Global Gas Report 2020

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Foreword

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This 2020 edition of the Global Gas Report comes in the midst of an unprecedented global pandemic, whose short- and long-term impacts on the global economy and the energy sector are still unfolding. This year's report, therefore, assesses the effect of Covid-19 on the gas industry in the first half of this year, and analyses the drivers for recovery in the next few years. It includes a special feature on the role hydrogen and the gas industry in the low-carbon transition.

The Global Gas Report 2020 is a collaborative effort between Snam, the International Gas Union and BloombergNEF. To create this report, we also got inputs from DESFA, Interconnector UK, Terēga and TAG, part of Snam Group.

As in previous editions, this report analyzes the key drivers that led to growth in supply and demand in the last year. It also offers insights into how abundant supply and low prices propelled fuel switching from more emissions-intensive fuels to natural gas and which policy measures have been effective in reducing pollution.

2019 was another year of continuous growth for the gas industry, with global consumption growing 2.3% to a new record. Supply rose in most regions around the world and producers took final investment decisions on a record 97 billion cubic meters of per annum of LNG liquefaction projects. LNG trade also grew 13% in 2019, the fastest since 2010, propelled by rising demand in new markets like South Asia and growing liquidity in the spot and derivatives markets. Major new pipelines, including a new link between Russia and China, were commissioned.

Covid-19 has caused significant disruption. Initial assessments suggest that gas demand will decline by around 4% this year, and LNG trade by a similar amount. However, abundant supply and continued cost-competitiveness, aided by a push for cleaner air, can lead to a recovery in demand to pre-Covid-19 levels in the next two years, as the global economy regains momentum.

Gas infrastructure investment is critical for growth in the long term, particularly in countries with potential reserves and those currently with a high dependence on coal. These investments should be supported by technological innovation to raise efficiency and keep prices low. And transparent price discovery mechanisms, establishment of new trading hubs and rising liquidity in the spot and derivatives markets will enable better risk management.

Continuous collaboration between industry participants, national and provincial governments, intergovernmental agencies and financial institutions can open up new avenues for growth while assisting the energy transition. The regulations from the International Maritime Organisation to reduce sulfur emissions starting this year, are a case in point. Positive trends are also emerging in the industry's effort to measure, manage and mitigate methane emissions – and this trend needs to continue and accelerate.

For sustained growth in the long term, low-carbon gas technologies will have to be scaled up significantly. These include biomethane and carbon capture and storage. Hydrogen has been gaining momentum and attracting heightened attention from industry players and government agencies alike. This report, therefore, has a special section detailing the potential market size and the technological options and costs of hydrogen production, storage and transport, highlighting the important role of infrastructure for its development. We also provide a list of actions (including ones on policy) that can be taken to reduce barriers for hydrogen's uptake, which in turn can help reduce carbon emissions in the 'hard-to-abate' sectors, and ultimately contribute to achieving our collective climate goals.

We invite you to explore this report and we hope that you find it a useful resource in evaluating the past, present and future of the global gas industry.

Contents

Executive summary

The global gas industry continued to grow strongly in 2019, reaching new landmarks on consumption and international trade. Prices have seen historic lows thanks to abundant supply, supporting the competitiveness of gas. Covid-19 is causing significant uncertainty in the global economy and the gas sector, but technological innovation and policy support can help the industry to bounce back strongly.

In this fourth edition of the Global Gas Report, we assess the key drivers currently shaping the natural gas industry, explore the potential impact of Covid-19 in the next 2-3 years and look at the long-term role of gas in the energy sector from the lenses of sustainability, competitiveness and supply security. We find that:

- **Cost-competitiveness is enabling new demand**. Recent low gas prices around key global hubs, in part due to the pandemic, have garnered much attention. However, rising supply and affordable prices were already enabling record gas demand in 2019 in key growth markets like China. LNG imports also hit record highs in Europe, supported by increasing carbon prices. A significant part of the growth came from coal-to-gas switching in major markets like the U.S. and China.
- **Security of supply is increasing**. Important new pipeline routes from Russia to China and Europe were commissioned in 2019, and new takeaway capacity has been built in the critical supply region of the Permian Basin in the U.S. A record number of LNG export projects were approved last year. Once commissioned, these will deliver close to 97 billion cubic meters per year of new LNG supply to the market. Future supply growth is expected to be led by the Middle East, but the U.S., Russia and Iran are expected to remain the top-producing countries in the medium and long term. China has seen domestic supply rise by a third in the last five years, and could double its production by 2040.

  Propelled by growth on the supply side, new LNG import terminals are being built in markets like Southeast Asia to ensure gas delivery to the power and industrial sectors, as domestic supply wanes.
- **Sustainability and enabling policy will define the future of the gas industry**. Clean air policies have provided an impetus for gas consumption in major markets like China, where gas can displace coal. Similarly, in Europe and the U.S., coal displacement by gas is leading to better outcomes for air quality and carbon emissions. Slowly and steadily, other countries, like India, are

following suit. Policies focused on clean air will provide growth opportunities for the gas industry in this decade. The recent regulations from the International Maritime Organization will also open up avenues of growth for LNG to be used as a major fuel in the shipping industry. And the role of gas-fired power generation as a flexible resource to complement growing renewable generation is becoming more established.

- **Gas technologies can play a major role in the low-carbon transition**. As countries and regions pursue a low-carbon transition, technologies such as biomethane, hydrogen and gas with carbon capture could play an important role, serving to decarbonize sectors of the economy that are currently seen as 'hard to abate', and providing opportunities for long-term growth for the gas industry. However, investment and policy support are needed to scale up these solutions.
- **The current level of excitement around hydrogen presents an opportunity**. Hydrogen is starting to garner policy support and, with enough investment, could abate up to 37% of energy-related greenhouse gas emissions, according to BloombergNEF estimates. While clean hydrogen is not yet cost-competitive in many applications, delivered costs could reach around $2/kg in 2030, and $1/kg in 2050, opening up possibilities in a variety of applications. These include steel and cement making, chemicals, aviation, shipping and heavy-duty transport. For hydrogen to achieve its potential, not only will strong policy action be needed to drive scale, but there will also be a significant need for infrastructure investment. Large-scale hydrogen networks will be necessary to connect high-quality production and storage resources to users, which can help lower supply costs, increase security, enable competitive markets and facilitate international trade.
- **Infrastructure investment can propel demand growth for gas, and prepare the ground for hydrogen**. Both LNG and pipeline infrastructure will be critical to deliver continuous supply to end-users. Between 2019 and 1Q 2020, 11 new LNG import terminals were commissioned, with India leading the way. The country is planning to almost double the length of its gas transmission pipelines and raise the number of households connected to the gas grid six-fold. Similarly, China is aiming to grow its transmission pipeline network by 60% by 2025. Gas storage will also play an important role in balancing the market and reducing volatility. Storage facilities in Europe, including Ukraine have already proved critical in balancing the global LNG market in the first half of 2020. China is also aiming to raise storage capacity to 10% of its demand.

  As the energy transition proceeds, gas transport and storage infrastructure can be readied for hydrogen blending, and indeed for pure hydrogen transport, at much lower cost than constructing new purpose-built hydrogen networks.
- **New market mechanisms are fuelling trade growth**. Global gas trade is being facilitated by a combination of market deregulation, establishment of trading hubs and growth in financial derivatives. Many markets, including China, are pushing for third-party access to LNG import and gas transmission infrastructure. India has recently launched a gas trading exchange with three delivery locations, and Spain is aiming to start is virtual trading hub this year. As new hubs and pricing benchmarks are established, liquidity in financial derivative contracts for gas-linked prices is steadily increasing too. These efforts will support the commoditization of gas and LNG, and help manage risk.

It remains difficult to assess the future impact of Covid-19 on the global economy, the energy sector and the gas industry. Initial assessments suggest that gas demand may decline 4% in 2020 and BloombergNEF estimates that global LNG demand will shrink by 4.2% this year, assuming the outbreak is contained by early 2021. The industry is expected to rebound quickly in 2021 and beyond, but it may be too early to gauge the full impact.

1 / Recent global gas trends

Highlights

- In 2019, natural gas continued its trend towards greater cost competitiveness, while contributing to global energy security and reductions in air pollution and emissions. Gas was the second-fastest growing source of primary energy demand, behind renewables.

Global gas: headline trends in 2019

24.2%	+2.3%	+3.5%	+13%	-37%
Gas share in primary energy mix	Gas demand growth	Gas production growth	Growth in LNG trade	Change in gas prices at key global hubs[1]

Gas demand grew 2.3% last year[2]. This growth rate was lower than the 4.9% seen in 2018 due to slower economic growth in China and milder winter, but the key drivers remained in place. Environmental policy supported fuel switching to gas in China and India, and low gas prices raised demand in the U.S. and Europe. New LNG import terminals and major pipelines came online.

Gas production grew faster than consumption in 2019, resulting in more gas being sent to underground storage. Growth in LNG exports and new gas discoveries enhanced supply security.

The Covid-19 pandemic has created significant uncertainty for the wider energy sector, and the gas sector was no exception. Gas demand growth is impacted by lockdowns, and fears of an extended and multiple-wave pandemic persist. The resulting price drop created uncertainty in the capital expenditure plans of the upstream sector and could slow down supply growth in the near term.

Table 1: Key changes in gas markets in 2019 (year on year)

Region	Consumption	Gas price	Production	Imports	Exports
North America	+ 3.2%	Henry Hub − 18%	+ 7.5%	− 6%	+ 18%
Europe	+ 1.2%	TTF − 38%	− 6.9%	+ 6%	− 6%
Asia	+ 4.1%	JKM − 42%	+ 5.6%	+ 2%	+ 5%
Middle East	+ 3.0%	-	+ 3.2%	+ 3%	+ 4%
CIS	− 0.6%	-	+ 1.8%	+ 10%	+ 3%
Latin America	− 2.2%	-	− 1.2%	− 9%	− 3%
Africa	+ 3.2%	-	+ 1.2%	− 22%	− 5%

Source: BloombergNEF, Cedigaz.
CIS: Commonwealth of Independent States.

1 Average of Henry Hub, TTF, and Japan Korea Marker (JKM) for 2019 vs 2018.
2 The Global Gas Market – 2020 Edition, Cedigaz.

Global gas market: 2019 overview

Gas in the primary energy mix

Global primary energy consumption grew by 1.3% in 2019, which is slower than the average 1.5% annual growth rate seen over the previous five years (2013-18)[3]. Natural gas continues to play a major role in this growth, contributing 36% of the additional energy consumed in 2019 – second only to renewables. Coal's share in the primary energy mix declined slightly, reaching 27% in 2019 as compared to 27.6% in 2018. The share of gas rose marginally from 24.1% in 2018 to 24.2% in 2019 (Figure 1).

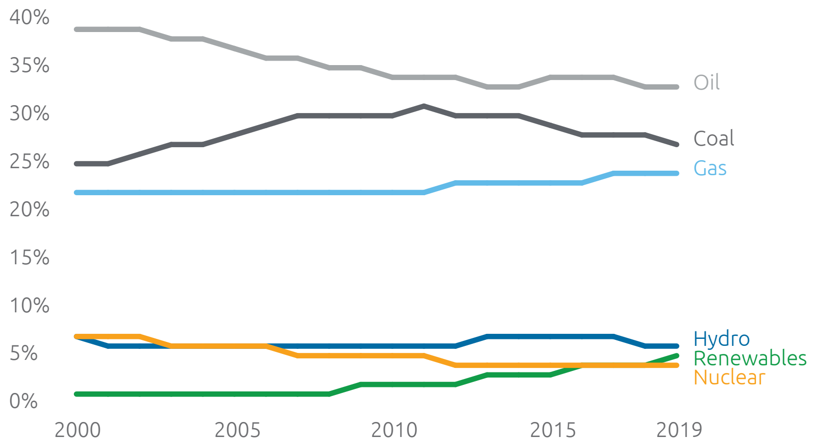
In the power sector, gas-fired generation saw an increase, to 23.3% from 22.8%, as it displaced coal, in light of the lower gas prices. Coal's share simultaneously declined to 36.4% from 38% the previous year (Figure 1). Only renewables grew more than gas.

Global gas consumption

The global gas market continued to enjoy growth in consumption, but at a slower pace compared to previous years. Global gas demand grew by 2.3%, or 87 billion cubic meters, in 2019 (Figure 2)[4]. The U.S. and China led this trend, accounting for 30% and 27% of global growth, respectively. Lower growth in gas demand compared to previous years was an outcome of slower economic growth in China and milder winter temperatures in the northern hemisphere, which reduced space heating demand.

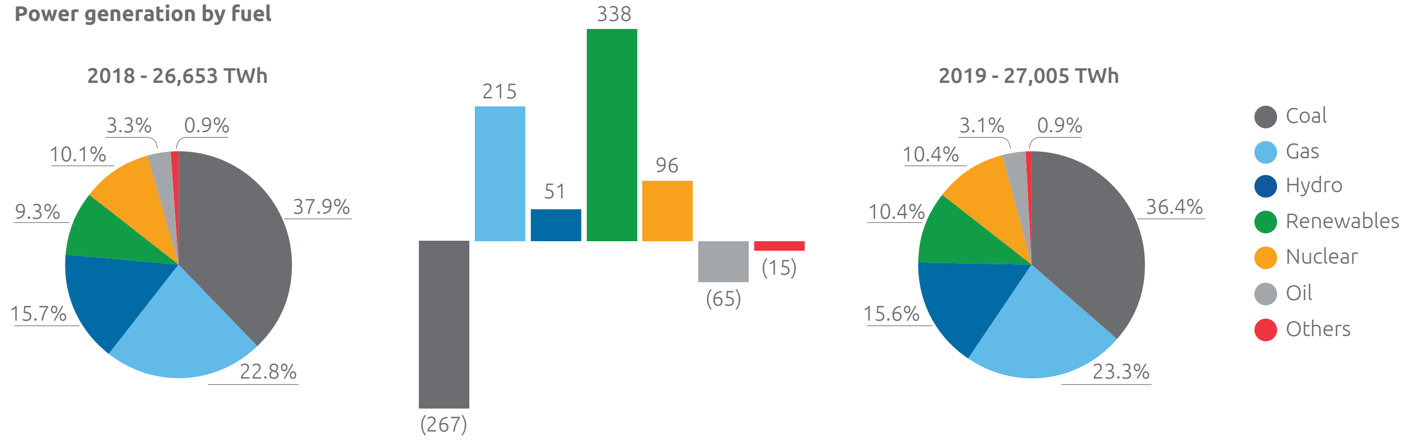
Gas demand in the U.S. expanded by 3.1% in 2019, as low gas prices incentivized greater use in the power sector. China's demand grew by 8.6% in 2019 as its clean air policies

Figure 1: Evolution of primary energy mix and power generation



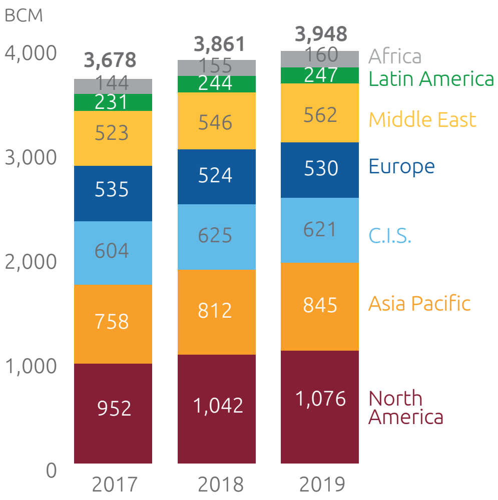
Source: BP Statistical Review of World Energy, June 2020.

Power generation by fuel



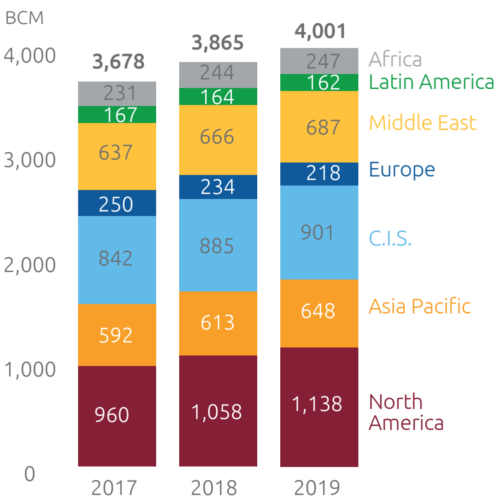
3 BP Statistical Review of World Energy, June 2020
4 The Global Gas Market – 2020 Edition, Cedigaz.

Figure 2: Global gas demand



Source: Cedigaz.

Figure 3: Global gas supply



Source: Cedigaz.

further supported coal-to-gas switching in the industrial and residential sector. However, higher nuclear power generation reduced annual gas consumption in Japan by 6.8% and in South Korea by 1.8%[5]. Demand growth in other countries in the Asia Pacific region came mostly through LNG imports.

European gas demand was up by 1.2% in 2019 with falling gas prices encouraging more coal-to-gas switching in the power sector.

Gas consumption fell 0.6% in the Commonwealth of Independent States (CIS) countries in 2019 and slipped by 2.2% in Latin America. Demand in the Middle East was up by 3% and African countries' consumption increased by 3.2%. Low economic growth reduced gas demand in the CIS region whereas a fall in gas use in power generation reduced demand in Latin America. The Middle East and North Africa saw higher gas demand due to rising power consumption.

Global gas production

Global gas production continued to grow strongly in 2019, rising by 3.5%, or 136 billion cubic meters (Figure 3)[6]. Growth was led by the U.S., which accounted for 64% of the global supply increase in 2019. Shale gas production surged by 10% in the U.S., supported by higher output from the Appalachian and Permian basins.

In the Asia Pacific region, China and Australia contributed most to gas supply growth. China's gas production was up by 9.8% in 2019 on a strong government push to raise domestic gas supply. Production in Australia rose 18% as it ramped up LNG exports.

In contrast, Europe's output fell by 6.9% in 2019 due to lower production from the Groningen field in the Netherlands. Supplies from Norway also declined.

In the CIS region, Azerbaijan's gas production surged by 28% in 2019 as supply from Shah Deniz II ramped up. Production in Russia increased 1.5% on higher LNG exports. Production in the Middle East was up by 3.2% on higher gas output in Iran. Africa saw its gas supply rise by 1.2% as production increased in Egypt. In contrast, the production in Latin America declined by 1.2%, as gas output declined in Venezuela and Bolivia.

International gas trade

International gas trade continues to grow faster than gas demand, contributing to enhanced global security of supply. Trade volumes increased by 2.9% in 2019, with pipeline trade accounting for 53% of the total gas traded. LNG accounted for the remaining 47%, against 43% the previous year[7].

LNG trade

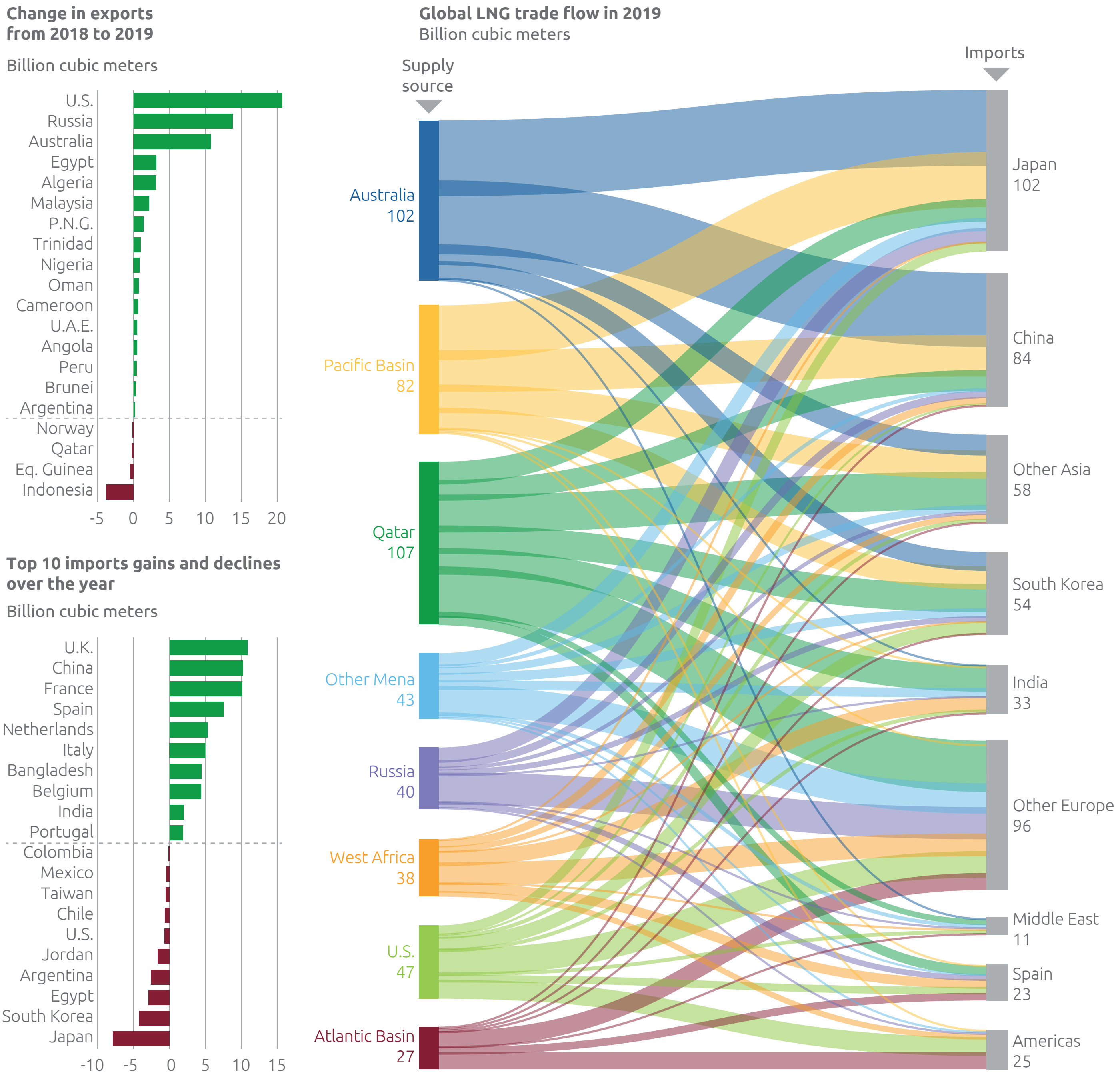
The global LNG market continues to be the engine of growth for international gas trade. Global LNG imports reached 482 billion cubic meters in 2019, up 13% from 2018[8]. Imports to Japan and South Korea each fell by 7% during the period. China's 14% increase in LNG imports offset declines in other parts

5 BloombergNEF estimate.
6 The Global Gas Market – 2020 Edition, Cedigaz.
7 The Global Gas Market – 2020 Edition, Cedigaz.
8 BloombergNEF

of the region. South Asia – India, Pakistan, and Bangladesh – contributed to the growth in Asia Pacific, with LNG imports in the region rising 20% last year. Bangladesh was the second biggest growth market in Asia, after China.

Europe emerged as the biggest growth market globally with net imports reaching a record 117 billion cubic meters in 2019 (+76% versus 2018), overtaking Japan (Figure 4).

Figure 4: Global LNG trade flows and growth in LNG exports and imports



Source: BloombergNEF, Bloomberg Terminal's AHOY JOURNEY <GO>. Note: LNG trade volumes shown is based on Bloomberg estimates. Exports based on 2019 departure year, imports based on 2019 arrival and supply source mapped accordingly

The U.K., France and Spain had the largest gains. This resulted in higher import terminal utilization in 2019 than the previous year (Figure 5). LNG demand in the Americas and the Middle East contracted, as domestic production curbed the need for imports. Similar dynamics played out in both regions; Egypt resumed LNG exports and pipeline exports to Jordan, while Argentina began LNG exports and resumed pipeline exports to Chile.

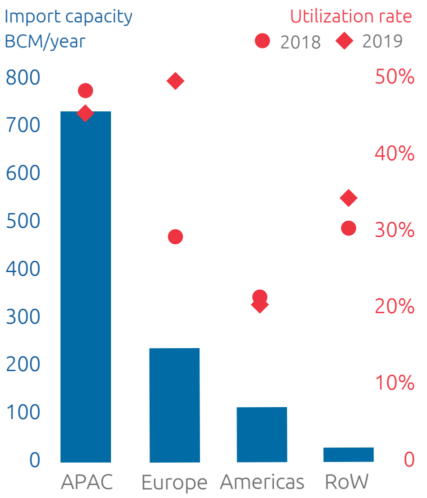
Growth in LNG supply came on the back of new production trains commissioned in the U.S. Gulf Coast (Table 2).

Australian and Russian LNG production continued to grow by 11% and 57%, respectively. Qatar retained the top export spot in 2019 but its share in the global supply market is now tied with Australia at 21-22%.

Table 2: LNG supply projects commissioned in 2019 and year-to-date 2020

PROJECT (COUNTRY)	Cameron LNG (U.S.)	Corpus Christi LNG (U.S.)	Elba Island (U.S.)	Freeport LNG (U.S.)	Prelude FLNG (Australia)	Tango FLNG (Argentina)	Vysotsk LNG (Russia)
CAPACITY (BCM/year)	18.5	12.3	2.7	20.5	4.9	0.7	0.9

Figure 5: Regasification terminal utilization



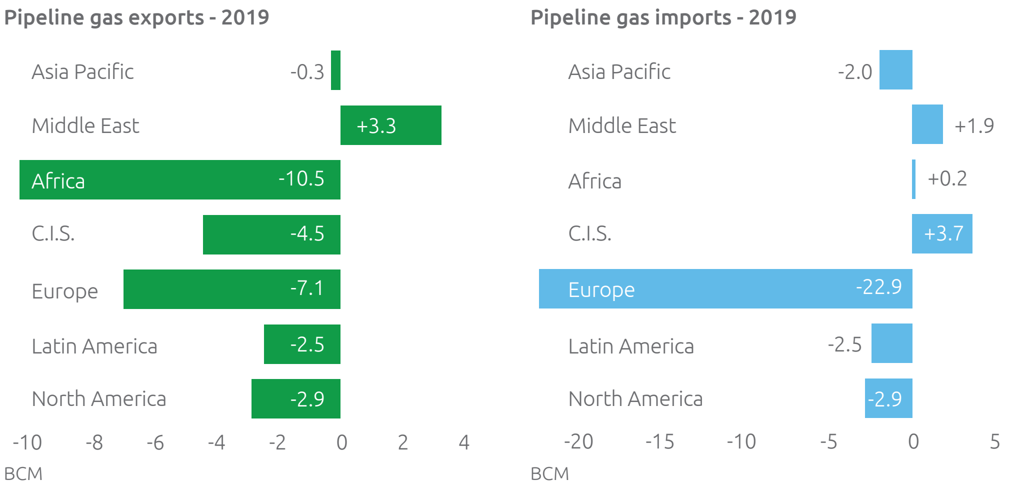
Source: BloombergNEF.

