

Global Gas Report 2022



RYSTAD ENERGY

Foreword

We appreciate the opportunity to present this 2022 edition of the **Global Gas Report** on the occasion of the 28th IGU World Gas Conference.



Stefano Venier

Chief Executive Officer,
Snam

This edition of the Global Gas Report covers two very turbulent years in the global gas industry and the wider global energy markets. The Covid-19 pandemic lockdowns, with a brief period of excess supply and low prices, gave way to tight energy markets, extreme price volatility, and a compounding geopolitical challenge to energy security. At the time of writing, the ongoing Russia-Ukraine conflict has been affecting the flows of gas and has put Europe on a quest to diversify its energy and gas supply that is now opening a new paradigm in the energy industry.

This report comes at a time when the situation for global commodity and gas markets is in a state of rapid change, and the strategic path forwards for the gas industry and energy policy-makers is continually developing. One thing is clear, this is a critical and decisive moment for the gas industry. How it navigates the way through this crisis and charts a path forward will shape its long-term success and the role that it will play in the energy transition and beyond. This is the moment for the gas industry to demonstrate that gas can deliver a sustainable and secure energy future for all, and that natural gas and a portfolio of decarbonized, low- and zero-carbon gases are key to an achievable energy transition.



John M. Kang

President,
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This year's report assesses key gas market trends from 2020 and 2021, including Covid-19 outcomes, tightness of supply, price volatility, investments, and the upward reversal in the global emissions trend. It then turns to the main topic on the global energy agenda – security – and considers key variables impacting it from industry and policy perspectives, as well as considering possible paths to reinforce it. Finally, the report looks at the main decarbonization pathways for gas supply, as they progressively develop to make gas itself a low or zero-carbon fuel for the future.



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This report seeks to deliver insights about the global gas sector and to inform its stakeholders, partners, and importantly global decision-makers about the state of play today and possibilities for the future. It concludes with key insights on how sustainability, security, and competitiveness can help to deliver a sustainable future in line with the goals of the Paris Agreement and the UN Sustainable Development Agenda.

The Global Gas Report 2022 is a collaborative effort between the International Gas Union and Snam, produced by Rystad Energy.

We invite you to explore this report and we hope that you find it a useful resource in evaluating the recent, current, and future trends for the global gas industry.

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Executive summary

In this 2022 edition of the Global Gas Report, we assess the key drivers currently shaping the gas industry, explore how gas can play an important role as a secure and reliable source of energy, and review the role of zero- and low-carbon gases in decarbonizing the global energy system. We find that:

A positive lesson from Covid-19 demand shocks has been the gas value chain's agility. The natural gas value chain demonstrated notable resiliency through the Covid-19 pandemic. Despite unprecedented shocks to the global energy system and challenging operational environments, gas has continued to reliably fuel society's critical functions, including power and water supply, hospital equipment, food production, and medical components manufacturing. The industry also nimbly adjusted to geographical and sectorial changes in demand patterns. For example, as the pandemic hit different regions at different times, gas volumes were rerouted to less affected areas where the demand was still strong. The value chain then adjusted back to the demand surge from the post-pandemic recovery, with 2021 natural gas supply surpassing 2019 levels.

The market has seen unprecedented volatility in gas prices over the past two years. TTF gas prices fell to record low levels of \$1.20 per MMBtu in May 2020, triggered by nationwide lockdowns and a pandemic-driven low demand environment. US LNG cargos were canceled between April and July, as the market demand remained depressed. Prices recovered quickly in 2021 and rallied upward, as the pace of global economic activity picked up, and gas demand increased, outpacing capacity additions. Both the Asia Spot and TTF gas prices hit record highs, with the Asia Spot price peaking at \$54 per MMBtu, as Europe and Asia competed for LNG cargoes. The Russia-Ukraine conflict that started in February 2022 further exacerbated the already tight market, and the TTF Front Month contract was propelled to a new high of \$68 per MMBtu in early March. A significant price premium was observed for European cargoes for the first time, as Asian gas was traded at a relatively discounted price.

Upstream oil and gas investments fell by 27% from 2019 to 2020, on top of reduced investments since 2015. This was a consequence of Covid-19 demand destruction and the associated price collapse, as well as uncertainty around future demand and policy direction. Upstream capital investments have been in the range of \$400-500 billion between 2016 and 2019, compared to a level of more than \$700 billion in 2013 and 2014.

Long-term LNG contracts are gaining in popularity to reduce exposure to spot-priced market volatility, particularly in Europe.

The European market, which has been purchasing most of its LNG from the spot and futures markets, was particularly exposed to the price shocks in 2021 and 2022. With lower volumes flowing from Russia, Europe's reliance on cargoes from the US, Africa and the Middle East increased. China was to some extent shielded from high gas prices, due to its preference for long-term oil-indexed contracts over spot cargoes. A higher share of long-term LNG contracts can be used to minimize exposure to market volatility.

The energy crisis prompted a renewed focus on supply security. For the first time in the history of gas markets, we are seeing a crisis close in scale only to the 1970's oil crisis, when the world faced shortages and price hikes. The crisis has been further exacerbated by supply shortages across all energy commodities, prompting an increased focus on energy security. Future energy systems must be designed with energy security in mind. When it comes to gas, the focus should be on developing a diverse gas supply chain through both upstream production and infrastructure developments. Storage can also play an important role in ensuring energy security by offsetting disruptions to the supply chain. In addition to investing in more storage capacity, governments can impose mandates for minimum storage levels. This has been a common practice with oil, where governments and private practices hold inventories to safeguard the economy and maintain energy security. The European Commission addresses both the questions around a diverse gas supply and storage levels through recently announced policies.

Global CO₂ emissions have risen 5% between 2020 and 2021. This is related to the recent gas-to-coal switching. To reverse this rising emission trend, global energy demand-supply will need to be rebalanced, along with appropriate emissions control pricing, carbon and pollution policies.

Extreme weather requires long-term, energy-system-wide, resource adequacy planning. In 2021, the increased frequency of extreme weather events posed significant challenges to the reliable functioning of the global energy systems. Periods of extreme heat and cold, as well as droughts and extended periods with low wind speeds, have highlighted some of the inherent reliability challenges for today's energy networks. Case studies from the California heatwave, the Texas deepfreeze, the Turkish drought, and periods with low wind speeds in Europe, demonstrated

both the key role of gas in ensuring system reliability during long periods of renewable intermittency and the interconnectedness of modern energy systems. These case examples point to the need for deliberate and energy-system-wide planning to assure reliability and avoid cascading failures.

Gas will be critical for an achievable, affordable, sustainable, and secure decarbonization of the global energy system. Initially this can happen through reversing the recent growth in coal use as well as through oil displacement, while supporting the acceleration of renewables deployment through grid balancing and integration in the power sector. Progressively, low-carbon and zero-carbon gases, such as hydrogen, biomethane and natural gas with CCUS, will support deeper decarbonization across sectors alongside renewables and other Paris-compatible fuels. Leveraging existing natural gas infrastructure will be critical in enabling these new decarbonized gas options to commercialize and scale. New gas infrastructure can be designed in a way to enable further scale up of low- and zero-carbon gases and, supporting the achievement of Paris agreement objectives.

Low-carbon and zero-carbon gases are critical to decarbonize heavy industry and manufacturing of vital materials. The industry sector is responsible for around 30% of total energy demand and emissions today, and gas has a crucial role to play in supporting global decarbonization ambitions. Industrial sectors, such as cement, steel, chemicals, and ammonia can be 'hard-to-abate'. The use of low-carbon and zero-carbon gases in these sectors can provide a viable option to help in deeper sector decarbonization and thereby can resolve the current technical and cost challenges faced by the industry to reduce emissions.

To achieve the desired pace of decarbonization, rapid scale-up of low- and zero-carbon gas technologies will be needed as many are not yet at commercial scale. This will require strong enabling policies, timely investment globally, as well as access to liquidity for capital-intensive projects. To meet the required global capture volume under Rystad Energy's 1.6-degree scenario, the deployment rate for CCUS needs to scale up by more than 170 times, from around 45 million tonnes per annum of CO₂ captured globally today to 8 gigatonnes by 2050. The same could be said for low- and zero-carbon gases. Current production of low- and zero-carbon gases is limited. Blue and green hydrogen contribute less than 1% of pure hydrogen demand, while biomethane represents less than 1% of total natural

gas production. While current production levels of green and blue hydrogen and biomethane are low today, there has been stronger policy interest, with more countries committing to development targets and funding over the next decade. In the Asia Pacific region, Japan, South Korea and Australia have introduced roadmaps to set up their hydrogen economies. Japan has committed to increase hydrogen demand to 3 million tonnes per year by 2030, South Korea is set to increase its hydrogen production to 3.9 million

tonnes by 2030 and Australia aims to be among the top three hydrogen exporters to Asian markets.

The European Union (EU), under its REPowerEU strategy plans to reduce reliance on natural gas imports and to increase green hydrogen consumption to 20 million tonnes by 2030, of which 10 million tonnes will be imported from non-EU countries. REPowerEU also aims to produce 35 billion cubic meters (Bcm) of biomethane by 2030.

Key insights for the gas industry

Supply Security: The industry should work with policymakers and continue to adjust to changes in demand as the energy transition progresses. It should also continue to work on developing new sources of supply and related infrastructure to ensure supply diversification. This can only be achieved with the right regulatory policy environment on all fronts, including policies that create stability and predictability around future investment decisions. Policymakers and the industry should also work together on defining ways of future-proofing new developments.

Competitiveness: A rebalanced gas market is expected to improve competitiveness and even the playing field between fuels. Market tightness has led to gas-to-coal switching for power generation, which has resulted in emissions trending upwards. Ensuring that more carbon intensive fuels are not preferred over gas will be key to meeting the emissions targets set by the Paris Agreement.

Sustainability: The industry should continue to deliver on emission reduction targets. The value of gas in the energy transition will be enhanced further by continuing to deliver on methane emission reduction opportunities. Efforts to scale low- and zero-carbon gas technologies should be strengthened, as these technologies play a key role in the decarbonization of global energy systems. As the gas industry is a key enabler of low- and zero-carbon technologies, future-proofing new assets and infrastructure should be prioritized.

1 / Key insights from the 2020-2021 gas market

Highlights

- **The global gas market** was highly volatile over the 2020-21 period, with fluctuating gas prices, and periods of both oversupply and market tightness observed over the course of these two years.
- **Gas demand dropped by 2% in 2020, reflecting lower economic activity levels with the spread of Covid-19 and lockdowns. Demand levels recovered in 2021 by 4% year-on-year, with a rebound in the economy and extreme cold weather events** driving higher use of gas for heating. Regionally, strong growth was seen in China and India. Increased LNG volumes flowing into China made it the largest importer in the world, surpassing Japan.
- **Gas production fell by 3.5% in 2020** driven by lower demand and with low oil and gas prices leading to reduced investment in the sector. The US, Europe, and the Asia Pacific region all saw declines in production levels. **Economic recovery in 2021 led to a 4% year-on-year increase in gas supply**, with Russia registering a significant increase in pipeline exports.
- **Global LNG trade grew by 2% in 2020**, despite the cancellation of some LNG cargoes from the US. Demand in Asia recovered in the fourth quarter, and prices climbed to record high levels in 2021 as Europe and Asia competed for LNG supply. China overtook Japan as the world's largest LNG importer. Cargoes were also re-routed mid-voyage to Europe as its demand rose, making European prices more attractive for suppliers. Pipeline trade dropped in 2020 but bounced back in 2021.
- **Despite reaching record high prices in 2021, investment in new production capacity and LNG liquefaction remained low**, given uncertainty regarding gas pricing and demand visibility in the medium term. Complicating matters, numerous liquefaction projects were delayed due to the global pandemic, with only one project being sanctioned in 2020. Three liquefaction projects were sanctioned in 2021.

Table 1: Key changes in global gas market from 2019-2021

Region	Consumption		Production		Gross imports		Gross exports		Gas price	
	2019-20	2020-21	2019-20	2020-21	2019-20	2020-21	2019-20	2020-21	2019-20	2020-21
Asia	+ 0.4%	+ 6.4%	- 2.7%	+ 4.7%	+ 3.0%	+ 11.0%	- 12.5%	+ 13.9%	- 20.4%	+ 317.8%
Europe	- 3.4%	+ 3.2%	- 6.9%	- 4.2%	- 13.0%	- 0.4%	- 28.4%	- 15.0%	- 37.6%	+ 397.0%
America N	- 2.0%	+ 0.4%	- 1.3%	+ 2.0%	- 3.4%	+ 7.3%	+ 7.9%	+ 21.0%	- 21.1%	+ 93.8%
America S	- 5.3%	+ 8.0%	- 8.1%	- 6.4%	+ 4.8%	+ 36.6%	- 7.6%	- 19.4%	-	-
Africa	- 13.7%	+ 9.7%	- 8.5%	+ 11.6%	+ 18.8%	+ 20.6%	- 5.8%	+ 19.0%	-	-
Middle East	+ 1.1%	+ 3.6%	+ 1.8%	+ 4.7%	+ 7.3%	+ 11.5%	+ 1.9%	+ 6.2%	-	-
Russia	- 5.2%	+ 9%	- 10.0%	+ 12.7%	- 55.0%	+ 56.4%	- 9.1%	+ 3.9%	-	-
Australia	- 5.5%	- 3%	+ 1.9%	- 4.8%	- 15.4%	+ 21.9%	+ 2.6%	+ 4.8%	-	-

Source: Rystad Energy

1 / Key insights from the 2020-2021 gas market

- **According to the Intergovernmental Panel on Climate Change (IPCC), the average annual global greenhouse gas (GHG) emissions were at their highest levels during 2010-2019.** Global GHG emissions will need to peak before 2025 at the latest and be reduced by 43% by 2030 to limit global warming to around 1.5°C and achieve net zero in the early 2050s. With less than 30 months to peak emissions, governments, policy makers and industry would need to develop realistic, achievable strategies to drive deep emission reductions across all sectors. **Natural gas and decarbonized, low/zero-carbon gases would need to play a key role supporting these decarbonization initiatives and driving the global energy transition forward.**
- **Emissions have been on an upward trend since 2020, especially in the power generation sector,** exacerbated by the post-pandemic upsurge in power demand and increased coal emissions **due to gas-to-coal switching.** This switching is the result of the high gas prices outpacing coal prices, exacerbated by the 2021-2022 global energy supply tightness and the 2022 Russia-Ukraine conflict.
- **To reverse the gas-to-coal switching phenomenon, energy demand-supply will need to be rebalanced,** along with appropriate emissions controls price, carbon and pollution policies around the globe, as well as greater international cooperation, as agreed at COP26.
- **Gas will provide near-, medium- and long-term value** to the energy industry. In the near term, gas could reduce direct emissions through coal and oil displacement and via enabling a greater share of renewable energy deployment through grid balancing and integration. Progressively, low-carbon and zero-carbon gases, such as hydrogen, biomethane and natural gas with CCUS, will support deeper decarbonization across sectors, alongside renewables and other Paris-compatible fuels. Leveraging the existing natural gas infrastructure will be key in supporting these low- and zero-carbon gases to commercialize and scale. New gas infrastructure can be designed in a way to enable further scale-up of low- and zero-carbon gases, supporting the achievement of Paris agreement objectives.

Demand

2020

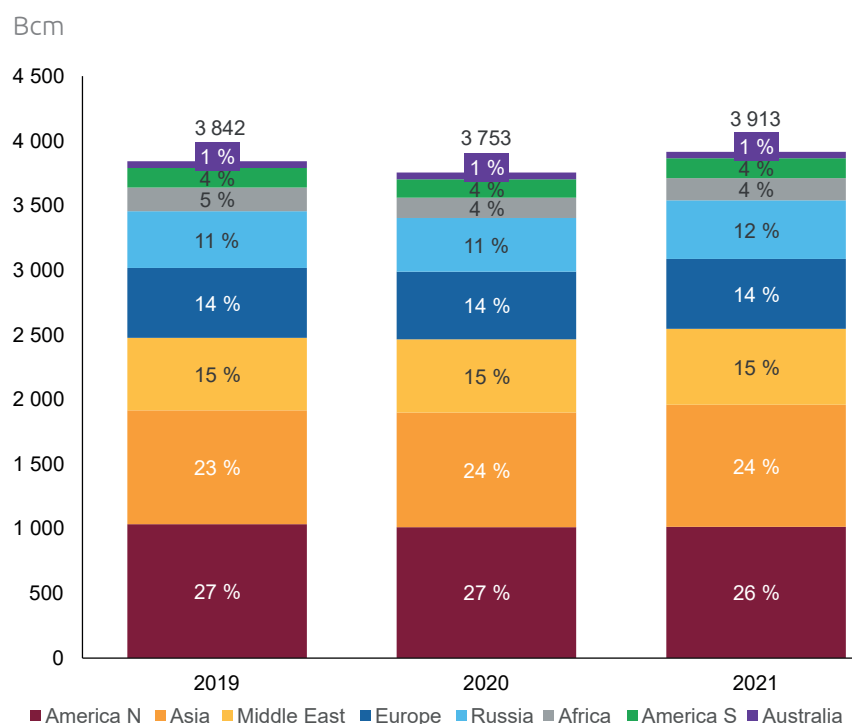
Global gas demand decreased by 2% in 2020. With the emergence of Covid-19 and the imposition of stringent lockdowns globally, imports decreased significantly from the second quarter of the year. Despite these headwinds, gas demand was relatively shielded in 2020 by low gas prices, which enabled gas to remain competitive in the power sector, thereby preventing a large drop in demand. Additionally, demand in Asia remained constant, and even managed to grow in the key Chinese market. Other buyers in the region also took advantage of low prices to substitute coal in the power generation sector.

Although China was dealt a heavy blow in the first quarter of the year as Covid-19 spread, its strict lockdown and social distancing regulations made it possible for industry and manufacturing to resume in late March 2020.

Despite a wide-reaching shut-down that lasted nearly two months, gas consumption in China reached 326 Bcm in 2020, a 7% increase from 2019. Gas demand in Japan, South Korea and Chinese Taipei, meanwhile, collectively decreased by about 2 Bcm (1.4%) from 2019 to 2020. Demand in Japan slipped marginally due to lower requirements in the power sector and increased competition from renewables, while South Korean gas demand remained constant at 56 Bcm.

In India, gas demand grew by 1.4% in 2020, with domestic production meeting about half of the country's needs. Despite lockdowns and economic

Figure 1: Global gas demand (2019-2021), split by continent



Source: Rystad Energy

uncertainty, LNG import volumes increased by 15%, reaching 25 million tonnes, supported by gas demand for the power and city gas sectors. Coal-to-gas switching at some power plants on the west coast also contributed to this trend, driven by record low LNG prices that challenged the economics of power plants fueled by imported coal.

In 2020, longer lockdown periods and reduced economic growth in Europe resulted in a total demand decrease of 4% from 2019 levels, with year-end demand touching 526 Bcm. The biggest decreases were observed in Spain, Italy, France, Germany and the United

Kingdom. Furthermore, Russia's domestic gas consumption fell by about 5% in 2020. Demand in Turkey, on the other hand, increased by 1.5 Bcm (3.4%) in 2020, attributed largely to a rise in household gas usage. The use of gas climbed also in Turkish power plants, as droughts in the latter half of the year caused a shortfall in hydroelectricity generation.

Gas consumption in the US and North Africa fell by 2% and 12%, respectively, largely due to restrictions introduced to combat the spread of Covid-19. However, gas demand in the Middle East still managed to increase by 1%.

1 / Key insights from the 2020-2021 gas market

2021

China’s strong economic comeback in 2021, coupled with unusually cold weather in Europe and Russia, caused global gas demand to rise from 3,753 Bcm in 2020 to about 3,913 Bcm in 2021, representing a 4.3% increase. Higher supplies in the Middle East were absorbed within the region. The increase in demand resulted in China ramping up LNG imports to about 80 million tonnes, overtaking Japan as the world’s largest importer.

Despite record-high prices, Japanese and South Korean imports remained strong, totaling 77 million tonnes and 47 million tonnes, respectively. A drought in Brazil forced the country to import more LNG to meet power demand, while Argentina and Chile also boosted their LNG imports.

After the slowdown due to Covid-19 in 2020, China’s gas demand saw a 12% increase in 2021, led by strong demand in the power and industrial sectors. The underperformance of hydropower in the country, coupled with tight coal supplies and high coal prices, incentivized more gas-fired power generation. Gas demand in Japan, South Korea and Chinese Taipei climbed by a collective 8%, largely due to strong winter demand during the first quarter and a build-up of inventory later in the year. Brazilian imports also increased significantly in 2021, driven by a decline in hydropower.

Russian gas demand reached new heights in 2021, growing by 9% versus the previous year. This was driven largely by the heat and power sectors amid intense weather fluctuations, between an unusually cold winter in 2020 and an extremely hot summer in 2021.

Figure 2: Global gas demand (2019-2021), split by demand sector

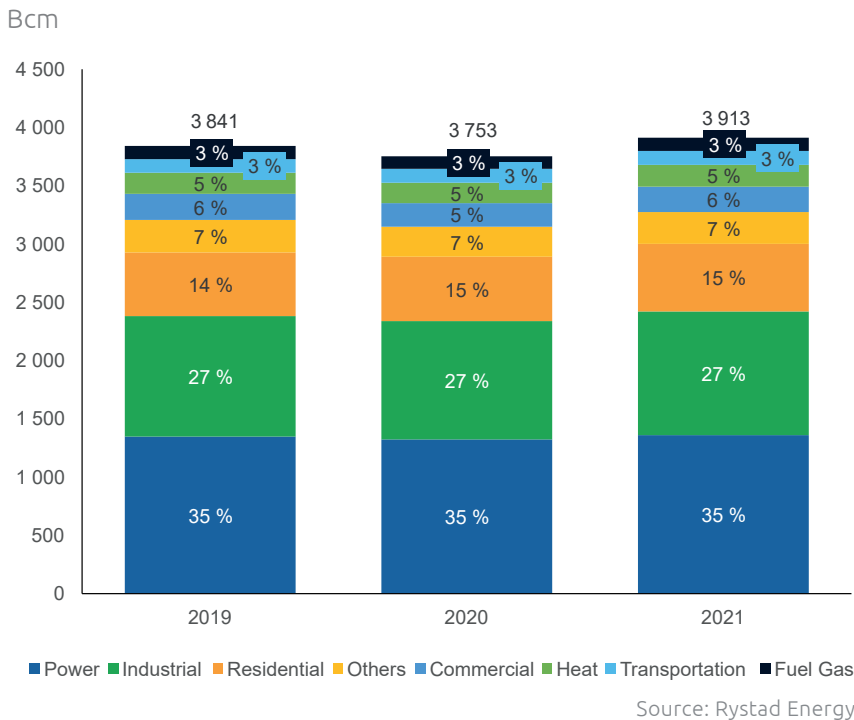
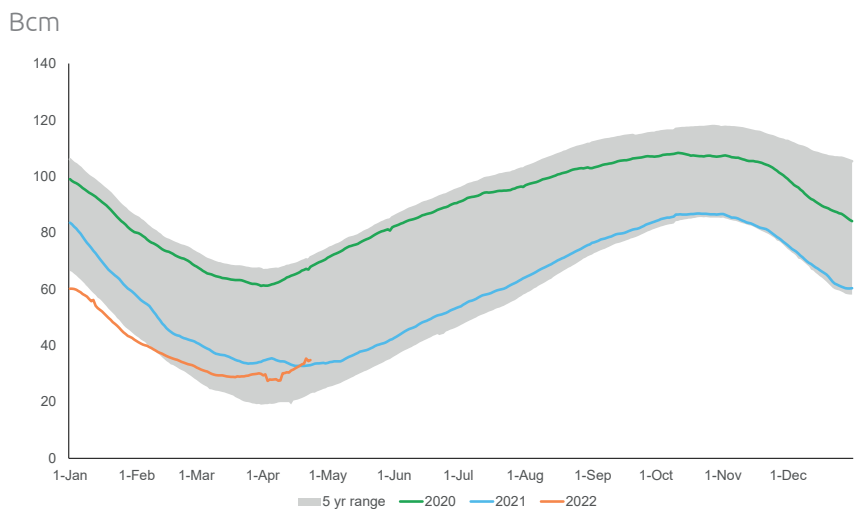


Figure 3: Europe underground gas volume and range in underground storage



Another contributing factor was the reduced output from the hydropower sector, arising from low water levels in rivers in countries such as Turkey and Brazil. Demand for gas in India, the

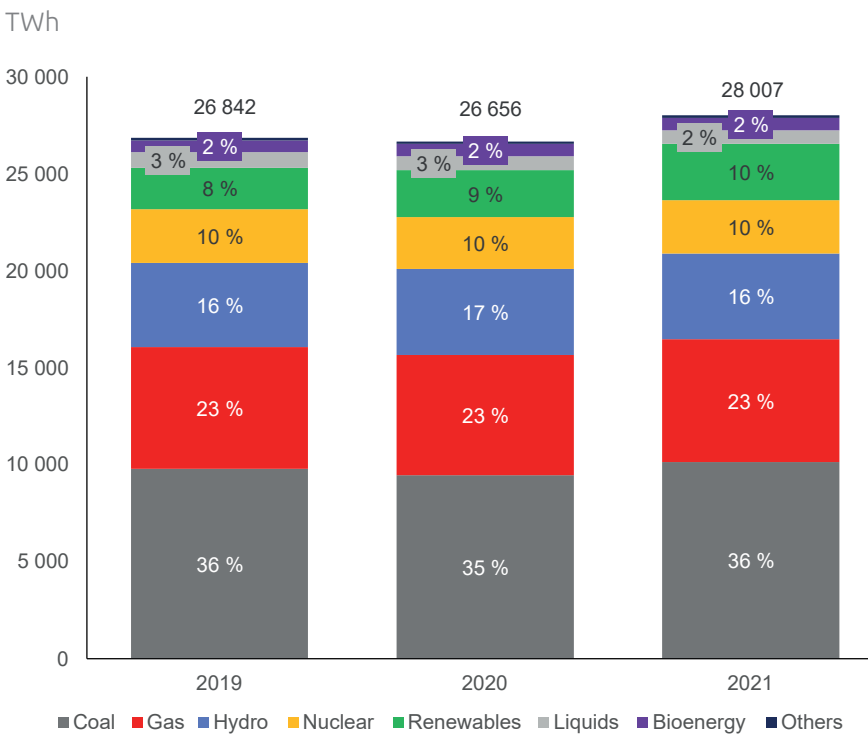
Middle East and North Africa climbed by about 5-8%, largely driven by the power and industry sectors, due to renewed growth in economic activity and ongoing coal-to-gas switching.

1 / Key insights from the 2020-2021 gas market

Gas consumption increased by 3% in Europe in 2021, nearly returning to 2019 levels. Demand growth was strongest in the residential sector, followed by the power and industrial sectors. Russian imports were lower than usual, and reduced storage fillings, especially from Russian companies, increased market tightness, keeping prices elevated throughout the year. To compensate for the decline in Russian imports, Europe withdrew natural gas supplies from storage, causing storage levels to drop to a five-year low.

Demand for coal dropped considerably from 2019 to 2020, with coal use for electricity generation leading the slide, especially in advanced economies. Rising output from renewables and low gas prices helped to drive this change in Europe and the US. Coal demand then rebounded strongly in 2021, even surpassing 2019 levels, but this recovery came largely from demand growth in China. Gas comprised 23% of the global power mix and 24%

Figure 4: Global power mix (2021)



Source: Rystad Energy

of the global primary energy supply mix in 2020, and volumes demanded were fairly stable from 2019. The share of renewables in the power

mix grew steadily, while power generation from nuclear and hydroelectric energy remained stable over the 2019-21 period.

