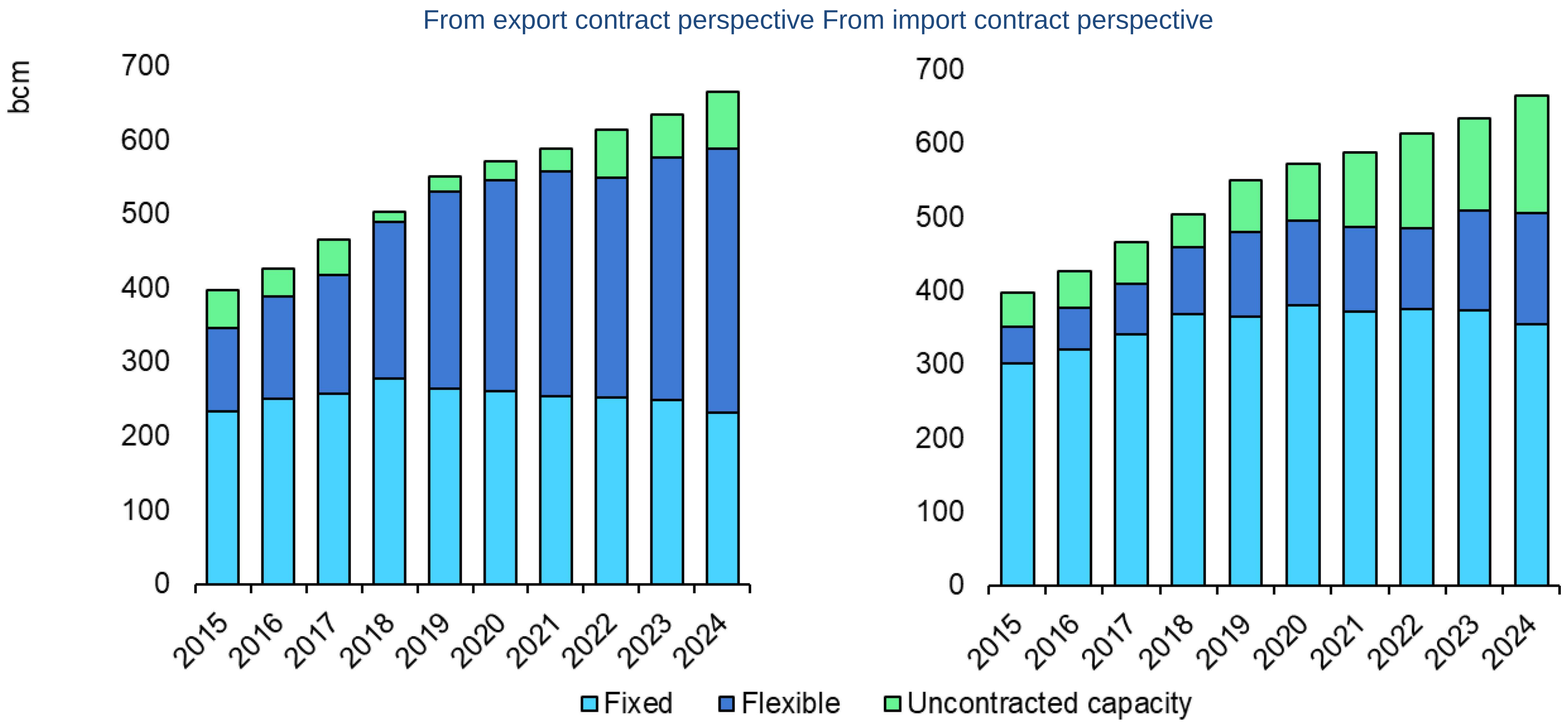
The share of destination-flexible LNG in total contracted volumes continues to increase, despite the lower share of flexible contracts in 2020 and 2021. In recent years, the movement towards more flexible contracts has been spearheaded by portfolio players and a new wave of liquefaction investment in 2018 and 2019, mainly targeting the United States. The share of contracts signed with a flexible destination increased to an average of 64% in the 2018-2020 period, a significant increase from an average of 34% in 2015-2017. This shift to destination flexibility has been led by both traditional and new buyers, and supported by portfolio players who require flexible conditions and by the equity-lifting projects that underpin their intermediary role in the market. In 2020 and 2021 so far, fixed-destination contracts have accounted for more than half of the total, but this does not mean that flexibility in the LNG market is in retreat.

Fixed-destination contracts continue to play a role for end users and price-oriented buyers alongside long-term contracts. With new liquefaction capacity coming online, by 2024 total capacity is due to increase by 16% from 2020. As older fixed-destination contracts expire and new flexible contracts enter into force, destination-flexible contracts are expected to account for over half of delivered gas volumes by 2024. The share of contracted destination-flexible volumes surpassed fixed-destination volumes in 2020 for the first time. About 150 bcm of active contracts are due to expire between 2021 and 2024.

The security and flexibility of the LNG market are improving year by year, but it still has much room for improvement. As we saw in Northeast Asia last winter, a combination of surging demand, availability of LNG supply, logistical constraints and a lack of storage pushed spot LNG prices to record high levels for a brief period.

Destination-flexible volumes have dominated the LNG contract mix since 2020

Contracted volumes for LNG delivery by destination flexibility clause (excluding portfolio purchase contracts)



Note: Analysis is based on project nameplate capacity.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Contract expiry could serve as a catalyst for further diversification of LNG contracts

About 150 bcm of active LNG contracts are set to expire between 2021 and 2024, with an additional 180 bcm expected to lapse by 2030. This highlights the scale of the marketers' challenge to reach new buyers. The Asia Pacific region, which is the largest current holder of contracted purchase volumes, is expected to account for more than 40% of expired contracts by 2024. On the seller's side, the Middle East is expected to see the largest turnover. This process provides an opportunity for market participants to more closely align contract terms with buyer requirements in the years ahead. The adoption of more flexible contractual approaches, such as gas-to-gas indexation, hybrid formulae and hub pricing, has continued to gain ground in recent years.

Although contracts with oil-indexed pricing still play a dominant role in total LNG trade, gas hub-linked pricing continues to increase. US-based projects have been the leading providers of flexible LNG contracts with gas-indexation and full destination flexibility. Gas hub-linked LNG contracts (especially to Henry Hub, but also to the Title Transfer Facility [TTF], the National Balancing Point [NBP] and the Japan Korea Marker [JKM]) are gaining a larger share than in previous years. The influence of major hub indices is extending beyond their markets, with some Henry Hub indexed LNG imported by South American buyers, and TTF indexed LNG imported by Asian buyers. This highlights the growing role of gas hub-linked LNG contracts in both long- and short-term markets.

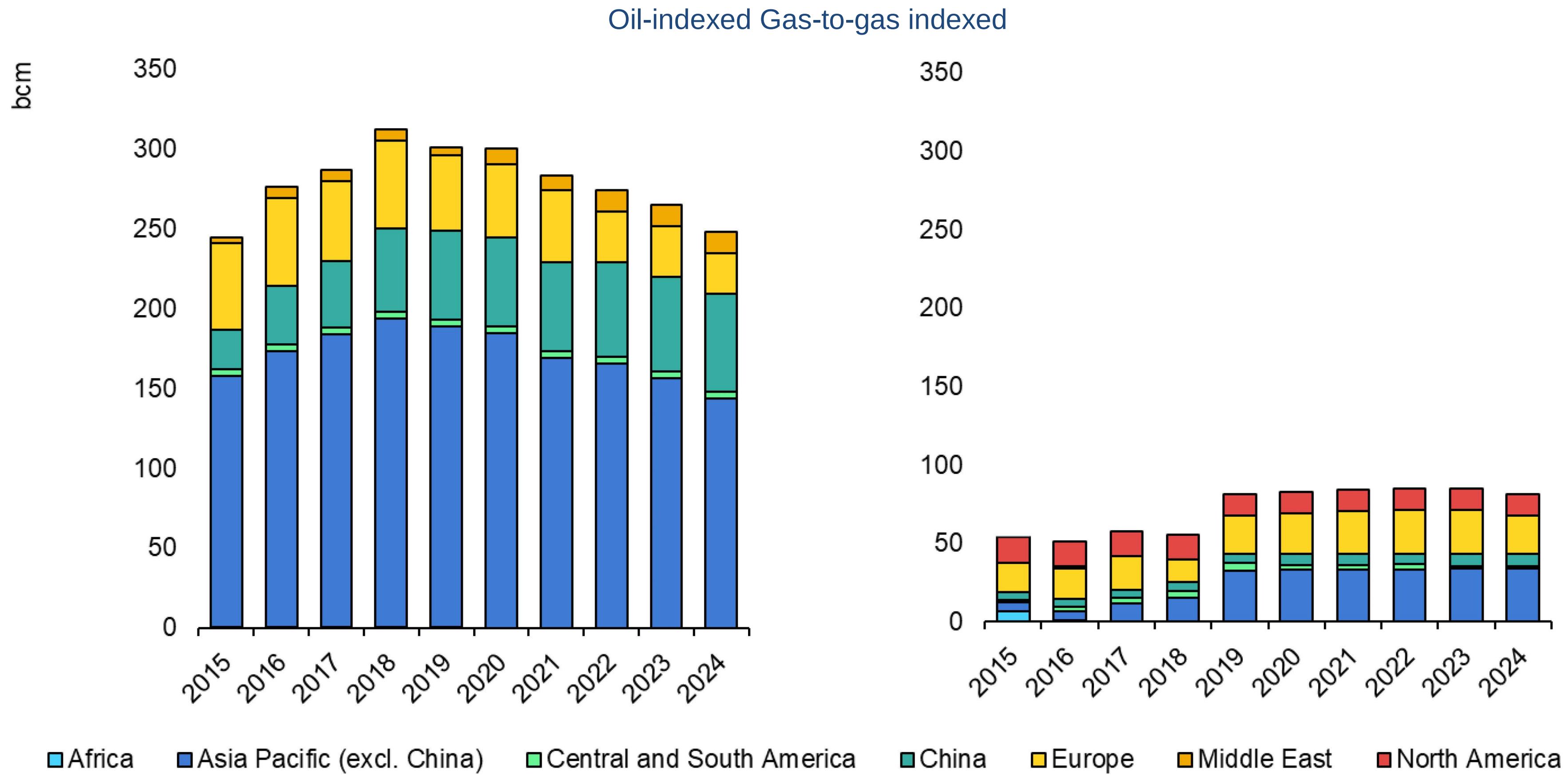
A variety of pricing formulae, such as oil-related floors and ceilings, S-curves and hybrid pricing with multiple indices, have become more common and sellers have had to keep up with this trend to attract buyers.

The development of carbon-neutral (or carbon offset) LNG transactions could further increase the diversity of LNG contracts in the future. Since 2019 over 20 carbon/GHG offset LNG cargoes have been delivered, mainly to Asian buyers. LNG projects that have carbon management technologies and low-carbon solutions are expected to be more competitive and appealing to buyers as the energy transition unfolds.

The large volume of uncontracted LNG could accelerate these trends and serve as a catalyst for further diversification of LNG contracts in the coming years.

Oil-linked pricing remains dominant in import contracts, although gas-to-gas indexation has a role to play

LNG import contract volumes with oil-indexed and gas-to-gas pricing by region and country (2015-2024)

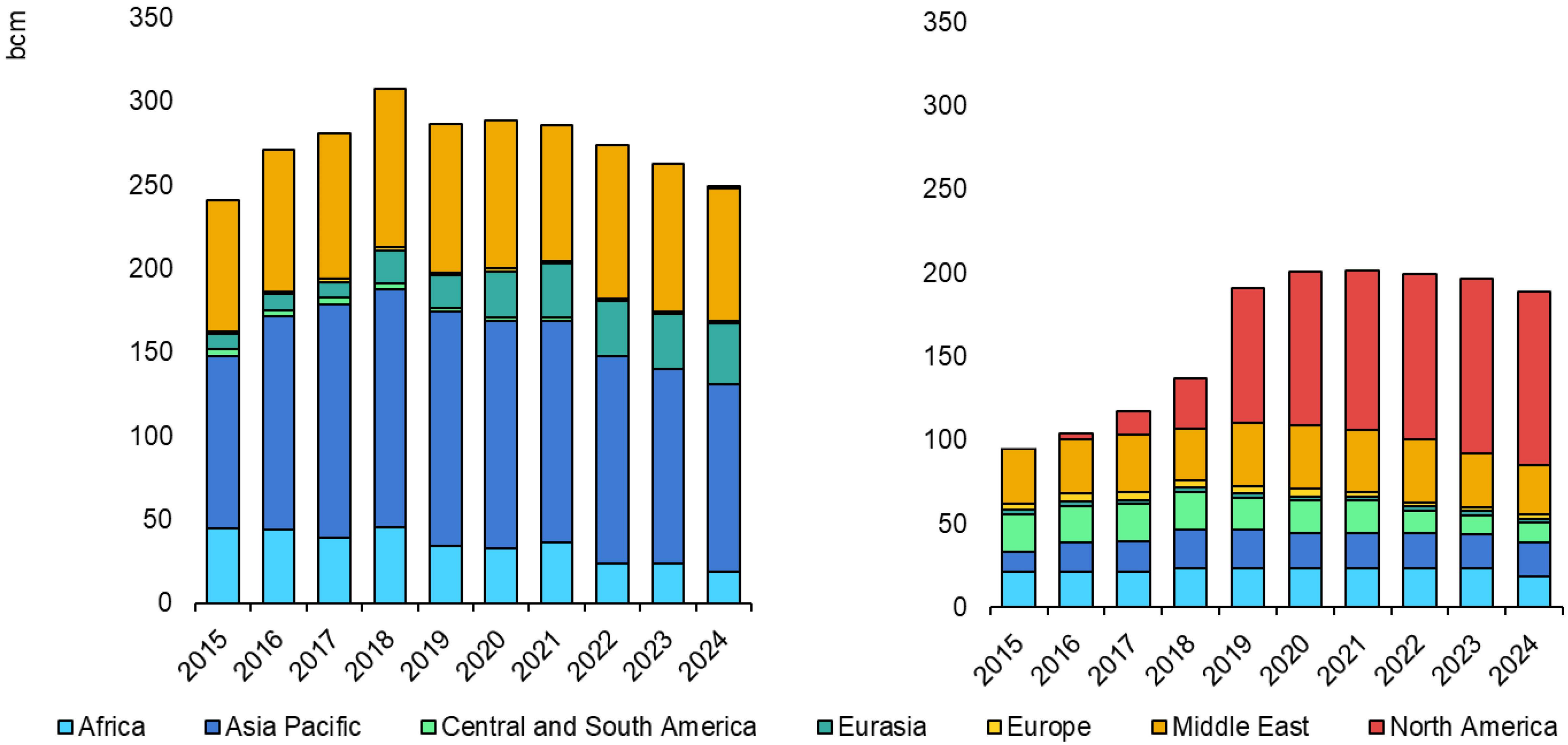


Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Among export contracts, the United States is the leading source of gas-to-gas indexed volumes

LNG export contract volumes with oil-indexed and gas-to-gas pricing by region and country (2015-2024)

Oil-indexed Gas-to-gas indexed



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2021), ICIS LNG Edge.

Out of order: LNG capacity outages set new records

LNG supply outages rose sharply in 2020 and remained elevated during the first eight months of 2021. Reduced supply availability, in turn, contributed to the rapid tightening of the global LNG market in H2 2020 and 2021, and most likely magnified the price spikes during the winter energy crisis in Northeast Asia in January 2021.

In 2020 nearly 50 bcm of LNG production was lost due to planned or unplanned events, an all-time high in absolute terms and an almost 30% jump from 2019. Offline volumes represented 8.2% of total nameplate capacity in 2020, a marked increase compared to both 2019 (6.7%) and the 2012-2019 historical average (6.6%), albeit lower than the relative outage peak in 2016, when the equivalent of 8.8% of nameplate capacity was affected by outages.

The 2020 jump in offline capacity was solely driven by unplanned outages, which rose by nearly 80% from 2019 levels and accounted for three-quarters of the total capacity loss (compared to a historical average of less than 50% in 2012-2019). This sharp rise in 2020 was due to a series of unrelated outage events in Australia, Norway, Malaysia, Algeria and the United States, which together accounted for nearly two-thirds of the capacity loss due to unplanned outages last year. Unplanned capacity outages reached 37 bcm (or 6.2% of total nameplate capacity) in 2020, which is the highest level in both absolute and relative terms since at least 2012. In contrast, offline volumes due to planned maintenance dropped by a third from 2019 levels and were at their lowest since 2012 in both absolute and relative terms. Planned activity declined in part because some operators deferred regular maintenance due to spending cuts and containment measures related to Covid-19 (e.g. in Russia and Australia), and in part because extended unplanned outages prevented scheduled maintenance taking place (e.g. in Algeria and Australia).