Pipeline trade

Pipeline trade fell 4.3%, or 25 billion cubic meters, in 2019 (Figure 6)[9].

Africa and Europe saw the largest reduction in pipeline exports. Tough competition with cheaper LNG in 2019 squeezed Algerian pipeline exports, leading to a 30% fall from a year earlier. A decline in gas production and planned maintenance work lowered Norwegian pipeline exports by 5.8% in the year. In North America, Canadian exports were down by 12.9% year on year (y/y). U.S. pipeline exports increased by 12% in the year on higher flows to Mexico. In the CIS countries, major exporters that saw lower pipeline exports include Turkmenistan

Figure 6: Pipeline trade 2019



Source: Cedigaz.

Source: Cedigaz.

9 The Global Gas Market – 2020 Edition, Cedigaz

(-10% y/y) and Uzbekistan (-23% y/y). Russian pipeline gas exports declined only marginally, slipping 0.5% despite competition from LNG. Azerbaijan's exports were up by 42% on higher gas production. Pipeline exports in the Middle East grew by 10.6% in 2019 as Iran raised its supply. Latin America and Asia saw their pipeline exports decline by 16.3% and 1.1%, respectively.

On the pipeline imports side, Europe saw the biggest decline among all regions as they fell 6.5% in 2019 from the previous year. U.K. pipeline imports dropped 35%, France and Belgium imported 26% less pipeline gas and Spain's imports were down by 15%. Pipeline imports also fell 5.2% in North America on lower flows to the U.S. from Canada, and in Latin America slipped 16.3% as Argentina and Brazil cut imports. Pipeline imports by the CIS countries were up by 10% as Ukraine imported more gas. Middle Eastern and African countries saw pipeline imports rise by 7.8% and 2.2% in 2019. Asia imported less pipeline gas on lower flows to China and Thailand.

Recent infrastructure buildout

Regasification terminals

Since the beginning of 2019, some 11 new LNG import terminals have been commissioned, bringing total regasification capacity to 844MMtpa, or 1,148Bcm per year (Table 3)[10]. New import terminals are a mix of onshore terminals, floating storage and regasification units (FSRU) and small-scale facilities, mostly supporting existing import markets.

Roughly half of the new regasification capacity addition in 2019 happened in Asia, led by India. The Americas came second as Jamaica and Brazil added FSRU capacity to supply gas to power plants. A further 473MMtpa (643Bcm/ year) of regasification capacity is either under construction or proposed, with Asia accounting for 70% of the projects.

Table 3: New LNG import terminals, 2019 & 1Q 2020

PROJECT (COUNTRY)	CAPACITY (BCM/year)
Bahrain LNG	8.4
Ennore (India)	6.8
Fangchenggang (China)	0.8
Gibraltar	0.14
Jeju Island (South Korea)	1.4
Kaliningrad (Russia)	3.7
Mundra (India)	6.8
Old Harbour (Golar Freeze) (Jamaica)	4.9
Sergie (Golar Nanook) (Brazil)	4.9
Shenzhen Gas (China)	1.1
Summit LNG (Bangladesh)	5.2

Source: BloombergNEF. IGU World LNG Report 2020.

Pipeline developments

There were a number of important gas pipeline developments in 2019, including the commissioning of new pipelines carrying Russian gas to China and Europe, and further takeaway capacity from the U.S. Permian Basin.

Russia commissioned Power of Siberia, its largest pipeline project in the east, in December 2019. The pipeline runs about 3,000km from the Chayandinskoye field in Russia to the Chinese border, and is expected to be a major contributor to China's pipeline gas import growth in the 2020s.

The bulk of new pipeline capacity from Russia to Europe comes from two projects, TurkStream and NordStream 2. TurkStream completed commissioning work in 2019 and started gas supply in January 2020. The pipeline, which runs roughly 930km offshore, connects Russia to Turkey and Europe. NordStream 2 crossed a major hurdle in October 2019 when Denmark approved construction through its national waters. The 1,200 km pipeline, with a capacity of 55 Bcm, will connect Russia to Europe, crossing the Baltic Sea. It is now due to be completed between 4Q 2020 and 1Q 2021. One other important pipeline development in Europe is the Trans Adriatic pipeline (TAP), which will supply Caspian natural gas to Europe and help to diversify Europe's supply options. Commissioning of TAP, which is 878 km long and will have 10 Bcm capacity, began in November 2019 with a target start within 2020.

In the U.S., the Gulf Coast Express began operations, as did the Valley Crossing-Sur the Texas pipeline system. The Sur de Texas pipeline brings U.S. gas across the border to Mexico, in turn displacing LNG imports into the east of the country. The next wave of pipelines to alleviate the Permian basin bottleneck are not expected to enter the market until 2021: the Pecos Trail and Permian Highway projects have delayed their target start dates to 1Q 2021 and mid-2021, respectively.

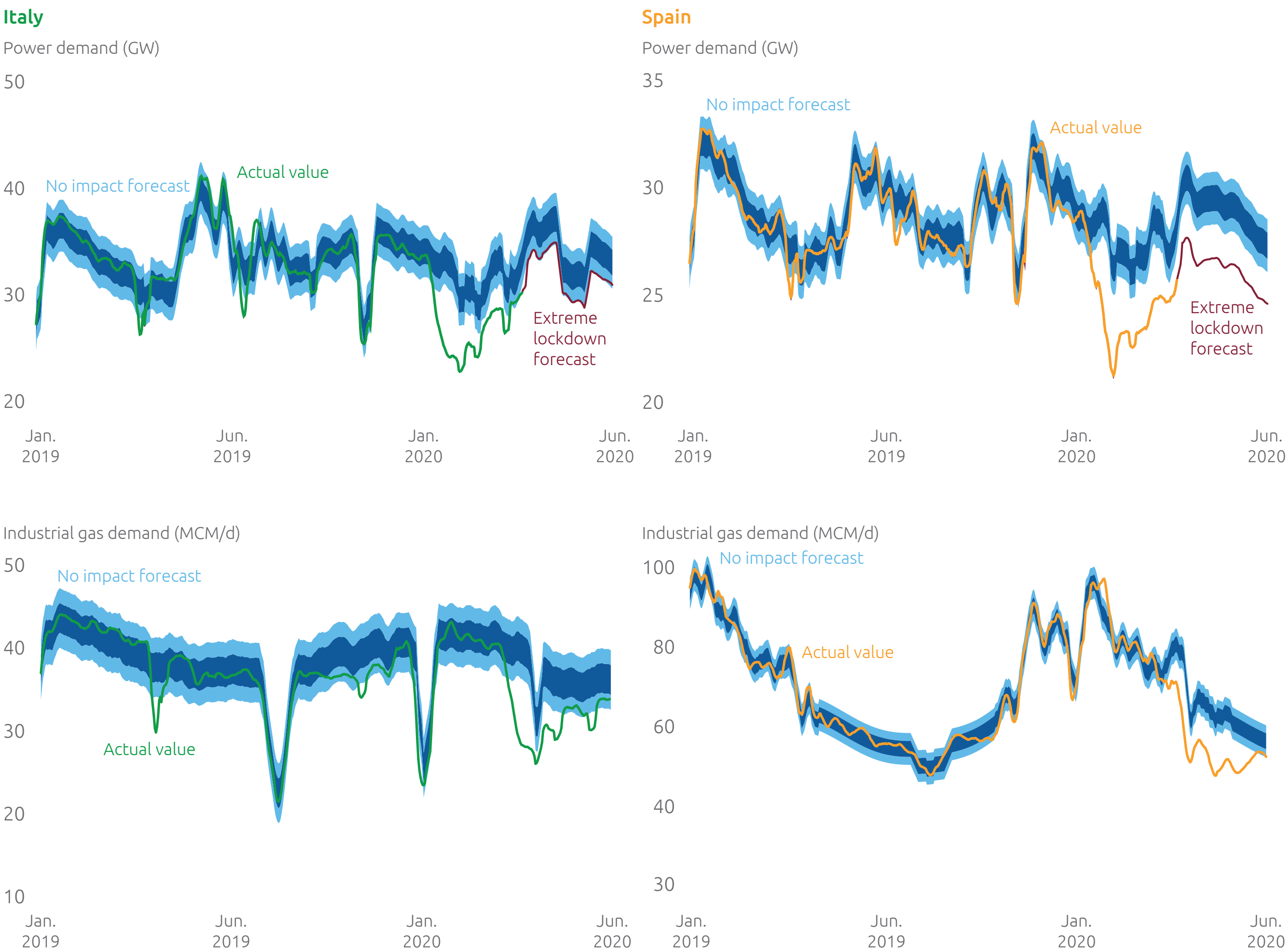
10 LNG import and export project database 1Q2020, BloombergNEF.

The impact of Covid-19

The onset of the Covid-19 pandemic created an unprecedented shock to the global energy system, and gas consumption across the world was significantly impacted. Gas demand declined in the power sector due to lower electricity use, and in the industrial and commercial sector due to shutdowns of factories and businesses. Residential gas demand held firm as people stayed at home.

These impacts varied by region. In Europe, gas demand declined by 7% y/y over the first five months of 2020[11]. In the first quarter, the fall was driven by a mild winter and higher renewable generation. However,

Figure 7: Italy and Spain's power demand and industrial gas demand (average load)



Source: ENTSO-E, TERNA, SNAM, Enagas, BloombergNEF.
Note: "No impact" demand forecasts are based on historical data, temperatures, cyclical factors, and take into consideration weekends and national public holidays, but not the impact of Covid-19. The solid blue series represents a 70% confidence interval, the light blue is 95%.[12] Chart on industrial demand in Spain shows daily pipeline flows that meet industrial and residential/commercial gas demand. In 2017 and 2018, industrial demand accounted for approximately 76% of these pipeline flows.

11 Gas 2020, IEA.

lockdown measures started to impact gas demand from March, and May consumption was 11% lower than March. Gas use in power plants was down by 11% in Italy and Spain in the last week of May, compared to business-as-usual (Figure 7).

Industrial gas demand also declined by 11% in Italy and by 14% in Spain compared to expected demand.

In the U.S., the impact was limited, despite lower economic activity. Consumption fell by 2.8% y/y over January-May 2020[13]. The main effect was on industrial gas demand from March onward due to factory shutdowns. Gas demand in power, on the other hand, went up during this period, due to low gas prices resulting in more coal-to-gas switching. Residential gas demand was also higher.

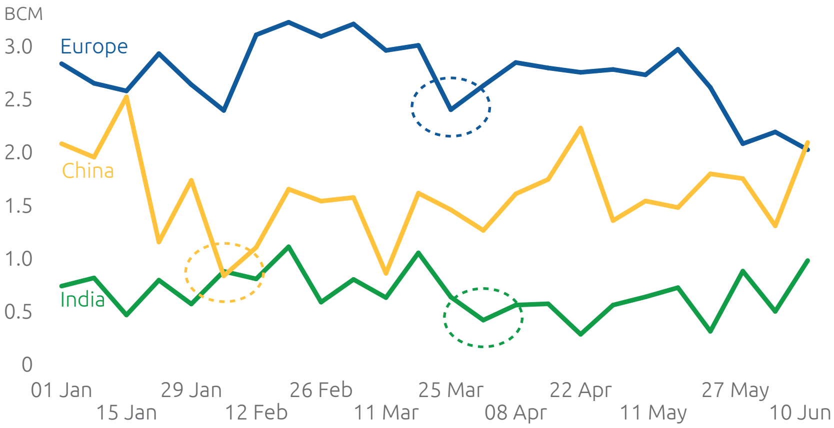
In China, the impact of the virus on gas consumption was largely contained to early 2020. Lockdown measures slowed down demand growth to 1.6% y/y in 1Q 2020 compared to 14% in 1Q 2019. Industries restarted gradually in 2Q 2020, which revived demand growth. April demand was 3.8% higher y/y. China's LNG imports are also recovering (Figure 8), and small LNG buyers are taking the opportunity to buy cheap spot LNG.

In other Asian countries, Covid-19 started to impact gas demand from March onward. Japan's LNG demand fell by 5% y/y over the first five months in 2020 due to various factors, including a mild winter, a lower share of gas in the power sector and Covid-19 impacts. In contrast, South Korea's LNG demand rose by 13% y/y over January-May 2020 despite reduced economic activity – thanks to temporary shutdowns of coal plants to control pollution. In India, gas demand increased by 10% in 1Q 2020, as the country raised LNG imports to take advantage of low spot prices. However, demand was down by 25% y/y in April 2020, mostly in the industrial and transport sectors. Gas consumption recovered in May once businesses reopened after lockdown measures were eased – particularly in the fertilizer sector, which consumes much of the country's imported gas.

Global gas demand could decline by 4% y/y in 2020[14]. This would be the largest-ever recorded decline in gas demand since the development of the gas industry in the second half of the 20th century. To compare, gas demand fell by 2% in 2009 due to the global financial crisis. Around 75% of the demand loss is likely to happen in the developed gas markets across Europe, North America, CIS and Asia due to lower power demand, a fall in industrial activity and lower space heating needs in the commercial sector. Gas demand in power is likely to see the largest drop, with consumption falling by 5% y/y in 2020.

The pandemic's impact on the supply side has been more muted, and preliminary estimates suggest gas production was relatively resilient. In the U.S., gas

Figure 8: Weekly LNG imports into key markets hit by Covid-19



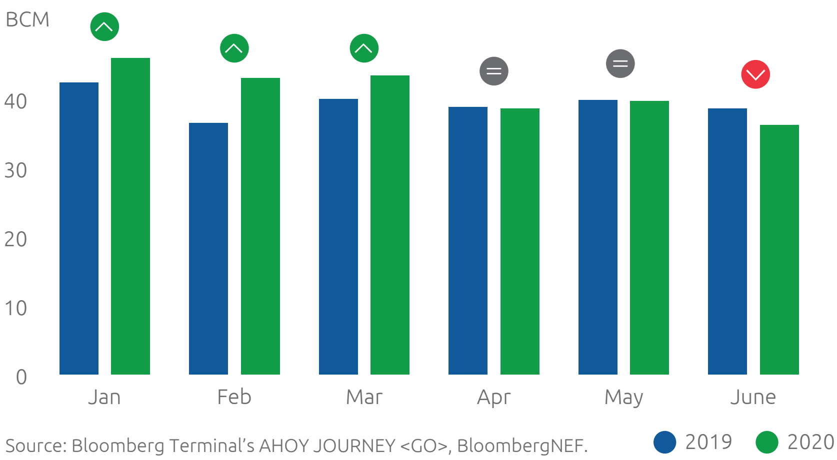
Source: Bloomberg Terminal's AHOY JOURNEY <GO>, BloombergNEF.

12 See Covid-19 Indicator reports at BNEF.com.
13 Gas 2020, IEA.
14 Gas 2020, IEA.

production was actually 5.3% higher in January-May 2020 compared to last year[15]. In China, government estimates show that domestic production went up by 10.4% y/y in 1Q 2020, growing even faster than the same period last year. Russian gas production, however, declined 9% y/y in the first five months of 2020, due to lower pipeline exports to Europe.

Global LNG exports increased by 5.2% y/y in January-June 2020 due to a surge in supplies from the U.S. (Figure 9)[16]. LNG exports from the U.S. were up by 58% y/y in 1H 2020 as production from new projects was ramped up. Supplies from Russian LNG projects were higher by 5.7% and Australian projects exported 5.3% more LNG over January-June 2020.

Figure 9: Global monthly LNG imports in 2020 versus 2019



Source: Bloomberg Terminal's AHOY JOURNEY <GO>, BloombergNEF.

15 Gas 2020, IEA.
16 BloombergNEF.

Cost-competitiveness

Gas continues to demonstrate its cost-competitiveness in the global energy landscape, and events of the last 12 months have served to make gas even more affordable.

Spot market development and historic low prices

Commodity price benchmarks have taken a big hit this year in the fallout of Covid-19 (Figure 10). But even before this, gas prices had started to drop on an LNG supply surge and lower demand. Asia's spot LNG benchmark price, the Japan-Korea marker (JKM), fell to a record low - from an average $5.6/MMBtu in 2019 to $2.1/MMBtu in May 2020. Contracted LNG, most of which is linked to oil prices such as Brent (shown by 13% slope/multiplier to Brent in Figure 10), averaged around $8.3/MMBtu in 2019 and fell to $4.2/MMBtu in May 2020, as oil prices collapsed due to unprecedented demand loss brought on by the pandemic.

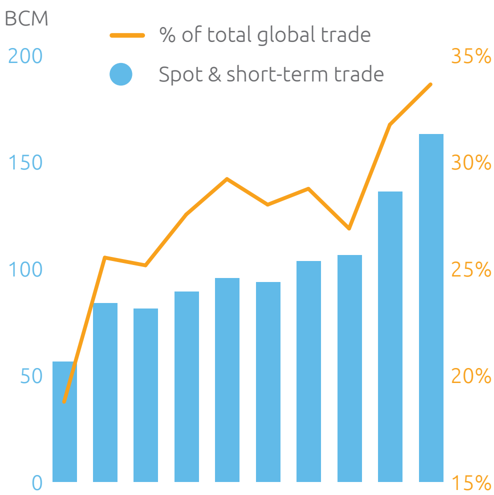
By late April 2020, global gas markets had entered uncharted territory, with the U.S. Henry Hub gas price benchmark surpassing Europe's Title Transfer Facility (TTF) index – Henry Hub averaged $1.8/MMBtu in May 2020 and TTF trading at an average of $1.7/MMBtu over the same period.

On the upside, the new low gas prices have bolstered the competitive position of gas, and unlocked purchasing potential by more price-sensitive LNG buyers, such as those in India. Again, this has been happening since before the pandemic. Global spot volume, defined as cargoes delivered within 90 days of transaction date, rose to 27% of total LNG trade in 2019 compared to 25% in 2018[17]. Total spot and short-term volume, defined as cargoes delivered under a four-year contract or less, reached 34% last year, compared to 32% in 2018 (Figure 11).

Figure 10: Futures prices

Source: ICE, CME - via Bloomberg Terminal.

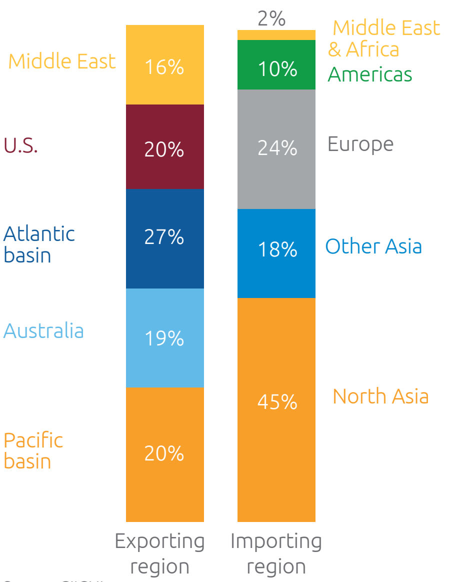
Figure 11: Futures prices



Source: GIIGNL.
Note: GIIGNL classifies short-term trade as contract under four-year tenure.

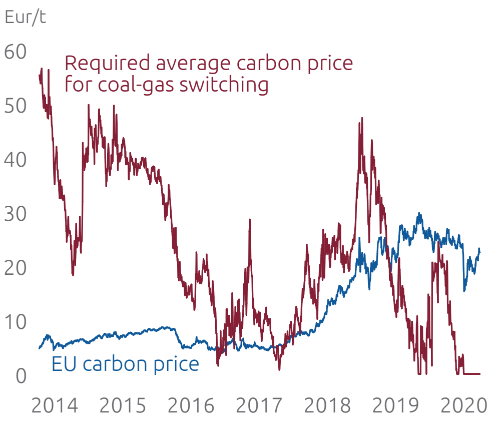
17 Annual Report 2020, GIIGNL.

Figure 12: Spot LNG activity in 2019



Source: GIIGNL.

Figure 13: EU carbon allowance price



Source: BloombergNEF.

Much of the spot supply came from the U.S., a function of the free-destination characteristic of its volume making it more flexible (Figure 12)[18].

Coal-to-gas switching unlocked

With these dynamics at play, Europe was able to absorb a record amount of LNG in 2019 – partially due to the potential for coal-to-gas switching in the power sector. Low gas prices continue to make gas-fired generation directly competitive with coal, but this potential varies by market – and carbon prices have played a big role in Europe. In contrast, current market structures limit the ability to take advantage of lower prices and increase coal-to-gas switching in markets like Japan and South Korea.

The role of carbon pricing

The number of countries where carbon pricing is either implemented or scheduled for implementation, including both as emissions trading systems (ETS) and carbon taxes, increased to 57 in 2019 from 51 in 2018[19]. A number of new carbon price initiatives were taken in 2019, particularly in the Americas. Singapore and South Africa also announced new carbon tax regimes last year.

While a positive development, this level of activity is still much lower than necessary to support the emissions reductions and fuel switching needed for a trajectory consistent with the Paris Agreement. For example, an economic case for gas technologies deployment to reduce energy sector emissions by a third would require a global social cost of carbon to be around $125 per ton[20].

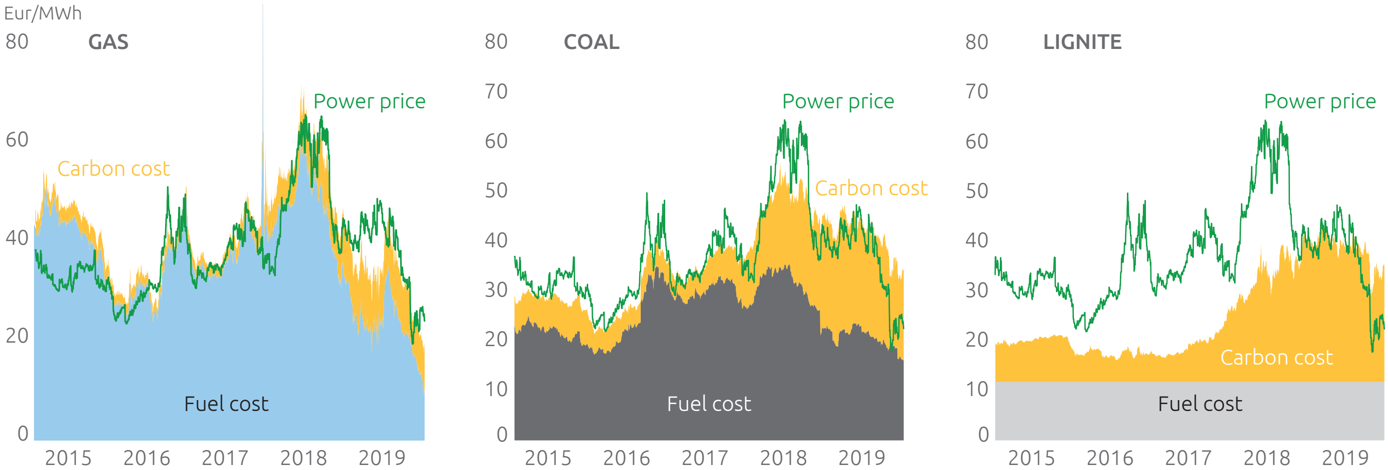
Potential for fuel-switching in Europe

In Europe, the ETS is instrumental in reducing power sector emissions by making coal generation less attractive than other sources of power generation, including gas. The combination of low gas prices and relatively high carbon prices has given gas an economic advantage (Figure 14). The prevailing EU Carbon Allowances (EUA) price was above the required average carbon price for coal-to-gas switching in North West Europe for most of 2019, resulting in higher gas generation at the expense of coal (Figure 13). This dynamic has been threatened by the onset of the Covid-19 pandemic, which caused carbon prices to fall, but they have since rebounded. Continued momentum for coal-to-gas switching will rely on carbon prices holding up in the coming years.

In addition, the EU Green Deal sets very ambitious targets for the achievement of a carbon-neutral economy by 2050 in Europe. In the medium term, there is potential for emissions reduction by further coal-to-gas switching, for example in Central and Eastern European (CEE) and Southeastern European (SEE) countries that are still highly dependent on lignite coal. This is a major emission-reduction opportunity. However, in Poland, one of the EU's largest coal-fired power producers, the limited installed capacity of the existing gas fleet significantly curbs the coal-to-gas switching potential. BNEF's recent analysis on transitions away from coal in Poland, Czechia, Bulgaria and Romania finds that a combination of coal-to-gas switching and renewables build could economically cut power-sector

18 LNG contracts in general are becoming more flexible and shorter in tenure, fostering growth of the spot market. Though long-term contracts will not go away as they provide supply security for base-load buyers, the increasing adoption of liquid spot price indexation in contracts is further commoditizing the LNG sector.
19 State and Trends of Carbon Pricing 2019, World Bank.
20 Gas Technology and Innovation for a Sustainable Future 2020, IGU.

