Global Gas Report 2024

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IGU
INTERNATIONAL GAS UNION
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RystadEnergy

Foreword

Li Yalan
President,
IGU

We present this flagship report on the state of the gas markets, which supply more than one-fifth of the world's energy needs during a time of extreme energy uncertainty. The findings show rising energy demand across all regions, record-breaking coal emissions, and extreme weather conditions, demonstrating an urgent need for more policy clarity around energy supply planning. Strong demand growth for gas underpins its crucial role in reducing global emissions, providing flexibility and resilience, enabling efficient, affordable, sustainable development, and supporting greater adoption of critical clean energy technologies, including the scaling up of renewables. However, the investment in natural gas and low-CO_2 gaseous energy technologies is falling short of demand growth, which must be reversed.

Stefano Venier
Chief Executive Officer,
Snam

The energy transition represents a unique challenge for mankind. A journey that will not be linear, marked by great aspirations and many hurdles, from geopolitical tensions to technology disruptions and unforeseeable global economy developments. In this continuously evolving transformation, natural gas and related infrastructure represents a critical element of sustainable resiliency for the global energy system, while new green and low carbon molecules will play an essential role to achieve a just and technologically neutral transition.

Jarand Rystad
Chief Executive Officer,
Rystad Energy

Natural gas is priced at 10-50 USD/MWh to end users, significantly below oil products at typically 100 USD/MWh. Natural gas is also cheaper than coal in America, and similar or slightly more expensive other places. However, CO_2 emissions from gas is only 50% of the coal emissions and 68% of oil emissions per energy unit. The share of gas being accessible for global trade as LNG has grown from 0% in 1965 to 12% today and will be 18% within a decade. Thus, being cheaper and cleaner than coal and oil and accessible globally, gas has doubled its market share versus coal and oil from 1965 to 2020 and is now 30% of the fossil fuel mix. In our scenarios for future energy mix, natural gas will be larger than coal by 2030 and larger than oil by 2050. It is a pleasure and honor for us to support IGU and Snam in detailing the current market trends and path forward for natural gas.

Executive Summary

Global gas demand sustained its growth in 2023, increasing 59 Bcm (1.5%) from 2022. This trend is expected to continue in 2024 with a further estimated ~87 Bcm (2.1%) rise in demand. Asia's strong demand growth continues to drive growth in global gas imports, while growth in exports from North America and the Middle East have been in the driving seat of the global supply growth. Although global gas markets have stabilised from record volatility and prices seen in 2022, they remain fragile as concerns about energy security persist. As 2023 became another record emissions and coal use year, it is important to highlight that shifting from coal to natural gas is a readily available, cost-effective, and affordable way to cut emissions by around 50% immediately. It is crucial to emphasize that this step should be taken alongside, not instead of, ongoing efforts to expand renewable energy, enhance efficiency, and scale up all emission-free energy sources that are technologically and economically viable.

It is also crucial to underline the importance of low-CO_2 gas technologies such as biomethane, zero- and low-CO_2 hydrogen, and CCUS. Currently, biomethane production is concentrated in North America and Europe, with emerging production markets in China and India. Zero- and low-CO_2 hydrogen production, albeit small in scale, is poised for a rapid annual growth of 45% from 2023 to 2030, if pre-FID projects currently in the pipeline materialise. Today, both biomethane and hydrogen volumes are small, with biomethane constituting roughly 1% of global natural gas supply volume and hydrogen not yet sufficiently present in the energy use market. Similarly, CO_2 capture capacity (CCUS) is set to grow by 42% annually, with 86% of the 2030 pipeline dependent on pre-FID projects.

These technologies are expected to play critical roles in the decarbonisation of energy, as they enable low-CO_2, reliable, and flexible gaseous energy to fuel sustainable, secure, and affordable future energy systems.

The importance of ensuring the continued flow of dense, efficient, flexible, and reliable gaseous energy is particularly pertinent, as global energy demand has been consistently growing, not only in the developing but also in the developed regions of the world, despite energy efficiency gains and structural decline in some sectors. Moreover, recent global shifts, such as the increasing adoption of artificial intelligence (AI) and rising temperatures, will spur power demand from data centres and cooling respectively, also impacting gas demand dynamics. These trends are challenging the assumptions of energy demand growth drop off that various institutions make in their demand scenarios. If global demand continues to grow as it has in recent years, future demand is likely to overshoot many of the world's major 2030 demand reduction targets. If energy demand were to maintain the growth rate observed between 2021-2024, the approximately 2.7% annual increase towards 2030 would significantly outpace most major scenarios assessed in this report (ranging from –0.2% to 1.7%). Even if global energy demand continued to develop at the relatively lower rate of growth observed in the past 10 years, the 1.8% annual increase would surpass scenario assumptions. In this era of uncertainty, continued investment in gas and its infrastructure, accelerating investments in low- and zero CO_2 gas technologies along with other clean energy supply, and ramping up energy saving, is essential for providing reliable, sustainable, and affordable energy into the future.

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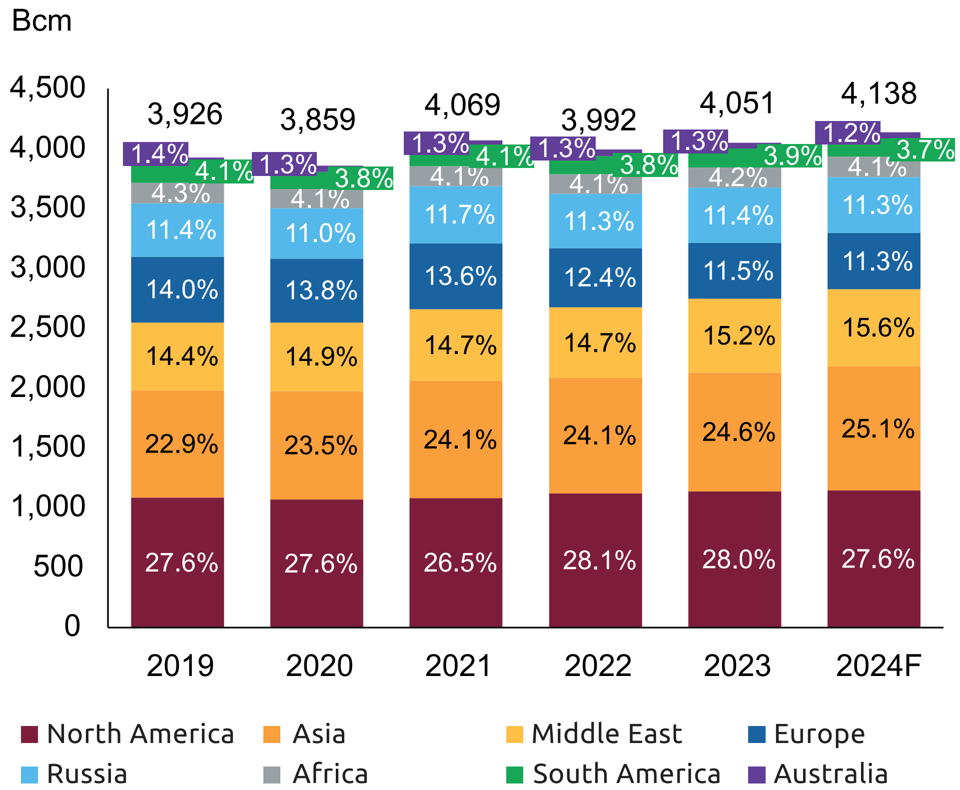
Key Messages

Figure 1: Global gas demand, split by region



Source: Rystad Energy

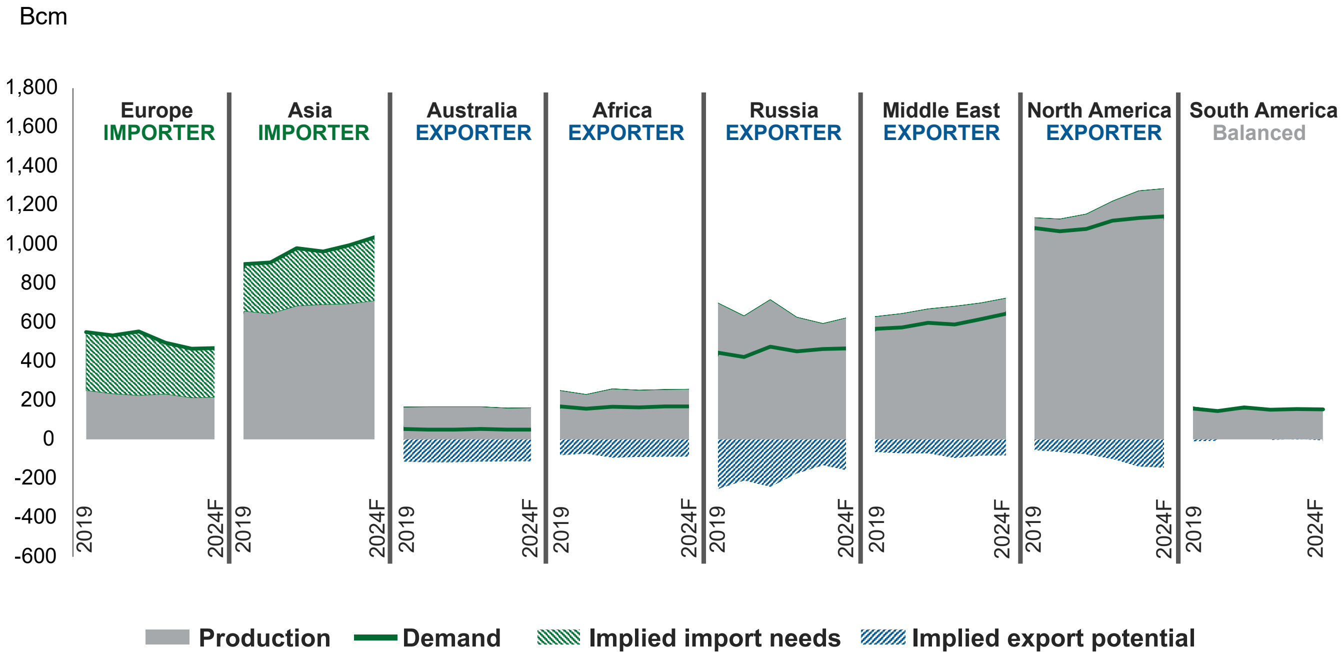
Global gas demand sustained its growth in 2023, increasing 59 Bcm (1.5%) and is expected to continue growing in 2024 with a further ~87 Bcm (2.1%) increase in demand.

In 2023, consumption increased in several regions, with Asia up by 32 Bcm (3.3%), the Middle East by 28 Bcm (4.7%), and North America by 14 Bcm (1.2%), outpacing a fall in consumption in Europe by 31 Bcm (-6.3%) and in Australia by 2 Bcm (-3.7%). In 2024, demand growth is expected to continue to be driven by Asia, up by ~43 Bcm (4.3%), the Middle East, up by ~29 Bcm (4.7%), and North America, up by ~8 Bcm (0.7%).

Global gas production also grew, rising 19 Bcm (0.5%) in 2023 relative to 2022 levels and is expected to continue growing in 2024, with supply increasing by ~96 Bcm (2.4%).

Growth in 2023 is largely attributable to increases in North America by 52 Bcm (4.3%), the Middle East by 16 Bcm (1.9%) and Asia by 3 Bcm (0.8%), offsetting a supply decline in Europe of 18 Bcm (-7.8%). Growth in 2024 is expected to be driven by the Middle East by ~26 Bcm (3.7%), Asia by ~17 Bcm (2.4%) and North America by ~12 Bcm (1.0%). Modest growth is also expected from South America with an additional ~4 Bcm (2.6%) of production increase, alongside Europe by ~2 Bcm (0.9%), Australia by ~1 Bcm (0.7%) and Africa by ~1 Bcm (0.5%).

Figure 2: Gas demand, production, and import/export volumes, split by region



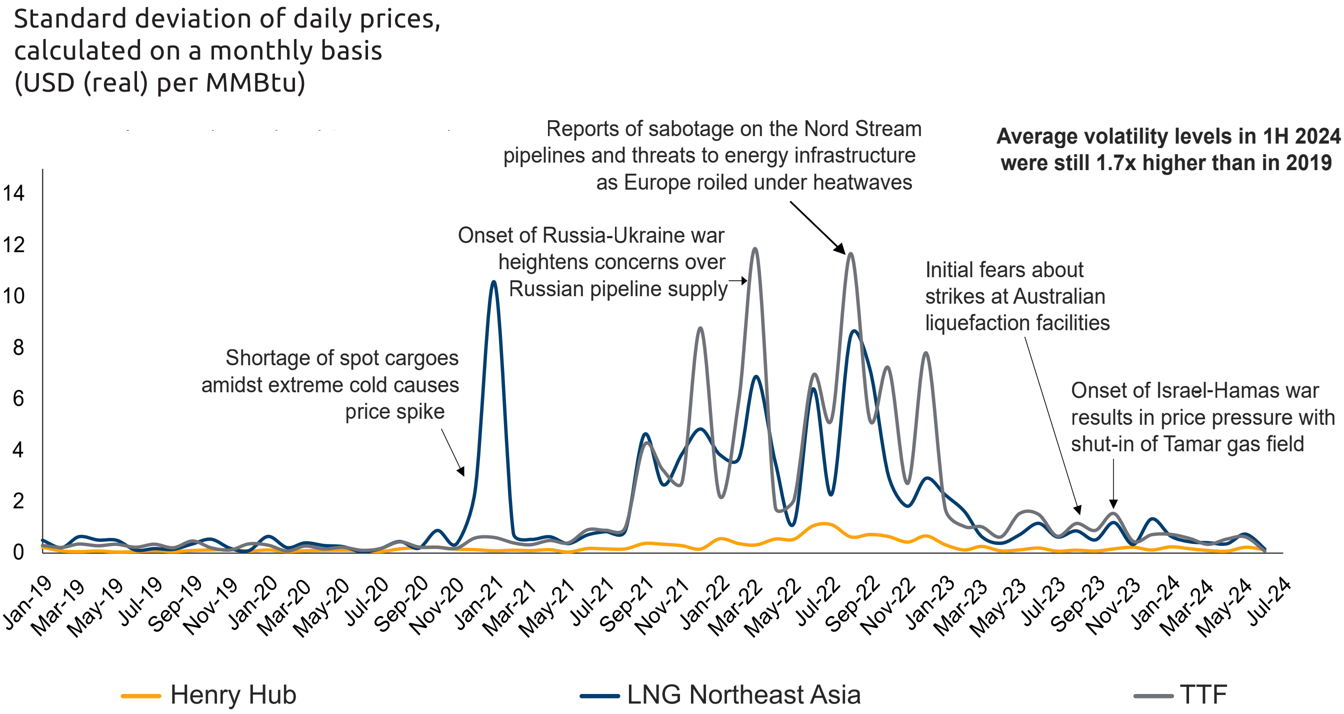
Source: Rystad Energy

Asia continues to drive import demand growth globally,
with North America and the Middle East growing exports to balance global supply and demand.

Implied import needs in Asia climbed by 29 Bcm (10.5%) in 2023 year-on-year, as countries like China boost gas consumption, a trend expected to continue into 2024. In contrast, European demand fell due to reduced demand from the power and industrial sectors, as well as lower seasonal needs.

This coincided with higher renewable and nuclear power generation. Implied import needs in Europe fell by 14 Bcm (-5.2%) in 2023 and are expected to remain flat in 2024. North America's export potential jumped by a notable 37 Bcm, as shale gas production boomed in the Permian, Haynesville and Eagle Ford plays, outpacing consumption. This trend is expected to soften in 2024, with some reversal of import potential growth. South America will continue to see a balanced market into 2024, as demand and supply match at continent level.

Figure 3: International natural gas price volatility

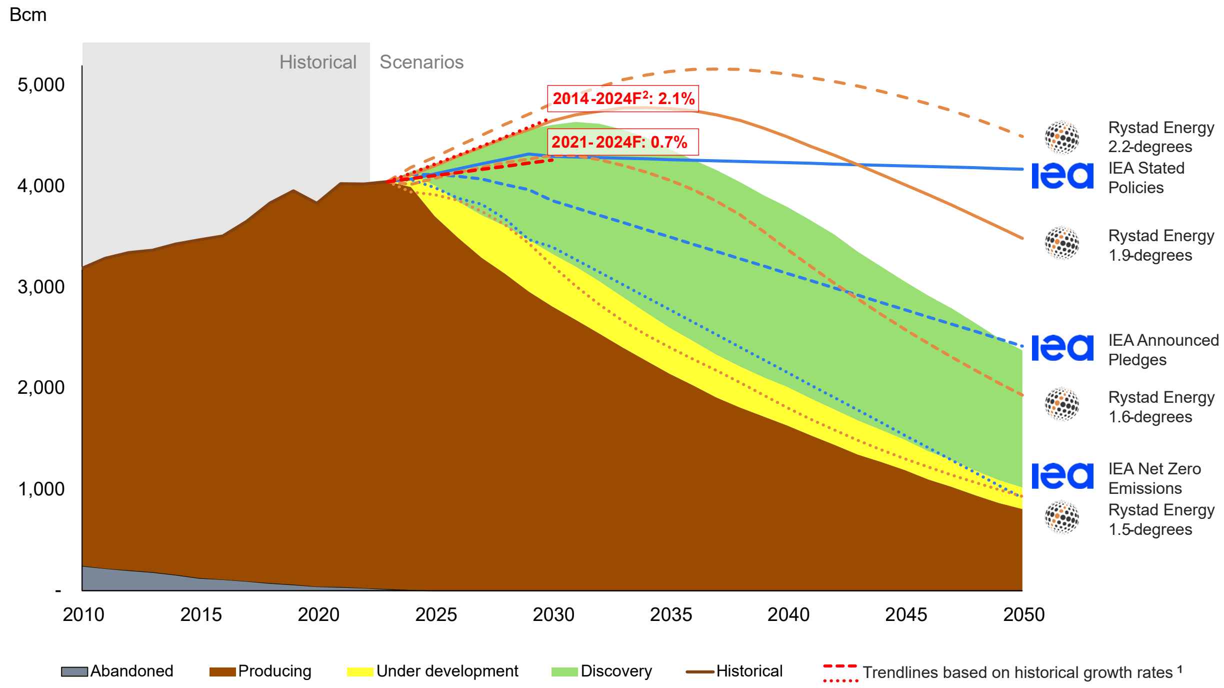


Source: Rystad Energy, Argus (LNG Northeast Asia)

Global gas markets remain fragile. While global gas markets have calmed down from record volatility in 2022, they remain fragile as energy security concerns persist.

Volatility levels remain above their levels during the pre-pandemic era. This is evident from market reaction to the Israel-Hamas war beginning in October 2023, and from implied Title Transfer Facility (TTF) volatility levels – as seen in the chart above – being 1.7x higher in the first half of 2024 relative 2019 (full-year) levels. Gas prices have also lowered since, especially in Europe, though they remain sensitive due to tight balances, with no major new supply additions expected to come online in 2024. Any significant shift in demand or supply has the potential to disrupt the current balance in place.

Figure 4: Global gas demand-supply balance under various degree scenarios, supply split by lifecycle



Note: [1] This analysis considers two trendlines: the 2021-2024F trendline and the 2014-2024F trendline. Each trendline uses a consistent annual growth rate towards 2030, which is calculated as the average of the annual growth rates of the historical years considered.

[2] The 2014-2024F trendline excludes Covid-19 impacted years 2020 and 2021 from the average growth rate calculation to adjust for the unusually low and high growth rates observed in the respective years.

Definitions: (a) Abandoned denotes all abandoned fields which have stopped producing or where production was suspended by owners. (b) Producing includes all the assets that are currently producing. Also, refinery gains are included. (c) Under development denotes assets for which development has been approved by companies & government, but production has not yet started. (d) Discovery includes assets where discoveries have been made but are not yet in a phase of further development (appraisal, field evaluation).