Some of these dynamics continued in the first eight months of 2021 as well. Overall outage levels remained elevated and were 8% higher than during the same period a year earlier. As a share of nameplate capacity, offline volumes remained at 8.0% of total capacity, higher than the historical average between 2012 and 2019 (at 6.6%), but slightly lower than the levels seen in 2020 (at 8.2%). Unplanned outages were up by 3% y-o-y, driven by ongoing repairs at Norway's Hammerfest terminal and upstream issues in Trinidad and Tobago and Nigeria. Planned activity was up by 20% y-o-y as LNG terminal operators in Australia and Russia in particular caught up with previously deferred maintenance programmes.

Unplanned issues pushed LNG capacity outages to fresh highs in 2020

Unplanned events broadly fall into five categories, as listed below. While most incidents in 2020 and 2021 to date were one-off events, some – especially hurricane-related outages in the United States and feed gas issues at legacy exporters, such as Trinidad and Tobago – may become a recurring source of outages in the future.

Force majeure events accounted for more than a third (13 bcm) of unplanned outages in 2020 and 45% (10 bcm) in the first eight months of 2021, making these the biggest cause of offline capacity in both periods. The largest disruptions in 2020 occurred in Malaysia (where an explosion on the Sabah-Sarawak pipeline in January 2020 reduced feed gas supply to the Bintulu LNG complex for several months) and in Norway (where a fire in September 2020 knocked the Hammerfest LNG facility offline until March 2022).

Plant failures quadrupled from 2019 levels and reached 12 bcm (or 32% of unplanned outages) in 2020. In Australia, regular maintenance at Gorgon in May 2020 revealed cracks in the propane heat exchangers, which necessitated staged repairs on all three liquefaction trains lasting well into 2021. The Prelude floating LNG terminal suffered an extended outage between February 2020 and January 2021 due to electrical issues. In Algeria, the Skikda LNG plant was offline for the first seven months of 2020 due to turbine damage, and again from June 2021 due to a technical issue. In July 2021 Peru's LNG terminal went offline for more than a month for repairs on a compressor unit, which followed both planned and unplanned outage events earlier in Q2.

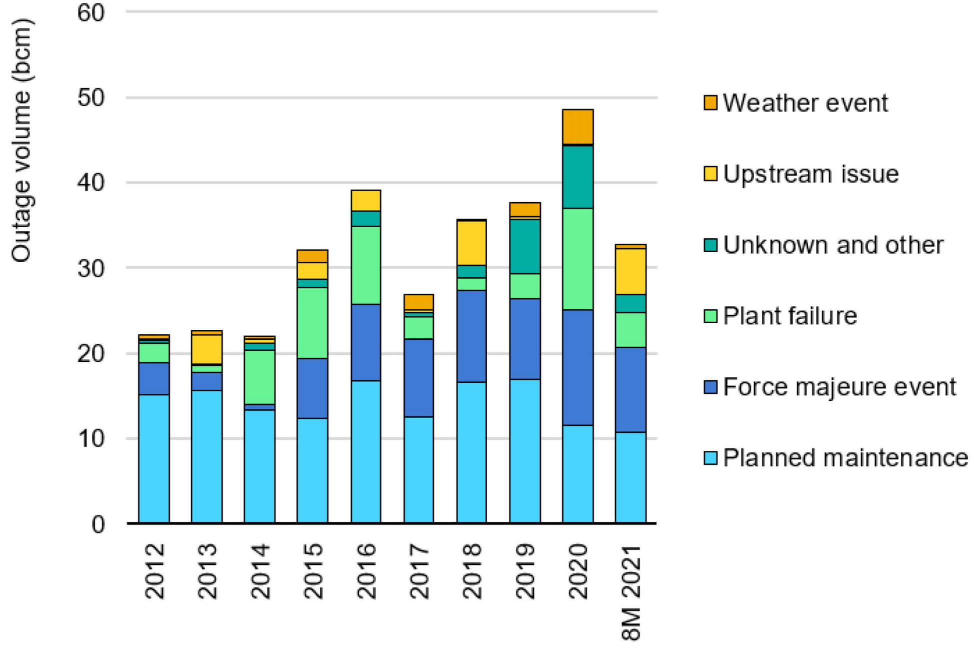
Weather-related issues accounted for 11% (4 bcm) of the total capacity loss due to unplanned events last year, almost exclusively attributable to hurricanes along the US Gulf Coast. In August 2020 Hurricane Laura caused a brief outage at Sabine Pass and a more sustained disruption at the Cameron facility. In October, Hurricane Delta once again forced the Cameron terminal offline. In February 2021 extreme cold weather – and a temporary export ban in Texas – led to brief interruptions at US Gulf Coast terminals. In mid-September, Hurricane Nicholas caused a power outage, disrupting operations at the Freeport LNG terminal for several days.

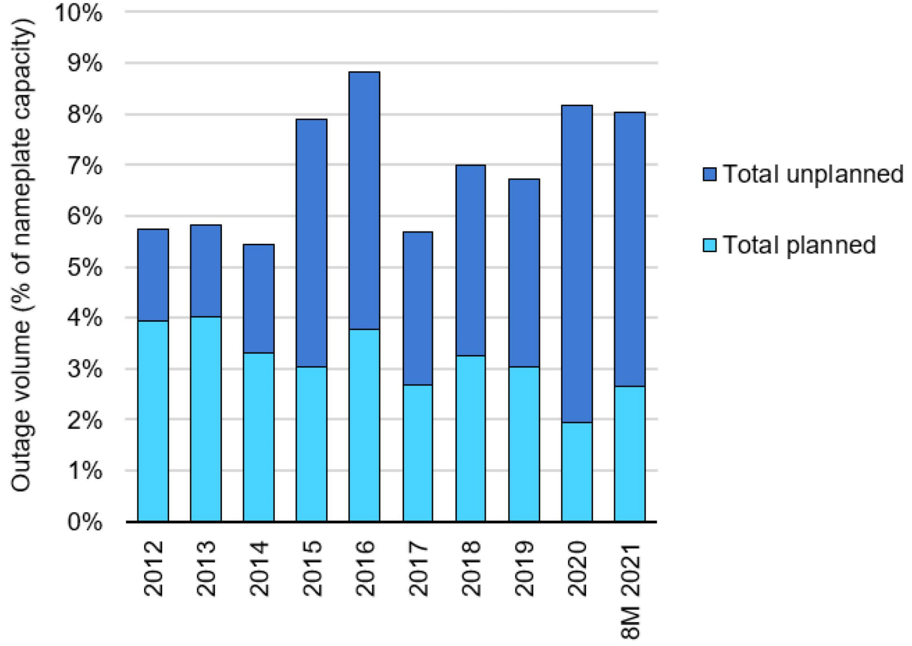
Upstream issues were not prevalent in 2020, accounting for less than 1% of total outages last year. In the first eight months of 2021 upstream outages jumped to 6 bcm (25% of the total) due to gas supply issues in Trinidad and Tobago and Nigeria.

Unknown or other causes were responsible for 7 bcm of lost capacity (or 20% of unplanned outages) in 2020 and 2 bcm (10% of the total) in the first eight months of 2021. Such unclassified incidents were reported from nine countries between early 2020 and late-August 2021, with the greatest contributions coming from Malaysia and the United States in 2020, and Qatar and Trinidad and Tobago in the first eight months of 2021.

LNG capacity outages hit an all-time high in 2020 and have stayed elevated so far in 2021

Planned and unplanned LNG capacity outages (2012-2021)





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

Low-carbon gases and security of supply: System integration and flexibility considerations

Reaching net zero emissions by 2050 requires the prompt deployment of low-carbon gases

The decarbonisation of the gas and broader energy system will require the deployment and scale-up of low-carbon gases. Low-carbon gas streams include biomethane, pure low-carbon hydrogen, synthetic methane, and natural gas subject to carbon capture, utilisation and storage (CCUS) both at production and at the end-use stage. In the IEA's Net Zero by 2050 roadmap, the share of low-carbon gases in the total final consumption of gaseous fuels increases to 20% by 2030 and over 80% by 2050, while accounting for the majority of gaseous fuels in the power sector. The Global Ambition scenario of the European Network of Transmission System Operators for Gas (ENTSOG) foresees the share of low-carbon gases climbing to 35% of the total European gas supply by 2035, before reaching 100% by 2050.

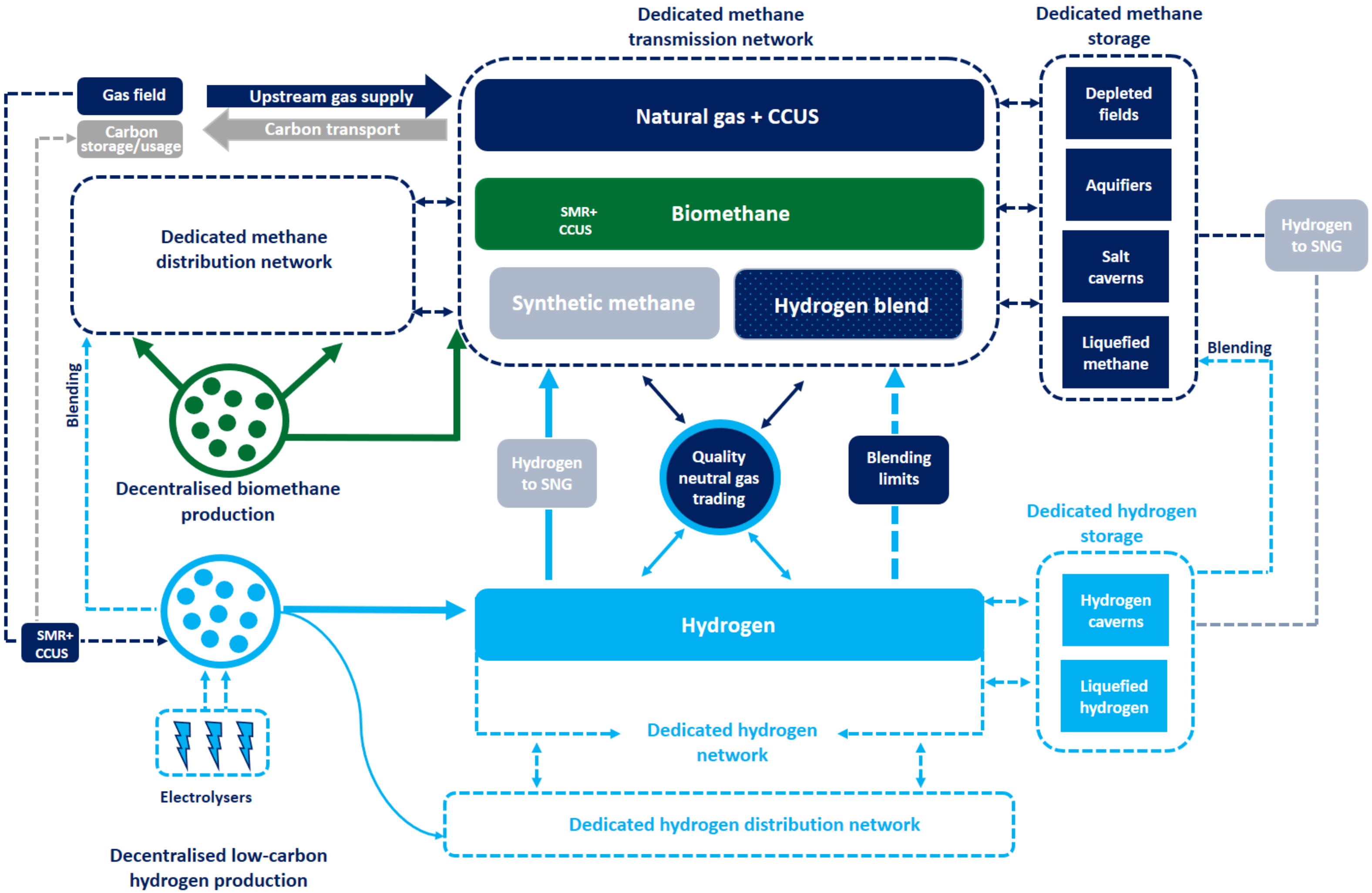
The existing natural gas infrastructure can act as an enabler in the deployment of low-carbon gases by providing network access, reducing transport costs and ultimately facilitating their integration into the broader energy system. **Blending** low-carbon gases into the methane stream could be a transitional solution supporting their initial deployment. Natural gas pipeline **repurposing** can offer a longer-term solution for the cost-effective transport of low-carbon gases.

The large-scale integration of low-carbon gases will transform existing gas systems in a number of ways:

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

The large-scale deployment of low-carbon gases will take time. However, **an orderly transition** from the current gas system to a model integrating multiple gases **already requires prudent market design** during the early stages, to take into consideration the network integration challenges and changing supply flexibility of low-carbon gases, and ultimately their implications for security of supply.

…leading to a more complex and intertwined multi-gas system



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

The decentralised production of low-carbon gases will necessitate closer integration between transmission and distribution networks

In contrast with natural gas, low-carbon gases are produced in a decentralised manner by a large number of relatively small-scale facilities. The output of a biomethane plant, electrolyser or SMR with CCUS is typically just a fraction of the annual production of a gas field. The decentralised nature of low-carbon gas production in operation today will naturally incentivise their **on-site use**, while **"virtual pipelines"** (such as tube trailers) might prove to be the most economic way to transport smaller volumes over short distances.

However, much larger-scale projects have been proposed in particular to produce hydrogen. The **large-scale system-wide deployment** of hydrogen and other low-carbon gases from such projects **will necessitate** their integration both into existing methane networks and newly developed hydrogen grids. **Network access** for low-carbon gases will need to be carefully assessed by distribution and transmission system operators, taking into consideration implications for gas quality and, in the case of hydrogen, the risk of embrittlement.

Low- and medium-pressure distribution networks could play a crucial role in providing grid access to low-carbon gases, as their widespread coverage is well-suited to the decentralised production of low-carbon gases (as demonstrated by biomethane). In the longer term, the high penetration of low-carbon gases at the distribution level will necessitate closer integration between transmission and distribution networks. **Bidirectional compressor stations** would enable reverse flows from distribution to the transmission network. **Reverse flows** could facilitate daily balancing (e.g. managing surpluses) while providing low-carbon gases with access to seasonal storage sites, which are typically connected to the transmission grid. This in turn would require **closer co-operation between distribution and transmission system operators** on network planning, investment assessment, capacity allocation, gas quality monitoring and linepack management.

Capacity ranges of existing and planned low-carbon production facilities compared to natural gas supply sources

Name	Process	Capacity range (CH_4-eq)
Biomethane plant	Upgrading biogas to methane	0.5-50 mcm/y
Existing electrolysers	Electricity to hydrogen	0.5-10 mcm/y (1-20 MW)
Large-scale electrolysers/clusters	Electricity to hydrogen	500-2 500 mcm/y (1-5 GW)
SMR	Methane to hydrogen	10-500 mcm/y
Synthetic methane plant	Hydrogen to methane	0.1-2 mcm/y
LNG regasification terminal (global average)		8 000 mcm/y
Norwegian average gas field		2 000 mcm/y
Giant gas fields		30-130 000 mcm/y

Note: DSO = CH_4-eq = methane equivalent.