14: Short-run marginal cost for different power plants in Germany and power price



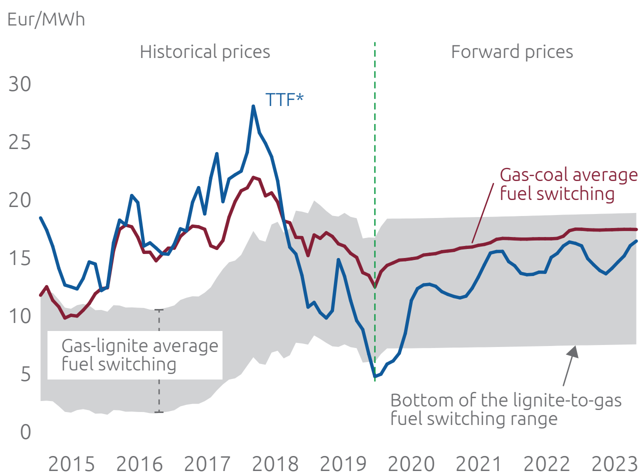
Source: BloombergNEF.
Note: Assumes a 49% gas plant efficiency, 39% coal plant efficiency, 36.5% lignite plant efficiency, 0.14334 metric ton of coal per MWh and a lignite production cost of 4 Eur/MWh. Power price is baseload month-ahead.

emissions in these four countries by 48% by 2030. This would require significant, but cost-effective, investment in both renewables and gas infrastructure.

More needs to be done to increase the coverage and effectiveness of carbon price schemes around the world. Carbon price schemes, including those scheduled for implementation, covered only 20% of global GHG emissions in 2019[21]. Besides this, very few schemes – less than 5% – are priced at a level that could reduce emissions in line with the goals of the Paris Agreement.

Elsewhere in the world, Covid-19 could push back the start of carbon-market schemes. For example, implementation of a national ETS in China might be delayed from its initial target of 2020, as the companies in the industrial sector are not able to calculate and report emissions data due to the lockdown in early 2020. This data is needed to prepare for the launch of ETS market.

Figure 15: Northwest Europe lignite/coal-to-gas fuel switching range



Source: BloombergNEF.
Note: *TTF is the Dutch gas price, the benchmark price for northwest Europe. [21]

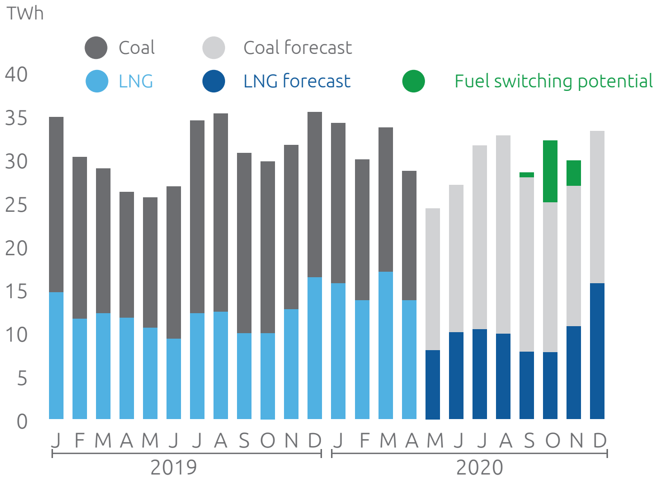
21 State and Trends of Carbon Pricing 2019, World Bank.

South Korea coal-to-gas switching possibility

Coal-to-gas switching in South Korea has long been considered highly challenging, as coal power generation was historically more economical than gas. This was due to the high cost of LNG imports, and despite a higher fuel tax for coal as compared to LNG. However, in April 2019, as part of its new environmental and clean air policy, the government moved to reduce the LNG fuel tax from 91.4 won/kg to 23 won/kg whereas the coal fuel tax was raised from 36 won/kg to 46 won/kg. This had a positive impact on the competitiveness of gas versus coal.

Supporting the competitiveness trend, came the sharp drop in oil prices, and hence oil-indexed LNG prices (Figure 16). Its LNG imports in 4Q 2020 may increase by as much as 1.88 Bcm (an additional 12% than the initially estimated), if the low oil price levels persist. This is a prominent example of government policy helping fuel-switching from coal to gas to achieve better air quality and emissions reductions, as we discuss in the next section.

16: South Korean coal and LNG generation with potential fuel-switching in 2020



Source: Korea Power Exchange, Kepco, BloombergNEF.
Note: Months from December to March assume fine dust policy takes place, replicating shutdowns seen in Dec. 2019-March 2020.

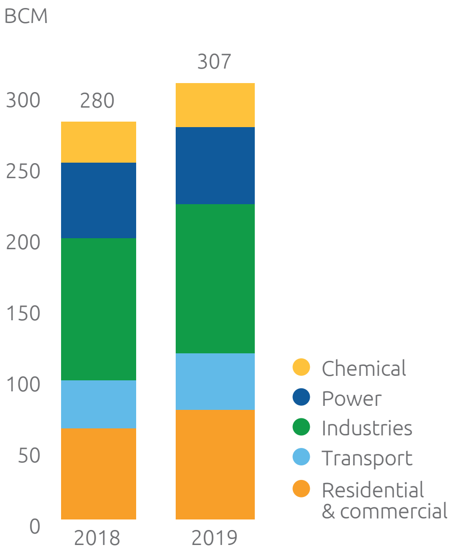
22 Explore more with BNEF's EU Lignite-to-Gas Switching Calculator – via BNEF.com.

Sustainability

Support for natural gas as part of the global energy transition stems from its cleaner emissions profile than other hydrocarbon fuels – namely coal and oil. Countries and international organizations adopting and advocating gas as a primary energy source have done so in large part because of the benefits for air quality and carbon emissions. As discussed in the previous section, where gas displaces coal it can lead to a net reduction in emissions. Moreover, with growing concerns about respiratory conditions, exacerbated by the new threat of Covid-19, there is renewed emphasis on the detrimental impact air pollution has on human health. This could prove to be a driver for faster switching away from more polluting fuels such as coal in favor of gas and renewables.

China's clean air push drives coal-to-gas switching

Figure 17: China's gas demand by sector



Source: NDRC, CNPC, Chongqing Petroleum & Gas Exchange, BloombergNEF.

China continues to push for clean air with policy support. The country's Blue Sky Initiative committed that by 2020, the total annual emissions of sulfur dioxide and nitrogen oxides would need to be down by more than 15% from the 2015 baseline. The initiative substantially promotes clean heating in the northern region, controls total coal consumption in key regions, and conducts integrated management of coal-fired boilers. The policy also supports raising energy efficiency and accelerating the development of clean energy. China's coal-to-gas switching has been directed mainly at the industrial sector and residential heating, and will continue to be. The country's gas demand (Figure 17) will rise with economic growth and industrial demand, adhering to strict environmental standards. City gas network expansions and the need for peaking power gas facilities to integrate renewables in the power sector will keep China's gas demand on a steady upward trajectory.

Some of the main components of air pollution

- PARTICULATE MATTER (PM)
- SULFUR DIOXIDE (SO_2)
- NITROGEN DIOXIDE (NO_2)

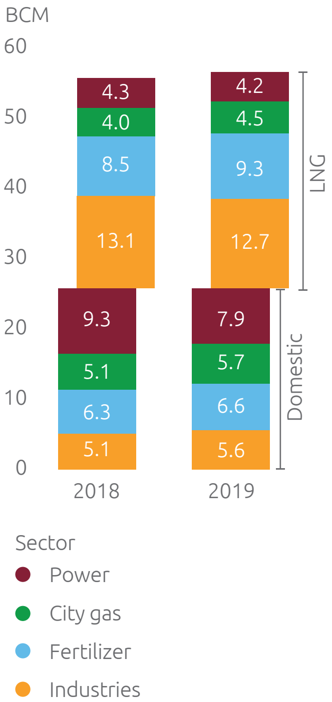
India's fight against pollution

Extremely poor air quality has consumed many cities in India, especially the capital New Delhi. A shift toward gas has turned India into one of the largest LNG growth markets as it combats pollution.

- **Gas in industry:** In 2017, the Supreme Court of India put a ban on the use of fuel oil and petroleum coke in Delhi and its surrounding states to combat high levels of pollution. This contributed to an increase in gas use in these regions. Then in 2018, the country banned petcoke imports for fuel use. Despite these measures, in November 2019, Delhi's local government was forced to announce a public health emergency due to poor air quality. Now, more states are considering banning fuel oil. Industry is India's largest gas-consuming sector (Figure 18).

- **Gas in transport:** The first big push for natural gas in transport came from a 1998 Supreme Court order that mandated all buses and pre-1990 registered three-wheelers and taxis in Delhi to convert to natural gas by 2001. In 2002-03, another 14 polluted cities were advised by the Supreme Court to switch

Figure 18: India's gas consumption by sector and by gas source



Source: Petroleum Planning and Analysis Cell.

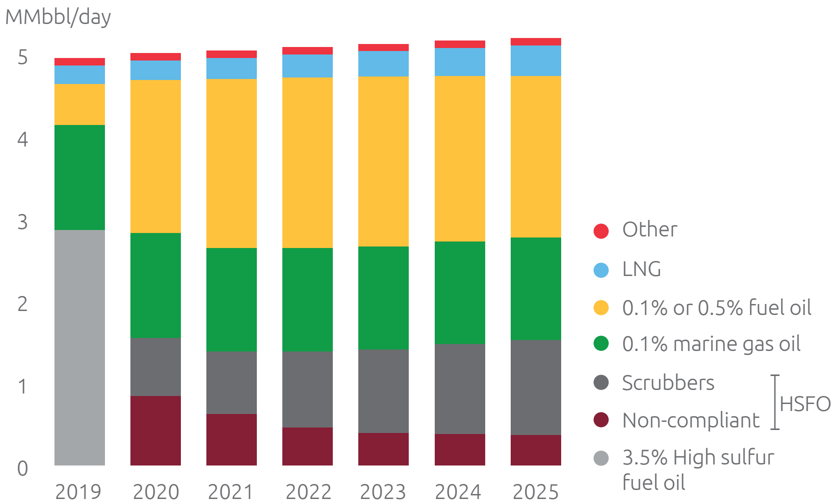
to clean transport fuels. A 2007 study[23] shows that conversion of buses from diesel to natural gas in Delhi resulted in lower concentration of PM10, SO2 and CO. More mandates were released in Delhi in 2015-16, including a short-lived ban on the sale of large diesel cars, removing diesel vehicles older than 10 years and a mandatory conversion of the capital's taxi fleet to gas.

LNG bunkering and IMO 2020

The International Maritime Organization (IMO) regulates the marine sector, and starting from 2020 has put a new pollution regulation into effect, which limits the sulfur content of marine fuels from the previously allowed 3.5% to 0.5%. This is one of the most significant shifts in marine fuel standards ever undertaken at a global scale, and is causing disruptions to oil refiners, ports and vessel operators. The push has, however, put LNG bunkering in the spotlight. LNG emits 1,000 times less SOx emissions than the IMO 0.5% limit and produces significantly lower NOx and particulate matter than heavy fuel oil[24].

Currently, LNG is only used as a marine fuel in a limited number of vessels – mainly passenger ferries and cruise ships that spend a lot of time in ports and coastal waters, as well as LNG tankers themselves utilizing boil-off gas. Usage is, however, set to rise gradually as ship owners look to gas as a lower-cost means of compliance with sulfur caps (compared with other low-sulfur oil distillates fuels such as marine gas oil) and as a prudent way to prepare for possible future regulations on greenhouse gas emissions (Figure 19).

Figure 19: Marine bunker demand outlook, 2019-25



Source: BloomberNEF.

Ships cannot easily be retrofitted to burn LNG, so many new ones are currently being constructed. Even LNG-fueled very large crude carriers (VLCCs) are on order.

China has decided to follow the IMO standards on low-sulfur marine fuel. The ban on dirty fuels and open-loop scrubbers (a device to remove emissions and directly discharge waste into the water) from 2020 will lead to marine fuel-switching and make LNG an attractive option for vessels sailing in Chinese waters. Only IMO-compliant fuels (0.5% sulfur limit) are allowed in China from 2020, with even stricter limits (0.1%) in the Yangtze River, Xijiang River and Hainan region. Compliance also requires shippers to either install hybrid/closed-loop scrubbers, which require more deck space and additional costs to remove waste, or switch

23 The Impact of Delhi's CNG Program on Air Quality, 2007, Resources For The Future.
24 Methanol as a Marine Fuel Report, Methanol Institute.

to low-sulfur marine fuel, which could be more expensive. Three LNG bunkering stations currently operate in China to serve more than 200 LNG-fueled ships. China announced plans to build as many as 74 such stations along key waterways by 2025.

In Europe, ship traffic to or from ports in the European Economic Area account for some 11% of CO_2 emissions from transport and 3-4% of total EU CO_2 emissions [25].

Marine LNG can facilitate long-term environmental objectives, by providing sustainable fuel transition for the maritime industry. LNG refueling points (small-scale LNG infrastructure) for bunkering are expanding across the EU; bunkering installations increased from 113 in 2018 to 131 in 2019, and LNG-fueled ships rose from 96 in 2016, to 175 in 2019, with 203 more ships expected by 2026 [26].

Case Studies in Improving Urban Air Quality – IGU Clean Air report series (2019)

Morbi, India: The city in Gujarat achieved a dramatic reduction in air pollution and environmental contamination when its ceramic industry switched from using coal to natural gas after March 2019. Access to the gas distribution network made the shift possible. Regulatory oversight and legal follow-through were also key to obtaining positive results. By August 2019, PM2.5, PM10 and $S0_2$ concentration was down by 75%, 72% and 85%, respectively, as compared to 2017.

London, U.K.: Following the country's 1950s Clean Air Act, policy action to regulate industrial and domestic pollution played a critical role in improving London's air quality. Switching from coal to gas, first in households followed by the power sector, lowered CO_2 emissions. Carbon prices were an effective policy tool delivered on both climate and clean air targets.

Urumqi, China: The capital city in gas-rich Northeast China started a major transformation of its energy sector in 2012 by replacing coal-fired heating with gas. By 2014, gas had replaced coal as the primary heating fuel and great great improvement was observed in air quality. Monthly PM2.5 concentrations declined by 75% and SO_2 levels were down by 50% in 2014 as compared to 2012. This translated into a 73% reduction in pollution related lung cancer.

Toronto, Canada: Toronto saw big improvements in air quality due to coal phase-out from Ontario's power sector. Coal generation accounted for about 25% of Ontario's power supply in 2000 and was replaced by nuclear, natural gas and renewables by 2014. PM10, SO2 and NO2 emissions from the power generation fell by 90%, 91% and 65%, respectively, in 2013 as compared to 2004.

See the full report on IGU's website (Morbi and London, Urumqi, Toronto).

25 Small Scale LNG Map, Gas Infrastructure Europe.
26 CO_2 emissions from shipping – encouraging the use of low-carbon fuels, European Commission.

Methane emissions: an industry view

The Natural gas consists mainly of methane, a potent greenhouse gas. The industry continues to prioritize management and mitigation of any losses along its production and delivery value chain. This is a key factor to support the part gas plays in the energy transition.

Natural gas combustion is highly efficient; however, small amounts of methane emissions can occur earlier in the value chain during its extraction, production, transport and distribution. These are reflected in the natural gas CO_2 emissions factor or its GHG footprint. Mitigating and eliminating methane emissions from the natural gas value chain provides an opportunity to further enhance the sustainability value of gas.

There is a long history of industry efforts to minimize methane emissions across its value chains, originating in routine safety requirements and operational efficiency improvements. More recently, the gas industry began to strengthen further its work in this area, with the intent of accelerating its environmental goals. Several large industry participants have also announced voluntary methane emissions reduction targets.

The IGU began engaging on the topic in 2016 when it instituted its Global Group of Experts on Methane Emissions consisting of international industry experts, across the entire value chain. The purpose is to enhance the level of knowledge and communication within and outside the industry, supporting informed discussions about this critically important and technically complex topic.

As a supporting organization to the Methane Guiding Principles, and a dedicated advocate for accelerating the global reduction of methane emissions, the IGU encourages the industry to continue to act on the methane emissions opportunity through consistent assessment, reporting and mitigation.

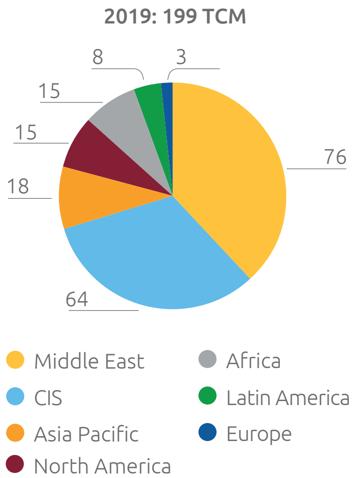
The science behind more granular understanding, detection, quantification and abatement of methane emissions is relatively new, but it has been rapidly evolving with governments and industry placing priority on this area. Importantly, there has been significant innovation activity, with a variety of promising technologies under development to aid in these efforts and bring down the cost of reduction efforts.

It is important to recognize that the current low price environment will put significant pressure on abatement economics. As governments are considering stimulus spending allocation, this is a very important area of opportunity, where it can both support jobs and enhance the environment. Investments to support technology commercialization and deployment should also be included.

Security of supply

In the last year, expanding LNG export capacity and new reserve discoveries have added to the diversity, flexibility and overall security of global gas supply.

Figure 20: Natural gas proved reserves



Source: BP Statistical Review of World Energy 2020.

Major gas discoveries support LNG and domestic demand

Total proved gas reserves are estimated to be around 199Tcm in 2019, up by 0.9% from 2018 (Figure 20)[27]. The center of gravity lies in the Middle East and CIS regions, which together account for 70% of global gas reserves – led by Iran and Qatar in the Middle East, and Russia and Turkmenistan in the CIS region. Gas reserves in Asia Pacific, which account for 9% of the global total, are more distributed across countries, including China, Indonesia, Malaysia and Australia. North America holds 7.6% of total gas reserves, dominated by the U.S. Algeria and Nigeria hold most of the African share, which accounts for 7.5% of global reserves. Venezuela tops Latin America's gas reserves, and Europe has the smallest share globally.

Gas discoveries in 2019 were skewed toward major gas finds across Russia, Africa and Asia Pacific (Figure 21). In Russia's Kara Sea, the Dinkov and Nyarmeyskoye finds boost the country's ambitions to lead the way on gas exports. The Orca Gas discovery in Mauritania further supports a potential LNG production hub at BirAllah, alongside the currently planned Greater Tortue Ahmeyin project. Another Yakaar-Teranga development off Senegal is also planned after successful exploration results. Following the major Calypso gas discovery

Figure 21: Major gas discoveries in 2019

Source: BloombergNEF, press releases.

27 BP Statistical Review of World Energy 2020.

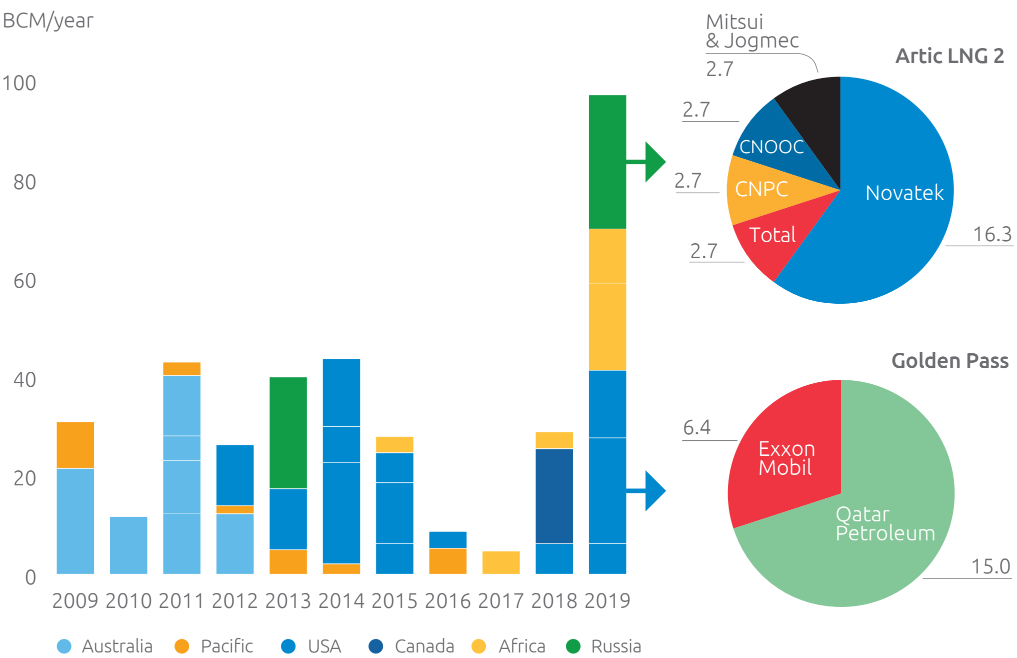
off Cyprus in 2018, the Glaucus field is another boost to the East Mediterranean gas bonanza. Further appraisal drilling at Glaucus has been pushed back amid Covid-19 concerns. In mature Southeast Asian basins, the Lang Lebah and Kali Berau Dalam discoveries were announced in Malaysia and Indonesia. One will support existing LNG exports whereas the other will cater to domestic gas demand.

So far in 2020, the United Arab Emirates announced the major Jebel Ali gas discovery, with approximately 2.3 Tcm of gas. This is a game-changer for the region. The country currently imports pipeline gas from Qatar and the new reserves could put the U.A.E. ahead of Saudi Arabian gas reserves – after Qatar and Iran. The gas would support ongoing exports from the LNG plant on Das Island and curb the long-term need for LNG imports into Dubai. The country was already on track to develop sour gas fields to meet growing domestic gas demand.

A record-breaking wave of new LNG supply project approvals

After a lull in LNG project final investment decisions in 2017, major LNG proposals started to take off after the approval of LNG Canada in October 2018. Last year saw a record number of projects sanctioned, spanning the U.S., Africa and Russia (Figure 22). Six projects, a mix of brownfield and greenfield developments, comprise approximately 97 billion cubic meters per year of new LNG capacity. The largest projects are the Arctic LNG 2 project in Russia, Golden Pass LNG in Texas, U.S., and Mozambique LNG. Two of the above, and the Nigerian LNG expansion, were approved without underlying sales and purchase agreements, relying on equity offtake by the project investors. Mozambique LNG, Calcasieu Pass LNG and the expansion at Sabine Pass LNG were supported by numerous sales agreements. Calcasieu Pass LNG will be the first major U.S. LNG project to adopt a mid-scale modular construction approach, while Arctic LNG 2 is pioneering the use of gravity-based structures to support the LNG production trains.

Figure 22: LNG project final investment decisions by capacity – including equity offtake



Source: BloombergNEF, IGU World LNG Report 2020.
Note: Pacific includes Papua New Guinea, Malaysia and Indonesia. Africa includes Cameroon, Mozambique, Mauritania/Senegal. Equity offtake figures are rounded.

LNG imports provide supply security when domestic production is falling

The growth of the global LNG market is easing the path for countries that are facing declining domestic production.

Europe's domestic gas production peaked in 2004 and continues to fall (Figure 23). U.K. North Sea production and supply from the Netherlands are expected to end by 2040. In addition, the Dutch government is mandating a phase-out of the giant Groningen gas field at a faster rate than previously announced because of earthquake risks. Norway is the dominant European producer and it will remain so into 2030, with the Troll field its single largest source. Europe's decline in domestic production is being offset by rising LNG and pipeline imports.

Southeast Asia is turning to LNG to fill a gap left by declining or slow growth in domestic production (Figure 24). Major producing gas fields in Thailand, Philippines and Myanmar are depleting. In the case of the Philippines, gas comes from a single source – the Malampaya field – and its rate of decline will dictate the country's growth in LNG needs. Indonesia and Malaysia, the two largest gas producers and LNG exporters in Southeast Asia, will avoid a net-import situation until at least 2040 even though domestic gas demand is rising. In Vietnam, indigenous production is growing at a slower pace than gas demand. Similarly, India's LNG imports are set to rise as growth in domestic gas production is outpaced by demand.

Figure 23: Europe gas production

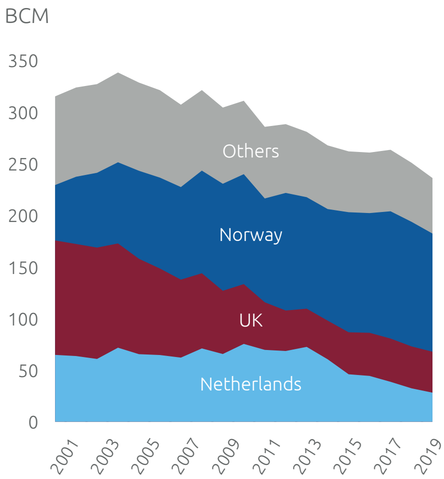
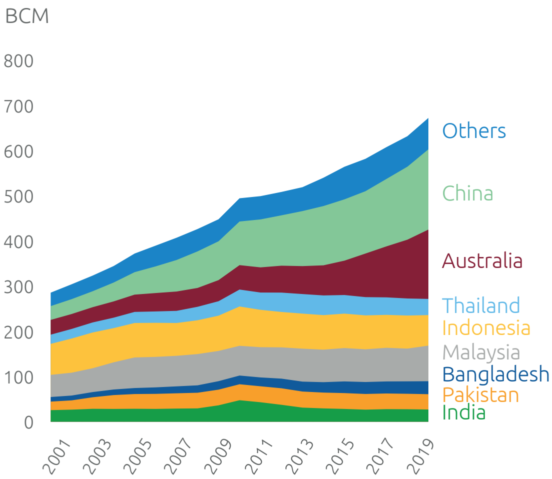


Figure 24: Asia Pacific gas production



Source: BP Statistical Review.

2 / Looking ahead

Highlights

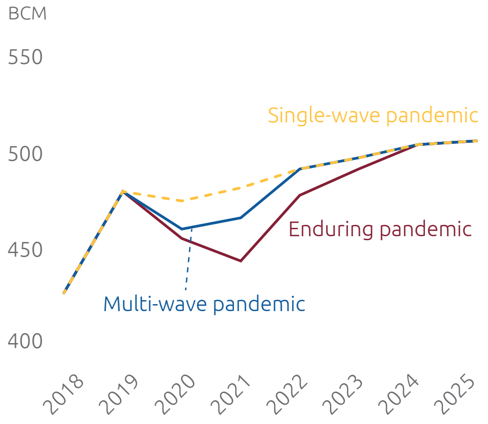
Natural gas demand is projected to fall 4% in 2020 due to Covid-19

- Cost-competitiveness, enabling policy and the speed of infrastructure build-out in emerging markets will drive the recovery in natural gas demand after the Covid-19 pandemic.
- In the longer term, the industrial sector is expected to gain in prominence in the gas industry, as switching from alternatives like coal, fuel oil and diesel supports consumption growth. In the power sector, gas demand can also continue to grow as gas displaces coal and complements renewables. Gas demand in transport could rise as uptake of LNG increases in heavy-duty vehicles and the shipping sector. However, gas demand in the buildings sector is likely to remain relatively flat. In terms of regions, Asia Pacific is likely to be the largest growth center.
- Ample natural gas resources exist to support demand growth, but more investment in infrastructure, including transmission and distribution networks and storage, as well as new technologies and innovation, will be required to bring it to consumers.
- The establishment of trading hubs and financial derivatives will contribute to enhanced competitiveness and liquidity in the market via transparent price discovery and risk management.