Source: Rystad Energy, IEA

Current levels of investment in natural gas supply are insufficient

to meet the demand trend towards 2030[1].

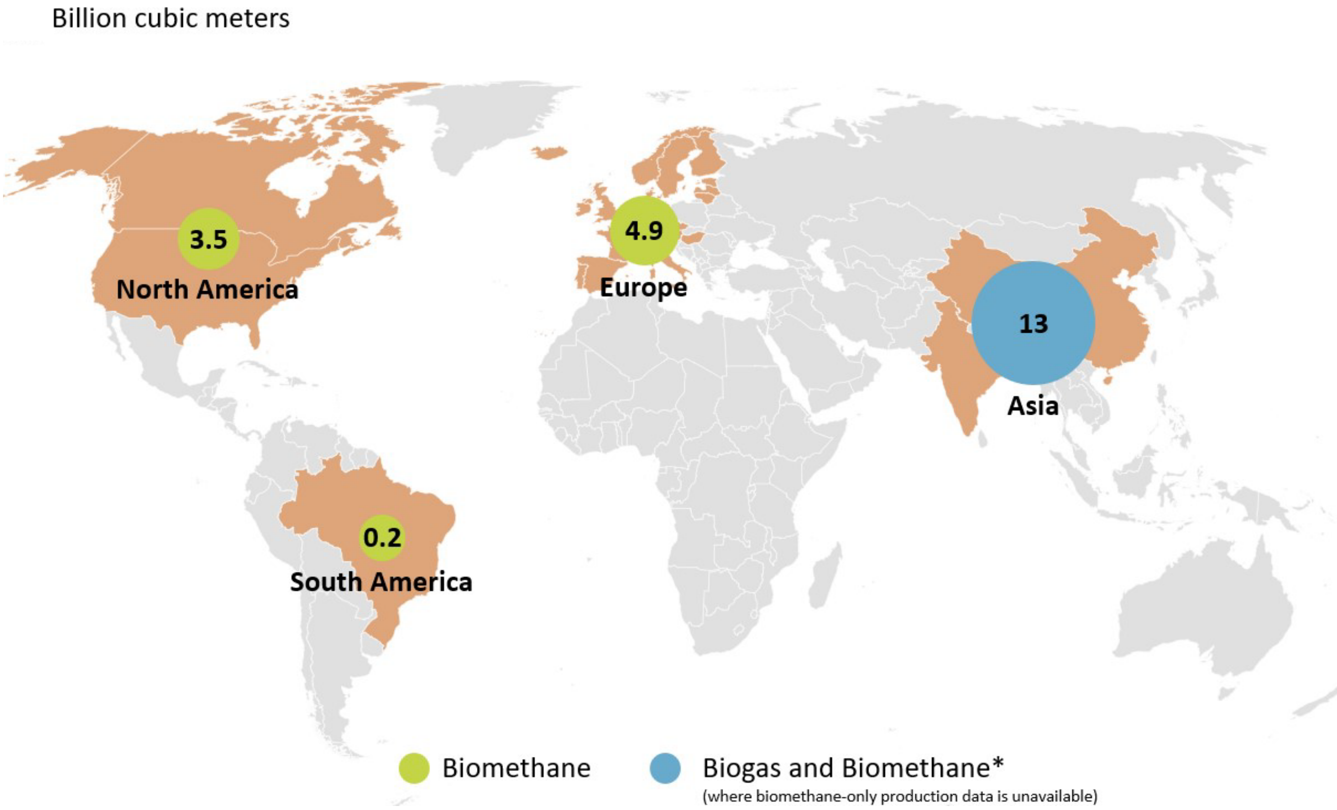
The historical trend of gas demand growth from economic development and improving living standards in the developing world, alongside new consumption trends and continued growth in energy use in the developed world, are keeping gas demand strong, while producing capacity and infrastructure investment are not keeping pace. The 2021-2024F gas consumption trendline on the chart shows a growth rate of 0.7%, in contrast with the demand decline trend assumed in the IEA's APS, NZE and Rystad Energy's 1.5-degree scenarios. The longer 2014-2024F growth rate of 2.0% further departs from the IEA's STEPS and Rystad Energy 1.6-degree scenarios.

If the more conservative trend of gas demand growth between 2021-2024F continues to 2030, and no new producing capacity is added, the gap in supply of around 927 Bcm (22%[2]) is expected in 2030. When considering trendline from 2014-2024F, this gap increases to around 1300 Bcm (29%[2]) in 2030, showing the extent to which supply needs to be scaled up if imbalances between gas demand trajectory and investments in gas production and infrastructure are not tackled. The world finds itself in a period of high energy uncertainty in 2024, and prudent policy to reconcile scenario assumptions with current trends will be essential to manage this uncertainty and ensure timely investment in needed supply resources. It is essential to balance current growth and development trends with long-term sustainability goals to effectively reduce emissions, while maintaining secure, reliable, and affordable energy systems.

[1] This is apparent when comparing gas production capacity with no additional investment towards 2030 to demand in IEA's Stated Policies, Announced Policies and Net Zero Emissions by 2050 scenarios from the 2023 Outlook, and Rystad Energy's latest 1.6-degrees, 1.9-degrees and 2.2-degrees scenarios. Rystad Energy's degree scenarios assume that global warming will be limited to the specified degree Celsius.

[2] This percentage refers to the gap between the historical trendline and 2030 production volumes given no new investment in gas supply, i.e. the shortfall in gas production volumes from currently operational and sanctioned projects in 2030, against the historical trendline.

Map 1: Global biomethane production, split by region



Note* The latest biomethane production values in each region are presented, using 2023 data where available; otherwise, 2022 data are used. Combined production value for biogas and biomethane values are provided for Asia where biomethane-only production data are unavailable.

Source: Rystad Energy; WBA; EBA; Argus

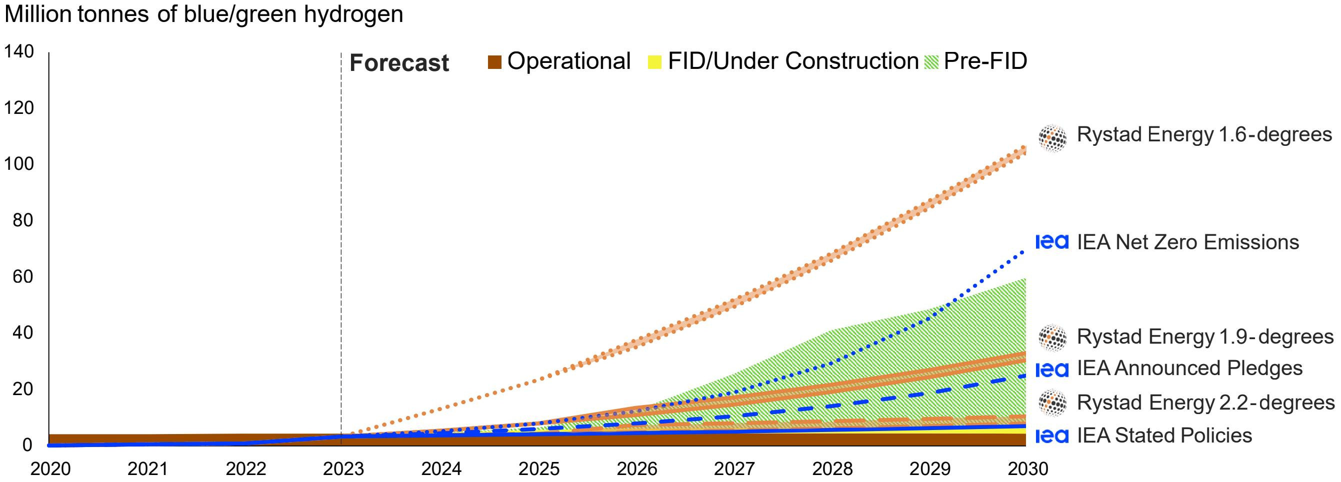
Global biomethane production is gaining momentum, with new centres of production emerging beyond the traditional market leaders of the EU and the US.

Biomethane offers a non-fossil renewably produced alternative to natural gas, which can be injected into existing natural gas infrastructure and used in the same way. Given that biomethane is often produced by capturing waste biogas from different parts of the economy, it has a high circular economy value.

Biomethane production in the EU grew rapidly at an annual rate of 24% from 2019 to 2022; however, to deliver on the EU's 2030 target of 35 Bcm, this pace needs to be accelerated to 36% from 2023 to 2030. North America continues to be another leader in biomethane production, and positive momentum has also been spreading to emerging production markets in China and India.

The current production levels of biomethane still remain significantly under their commercial potential, and this is a readily available opportunity to reduce global energy emissions that should be capitalised on. Supporting policy will continue to play an important role, including removing barriers, creating an incentivised environment to connect producers to existing natural gas grids to accelerate the adoption of biomethane, and facilitating efficient distribution and enabling economies of scale.

Figure 5: Global unrisked zero- and low-CO_2 hydrogen production capacity, known vs. aspired



Note: 'Unrisked zero- and low-CO_2 hydrogen production capacity' refers to the total production capacity of announced zero- and low-CO_2 hydrogen projects based on project owners' communicated production capacity and start-up date, without adjusting for the risk ('unrisked) related to project delays, regulatory permits and commerciality. Ranges for the different degree scenarios reflects variation in zero- and low-CO_2 hydrogen displacement rate in existing uses of grey hydrogen, that include but are not limited to conventional methanol-based chemicals, fertilisers, refineries and plastic.

Source: Rystad Energy; IEA

Zero- and low-CO_2 hydrogen production is expected to scale rapidly

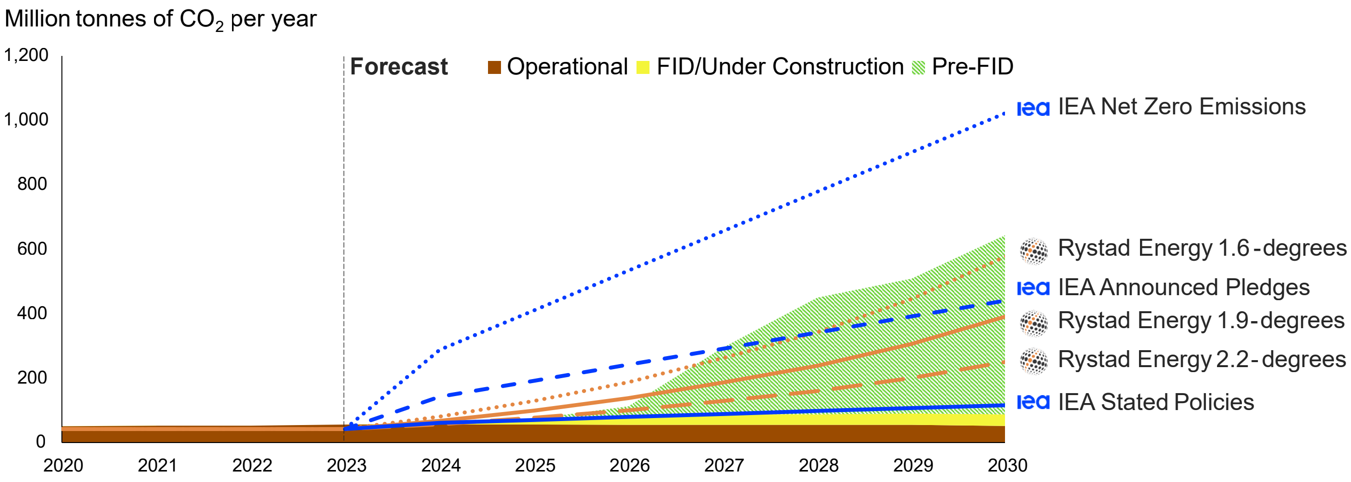
towards 2030 from its small base of ~4 to ~5 Mtpa, at ~45% per annum, though nearly ~90% of the projected 2030 production capacity is still in early planning stages, creating uncertainty over its growth momentum.

While the pace of FIDs has been increasing recently, the number of FIDs made today remains low. For instance, FID's for hydrogen generated using natural gas and carbon capture (blue) taken since 2023 account for around 76% of total blue hydrogen FIDs taken since 2019 (in terms of project capacity). Similarly, the capacity of hydrogen generated using renewable energy sources (green) projects that reached FID from 2023 onwards formed around 52% of total green hydrogen capacity that reached FID since the beginning of green hydrogen development. Historically, the pace of green hydrogen production build-out had lagged blue hydrogen development, with green hydrogen accounting for only around 4% (around 0.2 Mtpa) of total zero- and low-CO_2 hydrogen production today.

This could change moving forward. Based on announced addition, the annual growth rate of green hydrogen capacity from 2023 to 2030 (115%) is almost four-fold that of blue hydrogen (31%). Despite the strong growth momentum, the announced increase in green and blue hydrogen production capacity by 2030 remains inadequate to meet the decarbonisation trajectory under the IEA net zero scenario. This calls for more robust policy support for zero- and low-CO_2 hydrogen to prevent delays and ensure timely completion.

Recently, this came in the form of increasingly colour agnostic hydrogen policies, that focused more on the carbon intensity of the hydrogen produced rather than its production methods. In this context, natural gas production and infrastructure will play a critical role in enabling the rollout of zero- and low-CO_2 hydrogen. Natural gas can support the scaling up of blue hydrogen production by providing a readily available feedstock, and repurposing natural gas infrastructure can help reduce costs associated with the development of hydrogen infrastructure.

Figure 6: Global unrisked CO_2 capture capacity, known vs aspired



Note: 'Unrisked CO_2 capture capacity' refers to the total capacity of announced CO_2 capture projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality.

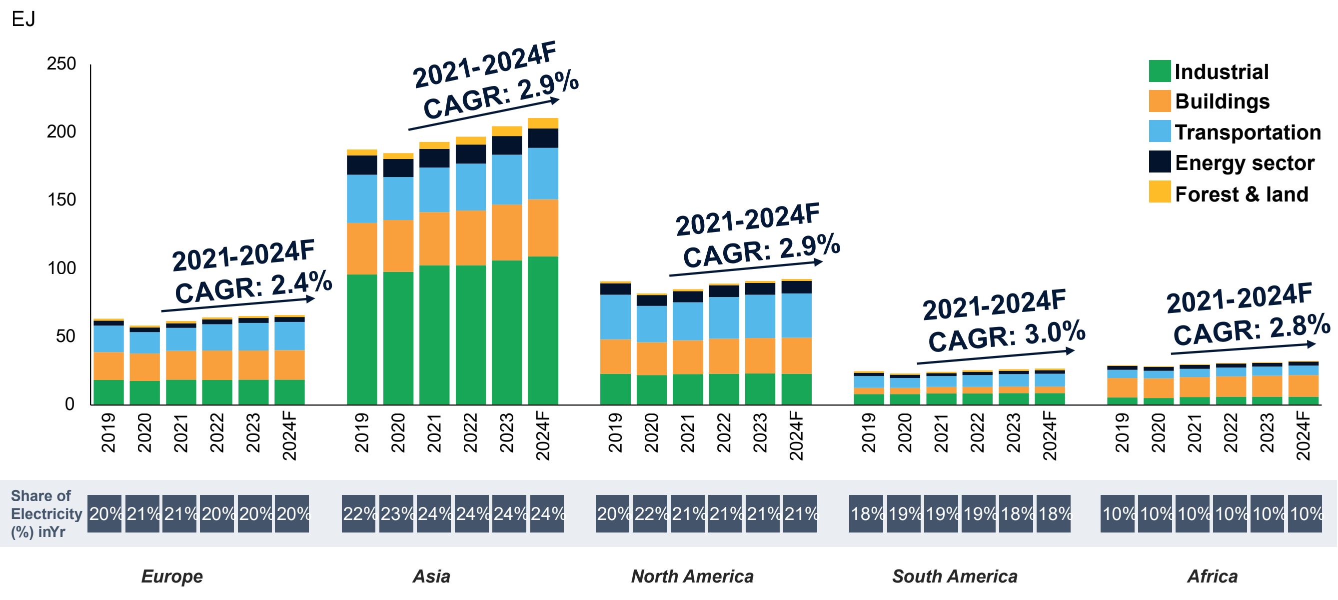
Source: Rystad Energy; IEA

CO_2 capture capacity is a fundamental technology for the energy transition to succeed, and its development has been picking up steam, but the rate and scale remain orders of magnitude below what is needed.

Based on announced projects, CCS capacity is set to grow by 42% annually from 2023 to 2030, 14 times higher than the growth rate of 3% annually from 2020 to 2023. However, 86% of 2030's CO_2 capture capacity pipeline is driven by pre-FID projects that have faced delays. This is primarily caused by prolonged front-end engineering and design (FEED) study phases, expected to affect one-third of projects this decade, as most commercial CCUS projects are still in the early stages of development. Medium and large CCUS hub projects – increasingly developed to take advantage of the flexibility and economies of scale gained – would be particularly impacted as they require extensive early assessment studies due to their scale and complexity. Thus, achieving the CO_2 capture capacity required under Rystad Energy's 1.6-degree scenario remains uncertain. However, this could be mitigated by stronger collaboration between industry players and governments to accelerate permitting processes and improve bankability of projects.

Natural gas infrastructure will be crucial for the wider adoption of low-CO_2 and renewable gases. The integration of biomethane – chemically identical to natural gas – into the existing energy system as well as its efficient distribution, will require a connection to the gas grid. Similarly, repurposed gas infrastructure will play a key role in enabling the large-scale roll-out of zero- and low-CO_2 hydrogen, by supporting scalable production and distribution. Lastly, existing gas infrastructure can be leveraged in the transport of captured CO_2, with depleted gas fields serving as potential storage sites. Overall, gas infrastructure is critical for the efficient integration of low-carbon and renewable gases into existing energy systems.

Figure 7: Final energy demand* split by sector, region and share of electricity in total demand



Note* Final energy demand is most reflective of global energy consumption trends, and has seen a consistent pace of growth with primary energy demand.

Source: Rystad Energy

Global energy demand is continuously growing in both developing and developed regions, overshooting energy transition scenario assumptions, and impacting demand drivers for natural gas, and compounding global risk of energy shortages.

Europe's overall energy demand has increased over the past five years, notwithstanding policy incentives to increase efficiency and continued industrial decline. North American energy demand has surpassed 2019 levels, driven by the transport sector and now new demand from data centres. Asia has seen much more robust energy demand growth, particularly in the industrial sectors of India and China.

Africa's energy demand has grown faster than most regions, led by urban development, but still remains below the rate it would need to achieve to reach full energy access for its population. In both South America and Africa, equitable electricity access remains a significant challenge. Should energy demand continue to evolve as it has in the recent past, none of the key regions are likely to reach 2030 targets outlined in different demand scenarios[3].

[3] *This analysis primarily considers 7 energy demand scenarios from 3 institutes: IEA's Stated Policies, Announced Policies and Net Zero Emissions by 2050 scenarios from the 2023 Outlook, IEEJ's Reference Case scenario from the 2024 Outlook, and Rystad Energy's latest 1.6-degrees, 1.9-degrees and 2.2-degrees scenarios. Rystad Energy's degree scenarios assume that global warming will be limited to the specified degree Celsius.*

New sources of power demand are emerging across regions and sectors, led by global events and shifts such as the adoption of energy-intensive AI technology and increasing temperatures (driving cooling demand) - this trend is expected to have implications on the gas market dynamics.