A greater diversity of gas qualities will raise questions related to interoperability

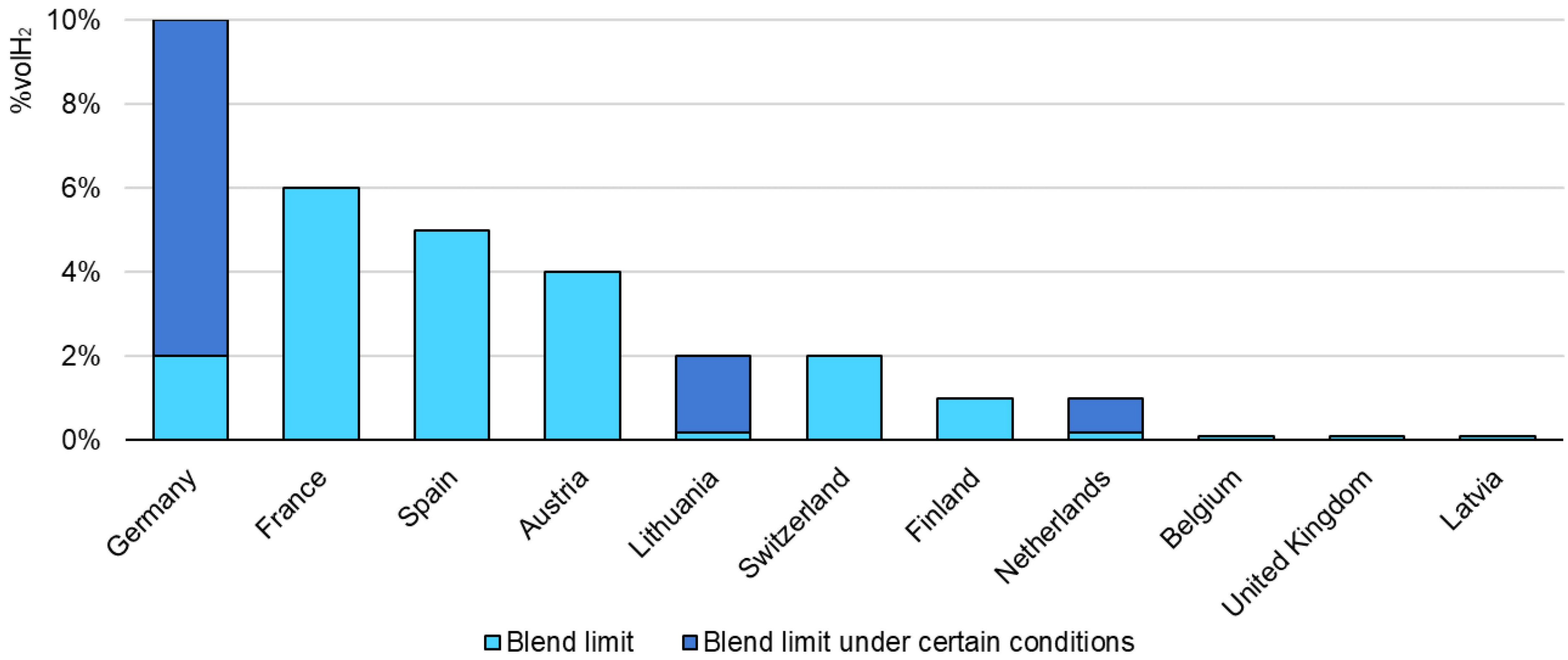
In today's gas systems, **harmonised gas quality standards** form the basis of the technical interoperability of interconnected gas networks. The integration of low-carbon gases will lead to a greater diversity of gas qualities, which might raise interoperability issues and hinder the free flow of gas streams between adjacent gas systems if not addressed properly in the market design. **Biomethane and synthetic methane** are perfectly interchangeable with conventional methane due to their almost identical chemical and physical properties. Nevertheless, they will require the development of standards to ensure uniform gas quality across interconnected gas systems and diminish any risk of deviating from them.

In the case of **low-carbon hydrogen**, interoperability will have multiple dimensions, which network operators and regulators will need to take into account. **Blending low-carbon hydrogen** into the existing methane stream can provide a transitional solution in the early phases of hydrogen market development and/or in cases where hydrogen demand cannot justify the development of a pure hydrogen network. In the IEA's Net Zero roadmap, hydrogen blending reaches a share of over 5% in gas grids by 2030. The exact hydrogen acceptance of methane networks is still being investigated by network operators and regulatory authorities. Current hydrogen blending thresholds in Europe range from 0.5% to 10% hydrogen by volume at the transmission level. Without the harmonisation of blending thresholds, the divergence of gas qualities in adjacent markets could occur and consequently lead to interoperability issues. While deblending is a promising technology (i.e. separation of hydrogen from the methane stream at a given exit point), national regulators and network operators should consider the **harmonisation of blending thresholds** so as to limit interoperability issues in the future. The **interoperability of future pure hydrogen networks** should be also considered, as the quality of pure low-carbon hydrogen is expected to show divergence. Renewables-based hydrogen produced via alkaline and proton exchange membrane (PEM) electrolysis has a purity of over 99.99%. This compares with a range of 97.5-98.5% purity for gas-based hydrogen produced via SMR. Ultimately, this creates the need to harmonise hydrogen purity standards to ensure the interoperability of future hydrogen networks.

A third dimension to consider is the **interconnectivity between methane networks and pure hydrogen grids**. Surplus hydrogen could either be blended into methane networks (within the blending limits) or converted into synthetic methane before being injected into the methane system. From this perspective, **synthetic methane** can play a key role in coupling methane and hydrogen networks and provide further system flexibility in the future.

Hydrogen blending thresholds are not currently harmonised

Current limits on hydrogen blending in natural gas networks in selected European markets



Source: IEA (2019), The Future of Hydrogen.

The integration of low-carbon gases will have profound implications for gas supply flexibility

The **natural gas system currently plays a vital role in meeting seasonal energy demand swings** in markets with cold and temperate climates, where space heating requirements drive strong seasonal variations in consumption. In certain markets, such as the European Union, natural gas alone accounts for over half of the overall seasonal energy demand swing. In addition, **short-term gas deliverability** is critical to meeting demand volatility driven by temperature variations in winter and the fluctuating needs of the power sector through the year.

The supply flexibility of the gas system is ensured through a range of tools and mechanisms along the entire value chain, including seasonal swings in upstream production, spare import capacity (both pipeline and LNG), midstream interconnectivity, underground gas storage (both seasonal and fast-cycling salt caverns), linepack and demand-side response. An overview of the gas flexibility toolkit is provided in Global Gas Security 2019.

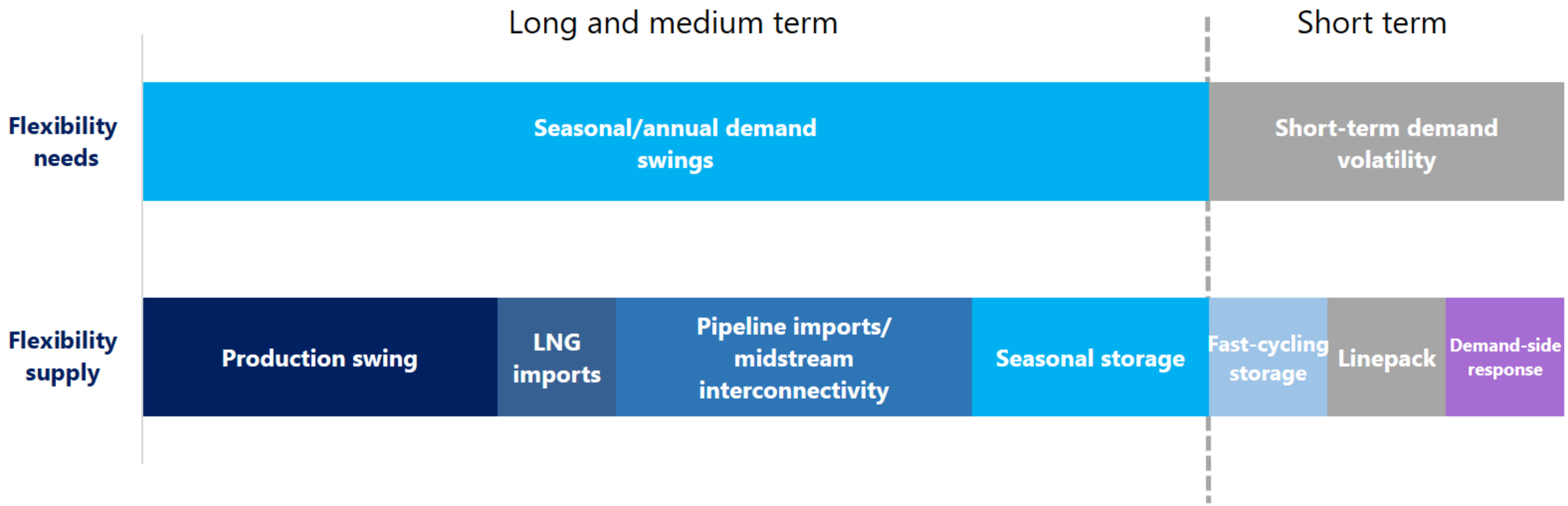
The integration of low-carbon gases will alter gas supply flexibility. While low-carbon gases will benefit from the flexibility toolkit of the existing gas system, their respective production routes and physical characteristics will change gas supply flexibility patterns along the entire value chain.

Production of low-carbon gases is expected to limit supply flexibility

Natural gas output typically displays a constant profile, while certain large **swing fields** can provide significant seasonal production flexibility, which can help to meet seasonal demand variations. For example, the Troll field in Norway allows variations in production of over 2 bcm/m. In contrast, **low-carbon gases** are typically produced by relatively small-scale facilities with limited operational flexibility. **Biomethane production** shows limited daily variability and seasonality as facilities typically operate close to nameplate capacity through the year. The rather minor contribution of biomethane plants in meeting overall gas demand variability is well demonstrated in Denmark. While biomethane accounted for 17% of total gas demand in 2020, the cumulative variability of daily biomethane production was less than 5% of the absolute cumulative daily variability of gas demand in 2020, indicating a proportionally lower contribution to the overall requirement for gas supply flexibility. The production flexibility of biomethane plants could be enhanced by providing incentives to invest in “buffer” capacity; however, the relatively complex and rigid supply chains of raw biogas could be a further limitation. The contribution of biomethane plants to gas supply flexibility could be enhanced by providing them with greater access to underground storage sites.

Gas supply flexibility is ensured through a range of tools along the value chain

Illustrative scheme of gas flexibility needs and supply



Electrolysers producing low-carbon hydrogen from variable renewable energy sources are expected to have a **volatile hydrogen supply** pattern – depending on wind speeds and solar radiation. Production at electrolysers connected only to one source of generation (e.g. either wind or solar) could see a strong **seasonal profile** of hydrogen output, not necessarily following demand requirements. Supply volatility can be reduced by installing batteries or by electricity grid connection, providing electrolysers with a more constant hydrogen output profile. The production profile of gas-based hydrogen through **SMR** combined with CCUS is expected to be **more constant,** as those plants are typically run close to their nameplate capacity. Further upward flexibility options would need to be investigated both from a technical and commercial point of view. Methanation plants producing **synthetic methane** from low-carbon hydrogen and CO_2 would face the same supply flexibility constraints as plants producing low-carbon hydrogen. In this context, **natural gas with CCUS** could be a key provider of supply flexibility both to the methane and hydrogen systems. However, this will largely depend on the upstream flexibility provided by the source field and the flexibility options embedded in the CCUS value chain.

Imports/midstream interconnectivity

In well-interconnected and liquid natural gas markets, **spare pipeline capacity** typically allows market participants to source additional volumes of gas from adjacent markets and/or from their upstream suppliers. As discussed previously, the greater diversity of gas qualities can lead to **interoperability issues** between potentially interconnected networks, hindering the free flow of gases. Close co-operation between network operators and regulatory authorities will be required at the regional level to address issues arising from variations in gas quality via a suitable market design. Higher volumes of hydrogen blending might also require more sophisticated **quality monitoring** and measurement systems. **Synthetic methane** and emerging **deblending** technologies can play an important role in addressing gas quality issues and integrating methane and hydrogen networks.

Underground gas storage

Underground gas storage plays a key role in meeting gas supply flexibility requirements, with global storage capacity close to 430 bcm (or ~10% of global gas demand). **Porous formations** (depleted fields and aquifers) account for over 90% of storage capacity and are typically used to meet seasonal variations, while fast-cycling **salt and rock caverns** are more suited to meeting short-term demand volatility. **Biomethane and synthetic methane** are well-suited to storage in underground facilities due to their almost identical physical and chemical characteristics to natural gas. The majority of storage sites are connected to the transmission network, while a great share of low-carbon gases is expected to be fed into the distribution grid. Reverse flows from distribution to transmission levels would allow low-carbon gases to access those storage facilities.

Hydrogen storage in salt caverns is a proven technology and has been used by the petrochemical industry since the early 1970s. The development of salt caverns depends on specific geological conditions, i.e. the availability of salt formations. Salt caverns that could potentially be repurposed account for just over 8% of global underground gas storage capacity. In contrast, there is **no practical experience of storing pure hydrogen in porous formations**. Hydrogen storage in depleted fields was demonstrated only by blending (up to 10%), while storage in aquifers requires further research. Notably, due to its low energy density, gaseous hydrogen is expected to require about four times as much storage space as methane for the same energy unit stored. Large-scale hydrogen storage will be critical to meet the flexibility requirements of future hydrogen systems, arising both from the demand and production sides. **Liquefied hydrogen** stored in cryogenic tanks would have considerably higher costs compared to LNG due to hydrogen's lower boiling point. **Synthetic methane** could provide an indirect (and costly) route for hydrogen storage in porous formations. A detailed review of recent hydrogen storage developments is provided in the IEA's *Global Hydrogen Review 2021*.

Linepack flexibility

Natural gas volumes "stored" within pipelines can provide short-term flexibility to meet intraday variations in demand both at the transmission and distribution level. Transmission system operators often provide **linepack flexibility services** as a commercial offer to market participants. A higher penetration of low-carbon gases at the distribution level might require **distribution system operators** to provide similar linepack flexibility services, potentially in a co-ordinated manner with the transmission system operator. In the case of hydrogen networks, linepack could play a similar role in intraday balancing. However, due to the lower energy density of gaseous hydrogen, the linepack in a **hydrogen** pipeline may be less than a quarter of a methane pipeline with similar diameter and pressure level. A more robust hydrogen linepack might require additional investment in compressor power.

Demand-side response

In liberalised gas markets, demand-side response is typically provided by price-driven fuel switching in the power sector and by the (limited use) of interruptible supply contracts with industrial consumers. Due to the decentralised form of low-carbon gas production and their different supply flexibility, **the role of demand-side response could increase in the future**. This would require investment from large gas and hydrogen consumers in decentralised, **small-scale storage options**, including high-pressure storage tanks and cryogenic storage facilities for liquefied hydrogen. Small-scale hydrogen storage is an already widespread practice, while remaining an expensive and energy-intensive solution due to the lower energy density of gaseous hydrogen and its lower boiling point compared to natural gas.