The post-pandemic recovery

Global natural gas demand will see a major dip in 2020, falling 4% from last year, according to recent IEA projections. However, this is a temporary condition brought on by the global lockdown measures. Demand is expected to recover to pre-pandemic levels in 2021 in mature markets, and sees additional growth in emerging markets as the low price environment spurs consumption. Still, the impact of Covid-19 on the global economy will reverberate for some time. This will result in average natural gas demand growth of 1.5% per annum from 2019 to 2025, according to the IEA. This is positive, but lower than the agency's pre-Covid-19 forecast of 1.8% average annual growth for the same period[28].

Figure 25: Global LNG demand under different Covid-19 pandemic scenarios



Source: BloombergNEF.

Similarly, global LNG demand could fall 4.2% in 2020 in a multi-wave pandemic scenario, according to BloombergNEF analysis [29](Figure 25), before recovering in 2021. The market is expected to begin re-balancing as producers curb supply and the pandemic delays commissioning of new LNG projects. An enduring pandemic scenario, where the pandemic stretches well into 2021, would have knock-on implications for critical gas infrastructure build-out in emerging Asia – creating bottlenecks for gas demand growth. That may have larger implications on demand recovery post-2021.

Looking to the future, China, India and other emerging markets are expected to increase LNG imports, as LNG prices remain low, supporting coal-to-gas switching.

China's and India's immediate plans for recovery will shape global gas demand projections in the near term. Both countries are set to continue supporting natural gas adoption in the energy mix via clean-air and environmental policies and regulations. The rate of demand growth, however, will be closely linked to post-pandemic economic performance, which impacts both domestic and export markets for industrial goods. Should the respective governments choose to stimulate economic growth by loosening environmental constraints, it would create headwinds for the role of natural gas in the recovery.

Overall, expectations are for a rebound in gas market growth – but there are risks to this outlook. The oil price collapse in 1Q 2020, while supporting the competitive economics of gas, could spell uncertainty for future investments in the energy sector, particularly upstream oil and gas development. The growth in global gas supply hinges on shale production from the U.S., which could be challenged under an outlook of prolonged low oil prices. Similarly, there are downside supply risks for a ramp-up in conventional natural gas production across the Middle East and Russia, if the oil price slump persists for longer. A lack of domestic gas production growth in some countries could put rising consumption in certain end-use sectors at risk – such as power generation in India and industries in the U.S., Middle East and Eurasia[30]

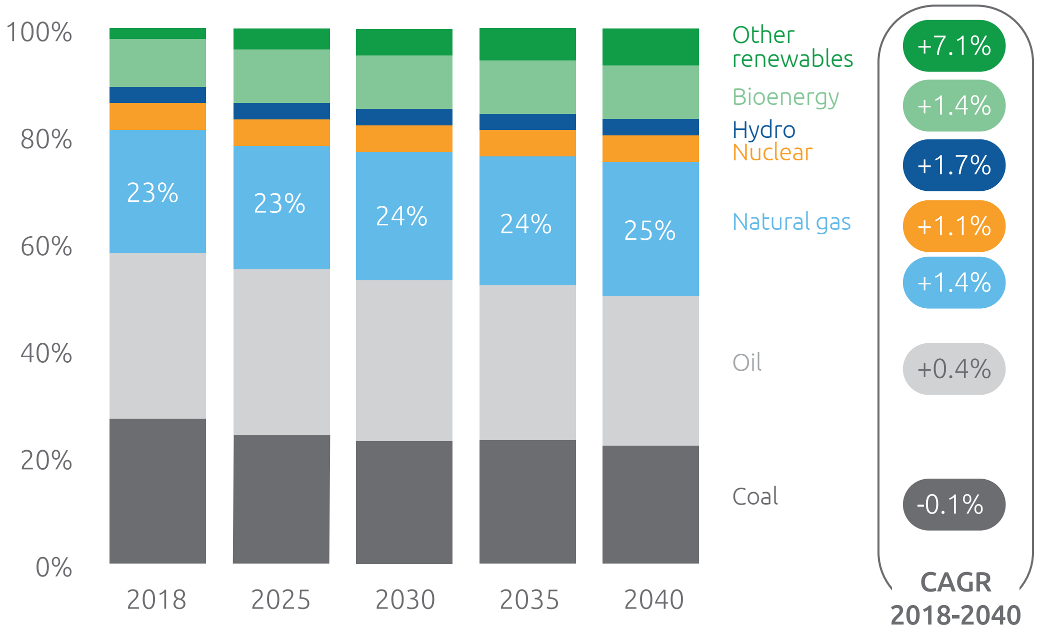
28 IEA's 'Gas 2020' publication
29 BloombergNEF pandemic scenario: in single-wave pandemic impact of Covid-19 is largely contained in 1H 2020, in multi-wave outbreaks is controlled in early 2021, in enduring pandemic repeated waves of coronavirus outbreaks occur across countries and suppression measures are required into 2021.
30 Eurasia includes Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, the Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

The role of natural gas in the future energy mix

Natural gas to reach 25% of global energy demand in 2040, overtaking oil

Gas demand is expected to see an average annual growth rate of 1.4% from 2018 to 2040 – according to the IEA's World Energy Outlook, Stated Policies Scenario. With a transition in global energy consumption patterns, the share of natural gas in the energy mix grows from 23% to 25% over the period, amounting to 5.2 trillion cubic meters in 2040. By then, natural gas is expected to overtake coal as the world's second-largest energy source (Figure 26).

Figure 26: Total primary energy demand outlook



Source: IEA (World Energy Outlook 2019, Stated Policies Scenario), BloombergNEF analysis.

Industry and the power sector are together expected to account for 61% of the incremental gas consumption by 2040 (Figure 27). Asia Pacific (including China) will provide 48% of the global demand increase, followed by the Middle East, North America and Africa.

Figure 27: Net additional gas consumption (2018-2040, billion cubic meters per year)

REGIONS	INDUSTRY	POWER	BUILDINGS	OTHER*	TOTAL
China	131	112	58	10	312 (23%)
Asia Pacific	183	57	27	65	333 (25%)
Middle East	74	70	73	53	270 (20%)
North America	29	36	-21	106	151 (11%)
Africa	35	49	35	33	151 (11%)
Latin America	40	18	7	17	83 (6%)
Eurasia	7	12	5	48	72 (5%)
Europe	-14	-19	-46	-8	-88 (-7%)
Global Bunkers				50	50 (4%)
Total	**485 (36%)**	**337 (25%)**	**138 (10%)**	**375 (28%)**	**1,334**

Source: IEA (World Energy Outlook 2019, Stated Policies Scenario), BloombergNEF analysis.
* "Other" includes transport sector and other final consumption sectors. Figures and percentages are rounded. Conversion factor of 1.163 used to convert Mtoe to BCM

However, the Stated Policies Scenario, while reflective of today's level of policy ambition, is not consistent with the Paris Agreement target of keeping global warming to well below two degrees.

When considering Paris-consistent trajectories, there are a variety of analyses that provide for different views of the gas sector. In the IEA's latest Sustainable Development Scenario, intended to show a trajectory towards 1.5 degrees of warming, global gas consumption rises by 0.9% per year to the end of the 2020s, before starting to decline as low-carbon alternatives such as renewables, hydrogen and biomethane scale up.

In a recent joint IGU and BCG analysis of the potential for gas technologies and innovation, accelerated fuel-switching in the short-term, and low-carbon gas technologies in the medium and long-term, were shown to be able to deliver direct emissions reductions of 12Gt, or a third of energy sector emissions by 2040. This would grow the global gas market by as much as two and a half times by 2040[31].

This divergence in outlooks highlights the importance of actions taken by the industry and governments to capitalize on new opportunities and mitigate risks for the global gas sector in the coming decades. In particular, early action will be critical to enable scaling up of low-carbon gas technologies. This topic is discussed in more detail in the final section of this report. The remainder of this section relies mainly on data from the Stated Policies Scenario to provide a baseline for growth expectations in the global gas sector.

Industrial natural gas demand to grow 2.3% a year to 2040

31 Gas Technology and Innovation for a Sustainable Future 2020, IGU

Demand: Gas demand and infrastructure outlook

Sectoral growth outlook

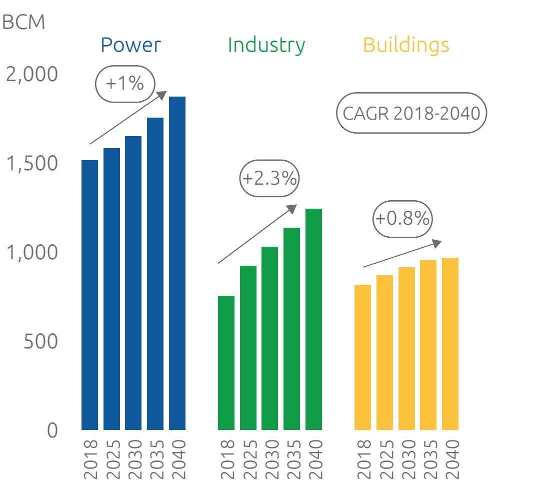
Natural gas demand in the industrial sector is projected to grow at an average 2.3% from 2018 to 2040 (Figure 28) – driven by emerging Asian markets – making the industrial sector the biggest driver of gas demand growth.

The demand for gas as a fuel for industrial processes will grow most in Asia, while demand for natural gas as a feedstock – such as in petrochemicals – will come from the U.S., Russia, the Middle East and other major gas producing regions. Fertilizers, in particular, represent a large growth opportunity, concentrated in South Asia (India, Pakistan and Bangladesh). In the U.S., industrial gas demand growth is driven by competitive prices for natural gas, enabling its use as methanol feedstock. Eurasia's industrial gas demand is also benefiting from low prices – the sector will account for half of incremental gas demand over the next five years.

Natural gas consumption in the power sector continues to see growth. However, the power sector's share in natural gas demand is projected to decrease from 24% in 2018 to 22% in 2040 (Figure 29). Gas demand for power generation is expected to see an average growth rate of 1% a year to 2040, according to the IEA's Stated Policies Scenario, lower than the 2.6% seen in the previous decade[32]. Natural gas demand in the power sector for mature markets, such as Europe, sees limited growth as renewable electricity gains ground, in particular over coal – in terms of both costs and policy support.

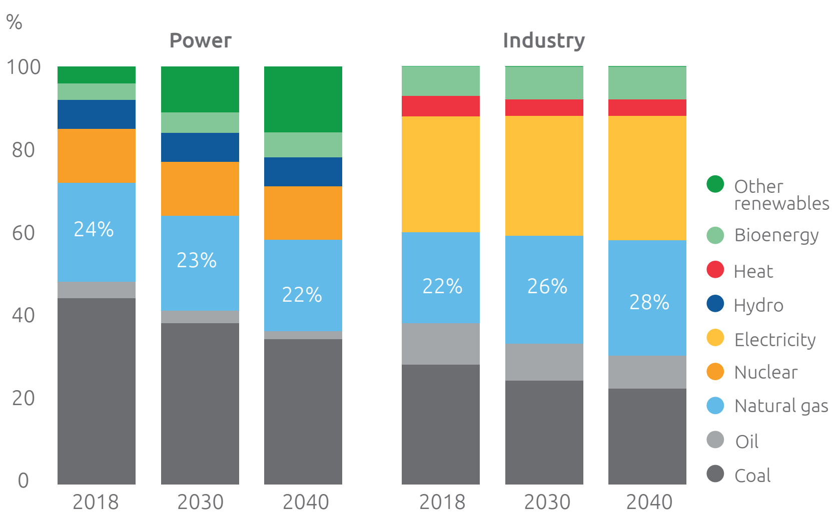
In emerging countries, the challenge for gas-fired generation will be its cost-competitiveness against other technologies. In most places, given the absence of low-cost domestic gas and pricing on emissions or weaker pollution controls, coal-fired generation remains cheaper. However, as the costs of renewable energy sources fall and their deployment rises, gas-fired power plants are likely to play a larger role as a flexibility provider, complementing variable generators, due to their lower emission profile and higher flexibility than coal.

Figure 28: Natural gas demand growth by sector



Source: IEA (World Energy Outlook 2019, Stated Policies Scenario), BloombergNEF analysis.
Note: Conversion factor of 1.163 used to convert Mtoe to BCM for Figure 28.

Figure 29: Share of natural gas in sectors



Source: IEA (World Energy Outlook 2019, Stated Policies Scenario), BloombergNEF analysis.
Note: Conversion factor of 1.163 used to convert Mtoe to BCM for figure 28.

32 IEA's 'Gas 2020' publication

This outlook for gas demand in the power sector is broadly in line with expectations for an economics-driven energy transition. In BloombergNEF's 2019 New Energy Outlook (NEO), which maps a least-cost future for the power sector, gas falls to 19% of global power generation by 2050 but overall power demand growth means that gas use is up 22% by the same year. A key difference, however, is that unlike in the Stated Policies Scenario, in NEO gas plays an important role in enabling a global power sector that is nearly half-powered by wind and solar, by providing flexibility and back-up while also displacing coal.

In the residential and commercial sectors (buildings), natural gas demand grows in a handful of countries where city gas distribution networks expand.

Gas in the transport sector is projected to be the fastest growing area, despite having the smallest share in the mix. Due to strong competition from electric vehicles, the growth potential of gas demand for light-duty vehicles, such as passenger cars and city buses, is expected to be moderate. A larger shift to LNG-powered vessels due to the International Maritime Organization (IMO)'s emission regulations will propel its use as a marine bunker fuel, which could account for 1% of total gas demand by 2040. Improved economics of LNG-fueled trucks over diesel, and local environmental regulations are also expected to support natural gas demand growth as a road transport fuel, particularly for heavy duty and fleets.

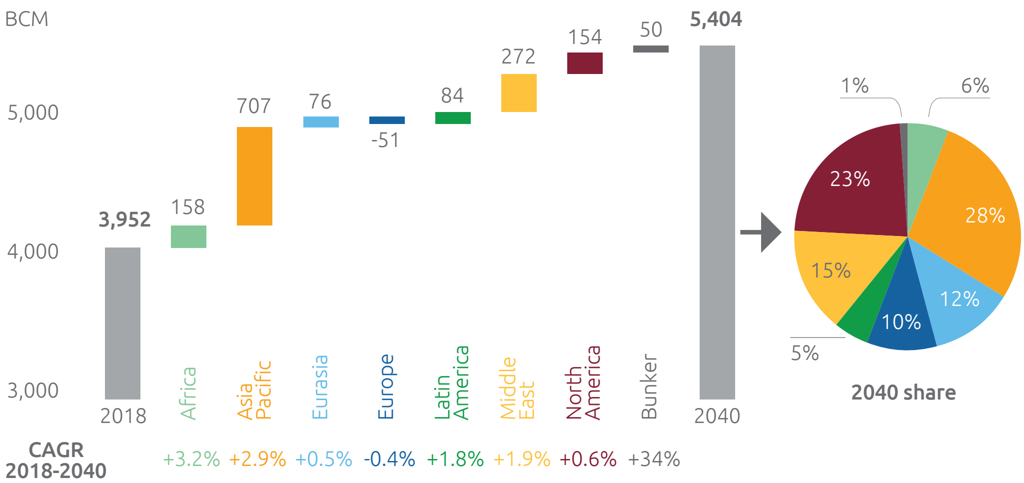
Regional growth

Asia Pacific will be the main engine of natural gas demand growth to 2040, led by China and India (Figure 30). Economic growth, expansion of gas pipeline networks, construction of LNG regasification terminals, market reforms and environmental policies will all support gas demand across the region. China will be the single largest growth market, led by its industrial sector. The country's gas demand is forecast to more than double by 2040, growing at a 3.9% average annual growth rate into 2040 (IEA Stated Policies Scenario). The country's gas demand growth comes on the back of economic development, market reforms, more coal-to-gas switching and infrastructure expansion. By 2040, China will make up 12% of global natural gas demand, only behind the U.S. at 18%. LNG demand in Japan and South Korea will start to decline with nuclear power restarts in Japan and a growing share of renewable energy power generation in both countries.

India's growth is supported by pipeline buildouts, more LNG regasification terminals and implementation of policies restricting the use of polluting fuels in industries, such as furnace oil and petroleum coke. Gas consumption could reach 196 billion cubic meters in 2040, registering a 5.4% annual growth rate between 2018-40 – the highest seen across all countries and regions. By 2040, natural gas will make up 18% of industrial sector energy demand. One of the key drivers to gas demand growth will be affordability, as India's gas customers are quite price-sensitive, especially in the industrial sector.

Asia Pacific makes up 28% of global natural gas consumption in 2040

Figure 30: Global natural gas demand outlook – by region



Source: IEA (World Energy Outlook 2019, Stated Policies Scenario), BloombergNEF analysis.

The speed of growth will depend on the execution of key infrastructure projects and further gas market reforms and liberalizations.

In emerging Asia, demand growth is propelled by the addition of new gas-fired power generation capacity. The industry sector will be the primary contributor to natural gas consumption growth in Pakistan, Bangladesh and Indonesia. Other Southeast Asian nations, such as Vietnam, see growth in electricity demand with rising use of natural gas in the power sector. Southeast Asia's natural gas demand grows at 2.7% a year to 2040. However, critical infrastructure is required to support these demand projections, and the Covid-19 crisis places some uncertainty around progress on these developments and their timelines. Delays in infrastructure development could mean that gas loses share to oil and/or coal.

In North America, gas consumption grows at 0.6% per annum, on average, to 2040. Industry underpins the modest rise in the U.S. and Canada, but Mexico's growth is from new power generation capacity over the coming years. Latin American natural gas demand growth too comes from rising electricity demand, but also from additional potential from fuel-switching in the power sector.

European natural gas demand in the power sector will get a lift from the phase-out of nuclear and coal power generation capacity, but will face growing competition from renewables. Europe's gas demand is set to fall – the only region where this is the case – and its share of global gas consumption drops to 10% in 2040 from 15% in 2018 – according to the IEA.

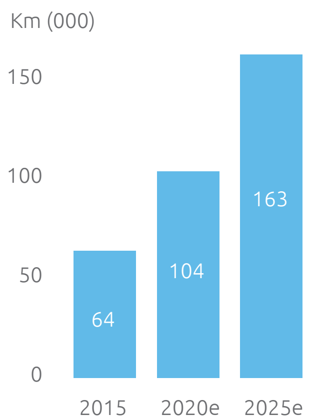
Natural gas demand in Eurasia will see modest annual growth of 0.5% over 2018 to 2040. Industries are expected to consume more domestic gas as feedstock, amidst continuing gas exports to neighboring countries.

More demand also emerges from the Middle East's large gas-producing markets, such as Saudi Arabia and Iran, as they increase their own domestic consumption with rising supply. The additional potential comes from growth in power generation and water desalination activities. Efforts to curb the use of oil-fired generation, reduce emissions and improve air quality, while also saving the supply of oil for the export market, continue to support gas demand. The increase in consumption pushes the region's share of total consumption up to 15% in 2040, surpassing Europe.

As a region, Africa will see the biggest growth potential in natural gas consumption with a 3.2% compound annual growth rate to 2040. The increase in consumption comes alongside new domestic gas production. The continent's growing power demand and phase-out of oil-fired power plants will support future gas usage. North African demand will continue to make up a large portion of the continent's industrial and power generation requirements.

Asia requires the most investment in infrastructure

Figure 31: China natural gas trunk pipeline length



Source: National Development and Reform Commission, BloombergNEF.

Infrastructure buildout enabling gas demand growth

End-user access to natural gas in various key markets remains a challenge to growth. For this reason, infrastructure build-out remains a key success factor for long-term gas demand projections. Asia presents the biggest growth potential, but also requires the most investment. Infrastructure developments, such as gas transmission and distribution pipelines, will play a critical role in unlocking gas demand in China, India and emerging Asia. Simply put, without more infrastructure buildout, gas will not be able to flow to and reach its potential consumers.

China's city gas network, which primarily serves residential and commercial users, is planned for a significant expansion. The country's transmission pipeline length could reach 163,000 kilometers by 2025 (Figure 31). Some 22 of the 31 provinces are committed to extending gas pipelines to every county or town. Provinces such as Guangdong, Zhejiang, Hunan and Guizhou are aiming to do so by the early 2020s, boosting city gas consumption in those regions. China's urbanization rate is expected to grow from 60% in 2019 to 75% in 2040 as more people move into cities/towns from villages. The share of China's population with access to natural gas will rise from 33% to 63% by 2040, by BloombergNEF estimates.

In India, households, businesses and small industrial customers are supplied using piped natural gas, while the transport sector uses compressed natural gas (CNG).

India concluded two big rounds of city gas distribution network auctions in 2018-19 (rounds 9 and 10). Once developed, more than two-thirds of the country's population will have access to gas supply, compared to less than 20% in 2019 (Table 4). As the networks are built out, an increasing number of users will make the switch to natural gas. A number of large transmission pipelines are also under construction or planned. These will serve as the backbone to carry gas from production sites and numerous LNG import terminals to end users, including refineries and fertilizer plants.

In South Asia, Pakistan and Bangladesh need to construct new pipelines to transport imported LNG to end users. Both nations need to adapt their gas transmission networks, from a system of pipelines that only carried gas from domestic fields to end users, to a system which caters to multiple sources of gas, both local production and regasified LNG. Similar investment is required in Southeast Asia, which also needs to strengthen its domestic pipeline network to accommodate LNG imports and connect more users to the national gas grid.

Table 4: India's natural gas infrastructure plans

INFRASTRUCTURE	CURRENT STATUS	PLANNED ADDITIONS
Transmission pipelines	Existing length is 16,800km	14,200km of pipelines under construction or proposed
Regasification terminals	Existing capacity is 39.5 million metric tons per annum (~54 billion cubic meters per annum)	More than 40 million metric tons per annum (~54 billion cubic meters per annum) of new LNG import capacity planned
City gas networks	5 million households	35 million* households
	1,730 CNG stations	7,200* CNG stations

Source: BloombergNEF, Petroleum and Natural Gas Regulatory Board, India, Petroleum Planning and Analysis Cell, India.
Note: *Based on the ninth and tenth bid rounds.

Supply: New discoveries and supply expansion

Global natural gas supply to grow 1.4% annually

Global natural gas production is expected to grow at a compound annual growth rate of 1.4% to reach about 5.4 trillion cubic meters by 2040, according to IEA projections (Figure 32). The Middle East will be the largest contributor to growth, followed by North America, Asia Pacific and Africa. Europe will be the only region to see a fall in production to 2040, with its share of global production dropping to 3%, from 7% in 2018. Africa's share of global production will see the biggest rise, from 6% to 9% in the same period. Today's top three natural gas producers – the U.S., Russia and Iran – are expected to retain their spots in 2040.

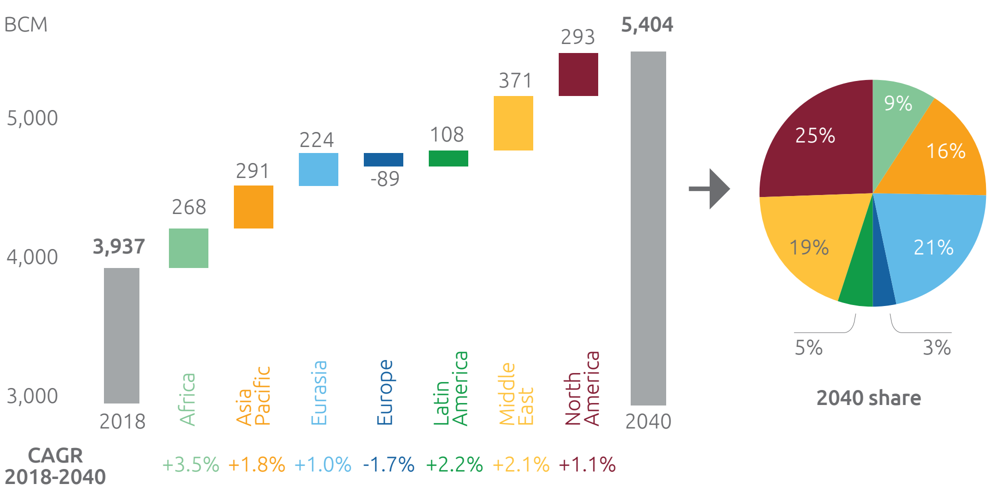
Much of Africa's growth will come from Mozambique and Nigeria, but Tanzania, Mauritania and Senegal will also contribute to rising supply. Asia Pacific supply growth is dominated by China and Australia, growing between 2.4% to 3% per annum over the outlook period. India's production, however, will record the highest annual growth rate for the region, at 4.4%. Indonesia's production grows at a 1.2% compound average annual growth rate from 2018 to 2040, whereas the rest of Southeast Asia sees 0.4% growth.

In Eurasia, Turkmenistan and Azerbaijan will see growth rates of 3.1% to 3.4% per annum, while Russia is projected to have modest annual growth of 0.8%. Kazakhstan and Uzbekistan are anticipated to see supply drop after 2040. All European producers will see their output fall, with the exception of Cyprus, which will eventually overtake the Netherlands as the region's third-largest gas producer.

For Latin America, Argentina and Brazil have the largest growth potential, while Trinidad and Tobago is forecast to see production fall. The region's gas production will grow at 2.1% annually, just over the Middle East's growth rate.

Iran and Qatar remain supply growth engines for the Middle East, but it is Iraqi gas production that is expected to see the largest increase, at 12.1% per annum from a low base. Finally, North American production will continue to be dominated by the U.S., which alone will make up 21% of global gas supply in 2040.