Supply

2020

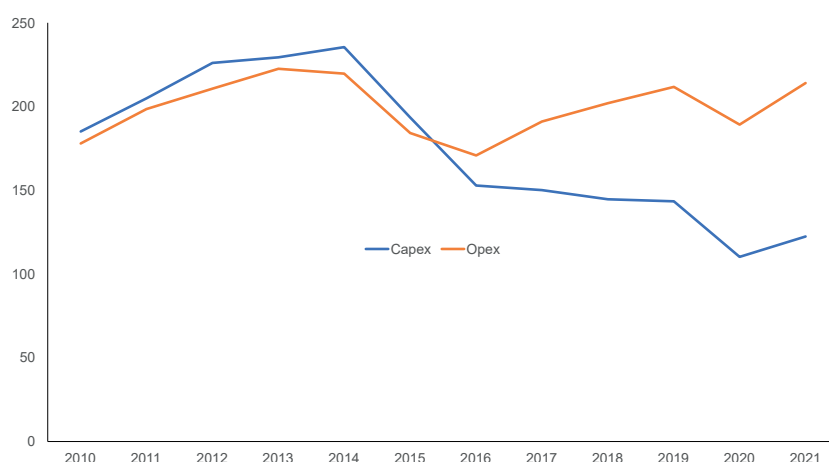
Due to Covid-19 impacts, global gas production dropped by 3.5% in 2020, as low oil and gas prices led to reduced investments into the sector.

Gas production in the US decreased by 10 Bcm (1.07%) in 2020, with the top five shale plays in the US accounting for about 56% of total US gas production that year. Global LNG production climbed by 3%, led by the US, where new trains allowed for higher exports despite record low prices. Production growth for 2020 was forecast to be strong, but many buyers canceled US LNG cargoes as Covid-19 hit demand. Canada's domestic gas production was also hit by declines, with lower domestic demand and export volumes to the US.

Europe saw an overall drop in gas production of about 7%, in part due to lower output from the Groningen fields in the Netherlands along with the maturing fields in the North Sea. Norwegian natural gas production levels remained relatively stable. In contrast, Russian output dropped by 10%, totaling 632 Bcm in 2020, owing largely to low demand during a relatively mild winter season and amid falling export volumes to Europe. In the Asia Pacific region, gas production dropped marginal-

Figure 5: Global gas market - Capex and Opex

Cost in billion USD



Source: Rystad Energy

ly, mostly due to low prices and declining output from mature fields in India, Indonesia, Thailand and Malaysia. China's domestic production increased in 2020 amid renewed prioritization of supply growth within the country, while India experienced a decline in production volumes. Gas production in the Middle East was 2% higher than 2019 levels, with a 2% increase in export volumes from the previous year. In Africa, on the other hand, lower export volumes impacted production, resulting in a 9% decrease year on year.

Figure 5 shows that capital expenditure was reduced in 2020, on top

of already low investment levels, as companies took measures to protect themselves from pandemic-related market uncertainty. Upstream operations took a hit, along with global exploration budgets and unsanctioned developments. Investment levels dropped by 27% from 2019 to 2020, driven primarily by cash preservation and uncertainty around future demand and policy direction. This reduction in 2020 investment levels amplified reduced investment levels since 2015. Operational expenditure dropped briefly in 2020, although it subsequently recovered in 2021, as global production picked up pace.

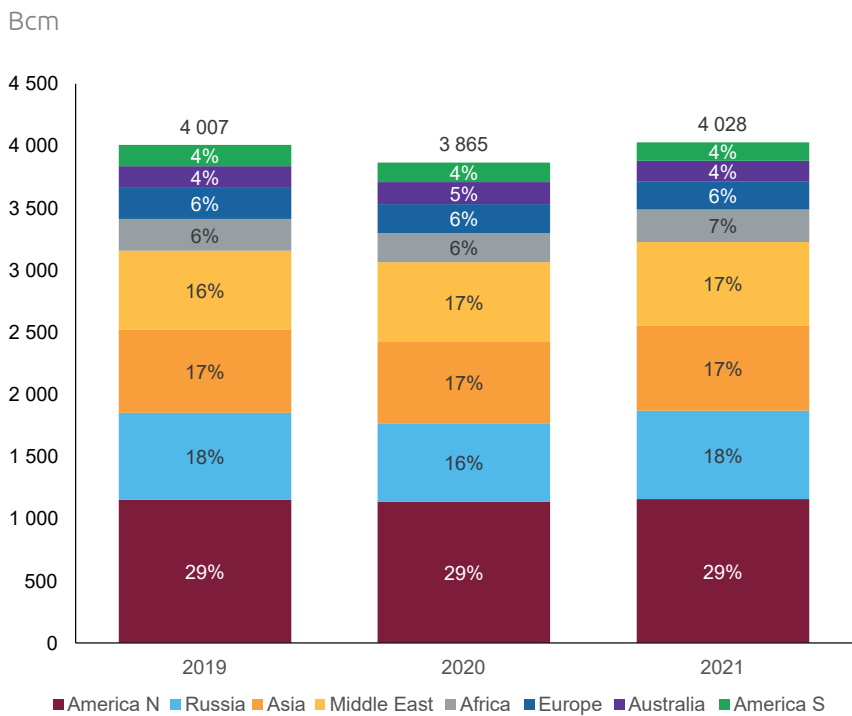
2021

A rebound in economic activity boosted consumption in the industrial, power and residential sectors, which led to a 4% increase in gas production globally, with levels at 4 028 Bcm. Gas production in the US, Russia, and the Middle East was ramped up to meet rising demand levels in Europe and Asia.

Production levels in the US climbed 2% from 2020 levels, despite significant outages during extreme winter weather in February and hurricanes in August. This was insufficient, however, for the US to meet its export market needs, thus necessitating import volumes from Canada. Both countries saw a decline in underground storage inventory over the year.

Gas output in Russia grew from 632 Bcm in 2020 to 712 Bcm in 2021, largely due to an increase in demand in the domestic market and an increase in pipeline exports. European gas production, meanwhile, declined by 4% despite a strong demand spike. This was attributed to significant production drops in the Netherlands and the United Kingdom, whereas Norwegian gas output grew by about 2%. The

Figure 6: Global gas supply (2019-2021), split by continent



Source: Rystad Energy

Asia Pacific region managed to boost gas production by 1.5%, to 662 Bcm, driven mainly by India and China. Gas output in India jumped by 25%, with two deepwater projects coming online in late-2020 and mid-2021. Meanwhile, China boosted its gas production level by 9%, to

touch 205 Bcm. Activity in the Middle East grew by 5%, with production levels rising in Qatar and UAE, and remaining relatively constant in Iran. Volumes in Africa jumped by 12%, to 263 Bcm, driven both by domestic and export markets.

Trade flows

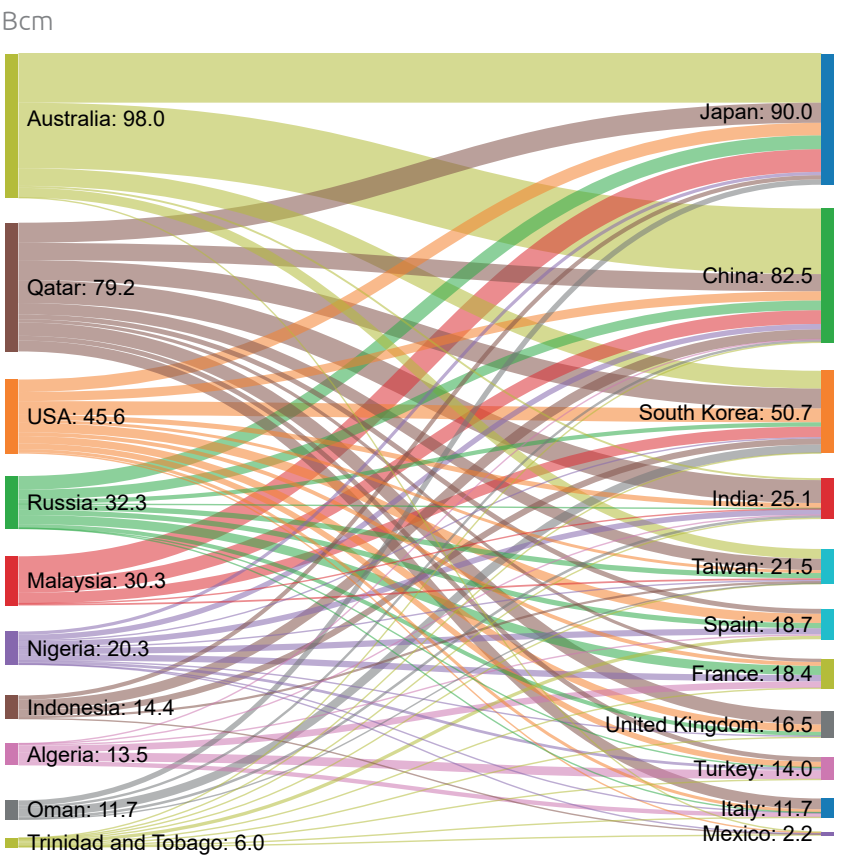
LNG trade flows

2020

Global LNG trade increased by 2% to reach 362 million tonnes in 2020, with most of the increase stemming from the beginning of the year. Asian LNG imports started to drop from the end of February 2020, referenced in Figure 14: LNG import volume, split by region, as the major importers in the region – Japan, China and South Korea – were affected first by Covid-19. Despite lower demand, supplies remained healthy. Export levels from Qatar and Australia, two of the largest exporters, remained stable, and US exports increased in March as Freeport and Cameron LNG ramped up production after commissioning. LNG imports into Europe remained strong as well, as buyers took advantage of the low market prices and substituted pipeline imports with LNG.

Lockdowns were imposed in March 2020 in the largest LNG importing countries in Europe (Spain, Italy and France), causing Asian and European prices to drop below \$3 per MMBtu. US exports had remained relatively resilient up to March, but export volumes then plummeted nearly 71% from April to July, as buyers started using the flexibility in their contracts to cancel cargoes from US liquefaction plants for the summer. Cheniere reduced production levels from its Sabine Pass and Corpus Christi LNG facilities in response, thus helping to balance the market. Subsequent bad weather in the

Figure 7: LNG trade flows (2020)



Source: Rystad Energy

Gulf of Mexico caused outages at the Sabine Pass and Cameron LNG facilities, triggering a rally in global prices that lasted until October 2020. Demand in Asia

picked up again in the fourth quarter of 2020, as buyers in the region were active in the market, restocking ahead of winter.

2021

Global LNG trade increased by 6% to 385 million tonnes in 2021, with economic activity picking up in several countries. Supply constraints and rising demand caused significant volatility in prices, as nations scrambled to secure LNG cargoes to meet potential gas demand for the winter.

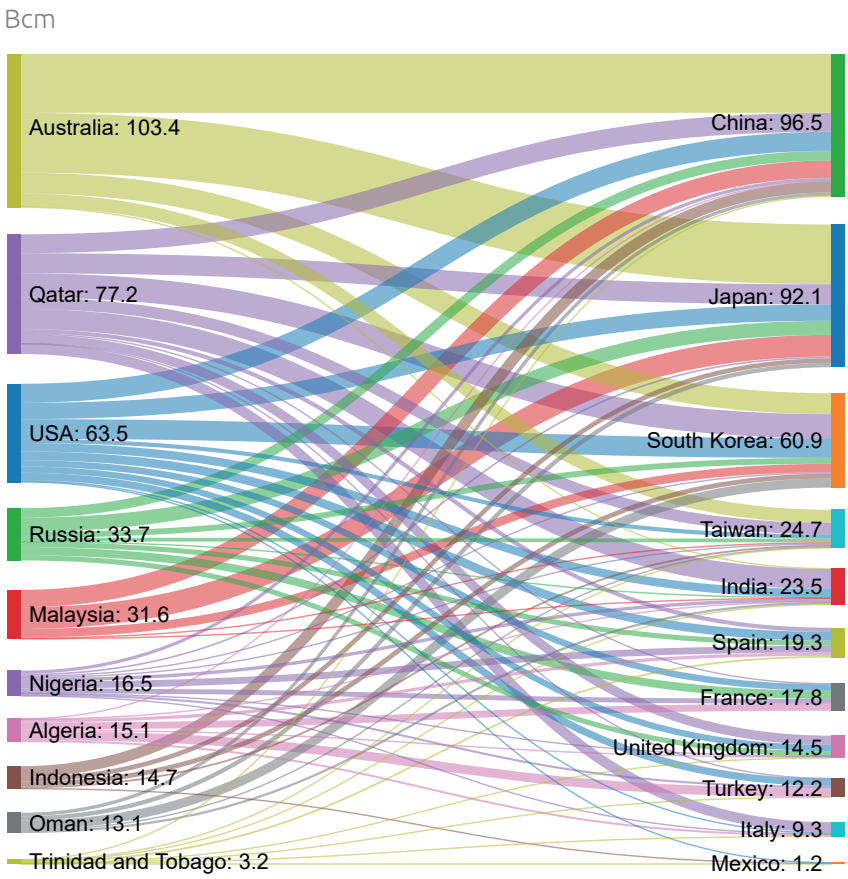
Overall, LNG exports grew in 2021, with the US leading the way through its year-on-year increase of 23 million tonnes. This provided security of supply to some extent, especially in a tight market. US LNG recovered well from the cancellation of cargoes and reduced usage of liquefaction

plants the previous year. About 48% of US export volume (ex-North America) was delivered to Asia, driven by increasing demand in South Korea and China. Japan was the third-largest importer of US LNG in 2021, with the three countries accounting for over 36% of all US export volumes in the year. LNG exports to Europe increased in March and April 2021, after a cold winter had depleted the region’s natural gas in storage. Volumes decreased during the following months but increased again in the fourth quarter and peaked in December 2021, as Europe’s natural gas inventories remained low. Intense

competition for LNG cargoes between buyers in Europe and Northeast Asia resulted in both Asia Spot and TTF benchmark gas prices hitting record highs.

US LNG exports to Brazil increased from 2.3 million tonnes in 2020 to 7 million tonnes in 2021, as an intense drought in the country limited hydropower generation and led to more consumption of natural gas for power. LNG exports from Australia, Qatar and Russia remained stable from 2020 to 2021, while there was a decrease in volumes from Nigeria and from Trinidad & Tobago over the same period.

Figure 8: LNG trade flows (2021)



Source: Rystad Energy

Pipeline trade

2020

Pipeline trade was adversely affected in 2020, with trade flows being reduced by 121 Bcm, largely due to a decrease in European imports. Low market prices for LNG, coupled with sufficiently high storage levels, drove down pipeline gas imports, and the market picked up again only in the second half of the year.

Pipeline trade balances shifted noticeably in the US, as lower volumes were imported from Canada and higher volumes were exported to Mexico. In the Asia Pacific region, meanwhile, there was a marginal increase in gas demand, driven mainly by China. However, net pipeline imports in the region decreased by 5%, with the additional demand being met

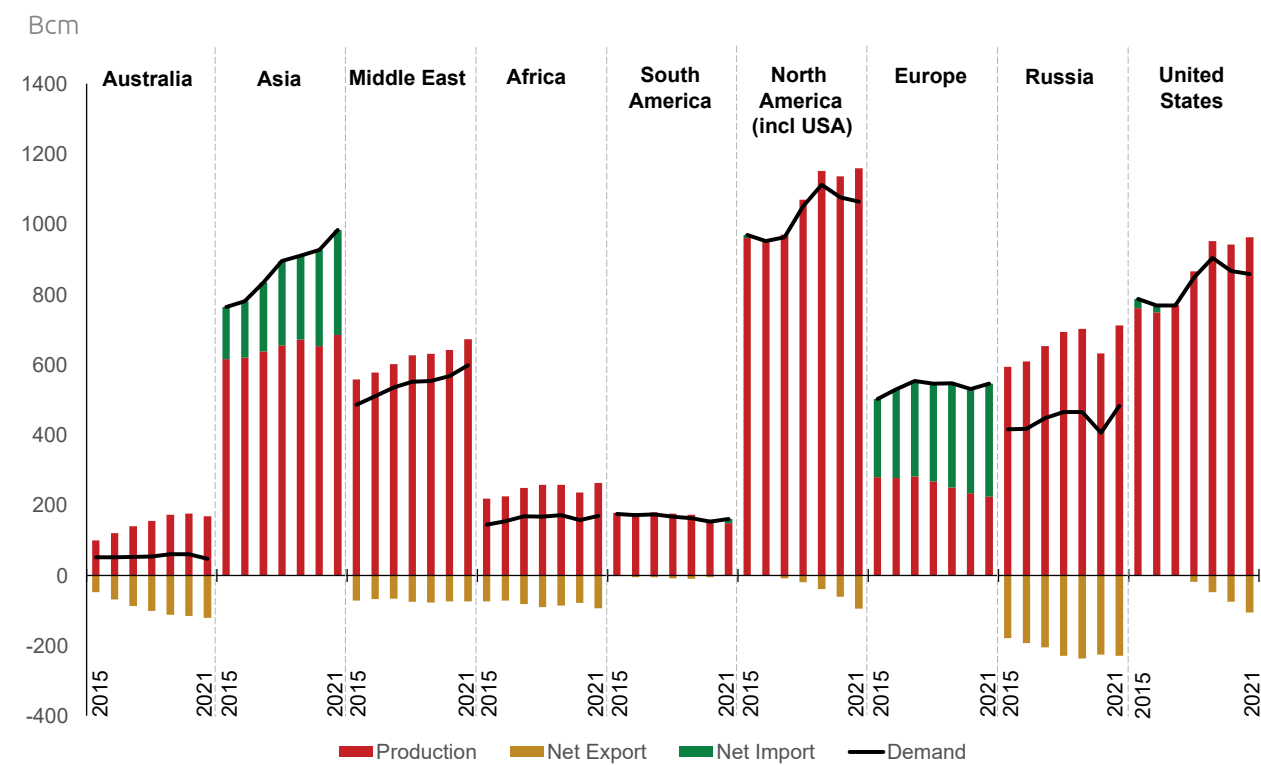
entirely by LNG. Pipeline deliveries from Russia to China amounted to 4 Bcm in 2020, mostly via the Power of Siberia pipeline.

Lower export volumes drove down Central Asian gas production, as the region’s pipeline supplies to China were reduced by nearly 13% year on year. Kazakhstan and Uzbekistan export volumes fell, whereas pipeline exports from Azerbaijan rose by 16% year on year, driven by the ramp-up of volumes through the Trans Anatolian Gas Pipeline (TANAP). Lower export volumes impacted production in Africa as well, with pipeline flows from Libya and Algeria at lower levels compared to 2019.

2021

Pipeline gas export volumes increased by 6% in 2021, mirroring the rebound of global economic activity. The US saw an 8% rise in pipeline exports to Mexico, while domestic consumption in the country remained low. In the Asia Pacific region, net gas imports grew by 17%, with one-fifth of that incremental volume attributed to increased pipeline imports. This was particularly prominent in China, as import volumes rose due to weather-related factors and higher economic activity. Russia’s pipeline export volumes increased by about 4% from 2020, with incremental volumes flowing to Germany, Italy and Turkey. Europe’s pipeline imports rose by 0.5% in 2021, supported by an

Figure 9: Global gas production and import/export volumes, split by continent



Source: Rystad Energy

1 / Key insights from the 2020-2021 gas market

increase in volumes flowing from Algeria. Russia's low pipeline deliveries to Europe declined further towards the end of the year, resulting in a tighter market

and higher gas prices. Production levels in the Middle East increased, with Iran's pipeline exports to Turkey and Israel's pipeline exports to Egypt

growing significantly. Africa's pipeline exports to Europe climbed 50%, with Algeria seeing a significant increase in volumes exported to Spain and Italy.

Figure 10: Additional pipeline gas import volume (2019-2020 and 2020-2021)

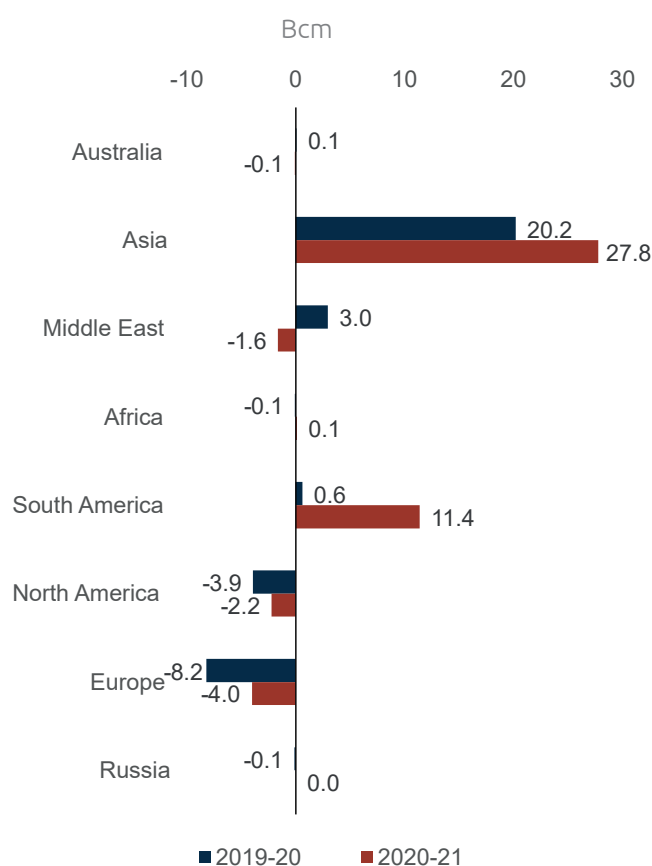
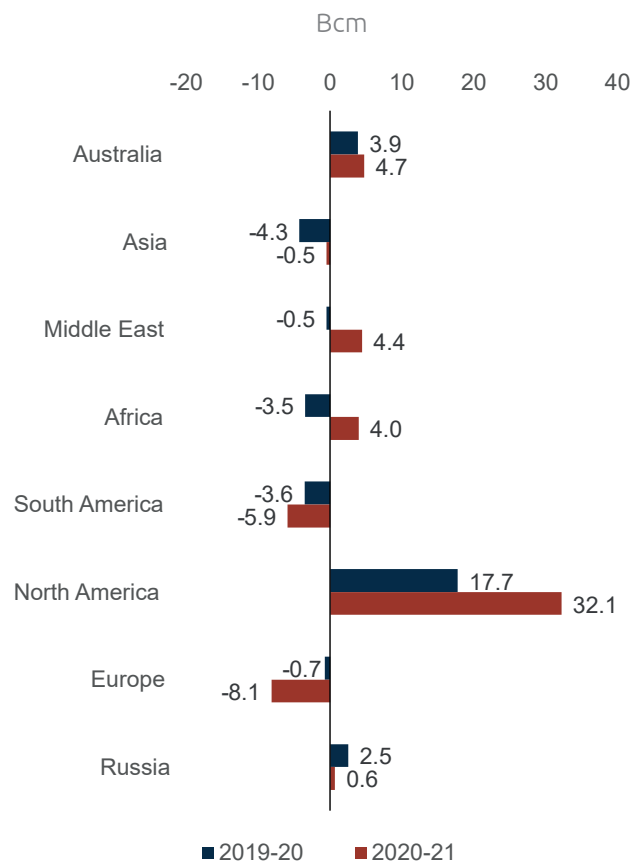


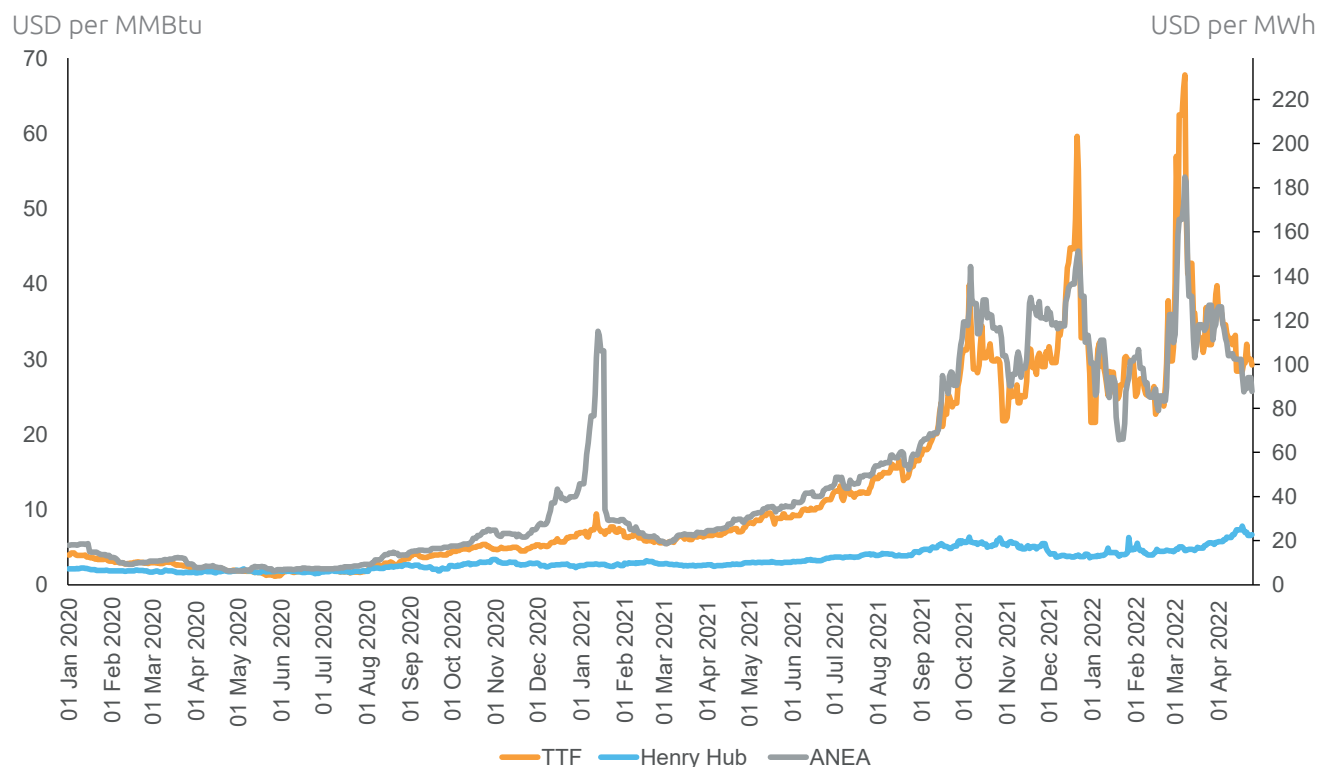
Figure 11: Additional pipeline gas export volume (2019-2020 and 2020-2021)



Source: Rystad Energy

Pricing

Figure 12: International natural gas Front Month prices



Note: TTF = Title Transfer Facility; ANEA = ARGUS Northeast Asia des price assessment

Source: Rystad Energy

2020

2020 saw natural gas prices in the three major gas hubs drop to record lows due to Covid-19 lockdowns. After a very mild winter and healthy supplies in Europe, Title Transfer Facility (TTF) prices were the first to decline, with the Front Month contract dropping from a level of \$5.20 per MMBtu at the end of November 2019 to only \$1.20 per MMBtu in May 2020, the lowest level on record. The ANEA Front Month contract followed a similar trend, going from a peak of \$6.50 per MMBtu in October 2019 to a low of \$1.80 per MMBtu in May 2020.

The Short Run Marginal Cost (SRMC) of US LNG delivered to

Europe and Asia is normally seen as the price floor for both benchmarks. During the April–June 2020 period, however, prices in both regions fell well below this level, with the TTF even sliding below the Henry Hub price. Given that demand dropped substantially during the summer and supplies took some time to adjust down, the market remained oversupplied until the end of June, when US LNG exports declined substantially.

The drop in Henry Hub prices was less dramatic: a record low of \$1.50 per MMBtu was recorded in June 2020 as domestic demand dropped due to lockdowns and

seasonality, and as international buyers canceled more US LNG cargoes. Although international demand fell as a result of lower economic activity, the low prices seen in all regions supported gas demand in the power sector. This shielded gas demand from suffering more serious consequences. Rystad Energy estimated at the time that demand levels in 2020 risked a drop of nearly 3%, whereas the ultimate outcome was a 2% reduction. Demand in the US and China (two of the biggest consumers) remained particularly strong, making up for larger drops in other regions, such as Europe.