Flexibility matrix of low-carbon gases

Flexibility options and challenges along gas value chains

Different types of gases

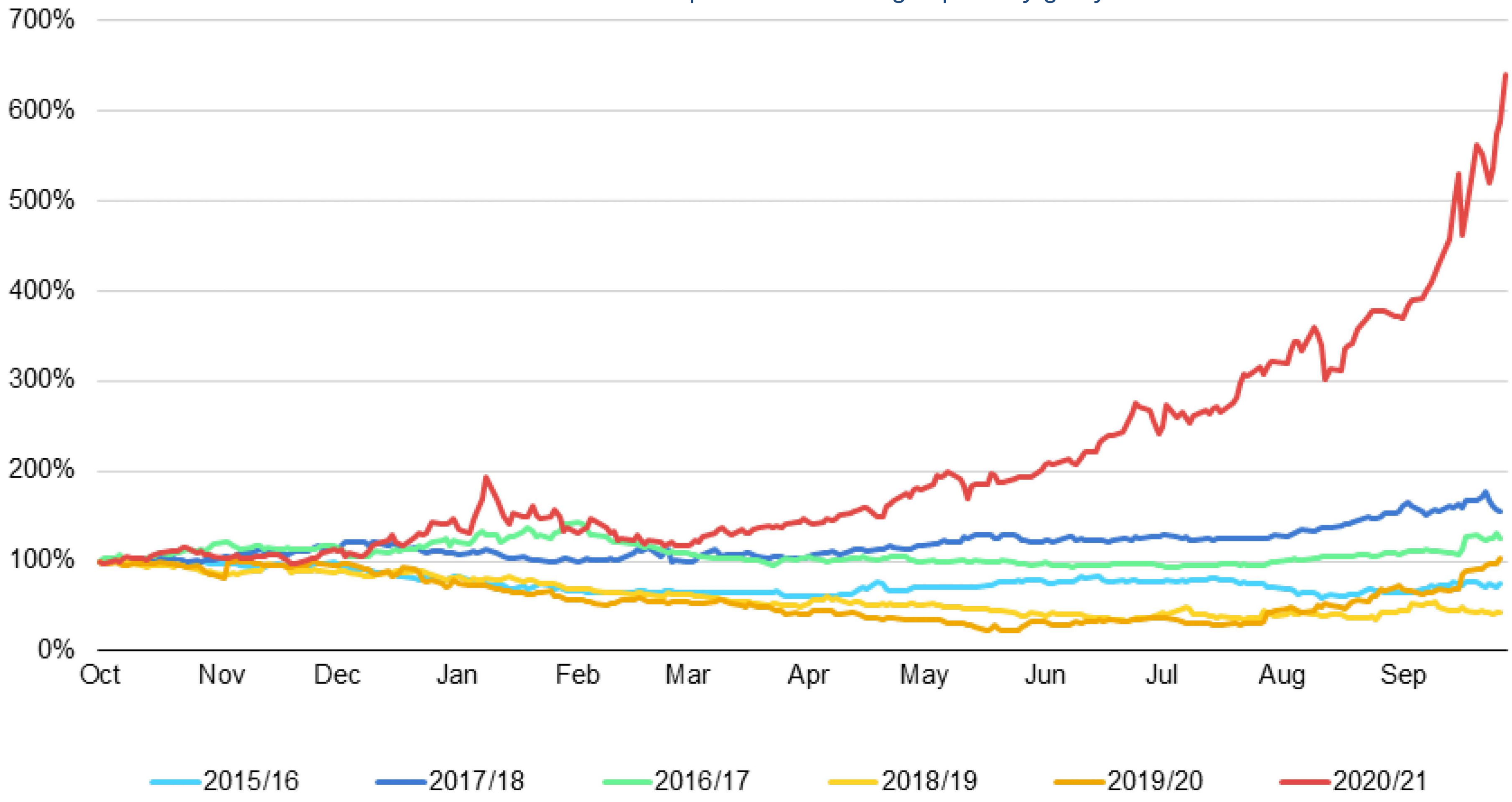
	Production flexibility	Midstream interconnectivity	Underground storage	Liquefied storage	Linepack flexibility	Demand response
Natural gas (with CCUS)	Upstream flexibility supported by swing fields Flexibility embedded in CCUS value chain will need to be considered	Interconnectivity ensured by the build-up of capacity and interoperability in a single-quality gas system Will require development of CCUS infrastructure (pipelines, storage systems)	Porous reservoirs meet seasonal demand swings Fast-cycling salt caverns provide short-term flexibility	Stored in cryogenic tanks at -162°C for peak shaving	Variability of pressure in pipeline system supports intraday balancing	Price-driven fuel switching by dispatchable power generation Limited use of interruptible supply contracts with industrial consumers
Biomethane	Biomethane plants typically have flat production profile	Midstream interconnectivity limited by lack of reverse capacity between TSOs and DSOs and divergent specifications of biomethane	Similar suitability to natural gas Access to underground storage sites limited by the lack of reverse capacity between TSOs and DSOs	Stored in cryogenic tanks at -162°C for peak shaving	Distribution systems typically have lower linepack flexibility due to lower operating pressure levels	Demand-side response might become more widespread Will require investment in decentralised small-scale storage options by large consumers
Hydrogen	Electrolysers may have flat profile or face supply variability when relying on dedicated renewable sources Natural gas reforming +CCUS: limited production flexibility	Midstream interconnectivity limited due to the lack of dedicated hydrogen-network Interoperability with methane networks limited due to blending caps Interoperability of hydrogen networks will require hydrogen quality standardisation	Pure hydrogen storage possible in salt and rock caverns Blending up to 10% has been demonstrated in porous reservoirs Access to underground storage limited by the lack of reverse capacity between TSOs and DSOs	Stored in cryogenic tanks at -253°C, resulting in significantly higher costs vs methane	Linepack in hydrogen transmission systems is ~25% of methane networks', due to lower energy density of hydrogen	
Synthetic methane	Production flexibility limited by the supply profile of hydrogen	Hydrogen converted to synthetic methane ensures greater interoperability with methane network	Similar suitability to natural gas Access might be limited due to missing interconnections	Stored in cryogenic tanks at -162°C for peak shaving		

Notes: DSO = distribution system operator; TSO = transmission system operator; NG reforming = natural gas reforming

Gas market update and short-term forecast

Fast and furious – tighter fundamentals trigger natural gas price escalation

Annual evolution of Europe's TTF natural gas price by gas year



Note: Each gas year begins at 100% on 1 October.
Sources: IEA analysis based on Powernext (2021), [Spot Market Data]

US power generation's switch back to coal on higher gas prices may delay North America's return to pre-Covid levels of gas demand

Natural gas consumption in the **United States** decreased by an estimated 1% y-o-y in January to September 2021, as temperature-driven gains in the initial months of the year were more than offset by a drop in gas-fired power generation. The rebound in natural gas prices from their low 2020 levels hampered fuel competitiveness, resulting in a 6% y-o-y decline in gas consumption for power generation during the first nine months of 2021. This happened in spite of a 2% increase in electricity demand. By contrast, coal-fired generation and renewables including hydro grew by 28% and 5% respectively. The June heatwave provided some support, gas-fired generation experiencing a y-o-y increase for the first month since January, but Q3 confirmed the negative trend – especially in July, when total electricity demand was lower than in 2020.

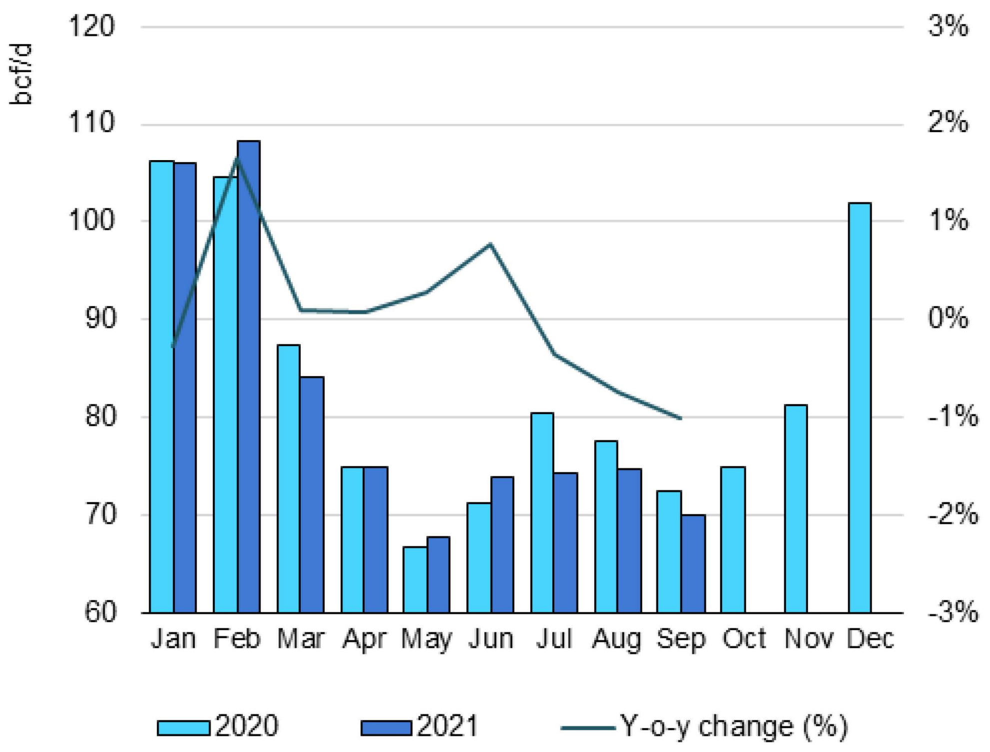
Industrial customers' demand registered positive y-o-y growth during the second quarter to reach a 1.2% increase as of end of June. Gas consumption was lower than last year during the summer months, resulting in a reduced 0.5% y-o-y growth rate for the first nine months of the year. Retail natural gas sales indicate an estimated 6% y-o-y increase in consumption by residential and commercial users in January to September 2021 (compared to 7% as of end of June), reflecting a relatively stable growth rate throughout the summer months.

Canada's natural gas consumption grew by 1.6% y-o-y in the first half of 2021. This increase resulted from wholesale demand from power generation and industrial customers (up 3.3%), whereas retail customers' demand declined by 2.4%. The uplift in wholesale gas demand is being supported by power plants' coal-to-gas conversion in Alberta – the province's largest power generator TransAlta has converted close to 800 MW of coal-fired capacity since the beginning of the year. Canadian pipeline flows to the United States increased by close to 18% y-o-y over the first eight months of the year.

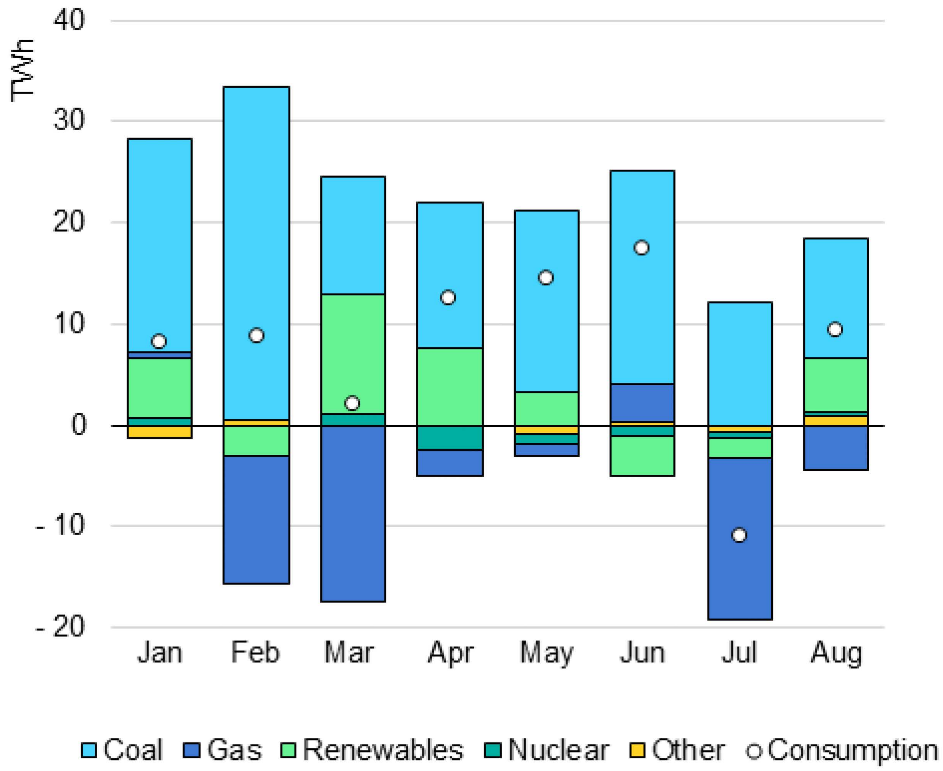
Apparent gas consumption in Mexico increased by over 2% y-o-y during the first half of 2021. The continuous fall in domestic production was more than compensated by imports, especially by pipeline from the United States, which increased by an estimated 14% y-o-y in the first eight months. We have revised our North American gas demand growth forecast for 2021 down to a slight decline (0.3%) – to reflect the continuous decline in US gas for power consumption – followed by a 1.1% increase in 2022, against a 2.5% decline in 2020. The less favourable gas price environment in US power generation is likely to push North America's return to 2019 gas demand levels beyond 2022.

Lower use in power generation dragged total US gas demand growth into negative territory in Q3

Monthly natural gas consumption in the United States (2020-2021)



Monthly power generation y-o-y change in the United States (2021 relative to 2020)



Sources: IEA analysis based on US EIA (2021), Natural Gas Consumption; Natural Gas Weekly Update; Hourly Electricity Grid Monitor.

Record droughts and recovering activity support gas consumption growth in Central and South America

Brazil's natural gas consumption soared by close to 33% y-o-y during the first half of 2021, due to extreme weather conditions. Exceptionally low rainfall levels and the resulting lower hydro reservoir levels prompted a sharp increase in gas use for power generation (up 60% y-o-y in H1). Preliminary data for Q3 indicate a confirmation of this trend, with a close to 10% y-o-y increase in total electricity demand in the first nine months of 2021, resulting from the combination of recovering economic activity and colder-than-average temperatures in the southern part of the country in Q3. Natural gas consumption increased by an estimated 20% y-o-y in the first eight months of 2021, leading to supply tensions and a soaring sixfold increase in LNG imports.

In **Chile**, lower hydropower production levels (20% y-o-y decrease as of end of August) also prompted an increase in thermal generation, which resulted in a 25% y-o-y increase in LNG imports in January to August 2021.

Gas consumption in **Argentina** stabilised over the first five months of 2021 compared to 2020 (with a modest 0.36% y-o-y increase). Growth was observed in most sectors and in particular in transport (24%), power generation (9%) and industry (3%) compared to the first five months of 2020, but these contributions were almost completely offset by a drop in gas use at refineries (down 75% y-o-y) as gas supply tightened. Domestic gas production fell by 7% y-o-y in the first five months, leading to supply tensions and a fourfold increase in LNG imports.

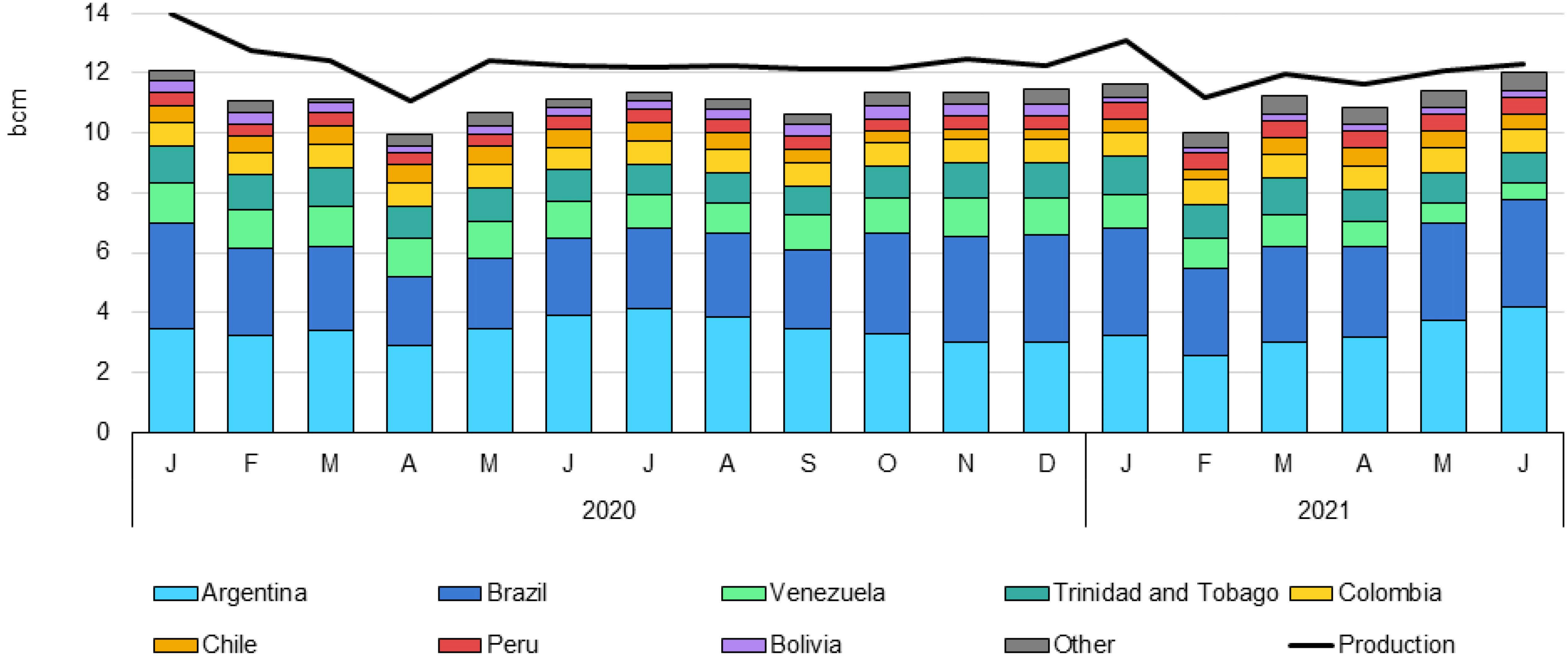
Apparent gas consumption rose in **Central America and the Caribbean** as LNG imports jumped by more than 43% y-o-y in the first eight months of the year. This was prompted by higher needs in the Dominican Republic, Jamaica and Puerto Rico, whereas flows to Panama decreased.

Preliminary data suggest that **Venezuela**'s natural gas consumption fell by 33% y-o-y in the first half of 2021. Domestic production declined further during the second quarter, with the closure of a high-pressure compression complex in late March 2021 due to a pipeline explosion, taking down close to 20% of the country's output.

This forecast expects gas demand in Central and South America to increase by 4% in 2021, followed by a slight decline of 1% in 2022 (on the assumption of normal temperature and rainfall conditions), insufficient to offset the close to 10% fall in consumption observed in 2020.