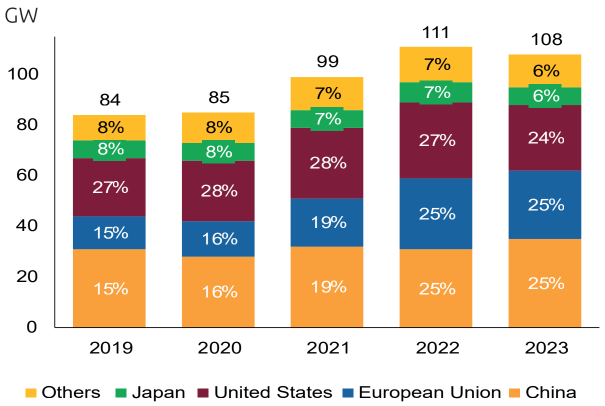
AI-focused data centres are driving a surge in electricity demand, especially in the US. Extreme weather conditions, such as heatwaves, are significantly increasing global cooling demand, especially in developing countries with low but growing air conditioner ownership, like India. As cooling becomes the fastest-growing use of energy in buildings, it puts upward pressure on electricity demand carving a space for gas to meet these needs.

Simultaneously, the rapid adoption of heat pumps, despite being on average more energy-efficient compared to incumbent heating systems, may increase electricity demand particularly during the heating season, thus also impacting system peaking. The continuous electrification of the transport sector, led by China, is also set to increase electricity demand. Electric vehicles are set to displace demand for gasoline, with natural gas stepping in to relieve pressure on power grids worldwide.

Figure 8: Electrification and new energy demand trends

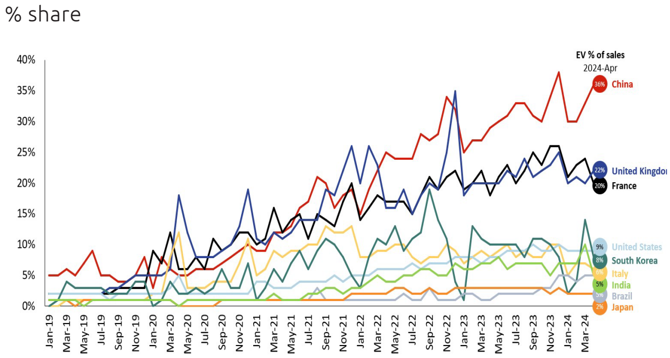
Heat pump adoption set to spike winter peak electricity demand

Annual heat pump sales, split by region, 2019-2023



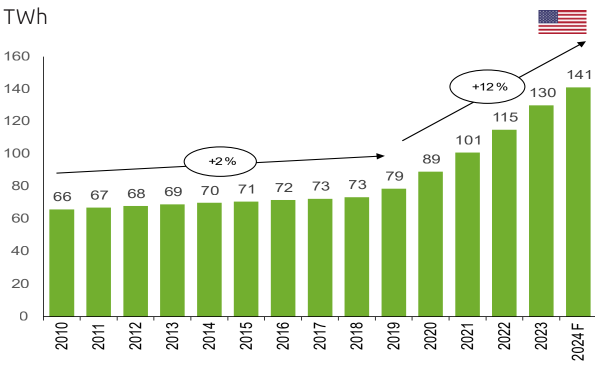
Strong momentum for EV adoption increases power demand

Monthly EV share of sales per country for selected countries



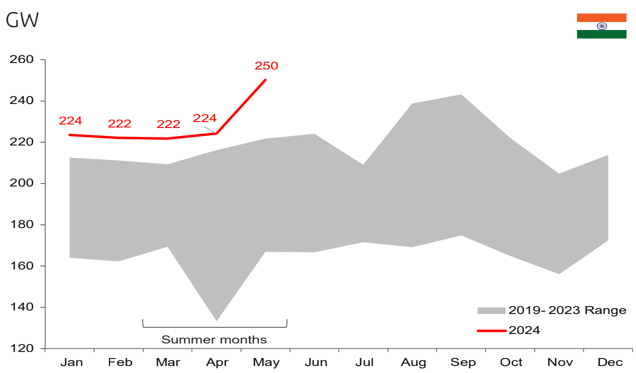
Growing AI-focused data centres contribute to electricity demand surge

Electricity demand from US data centres, 2019-2024F



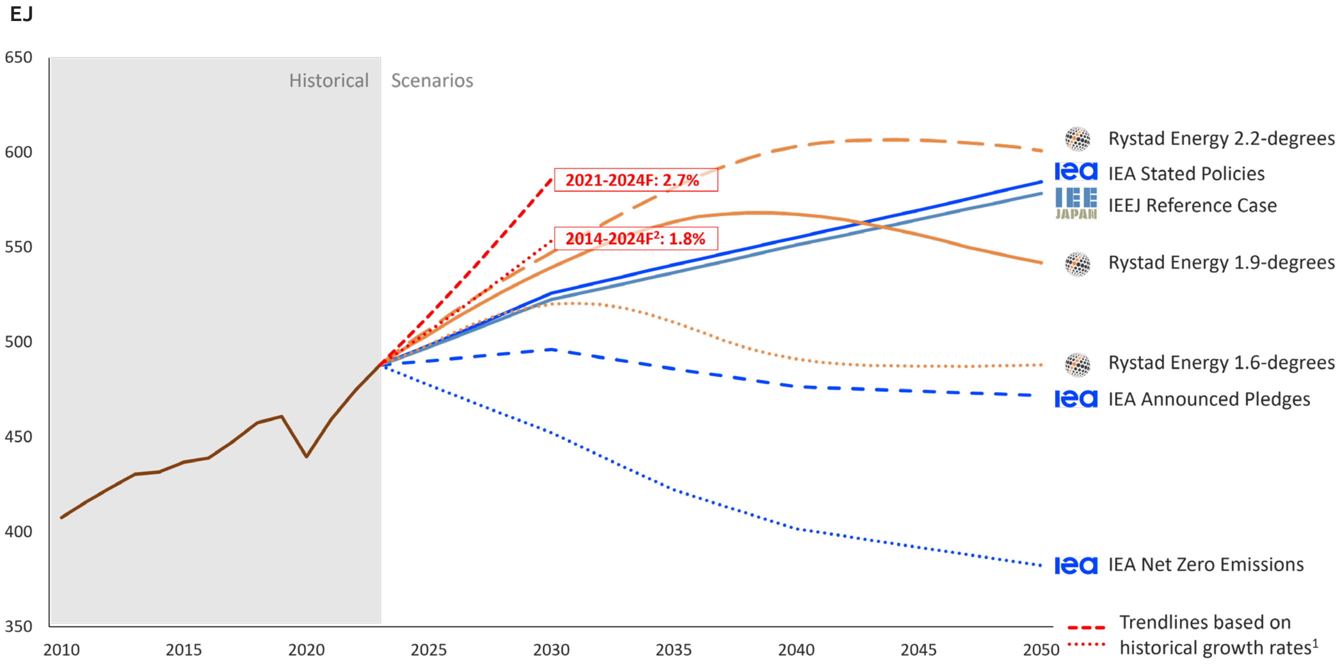
Higher cooling demand driven by extreme weather events challenges power systems

Monthly peak power demand in India, 2019-2024



Source: Rystad Energy

Figure 9: Global final energy demand growth trends, historical vs. aspired



Gap between trendlines and 2030 scenario targets: *For reference, Europe energy demand was 65 EJ in 2023*

Scenario	IEA Net Zero Emissions	IEA Announced Pledges	IEA Stated Policies	RE 1.6-degrees	RE 1.9-degrees	RE 2.2-degrees	IEEJ Reference Case
2021 – 2024F trendline gap	134 EJ	90 EJ	60 EJ	66 EJ	48 EJ	39 EJ	64 EJ
2014 – 2024F[2] trendline gap	101 EJ	57 EJ	27 EJ	33 EJ	14 EJ	6 EJ	31 EJ

Note: [1] This analysis considers two trendlines: the 2021-2024F and the 2014-2024F trendline. Each uses a consistent annual growth rate towards 2030, which is calculated as the average of the annual growth rates of the historical years considered.
[2] The 2014-2024F trendline excludes COVID impacted years 2020 and 2021 from the average growth rate calculation to adjust for the unusually low and high growth rates observed in the respective years.

Source: Rystad Energy; IEA

Uncertainty over future energy demand adds risk to the supply mix and infrastructure needs. **In an era of increasing energy uncertainty, where scenario assumptions of energy demand may understate the pace of current trends, natural gas will be essential as a reliable and scalable energy source for a balanced and future-ready energy system that considers sustainability, security, and affordability.**

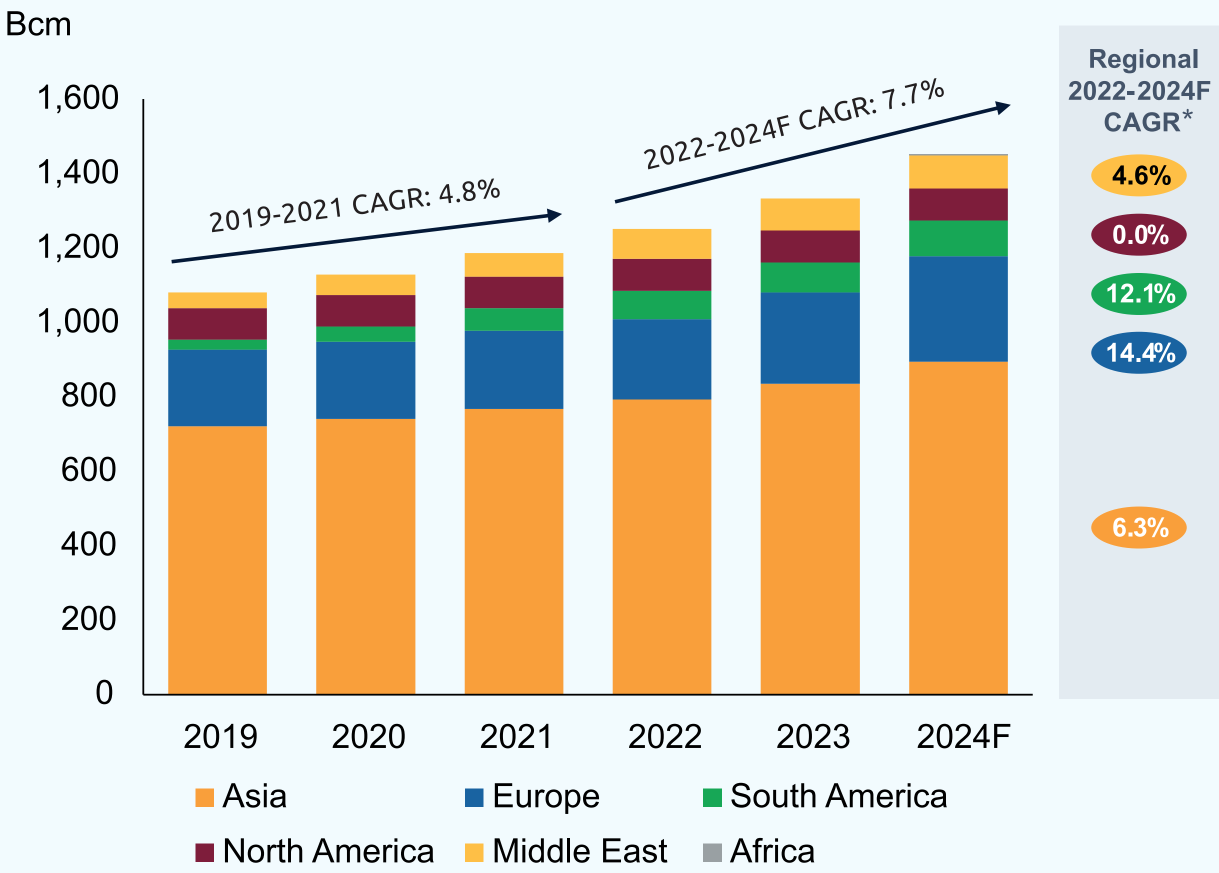
The future of energy demand is uncertain, influenced by factors such as economic growth, energy efficiency, emergence of energy-intensive technologies and growing incidence of extreme weather events. If energy demand continues to evolve as in recent years, it may diverge significantly from scenario pathways, potentially leading to a gap between demand and planned supply of gas and low-CO_2 energy. Alongside growing demand, global annual emissions have been rising and are set to exceed 2.5°C of warming on their current trajectory.

Balancing current growth trends with long-term goals calls for the planning of a resilient and adaptable energy system which makes use of a diverse and scalable mix of energy sources, including renewables and decarbonised gases. **Natural gas has the greatest potential to complement renewables in this energy transition, providing the reliability needed to balance intermittency and scalability issues. However, the decisions on investment in supply that could be available in 5-6 years from now should be made today.**

1 / Natural gas market fundamentals overview

Highlight

Figure 10: Global LNG receiving capacity, split by region



Note* Africa not shown in CAGR calculation as capacity increased from 0 to 3 Bcm in 2024F.

Source: Rystad Energy

Global regasification capacity has seen a rapid expansion since 2022, with the 2022 to 2024F Compound Annual Growth Rate (CAGR) expected to be 7.7%, building on an already strong 2019-2021 CAGR of 4.8%. For Europe, this was mainly driven by the need to pivot from Russian pipeline gas after the Russia-Ukraine crisis in 2022, with the largest regasification additions in Germany (25 Bcm), the Netherlands (12 Bcm), followed by Spain and Italy. In Asia, regasification capacity growth was largely attributable to imports meeting increasing natural gas demand in China and India, which has also resulted in a built-out of liquefaction capacity in other regions such as the US. The development of LNG infrastructure and trade helps to create a more liquid market, bringing gas where it is most needed. With increasing interconnectivity of the LNG market, regional demand or supply shocks can become more likely to impact global prices.

I. Key changes in the natural gas market

Through 2023 and to July 2024, the global gas market has seen significant relief from the historically high prices and volatility of 2022. However, fragility of the gas market is still top-of-mind, as energy security concerns persist amidst still tight supply, and both prices and volatility remain elevated compared to the pre-pandemic era.

Global gas demand in 2023 increased by 59 Bcm (1.5%) relative to 2022 levels, driven by demand growth in Asia, North America, and the Middle East, which outpaced a notable demand decline in Europe. **Global gas production** grew by a modest 19 Bcm (0.5%), attributable to supply increases from North America, counteracted by production declines in Europe and Russia. The **gas market** was relatively calm in 2023, with a downward price trend, which was temporarily counteracted in late August 2023, when fears about potential strikes at Australian liquefaction facilities drove prices up. Later in the year, the onset of the Israel-Hamas war also brought about a brief spell of volatility with the October temporary shut-in of the Tamar gas field in Israel. The last quarter of 2023 and the beginning of 2024 saw prices calming again, due to low seasonal demand with mild weather and full storage levels in Europe, at the start of the heating season. However, prices have climbed from March to July 2024, reacting to demand spikes, supply fluctuations, and geopolitical risks, including heatwaves in the US and across Asia, ongoing geopolitical

Table 1: Key 2023 year-on-year changes in the global gas market

	Consumption		Production		Gross imports		Gross exports	
Regions	Bcm	% change	Bcm	% change	Bcm	% change	Bcm	% change
Asia	+31.7	+3.3%	+3.0	+0.4%	+17.4	+3.9%	−5.7	−3.4%
Europe	−31.3	−6.3%	−17.7	−7.6%	−45.5	−7.9%	−3.7	−1.2%
North America	+13.8	+1.2%	+52.4	+4.3%	+4.5	+2.6%	+15.5	+5.6%
South America	+3.5	+2.3%	−2.0	−1.3%	−0.9	−3.3%	−4.7	−15.5%
Africa	+4.7	+2.8%	+3.9	+1.5%	+0.9	+6.0%	−2.3	−2.3%
Middle East	+27.6	+4.7%	+16.1	+2.4%	−5.9	−5.9%	−5.2	−2.9%
Russia	+11.0	+2.4%	−31.6	−5.0%	+0.2	+2.7%	−24.3	−14.1%
Australia	−2.4	−4.5%	−5.2	−3.1%	−3.9	−81.6%	−3.0	−2.4%
World	+58.6	+1.5%	+18.9	+0.5%	−33.2	−2.5%	−33.2	−2.5%

Source: Rystad Energy

Table 2: Key 2024 year-on-year changes in the global gas market

Regions	Consumption		Production		Gross imports		Gross exports	
	Bcm	% change	Bcm	% change	Bcm	% change	Bcm	% change
Asia	+ 43.2	+ 4.3%	+ 16.6	+ 2.4%	+ 35.2	+ 7.7%	+ 8.3	+ 5.0%
Europe	+ 3.6	+ 0.8%	+ 1.9	+ 0.9%	− 10.6	− 2.2%	− 2.9	− 1.3%
North America	+ 7.8	+ 0.7%	+ 12.5	+ 1.0%	+ 4.6	+ 2.6%	+ 7.7	+ 2.6%
South America	− 2.1	− 1.3%	+ 4.0	+ 2.6%	− 0.9	− 3.8%	+ 2.8	+ 11.2%
Africa	+ 1.1	+ 0.7%	+ 1.3	+ 0.5%	+ 2.2	+ 14.2%	+ 7.4	+ 7.7%
Middle East	+ 29.0	+ 4.7%	+ 25.9	+ 3.7%	+ 5.1	5.4%	+ 4.1	+ 2.4%
Russia	+ 4.1	+ 0.9%	+ 32.4	+ 5.4%	− 1.8	− 21.3%	+ 11.1	+ 7.5%
Australia	0.0	0.0%	+ 1.2	+ 0.7%	− 0.6	− 71.8%	− 3.7	− 3.0%
World	+ 86.8	+ 2.1%	+ 95.8	+ 2.4%	+ 33.2	+ 2.5%	+ 34.9	+ 2.7%

Source: Rystad Energy

tensions in the Middle East and Europe, and fluctuations and outages in Norwegian, Australian and American supply. **Global trade** in 2023 also grew, with net pipeline trade growing to 475 Bcm and LNG trade rising to 537 Bcm. The top three largest natural gas exporters in 2023 were Russia at 139 Bcm, Qatar at 128 Bcm, and the US at 127 Bcm, while the top three largest importers were China at 160 Bcm, Japan at 91 Bcm and Germany at 77 Bcm.

This chapter examines key developments in global gas markets in 2023 and includes a near-term forecast for 2024 (2024F), which is compiled using available actual data up to July 2024 and Rystad Energy's forecast to the end of the year. It offers a comprehensive overview and analysis of the forces at play and their impact on the global gas market today and for the near term.