1 / Key insights from the 2020-2021 gas market

2021

The global gas market was subjected to a particularly turbulent year in 2021, with prices spiking at the start and the end of the year, as an already tight market responded to unforeseen weather events and rising volatility in commodity supply and demand. A longer-term preference for gas over coal in power generation, coupled with Europe and Asia’s rising dependence on imported LNG, resulted in the two regions competing directly for marginal gas supply – until coal became more competitive than gas from the third quarter of 2021.

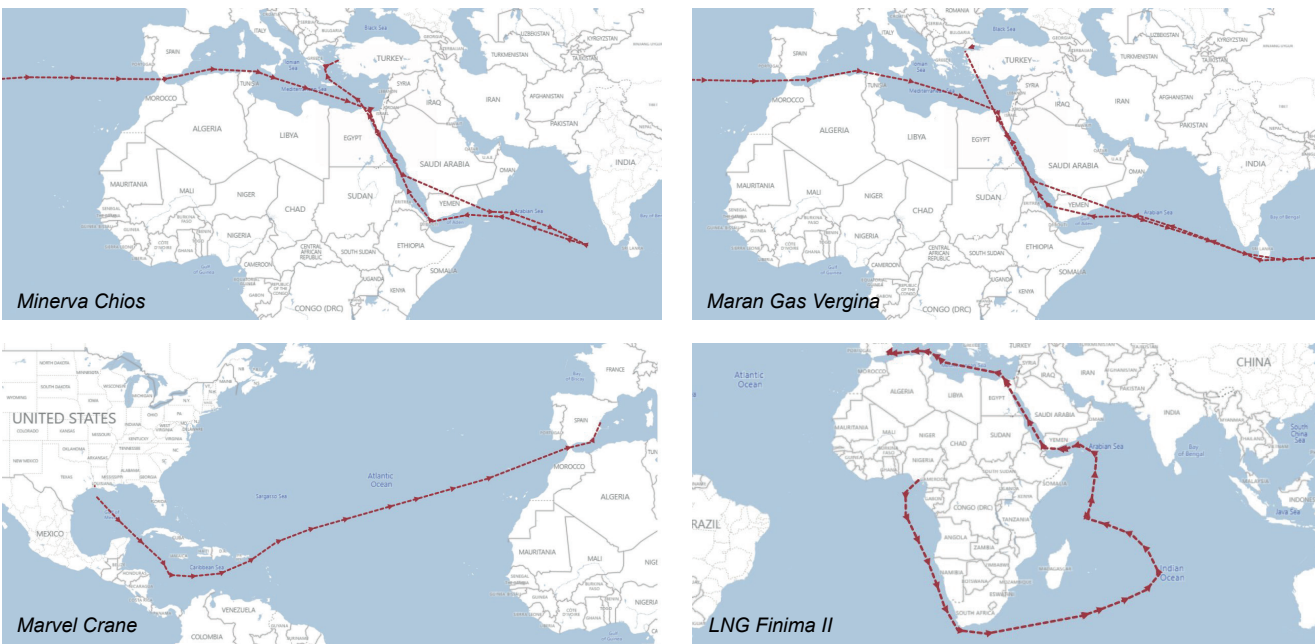
In Asia, spot gas prices hit record highs twice during the year. After a late winter spike in the first quarter of 2021, Asia Spot prices started to climb in the second quarter of the year and peaked again in October 2021, spiking to \$54 per MMBtu as sustained demand from industry and coal shortages in China coincided with higher European LNG import draws. Both Asia Spot and TTF benchmark gas prices hit record highs, with Europe and Asia competing for LNG cargoes. In addition, the decreasing likelihood of Russian gas volumes arriving in Europe through the

Nord Stream 2 pipeline compounded the tight market.

To some extent, regional competition and market volatility were also due to a lag in upstream investments, resulting in less new supply to match forecasted demand. Capital expenditure in the upstream sector has been in constant decline since 2015. In addition to the impact of Covid-19 on exploration activity in 2020, the rising pressure to reduce emissions and transition to zero- and low-carbon technologies had an exacerbated impact on gas market dynamics.

In December 2021, several ships carrying US LNG destined for Asia were directed to change course mid-voyage, as demand in Europe spiked and prices surged to new highs. Three LNG carriers – the Minerva Chios, the Maran Gas Vergina and the Marvel Crane, carrying cargoes from US LNG facilities at Sabine Pass, Cove Point and Cameron, respectively – were all diverted to Europe. Some African LNG cargoes en route from Nigeria and Equatorial Guinea to Asia were redirected to Europe as well.

Figure 13: Rerouting of LNG cargo in December 2021



Source: Rystad Energy

1 / Key insights from the 2020-2021 gas market

2022

Gas prices continued to climb during the early part of 2022, driven by the Russia-Ukraine conflict that started in late February. The general uncertainty regarding Russian gas exports to Europe as a result of the ongoing conflict propelled European prices to new record highs. The TTF Front Month contract hit \$68.30 per MMBtu on 8 March, which was about 12 times higher year-on-year. The monthly average price for March jumped 56% higher than that for February.

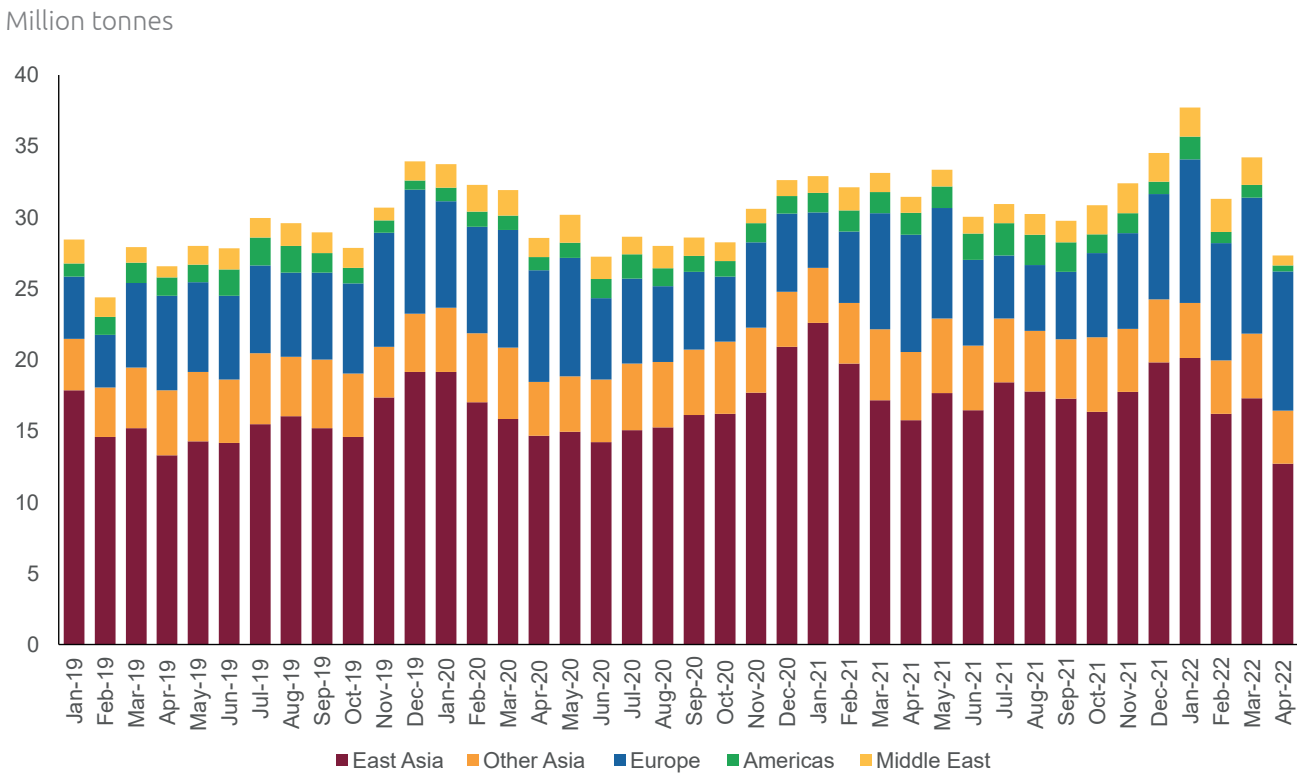
Asian spot prices have also been impacted by the geopolitical risk, as a disruption of pipeline supplies to Europe would mean even more competition for spot LNG cargoes. As a result, Asia Spot prices rose to an average \$39.30 per MMBtu in March, up 42% from February.

The graphs below indicate LNG import volumes from January 2019 through March 2022 – it is

evident that Europe and East Asia’s dependence on LNG imports, particularly volumes purchased on the spot market, has resulted in significant volatility in gas prices during the period. European import volumes from the US have increased since late 2021, as detailed in Figure 15, with additional volumes coming in from the Middle East and Africa, to supplement declining Russian imports.

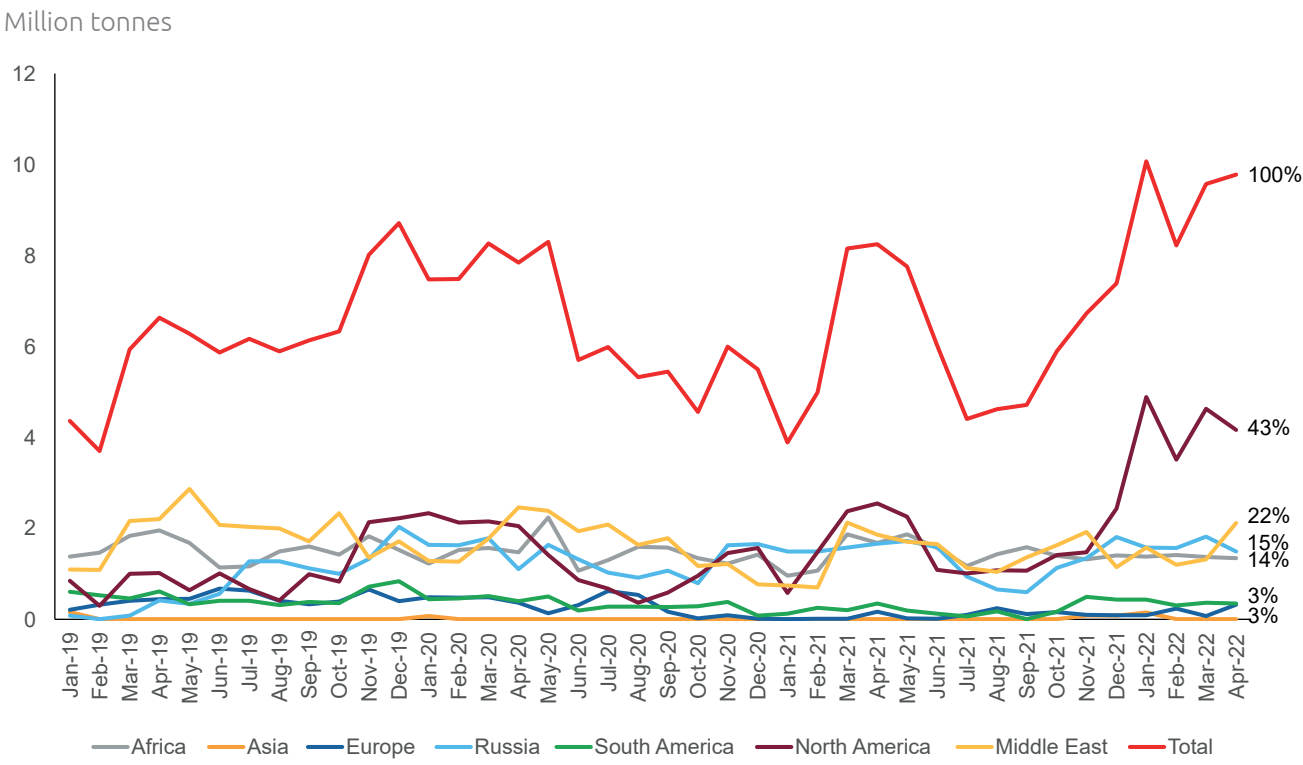
In March 2022, the European Commission proposed a new plan called REPowerEU to uplift Europe’s energy independence, in response to the Russia-Ukraine conflict. The main aim of this plan is to reduce EU dependence on Russian gas by two-thirds by the end of 2022, and to phase out Russian fossil fuels entirely by 2030. The REPowerEU plan was proposed by the European Commission in March 2022 and presented in May the same year. Significant effort will be made to rapidly increase the use of sustainable energy in the long term.

Figure 14: LNG import volume, split by region



Source: Rystad Energy

Figure 15: Europe LNG import volumes



Source: Rystad Energy

Depressed LNG investment since the pandemic

Short-term challenges led to delays on final investment decisions (FIDs) for liquefaction plants in 2020, with postponements to key projects in the US, Canada, Qatar and Mozambique. LNG cargo cancellations due to demand shortages resulted in short-term oversupply, the impact of which was felt also by long-term investors. Unlike natural gas supplied through pipelines, LNG requires significant upfront capital investment in liquefaction and regasification

facilities, as well as LNG carriers. The volatile price environment has proved to be a challenge to overcome for risk-averse lenders, especially those who prefer investing in projects with long-term contracts. This is a potential explanation as to why investments in LNG facilities failed to rise even as demand for LNG spiked in 2021. In addition, the decarbonization ambitions of the world are another potential factor impacting long-term investment

1 / Key insights from the 2020-2021 gas market

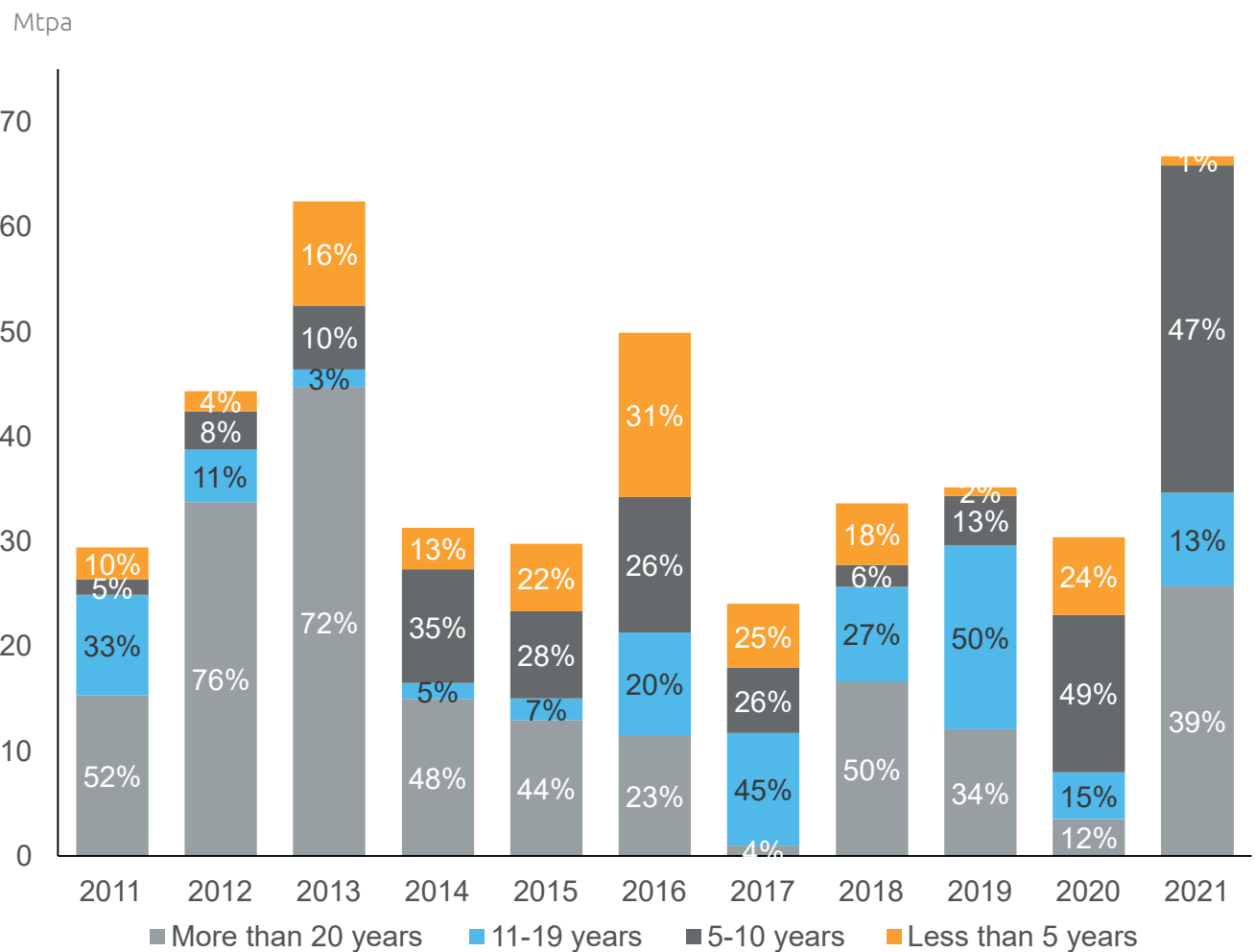
decisions in LNG. Lenders may prefer long-term SPAs, which have become less acceptable to buyers planning to phase out fossil fuels and use gas primarily as a transitional fuel. In such scenarios, it can be easier for investors to finance projects run by state-operated entities, in a controlled market that is striving to phase out coal, like China. Investing in LNG in a market that is closer to its decarbonization targets is less likely to be a favored option. This creates uncertainty in the LNG market due to the nature of the fuel. It is a cleaner replacement

for coal and oil, but it is not yet a zero-emissions fuel. However, the industry has been putting significant effort toward decarbonization, including ongoing work to advance carbon-neutral LNG, and technology to decarbonize the fuel itself with carbon capture and the introduction of renewable gas and hydrogen.

There was an increase in the number of long-term LNG contracts in 2021 compared to 2020, with buyers looking to guarantee future supply and hedge price volatility. Chinese

importers favored long-term contracts over buying spot cargoes, and China signed nearly 26 million tonnes per annum (tpa) of LNG SPAs in 2021, making it the country's highest-ever annual signing of LNG contracts. China's largest LNG contract partner in 2021 was Qatar, as about 6.5 million tpa of LNG SPAs were signed with Qatar Petroleum and about 2 million tpa with QatarEnergy. US suppliers were not far behind, signing 7.1 million tpa of LNG SPAs with China amid measures undertaken to deepen LNG cooperation between the two countries.

Figure 16: LNG SPA volumes, split by contract duration



Source: Rystad Energy

Slowed FID

The market, recognizing the threat of an emerging LNG deficit in the early 2020s, went on a sanctioning spree in 2019 as a record capacity of 73 million tpa reached final investment decisions (FIDs), driven by Mozambique (Area 1 LNG), Russia (Arctic LNG), Nigeria (NLNG T7) and the US (Calcasieu Pass, Sabine Pass T6, Golden Pass). It was assumed that 2020 would be another year with numerous major LNG projects reaching FID, even though the market was oversupplied at the time. However, everything changed with the spread of Covid-19, sending oil and gas prices on a steep descent and leaving operators struggling to finance their projects. Energia Costa Azul LNG in Mexico was the only LNG liquefaction project that reached FID in 2020.

In March 2020, it was announced that the Rovuma LNG project in Mozambique, led by ExxonMobil, would be delayed due to unfavorable economics and threats due to insurgency. Then, the Shell-led LNG Canada project, which was already under construction in British Columbia,

was put on hold due to the pandemic. In Australia, Woodside revealed that FID for its Browse LNG plant would not materialize before 2024 at the earliest. A similar trend emerged in the US, as FID for Phase 3 of the Corpus Christi LNG Terminal in Texas was delayed until 2022, and with delays also confirmed on the Rio Grande LNG Terminal amid challenges from environmental groups.

Nevertheless, several smaller scale regasification projects actually flourished in 2020, as low gas prices meant that it was cheaper to import LNG than it was to produce gas locally in some regions. About 51 million tonnes of new regasification capacity was scheduled to come online in 2020, compared to 27.5 million tonnes in 2019. However, with Covid-19 related uncertainties in the market, most projects scheduled for 2020 were delayed. New regasification capacity was added in China and Brazil, among others.

Global pipeline commissioning fell to low levels in 2020, largely due to logistical delays amid supply chain disruptions

during the initial phase of Covid-19. Projects such as the Coastal GasLink Pipeline in Canada, the Permian Global Access Pipeline (PGAP) and the Haynesville Global Access Pipeline in the US, and the Delhi Connector Gas Pipeline in India were all delayed as a result of the pandemic.

Pipeline commissioning recovered in 2021 to some extent, with the Permian Highway and Whistler pipelines in the US entering full commercial service in January and July respectively. The Trans-Adriatic Pipeline (TAP) had started operations earlier, in December 2020, transporting gas supplies from Azerbaijan to multiple European markets.

Three LNG liquefaction projects were sanctioned in 2021: Qatar's North Field Expansion, Baltic LNG and Pluto LNG T2. QatarGas LNG and Pluto LNG T2 are likely to commence operations around 2026, while a significant delay or even abandonment could be on the cards for Baltic LNG as a result of international sanctions imposed on Russia in the wake of the Russia-Ukraine conflict.

Emissions trends

Gas-to-coal switching is driving up power sector emissions

The current emissions trend has been going in the opposite direction of what is necessary to meet Paris goals. Global emissions have trended upwards since 2019, driven by the global economic and energy consumption recovery from the Covid-19 pandemic. One troubling phenomenon, and a side-effect of a tight gas market with high prices, has been a significant switching from gas back to coal since 2021. This contributed to the increase in recent power sector emissions.

The rise in coal emissions was driven by two factors, namely the 2021-2022 energy supply tightness and the recent Russia-Ukraine conflict. The 2021-2022 global energy supply tightness was the result of slower supply response to the demand recovery post the Covid-19 pandemic. Moreover, the recent Russia-Ukraine crisis has further weakened the global energy supply situation: Russia is a major energy exporter, whereby it serves approximately 40% of Europe's natural gas demand and is one of the biggest

exporters of oil to global markets. As with the recent situation, mounting global sanctions against Russia energy exports coupled with Europe's plan to reduce EU's gas dependence on Russian gas by two thirds by end of 2022 have led to further market tightness for gas.

The combination of the aforementioned factors has strained the global gas supply situation, driving gas prices to record high levels; the Title Transfer Facility (TTF) front-month contract reached around \$70 per million British thermal units (MMBtu) on 8 March 2022, which is more than double the TTF price of six months earlier. As such, various utilities across Germany, Romania and Italy, among other countries have all indicated plans to either boost current coal capacity utilization, bring retired coal-fired thermal power plants back online and/or delay coal phaseout. All of which have led to higher coal generation in the power mix and consequently resulted in higher emissions from the power sector.

1 / Key insights from the 2020-2021 gas market

Greenhouse gas emissions have risen between February 2020 and February 2022. For example, the three-month average emissions for three key regions, Europe (Figure 17), Japan (Figure 18), and United States (US) (Figure 19), have increased by 11%, 8% and 2%, respectively. Similarly, coal-related emissions in Europe (Figure 17), Japan (Figure 18), US (Figure 19), have increased by 20%, 12% and 28% respectively over the same period.

Figure 17: Europe Monthly Power Sector Emissions, million tonnes of CO2e

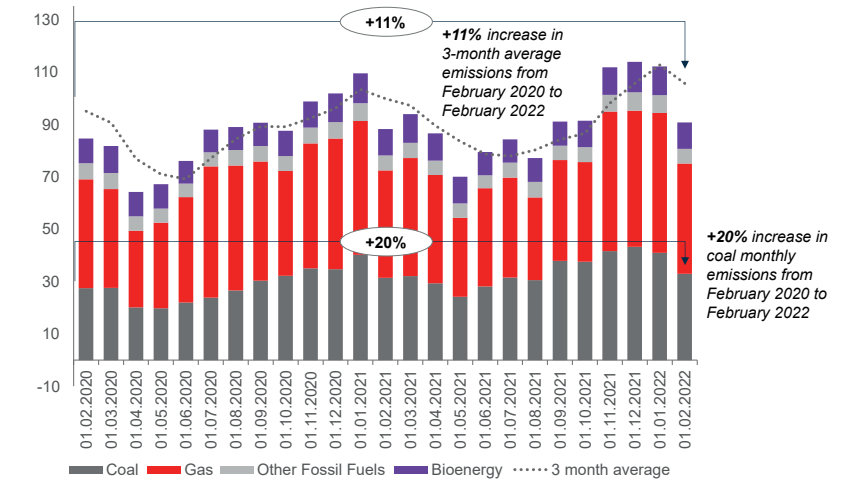


Figure 18: Japan Monthly Power Sector Emissions, million tonnes of CO2e

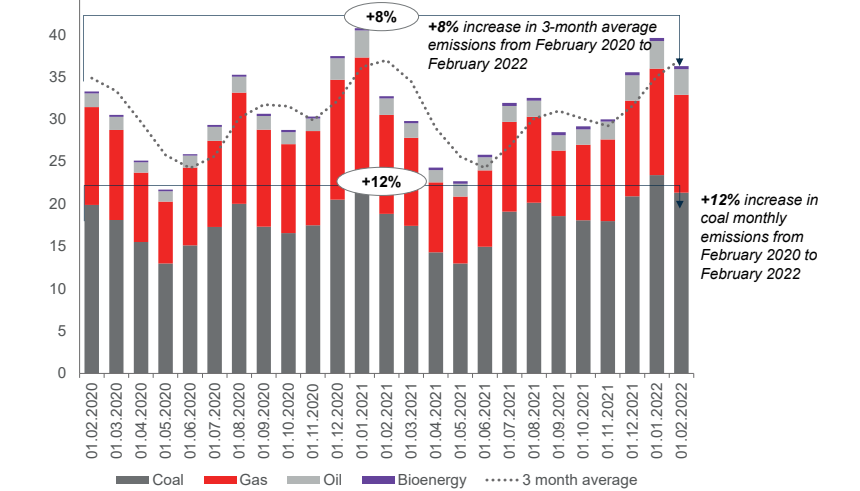
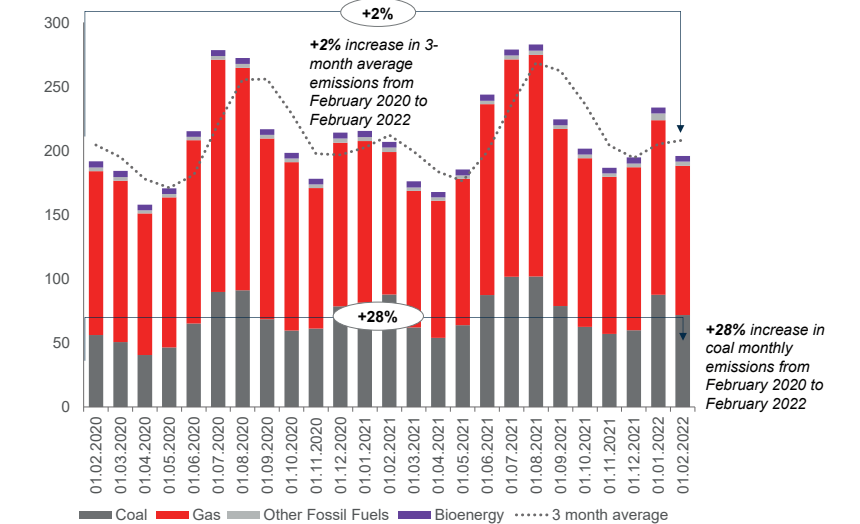


Figure 19: US Monthly Power Sector Emissions, million tonnes of CO2e



Note: Average emission factors are used in these graphs; Refers to direct emissions only; Other Fossil Fuels refers to oil and petroleum products, as well as manufactured gases and waste; Bioenergy refers to renewable biomass and biogas.

Source: Rystad Energy;
Ember Climate

1 / Key insights from the 2020-2021 gas market

With the current forward market pricing for coal, gas and carbon, coal is the lower price fuel for power generation compared to gas, with gas prices rising faster than coal. This has incentivized gas-to-coal switching in the key regions in the US (Figure 20), the Netherlands (Figure 21) and the Japan (Figure 22) beginning in September 2021.