Strong Brazilian needs pushed South American gas demand in June to its highest monthly level since January 2020

Monthly natural gas demand and production, Central and South America, 2020-2021



Sources: IEA analysis based on ANP (2021), Boletim Mensal da Produção de Petróleo e Gás Natural; ENARGAS (2021), Datos Abiertos; ICIS (2021), ICIS LNG Edge; IEA (2021), Monthly Gas Data Service; JODI (2021), Gas Database; MME (2021), Boletim Mensal de Acompanhamento da Industria de Gás Natural.

Following strong growth in H1 2021, European gas consumption dropped in Q3 2021…

European gas consumption grew by close to 10% y-o-y during Q1-3 2021. This growth was concentrated in H1 2021, when gas demand grew by a notable 14% y-o-y. Strong demand was supported by a prolonged heating season, higher gas burn in the power sector and gradual recovery in economic activity. Growth was particularly strong during Q2, with European demand soaring by close to 25% –its highest y-o-y growth on record.

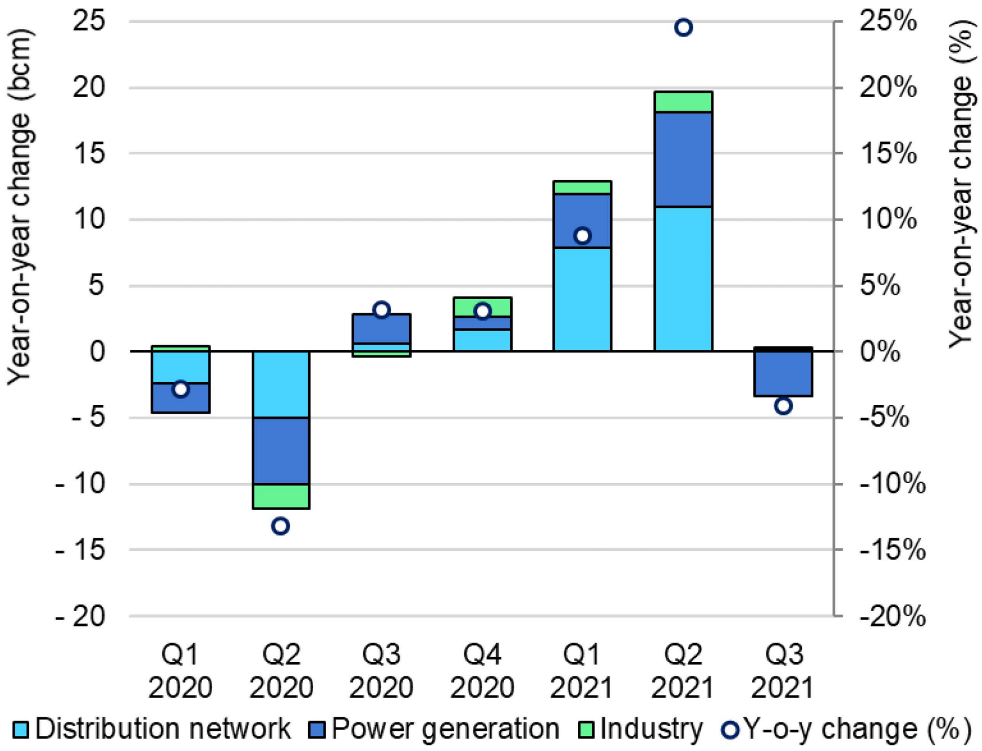
In contrast, **European gas consumption dropped by close to 4% y-o-y during Q3**, primarily due to lower gas demand in the **power sector**. Strong recovery in nuclear output (up by 18% y-o-y) reduced the call on thermal power generation. The strong increase in gas prices, soaring to a quarterly record of USD 16/MBtu on TTF, eroded the cost-competitive position of gas-fired power plants against coal-based generation during Q3. This resulted in substantial **gas-to-coal switching** in the European power sector despite the strong gains in carbon prices: while coal-based generation rose by close to 15%, gas-fired power output plummeted by over 12% y-o-y during Q3. In contrast with the rest of Europe, gas-fired power generation rose by 60% in **Turkey** compared to last year, amid a strong recovery in electricity demand and plummeting hydro output (down 33% y-o-y). Moreover, oil-indexed gas prices rose only moderately against soaring imported coal prices, which improved the cost-competitiveness of Turkey's gas-fired power plants.

Europe's distribution network-related consumption grew by an estimated 1% y-o-y on recovering activity in the **commercial and service sectors**. Gas prices surging to record highs in Q3 weighed on gas demand in **industry** in that quarter, with several companies reporting temporary curtailment of ammonia and fertiliser production at their plants.

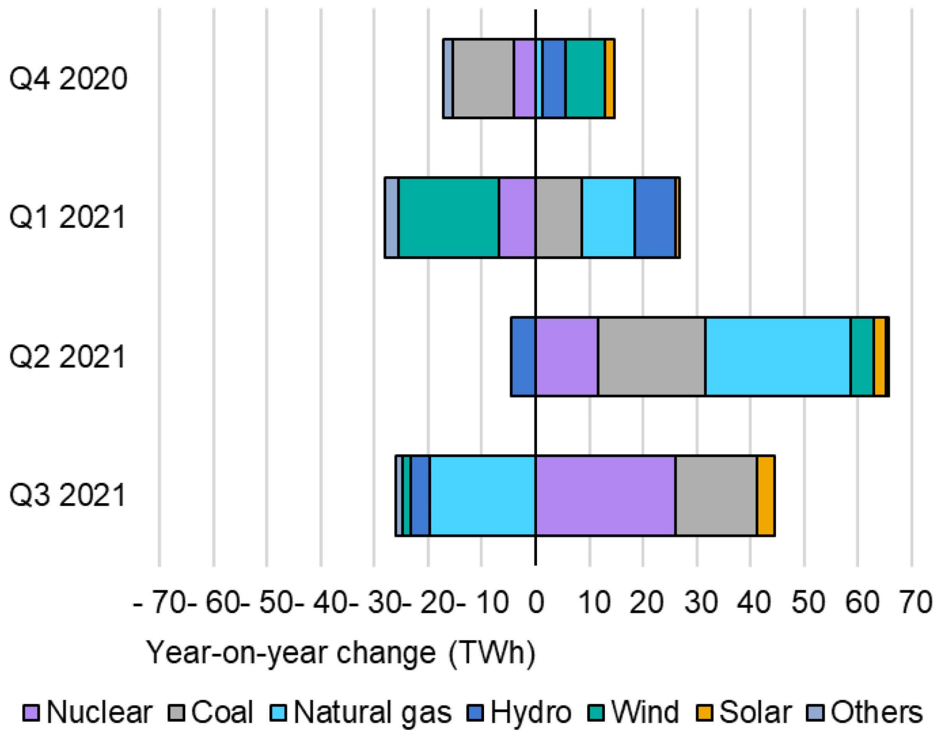
European gas demand is expected to increase by 4.5% y-o-y in 2021, with most of the demand growth concentrated in H1, while high gas prices during the heating season are expected to weigh both on gas burn in the power sector and gas demand in industry. Following the strong recovery in 2021, **European gas consumption is expected to decline by 2% y-o-y in 2022**. Assuming average weather conditions in Q1 and Q2, **distribution network-related demand in 2022 is expected to decline** due to lower space heating requirements. The IEA's latest Electricity Market Report foresees **a decline of 2% in European gas-fired power generation in 2022**, due to the rapid expansion of renewables and despite the continued closure of coal-fired power plants. **Gas demand in industry** is forecast to continue to recover close to its pre-2020 levels.

…as record high gas prices led to gas-to-coal switching in the European power sector

Estimated change in quarterly European gas consumption by sector (Q1 2020-Q3 2021)



Estimated change in quarterly European power generation (Q4 2020-Q3 2021)



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

Asia's uneven gas demand recovery continues in 2021-2022, despite headwinds from high prices

Asia's gas demand growth remained robust in the first eight months of 2021, driven by cold winter weather and hot summer temperatures across Northeast Asia as well as a sharp rebound in industrial activity, especially in China. The recovery in demand remained more muted in South and Southeast Asia, where high LNG prices tempered growth. In 2021 total gas consumption in Asia is expected to increase by 7%, predominantly led by China, which alone accounts for 73% of the net growth in demand. A group of emerging Asian economies together contribute 16% and Korea adds another 7% to Asia's growth in 2021. In 2022 the region's gas demand growth is projected to remain strong at 5%, driven mainly by China, emerging Asia and India, which account for 65%, 28% and 11% of the net demand growth in Asia, respectively.

China's gas consumption expanded at a breakneck pace in 2021, posting double-digit y-o-y rates in seven of the first eight months and growing by a remarkable 16% y-o-y in the January to August period. This rapid increase was fuelled by cold winter weather in January, followed by low hydro availability in the spring and hotter than average temperatures in southern China during the summer, which boosted power sector gas demand in the first eight months. Industrial demand growth also remained robust thanks to the strong rebound in economic activity and continuing coal-to-gas conversions (despite periodic gas shortages in H1 2021). In 2021 total gas demand is projected to increase by 13%, led by the industrial, power generation and residential and commercial sectors (accounting for 45%, 29% and 13% of total growth, respectively). The pace of demand expansion is set to decelerate in the rest of the year due to the expected normalisation of seasonal weather patterns and demand erosion due to surging fuel prices. In 2022 consumption growth is anticipated to slow to an annual rate of 8% due to normal weather and moderating growth in GDP.

India's gas demand increased by a modest 3% y-o-y in the first seven months of 2021, as high spot LNG prices dented demand in the refining and petrochemical sectors (where some operators switched from LNG to liquid fuels) and in power generation (where gas burn saw steep y-o-y declines during the summer months). The demand impact of India's second Covid-19 wave in Q2 2021 turned out to be muted, as the city gas segment – the worst-hit sector during India's first wave in 2020 – expanded by more than 40% y-o-y in the first seven months and by a whopping 75% in Q2 alone (partly due to the low basis from the previous year). In 2021 India's gas consumption is expected grow by 3%, as high LNG prices suppress demand in LNG-dependent downstream industries in particular. In 2022 demand growth is anticipated to reach 7%, driven by rising domestic production, expanding gas infrastructure, recovering GDP and a supportive policy environment. However, high LNG prices in 2022 would continue to limit the scope for a more rapid recovery.

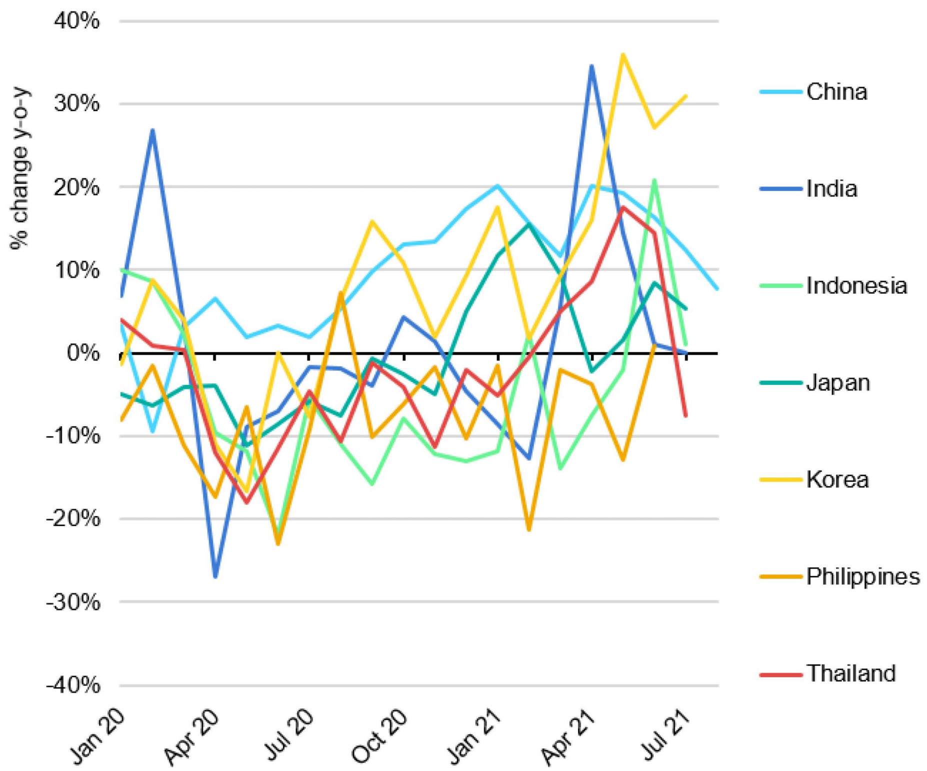
Japan's gas consumption increased by 8% y-o-y in the first seven months of 2021. This was driven by strong growth in power generation and the residential sector during a cold blast in January, as well as by a steady increase in industrial gas demand during the entire January to July period. Japan had a state of emergency in force for most of the first seven months, but the effect was limited due to the lack of a mandatory nationwide lockdown. Despite the strong growth up to July, gas consumption in 2021 as a whole is expected to remain flat compared with 2020, driven by a sharp decrease in gas-fired power generation (on the assumption of average winter temperatures and a series of nuclear restarts). In 2022 gas consumption is expected to decrease by 2% as continuing nuclear restarts and growing solar generation reduce demand in the power generation sector.

Korea's gas consumption increased by a remarkable 17% y-o-y during the first seven months of 2021, driven by strong growth in both the power generation and city gas sectors. Power sector gas demand was boosted by the temporary shutdown of several coal-fired power plants and nuclear reactors, especially during the cold blast in January. Korea's economic recovery also contributed to growing gas demand in both the power generation and city gas sectors. Overall gas consumption in 2021 is set to increase by 8% y-o-y, as the pace of growth is expected to slow in the second half of the year due to a return to average winter temperatures and the addition of a new nuclear unit (Shin Hanul 1). In 2022 gas consumption is expected to decrease by 3% due to higher nuclear generation and normal winter temperatures following a particularly cold start to 2021.

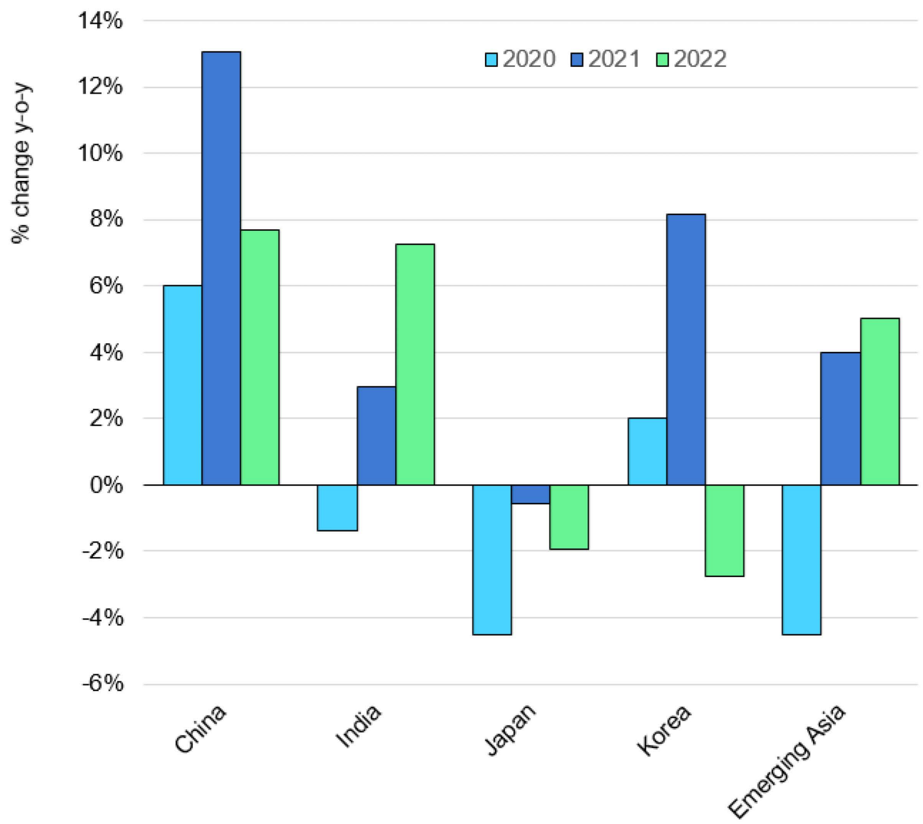
Emerging Asia's demand recovery remained subdued in early 2021 as price-sensitive markets, including Pakistan and Bangladesh, curtailed their gas use during the spot LNG price spikes in January. However, there were signs of recovering demand in H1 2021 as monthly y-o-y growth rates in Thailand, Indonesia and the Philippines returned to positive territory within the January to June period (before reversing again in July in the case of Thailand). Preliminary shipping data indicate that net LNG imports into the region posted a strong 13% y-o-y increase in the first eight months of 2021 (with most of the growth occurring since Q2). In 2021 total gas consumption in the region is expected to increase by 4%, fuelled by an ongoing economic recovery and strong power demand growth – albeit muted by sustained high LNG prices and resurgent waves of Covid-19 across the region. In 2022 gas demand in emerging Asia is projected to increase by 5% as the impact of Covid-19 wanes and economic growth accelerates, although higher than expected LNG prices present a downside risk to the forecast.