Figure 32: Global gas production growth outlook



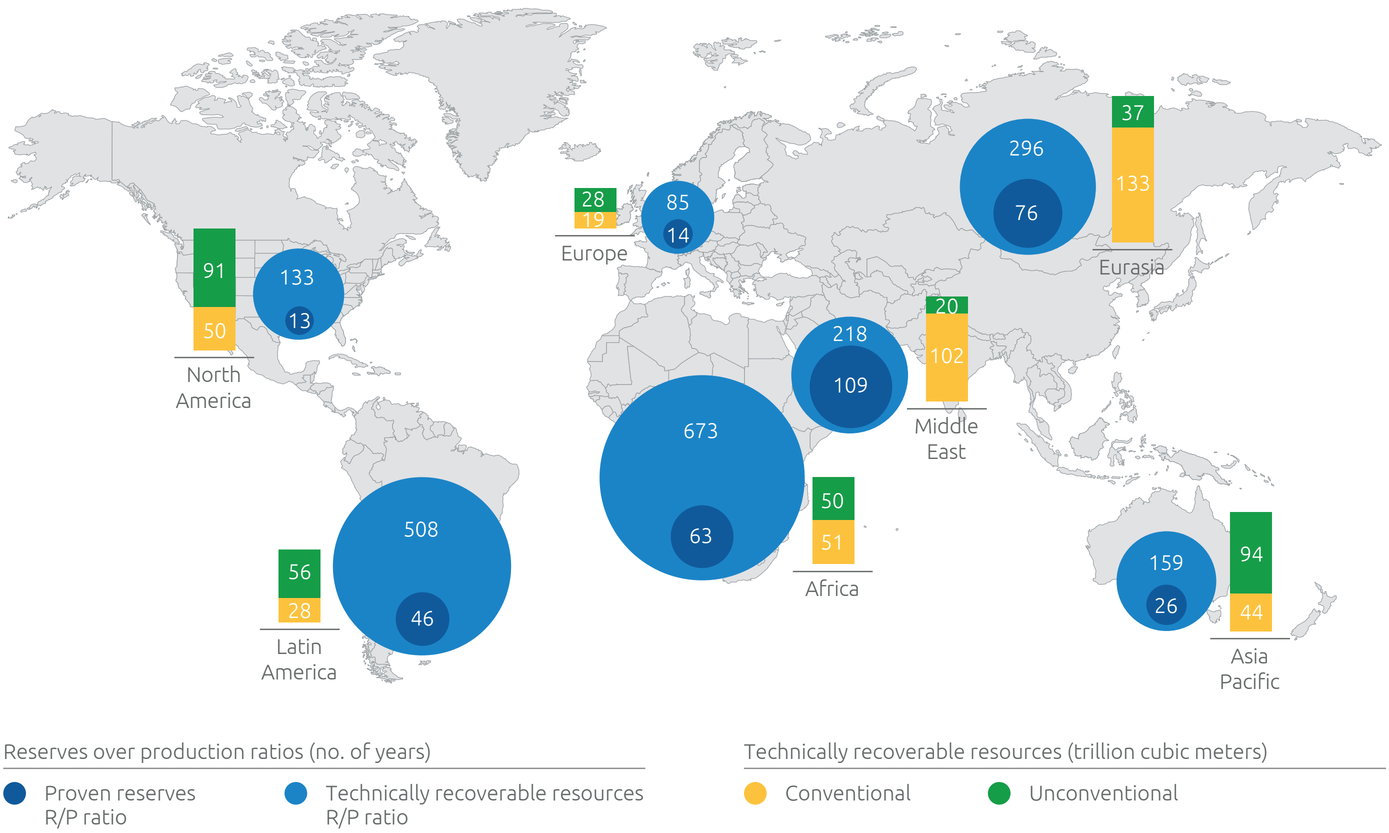
Source: IEA (World Energy Outlook 2019, Stated Policies Scenario), BloombergNEF analysis.

Sources of supply

Ample gas reserves are available across the globe to continue gas supply growth to 2040. Proven natural gas reserves across the globe would be enough for about 50 years of current gas consumption (Figure 33). When considering global technically recoverable gas resources, including unconventional resources, the world has another 204 years of gas supply.

The Middle East has the longest production life span of proven reserves, but falls behind other regions when considering total gas resource potential. The number of years of technically recoverable resources for Africa outpaces all other regions given its limited gas consumption level today. More upstream investment, local hydrocarbon policy support and infrastructure buildout will be key to unlocking much of the natural gas resource potential. Development of low-cost, and increasingly unconventional resources, will be critical to ensure cost competitive supply of natural gas to meet growing demand.

Figure 33: Global natural gas resources and production life years – by region

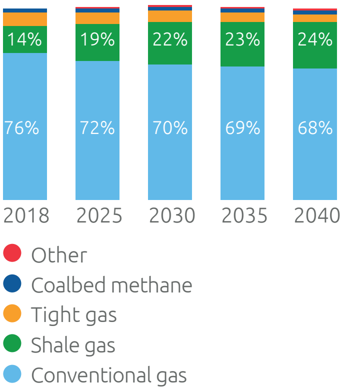


Source: IEA (World Energy Outlook 2019), BP (Statistical Review 2020), BloombergNEF analysis.
Note: Proven reserves from BP, technically recoverable resources based on IEA data as at end-2018, 2019 natural gas consumption assumption from BP.

Unconventional gas sources to make up 32% of supply in 2040

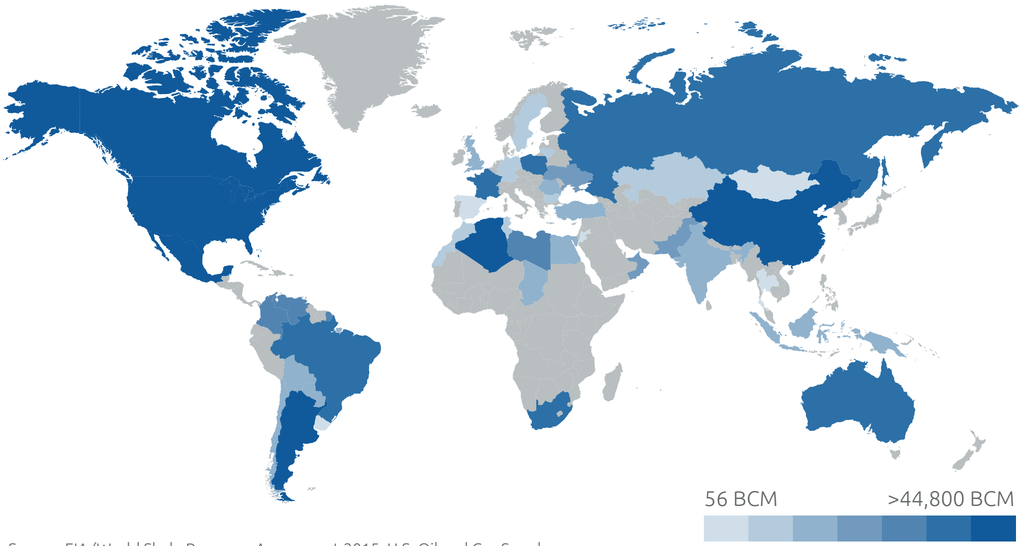
Currently, about a quarter of global natural gas production comes from unconventional sources of gas (Figure 34), largely from the U.S., but with Canada, Australia and China contributing a fair share. By 2040 that unconventional share is projected to grow to 32%, by IEA projections. Again, the growth is underpinned by rising output from the U.S., China, Canada and increasingly Argentina into the future. Algeria and Australia will contribute to grow too, but to a lesser extent. Total unconventional gas production is expected to reach 1.7 trillion cubic meters in 2040. Shale gas production will make up the bulk of unconventional supply, followed by tight gas and coalbed methane.

Figure 34: Share of natural gas production type



Source: IEA (WEO 2019), BloombergNEF analysis.

Figure 35: Shale gas technically recoverable resources (billion cubic meters)



Source: EIA (World Shale Resource Assessment 2015, U.S. Oil and Gas Supply Module: Jan. 2020), BloombergNEF analysis.

Markets: Growing trade, hubs and derivatives

Existing major gas consuming regions, such as North America, Russia and the Middle East, will increasingly consume their gas production domestically. A similar trend could play out with Africa as it starts to step up production significantly.

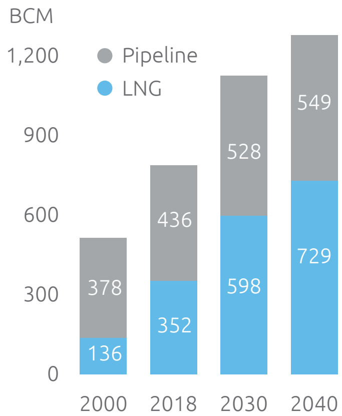
Pipeline flows in the near term are set to rise with major new infrastructure developments, most notably from Russia to China via the Power of Siberia, and Eurasia to Europe via Trans-Anatolian Natural Gas Pipeline (TANAP) and Trans-Adriatic Pipeline (TAP). Still, developments on new major transnational pipelines that traverse multiple countries tend to face many obstacles and delays, including logistical complexity and political alignment. For emerging Asian countries, the rise of LNG has tempered the need for progressing these major pipeline projects.

Natural gas trade share to rise to 24% in 2040

Asia will begin to see a rising trend in natural gas imports, both in the form of pipeline gas supply and LNG, the latter supporting much of the growth. China is projected to have 54% of its demand met through gas imports in 2040, and India's import share will rise from 48% in 2018 to 58% by 2040. South and Southeast Asian region, where LNG is being used to fill a gap left by falling domestic gas production, sees a similar trend. The share of international gas trade, as a proportion of global supply, is expected to grow from 20% in 2018 to 24% in 2040 (Figure 36) – according to the IEA.

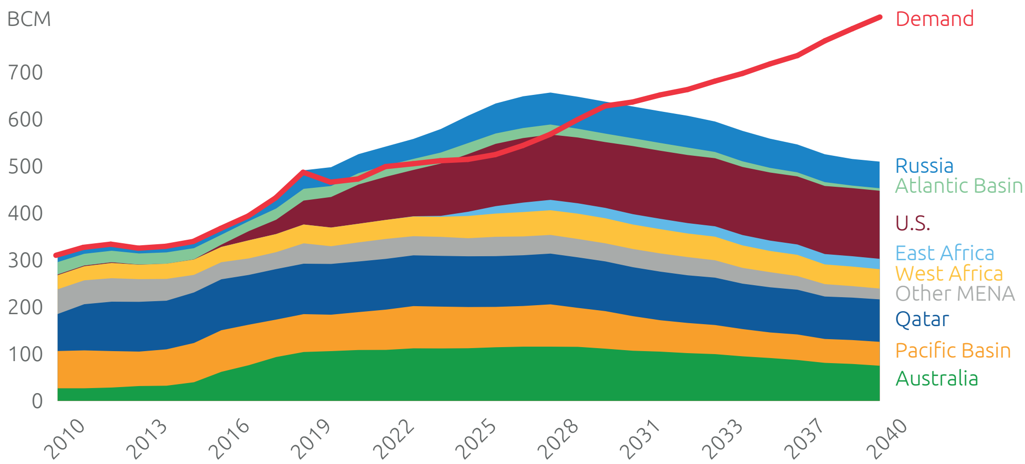
After a major year of final investment decisions (FID) on LNG supply projects in 2019, the global LNG market is not expected to need new supply until after 2030, based on BloombergNEF's latest supply-demand balance (Figure 37). New under-construction LNG capacity is expected to be added during 2023-26. Efforts to sustain LNG production at facilities built in the 1970s-80s with new gas and plant rejuvenation work will see some operational capacity hold out until 2030, but retirements are still assumed by 2040. Some legacy suppliers across the Middle East and Africa are expanding their liquefaction capacity, while others are looking to turn their plants into tolling LNG production hubs to prolong supply. The fate of many LNG producers though lies in finding new sources of gas supply through additional exploration investments.

Figure 36: Natural gas trade



Source: IEA WEO 2019.

Figure 37: Global LNG supply-demand outlook



Source: BloombergNEF.

Technological innovation and abundant supply are making LNG more accessible to new importers. With the increasing commoditization and new market developments, LNG can remain a cost-competitive energy supply option into the long-run.

Rising LNG trade is being complemented by the rise of trading hubs and financial derivatives. These are key mechanisms to raise liquidity and provide risk mitigation options in the gas market, thus helping make the fuel affordable.

Emergence of trading hubs, physical and virtual

Latest Trading Market Developments

Spain launched its virtual trading hub, Virtual Balancing Tank (PVB) in April 2020. This was done to increase utilization across its six LNG import terminals and avoid congestion at the high-demand ones, such as Barcelona and more recently Bilbao. The country has a total of 39 million metric tons (~53 billion cubic meters) of annual regasification capacity, the highest in Europe.

India launched its physical trading hub in June 2020. The country aims to improve gas price discovery in the domestic gas market by encouraging more buyers and sellers to trade on the gas exchange.

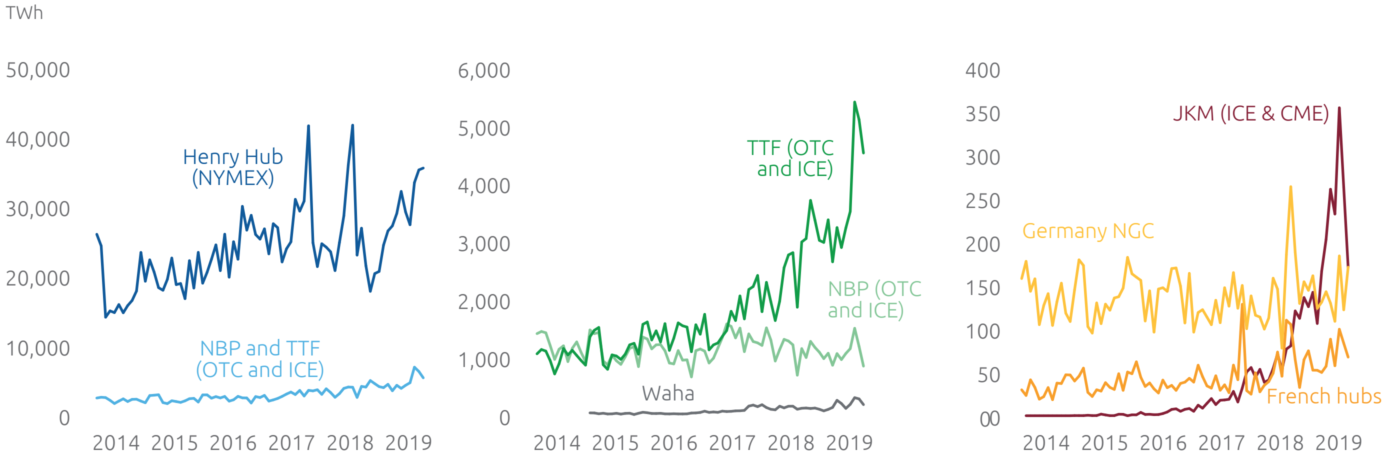
A number of countries in Asia are looking to establish LNG trading hubs. Establishing a trading hub needs LNG infrastructure (storage tanks, multiple jetties, re-load/re-export capable), access to infrastructure (third-party access, storage leasing) and additional services (LNG bunkering, cool-down services, transshipments, trucking). Government support, governance framework, price discovery and gas competition are key enablers to set up a trading hub.

Commoditization: Global pricing and the rising prominence of financial derivatives markets

With increasing price volatility comes a growing need for financial risk management. The liquidity in financial derivative contracts for gas-linked prices has been steadily increasing. The biggest, most liquid market continues to be the U.S.' Henry Hub, but Europe's Title Transfer Facility is growing in status, outshining the U.K.'s National Balancing Point. Other price benchmarks in the U.S. and Europe are gaining traction, but are still only a fraction compared to Henry Hub and TTF traded volumes. Though the Japan-Korea Marker (JKM) futures swap contract was established over five years ago, it only started to see a boost in traded volumes last year (Figure 38).

In November 2019, futures contracts equivalent to 296 LNG cargoes were transacted. This compared to the actual physical trade of LNG amounting to 528 cargoes in the same month. The daily record was a 22-cargo equivalent on November 2, 2019. Rising liquidity for the JKM indicators has supported the movement to start using it as a benchmark in long-term contract pricing, including in some U.S. LNG supply contracts as well. The rapid uptick in paper market liquidity over the past year suggests market players are further enhancing their hedging pabilities and that the LNG industry is on track for further commoditization.

Figure 38: Traded volumes of different gas benchmarks



Source: Nymex, ICE, CME – via Bloomberg Terminal, LEBA, BloombergNEF.
Note: The charts show the futures contracts traded volume as a TWh gas equivalent for comparison. Chart shows volume up to 1Q 2020.

Sustainability: toward a low-carbon gas industry

As the world enters a post-pandemic period, not only will global energy supply need to grow to spur economic recovery, but its environmental impact will also need to be abated. The aftermath of Covid-19 will only intensify efforts to improve air quality as prolonged exposure to air pollutants makes people more prone to respiratory illnesses. China and India together account for three-quarters of the top 50 cities by highest PM2.5 concentration. In these countries, gas switching is likely to be one of the key tools available to policymakers and regulators to combat harmful air pollution and greenhouse gas emissions.

In 2018, natural gas use resulted in 50% fewer carbon dioxide (CO_2) emissions than coal per unit of electricity generated for the power sector, and 33% fewer carbon dioxide (CO_2) emissions on average per unit of heat used in the industry and buildings sector, than coal according to the IEA.

Coal-to-gas switching is an effective immediate measure for cleaner development. In the longer term, the gas sector envisions its role as an enabler for greater energy efficiency and renewable integration, as well as a key vector for delivering on low-carbon technologies such as hydrogen, carbon capture and renewable gas (biomethane). Many of these technologies are not yet at scale. The box beside highlights a recent IGU report on this topic.

Gas Technology and Innovation for a Sustainable Future

IGU Publication

In this report, published in July 2020, the findings show that gas technologies could abate up to 12 gigatonnes, or 30% of energy-related greenhouse gas emissions by 2040. These technologies include a spectrum of end use, distributed, and low-carbon gas production technologies, such as CCUS and hydrogen. The reductions are set against a baseline of the IEA's Stated Policies Scenario.

Key highlights:

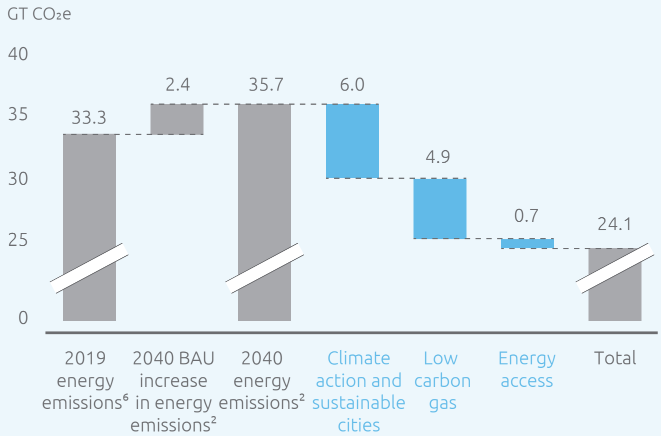
- Twelve different technology applications are analyzed across gas networks and end-uses. Existing gas technologies are already playing a part in facilitating a sustainable energy transition, but new innovations could do more in the medium- to long-term to enhance environmental sustainability measures.
- Near-term fuel switching from coal and oil to gas would immediately reduce greenhouse gas emissions and local air pollutants, at the same time improving energy access across the globe.
- Gas technologies can promote structural transitions by enabling distributed energy systems and increasing efficiency in energy consumption. Natural gas adoption also supports greater renewable energy integration.
- Low- and zero-carbon gas technologies – including renewable gas, hydrogen, carbon capture, utilization and storage (CCUS) – can provide an efficient and cost-effective pathway to reducing GHG emission in the long term. This is particularly so for the hard-to-abate sectors. This topic is explored in Section 3 of this report.

Figure 39: Gas technologies can abate up to 30% of global energy sector GHG emissions

GHG reduction potential by 2040[1] (GT CO_2)

	Technology	Base case[2]	Potential[3]
Climate action and sustainable cities	Power switching	0.6	3.3
	Industry switching	0.6	2.0
	Industrial efficiency	0	0.1
	Enabling renewable power	*Enables renewables*[4]	
	Road transport	0.1	0.4
	LNG bunkering	<0.1	0.2
Low carbon gas	Renewable gas Hydrogen	0	0.9
	CCUS	0.1	4.0
Energy access	Building adoptions	0.2	0.5
	Distributed generation	0.1	0.2
	SSLNG	*Enables fuel switching*[5]	

Global GHG emissions maximum reduction potential[3] from gas technologies by 2040



1. Estimated on the basis of gas demand growth multiplied by the average emissions benefit of switching from coal and or oil to natural gas or low carbon gas; 2. Base case is aligned with IEA 2019 Stated Policies Scenario; 3. Potential is based on the economic potential as defined in Chapter 1; 4. Emissions benefit achieved from the adoption of renewable power were not evaluated, as part of this analysis; 5. Emissions benefit accounted for in other categories; 6. Based on IEA data
Source: IEA, EIA, BP 2019 Energy Outlook, NGVA Europe, IPCC, BCG analysis

In the final section of this report, we present a vision for how hydrogen, among other decarbonization routes, can be scaled up to help realize its potential in a low-carbon energy future.

3 / Decarbonization opportunities for gas: focus on hydrogen

Highlights

- Low-carbon gas technologies, such as biomethane, hydrogen and gas with carbon capture could play a major role in the low-carbon transition. Hydrogen in particular has captured attention in recent years and, with enough investment and policy support, could abate up to 37% of energy-related greenhouse gas emissions, according to BNEF estimates.
- While clean hydrogen is not yet cost-competitive in many applications, a policy-driven scale-up could drive delivered costs down from around $4/kg today to around $2/kg in 2030, and $1/kg in 2050, opening up possibilities in a variety of commercial applications.
- The most attractive applications for hydrogen (and other fuels made from hydrogen) are likely to be the hard-to-abate sectors, where direct electrification with renewable power is difficult. These include steel and cement making, chemicals, dispatchable electricity generation beyond a few days, aviation, shipping and heavy-duty transport.
- For hydrogen to achieve its potential, not only will strong policy action be needed to drive scale, but there will also be a significant need for infrastructure investment. Large-scale hydrogen networks will be necessary to connect high quality production and storage resources to users, which can help lower supply costs, increase security, enable competitive markets and facilitate international trade.

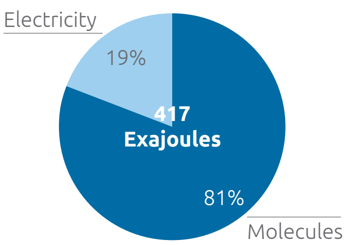
Decarbonizing gas: the opportunity

The global energy sector is undergoing a shift towards low-carbon technologies, driven by the plummeting cost of clean energy, as well as policies that seek to mitigate climate change or improve air quality. Renewable power generation has achieved cost-competitiveness in many markets and applications. The economics of electrified transport are increasingly favorable too, and the same may also be true for building heat electrification in some regions, particularly in mild climates where cooling demand also exists.

In 2018, electricity supplied 19% of the world's energy use (Figure 40); the rest was supplied by solid, liquid or gaseous fuels. That share is expected to increase significantly in future if climate goals are to be met[33]. But there are practical limits to what renewable power and electrification can achieve. Some sectors like aviation, shipping and long-haul trucking require energy to be stored in high densities that are ill-suited to batteries. Others, like steel and fertilizers, require high-temperature heat, chemical reactions or feedstock inputs that make molecule fuels almost indispensable. Even in the power sector, a role for fuels to provide long-duration storage and dispatchable electricity generation will likely remain.