Coal, gas, and carbon pricing dynamics may continue to favor coal in the power generation mix as gas prices remain above the coal-to-gas (C2G) switching range. Even with higher carbon prices, coal could remain more competitive than gas. This trend has been evident across the key regions of the US, Europe and Japan where gas prices have soared beyond the coal-switching price bands post September 2021.

In Europe, gas prices (TTF) have remained above the C2G band since October 2021 despite soaring coal prices (arising from a fear of supply disruptions and shortages), of which any switching from gas to coal that could take place has likely occurred. Coal plants may continue to displace gas power in the generation mix if the high gas prices were to continue in the short term.

Figure 20: Henry Hub gas price vs coal-switching price in the US, USD per MMBtu

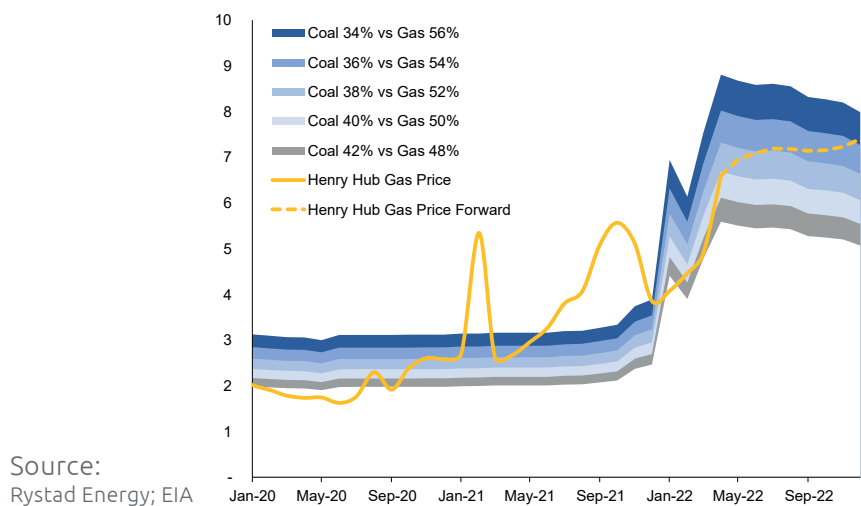


Figure 21: European gas prices vs coal-switching price in the Netherlands, USD per MMBtu

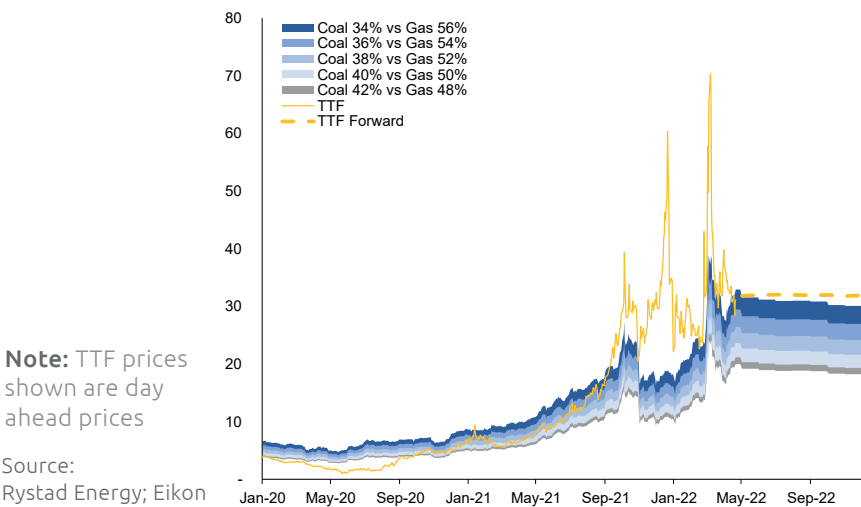
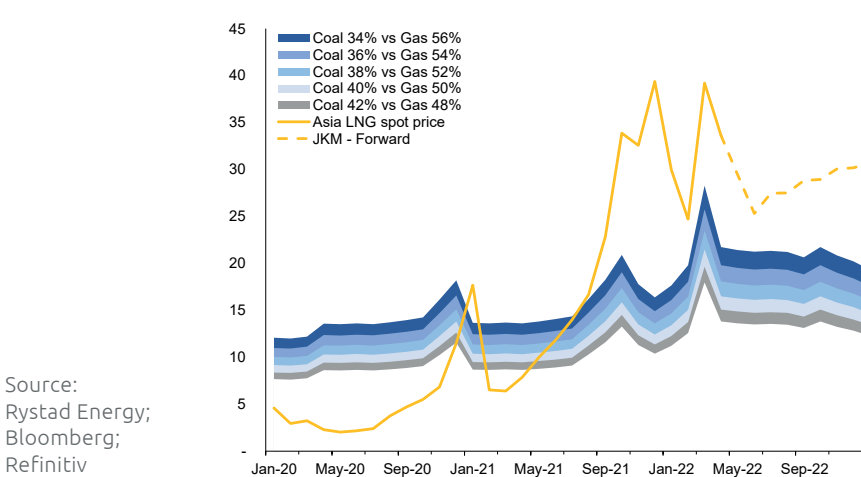


Figure 22: JKM (Japan Korea Marker) gas price vs coal-switching price in Japan, USD per MMBtu



1 / Key insights from the 2020-2021 gas market

Key implications

Longer term, the trend of gas-to-coal switching could be reversed by the following factors:

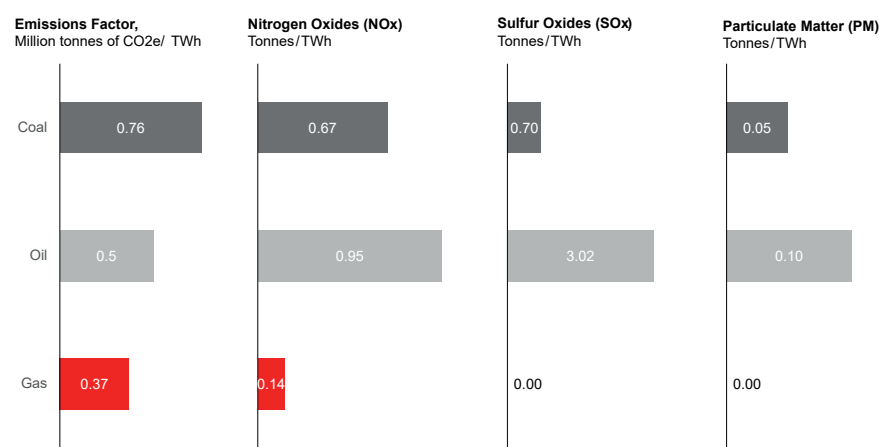
- **Energy demand-supply rebalancing**, with global gas production ramp up supply capacities to meet the demand growth such as new LNG mega train developments, such as Qatar and Mozambique, shale gas developments, such as in US Lower 48 and Argentina, and other global deepwater LNG projects.
- **Tighter carbon policy announcement**, of which various countries globally have recently either introduced or extended carbon taxes/emissions trading systems. For example, the EU 'Fit-for-55' policy recently announced annual reduction of EU emissions allowances to increase from 2.2% to 4.2% in the EU ETS. Other countries such as Canada, China have introduced new emissions trading systems while South Africa, Mexico have put in place new carbon taxes at the national/sub-national level. The result of these new carbon policies may result in higher carbon prices which could render high emissive fuels such as coal less competitive against other fuels.
- **Longer-term policy mandates** to phase out coal, such as EU countries already announcing firm plans to phase out approx. 40 GW of coal-fired generation before 2030. Other major-coal consuming countries, such as Canada, Indonesia, Poland, South Korea, and Vietnam, have also announced to phase out coal-fired generation, with the bigger economies achieving it by 2030s, and smaller economies achieving it by 2040s. However, an underlying risk to these policy mandates which could "lock-in" future emissions, would be the pipeline of 176 GW of new, under construction coal plants (China and South and South-east Asia account for over 50% and 37% of the new pipeline capacity respectively).
- **Higher gas-to-power demand growth** with global gas power net capacity expected to add about 257 GW by 2030, of which Europe will add about 34 GW of new gas capacity over the same period. These estimates are based on Rystad Energy's analysis on announced and planned capacity additions and forward view of capacity market developments.

Considerations for the global gas industry

Stricter and faster decarbonization commitments, as outlined in the COP26 and the European Fit for 55 policies, are expected to accelerate the decline in oil and coal consumption, while renewables and other clean energy sources will be required to support deeper decarbonization across various sectors in the longer term. The scale and speed at which these key policies (such as zero- and low-carbon investments and then phase-out of highly emissive plants) are implemented will remain a key challenge for the industry to deliver on its decarbonization commitments, such as the Global Methane Pledge announcement (Figure 24) pledging to reduce methane emissions by 30% from 2020 levels by 2030. At the same time, they must consider other factors such as affordability, energy security and energy mix constraints.

Implementation will be a key focus area for governments and policymakers beyond these policy commitments, such as detailing key specific policy guidelines, detailed roadmaps, enforcement mechanisms at both national and regional levels. The US's recent proposition of the latest Methane fee mechanism on sectors is a key example of an implemented policy supporting their longer-term COP26 commitments. Beyond such policy mechanisms, the government would also need to focus on standardizing

Figure 23: Comparison of emission factors and pollutant emissions by fuel type in the power sector



Note: Refers to direct emissions only

Source: Rystad Energy; Emission factors were derived from Intergovernmental Panel on Climate Change group, Pollutant emissions (NOx, Sox, PM) were derived from the Journal of Air Waste Management Association, which referenced Taipower, Taiwan (2008)

emissions measurement, reporting and accounting to ensure that their sectors are able to make meaningful emission reduction and actualize their targets.

It is a key moment for the gas industry to demonstrate the near-, medium-, and long-term value of gas technologies. Policymakers on the other hand should not discount a viable, available, flexible, and “decarbonizable” solution to the energy transition, such as natural gas. In the near-term using gas instead of coal and oil allows immediate drops in emissions in both greenhouse gases

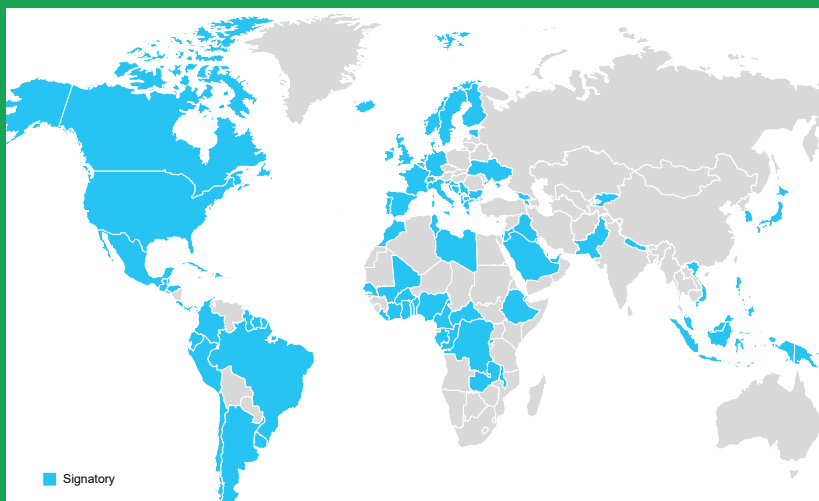
and air pollutants (Figure 23). It also enables greater shares of renewable energy deployment, as a valuable grid balancing tool – necessary for mitigating longer periods of renewable intermittency.

Progressively, low-carbon and zero-carbon gases, such as natural gas with CCUS, hydrogen and biomethane will support deeper decarbonization across sectors. Importantly, new gas infrastructure can be designed in a way to enable further scale-up of low- and zero-carbon gases, supporting the achievement of the Paris agreement objectives.

Global Methane Pledge

One of the prominent pledges under (United Nations Climate Change Conference 2021) COP26 is the Global Methane Pledge. As methane emissions are increasingly becoming the focus for international climate policy, both the US and EU launched this new initiative in 2021 to reduce economy-wide methane emissions by 30% from 2020 levels by 2030. With these new commitments, more than 70 countries have committed to the pledge. This represents about 30% of global methane emissions and 60% of the global economy.

Figure 24: Participants in the global methane pledge



Source: Rystad Energy; Global Methane Pledge

Key resource on methane emissions mitigation in the gas sector

- Methane Guiding Principles: <https://methaneguidingprinciples.org/>

Key insights from 2020-2021

2021 brought attention to the energy security challenges faced across the globe. The EU and China both dealt with health and economic crises triggered by the pandemic in 2020, followed by a natural gas supply crunch in 2021. In the EU, where large volumes are purchased from a potentially volatile spot market, the value of long-term contracts was reinforced. China, on the other hand, was able to protect its households from high prices through its state-controlled policies. However, the implementation of renewables at scale for the Chinese power market has been limited due to its state dispatch policy, which favors base-load power generation technologies.

The design of a contract for natural gas imports is important to maintain a balance between security of supply and cost. The European market was much more vulnerable to the price shock since the price of gas was predominantly set in the spot and futures market. This had benefitted European consumers when gas prices were low, but swung in the opposite direction with high prices. A long-term contract is preferable when the goal is to mitigate risk of market volatility. Devising an alternative that could combine the advantages of both market designs may prove to be a suitable contract design as well.

With the increase in renewable energy production, it is important to add flexibility in grid management, such that the intermittency of renewable output can be mitigated. In the UK, low wind speeds in 2021 forced the country to turn on coal

power plants to provide stability to the grid. The development of low- and zero-carbon alternatives is necessary to tackle the irregularity of wind and solar output.

Diversification of gas supply sources is another important factor for countries to consider, to lower the impact of geopolitical risk on energy security. Declining gas volumes from Russia to Europe in 2021 kept gas prices in the region high. In 2022, sanctions imposed on Russia pushed prices even higher, with the EU pledging to reduce dependence on Russian supplies to a third within a year. Improving domestic production levels, investment in renewable hydrogen and biomethane, coupled with diversification of gas supply sources could help to relieve some tightness in the market.

Gas will play a pivotal role in the energy transition and decarbonization. Besides enabling immediate emissions reductions in both greenhouse gases and air pollutants through direct coal and oil displacement in the power, industry, and transport sectors, it could also support greater shares of renewable energy deployment as a valuable grid balancing tool – necessary for mitigating longer periods of renewable intermittency. Over the medium-longer term, gas will progressively reduce its greenhouse gas footprint with the deployment of carbon capture and scaling of renewable gases and hydrogen supply to support deeper decarbonization across sectors.

2 / Energy Security and Reliability

Highlights

- **These recent security and reliability** events brought to surface several critical threads of lessons, all of which lead to energy system planning and the need for deliberate policy assurances for secure, reliable, affordable, and sustainable energy access in the future. An achievable energy transition must coexist with energy security assurances.
- **The ongoing conflict between Russia and Ukraine has reminded the world about the importance of energy security planning.** Europe is currently on a quest to achieve it as rapidly as it can, through diversification of supply, sources, new infrastructure investments, and conservation measures. Since the onset of the Russia-Ukraine conflict, more than ten LNG terminals have been proposed in Europe. The European Commission has also proposed a series of measures to diversify gas supplies and respond to rising energy prices through the REPowerEU plan. It outlines plans to reduce EU demand for Russian gas by two thirds before the end of 2022 and make Europe independent from Russian fossil fuels well before 2030.
- **Development of additional gas storage capacity and policies for storage are also ways of increasing energy security.** Over the last year, low gas storage volumes have caused concern around energy security and spikes in natural gas prices. As a result, the EU Commission has announced plans for mandating underground gas storage across the EU to be filled up to at least 90% of its capacity by 1 October every year.
- **Future infrastructure investments should be developed with flexibility in mind so that it can serve different sources of supply.** This will reduce the risk of the assets becoming stranded as a result of geopolitical events or other factors impacting the supply of natural gas.
- **The gas supply chain has shown resilience through the Covid-19 pandemic and the following post-Covid recovery.** Despite a challenging operational environment with lockdowns and reduced staffing, the gas industry has been able to continue meeting demand and delivering gas around the world. This has been achieved by many adaptation strategies, including rerouting volumes across geographies and sectors.

- **The last two years also showed how extreme weather can threaten the reliability of energy systems.** Periods of extreme weather have caused supply disruptions, demand spikes due to increased need for cooling or heating and volatile electricity prices. Droughts in Brazil and Turkey as well as periods with low wind speeds in Europe have also resulted in periods with low output from hydro- and wind power. In these instances, natural gas has proven to be a reliable source of electricity generation and has been able to offset the shortfall from other sources.
- **Given the volatile environment faced by most countries in 2020 and 2021, three key areas of improvement were identified to develop energy security and build resiliency.** Countries could better balance their portfolio structure with a combination of both long and short term contracts, to avoid being exposed to larger price fluctuations. They could also consider diversifying their gas imports geographically to minimize geopolitical risk. Lastly, diversification and capacity planning are also critically important in the electricity supply mix, particularly with growing shares of intermittent generation sources with limited capacity values (vs. energy).

Introduction

Energy security can be defined as continuous and consistent access to affordable energy. Put another way, having a secure energy system means that everyone has access to the amount of energy they want, when they want it (*Joshi, R. 2012*). Ideally, this energy is also modern, clean and safe and does not pose risks to health or the environment.

Three key aspects of energy security are:

Access: Energy should be universally accessible so that people and businesses can benefit from modern energy services and products.

Affordability: Energy should be offered at a price that allows all people to use energy to meet their needs for heating, cooling and other uses without compromising their ability to meet other basic needs.

Reliability: The energy system should be designed in a way that provides a continuous and consistent supply of energy despite geopolitical events, extreme weather and other disruptions that can limit access to energy.

Assuring energy security is a balancing act between these three dimensions, and too much focus on one of them can put the overall energy security at risk. Energy security is influenced by both policies and technology, so finding the right balance requires these to work together in tandem.

Geopolitical risks

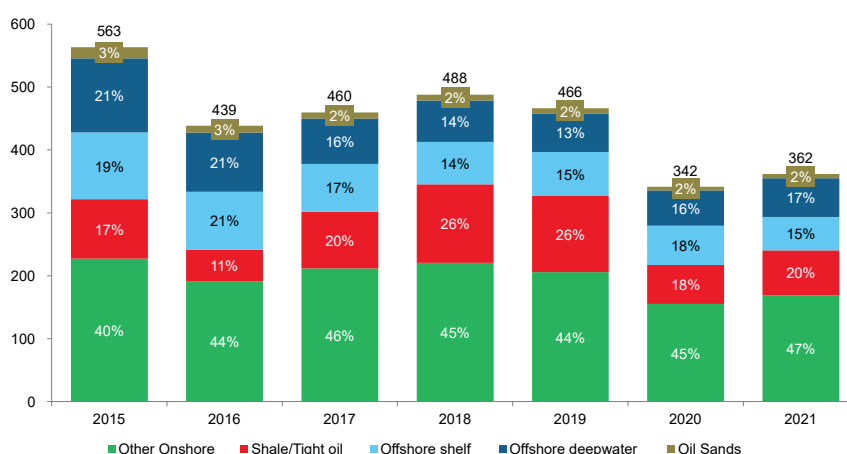
The Russia-Ukraine conflict has highlighted how vulnerable the energy sector can be to geopolitical events. It has shown that such events negatively impact all dimensions of what we call the energy trilemma: They can make energy less affordable, less sustainable, and less secure. Due to the globalized nature of the energy markets, the effects are also being felt globally.

The conflict's effect on natural gas comes on the back of an already tight market caused by several factors. The Covid-19 pandemic led to reduced investments in upstream assets. Figure 25 shows that upstream oil and gas investments fell by 27% from 2019 to 2020, followed by a 6% increase from 2020 to 2021. This drop in investments led to undersupply towards the end of 2021 as supply could not keep up with the strong post-Covid demand recovery. In addition, the gas storage levels in Europe reached unusually low levels in the summer of 2021 due to a cold preceding winter. The situation was exacerbated by lower Russian exports to Europe throughout the autumn of 2021, creating a tight market already before the onset of the Russia-Ukraine conflict.

The post-Covid recovery brought a significant surge in energy demand. This rapid increase in demand, combined with lower investments in the energy sector throughout the pandemic, resulted in price spikes across all energy commodities. The recent months' high energy prices translate into increased costs of electricity and goods that use energy as an input factor and put energy affordability at risk.

Figure 25: Upstream oil and gas investments by supply group

USD billion



Source: Rystad Energy

The higher gas prices have also led to gas-to-coal switching in the power sector, thereby increasing the CO2 emissions from electricity production. We have already seen gas supplies from Russia to Bulgaria and Poland being cut off, and physical damage to infrastructure remains a risk. Russian gas flows to Europe via Ukraine have also been disrupted as a consequence of the ongoing conflict. GTSOU, which operates Ukraine's gas system, halted flows through the Sokhranovka transit

point in the beginning of May 2022. Around 8% of Russian gas exports to Europe usually flow through the transit point. 37.5 Bcm of Russian gas was delivered via Ukraine in 2021, representing 22% of the gas volumes that Russia delivered to Europe that year.

In the following section, we will discuss some of the steps that can be taken to make the energy system more robust to geopolitical risks.

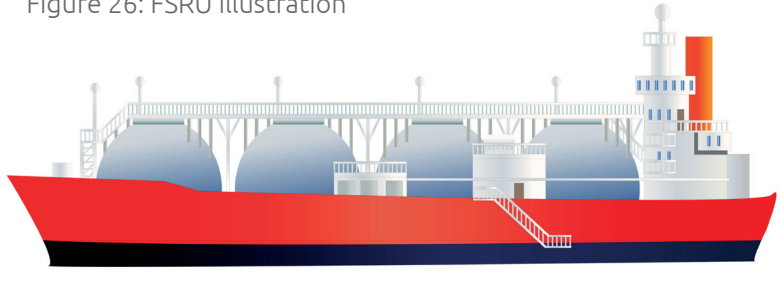
Diversification of supply

The ongoing conflict between Russia and Ukraine has reminded the world about the value of diversified energy markets and has made energy security a priority for the world, and particularly for the Europe.

One of Europe’s top priorities today is diversification of its energy supply sources, with a special focus on natural gas. More than 10 LNG import terminal projects have been proposed in Europe since the onset of the Russia-Ukraine conflict. These are a combination of greenfield and expansion projects in Italy, Estonia, Latvia, the United Kingdom, Netherlands, Germany, France, Slovenia, Croatia and Greece. The majority of these are floating storage and regasification units (FSRUs), which means that they can be brought online within months if the domestic gas delivery infrastructure is already in place. An example of projects with such short timelines is the Ain Sokhna LNG terminal in Egypt, where the FSRU was delivered three months after signing the contract. The construction of these import terminals will allow for diversified supply and reduce the dependency on Russian gas.

Poland is an example of a country that has worked to diversify its supply of natural gas since its national oil and gas company PGNiG in 2017 began taking steps to increase the security of the natural gas supply. These steps include investing in Norwegian upstream fields and the 10 Bcm Baltic Pipe pipeline to transport gas from Norway to Poland, as well as expanding its LNG import capacity. Once the expansion of the Lech Kaczynski LNG terminal is completed at the end of 2023, the country’s LNG import capacity will increase from 5.0 Bcm to

Figure 26: FSRU illustration



FSRUs are ships used for LNG storage and regasification directly, with the regasification equipment installed on the vessel. Compared to conventional onshore regasification terminals, FSRUs offer more flexibility, with the option to be deployed anywhere along the shore. FSRUs are deployed off the coast of the markets they serve, instead of on land, making it the preferred option for land-scarce regions and areas with poor accessibility. Capital expenditure and construction time for FSRUs are almost half of that of an onshore terminal, however, operating costs are usually higher.

Figure 27: European LNG import terminals announced since the onset of the Russia-Ukraine conflict



* The locations of the two Italian FSRUs are indicative, as the actual locations are still being discussed

Source: Rystad Energy

2 / Energy Security and Reliability

8.3 Bcm per annum. In April 2022, Russia suspended gas exports to Poland over the country's refusal to pay for the gas in rubles. Following the suspension, Polish officials have communicated that there is no need to draw gas from reserves, due to alternative sources. This example illustrates that supply diversification takes time and requires significant investments in infrastructure. As such, it needs to be proactively addressed and deliberately planned in long-term strategies and policies.

The European Commission has presented plans for increasing the imports of piped gas from non-Russian sources by 10 Bcm before the end of 2022, with most of these incremental volumes expected to come from Norway, Algeria and

Azerbaijan. There is sufficient spare pipeline capacity to meet this target, but the question remains around these countries' ability to increase output from their fields. The Norwegian Petroleum Directorate (NPD) published a revised production forecast in February 2022, implying a 5.15 Bcm increase in 2022 output compared to 2021. There is available gas pipeline capacity between Algeria and Europe, but an increase in flows is subject to Algeria's ability to increase upstream production. In April 2022, Eni and Sonatrach signed an agreement to increase gas flows from Algeria to Italy from 2022, by up to 9 Bcm per year in 2023-2024. If Azerbaijan maintains the current level of exports to Europe throughout 2022, exports will increase by around 3 Bcm year-on-year.

Infrastructure should be designed with flexibility in mind

One key aspect of supply diversification is the ability to switch between different supply sources. LNG brings a unique flexibility advantage in that its supply chain can be reconfigured in response to changes in resource availability and unplanned external risk factors (e.g. geopolitical events, extreme weather). As such, it can mitigate the risk of gas delivery infrastructure being stranded. Both Europe and Asia have increased their share of LNG in the import mix over the last decade, with the trend being most noticeable in Europe.

Similar considerations must be made when designing the infrastructure network for gas transportation. The infrastructure will stay in place for decades, so it must be flexible enough to accommodate changes

in supply, demand patterns and the transition to more low carbon gases. Additional investments must be made to expand the existing transportation network and make a diversified network that's not relying on a single source exporter. It is also expected that the existing natural gas infrastructure will be repurposed to also be used for low carbon gases in the future, and as such, any new investments in gas infrastructure should be designed with this in mind.

The European lesson is anyhow showing the important benefits of an integrated regional system, which could also be beneficial to other regions in order to both maximize security and create flexibility in domestic systems.

Focus on storage capacity build-out

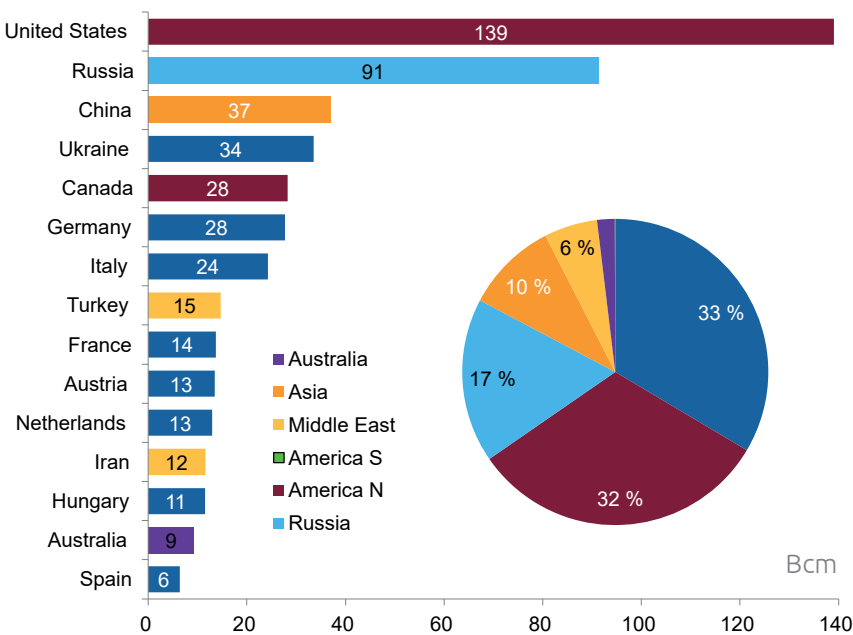
A key feature of today’s natural gas value chain is the ability to store gas and LNG, which enables gas to be consumed at different points and at different times to when it is produced. This is crucial to meet the seasonal fluctuations in gas demand through production that is stable throughout the year.