Asia's demand recovery is led by China and Korea; India and emerging Asia to catch up in 2022

Monthly gas demand in selected Asian countries



Gas demand in selected Asian countries (2020-2022)



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

Q1 lows in US gas output were balanced by summer growth, but limited increase is expected until 2022

US natural gas production grew at a modest though continuous rate during the summer months to reach close to 80 bcm in September 2021, in spite of storm-related production cuts in the Gulf of Mexico. This progressive growth offset the lower y-o-y production numbers experienced in Q1, resulting in a 0.4% y-o-y increase in the first nine months of 2021 – up from a 6% decline in Q1. The Appalachian Basin remains the main driver behind this growth, with monthly output standing above 28 bcm in September, its second-highest record after December 2020 (close to 29 bcm).

Drilling activity peaked in late July with 104 active gas rigs, its highest level since mid-March 2020, and returned to the 100 mark in mid-September. Activity remains stable in the Marcellus and Utica plays of the Appalachian Basin, oscillating around 65 to 70 new wells drilled per month since the beginning of the year, while growing in the Haynesville play – from 42 wells drilled in January to 49 in July. Well completion activity follows the same trends in the different pure shale gas plays, exceeding in all cases the monthly drilling numbers. The stockpile of drilled-but-uncompleted wells continues its decline in the Appalachian, down by 17% y-o-y in July, which enables additional production capacity despite stable drilling activity, and at lower cost.

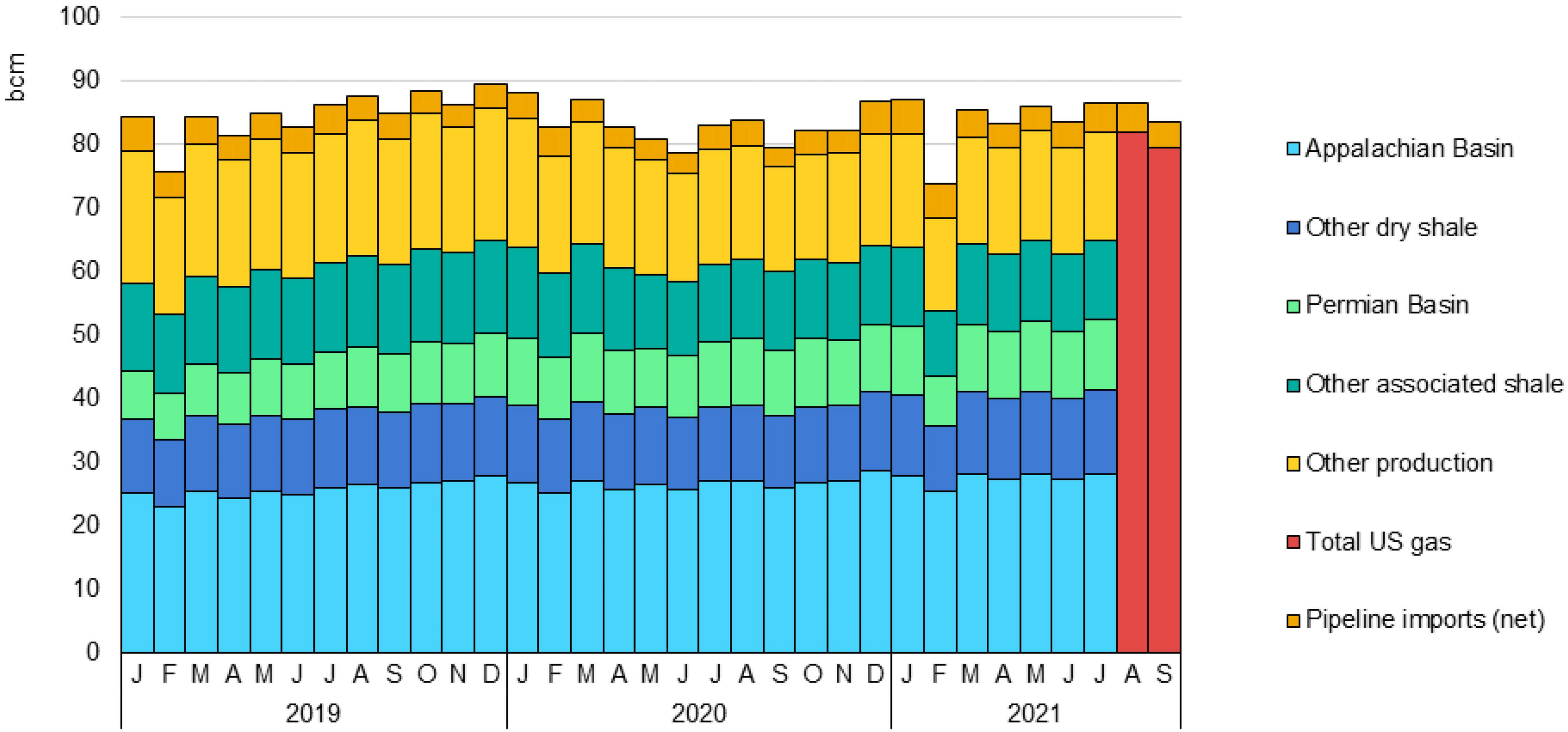
The associated gas contribution from the Permian Basin and other oil-driven plays has remained relatively stable since the beginning of the year, accounting for about one-third of total US shale production so far in 2021.

US gas output growth has remained limited so far this year in spite of a sharp recovery in oil and gas prices, as most upstream companies remain focused on keeping strict spending discipline and returning capital to shareholders. Supply needs increased as exports via LNG and to Mexico by pipeline rose by a respective 60% and 14% y-o-y in January to August 2021, which resulted in a 17% y-o-y growth in net pipeline imports from Canada over the same period.

US natural gas production is therefore expected to remain stable in 2021 compared to 2020, with a less than 1% y-o-y increase, principally supported by dry shale plays and associated production from the Permian Basin, compensating for declines from other oil-driven shale plays and conventional gas production. Continuous support from the ramp-up in LNG exports is expected to spur further production growth in 2022, with a forecast growth rate of close to 3%.

US gas production continued to grow during the summer, stands slightly above 2020's level over the first nine months of 2021

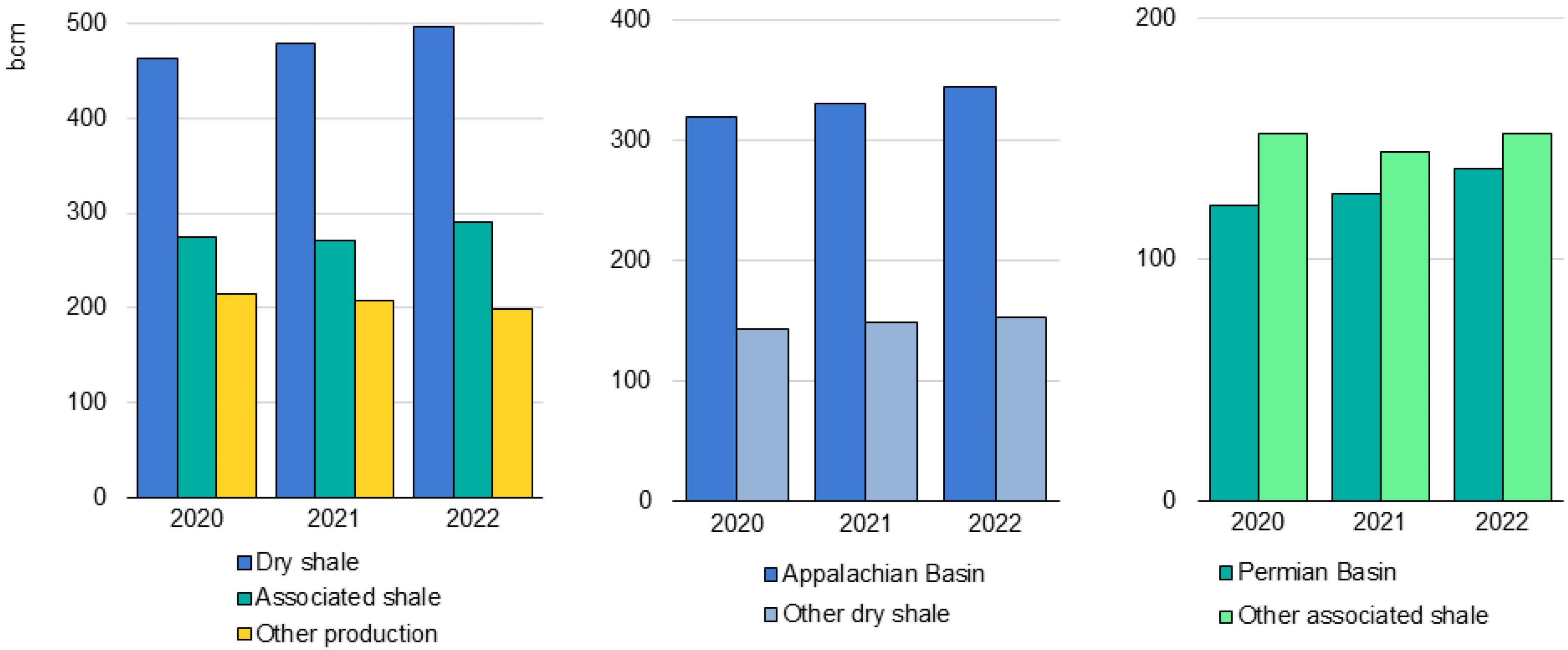
Gas production by type in the United States (2019-2021)



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

US dry gas production is expected to marginally increase in 2021 thanks to Appalachian plays; further growth is foreseen in 2022 with a rebound in associated shale gas output

Dry gas production by main source in the United States (2020-2022)



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

Tighter European gas supply continued during Q3 2021…

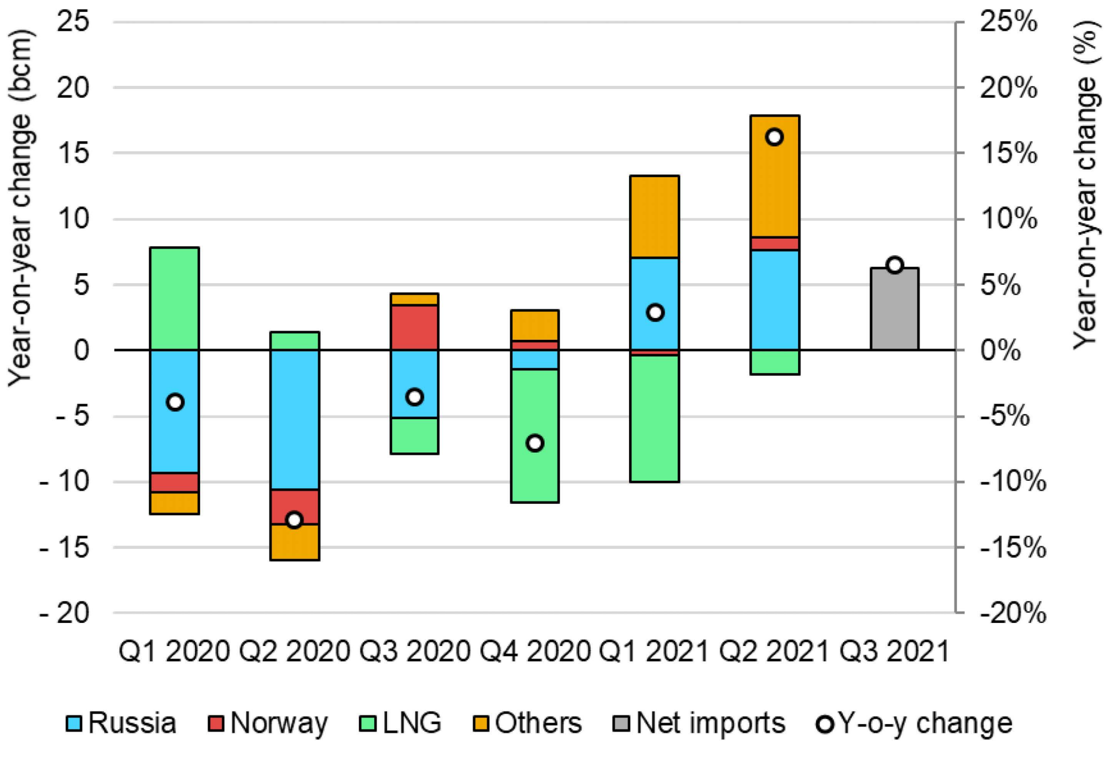
European natural gas supply continued to tighten over the summer, amid lower LNG inflow, declining domestic production and a moderate y-o-y growth in pipeline deliveries.

LNG inflows remained depressed during Q3 of 2021, falling by 9% y-o-y. The price spread between Asian spot LNG and TTF widened from USD 0.9/MBtu in Q3 2020 to an average of USD 1.4/MBtu during the same period this year. This incentivised the continued shift of LNG flows towards the Asia Pacific region. In addition, Europe faced stiff competition from Brazil and other hydro-rich South American markets, which ramped-up LNG imports amid plummeting hydro generation and severe drought in the region. Qatar's LNG deliveries to Europe fell by almost 30% y-o-y, with cargoes drifting towards more lucrative markets. US LNG deliveries to Europe doubled y-o-y, supported by a TTF-Henry Hub price spread averaging at USD 12/MBtu. **Non-Norwegian domestic production** fell by an estimated 16% y-o-y in the first seven months of 2021, with the Netherlands and the United Kingdom accounting for over 80% of the drop. Heavy maintenance on the UK Continental Shelf resulted in a steep output drop of 40% y-o-y during May to July. Lower LNG inflow together with declining domestic production created additional market space for pipeline suppliers. **Norwegian pipeline flows** rose by over 10% y-o-y in Q3, supported by higher deliveries to the Netherlands. Exports from **North Africa** rose by over 50% y-o-y in Q3, driven by higher flows from Algeria both to the Iberian gas market and Italy. **Net pipeline exports from Russia** rose by 14% y-o-y in Q1-3, although showing a pronounced differentiation: while deliveries to Turkey more than doubled, flows to the rest of Europe rose by a mere 3% y-o-y. **Azeri exports** via the TAP pipeline rose close to 5.5 bcm since the beginning of the year.

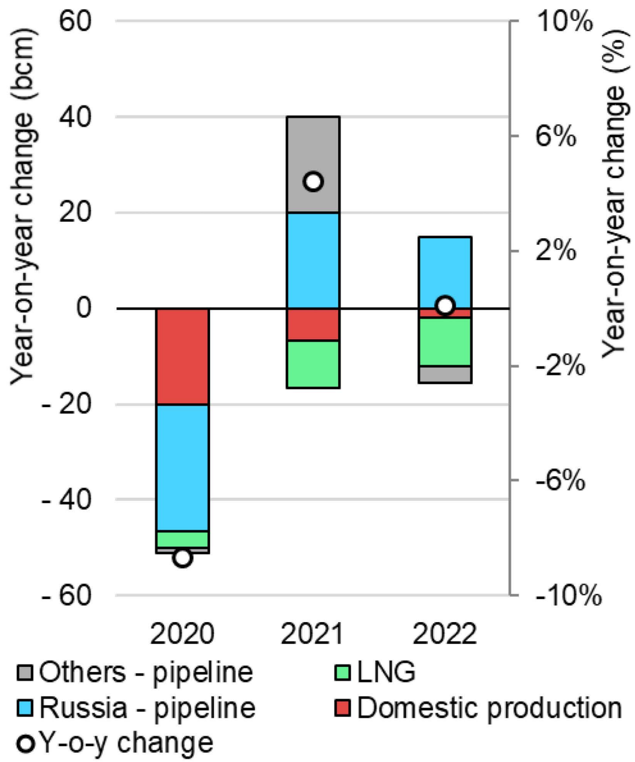
Tighter gas supply over the summer contributed to **lower gas storage levels** in Europe, standing 17% below their five-year average at the beginning of October. This is **set to increase Europe's import requirements in Q4** under average weather conditions, benefiting both pipeline and LNG suppliers. For the full year of 2021, combined pipeline deliveries from Russia and North Africa are set to increase by over 15%. The construction of Nord Stream 2 was completed, although the starting date of commercial flows remains uncertain. LNG inflows are forecast to fall below last year's levels. Following a drop of 3% in 2021, domestic production is expected to decline only marginally **in 2022**, as **higher output in Norway and the United Kingdom** is set to compensate for declining production in the rest of Europe. **Azeri exports** via the TAP pipeline are expected to reach 10 bcm. **Russian net pipeline exports** are set to oscillate between 190 bcm and 195 bcm, while **LNG inflows** into Europe are foreseen falling to close to 90 bcm.