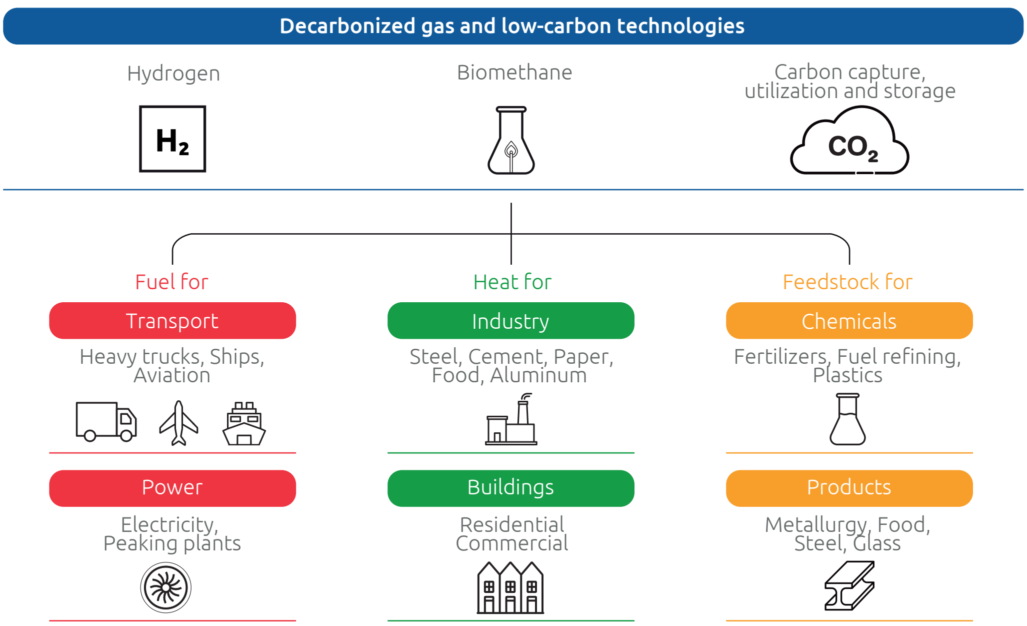
The development of decarbonized gases (also called green gases) like biomethane and hydrogen is a crucial next step to enable long-term climate goals to be reached. The CO_2 intensity of natural gas can also be lowered substantially with carbon capture, utilization and storage (CCUS) technologies. A combination of these three routes can enable the natural gas industry to continue to evolve and deliver low-carbon growth (Figure 41). Existing natural gas infrastructure can be repurposed for the transportation

Figure 40: Global final energy consumption in 2018



Source: IEA

Figure 41: Decarbonized gas can play a role in hard-to-abate sectors



Source: BloombergNEF

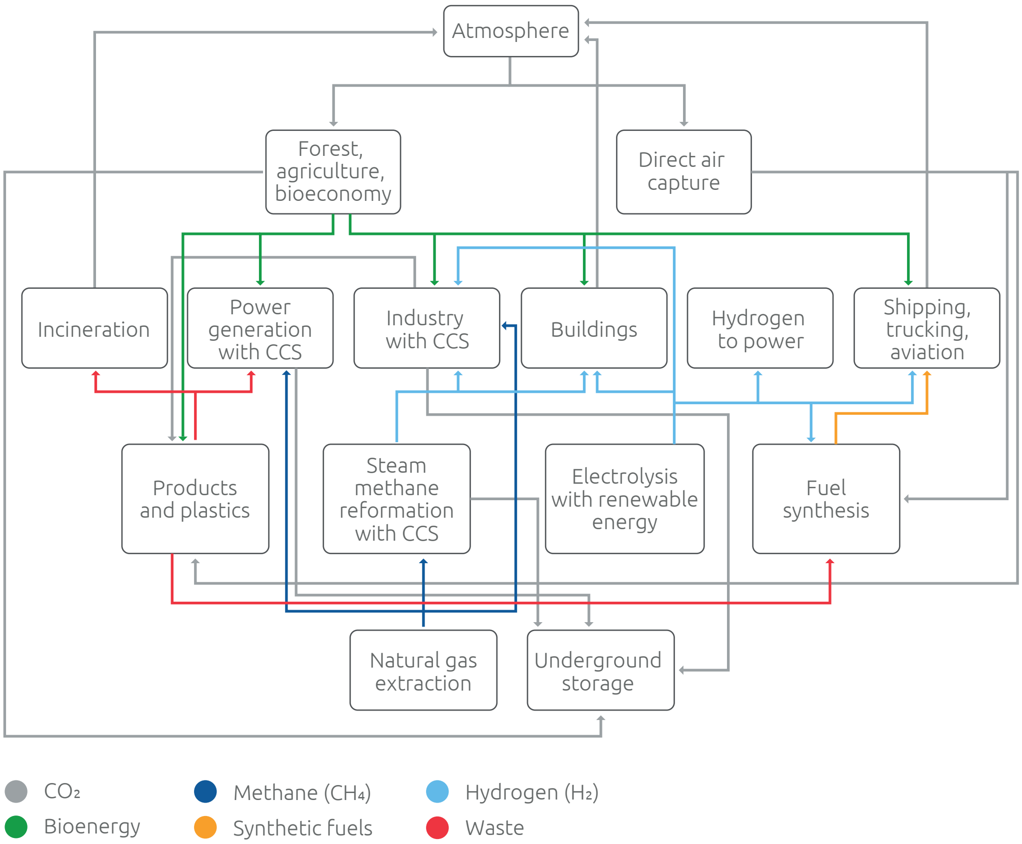
33 Intergovernmental Panel on Climate Change, Special Report: Global Warming of 1.5°C, 2018. The median share of final energy consumption met by electricity is 53% for all pathways limiting global warming below 1.5°C, or 1.5°C with limited overshoot.

or storage of hydrogen, carbon dioxide or biomethane. For instance, modifying existing gas pipelines to carry either hydrogen or carbon dioxide could be up to 90% cheaper than building new dedicated networks for these molecules[34]. Green gases and CCUS can also expand the gas industry's footprint by displacing coal and oil in major energy consuming industries like transport and heavy industry.

Biomethane, hydrogen and CCUS can also enable a circular carbon economy (Figure 42). This is a system where carbon dioxide is not simply emitted as waste; it is recovered and recycled into a new end-use. Some close this loop and recapture the emissions, while geological storage can be used to remove it from the system.

CCUS is the first step to build a more circular carbon economy, and can significantly reduce emissions. For full circularity and net-zero emissions, direct air capture and geological storage will be necessary[35]. Biomethane and hydrogen have a part to play as well in the circular use of carbon. The feedstocks used to make biomethane absorb carbon dioxide as they grow, while hydrogen can bind with captured carbon to form synthetic fuels and chemicals.

Figure 42: The "circular carbon economy" simplified pathway



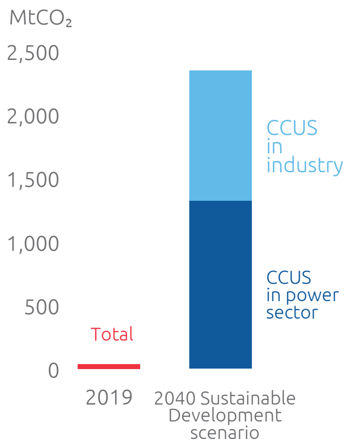
Source: BloombergNEF. Note: For a circular carbon economy to achieve net-zero emissions, direct air capture and geological storage will be necessary to sequester residual emissions unable to be captured by CCS and fugitive emissions from fossil fuel supply chains.

end-uses, like concrete and composite materials, effectively store the carbon for long periods. Others, like synthetic fuel or plastics, will release the carbon if they are combusted. Direct air capture (which draws CO_2 out of the atmosphere) can be used to

According to modeling presented in the IEA's Sustainable Development Scenario, CCUS could absorb over 2.3 $GtCO_2e$ by 2040, while consumption of biogases including biomethane could reach 324 million metric tons of oil equivalent

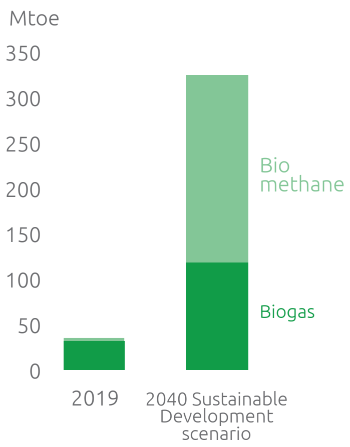
34 This estimate is based on current pilot project proposals including the Get H_2 Initiative for hydrogen in Germany and the ACT Acorn project for CCS in Scotland.
35 CCUS technologies are generally not designed to capture the full emissions associated with a project, and the cost of achieving capture rates above 90% is usually very high. In addition, fugitive emissions released in fossil fuel extraction and supply chains are difficult to eliminate. These residual emissions would need to be offset or sequestered using direct air capture to achieve net-zero emissions.

Figure 43: IEA scenarios for CO_2 absorbed by CCUS



Source: IEA World Energy Outlook.

Figure 44: IEA scenarios for biogas and biomethane consumption



Source: IEA World Energy Outlook.

(Mtoe) by 2040[36]. In this scenario, the use of biogases would more than quadruple compared to today's consumption of 25Mtoe – while CCUS would increase 62 times its current level in two decades. Other estimates put the potential for CCUS as high as 4 $GtCO_2e$.

However, demand for decarbonized gasses would likely be significantly higher still if net-zero emissions targets are to be reached. Hydrogen is well placed to play a key role, as it can be produced at massive scale and with zero greenhouse gas emissions.

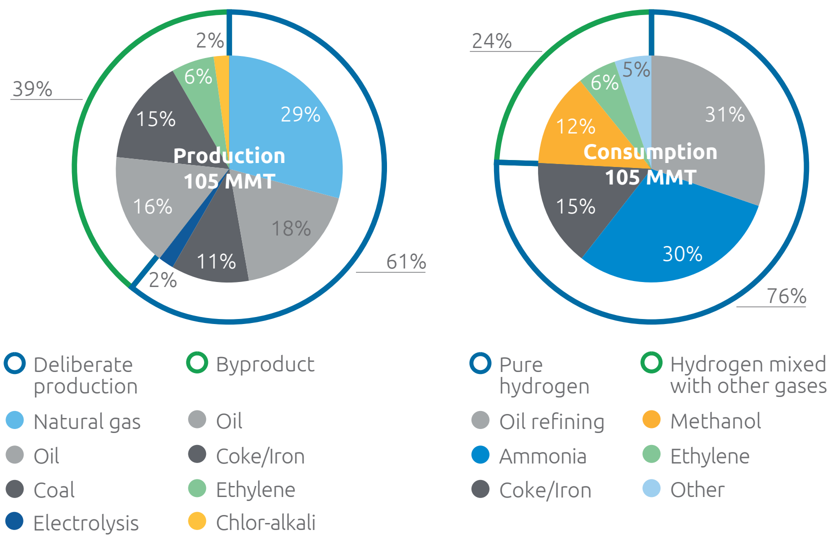
Covid-19 recovery packages may present a unique opportunity to support decarbonization initiatives in the gas industry. While decarbonized gas and CCUS projects are typically not "shovel ready", infrastructure to transport hydrogen and CO_2, or to demonstrate decarbonized gases in new applications, can create jobs that align with future industrial growth. Investments in RD&D also have longer-term positive impacts on the economy, by creating highly skilled jobs, increasing productivity and contributing to knowledge creation. Planned projects for biomethane, hydrogen and CCUS are therefore a suitable target for infrastructure stimulus. This opportunity has been embraced in Europe, where funding for hydrogen at the EU level and CCUS in Norway has been prioritized in response to the pandemic.

36 See the IEA reports Transforming industry through CCUS, Carbon Capture, Utilization and Storage in Power, and Outlook for Biogas and Biomethane: Prospects for Organic Growth

The basics and benefits of hydrogen

Hydrogen is the simplest and most abundant element in the universe. However, on Earth, it is mostly non-existent in its free form, and must be produced from other substances. Today, hydrogen is mostly produced from fossil fuels via reforming of natural gas and oil, and coal gasification (Figure 45). A substantial fraction is also produced as a byproduct of other processes like steel making. Only 4% is produced using electricity, with half the byproduct of the chlor-alkali process. Today, hydrogen is predominantly used as a feedstock to produce ammonia and methanol, and to remove impurities from crude oil and reduce sulfur in the petroleum-refining process.

Figure 45: Hydrogen production by source and application by sector, 2018



Source: BloombergNEF.
Note: For deliberate production, the category terms indicate the source materials; for byproduct, the terms refer to the industries. DRI = direct reduced iron.

The production of hydrogen today is, however, a significant source of emissions. The IEA estimates that hydrogen production globally releases 830 $MtCO_2$ per year – equivalent to 2.2% of global energy-related emissions in 2018.37 But hydrogen can be produced without emissions by splitting water using renewable electricity in a device called an electrolyzer (so called “green hydrogen”) or with low emissions by using carbon capture and storage technologies to reduce the emissions of fossil fuel-based production process (so called “blue hydrogen”). The different types of hydrogen common today are explained in the box beside up.

By using these technologies, the production of hydrogen could be massively expanded to provide decarbonized gas to the global economy in the coming decades. Hydrogen has several outstanding properties that make it an excellent clean carrier of energy[38]. It is light, non-toxic, reactive and emits no carbon pollution when combusted.

The uses for hydrogen are broad, and it could play a key role decarbonizing many of the hard-to-abate sectors which cannot be easily or economically electrified. It can be used as a fuel for peaking power generation, heavy trucking and for the light-duty vehicle applications that battery electric models may not serve well. Derivatives of hydrogen can be used as a fuel for aviation and shipping. Combusting it can provide both high-temperature heat for heavy industry, and space and water heating for buildings. And lastly, it can be used as a feedstock to make chemicals and perform the chemical reactions that are necessary to manufacture many basic materials like steel, ammonia and methanol. In broad terms, hydrogen can do almost everything natural gas does in the current economy, and can displace many of the non-power sector uses for coal and oil. The use of hydrogen also has other strategic benefits that make it valuable as a vector for decarbonization (see box beside low).

37 International Energy Agency, The Future of Hydrogen, 2019.
38 Hydrogen Strategy Group, Hydrogen for Australia’s Future, August 2019.

Types of hydrogen

Renewable hydrogen: hydrogen produced with zero carbon emissions from renewable energy sources like wind, solar or hydro, via water electrolysis. Renewable hydrogen can also be produced from biomass through a gasification process. Renewable hydrogen is often referred to as "green" hydrogen. Although the source is not defined as renewable, hydrogen can also be produced without carbon emissions from nuclear energy sources.

Low-carbon hydrogen: H_2 produced from fossil fuel with carbon capture and storage (CCS). This is sometimes referred to as "blue" hydrogen. Hydrogen can also be produced from fossil fuels using a technique called methane cracking, which produces solid carbon residue as the byproduct instead of gaseous CO_2.

Fossil hydrogen: H_2 produced from fossil fuels like coal, oil, natural gas or lignite with release of carbon dioxide and other waste gasses to the atmosphere. This is sometimes referred to as "brown", "black" or "gray" hydrogen.

The strategic benefits of hydrogen

Energy security: hydrogen can be made from renewable electricity at almost any location, enabling countries to diversify supply with new sources of production. Hydrogen can also be generated in remote and off-grid locations, transported and shipped from energy-rich to energy-poor regions and be stored in large quantities to act as a strategic reserve.

Synergy with existing industries: being a molecule-based energy carrier, the production, storage, transmission, handling and consumption of hydrogen has many similarities with existing oil & gas industries. Manufacturing hydrogen equipment also overlaps with many existing chemical, manufacturing, engineering and technology sectors. This makes transitioning the skills, jobs, infrastructure, assets and business models of individuals, companies and countries easier and more attractive. It could also help recast the narrative on the fraught politics of climate change for many crucial actors, from threat to opportunity.

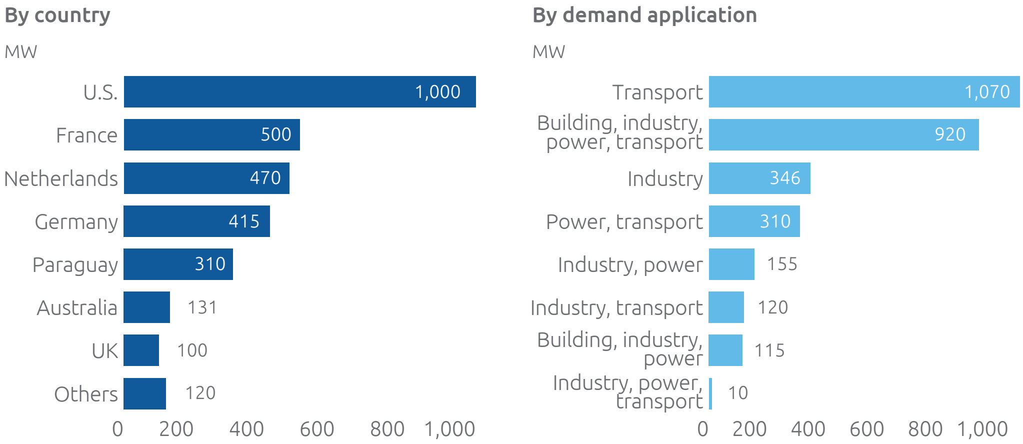
Viable and incremental transition pathway: natural gas-based infrastructure, such as pipelines, heaters, turbines and steel mills, has the potential for future conversion to hydrogen. This extends the use for many large assets, avoiding the costs of full replacement, decommissioning and write-offs. It also offers existing industrial users of coal or oil an incremental approach to carbon emission reductions – first switch to gas-based systems and later convert these to hydrogen.

Sector coupling and renewable integration: hydrogen can be used as a flexible store of renewable energy over long timescales, helping to solve one of the most challenging problems of a renewable power system. The massive amounts of wind and solar capacity required to produce hydrogen at the scales envisaged can also enhance power system reliability by acting as an additional swing supply source that can be diverted to the power grid when other generation is low. Electricity that might otherwise be curtailed can also be converted to hydrogen when renewable generation is high.

Current trends and potential

The use of clean hydrogen is expensive and uncommon today, however, there are some encouraging signs that the industry is scaling up and rapidly reducing costs. In 2018, around 130 MW of electrolyzers were installed, with a typical project size of just 2-3 MW. As of mid-2019, 21 electrolyzer projects with individual sizes equal to or greater than 10 MW had been announced, with a total capacity of 3 GW (Figure 46). In mid-2020, reports suggest the pipeline has grown further to over 8 GW. There are also four large-scale hydrogen production facilities with CCS in operation in the U.S. and Canada, and a further two are under construction.

Figure 46: Proposed electrolyzer projects over 10MW, as of July 2019



Source: BloombergNEF, IEA.
Note: For the application category, building refers to space and water heating; industry includes chemical and basic material production.

Potential uses

The technology exists today to use hydrogen in a wide variety of sectors. The strongest use cases for hydrogen are the manufacturing processes that require the physical and chemical properties of molecule fuels in order to work. In future, hydrogen could be used to manufacture goods or essential inputs in many industries for a cost comparable to mid- or high-cost fossil fuels (Figure 47). A carbon price will be required for hydrogen to be competitive in regions where fossil fuel prices are very low, in all applications except road transport.For example, with renewable hydrogen delivered at $1/kg, the carbon price needed to make it cost-competitive with the cheapest fossil fuels in use today would be $50/t$CO_2$ for steel making, $60/t$CO_2$ for heat in cement production, $78/t$CO_2$ for ammonia synthesis, and $90/t$CO_2$ for aluminum and glass manufacturing[39].

39 For further details on the economics and use cases for hydrogen see: BloombergNEF, Hydrogen Economy Outlook, 2020.

Figure 47: Cost of manufacturing goods or essential inputs, using $1/kg hydrogen

Steel
$582
per ton of hot rolled coil
(Using coling coal: $495-651)

Cement
$7
per gigajoule of heat
(Using coal: $1.40-4.30)

Aluminum recycling
$7
per gigajoule of heat
(Using natural gas: $1.90-11.40)

Ammonia
$368
per ton of ammonia
(Using natural gas: $244-574)

Methanol
$447
per ton of methanol
(Using coal: $145-435)

Oil refining
$1
per kilogram of hydrogen
(Using natural gas: $0.86-2.59/kg)

Source: BloombergNEF. Note: cost of producing goods using fossil fuels assuming prices of $60-310/t for coking coal, $2- 12/MMBtu for natural gas and $40-120/t for thermal coal

Hydrogen can also play a valuable role decarbonizing long-haul, heavy-payload trucks. These could be more cost-effective to run using hydrogen fuel cells than diesel engines by 2031, and achieve similar performance. Another significant advantage is that fuel cells produce no air pollution, as the only byproducts are water and oxygen. Hydrogen's use in the car, bus and light-truck market is likely to be limited, as battery electric drivetrains are a cheaper solution than fuel cells. But for other heavy transport modes like ships, green ammonia from hydrogen is a promising option, and could be competitive with heavy fuel oil with a carbon price of $145/tCO_2$ in 2050. Trains can also be powered using hydrogen or ammonia, and synthetic fuels made from hydrogen can be used for aviation.

Hydrogen can also be used for power generation or long-term storage in the power sector. With large-scale geological storage in place, hydrogen could be produced from renewable power that would otherwise be curtailed, then stored and transported back to a power generator at a cost of $8-14/MMBtu by 2050 in most locations. A carbon price of $115/tCO_2$ in 2050 would be required for hydrogen to compete with the lowest-price natural gas on a total cost-of-energy basis. But if future gas turbines are hydrogen-ready, a carbon price of $32/tCO_2$ would be enough to drive fuel switching from $7/MMBtu natural gas to hydrogen. Producing hydrogen from excess renewable electricity would help avoid curtailment and deliver a zero-emissions electricity system.

Potential demand

Hydrogen could play a major role in decarbonizing the global economy. BloombergNEF estimates that up to 37% of energy-related greenhouse gas emissions could be abated using hydrogen – 22% for less than $100/tCO_2$ (Figure 48). If hydrogen is used to meet all of the unlikely-to-electrify energy demand in each sector, demand would total 1,370 MMT – equivalent to 195 EJ or 30% of projected final energy needs in 2050 with current policies and sectoral growth trends[40,41]. However, the exact proportion of hydrogen that is used will depend on emissions targets, the amount of policy support, and the role that other decarbonization pathways also play, including direct electrification, biofuels, CCS, a circular economy, modal shifts and efficiency improvements.

40 Final energy consumption with current policies is assumed to be 643EJ in 2050. This is based on an extrapolation of final energy demand from 2030 to 2040 in the International Energy Agency's, World Energy Outlook, 2019, Current Policies Scenario.

41 Road transport and space and water heating only includes the portion of demand that is unlikely to be met by electrification in this total. This is assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty vehicles, 30% of busses and 75% of heavy-duty vehicles.

Figure 48: Marginal abatement cost curve from using $1/kg hydrogen for emission reductions versus low-cost fossil fuels, by sector in 2050

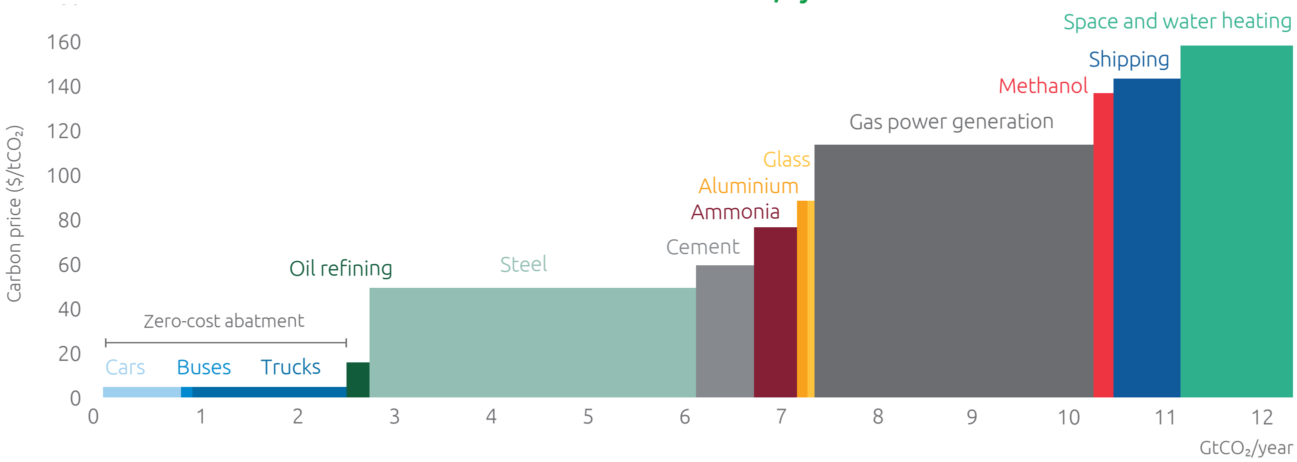
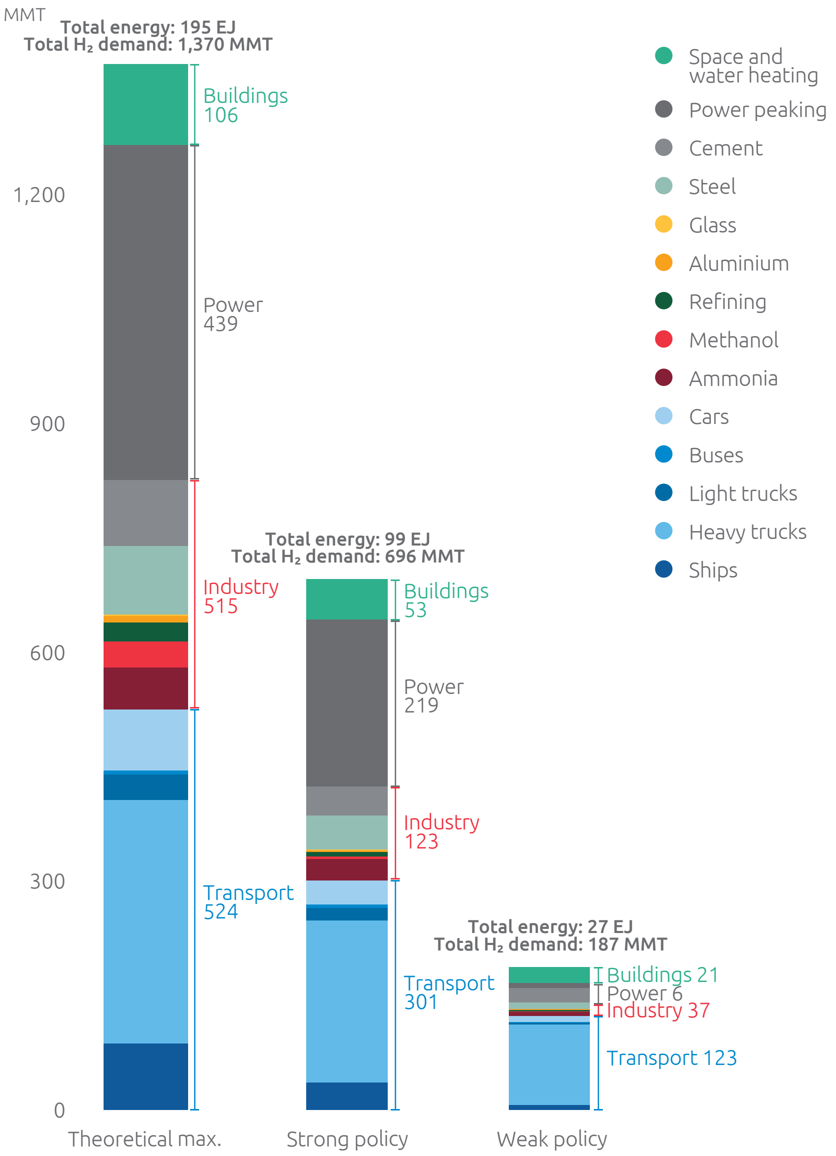


Figure 49: Potential demand for hydrogen in different scenarios, 2050



Source: BloombergNEF.
Note: sectoral emissions based on 2018 figures, abatement costs for renewable hydrogen delivered at $1/kg to large users, $4/kg to road vehicles. Aluminum emissions for alumina production and aluminum recycling only. Cement emissions for process heat only. Refinery emissions from hydrogen production only. Road transport and heating demand emissions are for the segment that is unlikely to be met by electrification only, assumed to be 50% of space and water heating, 25% of light- duty vehicles, 50% of medium-duty trucks, 30% of buses and 75% of heavy-duty trucks. The scenarios for hydrogen demand in 2050 detailed in this section are produced by BloombergNEF using a different methodology to the projections for total energy and natural gas demand to 2040 presented in Section 2, which utilize the IEA's World Energy Outlook 2019, Stated Policies Scenario. They should therefore be considered as seperate projections which are not necessarily connected.