Gas storage also provides security assurance to reduce the risk from unplanned external events, as it can buy time to replace imports. Increased storage will not only improve energy security, but it can also reduce price fluctuations by increasing supply in times of high demand.

The critical role of storage in securing stable supply of gas when supply and demand fluctuate was demonstrated throughout the Covid-19 pandemic. However, this part of the gas value chain needs to be further improved as gas continues to play an important role in providing a secure, affordable and sustainable source of energy. This will also become increasingly important with a higher share of renewables in the power mix, as the intermittent renewable power generation will require gas to be delivered to meet the supply shortfall from renewables in periods with less wind and solar irradiance.

At present, gas storage is quite

Figure 28: Underground storage capacity by country (top 15) and continent



Source: Rystad Energy

unevenly distributed around the world, as can be seen in Figure 28 above, with the vast majority of it in Europe, US and Russia.

In addition to investing in more storage capacity, governments can impose mandates for minimum storage levels. This has been a common existing practice with oil, where governments and private practices hold inventories to safeguard the economy and maintain energy security. As gas has become a global commodity subject

to greater impact by unpredictable external events, considering implementation of strategic reserves for gas may be appropriate, as for oil.

The European Commission has announced this mechanism in the RePower EU plan, proposing a requirement for underground gas storage across the EU to be filled up to at least 90% of its capacity by 1 October every year. The 90% filling level is enough to cover an estimated 17% of EU’s average annual gas demand in 2020 and 2021.

Investing in exploration and production

Governments can consider increasing domestic gas production to enhance security of supply. One example where this has been done historically is in Egypt. After a period of strong growth in gas demand in the early 2000s, Egypt went from being a large net exporter to becoming a net importer. This stimulated investments in exploration and development of new fields. This has in turn made Egypt self-sufficient with natural gas and the country has once again become a

net exporter. More recently, we have also seen the UK becoming increasingly focused on prioritizing domestic resources. The Cambo and Rosebank discoveries were at risk of being stranded, but the crisis in Ukraine has spurred renewed interest in developing these fields to reduce the UK’s reliance on energy imports.

However, there are also some challenges with increasing Europe’s domestic supply. First, there is

the geological aspect: many European countries have mature oil and gas industries with less potential for new discoveries. European production has been in decline since the early 2000s, largely driven by reduced output from the UK and the Groningen field in the Netherlands.

Second, there is a time lag from when final investment decisions are made until they result in

increased output. It is critical that the policy environment, both financial and political, does not impose barriers on the development of new supply sources outside of Europe holding great potential to support global energy security by adding new supply origins to the global gas markets. Africa is one example where development of new supply can benefit both, its domestic development and global energy security.

Role of natural gas through Covid-19

The Covid-19 pandemic created an unprecedented shock to the global energy system when it started in the first quarter of 2020. Lockdowns caused by the pandemic have led to significant reductions in economic activity and supply chain disruptions. Despite a

challenging operational environment caused by lockdowns and operational restrictions, the natural gas industry has shown it is highly flexible, adaptable and able to meet demand across the globe, even in most challenging conditions.

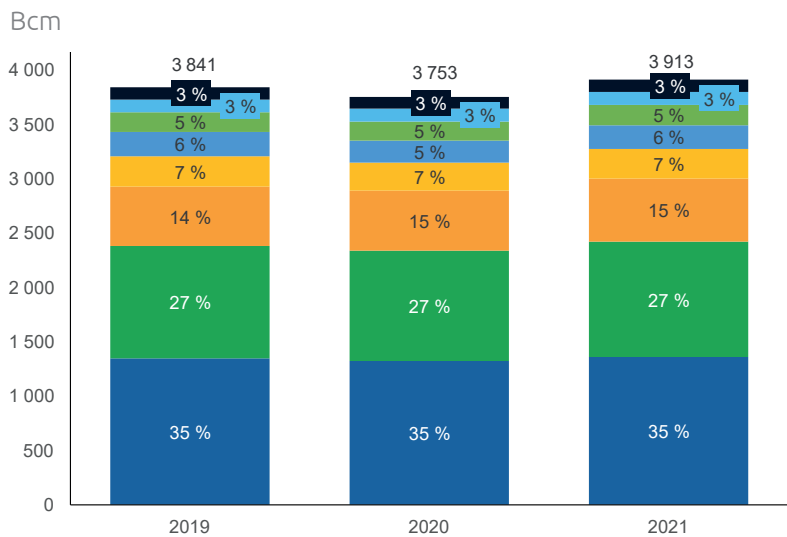
Demand resilience

The resilience of natural gas demand demonstrated during the Covid-19 pandemic can be attributed to a few key factors. First, natural gas is powering many critical functions in society that are crucial even in times of crisis – including hospitals, water supply, food production, and manufacturing of medical equipment.

On a global level, gas demand fell 2.3% from 2019 to 2020. Most of these reductions were related to industrial and commercial sectors, as well as power generation, due to lower economic activity. Some of the decline was offset by higher residential gas demand

As the post-Covid recovery has gained momentum, the supply side has been able to quickly ramp up production to meet the surge in gas demand. From 2020 to 2021, global gas demand increased by 4.3%, bringing it to

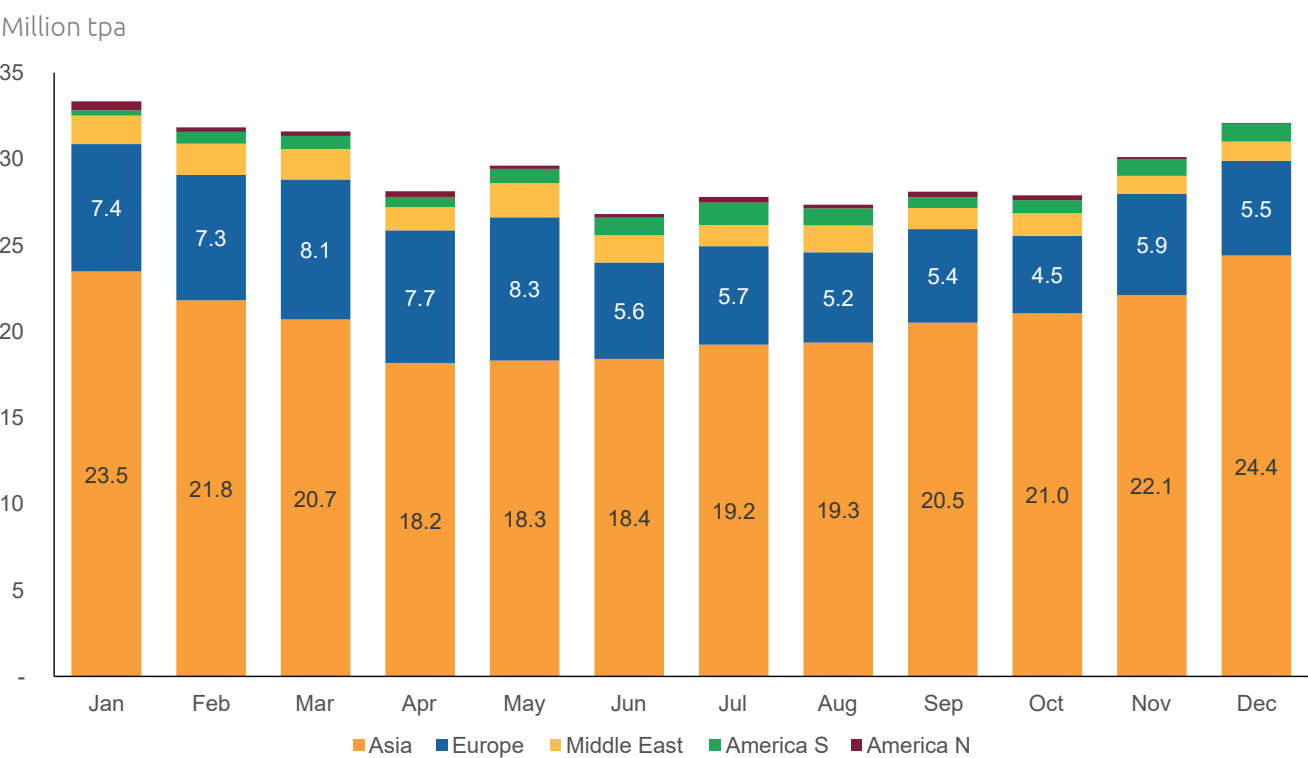
Figure 29: Global gas demand (2019-21), split by demand sector



Source: Rystad Energy

1.8% above the 2019 level. Overall, throughout the pandemic, the gas value chain has also shown it is able to adjust to changing geographical and sectorial demand patterns. Different regions were hit by lockdowns at different points in time, which allowed gas volumes to be re-routed from regions that were impacted by

Figure 30: 2020 monthly LNG imports by import region (million tpa)



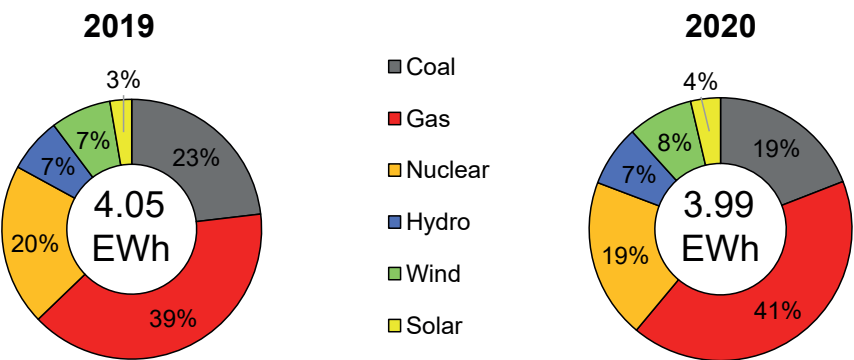
Source: Rystad Energy

lockdowns to other areas less affected by the pandemic.

As lockdowns were imposed in Asia in the first half of 2020, LNG volumes were rerouted to Europe where demand remained relatively strong. Figure 30 shows how LNG imports to Europe held up throughout May 2020, which helped offset the reduced imports into Asia.

Later in the year, when economic activity also slowed down in Europe, some US LNG volumes were redirected towards domestic consumption. US gas-fired power generation grew by 3% from 2019 to 2020, despite a reduction in overall power generation (see Figure 31).

Figure 31: US power generation by source (%)



Source: Rystad Energy

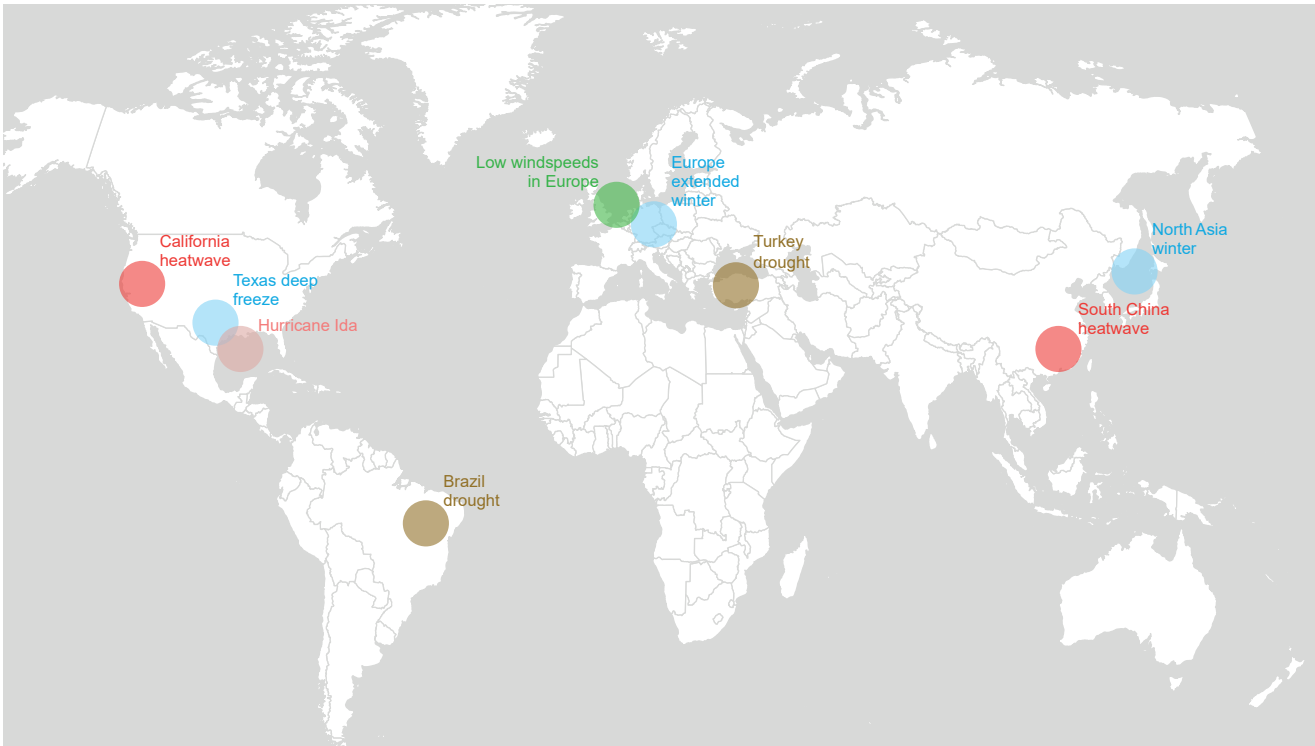
Extreme weather

The past two years have shown that the global energy system is vulnerable to extreme weather events. These events can take the form of extended periods of high or low temperatures leading to increased demand for cooling or heating, or shorter periods with extreme weather that disrupts energy supply.

The frequency of extreme weather events is expected to increase due to global warming, and it is critical to

design the energy system to be able to withstand such extreme events. Energy security must remain a priority through the energy transition. The energy industry and policymakers should seek for the right balance between an achievable energy transition and an energy system that is resilient and secure. Below, we look at several case studies highlighting the importance of gas and its security in the energy system’s reliability.

Figure 32: Overview of selected extreme weather events that impacted energy markets in 2021



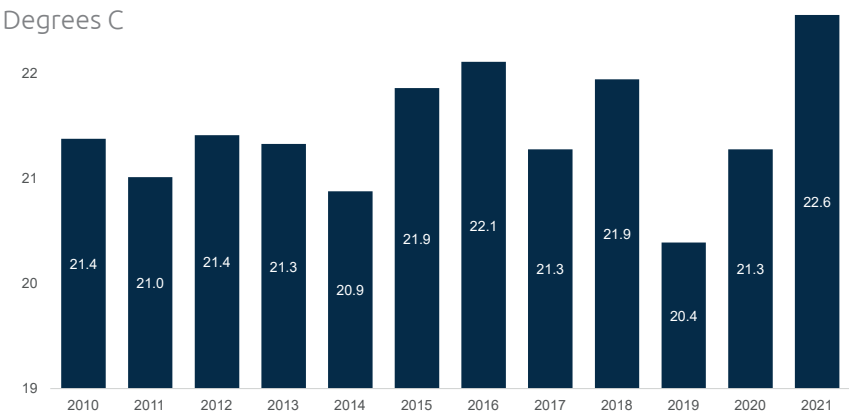
Source: Rystad Energy

Summer 2021 US heatwave

An early summer heatwave across the western US in 2021 broke records in multiple states, with temperatures in some places above 38 °C for extended periods. A series of exceptional heat waves made June 2021 the hottest one on record in the US, with the month’s average temperature in the Lower 48 states hitting 22.6 °C. This was 2.4 °C above average and 0.5 °C higher than the previous June record set in 2016 (Figure 9). Eight states – Arizona, California, Idaho, Massachusetts, Nevada, New Hampshire, Rhode Island, and Utah – recorded their hottest June ever.

At the same time, the recorded temperature in Portland, Oregon, reached a high of 46 °C, with power cables for the city’s streetcars melting and more than 6,000 people temporarily losing electricity. Authorities in California suggested in June that residents charge their electric vehicles (EV) during off-peak hours to save energy. Such extreme temperatures have exposed how vulnerable the

Figure 33: Average June temperatures for the Lower 48 US states



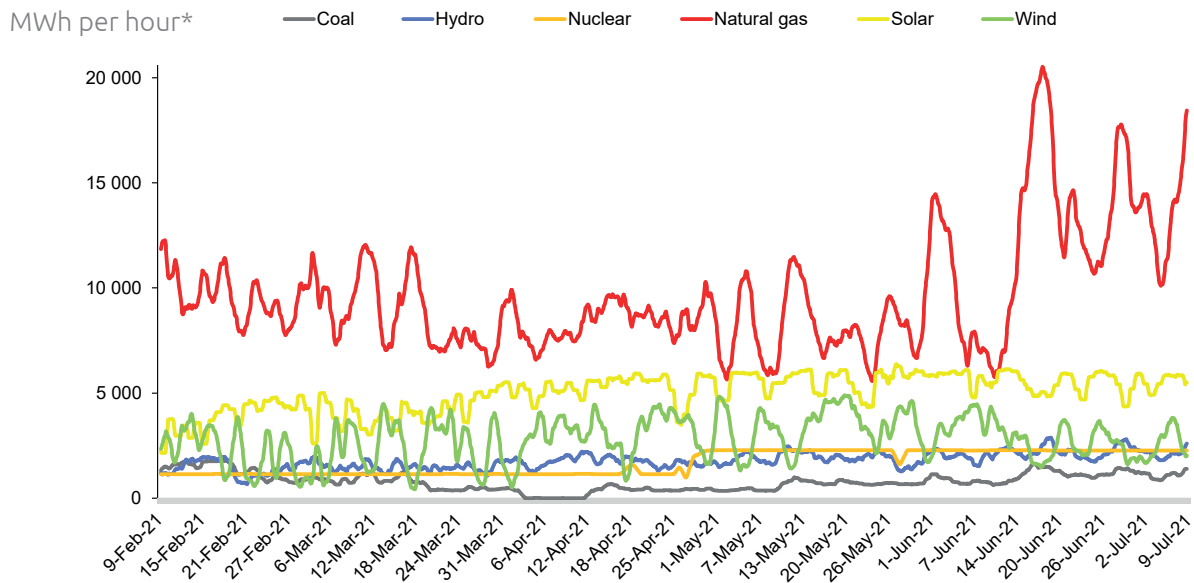
Source: National Centers for Environmental Information (NCEI)

US power grid is to the effects of climate change.

Summer demand peaks are nothing new in the western and southern US, and in 2021 there was a clear increase in overall power demand from the beginning of June until mid-July. In addition, the import-export balance has remained relatively unchanged, meaning power generation has – at least so far – been able to keep up with demand increases. How-

ever, the data shows that volatility in the export-import balance has been increasing while the average appears relatively stable. Since power generation has been able to keep pace with demand, one or more energy sources had to ramp up over the summer of 2021 to meet the increased demand for cooling. Figure 34 shows that natural gas served as the power source that was able to ramp up quickly to meet the volatile demand.

Figure 34: California power generation by source



• Data is transformed from hourly resolution to 24-hour moving average

Source: EIA; Rystad Energy

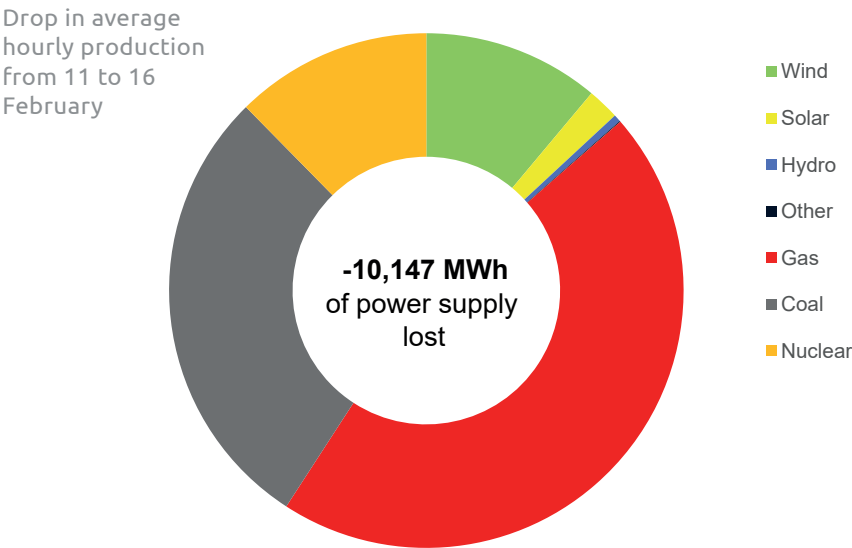
Texas deep freeze

The “Texas deep freeze” was an extreme weather event at the other end of the spectrum – when temperatures in Texas dropped to -18 °C and a polar vortex sent the state into freezing conditions that it hadn’t seen for more than 30 years. It left large parts of Texas in the dark and the cold in the middle of February 2021.

The root of the problem in Texas was a failure across the whole energy value chain: from frozen wind turbines to frozen natural gas wells and stalled nuclear units. This was a cascading blackout caused by several elements failing simultaneously, and it demonstrated the importance of comprehensive system adequacy assurances. At the same time, the spike in demand resulted in electricity prices reaching more than \$9,000/MWh, compared to a normal level of \$25-\$30/MWh for that time of year. The crisis did not spare the Texas gas market, with freezing pipelines causing supply disruptions that forced the Waha gas spot price to jump to as high as \$350/MMBtu on 12 February 2021 from \$3.20/MMBtu a week earlier. The drop in gas-fired power supply translated into nearly 812 million cubic feet per day (MMcfd) of lost gas supplies to the power sector.

Given that events with extreme weather are more likely to increase with time, grid operators will need to find solutions to ensure that they are able to provide stable electricity regardless of the circumstances. As this analysis shows, the problem during the Texas deep freeze was not caused by the intermittency of renewable energy but by all sources

Figure 35: Loss in generation in ERCOT¹ region by source



¹(ERCOT = Electric Reliability Council of Texas)

Source: EIA; Rystad Energy

of supply failing. The US power grid is fragmented and is managed regionally, leading to limited power flow between the various systems. The ERCOT system is particularly isolated from systems in the east and west of the United States. Better integration and coordination between the independent system operators could help reduce the risk of blackouts by distributing electricity generation across all states.

There are several lessons to be learned from the Texas deep freeze. First of all, it’s important to recognize the complexity of today’s energy system and the interdependency between different energy sources. The debate in the aftermath of the extreme weather event has been characterized by a lot of finger-pointing, where either natural gas or wind was accused

of being the sole reason for the incident. In reality, the event was a perfect storm where a surge in demand coincided with reduced supply due to all sources of supply failing at the same time.

The risk of similar events in the future can be mitigated by increasing interconnectors. Parts of the US power grid are still fragmented with limited power flows between the various systems. Better integration and coordination between the independent system operators could help reduce the risk of blackouts by distributing electricity generation across all states. Additionally, reliability planning standards enforced through inter-regional coordination can provide a useful insurance policy against cascading outages.

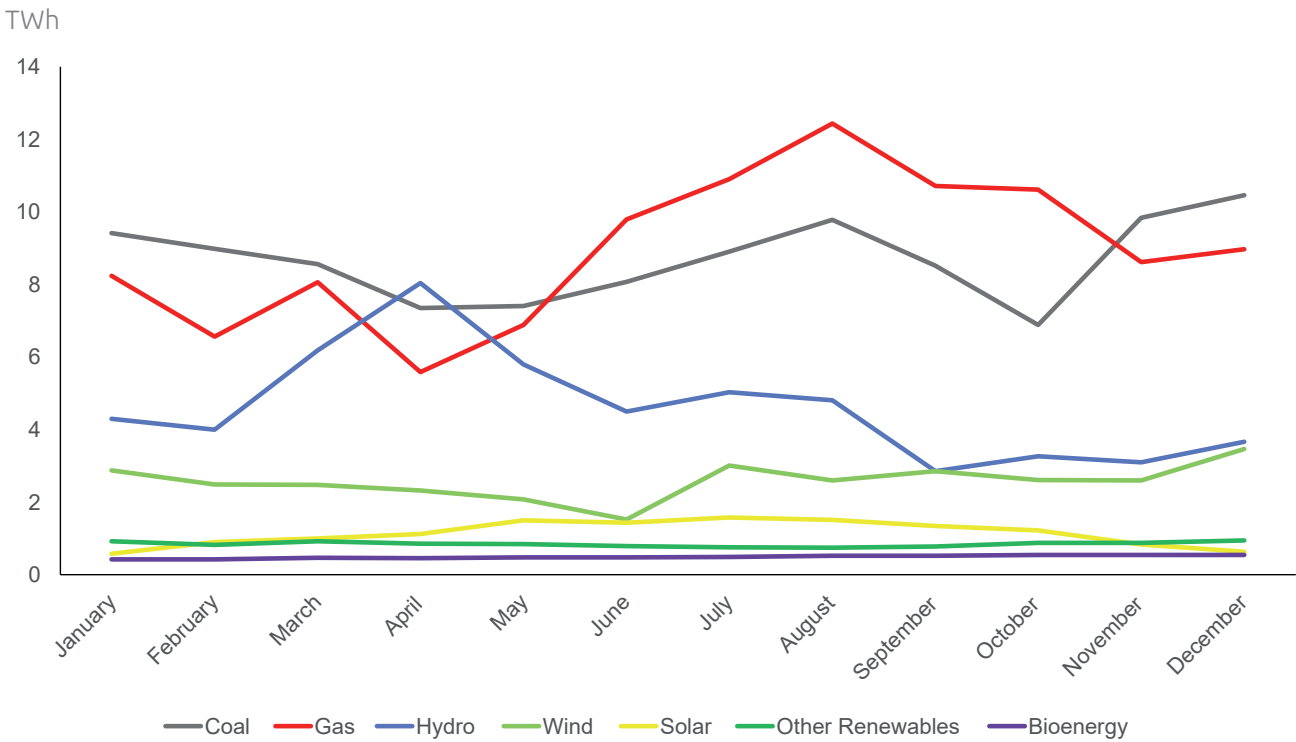
Turkish drought

A drought in Turkey that started in the fourth quarter of 2020 has impacted the electricity market in the country by changing the energy mix in the power generation sector and pushing prices higher. Due to limited rainfall, hydropower has been replaced by other energy sources in the power generation sector, most notably natural gas. A massive buildout of hydropower capacity in Turkey over the past decade has increased the capacity by over 80%, with more than 25% of the country’s power output being generated from hydropower in 2020.

During the drought, hydropower’s share in the Turkish power generation mix dropped to below 22%, with natural gas offsetting most of the lost output. This also impacted electricity prices, which were 70% higher in April and May 2021 than they were a year earlier due to the drop in hydropower supply.

Figure 36 shows how natural gas increased its market share in Turkish power generation from May 2021 onwards. This helped reduce the impact of the lower hydropower production over the same period.