…amid lower LNG inflows and moderate growth in Norwegian and Russian pipeline deliveries

Estimated change in monthly European gas imports and deliveries from Norway (Q1 2020-Q3 2021)



Change in Europe's natural gas supply (2020-2022)



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

Eurasian gas production: Strong growth in the first eight months of 2021…

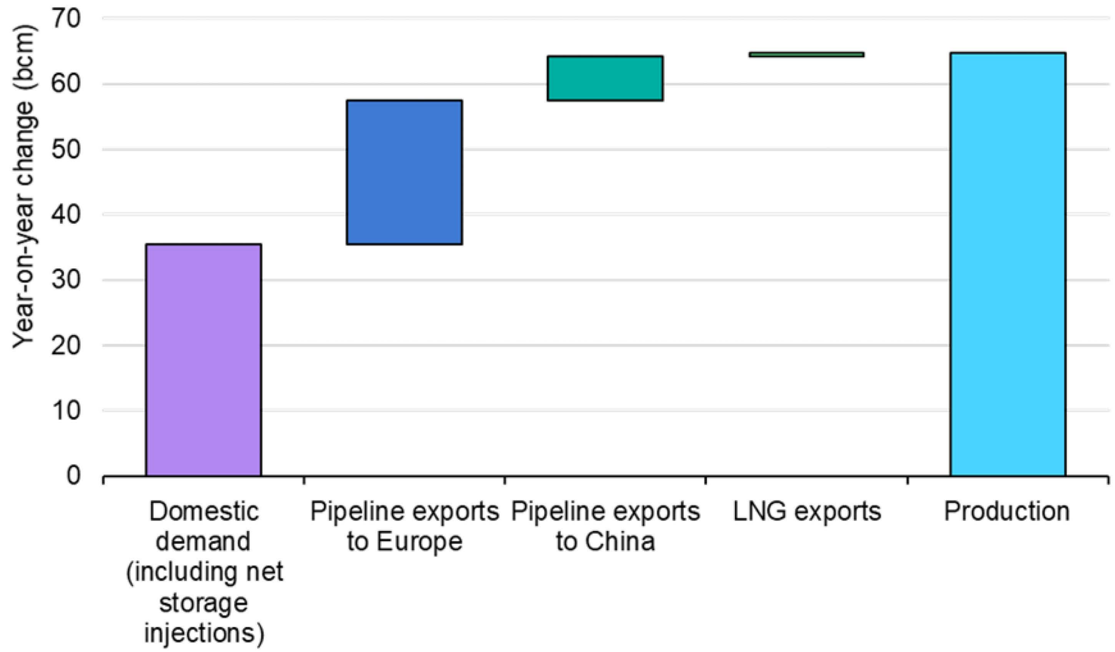
Natural gas output in Eurasia grew by an estimated 11% y-o-y in the first eight months of 2021. Strong recovery in extra-regional exports, rapidly rising domestic demand and restocking needs after a long and cold 2020/21 heating season all contributed to this strong growth in production.

Russia's gas output rose by 12% (or 53 bcm) y-o-y in the first eight months of 2021. This was partly driven by **domestic demand**, rising by close to 12% in H1 2021. Recovery in domestic consumption was driven by a cold and long heating season extending into Q2, higher gas burn in the power sector and a gradual recovery in economic activity. Moreover, Russia's storage injection needs are estimated to have doubled compared to last year during the first eight months of 2021, as storage sites closed the 2020/21 heating season with record low inventories. Russia's **extra-regional exports** rose by close to 20% y-o-y, largely supported by the strong recovery in **pipeline deliveries to Europe**. Growth has been particularly spectacular in pipeline exports to Turkey, more than doubling compared to last year. Pipeline supplies to **China** via Power of Siberia rose almost threefold, reaching 6.7 bcm in the first eight months of 2021. **LNG exports** rose by 2% y-o-y. **Central Asia**'s natural gas production rose by an estimated 10% y-o-y during January to August, largely driven by Turkmenistan and Uzbekistan. Pipeline exports to China rose by over 8% y-o-y, with growth concentrated in June-August, when exports rose by almost 20% y-o-y. This was supported by the widening price differential with Asian LNG spot prices. **Azeri** gas output rose by 15% y-o-y, driven by the ramp-up of exports to Europe via the TANAP and TAP pipeline systems. **Ukraine**'s gas production declined by 7% y-o-y.

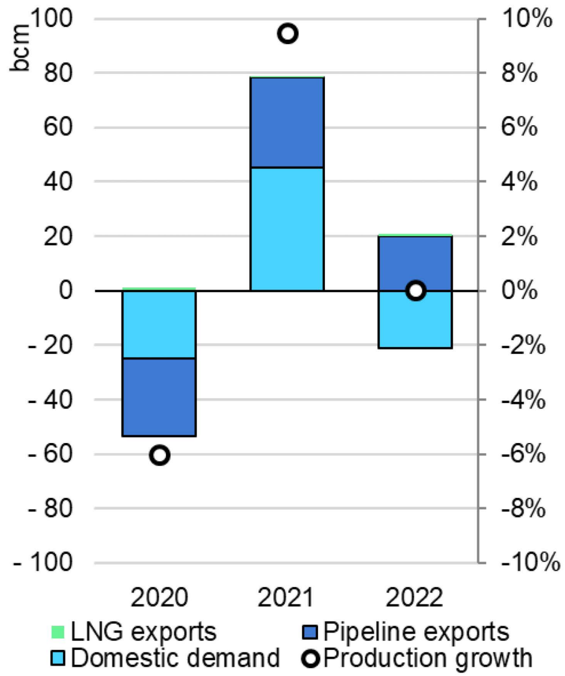
Eurasia's gas production is expected to increase by close to 9% y-o-y in 2021, amid continued strong export growth and sustained recovery in domestic gas demand in the remaining months of the year. New export corridors support this growth: Azeri flows via the TAP pipeline are foreseen to hover around 8 bcm, while pipeline exports to China are set to reach 10 bcm. Combined pipeline deliveries from Russia to Europe and Central Asia to China are expected to rise by 12%. Following strong growth in 2021, **Eurasia's production is expected to increase by 1% y-o-y in 2022**, as the return to average weather conditions weighs on space heating requirements during Q1 and Q2 and leads to an average storage cycle. Exports via new corridors are expected to grow, with Russian deliveries to China reaching 15 bcm and Azeri flows via TAP ramping up to 10 bcm in 2022. Russia's net pipeline exports to Europe are forecast to hover around 190-195 bcm and Central Asian supplies to China around 40-45 bcm. LNG exports are expected to increase by 3% with the full ramp-up of Yamal Train 4.

…driven by domestic demand, extra-regional exports and restocking needs

Estimated change in Eurasia's natural gas balance (January-August 2021)



Change in Eurasia's natural gas balance (2020-22)



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

Stronger than expected LNG trade growth of 5% in 2021 is set to decelerate to 2% in 2022

In the first eight months of 2021 global LNG trade increased by 6% y-o-y, a sharp acceleration from the 2020 growth rate of 1%, but lower than the average rate of 10% in the 2015-2019 period. Import growth was led by the Asia Pacific region, which registered a 13% y-o-y increase during the first eight months of 2021. Most of the expansion came from China (up by 24% y-o-y), Korea (up by 20%) and Japan (up by 6%) as the early 2021 cold spell gave way to hot summer weather in Northeast Asia. These conditions – combined with a strong economic recovery and limited coal, nuclear and hydro availability in parts of the region – led to a rapid rise in LNG imports. India recorded a 5% y-o-y import decline in the first eight months, as high prices and rising domestic production suppressed LNG demand. Importers in emerging Asia saw a 13% y-o-y increase in LNG inflows as a gradual gas demand recovery took hold in the region. Central and South America was another strong contributor, nearly doubling its LNG receipts in the first eight months over the same period in 2020. This was chiefly driven by Brazil, where the worst drought since 1930 led to a sixfold y-o-y increase in LNG inflows from January to August. Meanwhile, Europe saw an 18% y-o-y decline as higher Asian prices, low seasonal spreads and a rise in pipeline flows to Turkey combined to discourage LNG imports. The Middle East and North America experienced small declines.

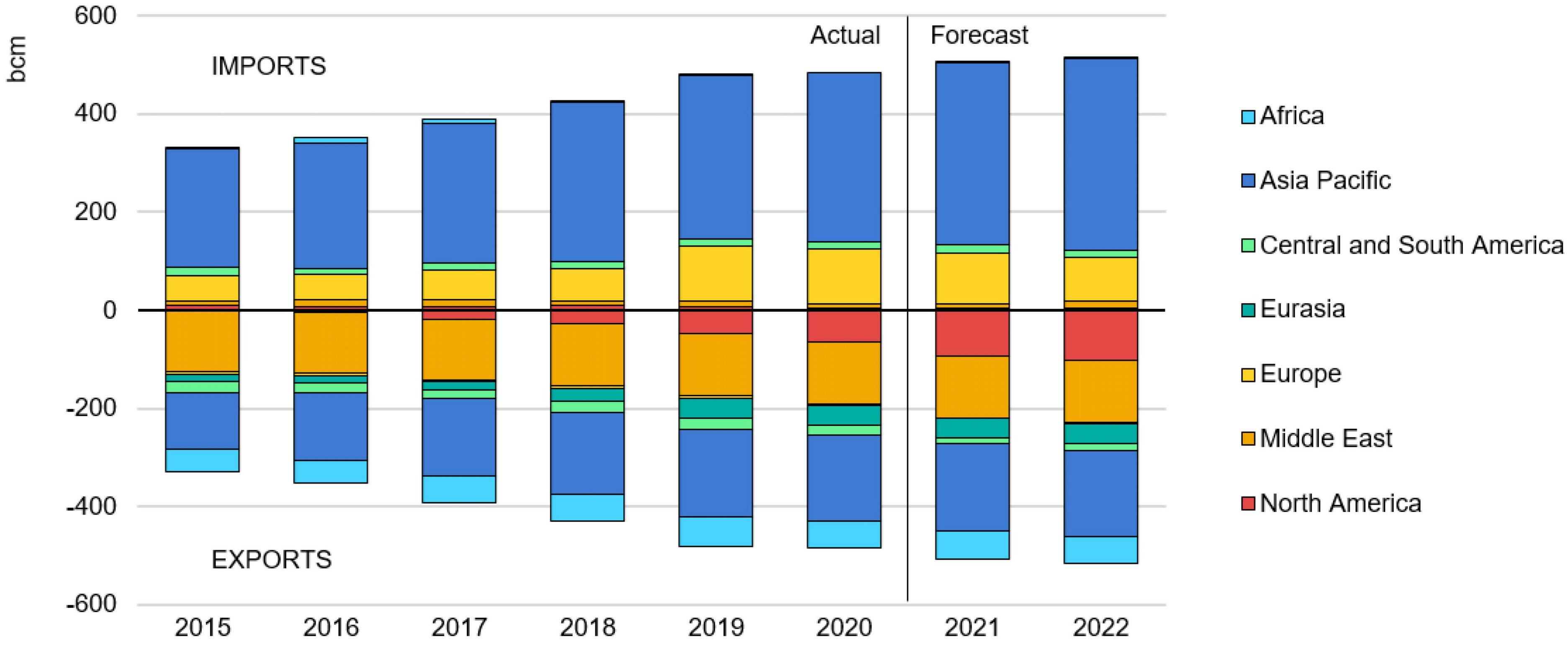
LNG export growth in the first eight months of 2021 was led by the United States, which recovered from a period of widespread cargo cancellations a year earlier and posted 65% y-o-y growth. Egypt, where the Damietta plant restarted operations in February 2021, registered a ninefold y-o-y increase in LNG outflows, making it the second-biggest contributor to global LNG export growth in the January to August period. The biggest export declines occurred in Trinidad and Tobago and Norway due to feed gas shortages and an extended outage following a fire in September 2020, respectively.

In 2021 global LNG trade is projected to expand by 5%, an upward revision of our previous forecast due to a series of extreme weather events earlier this year. All net import growth comes from the Asia Pacific region, while declines in Europe are partially counterbalanced by a spike in South America. Export growth is dominated by North America, while small increases in Africa and Asia Pacific are offset by declines in Europe and South America.

In 2022 global LNG trade growth is expected to slow to 2% as the Asian demand boom cools, European import declines continue and the drought-driven spike in South America reverses. Asia accounts for all net growth in imports, while North America is responsible for all incremental exports – with additional increases in Europe and South America largely offset by declines in the rest of the world.

Asia Pacific drives LNG import growth and North America leads LNG export growth in 2021-2022

LNG imports and exports by region (2015-2022)



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

A tight summer market propelled Asian and European spot prices to record seasonal highs

Tighter than expected supply, continued demand recovery in Asia and strong storage injections in Europe all contributed to the **soaring spot prices** seen in Q3 2021

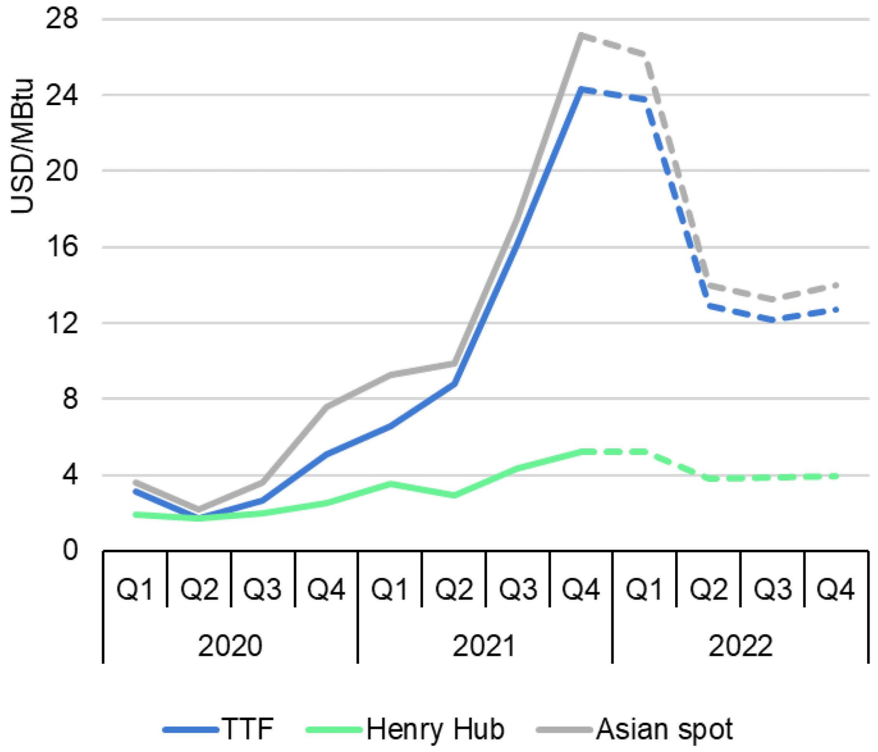
In the United States, **Henry Hub** more than doubled compared to last year and reached an average of USD 4.3/MBtu – its highest Q3 level since 2008. While production returned to growth and domestic consumption remained below last year's level in Q3, the strong growth in pipeline and LNG exports resulted in a tight summer market. Forward curves as of end of September suggest Q4 prices averaging USD 5/MBtu. This would translate into an annual average of USD 4/MBtu – its highest since 2010. In Europe, **TTF** prices rose sixfold compared to last year to an average of USD 16/MBtu – the highest quarterly average since the Dutch hub was set up in 2003. The strong rise in gas prices was driven by the combination of tighter than expected supply and a strong increase in regulation-driven storage injections (up by more than 76% y-o-y). Forward curves suggest TTF prices averaging USD 24/MBtu during Q4, translating into an average of USD 14/MBtu in 2021 – its highest level on record. **Asian spot LNG** prices soared fivefold to an average of USD 17.5/MBtu in Q3, with September trading at USD 22/MBtu – the highest level for this month in our records. Strong demand growth in key Asian markets, together with stiff competition for additional cargoes (with Europe and Latin America) and unplanned outages, provided upward pressure on spot prices.