II. Natural gas market demand

a. Global

Map 2: World map with gas demand by region

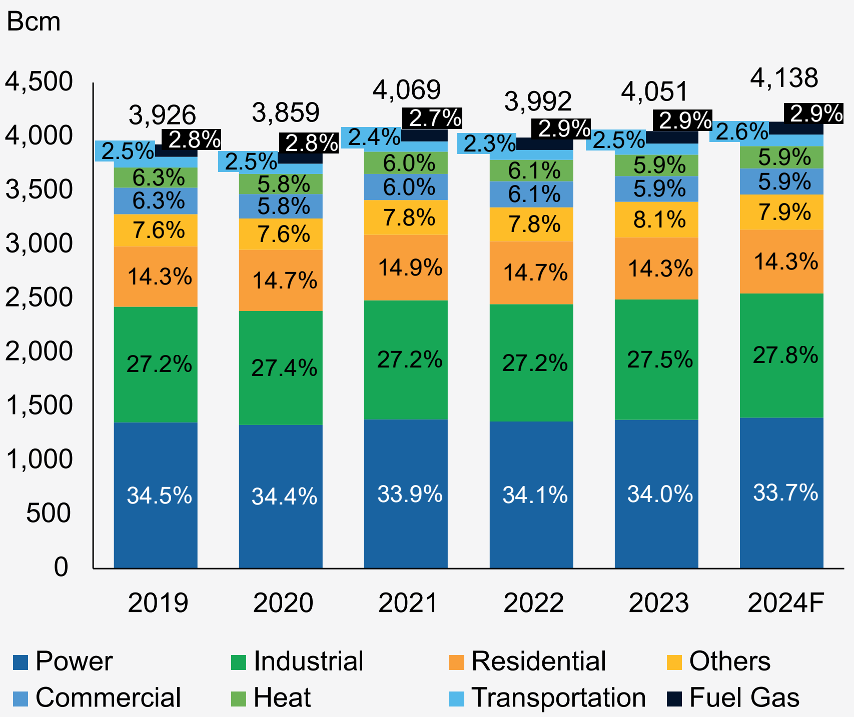
North America		South America		Europe		Africa		Middle East		Russia		Asia		Australia	
Year	Bcm	Year	Bcm	Year	Bcm	Year	Bcm	Year	Bcm	Year	Bcm	Year	Bcm	Year	Bcm
2019	1,088	2019	159	2019	550	2019	170	2019	567	2019	446	2019	898	2019	54
2020	1,067	2020	146	2020	534	2020	158	2020	574	2020	423	2020	906	2020	51
2021	1,079	2021	165	2021	553	2021	167	2021	598	2021	475	2021	980	2021	52
2022	1,121	2022	153	2022	496	2022	164	2022	589	2022	452	2022	964	2022	53
2023	1,135	2023	157	2023	465	2023	169	2023	616	2023	463	2023	995	2023	51
2024F	1,143	2024F	155	2024F	469	2024F	170	2024F	645	2024F	467	2024F	1,038	2024F	51

Source: Rystad Energy

Global gas demand grew by about 59 Bcm (1.5%) in 2023 year-on-year (y-o-y), driven largely by demand growth in Asia at 32 Bcm (3.3%), the Middle East at 28 Bcm (4.7%), and North America at 14 Bcm (1.2%), outpacing drops in consumption in Europe of 31 Bcm (-6.3%) and Australia at 2 Bcm (-3.7%). In 2024F, about 87 Bcm (2.1%) of further demand growth is expected, driven by Asia at ~43 Bcm (4.3%), the Middle East at ~29 Bcm (4.7%), and North America at ~8 Bcm (0.7%). In terms of sectors, industrial, power, and transport demand for gas grew the most in 2023, at ~28 Bcm (2.6%), ~17 Bcm (1.7%), and ~7 Bcm (7.5%) respectively. This growth is expected to continue at a similar rate in 2024.

Asia saw 32 Bcm (3.3%) of demand growth, with industrial and city gas needs in China counterbalancing declines in Japan and South Korea, attributable to the latter scaling up their nuclear generation. The strong growth trend in China has

Figure 11: Global gas demand, split by demand sector*



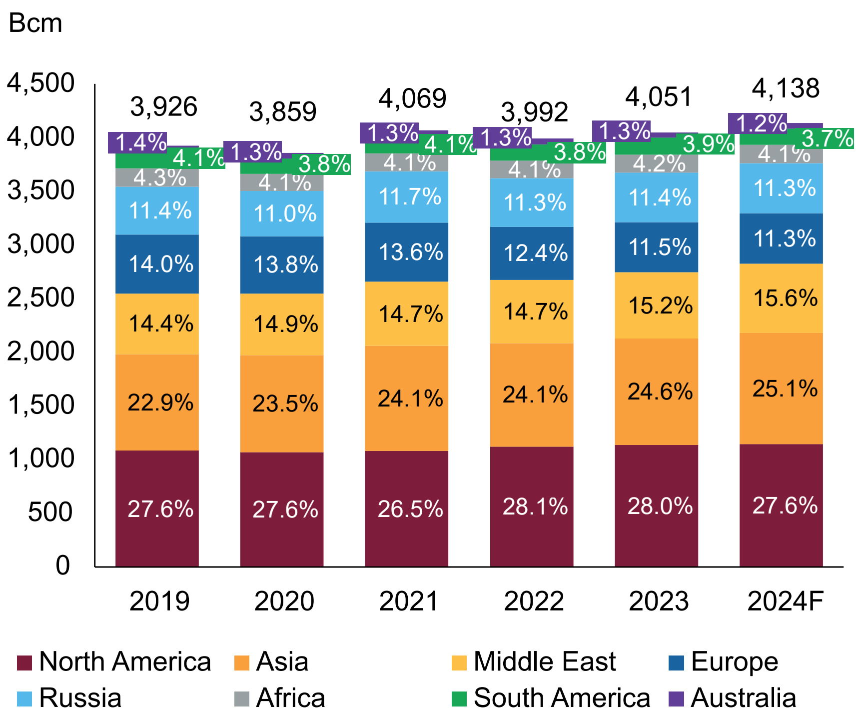
Source: Rystad Energy

Note*

Power: Gas used as fuel in the electric power sector (including combined heat and power plants) **Industrial:** Gas used in manufacturing establishments, refining, mining, mineral extraction, agriculture, forestry, fisheries, chemicals and other industrial activities. **Residential:** Gas used in private dwellings, including apartments, for heating, air-conditioning, cooking, water heating, and other household uses. **Commercial:** Gas used in the sale of goods or services for the same purposes as for the residential sector. **Transportation:** Gas used in well, field, and lease operations, field compressor and gas processing plants. **Heat:** Gas used in boilers and pumps for district heating. **Fuel Gas:** Gas used in well, field, and lease operations, field compressor and gas processing plants. **Others:** Gas used in non-specified sectors, or used in the operation of transporting gas, primarily in transmission and distribution pipelines.

continued and accelerated in 2024, with an expected ~34 Bcm of new demand this year. Southeast Asia experienced slight demand growth in 2023 with 2 Bcm of additional demand from Malaysia, driven by industry, and 2 Bcm from Thailand, driven by the power sector. South Asia also saw a boost in demand, responding to lower prices, notably India with 7 Bcm of growth. The Middle East in 2023 realised 28 Bcm (4.7%) of demand growth, from both power and industrial use – driven by rising consumption in Iran, Iraq, Saudi Arabia, Oman and Qatar. North America experienced 14 Bcm (1.2%) of demand growth in 2023, as low Henry Hub prices encouraged greater gas consumption, particularly within the power industry while coal consumption declined.

Figure 12: Global gas demand, split by region



Source: Rystad Energy

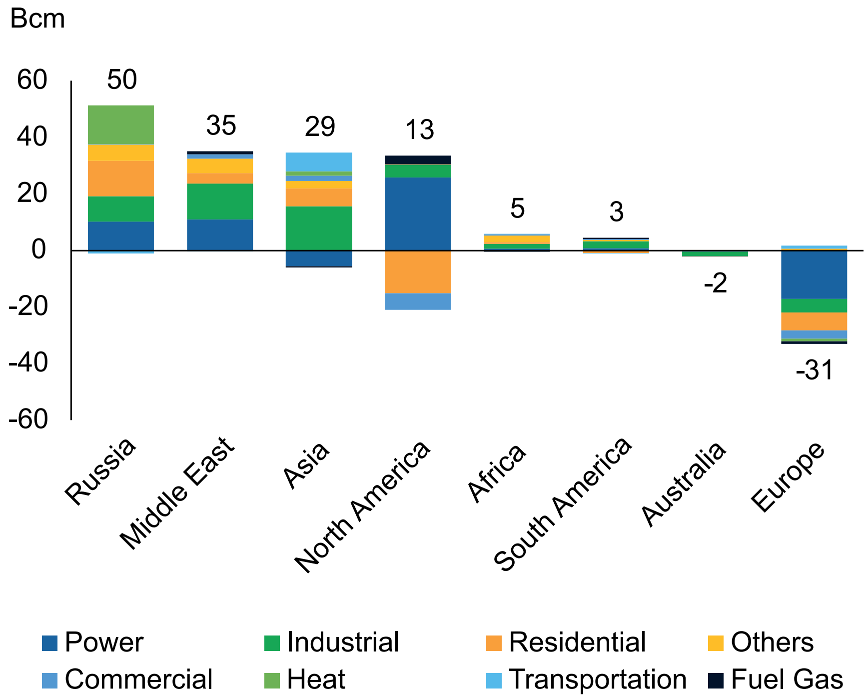
Africa, South America and Australia had less of an absolute impact on demand growth globally in 2023, with Africa's regional growth of 5 Bcm (2.8%) being driven by power and industrial sectors in Egypt and Algeria. South America saw an uptick of 3 Bcm (2.3%) y-o-y, attributable to growth in Argentina and Colombia offsetting a decline in Brazil. Australia had a small reduction in gas demand of 2 Bcm (-4.5%) due to a milder winter and ample coal and renewables generation in its east coast market. In contrast, European demand dropped by 31 Bcm (-6.3%) as total power demand fell, and renewable output climbed, amidst reduced demand in the industrial sector.

b. Europe

Over half of Europe's gas demand reduction was in the power sector, alongside a combined decline of 9 Bcm (-5.0%) in the residential and commercial sectors, driven by a milder winter, and a 5 Bcm (-4.0%) fall in industrial gas demand. Natural gas demand decline is anticipated to reverse slightly in 2024 as Europe and global markets adjust to a changed supply picture. This is likely to result in a slight growth of ~4 Bcm (0.9%), attributable to a marginal rebound in industrial demand and consumption in the residential and commercial sectors, outpacing the continued decline in the power sector.

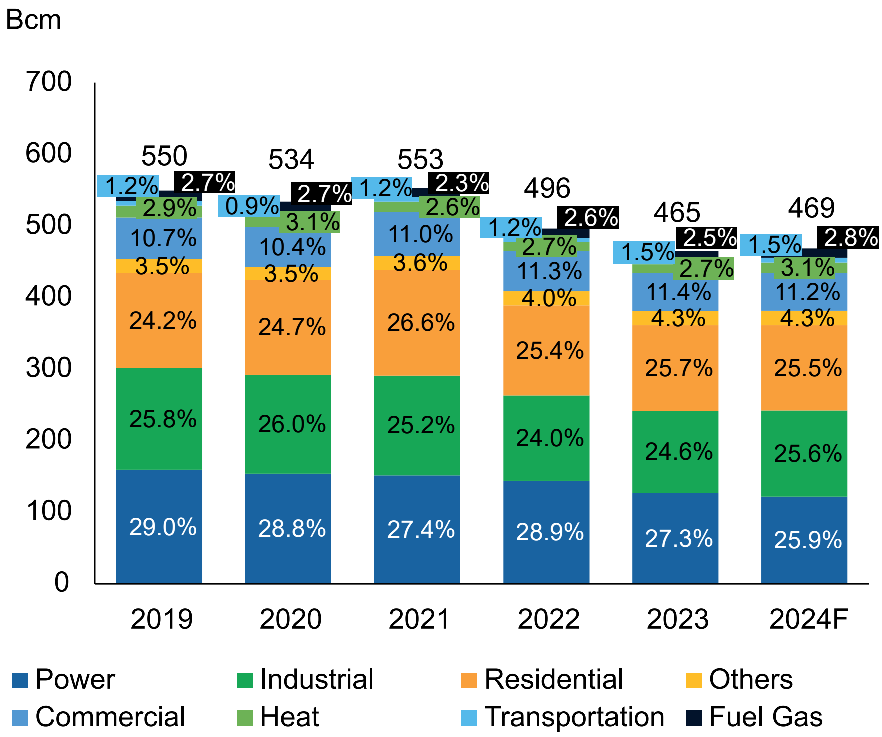
The overall decline in power demand coupled with this increased renewable generation has driven a 17 Bcm (11.7%) decline in gas demand for the power sector in 2023 relative to 2022. The decline is expected to continue into 2024 as Europe is expected to surpass 50% of power generation from renewables for the first time this year. However, this decline is slated to occur at a slower rate, reaching ~5 Bcm (-3.5%) relative to 2023.

Figure 13: 2023 Global gas demand year-on-year change, split by sector



Source: Rystad Energy

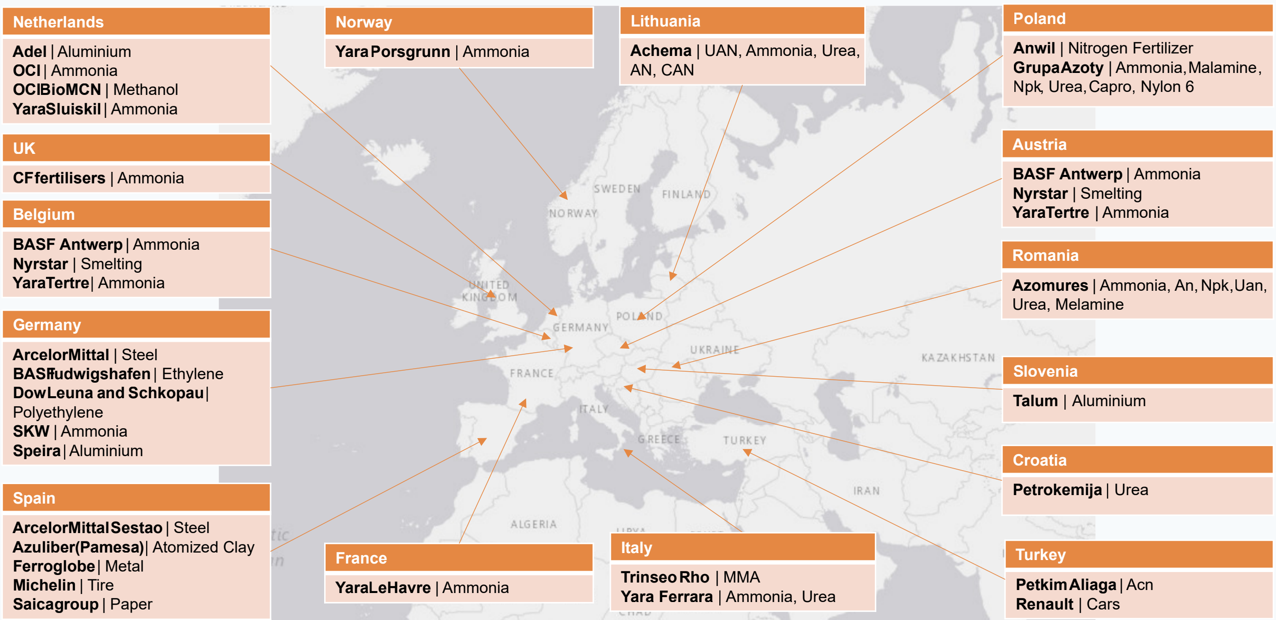
Figure 14: Europe gas demand, split by sector



Source: Rystad Energy

Case study: Industrial demand decline in Europe

Figure 15: Key European industrial plants with shut-in production in 2022



Source: Rystad Energy

The energy supply crisis in Europe led to a significant decline in gas demand used for industrial processes as feedstock, for heating, and for on-site power generation, as a response to high prices and high volatility in gas markets. The European industrial sector was already grappling with challenges remaining from the Covid-19 pandemic, including supply chain bottlenecks, rising costs, and material shortages. The onset of the Russia-Ukraine war exacerbated these issues, creating a perfect storm for industries reliant on natural gas. As the crisis progressed and prices skyrocketed further, numerous companies sought to reduce operations, shut down plants, or relocate production overseas. Industrial demand in Europe declined by 25 Bcm (-17.8%) from 2021 to 2023.

Moving forward, some demand is likely to rebound from temporary curbs and fuel-switching, which Rystad Energy estimates to be around 5% or 6 Bcm, in 2024. However, as much as two-thirds of the decline in European industrial gas demand could be structural, resulting from permanent efficiency optimisation, relocation of production beyond European borders, and the structural shift in European gas markets. To adapt, some manufacturers have also invested in alternative technologies. For instance, BASF built the world's largest heat pump at its Ludwigshafen site in June 2022, switching away from direct use of natural gas. Many companies have relocated production or increased investments outside of Europe, for instance to the US, where energy costs are lower and policy incentives like the Inflation Reduction Act (IRA) are attractive. For instance, Yara, a Norwegian fertiliser producer, announced in June 2023 its strategic ambition to invest in blue ammonia capacity in the US, a move that was directly influenced by the IRA, while its European ammonia production in 2023 was curtailed by 19%.

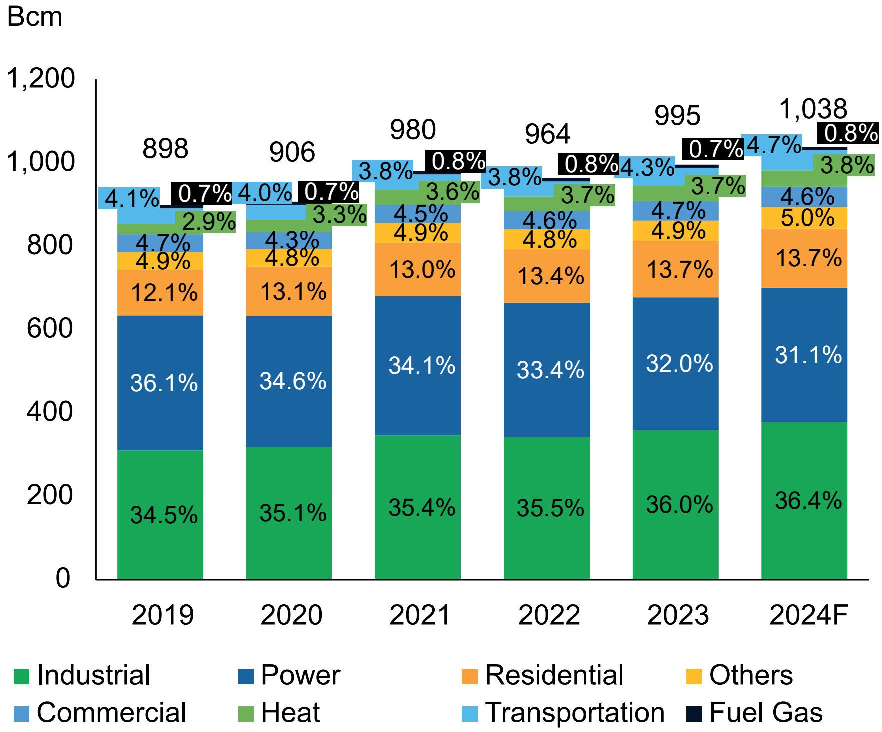
c. Asia

Gas demand in Asia saw continued growth in 2023, rising 32 Bcm (3.3%) from 2022 to reach 995 Bcm. At the continent-level, this was mainly driven by industrial, residential, and commercial growth outpacing a 3 Bcm (-1.1%) decline in power sector demand for gas in the year. At the country-level, China and India were the main contributors to the region's growth. China's gas demand increased by 25 Bcm (6.9%) in 2023 y-o-y, while India's gas consumption grew by 7 Bcm (12.7%).

China's natural gas demand rebounded strongly in 2023, after being supressed by high global gas prices in 2022. 9 Bcm of the increase was driven by a rebound in industrial activity, as the Chinese economy recovered, and fuel-switching from coal towards gas occurred as global prices declined throughout the year. A cold spell in January 2023, alongside a frigid winter at the end of the year, also drove growth in the residential and commercial sectors to meet heating requirements. Urbanisation and increased gasification in urban areas are also relevant drivers for growing residential and commercial demand, which is rising 6 Bcm in the year. The nation's coal-to-gas switching policy has significantly improved air quality in urban areas like Beijing by reducing particulate matter and other pollutants associated with coal combustion.

In India, gas demand growth was driven by industry, growing by 16.3% or 6 Bcm in 2023. The fertiliser sector was particularly one of key gas consumers in India, as increasing domestic urea production led to a one-fifth reduction in imports of the material, boosting demand for natural gas as a feedstock. According to government data, compressed national gas (CNG) vehicles, including three-wheelers and cars, grew 53% to 180,000 in India from 2022 to 2023. As a result, demand for natural gas from transport increased by 1 Bcm in the period, a trend slated to continue. With increased access to natural gas through the city gas distribution network, the residential and commercial sectors also saw a boost, growing by 1 Bcm in 2023 relative to 2022 levels.In 2024, Asian gas demand is expected to continue growing by ~43 Bcm (4.3%) from 2023. Industry will sustain its role as a strong growth driver, contributing ~20 Bcm over the year. Residential and commercial sectors will also carry on positive trends, accounting for a combined 8 Bcm of additional gas demand. The power sector demand is projected to reverse course from its previous decline, and grow by ~4 Bcm. In China, favourable policy and a strong economy are expected to sustain gas demand growth of ~34 Bcm (8.6%) by the end of 2024, with industry expected to account for ~15 Bcm of this growth. India will also continue to be the second largest growth market, albeit at a slightly slower pace, growing ~5 Bcm (7.1%) in 2024. In India, industrial and transport demand will largely continue to drive growth in gas demand, balancing a slower pace of residential and commercial natural gas demand growth.