Figure 36: Turkey power generation by source (2021)



Source: Rystad Energy, EPIAS (Energy Exchange Istanbul) Market Report, Eurostat

Low wind speeds in the United Kingdom

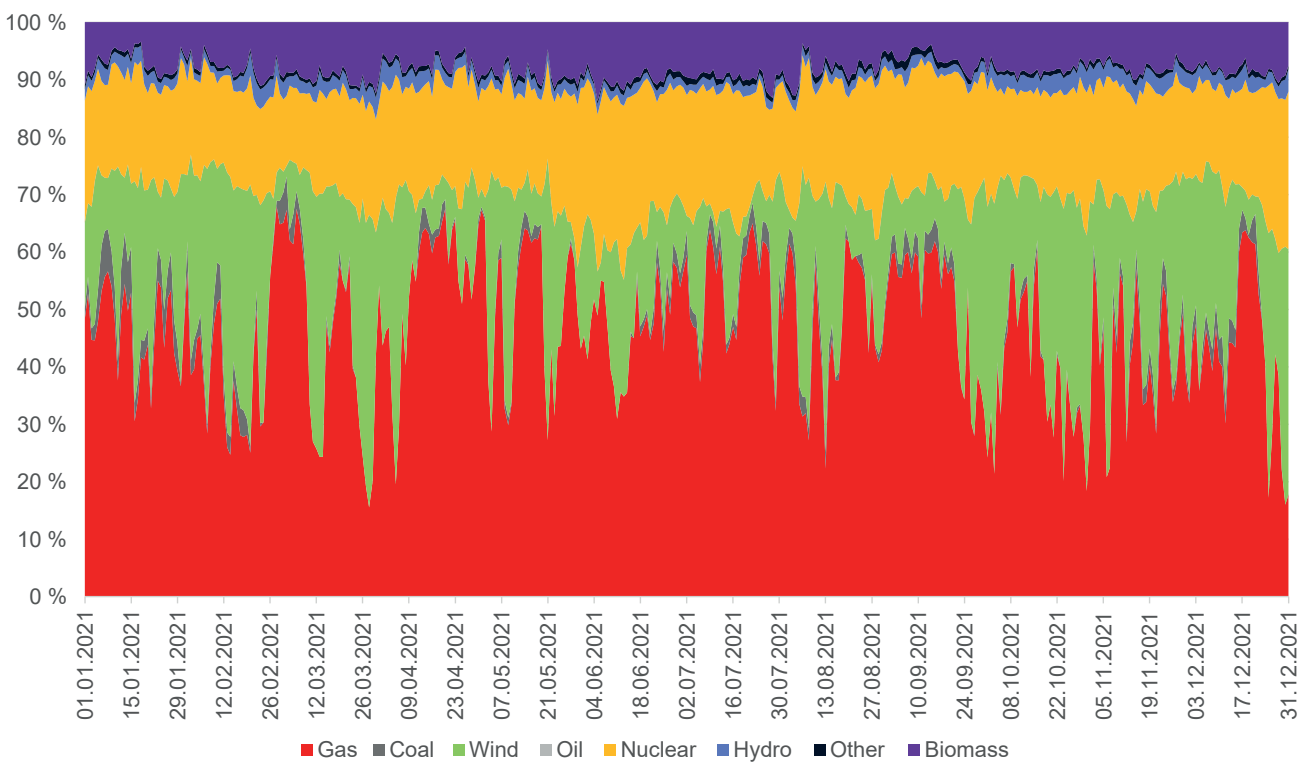
The UK’s electricity output from wind turbines and solar panels declined by 12% from 2020 to 2021, largely driven by lower average wind speeds. The average wind speed in the UK was 7.8 knots in 2021, compared to an average of 8.8 knots in 2001-2020.

Europe’s efforts to decarbonize its electricity grids have involved considerable investment in offshore wind farms in the North Sea. However, low wind speeds during certain periods of the year have left countries rushing for natural gas reserves for power generation. Figure 37 shows the daily power mix in the UK throughout 2021. In February, April and September, wind accounted for less

than 10% of the power generation in the country for extended periods of time, which is about one third of 2020 average levels. For these periods, the shortfall in power generation from wind was largely offset by increased gas-power generation, while the total for the other sources remained relatively constant.

This example demonstrates the need for a diversified power mix to ensure energy security during the transition to cleaner energy sources. The UK aims to close all coal plants in the country by 2024 – which will eliminate coal as an option for power generation in case of low wind output in the future.

Figure 37: Daily UK power generation by mix (2021)

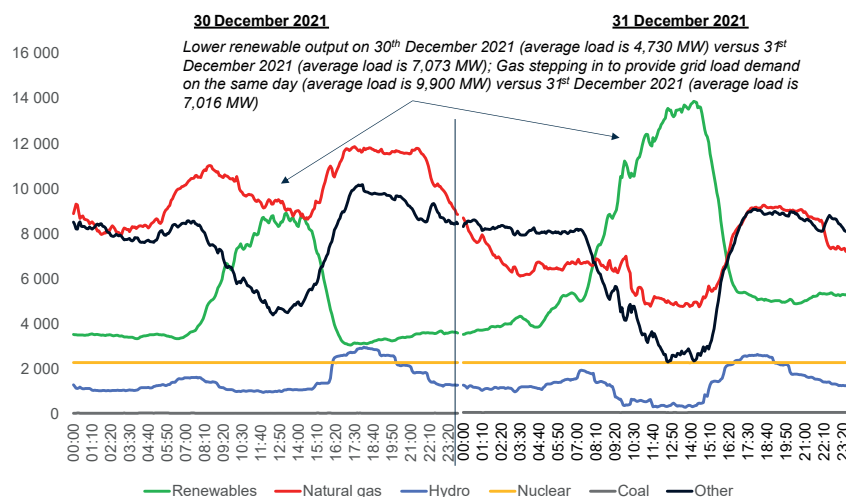


Source: National Grid

Case study: Role of natural gas in managing renewable energy intermittency

Natural gas can be a complement to renewable power generation given the intermittent nature of renewables. During periods of low renewable generation output, natural gas and gas networks can meet the shortfall in electricity supply and daily variation in demand as seen in Figure 38, where California utilities primarily rely on combined-cycle and combustion gas turbines to fill in the gaps when renewable generation was lower on 30 and 31 December 2021.

Figure 38: Two-day comparison of California power supply trend, energy in megawatts broken down by resource in 5-minute increments



Note: Renewables includes mostly solar and wind, and geothermal, biomass, biogas, small hydroelectric (< 30 MW); Other include imports, batteries, and proxy demand response

Source: Rystad Energy; California Independent System Operator

The case studies above demonstrate that with the increasing unpredictability of weather patterns and greater extreme weather events, deliberate planning of reliability measures and reserve capacity become more and more vital to ensure uninterrupted energy supply.

It is clear from the above that gas is a critical tool for assuring power system reliability. It has been able to provide vital flexibility resource to the power grids, when demand spiked and other generation sources experienced extended periods of intermittency. As the shares of intermittent renewable energy in electricity grids grows, the importance of flexible and available capacity supply increases even faster. In the Texas case, the main lesson was for policy and the great interconnection between generation sources - making it important to design comprehensive

security of supply assurances for electricity and energy systems.

Extreme weather events can have an adverse impact on the global energy system, causing disruptions to supply and demand as well as impacting energy prices. These disruptions often occur when the need for energy for heating or cooling is the greatest. It is therefore vital to make the energy system resilient to extreme weather so that it can resist the strain imposed by this kind of events. While strong policy is important for driving energy transitions, it should be backed with expert-led energy system planning to ensure that near, medium, and long term supply adequacy requirements are in place. Appropriate market design and incentives for capacity, not only energy are going to become increasingly more critical. Finally, infrastructure capacity and sufficient interlinkages are also key for flexibility.

3 / Green and Low Carbon Gases Developments

Highlights

- **The future of the gas industry will be closely linked to sustainability.** A growing coalition of countries, businesses and investors have committed to achieving climate neutrality by mid-century. With gas having a low carbon profile compared to other fossil fuels, coal-to-gas switching is an effective immediate measure to reduce emissions.
- **Zero- and low-carbon gas technologies will progressively play a critical role for the world to reach climate change mitigation ambitions,** especially in the hard-to-abate sectors. Carbon capture, utilization and storage (CCUS), hydrogen and biomethane are important examples of green and low-carbon gas technologies. In the development these three gas technologies, the natural gas industry acts as a key enabler, providing feedstock and infrastructure. This presents opportunities for the long-term growth of the gas industry.
- **Global capture capacity is projected to grow to around 550 million tonnes per annum (mtpa) over the next decade, from around 45 mtpa today.** To meet the required global capture volume of 8 gigatonnes per annum by 2050 under Rystad Energy's 1.6-degree scenario, CCUS deployment rate needs to scale up rapidly. Rising carbon prices, stronger decarbonization commitment from hard-to-abate sectors, and declining capture costs are positive forces for expanding CCUS capacity.
- **Similarly, current production of zero- and low-carbon gases is limited.** Green and blue hydrogen contributes less than 1% of pure hydrogen demand, while biomethane is less than 1% of total natural gas production today. Interest in zero- and low-carbon gases has gathered pace, with more and more countries committing to development targets and funding over the next decade. In the Asia Pacific region, Japan, South Korea and Australia have introduced roadmaps to set up their hydrogen economies. In the European Union, the European Commission recently launched "REPowerEU", which envisages 35 Bcm of biomethane and 20 million tonnes (approximately 70 Bcm equivalent) of clean hydrogen demand by 2030, together representing around 25% of the EU natural gas market today.
- **Natural gas infrastructure is a key enabler of decarbonization** as it can be repurposed and expanded to provide essential transport and storage infrastructure for green and low-carbon gases. To achieve required targets for the world's carbon neutrality in time, these technologies will have to be scaled up rapidly and substantially as many are not yet at a commercial scale. This will require strong and clear policy support and timely investments globally.

Introduction

Around 130 countries, which together account for over 88% of global CO₂ emissions, have pledged to achieve net-zero by mid-century. They are joined by thousands of companies, representing \$38 trillion in global market capitalization, that had approved emission reduction targets or commitments with Science-Based Targets initiative (SBTI). This is on the back of falling renewable energy costs, the need to maintain energy security, and growing investor scrutiny of any fossil fuel-related investments. In addition to countries introducing mandatory climate risk reporting rules, investors have also stepped up their effort to collectively push for increased climate commitment and reporting from the private sector. For example, close to \$130 trillion of private capital globally has been committed to supporting the transition to a net-zero economy under the Glasgow Financial Alliance for Net Zero. The global coalition involves more than 450 banks, insurers, and asset managers across 45 countries, leading to more vigorous scrutiny of fossil-fuel-related investments.

There are two key pathways to reach the Paris Agreement's emissions targets; decarbonizing the global electricity supply, and decarbonizing carbon-intensive activities that are prohibitively expensive or technically impossible to electrify. Regardless of overall ambitions and spending commitments, electrification may not be a feasible option in some parts of the economy due to inherent structural requirements or technological limitations. This is currently the case in aviation, shipping and heavy-duty road transportation, which require energy-dense and lightweight fuels. In many heavy-industry sectors such as steel, cement, and chemicals, industrial production processes cannot be fully decarbonized via electrification due to high heat and molecule feedstock requirements.

This presents an opportunity for alternative decarbonization technologies – more specifically, zero- and low-carbon gas technologies. They will play a critical role in achieving deep decarbonization, particularly in hard-to-abate sectors with limited potential for renewables and electrification. Deployment of zero- and low-carbon technologies will drive development of the natural gas industry in a climate-neutral future, where the gas industry is both feedstock and infrastructure provider. Despite being a fossil fuel, natural gas can

be developed into a zero- and low-carbon energy option by applying CCUS or converting to blue hydrogen, effectively decarbonizing the gas supply. In terms of infrastructure, green gases and captured carbon dioxide can make use of existing natural gas infrastructure for transportation and storage, reinforcing the role of gas infrastructure in a deep-decarbonization future. In Italy, Snam has conducted a trial where it blended 10% hydrogen by volume into its transmission network and is working to ensure its infrastructure is fully compatible with increasing quantities of hydrogen mixed with natural gas. Current assessment has demonstrated the potential for Snam's pipeline system to transport up to 100% hydrogen, of which 70% will require no or limited reduction on the maximum operating pressure. Repurposing existing gas pipeline to carry hydrogen or carbon dioxide can bring substantial cost savings.

Zero- and low-carbon gas technologies are poised to grow rapidly as they emerge as key complements to renewables in a decarbonized energy system providing grid balancing in longer periods of intermittency, as well as other vital flexibility and capacity services. As future energy systems will see increased seasonality due to higher renewables penetration and electrification, this translates to a need to store larger volumes of energy over longer periods. Both green and blue hydrogen are promising solutions and provides long-term flexibility. New studies have shown that hydrogen can be stored in underground storage sites. This unlocks substantial net-zero flexibility at a fraction of the costs of equivalent electrochemical storage capacity. There is a need to pursue a full spectrum of zero- and low-carbon gas technologies as quickly as possible in order to achieve deep decarbonization targets.

Decarbonization developments will largely depend on the interplay between energy security, competitiveness, and sustainability. There is already momentum for low-carbon gases, but more needs to be done. In this section, all three technologies are discussed as critical technologies in a climate-neutral world. This report delves into carbon capture, utilization and storage (CCUS), with greater coverage of its application, value chain development, market outlook and economics. The report also looks at development status, outlook, and regulatory trends for hydrogen and biomethane markets.

Carbon capture, utilization and storage

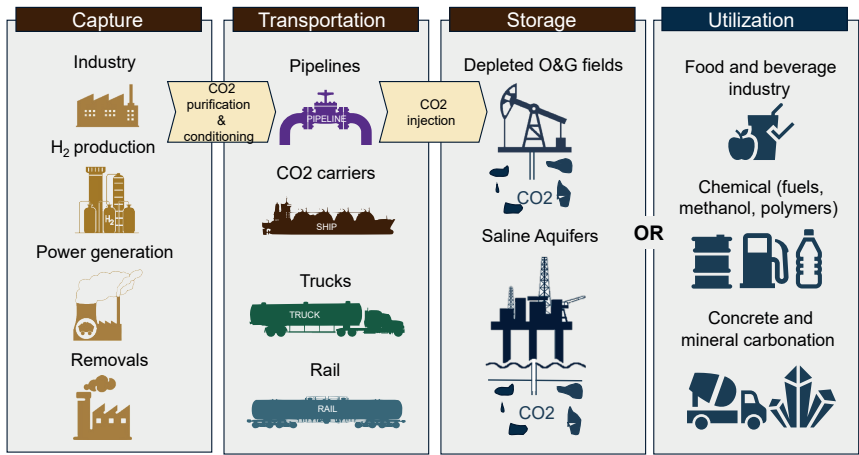
Introduction

Carbon capture, utilization and storage (CCUS) technology is projected to take on an increasingly vital role in the fight against climate change. To achieve a carbon-neutral world by mid-century, the relevance of CCUS will intensify as more and more industrial sectors commit to generating zero or negative emissions. In recent years, the cost of emissions has also climbed through rising carbon taxes in certain regions. At the same time, the cost of CCUS is expected to decline as the technology continues to advance, potentially achieving a cost reduction between 18% to 30% from today’s leveled cost of capture. When the cost of emitting becomes greater than the cost of CCUS, companies will be inclined to move forward with CCUS developments. While CCUS can be used across many industries, it is still the most cost-effective at gas processing plants. It can be used to efficiently reduce emissions from the gas sector, with potential applications at natural-gas-fired power plants. The need for CCUS is also driven by blue hydrogen, which is a likely zero- and low-carbon energy source for the future.

Capture

The CCUS value chain starts at the CO2 capturing location. This is traditionally a large point source of CO2, such as a power plant or industrial facility. Various Direct Air Capture (DAC)

Figure 39: CCUS value chain



Source: Rystad Energy

technologies – which draw CO₂ out of the ambient air – are also beginning to emerge. The latter is still a developing technology, but it has huge potential if costs can be brought down to competitive levels. For traditional CCUS at a large point source, different methods and technologies may be applied depending on the specific emission source. For example, in any natural gas processing facility today, CO₂ in the gas stream must be separated out before the methane can be exported to consumers – this is a much simpler process, which involves merely collecting the processed CO₂ for further handling. These varying factors impact the energy consumption required of the process itself, as well as the overall cost of the capturing equipment.

Transportation

Once the CO₂ has been captured, the remaining value chain is essentially the same regardless of the original capturing facility. CO₂ is normally transported either as compressed gas in pipelines, or in liquefied form on ships. The preferred mode of transportation is determined by the distance between the capture and storage locations, and the optimal route between the two. It might also be affected by CO₂ purity requirements, as liquefaction will require less impurities in the CO₂ stream than a pipeline.

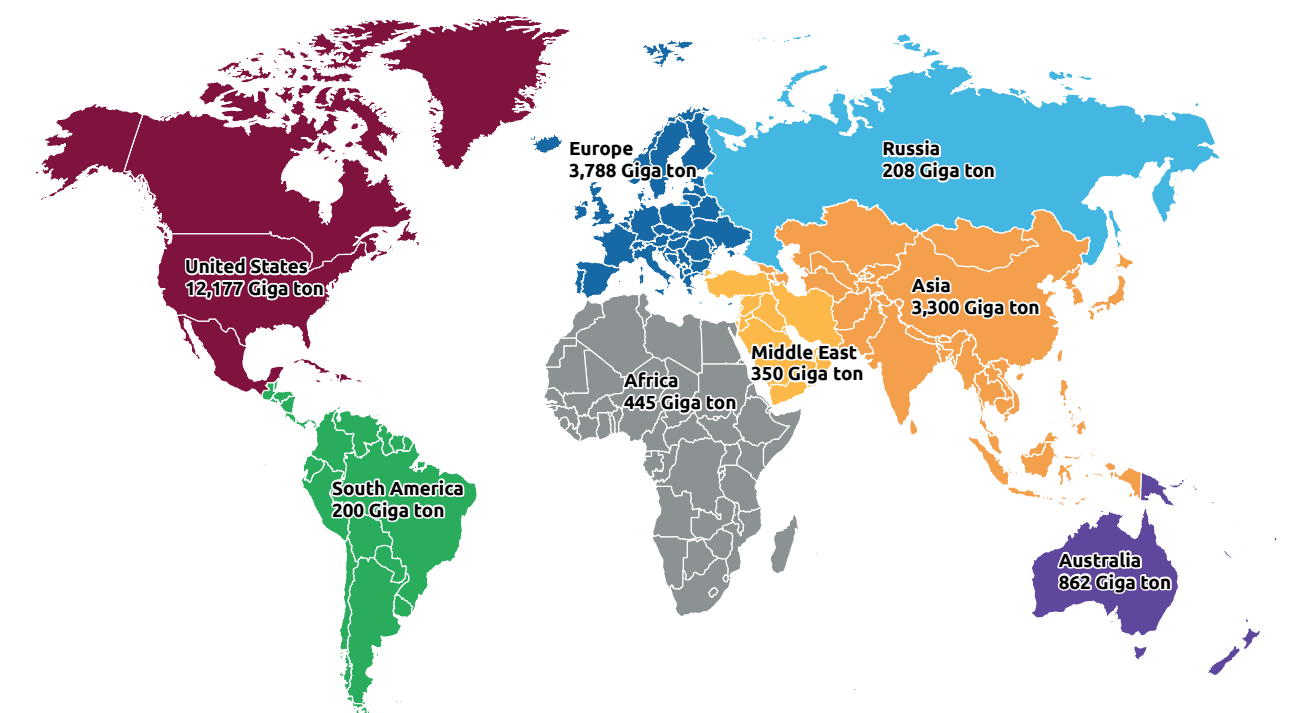
In general, pipes are the most efficient method to transport CO₂ over long distances and in large volumes, where feasible. Several of the larger projects seen to date, especially in

the United States, have partly utilized existing repurposed onshore pipeline infrastructure, which has had very positive impacts on overall project economics. New onshore CO2 pipelines are the second cheapest transportation option;

indeed, newer CCUS projects are being developed further away from existing oil and gas infrastructure. The mechanics of offshore CO2 transportation are rather nuanced – a combination of distance, project lifetime, transported volume and other

factors. Several new projects in Europe are being developed using liquefied CO2 on ships as the planned transportation solution. The technology is similar to transportation of LNG and LPG, and as such, is quite mature.

Figure 40: Potential global CO2 storage capacity by region



• Storage in depleted oil and gas field (including EOR) and saline aquifers based on available research

Source: Rystad Energy

Storage or utilization

The majority of CO2 sinks today are either permanent storage – in saline aquifers or depleted oil and gas fields – or as CO2 injection in enhanced oil recovery (EOR) in mature oil fields. Using CO2 for EOR is a key force behind the US dominance in the global CCUS market, and the nation currently boasts around 50% of global CO2 capturing capacity. Australia, Canada, and China each account for around 10% of the remaining operational capture capacity, while other countries such as Qatar, Norway and Brazil make up the remaining 20%. Storage in saline aquifers and depleted hydrocarbon fields is becoming increasingly attractive as carbon pricing and CCUS subsidies rise.

According to Rystad Energy’s analysis, the global potential storage capacity in miscible depleted oil

gas fields is approximately 2,900 gigatonnes, while for saline aquifers the estimated storage capacity is close to 20,000 gigatonnes, about 10 times more than in depleted reservoirs. North America dominates the potential CO2 storage capacity, with the US and Canada offering 54% of total assessed global storage capacity. Europe follows with 22%, mainly in basins offshore Norway, the United Kingdom, the Netherlands, and Denmark. CO2 storage hubs may emerge in certain areas (e.g., North Sea) where CO2 from neighboring countries may be gathered. The third-best region is Asia, where potential onshore storage capacity is available in China and in several countries in Southeast Asia. Beyond the traditional alternatives, there are also new applications of CO2 utilization including production of synthetic fuels and building materials.























Key CCUS applications

There are many potential applications for CCUS. The selection of key applications is partly based on observed projects today and where we see the largest potential for future decarbonization through CCUS. The common factor across all CCUS applications is a large stationary source of CO2 emissions. Primary sources of CO2 are either from the combustion of fossil fuels or from chemical reactions in various industrial

processes. While combustion emissions can be also addressed via fuel-switching from fossil fuel to hydrogen or biomethane, process emissions can only be abated by CCUS or direct air capture, unless changes are made to the process or feedstock. Capturing emissions from fossil fuel combustion (post-combustion CCUS) uses quite standardized technology, which can be incorporated into various applications in a similar fashion – although

scale matters. For example, CCUS on small industrial boilers is generally harder to justify from an economic perspective. This is due to the high cost of the transportation and storage parts of the value chain, which become a bigger share of the investment for smaller volumes. However, this is about to change with the trend towards industrial clusters and co-investments in CCUS networks.

Table 2: Key CCUS applications

Sector	Key CCS applications	Combustion emissions	Process emissions	Alternative decarbonization pathways
Industry	Chemicals Primarily production of ethanol and methanol, but with various other applications in the future			Green hydrogen and CO2 utilization technologies
	Hydrogen production Production of blue hydrogen from natural gas or coal			Green hydrogen
	Cement Process emissions account for 70% of emissions from cement production, the remaining from combustion			Carbon-free concrete and low carbon fuels
	Iron and Steel Both a high degree of process emissions from iron ore reduction and combustion emissions			Iron electrolysis or direct iron ore reduction with hydrogen
Power generation	Gas Flue gas CO2 separation			Renewables and nuclear Green hydrogen
	Coal Flue gas CO2 separation			Renewables and nuclear Green hydrogen
	Bio energy Bio energy with CCS (BECCS) with potential of being net negative			Carbon free
Energy	Natural gas processing High concentration CO2 from natural gas processing is currently the easiest to abate with CCS			Substitution of end -use consumption
	Oil refining Majority from process emissions, but dependent on refinery setup, feedstock and product composition			Substitution of end -use consumption
Other	Waste incineration Flue gas CO2 separation			
	Direct air capture CO2 extracted from the ambient air. Ideally located close to storage site and with access to cheap, clean electricity			Carbon free

Source: Rystad Energy

CCUS applications in gas decarbonization

Among the many potential applications for CCUS, the technology is critical for decarbonizing gas supply. Within power generation, there is a large emission reduc-

tion potential for CCUS within gas-fired generation – which contributes to 5% of global CO2 emissions. At present, CCUS can remove around 90% of CO2

from the combustion flue gases. Full decarbonization at gas-fired power plants may be achieved by complementing traditional point-source CCUS technology

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with emerging technologies such as Direct Air Capture (DAC), which removes emissions directly from ambient air. Cost of power generation from gas-fired power with CCUS could potentially be more economical than coal-fired power with CCUS on a per-MWh cost basis. With natural gas emitting around 50% less CO₂ than coal, there is less CO₂ to transport and store for every unit of power generated, contributing to reduced cost.

CCUS may also be applied in the energy sector to effectively reduce carbon footprint at gas-related upstream production and processing activities. A large share of CCUS projects today is installed at natural gas processing and reforming facilities, where CO₂ is removed from CO₂-rich natural gas fields to meet the quality required for sales gas. Generally, process gas stream at gas processing plants has higher CO₂ concentration and pressure than flue gases in power sector and other industries (low-concentration dilute gas stream). Higher CO₂ concentration and pressure lowers the CO₂ capture cost as less energy consumption is re-

quired per unit of CO₂ captured. Emission-abated gas production is expected to grow in demand. LNG importers have shown high interest in and willingness to pay for carbon-offset LNG, which is reflected in higher trading volumes in 2021. Rising demand and more stringent national targets for reducing greenhouse-gas emissions have prompted LNG exporting nations to include more zero- and low-carbon options in their hydrocarbon production. This has become a main driver for new CCUS projects in regions where the carbon pricing is currently lower than in Europe and the US. Carbon-offset LNG, which involves the purchase of carbon credits from the voluntary carbon market to offset all or partial LNG-associated emissions, have also gain popularity in recent years.

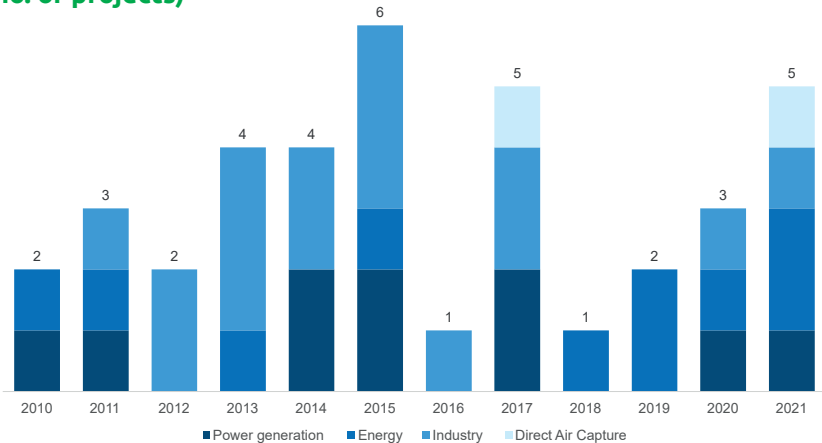
Within the industrial sector, CCUS may be applied to decarbonize gas-fired industrial combustion and natural-gas-based hydrogen production. Industrial combustion emissions may be captured by a similar technique as flue gas in power generation. Unlike most large power plants, though, the sector is made up of

smaller, more varied, and more widely distributed facilities and therefore does not benefit from the same economies of scale. Greater standardization of CCUS mechanisms across industries will be needed improve project economics and develop the CCUS value chain. Natural-gas-based hydrogen production, typically via steam methane reforming, could be coupled with CCUS to enable production of low-emission hydrogen or ammonia (blue hydrogen or ammonia). New project announcements are spiking for hydrogen and ammonia, which play an important role in decarbonizing hard-to-abate sectors. Before green hydrogen (hydrogen production through electrolysis from renewable power sources) and associated electrolyzer manufacturing capacity are ready to scale up, blue hydrogen will likely remain the interim solution due to lower production costs. In the near term, blue hydrogen's cost competitiveness may be eroded due to high prices of natural gas, which is a key cost driver of blue hydrogen production. The role of blue hydrogen will be highly dependent on developments in the natural gas market.