Oil-indexed LNG contracts traded at an estimated discount of 40% during Q3. Forward curves indicate that the market expects Asian spot LNG prices to average USD 27/MBtu during Q4, resulting in an annual average of USD 16/MBtu – its highest since 2013. The strong growth in regional spot prices was accompanied by **widening price differentials**: the Asian spot LNG-Henry Hub and TTF-Henry Hub spread averaged at USD 13 and USD 12/MBtu respectively, their highest level since the conterminous US started LNG exports in 2016.

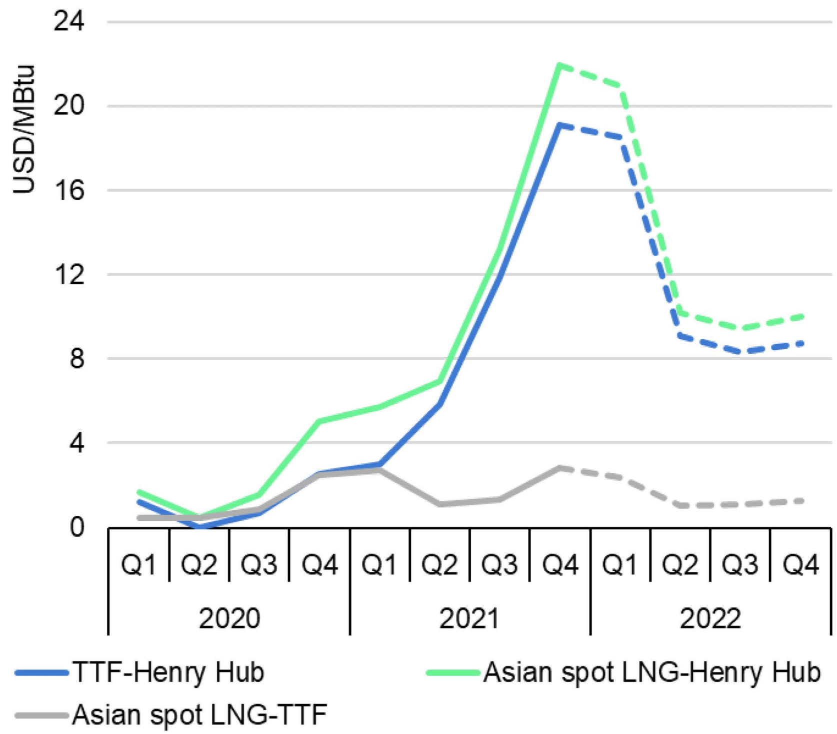
Current high gas prices are expected to linger into Q1 2022, while expectations around improving supply availability are weighing on H2 2022 prices. Forward curves as of end of September suggest an expectation of Henry Hub rising by 5%, TTF by 10% and Asian spot LNG prices by 6% in 2022 above this year's levels. Prices are expected to moderate after the end of the heating season. During the second half of 2022 Henry Hub prices are expected to average 18% below H2 2021 levels, with both TTF and Asian spot LNG almost 40% below. Based on current forward curves, oil-indexed LNG contracts are set to retain a discount during 2022. Regional price spreads between Asian spot LNG and Henry Hub, and TTF and Henry Hub, are expected to tighten to USD 12.5 and USD 11/MBtu respectively, incentivising growth in inter-basin LNG trade.

Improving supply availability is expected to moderate H2 2022 prices

Main spot and forward natural gas prices
(January 2020-December 2022)



Interregional price spreads
(January 2020-December 2022)



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

Strong growth in LNG trade propelled LNG spot charter rates to new seasonal highs in Q3 2021

The LNG shipping market remained heated during the summer of 2021, with LNG spot charter rates climbing to new seasonal highs in Q3, reflecting strong growth in LNG trade and higher tonne-mile demand.

LNG spot charter rates more than doubled compared to last year in both the Atlantic and Pacific basins, to reach an average of USD 84 000/day and USD 80 000/day respectively during Q3. This is despite the significant increase in the LNG carrier fleet, with over 50 new vessels being delivered since the beginning of Q3 2020. In contrast with last year, when LNG trade contracted by 4% y-o-y in Q3 and led to cargo cancellations, spot charter rates in Q3 2021 were **supported by the strong growth in LNG trade** (up by over 9% y-o-y) and the rapid recovery in the US-Asia Pacific LNG flows, which more than doubled compared to last year. These longer shipping routes in turn supported **tonne-mile demand** (tonnage of cargo multiplied by shipping distance), which rose more rapidly than LNG trade. According to Kpler data, tonne-mile demand increased by 14% y-o-y during July and August, contributing to a tighter shipping market and higher spot charter rates.

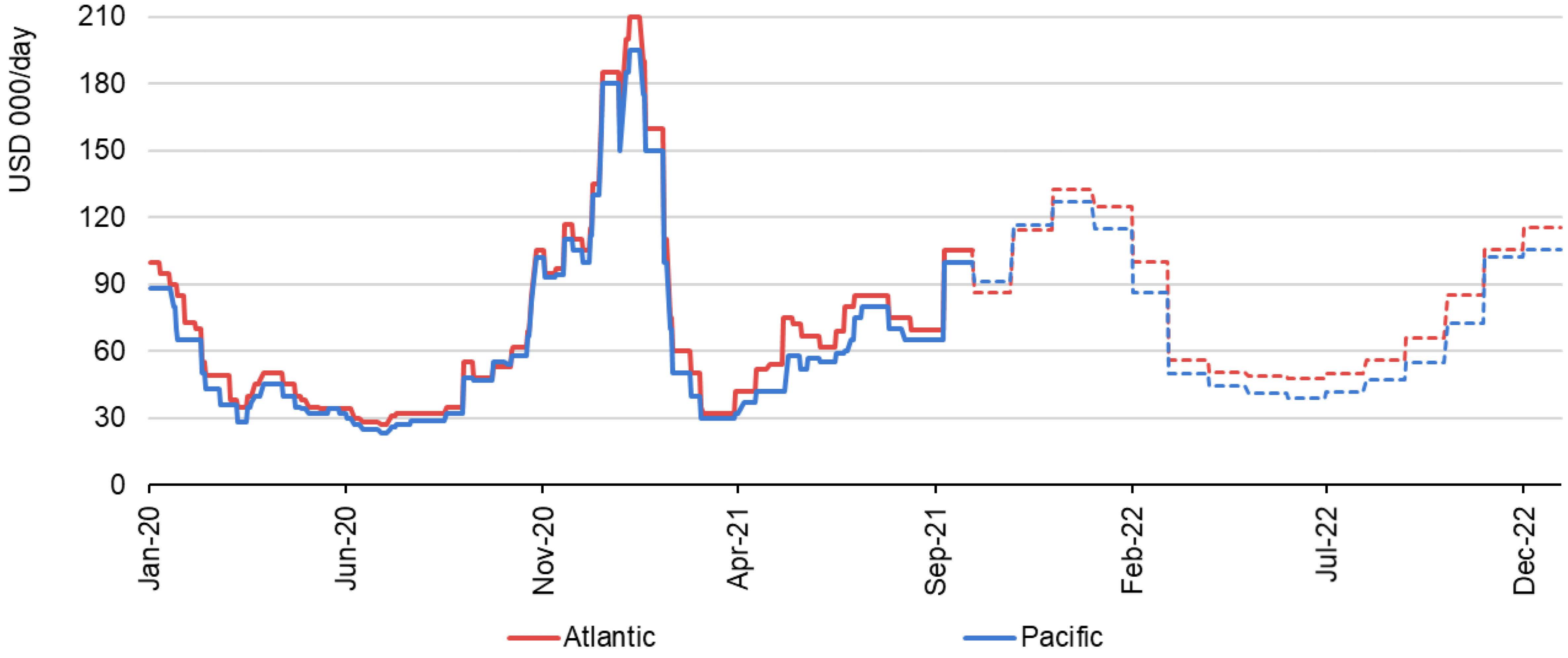
Forward curves at the end of September indicate the **return of a strong seasonal pattern**. Spot charter rates during the **2021/22 heating season** in the Northern Hemisphere are expected to climb 45% above their average during the gas summer, and remain close to their average during the 2020/21 heating season.[3] Nevertheless, they are **expected to stay below last winter's January average**, when spot charter rates climbed to historical records amid a severe cold spell in Northeast Asia and congestion on the Panama Canal.

For the full year of 2022 forward curves suggest that spot charter rates are set to average almost 10% below their 2021 levels. The **loosening of the shipping market** would be driven by the continued strong addition of new LNG carries (with 30 new vessels expected in 2022) and slower growth in LNG trade (just at 2% y-o-y).

[3] For the purpose of this analysis, the heating season (or gas winter) refers to the period between October and March (inclusive), while the gas summer refers to the period between April and September (inclusive).

Slower LNG trade growth combined with the strong addition of newly built LNG carriers is expected to weigh on LNG spot charter rates in 2022

Atlantic and Pacific spot and forward charter rates (January 2020-December 2022)



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

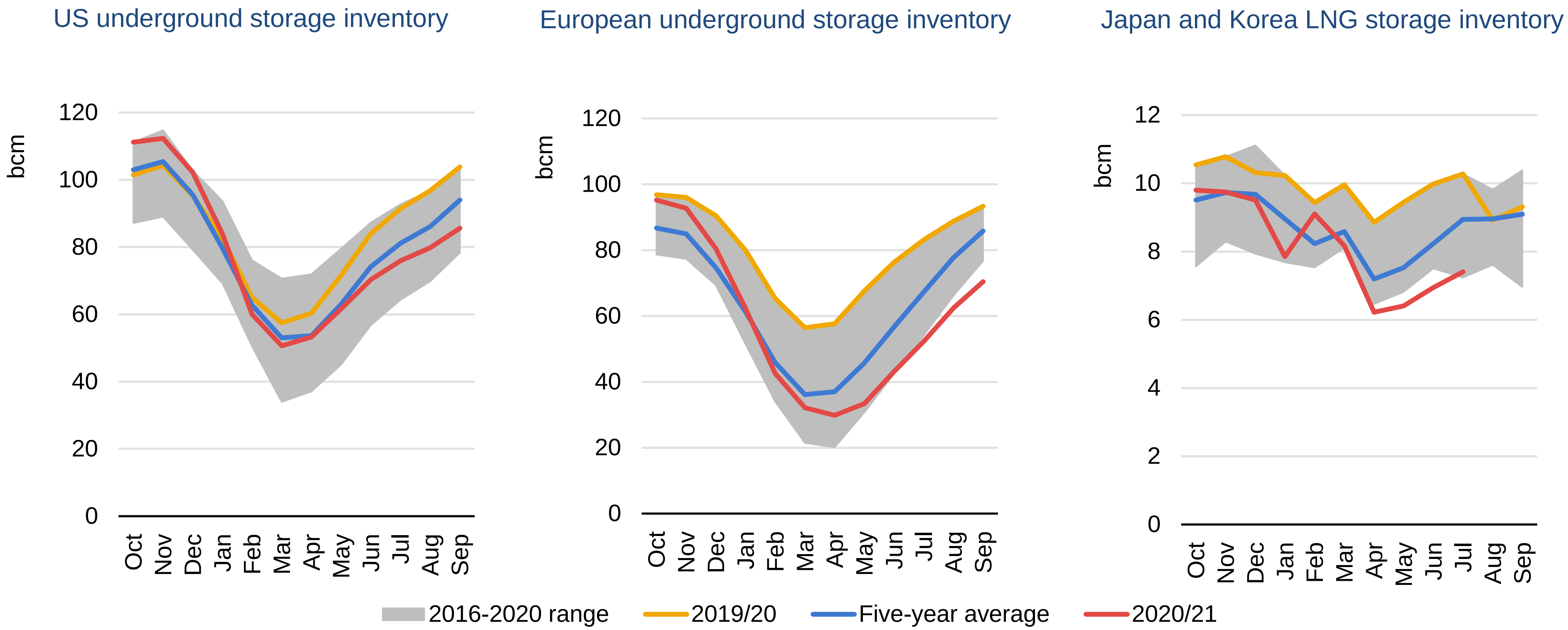
Winter is coming: Storage sites approach the heating season with lower than average levels

A long and cold 2020/21 heating season was followed by a gas summer with tight seasonal price spreads and slower storage injections. This translated into lower than average fill rates at gas storage site across key gas regions, which in turn could increase primary gas supply requirements (production and imports) during the 2021/22 heating season.

In Europe, inventory levels stood 16% (or 14 bcm) below their five-year average, and 22% (or 21 bcm) below last year's levels by the beginning of October, which marks the start of the European heating season. Net injections picked up during Q3 2021, increasing by more than 76% compared to the same period last year, albeit remaining slightly below their five-year average. Net injections rose y-o-y despite tight seasonal price spreads and were mainly driven by regulatory obligations, i.e. fill rates linked to strategic storage sites and to storage obligations of midstream utilities. Storage fill levels by the end of September were particularly low in **Northwest Europe**, standing at 64% of working storage capacity when excluding France (against 75% European average). Notably, the Grijpskerk storage site in the Netherlands has recorded no injections since the beginning of July. In **Ukraine**, net storage injections were 18% below last year's levels in Q3. Inventory levels stood 40% (or 8 bcm) below last year's levels at the end of September. In **Russia**, estimated storage injections over the summer more than doubled, with inventory levels set to reach 72.6 bcm by the start of the heating season.

In the **United States**, inventory levels stood 7% (or 6.5 bcm) below their five-year average and 16% (or 16.5 bcm) below their level last year by mid-September. Net injections during Q3 averaged 7% below their five-year average, due to tight seasonal price spreads on Henry Hub. Injections were largely driven by the **East storage region,** with an increase of 19% y-o-y, supported by wide summer-winter spreads on the regional hubs. In **Canada**, net storage injections during Q3 fell by 7% y-o-y, further weighing on storage inventory levels, which stood 9% (or almost 2 bcm) below last year's levels by the end of September. In **Japan and Korea**, LNG closing stocks stood 17% below their five-year average and 28% below their level last year at the end of July, as tight supply-demand fundamentals weighed on LNG restocking. Following the price spikes during 2020/21 winter, Japan's METI is considering the introduction of a new LNG stock monitoring system.

Lower storage levels could increase primary gas supply requirements during the 2021/22 heating season



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

Annex

Summary table

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

	Demand					Production				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
Africa	157	162	160	164	169	244	248	240	247	249
Asia Pacific	824	850	854	910	954	627	654	648	675	691
of which China	*283*	*307*	*325*	*368*	*396*	*160*	*174*	*189*	*206*	*220*
Central and South America	153	152	137	143	141	167	167	152	158	157
Eurasia	666	658	633	668	665	932	941	884	968	976
of which Russia	*493*	*482*	*460*	*488*	*484*	*726*	*738*	*692*	*761*	*763*
Europe	536	537	522	545	534	246	227	211	204	202
Middle East	544	543	547	566	583	666	677	680	694	709
North America	1 061	1 097	1 070	1 066	1 078	1 062	1 166	1 145	1 148	1 177
of which United States	*854*	*888*	*869*	*862*	*870*	*868*	*968*	*953*	*958*	*985*
World	**3 940**	**3 998**	**3 923**	**4 063**	**4 125**	**3 944**	**4 080**	**3 960**	**4 094**	**4 161**

Regional and country groupings

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

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

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

Eurasia – Armenia, Azerbaijan, 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

CAPEX	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CO_2	carbon dioxide
CST	Central Standard Time
DSO	distribution system operator
EIA	Energy Information Administration (United States)
ENTSOG	European Network of Transmission System Operators for Gas
ERCOT	Electric Reliability Council of Texas (United States)
FID	final investment decision
GHG	greenhouse gas
IEA	International Energy Agency
ICIS	Independent Chemical Information Services
JKM	Japan Korea Marker
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
m-o-m	month-on-month
NBP	National Balancing Point (United Kingdom)
OGT	Oneok Gas Transmission
SMR	steam methane reformer
SNG	synthetic natural gas
TSO	transmission system operator
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
w-o-w	week-on-week
y-o-y	year-on-year

Units of measure

bcf/d	billion cubic feet per day
bcm	billion cubic metres
bcm/m	billion cubic metres per month
bcm/y	billion cubic metres per year
GW	gigawatt
mb/d	million barrels per day
MBtu	million British thermal units
mcm	million cubic metres
mcm/d	million cubic metres per day
MW	megawatt
TWh	terawatt hour

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