Figure 16: Asia gas demand, split by sector



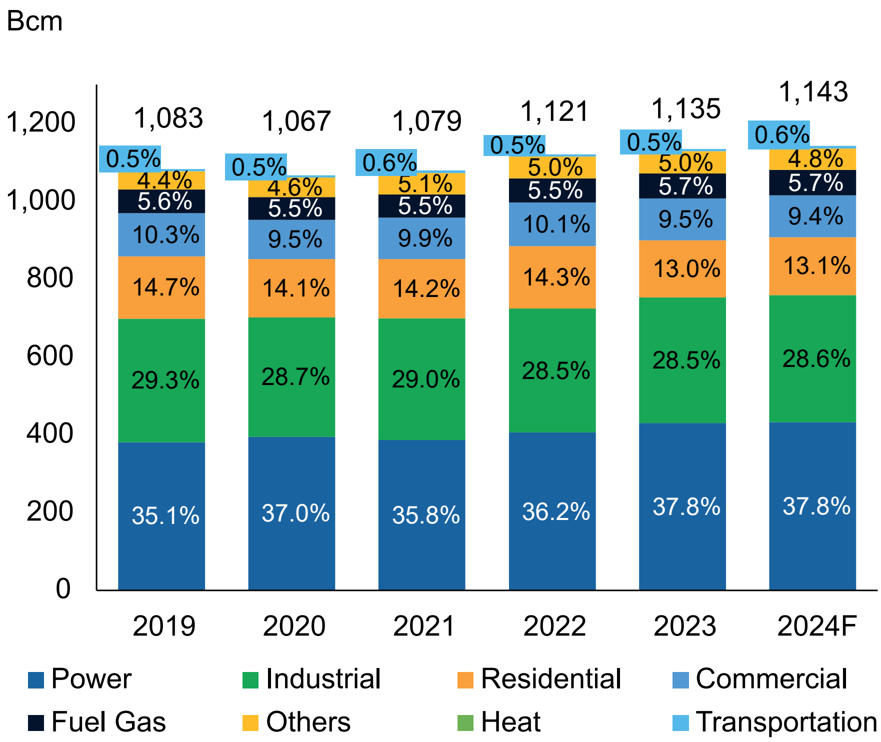
Source: Rystad Energy

d. North America

North American gas demand grew slightly in 2023, increasing by 14 Bcm (1.2%) from 2022. This growth was attributable to a 24 Bcm (5.9%) rise in power sector demand, outpacing an 18 Bcm (-6.8%) combined decline in the residential and commercial sectors, driven by a warmer-than-usual winter and lower heating demand. The US accounts for over 80% of gas demand in North America, and drove most of this growth, while Canada and Mexico experienced relatively stable gas demand across power, residential and commercial sectors.

The region's natural gas prices fell dramatically in 2023 as global gas markets returned to relative stability from 2022. The Henry Hub averaged about US$2.5 per MMBtu, returning to 2019 levels, resulting in gas becoming more competitive for power generation across the United States. This resulted in record gas consumption for power generation in 2023, even amidst falling overall power demand. Coal-to-gas switching was pronounced in the region, with coal consumption falling 5.4% from 2022. In November 2023, gas-fired power generation had a 50% cost advantage over coal in the PJM market on the East Coast of the United States.

Figure 17: North America gas demand, split by sector



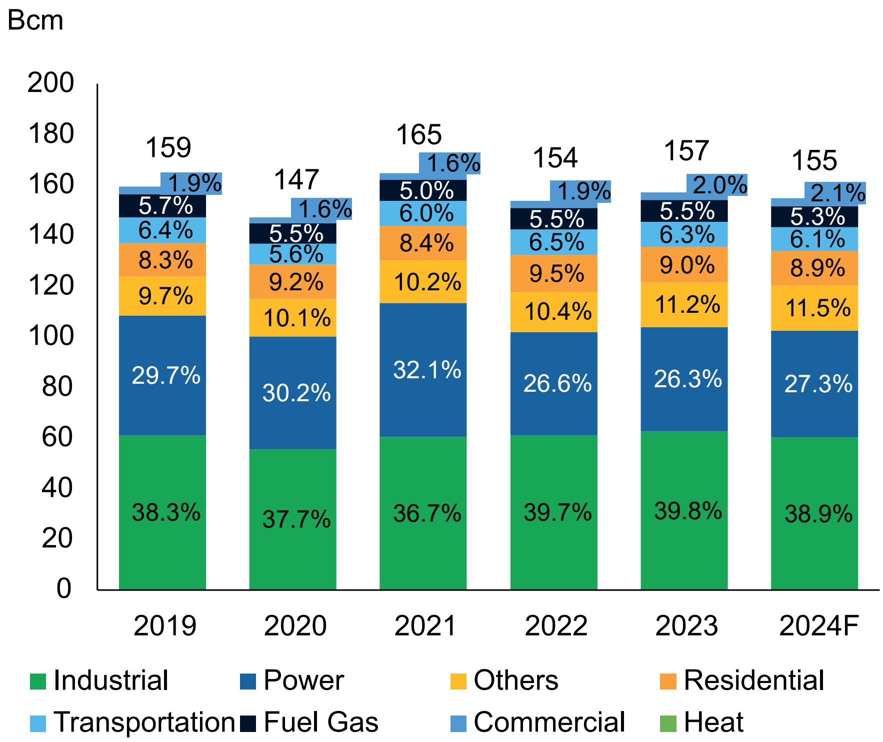
Source: Rystad Energy

In buildings, the most significant factor driving down gas demand was unusually warm weather during the 2023 heating season. In 2024, gas demand in North America is expected to continue to rise by ~8 Bcm (0.7%) y-o-y. Industrial demand is expected to continue growing by ~3 Bcm (1.4%) in the year, with one key driver being European industrial demand shifting gears towards the US in light of lower gas prices and favourable incentives. Gas demand from the power sector is anticipated to continue its growth, albeit at a slower pace, increasing by ~3 Bcm (0.7%) in the year. Residential and commercial demand is also expected to rebound slightly, growing a combined ~2 Bcm (1.0%).

e. South America

South American gas demand grew 3 Bcm (2.3%) in 2023, driven by increased demand in key markets such as Argentina and Colombia, offsetting a 3 Bcm decline (-8.7%) in Brazil relative to 2022 levels. Argentina is reducing Bolivian gas imports in the north and replacing them with domestically produced gas. Lower demand in Brazil was attributable to stronger hydropower generation, alongside slightly weaker industrial demand. In 2024, good storage levels in hydro reservoirs and a slowdown in industrial demand are expected to lead to a ~2 Bcm (-1.5%) fall in overall gas demand on the continent.

Figure 18: South America gas demand, split by sector

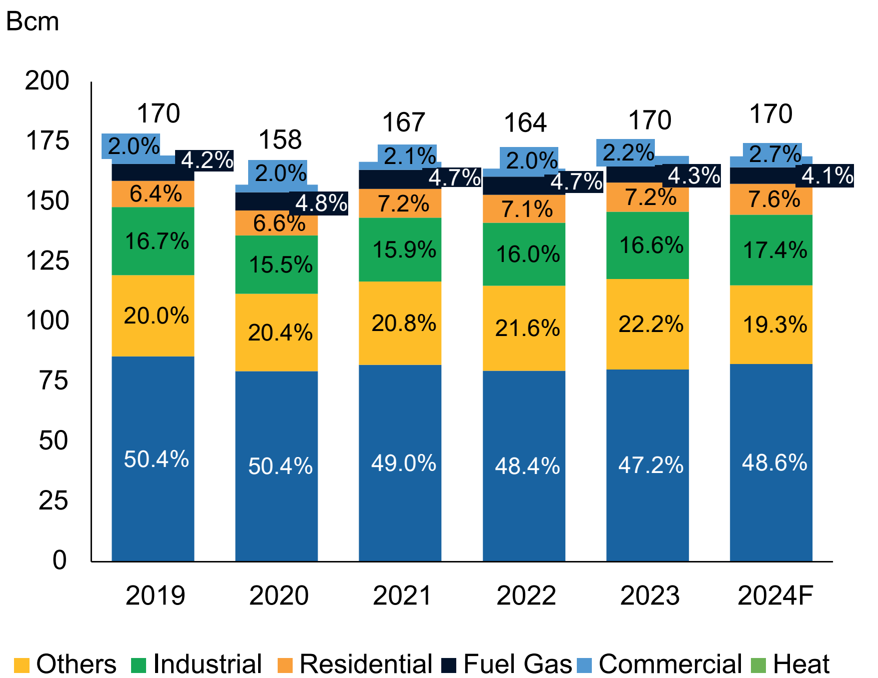


f. Africa

As Africa's power and overall energy needs have experienced growth, its gas needs have also been growing, rising by 5 Bcm (3.2%) in 2023 y-o-y. This increase has been driven by 2 Bcm (6.8%) growth in the Industrial sector and 1 Bcm growth each in the residential (4.9%) sector and power sector (0.7%). At a country-level, this was largely driven by developments in Egypt, Algeria and Nigeria. Gas demand growth in Egypt has been driven by the power sector, resulting in 2 Bcm (4.2%) of growth in 2023.

This growth has occurred in the face of power cuts and no LNG exports during the summer months, due to gas shortages. Egypt has also seen 1 Bcm (5.5%) of industrial gas demand growth, owing to an expansion of the industrial sector. The Minister of Trade and Industry cited a growth rate of 3.8% in fiscal year 2022/2023 for the industrial sector in Egypt, the same period for which the government invested 1.7 billion USD into the manufacturing sector. This rapid growth in gas demand turned Egypt from being a net exporter to a net importer in 2023. Algeria saw 1 Bcm of growth in gas demand for power (4.0%) and 1 Bcm in Industry (10.8%), on the back of GDP growth of 4.2% in 2023 relative to 2022 levels.

Figure 19: Africa gas demand, split by sector



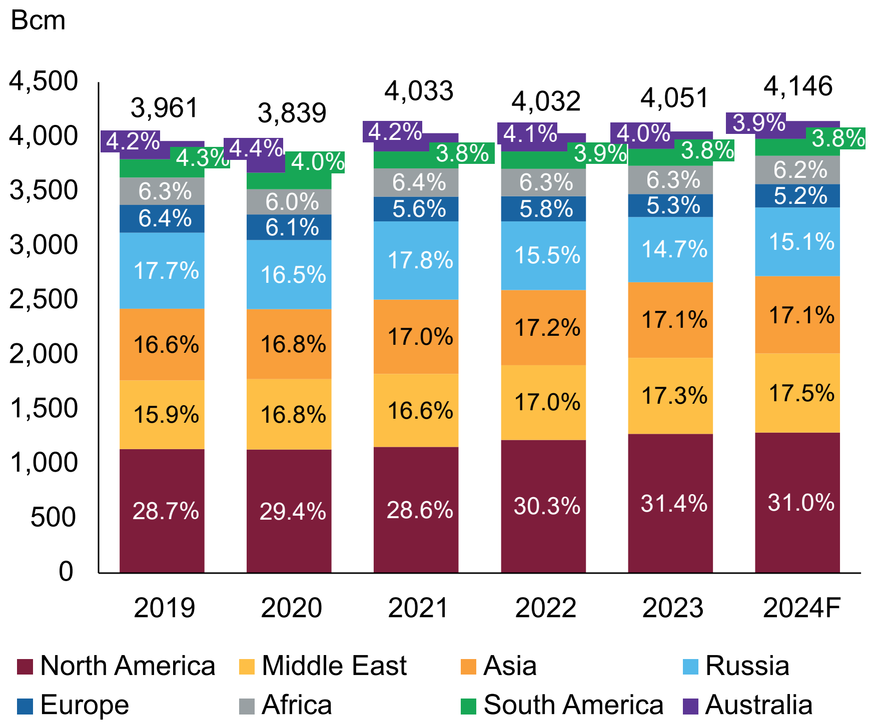
Source: Rystad Energy

Nigeria also saw 1 Bcm of y-o-y growth in 2023, driven by growth in the industrial and heating sectors. African gas demand is expected to remain flat in 2024.

III. Natural gas market supply

Global gas production rose by 19 Bcm (0.5%) in 2023 y-o-y, largely attributable to increases in North America of 52 Bcm (4.3%), the Middle East of 16 Bcm (1.9%) and Asia of 3 Bcm (0.8%), which offset a supply decline in Europe of 18 Bcm (-7.8%). The gas production growth is expected to continue in 2024, with supply increasing by ~96 Bcm (2.4%), led by the Middle East at ~26 Bcm (3.7%), Asia at ~17 Bcm (2.4%) and North America at ~12 Bcm (1.0%). Modest growth is also expected from South America with an additional 4 Bcm (2.6%) of production, alongside Europe with 2 Bcm (0.9%), Australia with 1 Bcm (0.7%) and Africa with 1 Bcm (0.5%). On the other side of modest production growth, several mature fields are coming of age, adding to the urgent need to revisit future demand and supply balances to ensure that investment on the supply side are sufficient to deliver the volumes that may be needed in the 5-10 year timeframe, given that conventional gas fields can take anywhere from 5-8 years to develop, depending on asset-specific parameters such as size, location, fiscal regulatory environment.

Figure 20: Global gas production, split by region



Source: Rystad Energy

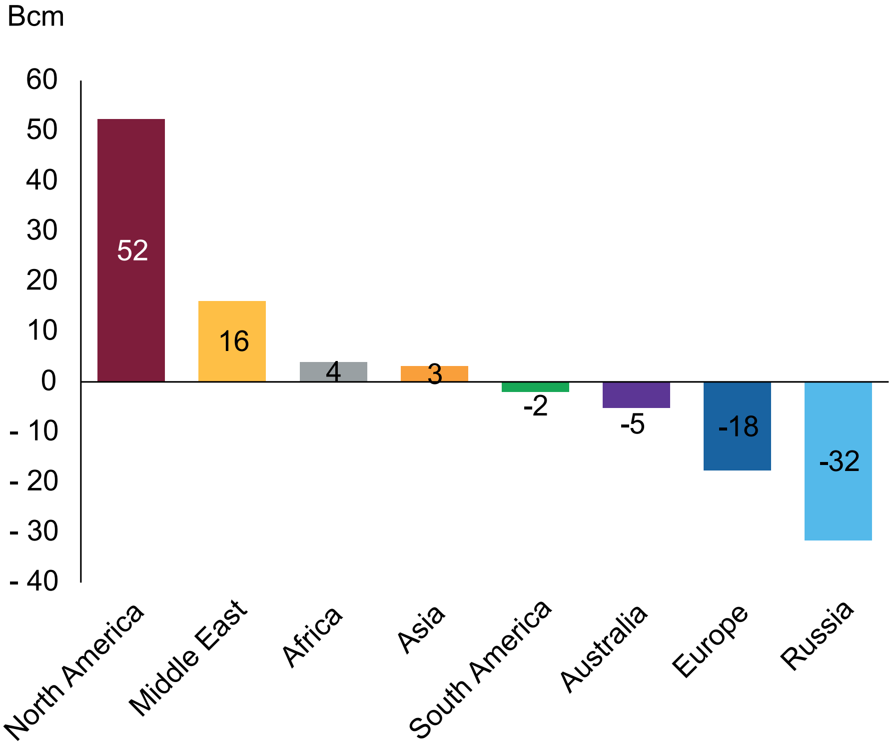
North American production boomed in 2023 with a growth of 52 Bcm (4.3%), of which the US accounted for 44 Bcm. This was partially due to associated gas production from its oil fields, as high oil prices throughout the year encouraged increased oil output[4]. Shale activity in the strategic Haynesville and Eagle Ford plays also contributed, with 14 Bcm and 6 Bcm of production growth, respectively. In the Middle East, gas production rose by 16 Bcm (2.4%), thanks to key assets such as South Pars in Iran, Khazzan-Makarem and Yibal-Khuff in Oman, and Karish in Israel, as these countries seek to increase their self-sufficiency and export potential. African gas production added 4 Bcm, driven by strong growth in Algeria and Mozambique, outpacing mature field declines in Egypt and Nigeria, showing different trajectories in a diverse region. Asia's 3 Bcm (0.4%) of growth was bifurcated. China boosted its gas output by 10 Bcm, achieving strategic objectives aimed at enhancing energy security as outlined in the country's latest five-year plan, ahead of schedule. This was contrasted with lower production from mature basins in Southeast Asia, and a mix of issues in Central Asia such as mature field decline in Uzbekistan, lacking infrastructure in Kazakhstan, and technical issues in Turkmenistan.

South American gas production fell by 2 Bcm (-1.3%) in 2023 as output dropped in Argentina and Bolivia. Australia recorded a larger decline of 5 Bcm (-3.1%) due to natural decline at legacy fields, especially in the Bass Strait. European output slumped by 18 Bcm (-7.6%) as a result of extended maintenance at the Troll field and Kollsnes gas processing

[4] This is exemplified by an additional 19 Bcm from the oil-prone Permian basin during the year.

plant in Norway, alongside further mature field declines in the Netherlands and the UK. Finally, Russia saw the largest production slide with 32 Bcm (-5.0%), attributable to shut-in production due to a lack of international monetisation routes. In general, without significant growth in new resource development, declines in mature basins such as in Southeast Asia (notably Malaysia and Indonesia), Africa (notably Egypt and Nigeria), and the North Sea (notably Netherlands and the UK) are contributing to the uncertainty of gas supply for domestic consumption, pipeline exports and LNG feedgas. This is a key trend to monitor, contributing to uncertainty in global gas markets.

Figure 21: 2023 Global gas production year-on-year change



Source: Rystad Energy

IV. Natural gas market prices and trade

Asia's demand, production and import needs continued to rise in 2023, a trend that is expected to continue through 2024, as countries such as China increasingly rely on gas imports. Implied import needs in Asia climbed by 29 Bcm (10.5%) in 2023, with growth expected at a similar pace in 2024.

In contrast, European demand fell due to lower seasonal needs, and reduced demand from the power and industrial sectors. This coincided with higher renewable and nuclear power generation and lower gas output due to maintenance and declining mature fields. Implied import needs in Europe fell by 14 Bcm (-5.2%) in 2023, and are expected to remain flat in 2024. North America's export potential jumped by a notable 37 Bcm, as shale production boomed in the Permian, Haynesville and Eagle Ford plays, outpacing consumption. This trend is expected to soften in 2024, with some reversal of import potential growth. South America will continue to see a balanced market into 2024, as demand and supply match at a continent level.

When aggregating pipeline and LNG flows, the largest five net exporters of gas in 2023 were Russia, Qatar, the US, Norway, and Australia. Russia led with a net export of 139 Bcm, followed by Qatar at 128 Bcm. The US exported 127 Bcm, Norway came fourth with 120 Bcm, and Australia rounded out the top five net exporters with 110 Bcm. On the import side, China was the largest net importer with a deficit of 160 Bcm. Japan follows with 91 Bcm, Germany with 77 Bcm, Mexico with 64 Bcm, and South Korea with 61 Bcm.