Market development and outlook

Historically, CCUS developed within the energy sector and has predominately been applied to natural gas processing. Additionally, CCUS has been used for industrial applications, mainly in the chemical sector and very much linked to energy players. Today, there is very limited CCUS applications in the heavy industries. Over 80% of CO₂ capture today comes from gas processing, hydrogen and ammonia production facilities. There have also been some applications in power generation, and in other parts of the industrial sector including cement. The new project pipeline is heavily centred

Figure 41: CCUS development by application type and start-up year (no. of projects)

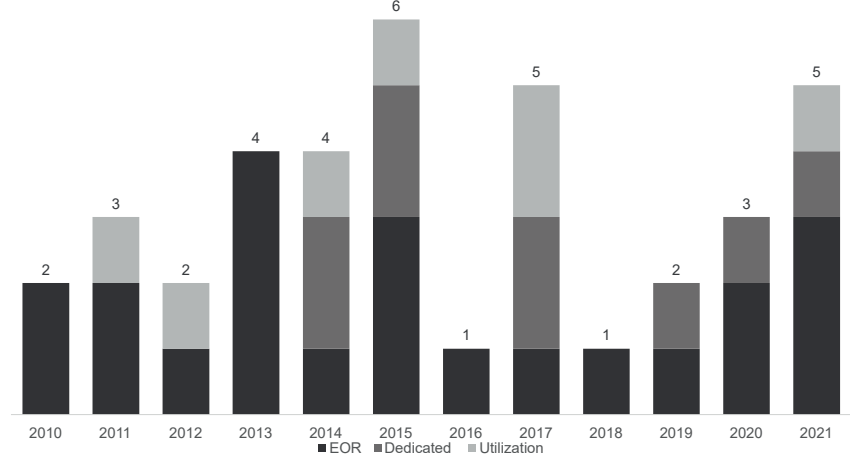


Source: Rystad Energy

around new applications, however. In terms of storage, enhanced oil recovery (EOR) has been a key enabler for CCUS projects historically. With increasing carbon pricing and incentives, there is growing momentum for projects targeting dedicated storage, including several offshore projects in Europe. Regionally, North America has dominated the CCUS market, a trend that is expected to continue based on the project pipeline. This dominance has been driven by EOR in maturing oil fields, and most recently from the effect of the rising 45Q tax credit scheme and the low-carbon fuel standard (LCFS) in California.

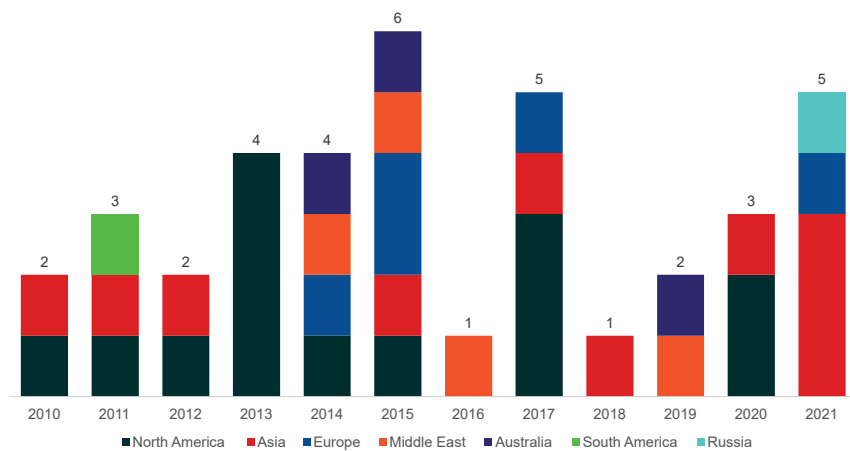
By the end of 2021, there were 44 CCUS projects in operation with a capacity to capture around 40 million tonnes of CO₂ per year. Some of the largest projects were developed by ExxonMobil (Shute Creek Gas Processing Plant), Occidental Petroleum (Century Plant) and Chevron (Gorgon Plant). The world is currently capturing around 45 million tonnes per annum (tpa) of CO₂ and has a project pipeline of more than 380 million tpa. The number of CCUS project announcements spiked in 2021 (around 120), propelled by a growing number of countries and companies ramping up efforts to meet 2030 net zero targets. Global CO₂ capture capacity is expected to reach around 550 million tpa by 2030 (modeled based on currently announced projects), which is an average 25% annual growth between 2021 and the end of the decade. North America and Europe are expected to contribute up to 80% of the market, driven by encouraging policies and support. Other regions, especially developing countries, could slowly pick up pace amid anticipated cost cuts as well as the support of and learnings shared by developed

Figure 42: CCUS development by storage type and start-up year (no. of projects)



Source: Rystad Energy

Figure 43: CCUS development by geography and start-up year (no. of projects)



Source: Rystad Energy

countries. While encouraging, expected global capture volume in 2030 falls short of the level required to achieve Rystad Energy's 1.6-degree scenario, which calls for global CO₂ capture volumes of around 870 million tpa by 2030. Towards 2050, the required global CO₂ capture volume grows to 8 gigatonnes (Gt) to achieve Rystad Energy's 1.6-degree scenario – highlighting the need for rapid deployment over the next two decades if decar-

bonization targets are to be met. Today, the addressable market for CCUS is largely constrained by attractive pricing, as most of the capital expenditure required must be spent on the capture plant itself, while the rest is earmarked for CO₂ transportation and storage infrastructure. Most of the CO₂ capture projects in North America and Europe are expected to come from cluster projects, which heavily rely on the availability of new-built

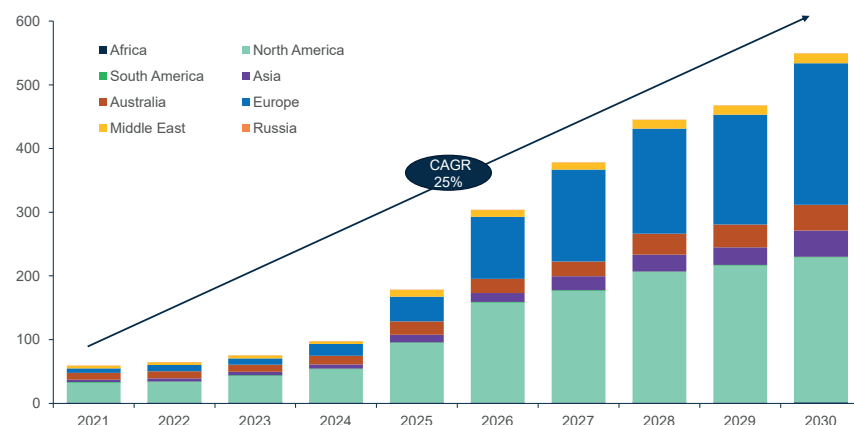
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infrastructure. Up to 25% of the capacity in cluster projects is currently still in the process of evaluating the source of emissions, which may or may not be filled as planned. Economic and financial constraints are among the key reasons for projects not moving ahead, but more countries are starting to see the importance of providing support to CCUS projects. CCUS demand towards 2030 will likely be highly driven by policies and support, especially for hard-to-decarbonize sectors such as cement, steel, aviation, and chemicals.

Towards 2030, rising carbon prices in Europe are set to be a catalyst for CCUS project uptake. One-third of the anticipated announcements are likely to come from the UK, Netherlands, and Norway. Across the Atlantic, Canada announced a tax credit scheme in this year's budget, including a 60% tax rebate for direct air capture (DAC), 50% for traditional capture technology, and 37.5% credit for transportation and storage equipment. This will significantly improve CCUS economics for projects in Canada, coming closer to the current average cost of emitting CO₂ in the country (\$30 per tonne). For the US, the tax credit provided under 45Q is set to increase from \$50 to \$85 per tonne of CO₂ under the Build Back Better bill once it is passed by the Senate. Also, the infrastructure bill that was passed at the end of last year is going to give the market an additional boost.

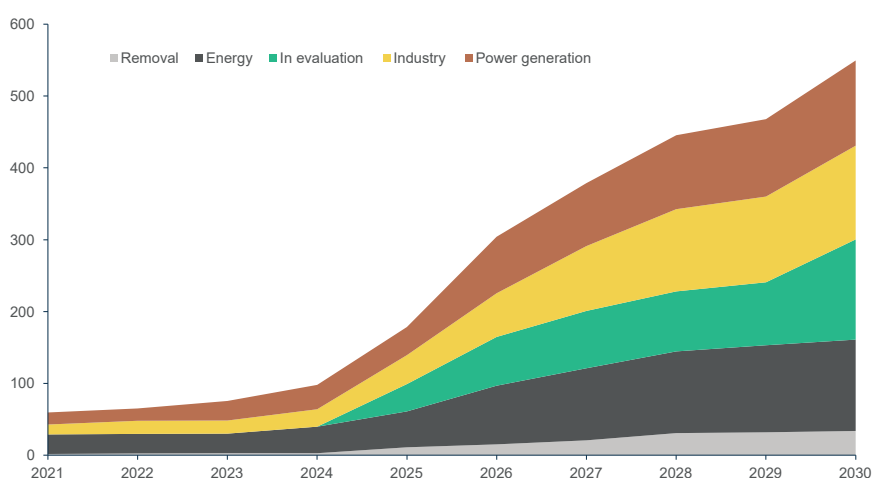
Regions outside of Europe and North America are lagging on both technical knowledge and carbon policies. Nonetheless, project announcements surged in 2021 and the first quarter of this year. Australia is set to lead the

Figure 44: CO₂ capture demand outlook by region (million tpa of CO₂ capture)



Source: Rystad Energy

Figure 45: CO₂ capture demand outlook by sector (million tpa of CO₂ capture)



Source: Rystad Energy

CCUS market in Asia-Pacific, followed by China, which relies heavily on coal as an energy source but has been taking necessary steps to decarbonize, including significant update of gas to substitute coal, while growing its economy. Over this decade, China is likely to focus on transforming its successful pilot projects into commercial-scale assets. Oil and gas producing countries in the Middle East and Southeast Asia are enjoying improved

margins from oil and gas production. This, coupled with national targets for CO₂ reduction, will drive project uptake in these regions. CO₂ from gas processing, oil refining and hydrogen production is expected to be the main carbon source for capture demand towards 2030. Besides the relatively low abatement cost (\$25-75 per tonne), the increase in demand for clean fuels will be driving the use of CCUS in fossil fuel production plants. Initiatives to

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decarbonize power plants, the iron and steel industries, as well as the chemicals sector are more prominent in young assets (built after 2010) to prolong their lifespans. In older assets, CCS technology economics would need to compete

with other options, including renewable gas. It is expected that, carbon source from young assets, especially those located in developing countries, will become the largest market for CCUS beyond 2030.

Cost and carbon pricing

Capture cost is the largest cost component across the entire CCUS value chain. The majority (60% to 90%) of total capex is usually spent on the capture plant itself, while the rest is earmarked for CO₂ transportation and storage infrastructure. Given the abundance of capturing sites and storage potential worldwide – which is likely to be tens of thousands of Gt – the key constraint to growing the addressable market for CCUS is attractive pricing.

Capture

Carbon capture costs are heavily influenced by the concentration of CO₂ in the gas stream, which determines the energy required to capture CO₂. For example, gas processing has very high CO₂ concentrations (more than 50%), while DAC has the lowest (0.00004%), which means DAC

is the most expensive in energy terms. The levelized cost of capture (LCOC) for gas processing is around \$40 per tonne of CO₂ captured, while direct DAC could be almost seven to 26 times its cost, ranging from \$260 to \$1050 per tonne of captured CO₂. Gas processing is a relatively mature

technology with less potential for further reduction, while DAC and other applications of CCUS - including hydrogen production, power generation and waste incineration - may see higher learning rates and achieve cost reductions in the range of 18% to 30% over the next decade.

Transportation and storage

CO₂ can be commercially transported in both gas and liquid form using pipelines, trucks and ships. The transport of CO₂ accounts for around half of the transport and storage costs in a typical CCUS project. Prices vary depending on distances and CO₂ end use, ranging from less than \$5 per tonne (for short distances and onshore pipelines) to more than \$25 per tonne (for long distances and offshore transport). Volume of CO₂ transported is another key price determinant. Pipelines gathering large volumes of CO₂ from large-scale capture facilities (or cluster of emitters) could achieve significant cost savings. The capital cost of steel in new pipelines significantly increases transportation costs as distances increase, and the planning-to-operation phase can take several years. These costs can be avoided by

re-using oil and gas pipelines, but these will have a shorter service life. The Acorn CCUS project in the UK found that pipeline costs could be cut by up to 90% by repurposing offshore pipelines. Re-using pipelines should, however, be assessed on a case-by-case basis. Pipelines not designed to carry CO₂ can only transport it in gas form, significantly reducing capacity compared to new CO₂ pipelines. This increases the operating cost per tonne of CO₂ and, combined with a shorter service life, could push lifetime costs above those of a new pipeline. Transport technology is very mature and technological advancement is not expected. Cost cuts are likely to be from economies of scale and cheaper energy to power compressors.

Ship transport is less sensitive to

capital costs than pipeline transport. Most costs are related to the operation of the ship, with the liquefaction of CO₂ accounting for almost half of the total costs. However, ship transport also requires additional infrastructure at the port for loading/unloading as well as temporary storage, generating additional costs. As a result, the difference between refurbishing an old vessel and building a new one is minimal. Ships have more flexibility than pipelines as they can collect and deliver to several different places – the Northern Lights and Acorn projects are good examples of this. Not all emitters are close to the coast and not all ports can handle CO₂ shipping, which limit the geographic reach of ship-based CO₂ transportation. Shipping costs are relatively stable with distance and are likely to be

Table 3: Key CCS transportation methods

Transport method	Costs (USD/t)	Capacity (Mtpa)	Advantages	Disadvantages	Ideal application
Offshore pipeline (new)	3-25	1 - 20	Long lifetime, high capacity	High capex, long permitting times	Large-scale offshore storage projects
Offshore pipeline (refurbished)	3-25	1 - 10	Reduced permitting time and environmental impact	High opex, shorter lifetime, reduced capacity	Large-scale offshore storage projects
Onshore pipeline (new)	5-20	0.5 - 20	Long lifetime, high capacity	Long permitting times, potential planning issues	Connecting clusters to onshore storage projects and coastal terminals
Onshore pipeline (refurbished)	5-20	0.5 – 10	Reduced permitting time, environmental impact and planning issues	Shorter lifetime, reduced capacity	Connecting clusters to onshore storage projects and coastal terminals
New build ship	10-20	0.1 - 1	Flexible source and storage locations, cheap over long distances	Lack of experience, not all ports can accommodate CO2 vessels	Connecting coastal point sources to terminals and offshore storage/EOR projects
Truck	15-20	0.01-0.1	Established technology from food and drink industry	Expensive for high capacity	Connecting small emitters outside of clusters to onshore storage projects and coastal terminals
Rail	~10	0.1-1	Existing infrastructure reduces capex	Limited routes	Connecting small-to –medium-size emitters to storage sites and coastal terminals

Source: Rystad Energy

between \$10 and \$20 per tonne of CO₂.

Cost of storage is generally less variable than the cost of transport, as the variables involved in storage are fewer than in transportation. The bulk of the storage cost comes from the initial investment in exploration. Once a well has been drilled, the marginal costs of injecting CO₂ are low. As such, one of the biggest cost determinants is the location of the

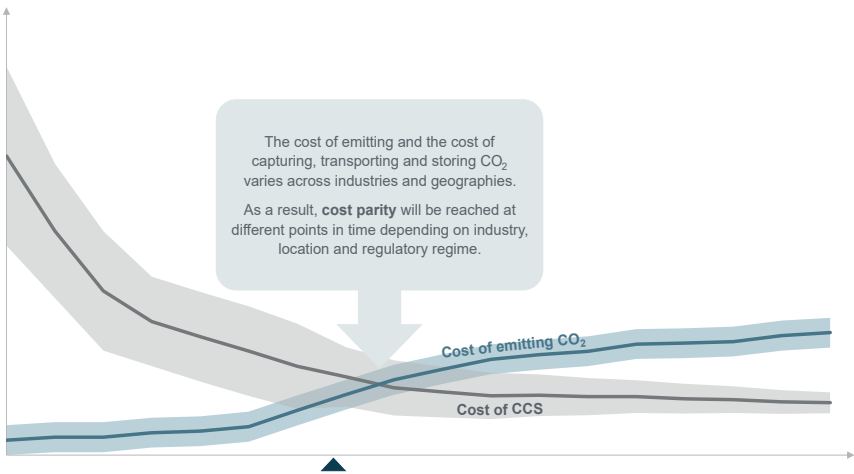
storage site (onshore or offshore), which varies on a regional basis. Current estimates point to around \$20 per tonne in storage cost, with offshore storage being more expensive than onshore. Offshore storage sites require larger, more expensive drilling rigs than onshore sites, as well as platforms or subsea structures. Engineering and rig rates differ across regions and have a significant effect on the cost, with Southeast Asia being among

the cheapest. Most of the CO₂ captured to date has been stored in depleted oil and gas fields or used for EOR. The availability of onshore saline aquifers will be a very important factor to help onshore emitters adopt CCUS into their plants. Beyond storage, there are new applications of CO₂ utilization including production of synthetic fuels or building materials, where CO₂ is mineralized into a solid product.

Carbon prices

To make the capture and storage of carbon economically viable, it must become more costly to emit CO₂ than to capture it. This is often not the case, as CCUS remains costly when applied to most applications compared to local carbon pricing, but as technology improves and carbon prices increase, CCUS will make economic sense for an increasing number of projects. Carbon pricing is not the only mechanism pushing companies towards carbon capture solutions - their social license to operate is also being challenged to a much greater degree. Customers are focusing more on sustainability, and investors are increasingly shying away from emission-heavy projects, putting pressure on both fossil fuel producers and industrial emitters. Carbon capture is just one solution, but for many applications there are alternatives,

Figure 46: Cost of emitting CO₂ versus cost of capture (relative cost)



Source: Rystad Energy

such as electrification or altering parts of industrial processes. Along with an increased cost of emitting, the cost of capturing carbon is decreasing through learning curves and technology development.

Factors driving cost of emitting

An increasing share of global emissions is covered by CO₂ taxes or quotas, or both. In 2020, 11% of global emissions were covered by an emission-trading scheme. If emissions covered by carbon taxes are included, about 23% of global emissions are covered. The prices of these quotas and taxes are increasing and are expected to continue to increase going forward. The EU emission trading system (ETS) price has surged in recent years and rose sharply during 2021 to reach new all-time highs nearing €100. As of April 2022, ETS prices are trading at around €80 to €90, compared to an average of €25 in the period 2019-2020 and €53 in 2021. Similarly, the Norwegian government has proposed plans

to gradually raise carbon taxes to about NOK 2,000 (equivalent to about €195) per tonne of CO₂-equivalent by 2030. An increasing number of countries are incorporating strict carbon targets – as of April 2022, at least 19 countries have net-zero commitments legislated in a law or policy document. Most have pledged full decarbonization by 2050, except a small number of countries that have set out a longer time horizon to reach net zero (for example, China by 2060 and India by 2070). To reach these targets, governments are incorporating regulations in addition to other measures, such as CO₂ taxes and quotas. Such regulations could, for example, include the forced reduction of emissions and

targets. Companies are also faced with indirect costs. Product demand is affected as consumers begin to incorporate environment, social, and governance (ESG) criteria into purchasing decisions. ESG criteria are a set of standards that identify companies with positive environmental, social and governance practices, with the goal to bring about sustainable development outcomes. The quality and quantity of new recruitments could be affected as employees incorporate ESG criteria into decisions. These indirect costs are increasing, while there is also a general uncertainty and an emerging view that strong ESG performance is important for companies to have a “license to operate” in the future.

Factors driving down cost of CCUS

There is large cost reduction potential at the capture stage. Over the next decade, emerging technology applications of CCUS – such as hydrogen production and power generation - could achieve a substantial cost reduction of between 18% and 30% from today's levelized cost of capture. Several factors are driving down costs. There has been rapid technology development in the CCUS industry in recent years, where technology providers prioritized process improvements through the development of modular designs. Plug-and-play technologies are starting to emerge, such as Aker Carbon Capture's Just Catch modular capture plant and smaller modular units such as CycloneCC from Carbon Clean, which can handle as little as 4,000 tpa of emissions. Modular systems will allow

emitters of all sizes to scale up their capture capacity in line with carbon prices, rather than investing in one large capture unit that may not be viable in the short term. The high capex associated with capture units has been a major obstacle for smaller emitters as they struggle to finance their CCUS plants. The modular systems, coupled with new integrated business models, should open the market to even very small emitters – an important market segment that makes up 78% of emitters and accounts for one-quarter of emissions in Europe and North America combined.

Increased volumes and resulting economies of scale will be the main contributors in driving down costs of storage, but contrary to capture and transport,

much of the technology needed for storage is quite mature and has less cost-reduction potential. There is room – albeit limited - for cost reductions by utilizing existing infrastructure and optimizing well construction. The provider of CO₂ storage often also provides transportation services through operated or leased infrastructure. Customers normally provide initial transportation to the main grid, while a transportation and storage fee covers the remaining transportation as well as the storage. There are two key drivers for reduced transportation cost: formation of CCUS hubs; and liquid CO₂ transportation. Both will likely lead to significant economies of scale as more customers - particularly cross-border end users - share a common infrastructure.

Hydrogen

Introduction

Hydrogen will be an essential energy carrier in a net-zero energy system and is already being rapidly implemented in a variety of sectors and innovative applications. Hydrogen production and supply can take many routes within the energy system. In this report, grey hydrogen refers to fossil fuel-derived hydrogen, while blue hydrogen refers to hydrogen produced from natural gas with the addition of CCUS to remove emissions from the production process. Green hydrogen is used to describe hydrogen produced

via electrolysis (splitting water into hydrogen and oxygen) using renewable electricity. Green and blue hydrogen are collectively referred to as zero- and low-carbon hydrogen. Blue hydrogen has been the more economical form of environmentally friendly zero- and low-carbon hydrogen. However, in the near term, blue hydrogen's cost competitiveness may be eroded due to high prices of natural gas, which is a key cost driver of blue hydrogen production. The role of blue hydrogen will be highly dependent on

developments in the natural gas market. As the feedstock for blue hydrogen, natural gas supply will be an important ingredient in the hydrogen economy. The rate of penetration of zero- and low-carbon hydrogen will vary across different sectors depending on its competitiveness against alternatives. Fossil fuels would likely be displaced first in road freight transport and large industrial applications, followed by industrial heating and hard-to-abate sectors e.g., aviation and maritime.

Table 4: Key end-use applications for hydrogen

Sector	Sub-sector	Application	Main competition
Transport	Passenger vehicles & Road freight	Hydrogen can be used as transportation fuel through fuel cell electric vehicle (FCEV). Though battery electric vehicles (BEVs) are likely to emerge as dominant technology within passenger vehicle market, regional applications of FCEV could still create significant demand, such as in Japan, South Korea, and China, driven by strong regulatory push. Additionally, hydrogen-derived synthetic fuels may have a role in heavy transport as fuel cells are generally lighter than batteries, offering higher capacity for the same payload.	<ul style="list-style-type: none">Battery
	Aviation	Decarbonization pathways for aviation are still immature and unproven. Hydrogen-based synthetic jet fuel shows promise, along with biojet.	<ul style="list-style-type: none">SynfuelsBiojet
	Shipping	Zero-carbon fuels, such as ammonia and biofuel, seem the likely pathway for most shipping applications. Batteries show potential in short-sea voyages.	<ul style="list-style-type: none">SynfuelsBiofuelBattery
Industry	Steel production	Within steel sector, hydrogen can be used in electric arc furnace steelmaking by using H2 in a direct reduction process. Electric arc furnaces are well tested at industrial scale, producing around 30% of global steel. However, hydrogen direct reduction (H-DRI) has only recently been technologically proven. Low carbon hydrogen coupled with electric solutions will likely play a pivotal role in decarbonizing steel production.	<ul style="list-style-type: none">Iron ore electrolysisCCUS
	Chemical industry	Within the chemical industry, fertilizer industries could decarbonize by utilising low-carbon hydrogen within an electrified Haber-Bosch process to produce green or blue ammonia. The technology underpinning this system is already being brought to mass market and large-scale adoption would only be hindered by low-carbon hydrogen supply constraints and the adoption of learning curves.	<ul style="list-style-type: none">CCUSBioplasticsRecycling
Power and buildings	Power generation	Hydrogen could be used for long-duration energy storage and is especially applicable in regions with high penetration of renewable generation, where periods of intermittent generation may be significant. Natural gas turbines can be converted to burn a blend of natural gas and hydrogen, and many turbine manufacturers have commercial models capable of burning fuel mixes with high concentration of hydrogen.	<ul style="list-style-type: none">Other energy storage solutions
	Buildings	The energy needed to heat buildings with hydrogen is five to six times that of electric heat pumps. This implies that hydrogen will likely have limited potential in this segment. This market will likely be nearly 100% electrified.	<ul style="list-style-type: none">Electricity
Energy	Refineries	Hydrogen is utilized for refining processes to sweeten crude (reduce the sulphur content) and hydrocarbon cracking. This is relevant for jet fuel, gasoil, gasoline and diesel. The competitiveness of the application is dependent on the displacement of oil in these sectors.	<ul style="list-style-type: none">BatterySynfuels

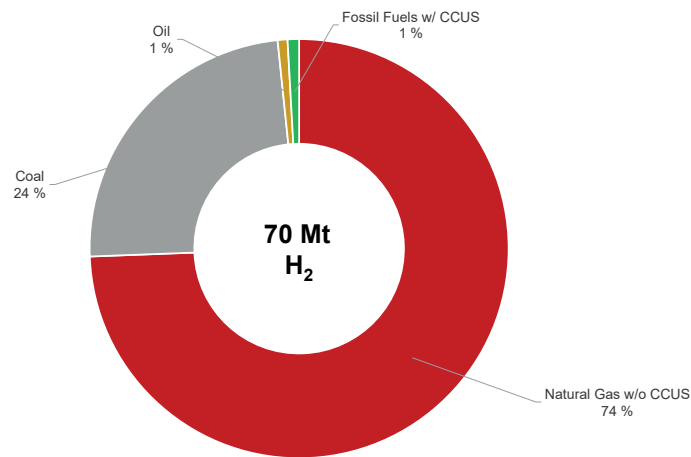
Source: Rystad Energy

Market development and outlook

Global pure hydrogen production of 70 million tpa is currently almost entirely met by fossil fuel-based hydrogen. Very little zero- and low-carbon hydrogen is currently produced, with less than 1% coming from zero- and low-carbon hydrogen – despite hydrogen receiving growing attention for its role in the energy transition, there has been a very small increase in zero- and low-carbon hydrogen output in the last five years. Natural gas is the main fuel for hydrogen production (74%), with steam methane reformation being the dominant method in the fertilizer industry and refineries. Due to its prevalence in countries where coal is more accessible, such as China, coal contributes to another 24% of global pure hydrogen supply via coal gasification. Existing hydrogen production using natural gas as feedstock may be retrofitted with CCUS to substantially decrease its carbon footprint (for example, blue hydrogen). In terms of demand segments, refineries and fertilizer production currently contribute around 86% of global hydrogen demand. In refineries, hydrogen is used for the desulfurization of diesel and cracking of heavier hydrocarbons to increase refinery yield. Hydrogen is also used as a feedstock for manufacturing ammonia, ammonia nitrate, urea and other fertilizers.

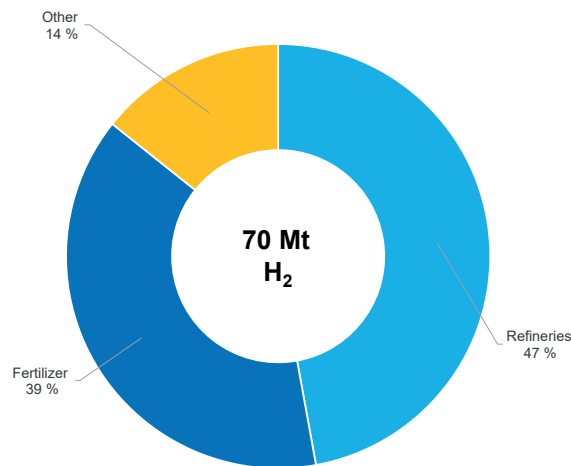
Although not currently available in abundance (less than 1%), low-carbon hydrogen adoption will likely grow in the future, underpinned by an emerging shift towards cleaner sources of hydrogen from existing demand segments, such as fertilizer production, and a surge in zero- and low-carbon hydrogen demand from new end-use segments, such as green maritime fuel and steel.