If supportive but fragmented policy to decarbonize and expand the use of hydrogen is in place, BNEF estimates that 187 million metric tons (MMT) of hydrogen could be in use by 2050, enough to meet 7% of projected final energy needs in a scenario where global warming is limited to 1.5 degrees[42]. If strong and comprehensive decarbonization and hydrogen industry policy is in force, 696 MMT of hydrogen could be used, enough to meet 24% of final energy in a 1.5 degree scenario.

The creation of a clean hydrogen industry of this magnitude would present big investment opportunities. Over $11 trillion of spending on production, storage and transport infrastructure would be required for hydrogen to meet around a quarter of global energy needs in 2050. Annual sales of hydrogen would be $700 billion, with billions more also spent on end-use equipment. However, if policy measures to meet emission targets and promote the use of hydrogen do not materialize, then demand is unlikely to increase significantly outside of current uses.

42 Final energy consumption in a 1.5°C scenario is assumed to be 405 EJ in 2050. This is based on the median value for all pathways limiting global warming below 1.5°C, or 1.5°C with limited overshoot, in the Intergovernmental Panel on Climate Change's, Special Report: Global Warming of 1.5°C, 2018.

The economics of hydrogen

Producing hydrogen

The most commercially mature routes for clean hydrogen production are water electrolysis powered by renewable electricity and fossil fuel-based production with carbon capture and storage.

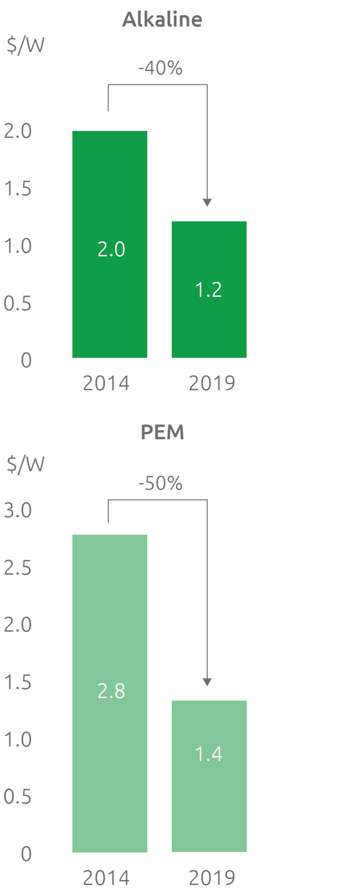
Water electrolysis

Water electrolysis is currently a small industry and hardware costs are high. Consequently, hydrogen produced in an electrolyzer powered by renewables costs between $2.5-4.6/kg, or $19-34/MMBtu. However, these costs could fall rapidly due to a decline in the cost of electrolyzers and renewable electricity.

For instance, the price of alkaline electrolyzers sold in North America and Europe fell 40% between 2014 and 2019 (Figure 50). Chinese made systems are already sold for around 80% less than those in the West, due to a combination of cheaper raw materials and labor, more efficient use of production facilities and lower spending on R&D and marketing. This demonstrates that low production costs are readily achievable. If electrolyzer manufacturing can scale up, BNEF projects that the cost of units made in Europe should converge to the prices in China due to competition and offshoring of production, and could fall from around $1,200/kW today to around $115/kW by 2030 and $80/kW by 2050[43]. When combined with the falling cost of wind and solar power, the cost of producing hydrogen around the world using renewable power could fall to $1.1-2.7/kg ($8-20/MMBtu) by 2030, and $0.7-1.6/kg ($5-12/MMBtu) by 2050 (Figure 53). This would make hydrogen competitive with current natural gas prices in Brazil, China, India, Germany and Scandinavia on an energy-equivalent basis.

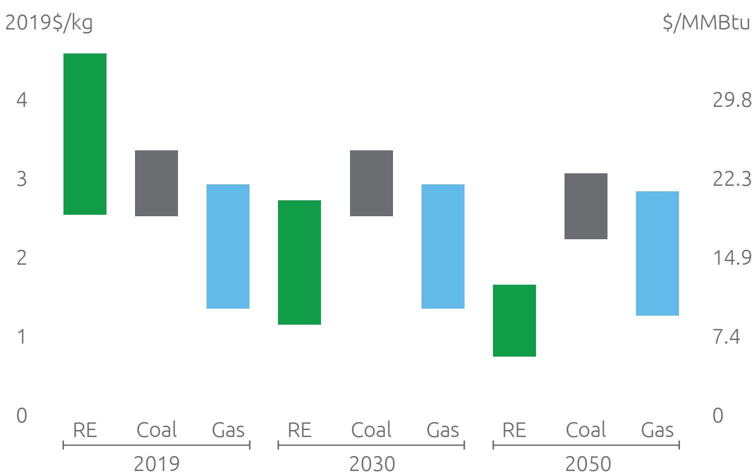
Achieving costs this low will require careful optimization, as the cost of producing hydrogen increases linearly with higher power costs. Two approaches can be employed to do this. Firstly, the cost of

Figure 50: Benchmark system capex (Western-made electrolyzers)



Source: BloombergNEF.

Figure 51: Forecast global range of levelized cost of renewable and low-carbon hydrogen production from large projects



Source: BloombergNEF.
Note: renewable hydrogen costs based on large projects with optimistic projections for capex. Natural gas prices range from $1.1-10.3/MMBtu, coal from $30-116/t. Coal and gas include the cost of carbon capture and storage.

43 BloombergNEF, Hydrogen: The Economics of Production From Renewables, 2019

power into the electrolyzer can be trimmed by 15-20% by integrating wind or PV plants directly with the electrolyzer to eliminate grid connection fees and some power electronics. Secondly, the utilization rate or run hours of the electrolyzer can be maximized by coupling wind and PV generators, where there is a negative correlation between their generation profiles, reducing hydrogen production costs by around 5%. Higher run hours can also be achieved by oversizing the renewable energy generator relative to the electrolyzer, which means more energy can be delivered in periods when the generator is below maximum output, increasing overall electrolyzer utilization. That does mean there would be some curtailment at times of maximum output but this has only a minor impact on system cost, particularly for systems powered by wind, or wind with PV. These same strategies can be used to achieve more stable supply of hydrogen from an electrolyzer and reduce the amount of gas storage required.

Fossil fuels with carbon capture and storage

The cost of producing hydrogen using fossil fuels fitted with carbon capture and storage (CCS) technology is lower than from renewable electricity today, but has less potential to fall in future. Today, hydrogen can be produced from natural gas in a stream methane reformer with CCS for $1.3-2.9/kg, with the variation dictated mostly by the fuel price. The added cost and loss of efficiency from CCS accounts for around $0.6/kg of this cost. Hydrogen can also be produced by coal gasification with CCS for $2.5-3.3/kg.

If the use of CCS technology becomes widespread and the cost of equipment halves, production costs could fall by around 10%, to $1.2-2.8/kg from natural gas or $2.2-3.1/kg from coal[44]. The fall is modest because the capex of a CCS unit has less of an impact on cost than the efficiency losses and operational costs, which will need to be reduced for further cost reductions. Using the best technology currently available, CCS can reduce the carbon intensity of hydrogen production from fossil fuels by around 90%. Technology developers are working to achieving even higher capture rates, as any emissions not captured would require offsetting for the process to be considered carbon-neutral.

Storing hydrogen

Storing hydrogen is challenging, as it takes up three to four times as much space as methane for the equivalent amount of energy, and it takes more energy to compress and liquefy. Eight major technologies can be used to store hydrogen, either in a gaseous, liquid or solid state (Table 1)[45]. Each technology has different capabilities, applications, advantages and disadvantages. Salt caverns are the lowest-cost option for storing hydrogen in large quantities, for long durations. A levelized cost of storage (LCOS) of $0.23/kg ($1.71/MMBtu) can be achieved when salt caverns are cycled monthly, and this could fall to $0.11/kg ($0.82/MMBtu) in the future if U.S. Department of Energy capex targets are met. Six salt caverns are already used to store hydrogen around the world, and thousands more store natural gas and other substances. However, storing hydrogen in salt caverns currently costs two to three times more than storing natural gas, and they also require specific geology. Depleted gas fields can in theory also be used for hydrogen storage, however, solutions are needed to address methane mixing with the stored hydrogen. Rock caverns are likely the next best option after salt caverns, but are more costly to construct and generally smaller.

Pressurized containers are the most viable option for storing hydrogen in small quantities for short periods, with costs starting at $0.19/kg. Tanks are already widely used and are getting lighter and stronger, enabling them to store hydrogen at higher pressures and in larger quantities. With continual improvements in technology, costs could fall to $0.17/kg based on the targets of the U.S. Department of Energy and major manufacturers. Technologies that store hydrogen in a liquid state like liquid hydrogen, ammonia and liquid organic hydrogen carriers (LOHCs) are

44 BloombergNEF, Hydrogen: The Economics of Production From Fossil Fuels, 2020.
45 BloombergNEF, Hydrogen: The Economics of Storage, 2019.

geographically versatile but are costly, primarily due to the large amounts of energy that are required for chilling or chemical conversions. Storing liquid hydrogen currently costs around $4.57/kg, but costs could fall to $0.95/kg in future by building larger and more efficient facilities, according to the U.S. Department of Energy. Liquid-state technologies are unlikely to be utilized purely for stationary storage purposes due to high costs, but may be employed at the start or end of transport supply chains.

Table 5: Hydrogen storage options

	GASEOUS STATE				LIQUID STATE			SOLID STATE
REGIONS	SALT CAVERNS	DEPLETED GAS FIELDS	ROCK CAVERNS	PRESSURIZED CONTAINERS	LIQUID HYDROGEN	AMMONIA	LOHCS	METAL HYDRIDES
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Working capacity (t-H_2)	300-10,000t per cavern	300-100,000t per field	300-2,500t per cavern	5-1,100kg per container	0.2-200t	1-10,000t	0.18-4,500t per tank	0.1-20kg
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated
Geographical availability	Limited	Limited	Limited	Not limited	Not limited	Not limited	Not limited	Not limited

Source: BloombergNEF.
Note: Benchmark levelized cost of storage (LCOS) at the highest reasonable cycling rate (see detailed research for details). LOHC – liquid organic hydrogen carrier

Transporting hydrogen

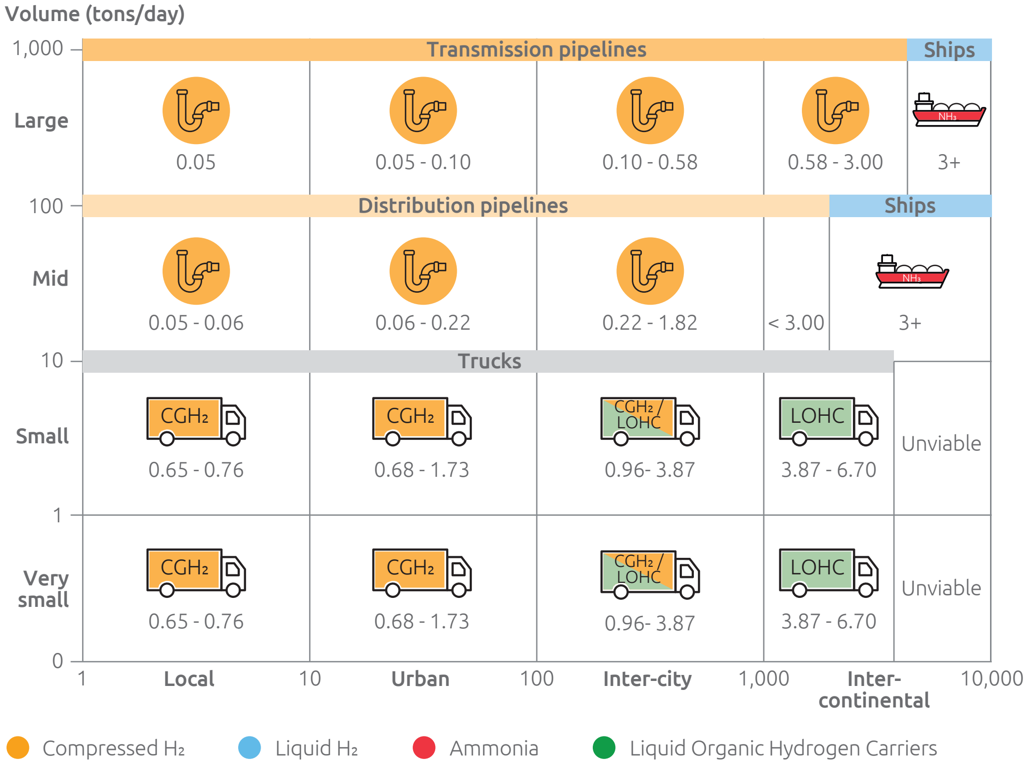
There are three main methods for moving hydrogen, depending on the distances and volumes required: pipes, trucks and ships[46].

Pipeline transport works in a very similar way to natural gas, where hydrogen flows under pressure through pipes. There are around 4,542 km of dedicated hydrogen pipelines in operation today. The natural gas network can also potentially be repurposed to carry hydrogen, however care needs to be taken to ensure large-scale pipeline infrastructure is compatible, as the materials used in some existing high-pressure natural gas pipelines can be embrittled when hydrogen is introduced[47]. Blends of up to 5-20% hydrogen by volume can generally be tolerated by the pipes used in gas distribution networks, as these operate at lower pressures and often use different materials. Modern distribution pipes made of polyethylene could be used to transport pure hydrogen, as most plastic materials are not susceptible to hydrogen embrittlement.

The cost of hydrogen transport using pipelines is similar to that of natural gas, even though hydrogen is less dense. This is because hydrogen is lighter than methane, so travels nearly three times faster through a pipe. The cost of the materials used for hydrogen pipes are also broadly comparable with gas pipes. These factors give pipelines a particular advantage over other modes of hydrogen transport. A 100 km journey via a high-capacity pipeline, moving more than 100 tons per day, costs around $0.10/kg today (Figure 52)[48]. This could fall to about $0.06/kg with better technology and wider adoption of large-scale hydrogen storage technologies.

46 BloombergNEF, Hydrogen: The Economics of Transport and Delivery, 2019
47 Because hydrogen is a tiny molecules and highly reactive it can diffuse into the molecular structure of materials like steel and react with carbon in the molecular structure, causing it to fail.
48 This includes the cost of compression and storage of 20% of the gas in a salt cavern. Storage infrastructure must be used in the process of transporting hydrogen to ensure supply can meet demand, manage flow rates and maintain pressure. The cost of the 100km pipeline movement on its own is $0.06/kg.

Figure 52: H_2 transport costs based on distance and volume, $/kg, 2019



Source: BloombergNEF. Note: figures include the cost of movement, compression and associated storage (20% assumed for pipelines in a salt cavern). Ammonia assumed unsuitable at small scale due to its toxicity. While LOHC is cheaper than LH2 for long distance trucking, it is less likely to be used than the more commercially developed LH_2.

Even bigger pipelines – for instance for international trade – cost less. A much longer 1,000 km journey via a very high-capacity onshore pipeline moving more than 5,000 tons per day could cost around $0.09/kg in future[49]. That is well within the expected variance in production costs between countries, which differ based on the quality and cost of their renewable and fossil fuel resources.

Trucks can also be used to carry trailers of compressed hydrogen gas (CGH_2), liquid hydrogen (LH_2), LOHCs or ammonia. Trucks carrying CGH_2 and LH_2 are already in common use, safely moving hydrogen around cities on a regular basis, but are expensive. For low-volume delivery less than 300 km, trucks with compressed hydrogen are the cheapest option today, with a 50 km trip costing $0.81-1.19/kg. These costs could fall to $0.64/kg for the same 50 km journey as trailer capacity grows and cylinders get cheaper. For longer distances of 300-400 km, converting or refrigerating the hydrogen into LOHC or LH_2 is cheaper than compressed hydrogen, and should cost around $3.30/kg today and could drop to $1.10/kg in future for a 400 km trip if these technologies develop. Trucking ammonia poses greater safety risks due to its toxicity, and should generally be avoided in urban areas, as accidents are often fatal.

Hydrogen can also be moved via ship as LH_2, LOHC or ammonia in purpose-built vessels. Shipping is a costly form of transport due to the need for expensive conversion and reconversion of hydrogen to either liquid or other chemical forms. Liquefying hydrogen requires about one-third of the energy contained in the hydrogen, but can be done using electricity at the exporting terminal, where energy should be cheap and abundant. Less energy is required to produce LOHCs and ammonia, but large amounts of energy are required to reconvert, or crack the chemicals back to hydrogen at the destination country, which is by definition energy-poor. The costs of conversion, shipping and reconversion to pure hydrogen at the destination start at $3/kg for a 5,000 km voyage using

49 Also including the costs of compression and storage. Estimation based on the current cost of high pressure gas transportation (from Mokhatab, S. et al, Handbook of Liquefied Natural Gas, 2014), adjusted for the lower density of hydrogen.

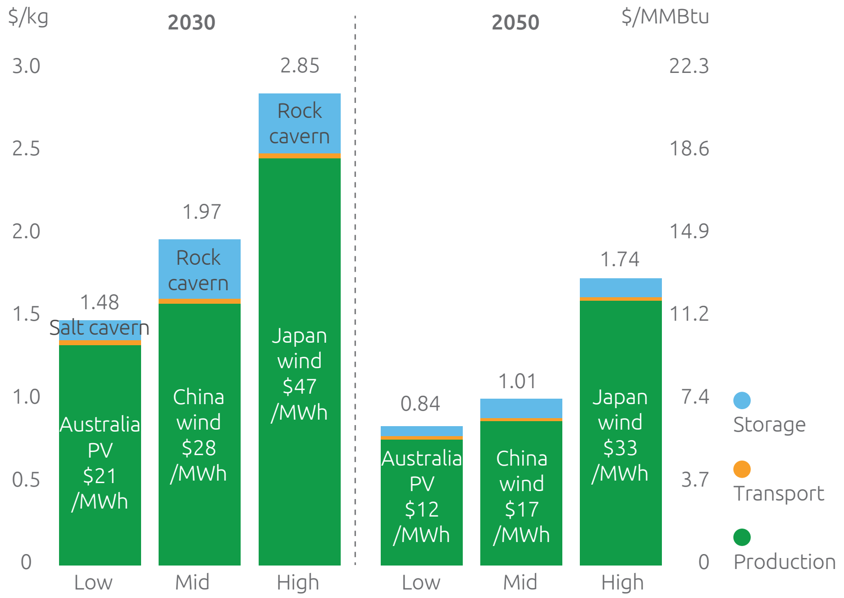
ammonia, $7/kg using liquid hydrogen and $5/kg using LOHCs. Costs could fall to around $2/kg in future for all technologies with greater scale and more efficient equipment, but this is still expensive relative to the cost of producing hydrogen.

Delivered cost estimates

Considering the cost of production, storage and transportation, a scaled-up renewable hydrogen industry could deliver fuel to large-scale users for a benchmark cost of $2/kg ($15/MMBtu) in 2030 and $1/kg ($7.4/MMBtu) in 2050. These delivered costs are likely to be achievable for clusters of large-scale industrial users in China, India and Western Europe (Figures 53 and 54).

Costs would be 20-25% lower in regions with the best renewable and hydrogen storage resources, such as the U.S., Brazil, Australia, Scandinavia, the Middle East and North Africa. However, costs would be up to 50-70% higher in Japan and Korea, which have weaker renewable resources and unfavorable geology.

Figures 53 and 54: Estimated delivered hydrogen costs to large-scale industrial users, 2030 and 2050



Source: BloombergNEF.
Note: Power costs depicted are the LCOE used for electrolysis. Production costs are based on a large-scale alkaline electrolyzer with capex of $115/kW in 2030 and $80/kW in 2050. Storage costs assume 50% of total hydrogen demand passes through storage. Transport costs are for a 50 km transmission pipeline movement. Compression and conversion costs are included in storage. Low estimate assumes a salt cavern, mid and high estimate a rock cavern for both 2030 and 2050.

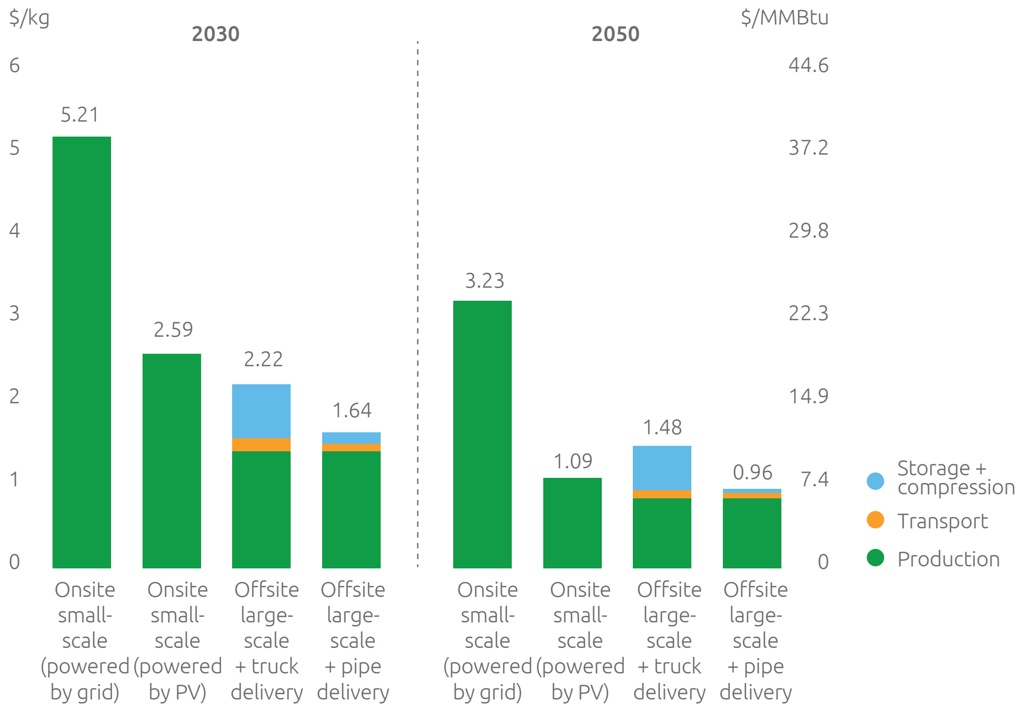
The role of infrastructure

For hydrogen to become as ubiquitous as natural gas, a wide range of infrastructure would be needed to efficiently produce, store and transport it at large scales. This would require a planned and coordinated program of infrastructure upgrades and construction.

Hydrogen supply models

Today, clean hydrogen projects are small in size and focused on demonstrating the use of hydrogen technology. Renewable hydrogen is usually produced onsite with a small grid-connected electrolyzer. This is the simplest option for procuring supply in small quantities as transport of the hydrogen is not required. However, the ongoing costs of producing hydrogen at small scales from an onsite electrolyzer are almost always higher than receiving offsite supply from a large-scale producer, particularly if delivery via pipeline is possible (Figures 55 and 56). This is because grid supplied power is more costly than direct output from a power station, cost and efficiency savings from direct connection to a wind or PV plant cannot be achieved, and small-scale electrolyzers have a higher capex on a unit basis than large systems.

Figures 55 and 56: Estimated delivered hydrogen costs to small-scale users



Source: BloombergNEF.
Note: Large-scale production based on alkaline electrolyzer with capex of $135/kW, powered by PV with an LCOE of $16.9/MWh. Small-scale production based on a PEM electrolyzer with capex of $440/kW, powered by distributed PV with an LCOE of $39/MWh or the grid with a power cost of $100/MWh. Transport costs are for a 50km movement in 2019, and storage.

Source: BloombergNEF.
Note: Large-scale production based on alkaline electrolyzer with capex of $98/kW, powered by PV with an LCOE of $16.9/MWh. Small-scale production based on a PEM electrolyzer with capex of $95/kW, powered by distributed PV with an LCOE of $26/MWh or the grid with a power cost of $70/MWh. Transport and storage costs are for a 50km movement in the future best base.

Distributed production using PV or wind also becomes impractical when commercial quantities of supply are required, as it is difficult to host sufficient capacity. Onsite storage is also only possible at small scales using costly above-ground facilities. The strategic benefits of hydrogen as a clean fuel are also diminished, as widespread hydrogen production via distributed electrolysis couples the reliability of supply to the electricity network and precludes the development of competitive markets.

For hydrogen to be consumed at commercial scale, efficient systems of supply need to be established. The most cost-effective and practical way to deliver hydrogen to consumers in the near-term is likely to be via large-scale, localized supply chains established under a utility model. An example of this would be a cluster of industrial facilities that consume hydrogen, located within a radius of 50-100 km. A network of high-capacity transmission pipes could supply these users with clean hydrogen produced across a portfolio of wind- and solar-powered electrolyzers, with supply smoothed by the use of a large-scale geological storage facility like a salt or rock cavern. Alternatively, production could come from a fossil fuel facility with CCS.

In the longer term, these clusters can be connected using high-capacity pipelines to form comprehensive, interconnected networks. This configuration is likely to offer the lowest supply cost once there is sufficient demand to support (Table 6). This is because hydrogen production can occur in the very best locations, where renewable resources are strongest and most abundant, and storage can occur at multiple points in the network where geology is most suitable. Although long-distance transmission pipelines can have a high upfront cost, this would likely be offset by lower production costs. Interconnection also increases the security of supply, as sources of production and storage are more geographically diverse and numerous. Large networks also allow efficient markets to develop because there is likely to be a multitude of participants and greater balancing flexibility.