Global LNG trade rose to 537 Bcm in 2023, as the growing importance of LNG continues amid energy security and supply uncertainty concerns across the globe. The US became the world's largest net exporter of LNG in 2023, overtaking both Australia and Qatar to reach 117 Bcm of exports. The US volumes primarily flow to Europe, while Australia and Qatar export to Asia more than to Europe, owing to legacy agreements and geographical advantages. Algeria also increased

Figure 22: Gas demand, production, and import or export volumes

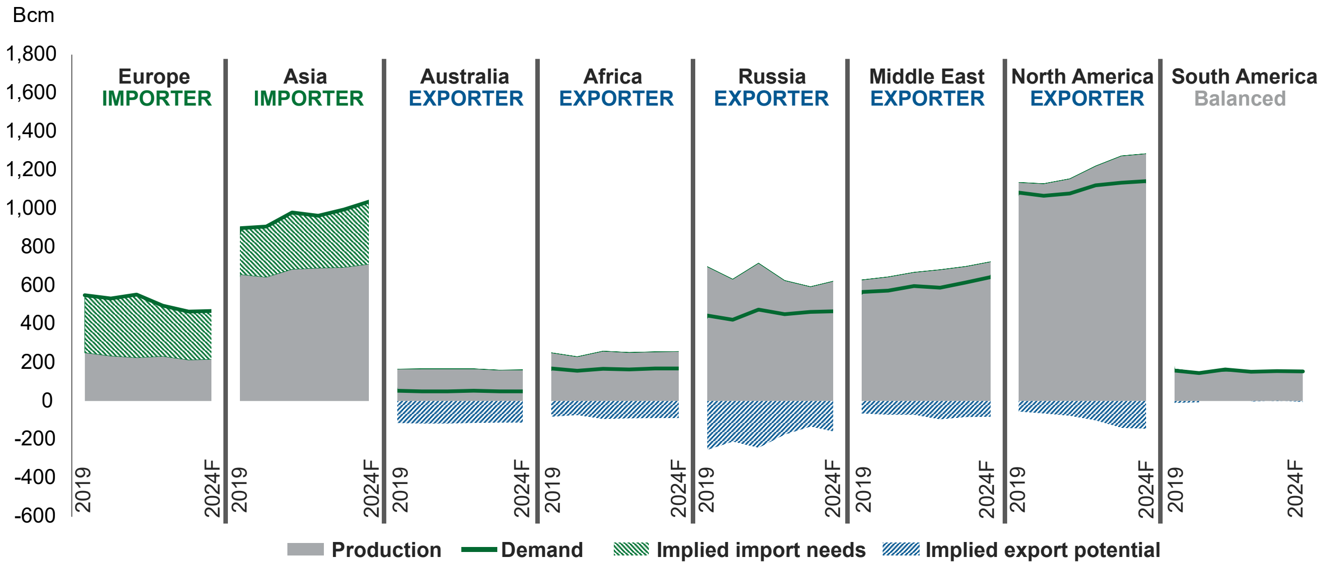


Figure 22 illustrates the disparity in gas production and demand across various regions. Some regions have a surplus of gas production over their local demand, categorising them as exporting regions, while others have a deficit, classifying them as importing regions. In the case of exporting regions, the volume they can export without tapping into their stored gas reserves is termed the "implied export potential". Conversely, for importing regions, the quantity they need to import without resorting to their stored gas reserves is denoted as the "implied import needs".

Source: Rystad Energy

its LNG exports to overtake Indonesia, Oman, and Nigeria, with 18 Bcm of exports last year. Australia-to-Japan remained the world's most popular LNG trade route in 2023, accounting for 39 Bcm of flows in the year. However, this was a drop from the previous year's high of 43 Bcm. In terms of imports, China overtook Japan as the globe's largest LNG importer, accounting for 94 Bcm of net exports in 2023. India and Chinese Taipei also grew in importer ranking in the year, overtaking Spain.

Net pipeline trade flows fell 6.8% to 475 Bcm in 2023, owing mainly to lower exports from Russia. This was the most significant change to pipeline exports through the year. Russia still remained the second-largest pipeline exporter globally, with most volumes going to China (26 Bcm), Turkey (21 Bcm) and Belarus (18 Bcm). Iran's exports climbed 19% to overtake Qatar, while the ranking of the other top 10 exporters remained the

Table 3: Top 10 gas exporters and importers in 2023

Top 10 Exporters (Bcm)		Top 10 Importers (Bcm)	
Russia	139	China	160
Qatar	128	Japan	91
United States	127	Germany	77
Norway	120	Mexico	64
Australia	110	South Korea	61
Canada	53	Italy	59
Algeria	52	Turkey	49
Turkmenistan	41	France	41

Note: Exports and imports in the Table are net, subtracting imports from exports for any given exporter and vice versa.

Source: Rystad Energy

same. In terms of imports, France dropped its pipeline imports to 13 Bcm in 2023 from 25 Bcm in 2022, reducing its dependence on Russia while its nuclear power generation rose. The UK's pipeline imports rose to 18 Bcm from 12 Bcm on the back of higher Norwegian supply. Turkmenistan-to-China was the most common pipeline trade route in 2023, accounting for 30 Bcm.

The reduced pipeline export volumes from 2022 were sustained in 2023, with similar overall volumes as 2022. The LNG share of net export volumes rose to 53%, largely attributable to the Russia-Europe dynamic, as Europe turned to LNG to replace its Russian pipeline gas imports. In 2024, total global export volumes are expected to regain ground, growing by ~48 Bcm (4.7%), driven by demand growth in regions including Asia. While both segments are expected to grow, the share of piped exports is slated to increase slightly faster than LNG, as suppliers such as Norway and Algeria continue to boost pipeline exports, and Russia increases its eastward flows. Nevertheless, LNG's share is still expected to remain above 50% of export modality, showing a sustained shift in gas markets since 2022.

As the world adjusts to a new reality of continuing wars between Russia and Ukraine and between Israel and Hamas, global gas markets have found themselves remaining at a fragile equilibrium in 2024, with global gas prices cooling in 2023 from their historic peaks and volatility of the preceding year, but with remaining supply constraints maintaining the suspense. Europe's Title Transfer Facility (TTF) price fell steadily from about US$22 per million British thermal units (MMBtu) in January 2023 to trade in the US$10-12 per MMBtu range from May until

Figure 23: Global LNG trade flows for 2023 for top net importers and exporters

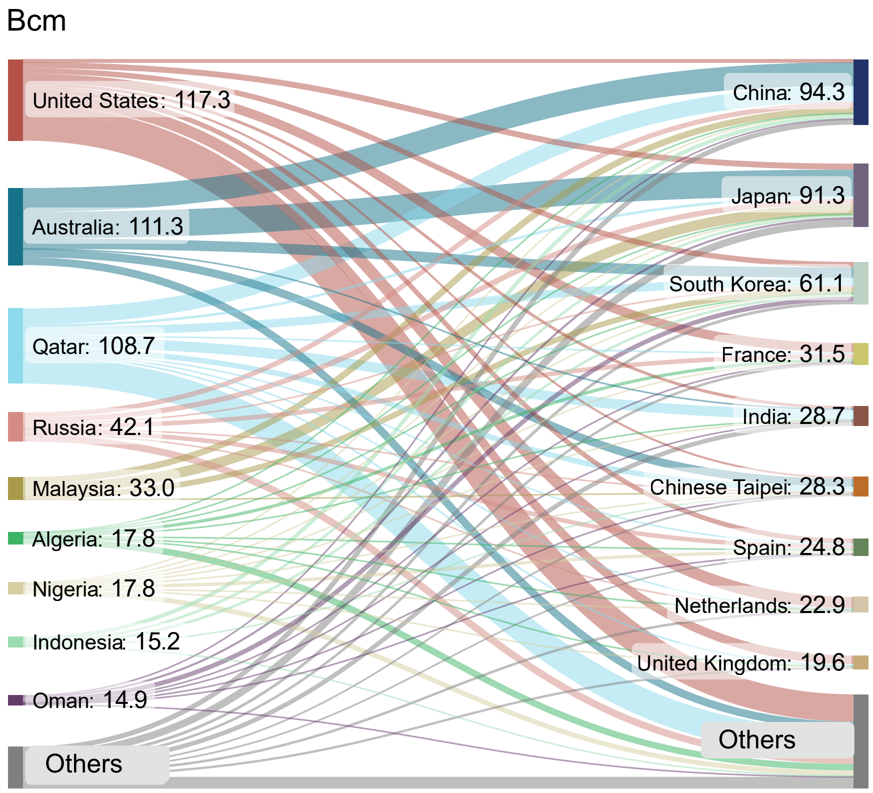
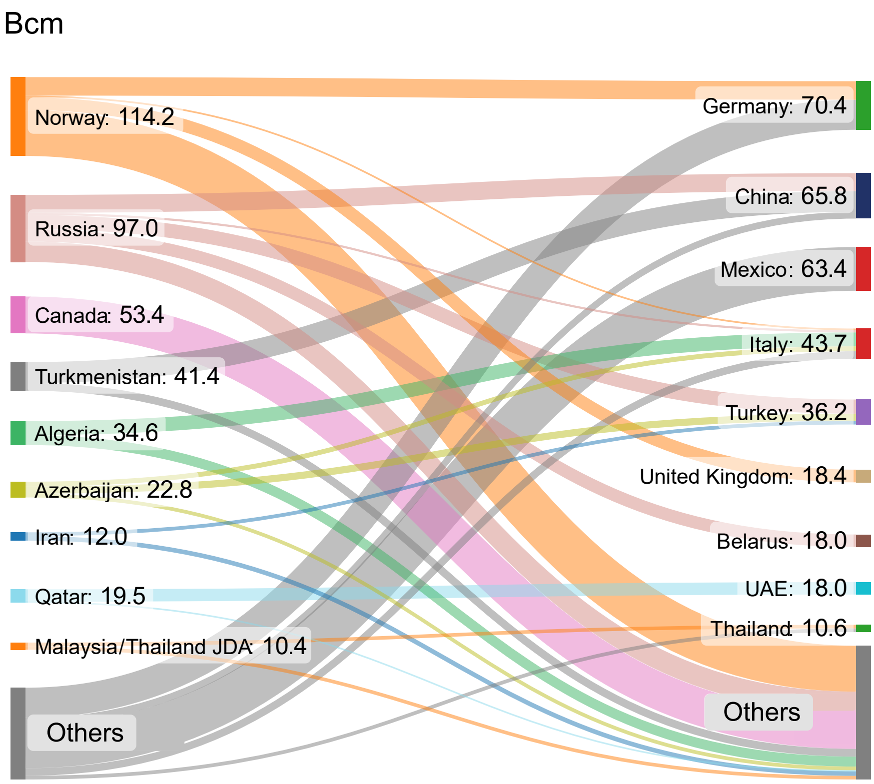


Figure 24: Global pipeline trade flows for 2023 for top net importers and exporters

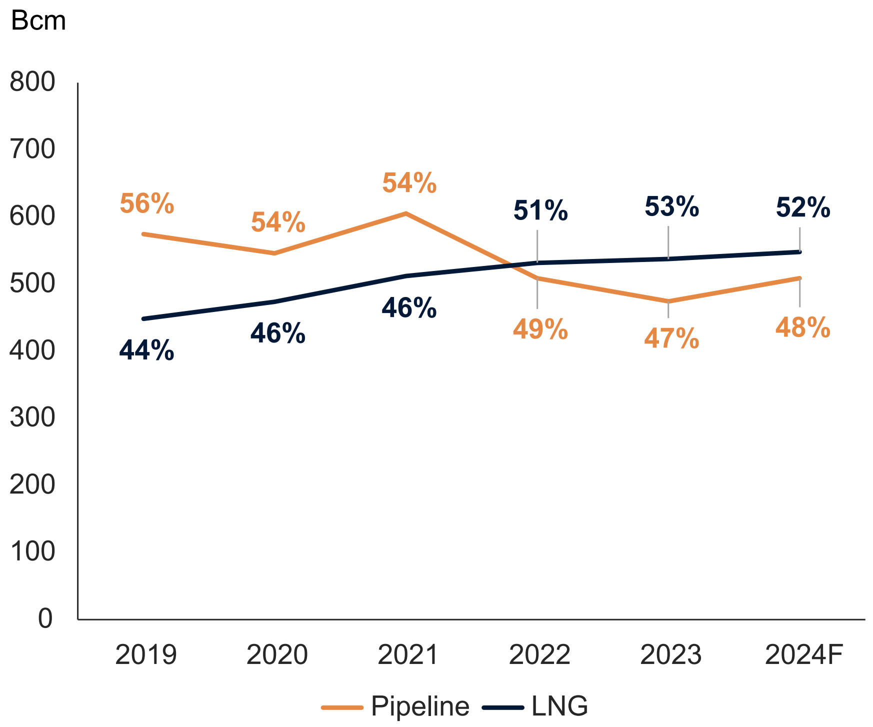


Source: Rystad Energy

mid-August. However, fears about potential strikes at Australian liquefaction facilities drove prices up briefly in October 2023, and the onset of the Israel-Hamas war that resulted in the shut-in of the Tamar gas field added to the price increase in the last quarter of 2023. Subsequently, the TTF peaked at US$17 per MMBtu in October 2023, up 37% from mid-August, before prices cooled again through the last quarter of 2023 as European storage levels hit record highs.

The start of 2024 saw further downward price pressure, despite a January cold spell in some areas of the world, including parts of China and the US, alongside escalating geopolitical tensions in the Middle East. At the end of February 2024, the TTF prices fell to US$7 per MMBtu before rebounding slightly. This rebound was attributable to colder-than-expected weather in Asia, an outage at Freeport LNG in the US, and reduced production levels in Norway. Subsequently, issues such as

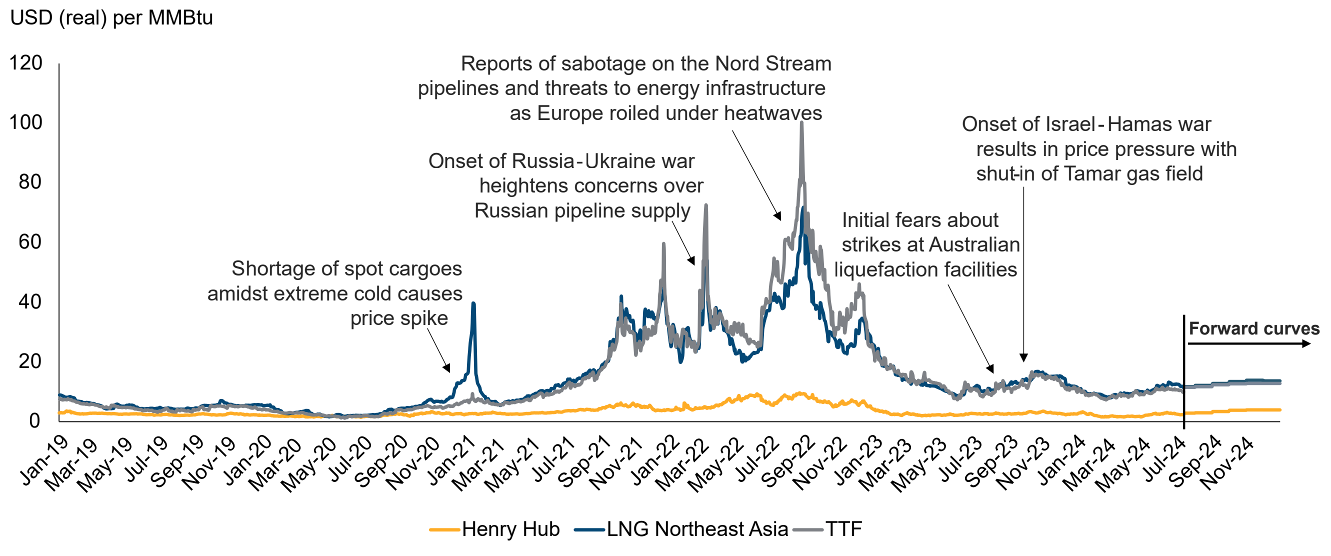
Figure 25: Global net gas export volumes, split by flow type



Note: Global gas export volumes are calculated on a country-by-country basis, aggregated at a global level. They are also net, subtracting imports from exports at a country-level.

Source: Rystad Energy

Figure 26: International natural gas prices



Note: Forward curves outline Futures contract pricing for each benchmark as of July 2024 and are not a forecast.

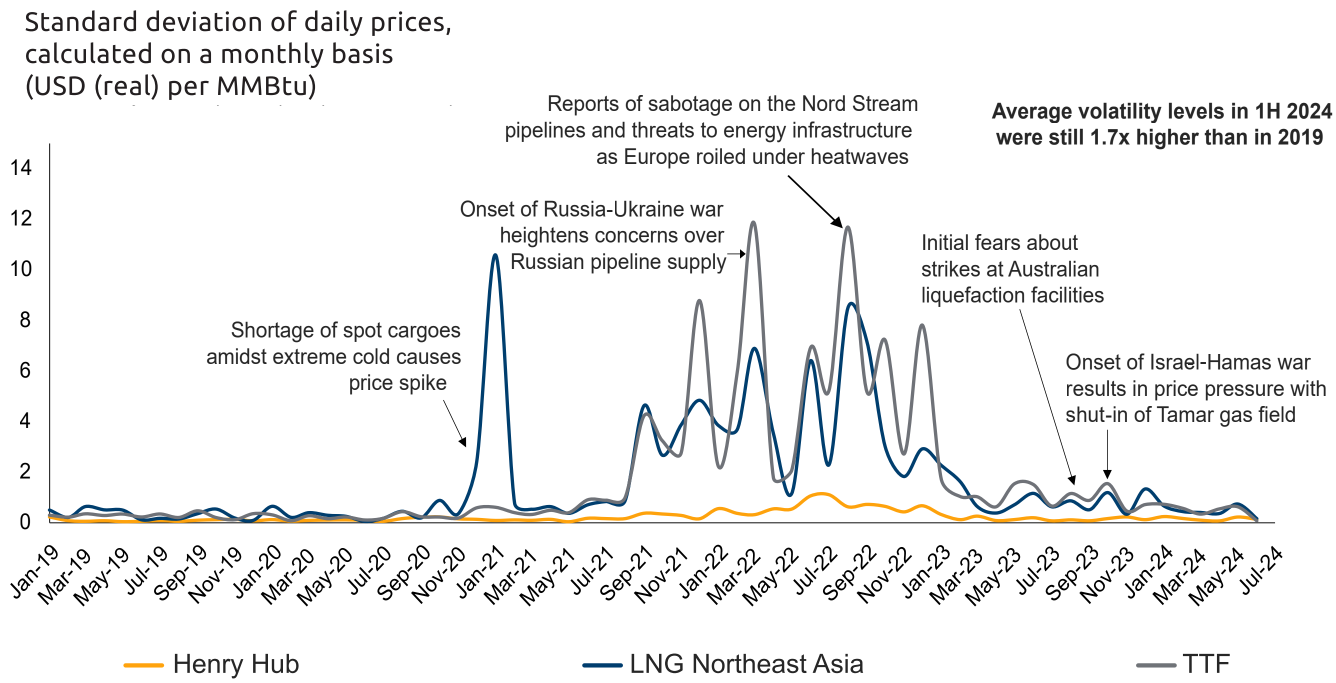
Source: Rystad Energy; Argus (LNG Northeast Asia) heatwaves across parts of Asia and the US, supply interruptions in Norway, Australia and the US, and further heightened Middle Eastern geopolitical tensions between Israel and Iran drove TTF prices up to US$10 per MMBtu. As of the start of July 2024, the TTF was still trading in that region, as players bridge demand and supply through summer.

The Northeast Asia spot price for LNG delivered ex-ship to ports in Japan, Soth Korea, Taiwan, and China has trended closely with the TTF. Demand competition between Europe and Asia remains a major market shaping force, given Europe's current reliance on LNG to meet 40% of its gas demand. In contrast, the Henry Hub (HH) benchmark is characterised by its location in Louisiana in the US, with sufficient local gas production to supply the domestic market. As a result, the HH trades in a lower and tighter price range – the benchmark started 2023 trending downward from highs of US$4 per MMBtu, falling steadily to about US$2 per MMBtu by February. It traded in the US$2-3 per MMBtu range until October 2023, when volatility from the Israel-Hamas war created a brief upward pressure on prices.