Figure 47: Global pure hydrogen production by feedstock (2020)



Source: IEA

Figure 48: Global pure hydrogen production by demand segment (2020)



Source: Rystad Energy

A considerable proportion of the hydrogen projects in the pipeline is being set up specifically to cater to new end-use segments. This includes a plethora of new developments appearing in the vicinity of some of Europe’s largest ports, such as Rotterdam and Antwerp. Similarly, many large new projects are dedicated exclusively to the development of green jet fuel and green steel. Upstream oil and gas players have also imple-

mented several blue hydrogen projects associated with existing facilities. Approximately 26% of the full-scale CCUS projects in operation (excluding pilot and demonstration projects) involve a blue hydrogen facility in North America or Europe. These projects have the collective potential to capture more than 7 million tpa of CO2 through traditional capture techniques, before sequestering the captured CO2 underground

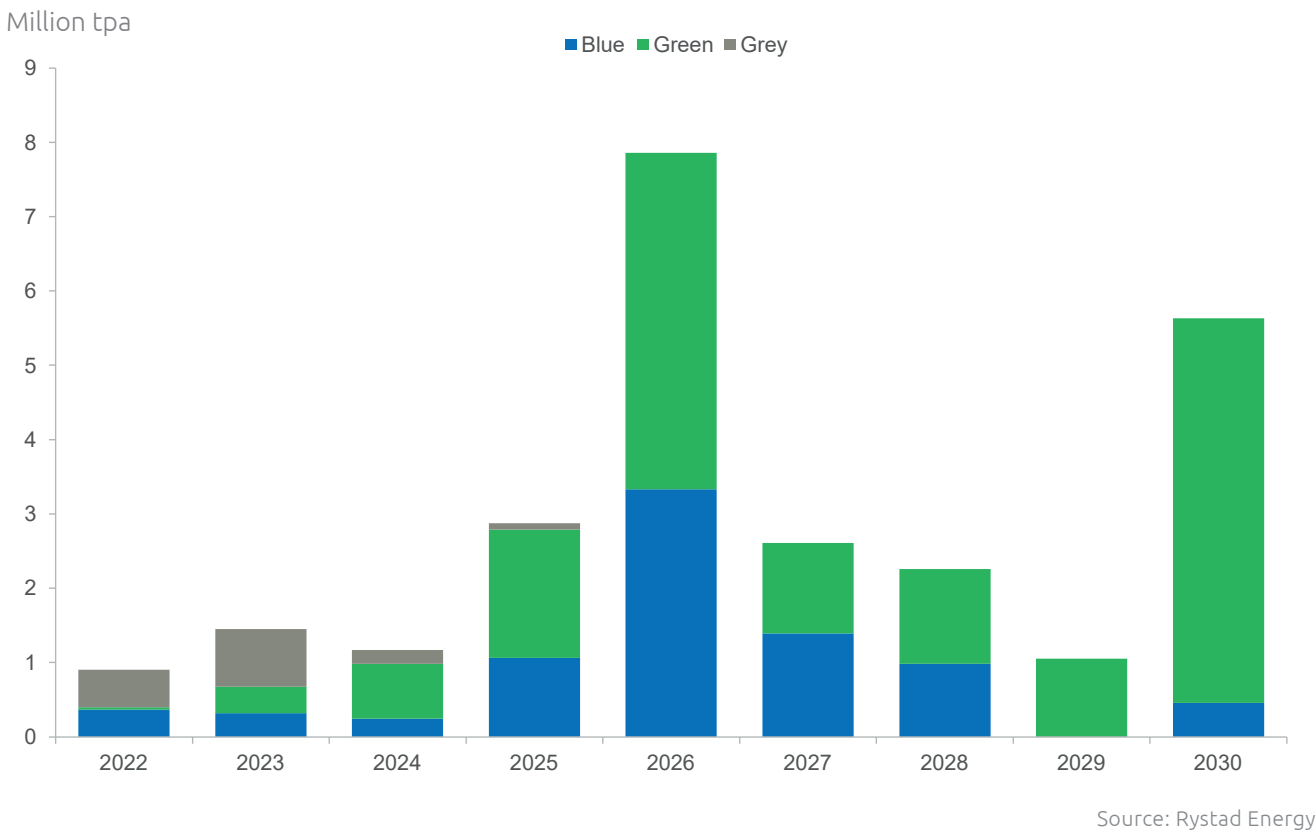
for permanent storage in depleted fields or for use in EOR projects. A shift in the hydrogen supply pipeline is expected, where the dominance of grey hydrogen in recent years will be overtaken by green and blue hydrogen in the years ahead.

Figure 49 shows the current pipeline of hydrogen projects by type and start-up year where there is a noticeable shift from grey hydrogen production into zero- and low-carbon hydrogen production. Once fully operational, these announced projects will add another 25 million tpa of hydrogen production globally over the next decade, of which 90% will be zero- and low-carbon hydrogen. Green hydrogen has been relatively expensive compared to blue hydrogen, but costs are expected to fall over time, primarily driven by technological improvements in electrolyzers and a reduction in renewables electricity cost. Moreover, cost competitiveness of blue hydrogen may be eroded in the near term due to high prices of natural gas, which is a key cost driver. The cost of

green hydrogen is expected to reach cost parity with blue hydrogen during the 2030s though green hydrogen is already competitive in areas with excellent renewable resources. To drive greater cost reduction across the board, sufficient deployment of green hydrogen is required to reach a critical scale where economies of scale can be achieved. While CCUS adds a small premium to the hydrogen cost, blue hydrogen may be more economical than grey hydrogen if carbon prices increase over time.

Infrastructure also plays a key role as an enabler for the development of a hydrogen market. It enables the creation of an international market by connecting areas with low production costs with demand centres, e.g., North Africa to Germany. Existing infrastructure such as natural gas pipelines can also be repurposed, thereby reducing delivery cost. By providing an intrinsic storage functionality for hydrogen (and indirectly for renewable electricity), it improves the security of supply.

Figure 49: Shift towards zero- and low-carbon hydrogen production capacity across project pipeline by start-up year



Regulatory support






There has been growing momentum for zero- and low-carbon gas as its decarbonization potential is being increasingly recognized. However, zero- and low-carbon hydrogen faces challenges associated with economic and infrastructure constraints that may dampen the speed and scale of deployment. At present, all forms of renewable gases are still more expensive than fossil fuel-derived hydrogen, meaning more needs to be done by regulatory bodies to support significant investment in zero- and low-carbon gases. In recent years, coordinated policies that incentivize production and consumption of hydrogen have been implemented across Asia Pacific countries and Europe, which will help grow the pipeline

of hydrogen projects. In the Asia Pacific region, Japan, South Korea and Australia have introduced roadmaps to set up their hydrogen economies. Policy measures in Japan and South Korea are generally focused on end-use applications and infrastructure support. Japan was the first country to adopt a national hydrogen framework in 2017. It has adopted a broad end-use approach that looks at power, transportation, residential, heavy industry and potentially reforming. Japan sees hydrogen as a major way of decarbonizing its economy while sustaining industrial competitiveness and energy security. South Korea seeks to become a global leader in the production and deployment of fuel cell electric vehicles (FCEVs) and

large-scale stationary fuel cells for power generation. South Korea has in recent years begun to develop domestic infrastructure to import hydrogen. In Australia, government efforts are targeted at setting up the hydrogen industry to become a major player in global hydrogen production and trade. The Canberra administration has funded a variety of hydrogen demonstration projects and 'hydrogen hubs' to prove its potential. Regulatory support for hydrogen development has mainly relied on public-private partnership over quantitative targets and clear mandates.

Within Europe, many countries have also published hydrogen strategies to offer grants and government project financing.

Table 5: Selected hydrogen development commitments

Jurisdiction	Development commitment
 Japan	<ul style="list-style-type: none"> Procure 300,000 tonnes of hydrogen annually by 2030 at cost of 30 yen/Nm³ (USD 3/kg-H₂) Increase hydrogen demand to 3 million tonnes per year by 2030 and 20 million tonnes per year by 2050
 South Korea	<ul style="list-style-type: none"> Increase hydrogen production to 3.9 million tonnes per year by 2030, and 27 million tonnes by 2050
European Union (EU)	<ul style="list-style-type: none"> Produce 6.6 million tonnes of renewable hydrogen through wind and solar deployment by 2030 under Fit For 55 Increase domestic renewable hydrogen production by 3.4 million tonnes by 2030 under REPowerEU (in addition to capacity included in Fit for 55) 10 million tonnes of hydrogen imports by 2030
 Germany	<ul style="list-style-type: none"> Increase green electrolyzer capacity target to 5 GW by 2030, and additional 5 GW by 2035 -2040
 France	<ul style="list-style-type: none"> Achieve 10% carbon-free hydrogen for industrial usage by 2023 and 20 -40% by 2028 Achieve 20-40% low-carbon and renewables hydrogen from total hydrogen and industrial hydrogen consumption by 2030
 United Kingdom	<ul style="list-style-type: none"> Aims to increase low-carbon hydrogen production to 10GW by 2030, with half from electrolytic hydrogen

Source: Rystad Energy

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In response to the Russia-Ukraine conflict, the European Commission proposed a new strategy (REPowerEU) to strengthen Europe's energy security and reduce the bloc's dependency on Russian fossil fuels by 2030. The REPowerEU plan strengthens hydrogen ambitions beyond the Fit-for-55 package by calling for 20 million tonnes (Mt) of renewable hydrogen usage by 2030. In addition to the 6.6 Mt of domestic renewable hydrogen production

already planned under the Fit-for-55 scenario, the REPowerEU plan increases domestic production by 3.4 Mt while 6 Mt of renewable hydrogen and approximately 4 Mt of ammonia are imported. Out of the approximately additional 10 Mt hydrogen under REPowerEU, the Commission estimates that 8 Mt can replace 27 bcm of gas and remaining 2 Mt can replace oil and coal. The European hydrogen industry estimates that 120 GW

of electrolyzer capacity will be required in the EU to meet the 2030 target of producing 10 Mt of renewable hydrogen domestically. France has set an objective for zero- and low-carbon hydrogen to contribute between 20% and 40% of total and industrial hydrogen consumption by 2030. Germany aims to build 5 GW of electrolyzer capacity by 2030 and earmarked €9 billion to support the development of a green hydrogen supply chain.

Table 6: Selected hydrogen funding commitments

Jurisdiction	Funding commitment
 Japan	<ul style="list-style-type: none"> JPY 80 billion in funding in fiscal year 2020 allocated to hydrogen society initiatives (including FCV subsidies) FCV subsidy of up to JPY 2 million per vehicle JPY 2 trillion to provide 10 years of continuous support to business-led decarbonization initiatives (not exclusively hydrogen)
 South Korea	<ul style="list-style-type: none"> KRW 8.6 trillion by 2022 and 20.3 trillion by 2025 to be invested under Green New Deal to develop green mobility, particularly hydrogen projects FCV subsidy of up to KRW 35 million (\$30,000) per vehicle
 Australia	<ul style="list-style-type: none"> AUD 70.2 million allocated to develop a regional hydrogen export hub AUD 370 million (\$255 million) allocated to support hydrogen projects by the Australian Renewable Energy Agency and Clean Energy Finance Corporation.
European Union (EU)	<ul style="list-style-type: none"> EUR 180 to 470 billion by 2050 to invest in renewable hydrogen in Europe under the EU's Hydrogen Strategy EUR 1.3 billion funding for Clean Hydrogen Partnership program
 Germany	<ul style="list-style-type: none"> EUR 7 billion to develop green hydrogen and EUR 2 billion to foster international partnerships EUR 1.4 billion over 10 years for the National Innovation Programme for Hydrogen and Fuel Cell Technologies FCV subsidy of up to EUR 6,000 per vehicle
 France	<ul style="list-style-type: none"> EUR 7 billion by 2030 to finance research and development of low-carbon and renewable hydrogen GBP 240 million to be awarded under Net Zero Hydrogen Fund
 United Kingdom	<ul style="list-style-type: none"> GBP 100 million to be invested in electrolytic hydrogen production under Hydrogen Business Model GBP 26 million under Industrial Hydrogen Accelerate to support hydrogen adoption in industries e.g., manufacturing GBP 171 million committed to support development of decarbonized industrial clusters

Source: Rystad Energy

Biomethane

Introduction

Biomethane, also known as renewable natural gas (RNG), is a purified source of methane produced from processing raw biogas (produced from anaerobic digestion) or solid biomass. To form biomethane, raw biogas is upgraded to remove CO₂ and other impurities, while woody biomass undergoes thermal gasification (less common). With a quality comparable to natural gas, biomethane can be used to supplement or directly substitute natural gas while using existing

infrastructure and equipment, thereby decarbonizing the gas industry. Existing natural gas infrastructure also requires little to no modification or investment to transport and store biomethane. Given its wide range of applications, biomethane will be an attractive renewable energy source, particularly in the generation of heat and power.

Based on findings from the European Biogas Association (EBA), close to 70% of biomethane

production in Europe uses agriculture-based feedstock, while the remainder uses municipal and industrial waste (23%), sewage (7%) and landfills (1%). Production volumes per plant also varies between feedstock type. Biomethane plants using agriculture and municipal and industrial waste as feedstock generally have higher average yearly production per plant (36 GWh per year per plant) compared to sewage-based and landfill-based plants (17 to 18 GWh per year per plant).

Table 7: Key applications of biomethane

Sector	Application
Transport	Biomethane could be converted into compressed natural gas (CNG) or liquefied natural gas (LNG) to be used as a biofuel. In its LNG form, it could be used to decarbonize sectors such as heavy-duty transport and maritime sector where electrification might be challenging.
Power generation	Grid-quality biomethane is a chemically identical to natural gas. Decarbonization at gas -fired power plants can be achieved through the use of emission -free biomethane without additional modification or investment to existing infrastructure. Easily stored, biomethane also helps to balance the grid with intermittent renewables generation.
Building	Biomethane also supports efficient combined -heat-and-power generation. In grid -connected buildings, biomethane could be used through hybrid heat pumps to decarbonize heating systems
Industry	As a substitute for natural gas, biomethane has a role in difficult -to-electrify areas that require high temperature and heat. It could be used as a feedstock to decarbonize methanol and steel production.

Source: Rystad Energy

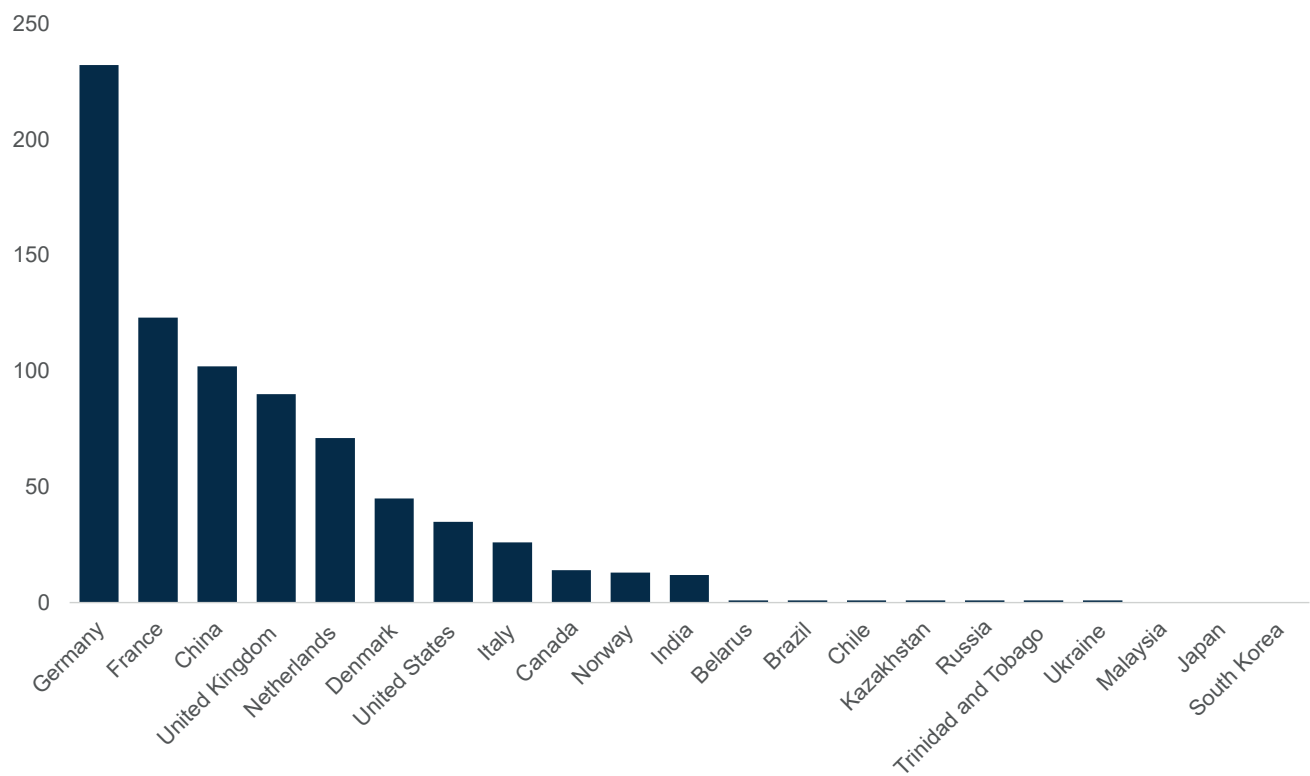
Market development and outlook

Making up only 1% of total natural gas production, the global supply of biogas and biomethane (2018) is around 35 million tonnes of oil equivalent (400 TWh or 40 Bcm of natural gas equivalent). There are around 770 biomethane plants globally, placing biomethane ahead of zero- and low-carbon hydrogen in terms of deployment. The market is concentrated within China and a few countries in Europe, contributing a little over 75% of

global supply. In key markets such as China and Europe, most biogas is produced by anaerobic digestion and generally used for electricity generation or combined heat and power generation close to the point of production. While it may be useful as a dispatchable source of renewable energy, biogas has limited connection to the mainstream natural gas businesses. Among markets producing biogas, only a limited amount of this is upgraded

to grid-quality biomethane where it has better linkage to natural gas businesses. According to the European Gas Association, only 10% of European biogas production historically is made suitable for injection into the natural gas grid via an upgrade into biomethane. However, an increasing amount of biogas is being upgraded into biomethane within Europe. Of these markets, Denmark has committed to achieving a 100% biomethane-fed gas grid by 2040.

Figure 50: No. of biomethane plants reported in IGU database



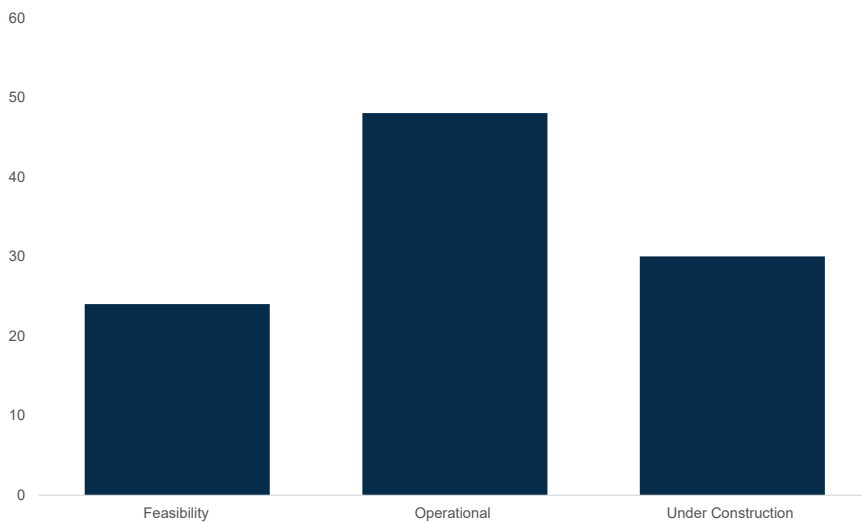
Source: IGU Global Renewable and Low-Carbon Gas Report (2021)

Key regional biomethane markets

China has 48 large-scale operational plants with an expected biomethane production of 3,650 GWh per annum. The majority of the operational biomethane plants have received government construction incentives. All the projects produce biomethane through the anaerobic digestion of biomass, typically agricultural waste, animal waste and industrial wastewater. There are another 30 projects under construction, 24 of which are at the feasibility stage. This is expected to generate at least an additional 3,808 GWh of biomethane production when fully operational. The strength of China’s policy support and maturity of the projects’ business models will, to a large extent, determine if the project pipeline is realized. China is one of the earliest users of biogas, dating back to the 19th century. Around 23 million biogas digesters were built in the 2000s along with many medium- and large-scale biogas plants, propped up by the state’s heavy investments. By 2015, the Chinese government funded 25 biomethane demonstration projects and subsequently approved 22 and 18 more biomethane projects in 2016 and 2017, respectively. While China’s biomethane market has developed over a long time, it is still reliant on policy support. To scale up production, the biomethane market in China needs to overcome a few challenges related to limited availability of feedstock, unfavorable project economics without government subsidies, and difficulties in connecting to the city gas grid due to rural production sites.

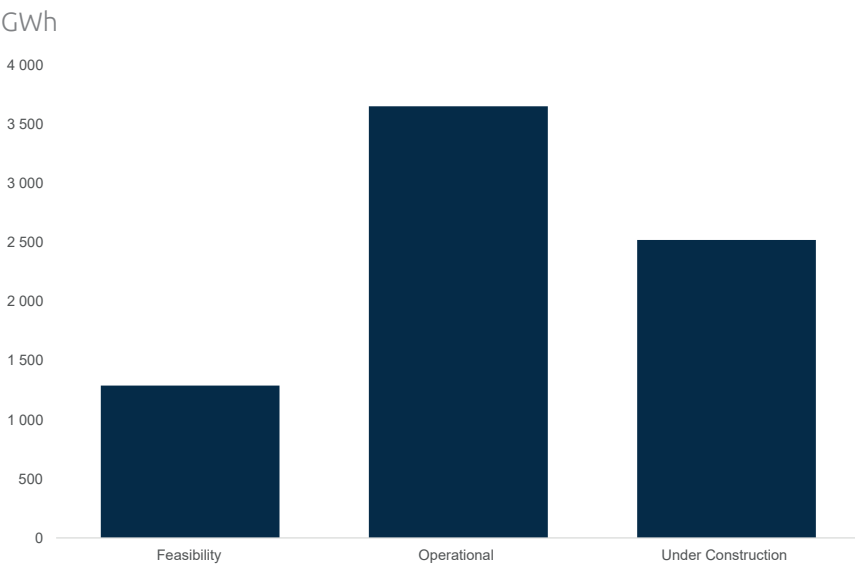
As the world’s largest biomethane producer, Germany has 194 operational biomethane plants with a total production of 8.8 TWh. Currently, around 10% of

Figure 51: No. of biomethane plants in China by status



Source: IGU Global Renewable and Low-Carbon Gas Report (2021)

Figure 52: Estimated annual output of biomethane plants in China by status



Source: IGU Global Renewable and Low-Carbon Gas Report (2021)

total raw biogas production is upgraded to grid-quality biomethane but an increasing amount is expected to be upgraded over time. Some 84% of the biomethane is produced from energy crops (164 plants), 6% produced

from bio and municipal waste (11 plants), and the remaining 10% from a diverse range of feedstock, including agricultural residues and industrial organic waste from the food and beverage industries. Biomethane is mainly used

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in power generation in Germany, although application in transport has increased significantly, driven mainly by mandatory regulatory requirements on fuel companies to reduce their carbon footprints. All biomethane plants in Germany are connected to the gas grid and 45% of them are also connected to the transport grid. If its production cost becomes more favorable, biomethane will become a very promising medium- to longer-term option to decarbonize the transport and heat sectors. Biomethane production may be expanded in Germany over the next decade, but growth is not expected to be significant due to a limited policy focus at present.

Another 67 operational biomethane plants are in Denmark, producing a total of around 4,417 GWh. Of this, 97% of the biomethane produced comes from using agricultural residues as feedstock. As Europe's second-largest producer of biomethane, Denmark saw the sector grow in 2019 by more than any other European country, apart from France. Following its transition towards biomethane in 2011, Denmark has connected around 51 plants to the gas system, where the injected biomethane may be used for heating and power generation. The use of biogas and biomethane is expected to increase Denmark's gas self-sufficiency and provide a larger decentralized and dispersed gas supply to gas consumers. Denmark has committed to a series of ambitious renewable gas targets, including one that aims to achieve 100% biomethane in its gas grid. This is expected to drive strong biomethane

production and injection into the grid over the next decade.

According to IEA Outlook for biogas and biomethane (2020), the total sustainable production potential of biogas and biomethane could grow to 20 times its current level, hitting 730 million tonnes of oil equivalent (toe) or around 835 Bcm of natural gas equivalent. This potential production level is deemed sustainable as it will largely come from waste streams, including forest residues used for gasification, so it does not result in additional land use change, competition with food production or other negative environmental impacts. Assuming all biogas at the potential level were to be upgraded to grid quality, biomethane could substitute 20% of today's natural gas consumption. This represents a substantial decarbonization of around 1.5 Gt of CO₂e globally. To achieve its sustainable production potential, biomethane production capacity needs to expand substantially and quickly from today's volume.

The cost of biomethane production is estimated to range from \$ 2 to \$3 per kilogram of biomethane by 2030, which puts it on par with the average cost of green hydrogen. A key advantage of biomethane lies in its ability to seamlessly blend with natural gas. This allows for its use in existing gas networks and end-use applications without any major modifications. As an effective decarbonization option, biomethane should be raised up the policy agenda, and greater policy support and investment could be called upon to strengthen its development.

Regulatory support

There has historically been much stronger policy interest in zero- and low-carbon hydrogen than biomethane despite the latter having a larger volume of operational production and relatively lower cost. To support decarbonization of global energy systems on as many fronts as possible, there is a need to accelerate the adoption of biomethane at a sufficient speed, scale and scope, given its wide-ranging applications as a renewable form of natural gas. This

will require strong and clear policy support from governments. The EU recently announced a biomethane production target of 35 Bcm within the bloc by 2030 under its REPowerEU plan to reduce its reliance gas imports. With a current production level of 3 Bcm per annum, the EU will need to expand its production capacity by at least 12 times over the next decade and focus on using sustainable feedstock to meet its target.

Regulatory trends across key biomethane markets

As the world's largest consumer of coal, China will need to switch to more renewable fuels such as hydrogen and biomethane to decarbonize and achieve its target of carbon neutrality before 2060. China has invested heavily since 2015 in the construction of large-scale biogas and biomethane demonstration projects. The biomethane industry is still heavily reliant on government support as it is not yet economical without subsidies. Operational plants are struggling to run profitably without clear incentives, while under-construction projects face the risk of being stopped or delayed due to economic reasons. According to a policy paper published by the National Energy Administration, it was proposed that annual biomethane output should grow to 15 Bcm by 2025 and 30 Bcm by 2030. Operational plants in China currently produce around 4 Bcm of biomethane.

Biogas and biomethane production in Germany expanded significantly following the implementation of subsidies for renewables electricity production under the Renewable Energy Source Act in the 2000s. In addition, regulations driving the application of biomethane in transport were also introduced under the Federal Pollution Control Act, which mandates fuel companies to reduce their carbon footprints. To that

end, there are now more than 120 filling stations in Germany offering pure biomethane in the form of bio-CNG and another 170 offering blended stream of bio-CNG and natural gas. The heavy usage of energy crops has also raised concerns over the sustainability of biogas production in Germany, contributing to a policy shift to focus future developments on bio-waste substrates.

As the largest biogas and biomethane producer globally, Denmark has set out ambitious renewable gas targets over the next decade. It hopes to meet 75% of its gas demand, which is currently around 3 Bcm per annum, with biogas by 2030 and expects it to cover all its gas consumption by 2034. By the end of 2021, Denmark had increased its share of biomethane injection into the gas system to just under 25%, a record amount and up from 21% in 2020. The Danish government has subsidized the biogas and biomethane market since the 1990s. Since the Energy Agreement in 2018, Denmark has implemented a phase-out of current biogas and biomethane subsidy frameworks whereby subsidies will not be permitted for new plants, while existing plants can maintain their subsidies until 2032.

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