Table 6: Comparison of hydrogen supply models

SUPPLY MODEL	PRODUCTION COSTS	STORAGE COSTS	TRANSPORT COSTS	SECURITY OF SUPPLY	EFFICIENT MARKETS
Distributed electrolysis at the end user	High due to use of expensive grid-supplied electricity and smaller electrolyzers	High as storage occurs mostly at small scales using costly above-ground facilities	Low as little movement of hydrogen is required	Medium due to singular sources of production, and dependence on electricity network	Unlikely to develop in hydrogen as electricity would be the primary commodity
Large-scale, localized supply chains	Low as production occurs at feasible large-scale sites, but resources may not be optimal	Low as storage occurs at the closest feasible site, but geology may necessitate use of higher-cost technologies	Medium as hydrogen moves small distances	Medium as sources of production and storage are few, and concentrated to a small geographic area	Unlikely to develop as infrastructure setup favors singular ownership and a utility operating model
Comprehensive interconnected networks	Very low as hydrogen is produced at large scales where renewable resources are strongest and most abundant	Very low as storage occurs at multiple points in the network where geology is most suitable	Medium as hydrogen moves large distances, but at large scales	High as sources of production and storage are numerous, diverse and spread over a large geographic area	Likely to develop as infrastructure facilitates a multitude of participants

Source: BloombergNEF.

The upfront cost of establishing large hydrogen transportation networks can potentially be reduced by repurposing the natural gas network to supply up to 100% hydrogen (see box below). Retrofits will be required in networks where pipelines are made of steel that is susceptible to hydrogen embrittlement, but systems made with polyethylene or steel alloys that are compatible with hydrogen will face lower hurdles. The compatibility of pipeline infrastructure with hydrogen should be considered when new natural gas systems are being built.

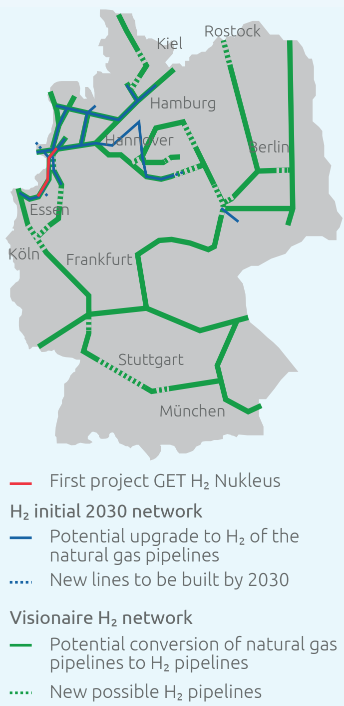
Get H_2: hydrogen gives gas infrastructure certainty over long-term use

The **Get H_2 Initiative** aims to establish nationwide hydrogen infrastructure in Germany, backed up by more than 30 hydrogen-related companies and institutions. The vision is for a 5,900 km hydrogen grid (Figure 57), connecting both local renewable H_2 production and international imports with industrial demand from steelmakers, oil refineries and basic chemicals manufacturers. The plan is to create 90% of the network by converting existing gas infrastructure to hydrogen. It is estimated that converting gas pipelines to hydrogen results in a total spend that is 10-20% of the cost of constructing a dedicated pipeline from scratch.

The first project, **Get H_2 Nukleus**, was announced in March 2020. It aims to commission a 130-km hydrogen transmission pipeline and 100 MW electrolyzer in late 2022. BP, Evonik, Nowega, OGE and RWE are involved with different roles: BP and Evonik are on the demand side running oil refining and chemical factories; RWE is to provide hydrogen yielded from electrolyzers; Nowega and OGE are the operators of the existing gas transmission system that is to be converted. Most of the pure hydrogen pipeline will be developed by replacing components of an existing low-calorific gas network that is scheduled to be phased out. However, Evonik is committed to building a small new section of pipeline.

This Nukleus project will directly help BP and Evonik lower their carbon emissions, but it holds even more value in demonstrating the feasibility of converting existing gas pipelines to hydrogen. This can benefit both new users of hydrogen and owners of existing gas infrastructure. Importantly, the project should also accelerate adjustments to the legal and regulatory framework for the development of hydrogen pipelines with non-discriminatory access.

Figure 57: Get H_2 Initiative for hydrogen network in Germany



Source: FNB Gas e.V.

The need for markets and trade

Long-distance transport of hydrogen will likely be a necessity in the long term, as local land or renewable resource constraints might prevent individual countries from meeting their hydrogen and broader renewable energy requirements using domestic resources alone. BloombergNEF estimates that over 60,000 TWh of onshore wind and solar generation might be required to produce enough renewable power to supply 100% of hydrogen and 50% of electricity for the grid in a 1.5 degree scenario in 2050[50]. This is more electricity than is currently produced worldwide from all sources[51]. Germany would need to dedicate 5% of its landmass to onshore wind and PV in order to produce the energy required in such a scenario. For South Korea the land required is 19%, Japan 7%, India 5%, the UK 4%, and China 3%. This may not be possible due to competing uses for land, the need to protect and restore natural ecosystems to avert a catastrophic loss in biodiversity,[52] and community resistance.

Taking into account competing uses of land with an estimate of the technical potential to generate renewable electricity on land already impacted by humans,[53] BNEF finds that 33 countries may be unable to generate the renewable power required in 2050 (Figure 58)[54]. This includes China, Japan, Germany and South Korea – four of the top 10 greenhouse gas emitters in 2017. In contrast, many countries could have a surplus of generation potential, and therefore have the capacity to export renewable electricity. Countries with the largest export potential are the U.S., Australia, Kazakhstan, Zambia, Argentina and Saudi Arabia.

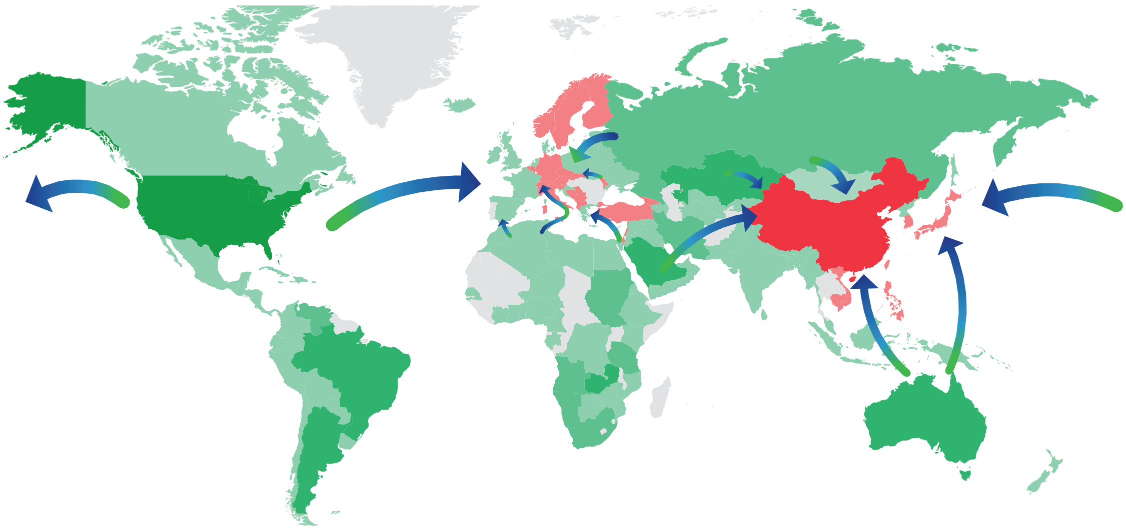
Taking into account proximity, North African countries and Russia can be identified as potential exporters to the European

50 Assumes final energy consumption of 405EJ in 2050, with 24% met by hydrogen and 53% met by electricity. The remaining 50% of generation for the electricity grid and 26% of final energy would need to be provided by other low-carbon sources, such offshore wind, hydro, nuclear, bioenergy and fossil-fuels with CCS.
51 BNEF estimated that 26,653TWh of electricity was produced in 2019. For details see New Energy Outlook 2019.
52 The UN Convention on Biological Diversity has proposed targets for at least 30% of the world's oceans and land to be protected by 2030, to avert the sixth mass extinction.
53 Baruch-Mordo, S. et al, From Paris to practice: Sustainable implementation of renewable energy goals, Environmental Research Letters, December 2018.
54 The methodology used by Baruch-Mordo to estimate potential renewable generation is conservative, and may underrepresent the amount of wind and PV generation achievable in some locations. We have excluded countries where the estimate for potential generation is below current levels.

market, while Australia, Kazakhstan and Russia could potentially help supply China, Japan, South Korea and other countries in South East Asia. Some of these energy flows are similar to the established trade routes for fossil fuel exports today.

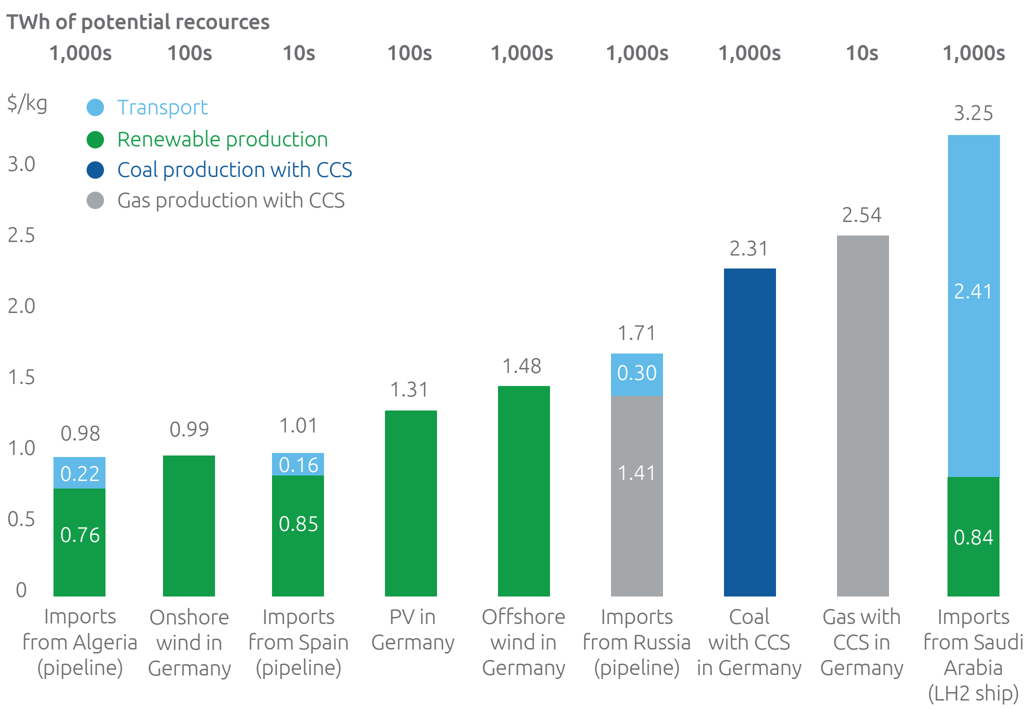
Hydrogen imports via long-distance pipeline are likely to be a cost-effective form of supply for many countries. Germany, for example, should be able to import hydrogen via a pipeline from sun-drenched Spain or Algeria via a pipeline through Italy for a comparable cost to domestic production from onshore wind, and at a lower cost than production from domestic offshore wind (Figure 59). Similarly, low-carbon hydrogen from natural gas with CCS imported via pipeline from Russia should be cheaper than hydrogen produced domestically from Germany's pricier gas, and even its comparably low-cost coal.

Figure 58: Indicative estimate of the ability for major countries to generate 50% of electricity and 100% of hydrogen from wind and PV in a 1.5 degree scenario, 2050



Source: BloombergNEF, Baruch-Mordo et. al, 2019.
Note: Green = Country has sufficient estimated solar and wind resources to generate 50% of electricity and 100% of hydrogen by 2050. Red = Country has insufficient estimated solar and wind resources to generate 50% of electricity and 100% of hydrogen by 2050. Purple = illustrative hydrogen or electricity trade flows to deliver renewable energy from locations of surplus to deficit. The methodology used to estimate the potential for renewable generation is conservative, and may underrepresent the amount of generation achievable in specific locations. In some countries the estimate for potential generation is below current levels. These countries have not given a sufficiency rating.

Figure 59: Potential magnitude of resource and landed cost of hydrogen in Germany, 2050



Source: BloombergNEF.
Note: Based on a levelized cost of electricity from a standalone PV generator of $16/MWh in Algeria and Spain, $26/MWh from onshore wind and $41/MWh from offshore wind in Germany, natural gas price of $1.5/MMbtu in Russia, $8.7/MMbtu in Germany, coal price of $40/t in Germany, pipeline distance of 2,800 km from Algeria to Germany, 2,000 km from Spain to Germany and 4,000 km from Russia to Germany.

The need for policy

For the use of hydrogen to become widespread, policy measures that recognize its emissions reduction benefits need to be put in place. The cost of hydrogen technologies can fall rapidly with further investment, but to do this, the industry needs to scale up. This requires comprehensive and coordinated policy, which is now starting to gather pace, particularly in Europe.

Policy today

Today, there is a growing mix of government policies aiming to increase the use of clean hydrogen. The European Commission's has announced a 470-billion euro hydrogen strategy that targets 10 MMT of renewable hydrogen production by 2030 and the construction of 40 GW of electrolyzers in Europe. The plan will be partly funded through the Commission's 1.85-trillion euro Covid-19 recovery package, but funding will also need to come from member states. European states have already announced significant targets for 2030: Germany aims to build 5 GW of electrolyzer capacity and announced 9 billion euros of funding to build the required hydrogen infrastructure; the Netherlands aims for 4 GW by 2030 and has plans to make funding available across several new policy initiatives, and Portugal has targeted 2GW but has yet to commit funding. If delivered on, these plans alone would bring the hydrogen sector to scale, and comfortably cut the cost of producing renewable hydrogen in Europe by 60% to just $1.5/kg by 2030.

The governments of Australia, Austria, Belgium, New Zealand, Norway, France, Japan and Korea have, or are also in the process of developing, national hydrogen strategies. These countries are yet to introduce comprehensive targets with investment mechanisms such as contracts for difference to drive private investment in clean hydrogen projects. However this could soon change as countries seek to keep pace with Europe.

Outside of the EU, policy measures are generally focused on road transport applications. Targets for the sale of cars powered by hydrogen are relatively common, and add up to over 3.7 million vehicles on the road by 2030 in major markets such as China, Europe, Japan, Korea and California. However, the government money on offer to support those targets is currently enough for just 480,000 vehicles. Funding for hydrogen usage in other sectors generally comes in the form of one-off grants for demonstration projects.

There is also growing interest from energy, transport and industrial companies to invest in hydrogen. According to the Hydrogen Council, its members have planned investments of over 10 billion euros ($11.1 billion) for commercializing hydrogen[55]. Experience suggests, however, that government co-funding will be essential for these projects to materialize. Table 7 provides a summary of the notable hydrogen funding commitments and subsidies in place around the world.

55 Hydrogen Council, How hydrogen empowers the energy transition, January 2017.

Table 7: Summary of notable hydrogen funding commitments and subsidies

JURISDICTION	FUNDING COMMITMENT
European Union	• Some fraction of EUR 463 billion Covid-19 recovery package will flow to hydrogen. • EUR 1.3 billion funding for Clean Hydrogen Partnership program.
Germany	• EUR 9 billion allocated to funding hydrogen infrastructure as part of Covid-19 recovery package. • EUR 1,400 million ($1,550 million) over 10 years for the National Innovation Programme for Hydrogen and Fuel Cell Technologies. • FCV subsidy of up to EUR 6,000 per vehicle.
United Kingdom	• GBP 40 million ($52 million) in funds for innovation in low-carbon hydrogen supply and storage at scale. • GBP 170 million ($220 million) Industrial Strategy Challenge Fund (not exclusively hydrogen). • FCV subsidy of up to GBP 3,500 ($4,500) per vehicle.
France	• EUR 100 million ($111 million) under the Hydrogen Deployment Plan.
Belgium	• EUR 50 million ($56 million) regional investment plan for power-to-gas.
US	• FCV subsidy of up to $7,000 per vehicle available in California .
China	• FCV subsidy of up to CNY 300,000 ($43,000) for light-duty and CNY 500,000 ($72,000) for heavy-duty vehicles.
India	• INR 60 million ($850,000) support for research proposals on hydrogen and fuel cells.
Japan	• JPY 80.7 billion ($736 million) in funding in fiscal year 2020 allocated to hydrogen society initiatives (including FCV subsidies). • FCV subsidy of up to JPY 2 million ($18,350) per vehicle.
South Korea	• FCV subsidy of up to KRW 35 million ($30,000) per vehicle.
Australia	• AUD 370 million ($255 million) allocated to support hydrogen projects by the Australian Renewable Energy Agency and Clean Energy Finance Corporation.

Source: BloombergNEF. International Energy Agency.

Barriers to development

Despite the growing interest in hydrogen, a number of barriers to investment in hydrogen projects and infrastructure still exist in many countries. Along with increasing support for research, development and demonstration, barriers to investment need to be removed to facilitate and unlock opportunities in hydrogen:

1. **Lack of carbon prices and long-term emissions reduction targets**: most countries have not set long-term emissions reduction targets that are consistent with the objectives of the Paris Agreement, or implemented carbon pricing systems that are consistent with these goals. Short-horizon emissions reduction targets do not provide a signal for the hard-to-abate sectors to plan decarbonization and the usage of clean fuels like hydrogen.
2. **Regulatory barriers**: many countries have legacy regulations in place that limit, prohibit or impede the use of hydrogen. Common examples are restrictions on the use of liquid hydrogen by civilians in China, very low limits on allowable hydrogen concentration in gas networks in the United Kingdom, and prohibition on carriage of hydrogen through tunnels in Japan. Safety concerns and issues around social acceptance also exist.
3. **Lack of long-term investment signals**: most countries have not yet put in place investment mechanisms to drive private investment in clean

hydrogen production, storage, transport and usage projects. Targets for the sale of vehicles powered by hydrogen are often poorly funded, and too focused on cars. One-off grant funding for other use cases does not provide a strong framework or signal for long-term investment and scale-up, and the overall level of R&D funding worldwide has stagnated.

4. **Weak heavy transport emissions standards**: tailpipe emission standards or fuel efficiency standards for heavy vehicles like buses, trucks and ships are generally designed to encourage incremental improvements in efficiency, and are not yet stringent enough to drive a switch to clean fuels like hydrogen.

5. **Immature market for low emissions materials**: there is currently little production and demand for low emissions materials like steel and concrete. Awareness of the embodied emissions in many materials is often low, and voluntary markets and labelling standards for green products do not yet exist.

6. **Absence of coordinated plans to decarbonize industry**: most countries do not yet have clear policies and roadmaps in place for decarbonizing industry and developing the necessary enabling infrastructure, such as new low-carbon energy supply chains. Potential investors face significant chicken-and-egg dilemmas for using a new fuel, and issues coordinating between a multitude of actors.

7. **Investment in incompatible equipment**: new investments are frequently being made in fossil fuel infrastructure without regard to its compatibility to transition to clean fuels like hydrogen. This increases the cost and barriers to changeover in future.

Required policy to overcome barriers

To increase investment in hydrogen projects and drive down the costs of hydrogen technologies, policy support will be required. In the short term, to drive innovation and achieve delivered costs of $2/kg by 2030 BNEF estimates that around $15 billion per year of incentives or $150 billion over the next 10 years would be required, to support around $300 billion of investment in clean hydrogen projects[56]. This could be delivered through existing mechanisms like upfront capital offsets and grants. However, investment mechanisms like contracts for difference for projects switching from fossil fuels to clean hydrogen, as well as new approaches such as gas blending mandates (see example in box beside), provide a more potent signal. It would also be necessary to remove regulations that limit, prohibit or impede the use of hydrogen and introduce standards to govern its safe use.

In the medium term, policies are needed to help clean hydrogen industrial clusters to be built, to facilitate large-scale use and achieve delivered costs below $2 and closer to $1/kg. Building industrial clusters is likely to require a suite of supportive measures. These could include carbon pricing; specific industrial decarbonization policies such as tax concessions to help pay for converting infrastructure to hydrogen; and green product mandates that require a percentage of products like steel to be sourced from near-zero emission producers. For FCEV truck sales to increase materially, policy measures such as stringent emissions standards for heavy transport would need to be introduced. Increasing the volume of clean hydrogen production more broadly could also be achieved by the use of increased blending mandates into the gas network.

In the longer term, policies that support comprehensive clean hydrogen supply networks are needed. This would allow widespread use of hydrogen at a delivered cost of $1/kg for large users and widespread conversion of existing natural gas networks to hydrogen. Broad-based conversion would need carbon prices to be complemented with instruments that

56 The Hydrogen Council estimates that $280 billion of total investment is required to 2030, with $70 billion in subsidies. However, this subsidy value represents the cost gap between hydrogen technologies and the cheapest low-carbon alternative, whilst the $150 billion represents the cost gap between hydrogen and the cheapest fossil fuels.

Snam and LADWP: blending allows partial but more immediate transition to hydrogen

Italy-based Snam is Europe's biggest natural gas pipeline operator. In April 2019, Snam started the **first commercial experiment** of blending hydrogen into a transmission network in Europe. The volume ratio of hydrogen was 5%, and the blended gas was delivered to a pasta factory and a mineral water bottle company as fuel for heat. Eight months later, Snam **doubled** the percentage of hydrogen in the project. If the gas flows continuously at predefined pressure, the pipeline under testing could deliver 0.63 MMT of hydrogen per year, equivalent to 1% of deliberately produced hydrogen in 2018. Snam's project demonstrates the technical feasibility of injecting hydrogen into existing natural gas pipelines, which can be the lowest-cost method for transporting the fuel, albeit at a restricted concentration.

On the other side of the Atlantic, The United States' largest municipal utility, Los Angeles Department of Water and Power (LADWP), is also pursuing hydrogen blending. Its project will support the world's first utility-scale power plant to partially source hydrogen as a fuel. In March 2020, Mitsubishi Hitachi Power Systems (MHPS) received a **contract** to supply gas turbines for a 840 MW power plant in Utah. The equipment will be compatible with a mixture of 30% hydrogen and 70% natural gas. LADWP plans to start running the new facility in 2025, with hydrogen supplied from co-located electrolyzers powered by renewable electricity. Hydrogen for the site will also be stored in adjacent **salt caverns**, which are the cheapest option for hydrogen storage. This comprehensive demonstration project therefore addresses on-site green hydrogen production, long-duration storage, and utilization in power generation.

Both Snam and LADWP's projects feature hydrogen blending, which is a highly practical strategy for scaling the industry: it involves the least capital investment and makes immediate use of existing infrastructure and equipment. However, there is an upper limit to how much hydrogen production can be absorbed with blending.

There will also be a limited impact on carbon emissions. Hydrogen has a lower volumetric energy density than natural gas, which means the carbon emission reduction potential is lower than the volumetric concentration. A blended gas with 10% hydrogen results in only 3% carbon reductions, while a 30% mix corresponds to a 12% cut.

prevent overseas carbon leakage, as many emission-intensive industries are subject to international trade pressures. Measures that encourage the use of hydrogen in end-use appliances, and financial models like regulatory allowances that support investment in hydrogen transport and storage infrastructure would also be required. The effective carbon prices required with hydrogen available at $1/kg should fall to zero for road transport options and to between $16 and $160/t$CO_2$ for other sectors.

Table 8 shows seven key actions required to develop the hydrogen economy.

Table 8: Actions to scale up the hydrogen economy

ACTION	OBJECTIVE	EXAMPLES
1) Price emissions and set long-term climate targets that are consistent with the Paris agreement	Provide clear signals for the capital intensive, hard-to-abate industries to decarbonize	• 46 countries including the European Union, Korea, New Zealand and Canada have introduced a price on carbon • Countries that have legislated long-term emissions reduction targets that support the trajectory toward meeting the Paris Agreement include the United Kingdom, France, Sweden, Norway and New Zealand
2) Standards governing hydrogen use are harmonized and regulatory barriers removed	Clear or minimize obstructions to hydrogen projects	• Removal of regulations that limit, prohibit or impede the use and transport of hydrogen • Consistent technical standards are set on hydrogen pipeline pressures, compatible materials, refuelling nozzles for vehicles, end-use appliances etc
3) Targets with long-term budgets and investment mechanisms are introduced	Provide a revenue stream for production, storage and transport infrastructure, increase competition, build capacity and experience, support innovation and R&D and give equipment manufacturers confidence to invest in plant	• Open-access schemes that provide revenue for independent project developers to produce low or zero-emissions hydrogen, e.g. contracts for difference, tradeable certificate schemes and feed-in tariffs or premiums for hydrogen supplied into gas networks • Reverse auctions for hydrogen supply • Long-term R&D budgets
4) Stringent heavy transport emissions standards are set	Provide an incentive for manufactures to produce, and users to buy, fuel cell trucks and ammonia-powered ships	• Tailpipe emission standards or fuel efficiency standards for buses and trucks are significantly tightened • Emissions reduction goals for shipping and aviation
5) Markets for low-emission products are formed	Provide an incentive for manufacturers to produce low-emission goods (e.g. steel, cement, fertilizers, plastics) that will often require the use of hydrogen	• Governments or large corporates set embodied emission standards or green purchasing commitments for inputs to buildings, infrastructure and products • Voluntary markets and labelling standards for green products are introduced, e.g. green fertilizers, zero-embodied-emission cars • Markets, trading hubs, exchanges and price benchmarks are established for trade in hydrogen
6) Strategies to coordinate infrastructure rollout and industrial decarbonization are put in place	Help to facilitate and coordinate infrastructure investment and scale the efficient use of hydrogen; provide incentives for hydrogen use	• National hydrogen strategies include plans for large-scale infrastructure for the production, storage, transport and trade of hydrogen. • Grants/funding/tax exemptions that support large energy users to convert equipment and plant to use clean fuels • Regulatory structures that allow utilities to build hydrogen infrastructure • Extension of carbon pricing systems to heavy industry and phase-out of exemptions
7) Hydrogen-ready equipment becomes commonplace	Enable and reduce the cost of fuel switching to hydrogen	• New pipeline infrastructure uses hydrogen-tolerant materials like polyethylene • New gas turbine models are capable of operating on hydrogen • New marine internal combustion engines are capable of operating on ammonia • End-use appliances such as boilers are designed to operate on hydrogen • New steel plants show preference for Direct Reduction furnaces

Source: BloombergNEF