2024 saw the HH open at about US$3 per MMBtu, trending lower after winter to trade in the US$1.5-2 per MMBtu band until May and June, when prices hit US$3 per MMBtu on the back of production cuts, higher power demand and hot weather, before ticking downwards to about US$2.5 per MMBtu as of July 2024.

In terms of price volatility, 2024 has been calm up to July, characterised by less turbulent gas markets. On average, volatility in the year was less than half of that observed in 2023, and one-fifth of that in 2022. However, both prices and price volatility are still elevated relative to the pre-pandemic era, primarily due to the still very tightly supplied market. Gas price sensitivity remains high, as seen from price and volatility response to the Australia supply fears and the Middle East conflict. Any notable shift in demand or supply has the potential to disrupt the fragile balance in place.

Figure 27: International natural gas price volatility



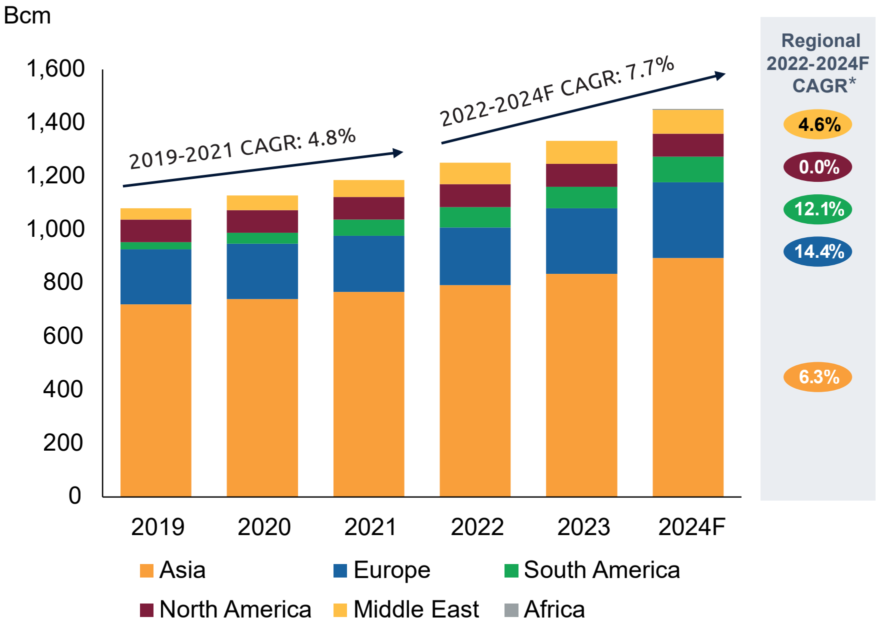
Source: Rystad Energy; Argus (LNG Northeast Asia)

V. Global regasification capacity growth from 2022

Global regasification capacity has seen rapid expansion since 2022. The rate of growth in global LNG receiving capacity between 2022 to 2024F is expected to be 7.7%, nearly double the 2019-2021 CAGR of 4.8%. This change was seen in both the largest regional importers, Asia with a 2022-2024F CAGR of 6.3% and Europe with 14.4%, accounting for over 80% of global regasification capacity. In Asia, this growth was largely attributable to China and India, with imports meeting increasing natural gas demand. In China, regasification plants have been built to support the promotion of natural gas as part of the nation's efforts to shift to cleaner energy sources and reduce its reliance on coal. Capacity additions in India are helping the country achieve its 2030 target of a 15% increase in the share of natural gas in its energy mix, up from 6.7% today[5]. In Europe, regasification capacity growth was primarily attributable to a pivot from Russian pipeline gas because of the Russia-Ukraine war in 2022[6].

Prior to the onset of the Russia-Ukraine war in 2022, Europe was heavily reliant on Russian pipeline gas, accounting for over 40% of gas imports to the continent. As the war unfolded, Europe pivoted rapidly towards greater reliance on LNG imports. The scale and pace of the regasification facility buildout that Europe has carried out to meet this goal has been unprecedented, including rapid deployment of onshore facilities and Floating Storage Regasification Units (FSRUs) even in nations without prior LNG terminals, such as Germany.

Figure 28: Global LNG receiving capacity, split by region



Note: * Africa not shown in CAGR calculation as capacity increased from 0 to 3 Bcm in 2024F

Source: Rystad Energy

European regasification capacity stood at 210 Bcm in 2021, following a decade of slower growth. In 2023, its regasification capacity reached 245 Bcm, showing an 8.0% CAGR over the two years, a sharp departure from the 2.3% CAGR observed from 2011-2020. Only counting projects that have been sanctioned, Europe's regasification capacity in 2024 is slated to reach 283 Bcm, a further 15.3% growth over 2023. This has been driven across Europe, with the largest four additions coming from Germany, the Netherlands, Spain and Italy. Germany is expected to have added 25 Bcm of regasification capacity between 2022 and 2024, deploying its first three regasification terminals. The Netherlands is expected to have added 12 Bcm over the same period, doubling its capacity.

In addition to providing essential supply, a surplus in regasification capacity provides an essential safety reserve to satisfy peak demand, and to provide flexibility to the energy system on gas supply intake and routing optionality. This is essential to maintain energy security in a highly

[5] *Source: Share of natural gas in total energy mix. Ministry of Petroleum and Natural Gas. (2023. December 18). https://pib.gov.in/PressReleaseIframePage.aspx?PRID=1987803*
[6] *This section builds on analysis conducted in IGU's 2024 World LNG report, which can be accessed at the following link: https://www.igu.org/resources/2024-world-lng-report/*

uncertain demand environment, while providing diversification of supply opportunities. At the height of the energy crisis, when infrastructure was limited, some facilities saw utilisation rates above 100%, causing major stress to the energy system. For example, France's average regasification utilisation rate reached a high of 108% in 2022 as LNG imports were heavily relied on to replace Russian pipeline gas. Planning for spare LNG receiving capacity is a positive energy security policy measure, helping to tap into the value of LNG as a flexible and reliable resource for balancing the energy systems in case of unexpected spikes in demand or supply.

VI. Tracking emissions

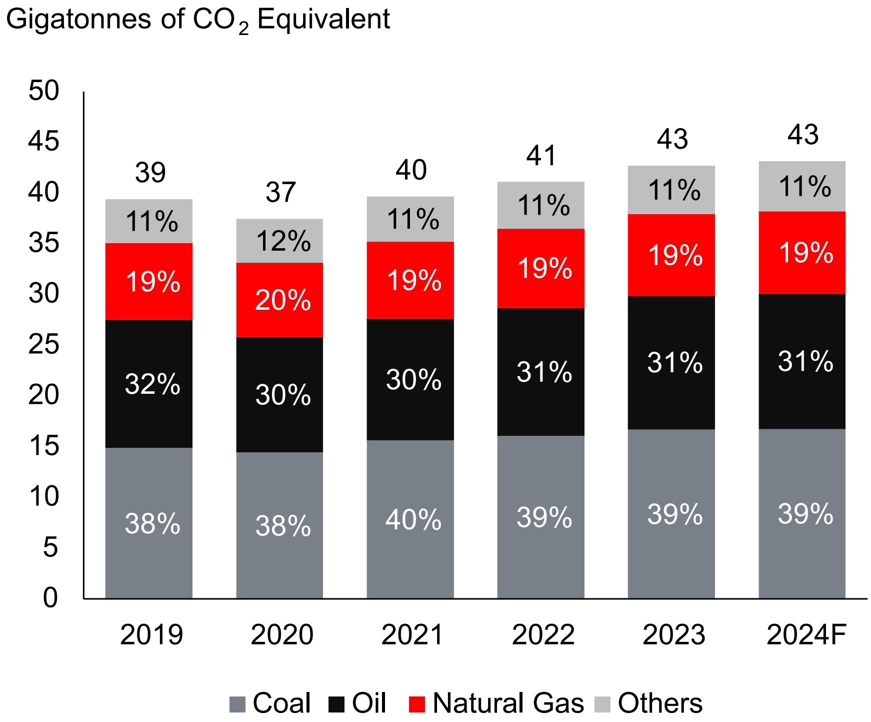
In 2023, energy-related emissions reached another peak, adding another 1.6 (3.9%) gigatonnes of CO_2 equivalents (Gt CO_2 eq.) to 42.7 Gt CO_2 eq. from 2022, continuing their upward trajectory from pandemic-era lows as seen in Figure 29. Total emissions from coal also grew from 2022 to a record 16.7 Gt CO_2 eq., accounting for almost 40% of energy-related emissions in 2023. The rate of energy-related emissions growth is expected to slow to 1.0% in 2024, growing by ~0.4 Gt CO_2 eq., maintaining a similar sectoral split. Emissions from gas are expected to remain level, despite growing demand and production, due to an ongoing reduction in gas value chain emissions intensity.

Coal remained the largest and growing source of emissions in the power sector in 2023, accounting for 71% of the total, evident in Figure 30. Gas-fired power plants have a ~50% lower emissions footprint, as seen in Figure 32. Even with advanced ultra-supercritical technologies, the emissions factor of the most efficient coal power generation technologies is still higher than that of the least efficient gas power generation, thus making the switch from coal to gas a significant contributor to reducing the emissions from the energy sector.

The level of gas-to-coal switching is commonly evaluated using coal switching price bands, as illustrated in Figure 33 and Figure 34. Coal 42% vs Gas 48% (grey shaded area) signifies the lower range of the coal-to-gas switching band between high-efficiency coal (42%) and low-efficiency gas (48%). When gas prices (yellow line) cross the grey area, it is cheaper to turn on the most efficient coal-fired power plants at the expense of the least efficient gas-fired ones, similarly, if the line is above all the bands, even the most efficient gas-fired power plants are more expensive than the least efficient coal-fired ones.

2023 saw European gas prices fall to the lower end of the coal switching price bands,

Figure 29: Global energy-related GHG emissions, split by energy source



Note: Non-energy sectors such as Land Use, Land-Use Change and Forestry (LULUCF) and emissions from sectors where fossil fuel products are used as a feedstock are not included. Oil refers to crude oil, natural gas liquids, refinery gains and other liquids.

Source: Rystad Energy

Figure 30: Global power emissions in 2023, split by energy source

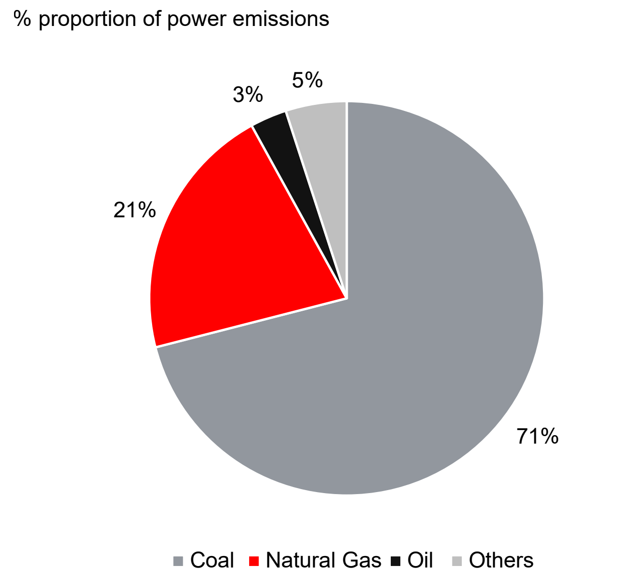
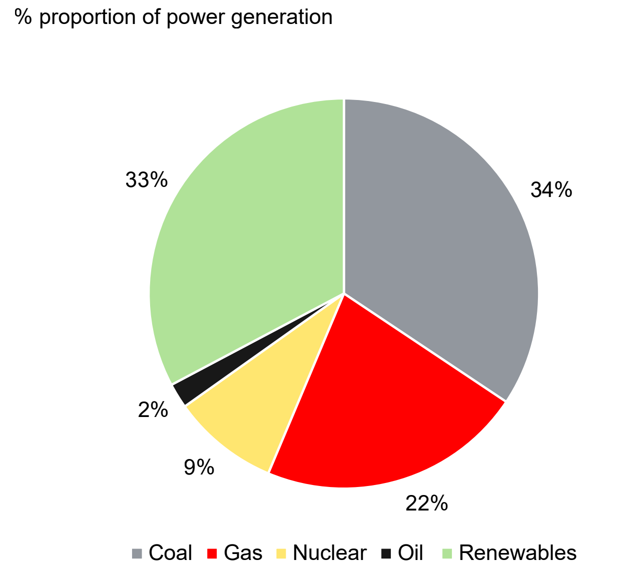


Figure 31: Global power generation in 2023, split by energy source



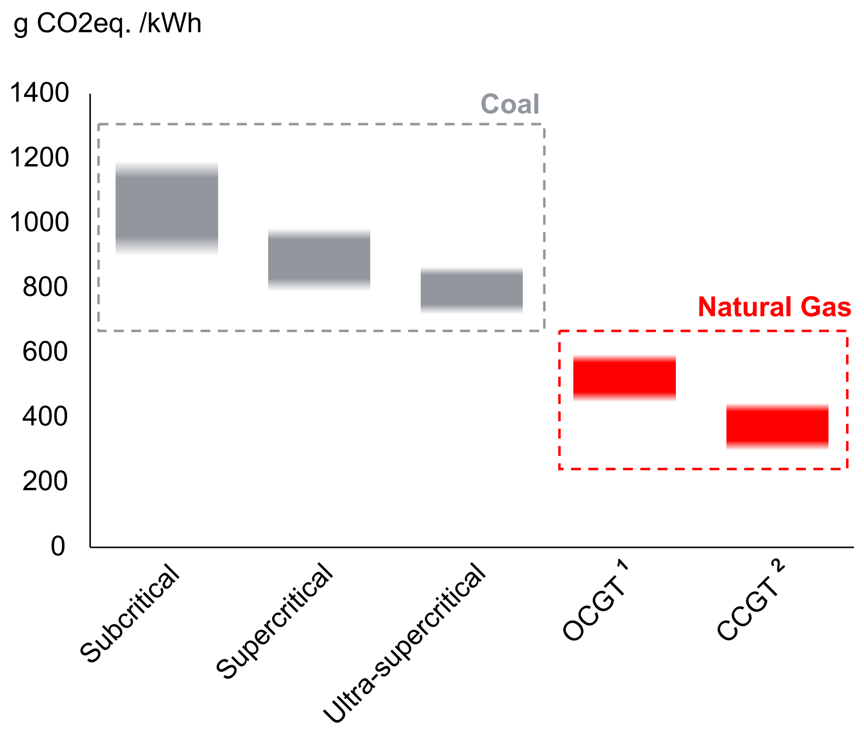
Note: Oil refers to crude oil, natural gas liquids, refinery gains and other liquids.

Source: Rystad Energy

making gas power generation competitive with coal generation. Correspondingly, coal power generation in Western Europe saw a rise of 8% in 2022 but subsequently fell 28% in 2023 as the cost of gas became competitive with coal power generation. In Asia, gas prices have been consistently higher than coal switching price bands since 2021, with gas prices becoming more competitive against coal in the first half of 2023.

Asian countries, led by China and India, have experienced a surge in power demand to meet their robust economic growth demand over the last decade, with the increased demand primarily met through coal-fired power generation. Looking ahead, significant volume of planned addition of coal power generation is expected to be built in China, India, and Indonesia. The utilisation rates of these new Asian coal power plants will be dictated by electricity demand growth, renewables capacity

Figure 32: Emissions factor of coal vs gas combustion in power generation, split by technology



Notes: [1] OCTG: Open Cycle Gas Turbine
[2] CCGT: Closed Cycle Gas Turbine

Source: Rystad Energy

Figure 33: European gas prices vs coal-switching price in the Netherlands

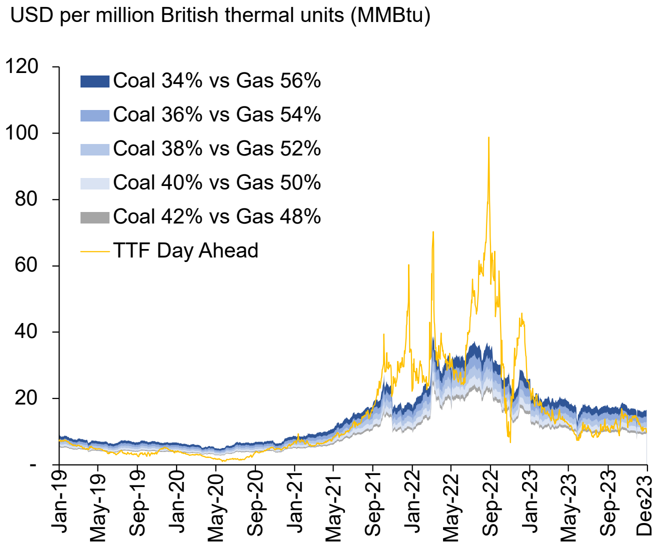
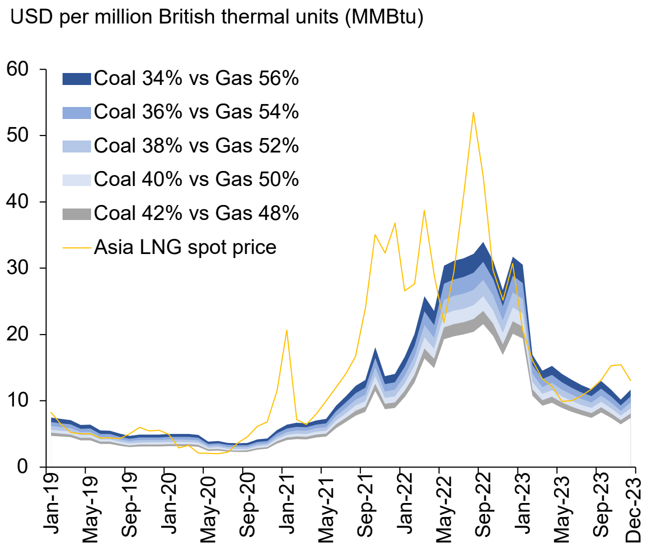


Figure 34: Asian LNG prices vs coal-switching price

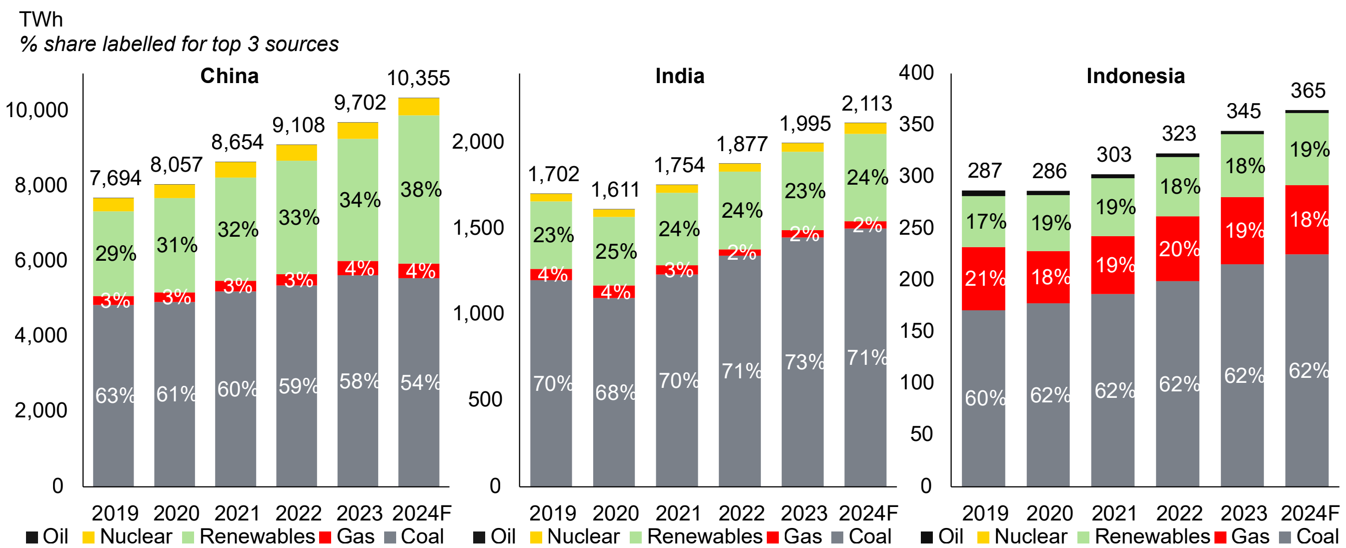


Source: Rystad Energy

growth and the age and health of existing coal infrastructure in each country. In China, new coal power plant projects are developing at a rapid pace. Since China began its spree of coal power plants in 2022, 152 GW has been permitted while a further 169 GW has been announced. Large-scale additions of coal-fired power plants could pose a risk to meeting China's decarbonisation targets such as "peak emissions by 2030".

In India, coal has become even more dominant in the power sector, increasing rapidly since 2019 – according to the Indian Power Ministry, and 2024 is expected to see the highest annual increase in coal-fired power capacity. This pace is not expected to slow as India's Ministry of Power is planning to minimally add 54 GW of coal-fired power generation capacity by March 2032 in addition to the 26 GW already under construction. If the government's target is met, coal capacity is set to rise by 34% from 232 GW in

Figure 35: Power generation in Asia, split by selected country and energy source



Source: Rystad Energy;

2023 to 312 GW by 2032. In Southeast Asia, Indonesia's coal power generation has been steadily increasing and is expected to continue as the country seeks to increase its coal power capacity with 14.5 GW under construction and further announced projects amounting to 4.75 GW. Though planned coal addition in Indonesia is smaller than China and India, the planned 19.25 GW addition is greater than Indonesia's total 2023 renewable capacity (13.2 GW) and accounts for 22% of 2023's total power capacity.

This has resulted in much uncertainty surrounding Asia's future gas demand and the overall energy landscape, as the switch back to coal deviates away from sustainability and could potentially set emerging economies in Asia back in terms of industrialisation and risk significant delays in local decarbonisation efforts and global net-zero targets.

One way to reverse this troubling trend of growing carbon footprint from new and existing coal plants would be to convert them to burn natural gas instead. Looking at emissions factors in Figure 32, we see that this switch would reduce emissions from power generation substantially. Siemens Energy estimates that capital expenditure for conversions of coal plants to gas plants would save 30% in capital expenditure relative to a new plant. According to power generator TransAlta, in Canada, the payback period for such a conversion is one year, as efficiency gains and carbon tax savings result in cost savings. Gas power plants have further decarbonisation potential, with the possibility of fitting carbon capture units, or co-firing with low-CO_2 gases.

Natural gas market value chain emissions

Efforts to continuously enhance identification, measurement, verification, and reporting methane emissions are actively being advanced by the industry and policy makers, presenting both challenges and opportunities. Reliable measurement, reporting, and verification (MRV) are essential for reducing emissions, yet the industry faces hurdles such as reliance on outdated estimation methods. Increasing transparency through advanced measurement technologies, transparent recordkeeping, and independent audits can significantly improve accuracy and accountability. A call to action is to be made – natural gas players must prioritize enhancing MRV systems to ensure compliance, build public trust, and maintain their license to operate. Immediate action in this area is crucial for effective methane mitigation and achieving global climate goals.

Many companies have set targets to restrict emissions or emission intensity, and voluntary industry-led efforts like the Oil and Gas Climate Initiative's goal of near-zero methane emissions by 2030 have driven progress. Member companies, representing major global producers, have significantly reduced their upstream methane intensity, achieving a 50% decrease from 2017 to 2022, with an aggregate intensity of 0.15%, already surpassing their 2025 target of well below 0.20%.

Natural gas offers enormous benefits in the energy transition as a companion fuel to renewables, with significantly lower emissions relative to coal and oil, high efficiency and flexibility to be delivered in gaseous or liquid form to any point of use around the world, all while keeping the air, land, and water clean. It is also important to highlight that a continued momentum and strengthening of efforts toward elimination of methane emissions along the gas supply chain is essential to maximise value, and the IGU is calling for the gas industry to adopt a zero-methane emissions culture. It is also critical to continue accelerating the efforts of scaling decarbonisation technologies, including low and zero-carbon gases and carbon capture utilisation and storage.

VII. Natural gas market policy impact on selected regions

Overall, current policies across major regions are rapidly reshaping global natural gas flows and market dynamics globally. Recent examples of policy changes impacting natural gas and its market in the European Union, the United States, China, and India are explored below.

Driven by the intent to phase out imports of Russian gas, the EU put in place measures targeting the reduction in natural gas use, including a voluntary 15% demand reduction target, in response to the Russia-Ukraine war. The EU's 14th round of sanctions[8] against Russia includes a ban on transshipment of Russian LNG to third countries via the EU, a ban on future investments in LNG projects in Russia, and a ban on the use of 27 LNG vessels in Russia's shadow fleet. EU Member states have also implemented individual measures, such as public awareness campaigns, efficiency and conservation incentives, and fuel switching, where feasible. Complementing the demand-side actions, the EU set a target of achieving gas storage levels of at least 90% by October 31st each year to support security of supply in a tight market environment.

In parallel, the EU is aiming to cut its greenhouse gas emissions by at least 55% by 2030 relative to 1990 through its Fit for 55 package. To facilitate this, the European Council adopted the hydrogen and decarbonised gas market package in May 2024[8], aiming to shift 66% of current natural gas consumption to renewable and low-CO_2 gases by 2050, up from 5% today. This also includes a 40 GW 2030 renewable hydrogen capacity and 10 million tonnes renewable hydrogen production goal. The package also prohibited long-term natural gas contracts from being signed[9]. More recently, the European Commission recommended reducing the EU's net greenhouse gas emissions by 90% by 2040 relative to 1990, as an intermediate step between the 55% by 2030 target and the goal of climate neutrality by 2050.

The EU's new methane regulation[10], gradually entering into force in 2025 through to 2027, mandates strict monitoring and reporting of methane emissions from fossil fuel industries, requiring operators to stop routine flaring. It also applies these requirements to fossil fuel imports from 2027 and will gradually extend it to exporters. In addition, the regulation will impose allowable methane intensity limits on fossil fuel imports by 2030, with potential financial penalties for non-compliance, creating a concern over security of supply.

In the US, the Inflation Reduction Act (IRA) also imposes a methane emissions charge on oil and gas producers starting with 2024 emissions[11]. This charge aims to provide a financial incentive for operators to minimise methane leaks across their production systems. The charge applies an annual fee starting at US$900 per metric tonne of excess methane emissions above facility-specific thresholds in 2025, increasing to US$1,200 per tonne in 2026, and $1,500 per ton in 2027 and beyond. While the methane charge could impact production costs and supply, it also presents an opportunity for producers to continue to eliminate emissions and monetise more gas. The IRA also enhances tax credits for carbon capture utilisation and storage (CCUS), which is an essential technology for meeting global emissions reduction targets and addressing climate change. In July 2024, the US ended a blanket pause[12] issued earlier this year on approving of new LNG export terminals, saying that the pause would adversely affect the economy and violate the Natural Gas Act[13]. This was a positive sign for de-politicisation of the market functioning, after the Biden

7 Source: EU adopts 14th package of sanctions against Russia for its continued illegal war against Ukraine, strengthening enforcement and anti-circumvention measures. European Commission. (2024. June 24). https://ec.europa.eu/commission/presscorner/detail/en/ip_24_3423

8 Source: Fit for 55: Council signs off on gas and hydrogen market package. Council of the European Union. (2024. May 21). https://www.consilium.europa.eu/en/press/press-releases/2024/05/21/fit-for-55-council-signs-off-on-gas-and-hydrogen-market-package/

9 This outlines 2049 as the deadline to ban long-term contracts for unabated fossil gas. Short-term contracts less than a year in duration and gas fitted with carbon capture and storage technology is exempt from this ban.

10 Source: New EU methane regulation to reduce harmful emissions from fossil fuels in Europe and abroad. European Commission. (2024. May 27). https://energy.ec.europa.eu/news/new-eu-methane-regulation-reduce-harmful-emissions-fossil-fuels-europe-and-abroad-2024-05-27_en

11 Source: Waste emissions charge. United States Environmental Protection Agency. (2024. April 12). https://www.epa.gov/inflation-reduction-act/waste-emissions-charge

12 Source: Federal judge stays Biden administration's freeze on LNG export permits. Houston Public Media. (2024. July 2). https://www.houstonpublicmedia.org/articles/news/energy-environment/2024/07/02/492563/federal-judge-stays-biden-administrations-freeze-on-lng-export-permits/

13 The Natural Gas Act requires any person to obtain an authorisation from the US Department of Energy to import or export gas, taking public interests into consideration when granting licenses.

administration's announcement in January 2024 of this pause on approving new export terminals and unapproved expansions seeking to export to non-free trade agreement (non-FTA) countries, including most major LNG import markets like Europe and Asia. The US Department of Energy planned to use the halt in approvals to assess the economic and environmental effects of proposed LNG export terminals. The pause impacted about one-quarter of all US LNG export capacity under development and one-tenth globally (70 MPTA), though it did not affect existing terminals, those already under construction, or projects exporting to FTA countries. The Department of Energy continues to evaluate its next steps, which could decide the future of natural gas exports from the US.

On the other side of the spectrum, China has been actively promoting natural gas as part of its efforts to shift to cleaner energy sources and reduce its reliance on coal. China views gas as a clean and sustainable fuel, which is necessary to partner with renewables and ensure stability for its rapidly scaling power system, especially with heavy renewables buildout – over 40% of global operational renewables capacity is in China. The importance of gas in the nation is evident from it surpassing its 230 Bcm production goal in 2023, two years ahead of schedule. This target was part of its 14th five-year-plan, alongside a national storage capacity target of 55-60 Bcm, which is on-track to reach 70 Bcm by 2025. A draft Chinese energy law by the National People's Congress seeks to take measures to strengthen exploration of oil and gas resources, improve production and storage, and improve domestic supply capability. The Chinese government has streamlined approvals for gas-fired power plants to improve their competitiveness and accelerate deployment.

India also has an ambitious target to increase the share of natural gas in its primary energy mix from the current 6.7% to 15% by 2030[14], surmounting challenges of affordability and availability. To address these issues, India has implemented several policy measures. In March 2023, a new domestic gas pricing formula was introduced, linking prices partially to crude oil with a ceiling of US$6.50 per MMBtu, aiming to make gas more affordable for consumers, especially in the city gas and fertilizer sectors. This is expected to lower prices by US$1-2 per MMBtu.

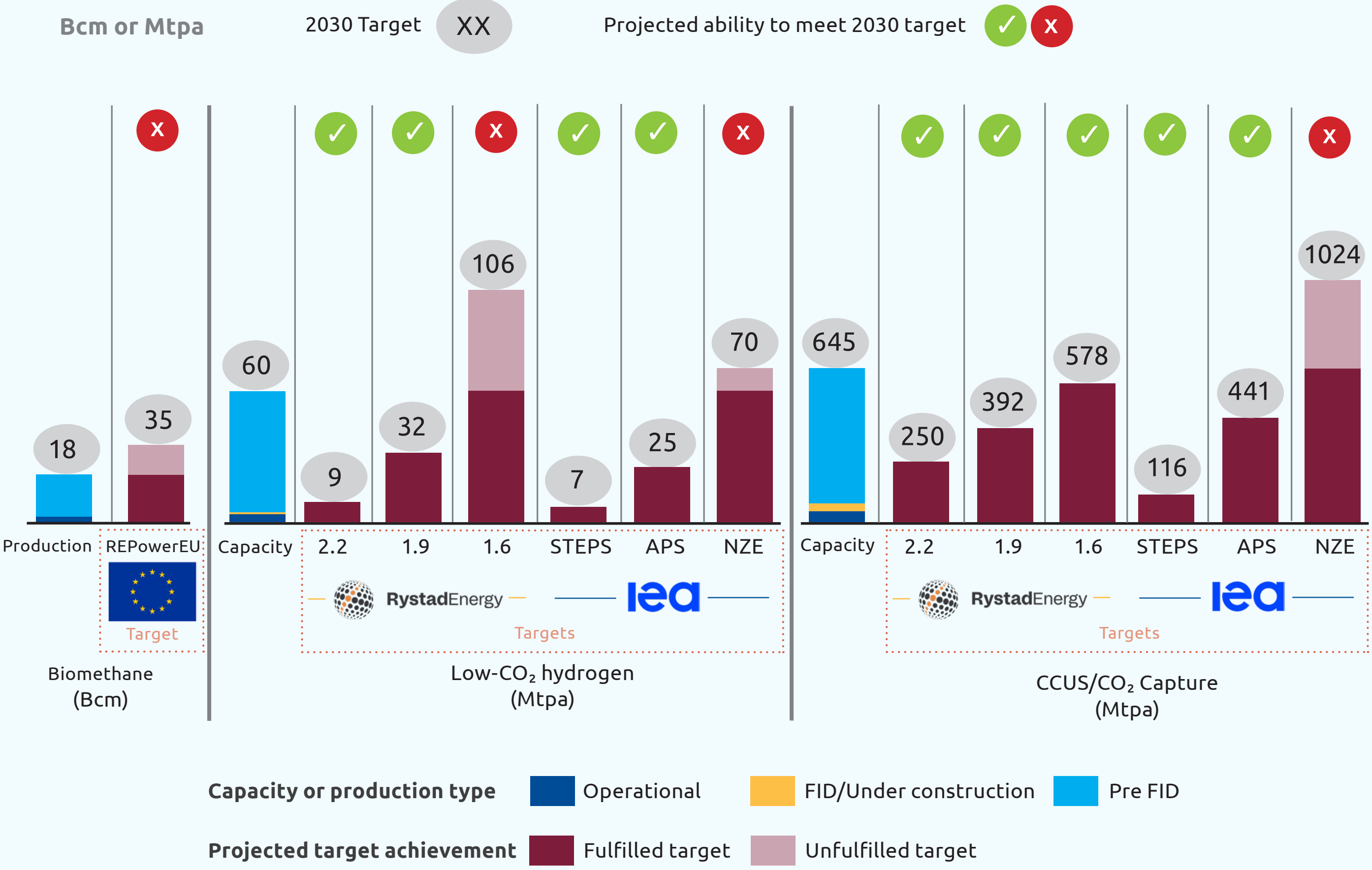
However, such caps can introduce the pitfall of distorting long-term economics for suppliers and producers, resulting in a mismatch of investment, and ultimately slow down progress for gas access. In April 2023, India also revised its gas transmission tariff structure, implementing a 'unified' system to replace the zonal structure, reducing transmission costs for inland industries and city gas distributors. These changes are likely to boost domestic consumption and encourage fuel switching from coal and oil to natural gas - a positive possibility for reducing greenhouse gas emissions and improving air quality.

[14] *Source: Share of natural gas in total energy mix. Ministry of Petroleum and Natural Gas. (2023. December 18). https://pib.gov.in/PressReleaseIframePage.aspx?PRID=1987803*

2 / Evolution of low-CO_2 and decarbonised gas technologies

Highlight

Figure 36: Global low-CO_2 and decarbonised gas technology capacity and production, known vs aspired



Note: Only EU27 numbers are used for biomethane due to limited data availability of either biomethane production targets, production levels, or both, in other major biomethane-producing countries. 'STEPS' refers to IEA's stated policies scenario while 'APS' refers to IEA's announced pledges scenario and 'NZE' refers to IEA's net zero emissions by 2050 scenario.

Source: Rystad Energy; IEA; EBA

Without significant acceleration in the building of projects, the majority of 2030 targets of 1.5-degree decarbonisation scenarios will likely not be met across the technologies analysed. On the contrary, 2-degree decarbonisation targets appear to be within reach. Nonetheless, the project capacities reported are uncertain, due to a significant share of pre-FID volumes which could push completion timelines into the next decade.

Concerted action by governments and industry, with prudent and efficient policy support and predictability are needed to mitigate these risks, and correct course to reach carbon neutrality targets. In the EU, current biomethane production levels are still far below the targets set, which would require a nine- to tenfold increase. For low-CO_2 hydrogen, while 2030 global capacity is expected to be formed by equal amounts of blue and green hydrogen – showcasing the rapid growth potential of green hydrogen capacity – nearly 90% of the 2030 capacity involves pre-FID projects, posing significant uncertainty.

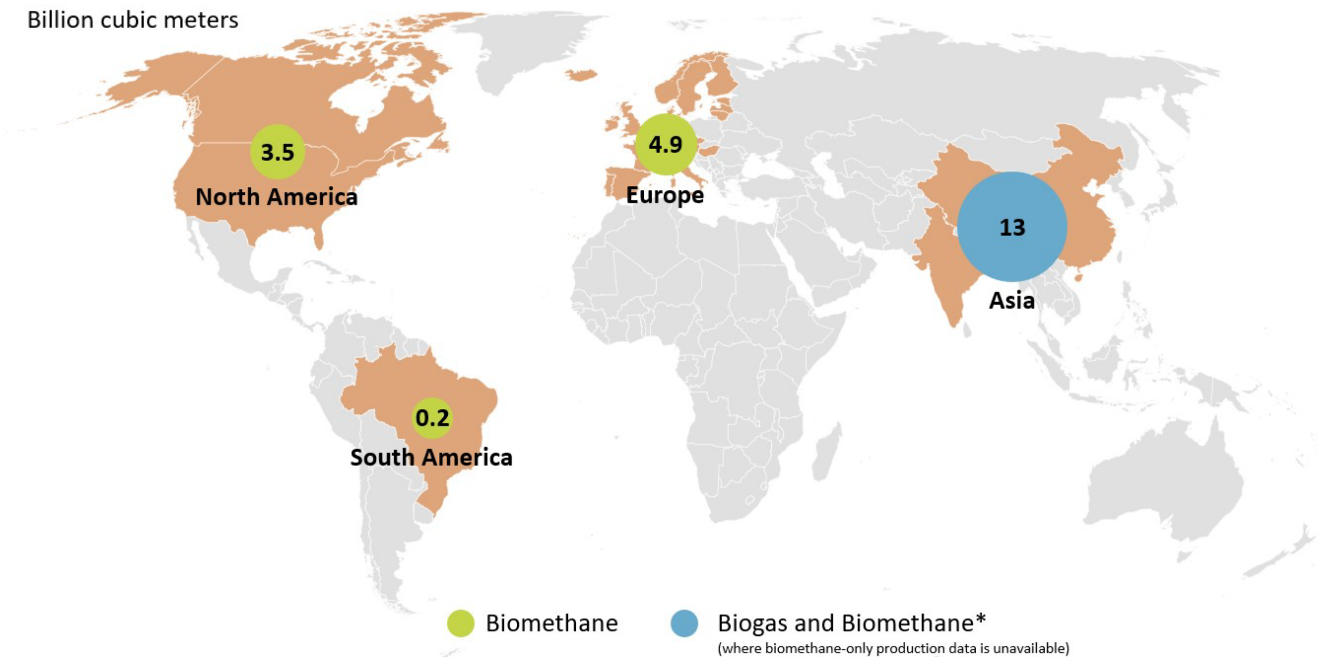
For CCUS, global carbon capture capacity is projected to grow by 42% annually until 2030, but the majority is made up of pre-FID projects, thus this growth is dependent on overcoming development, regulatory and economic challenges through improved government and industry collaboration.

I. Biomethane and synthetic methane

Biomethane, also called renewable natural gas, is an upgraded and purified version of biogas, typically having a methane content of at least 90%. It is produced by capturing biogas from (a) decomposing organic materials, such as biowaste including in landfills and agricultural biomasses, or (b) from thermal gasification of solid biomass followed by methanation. It is a carbon-neutral fuel, since emissions from decomposition in (a) would have otherwise been released into the atmosphere, while carbon content from gasification in (b) is removed from the atmosphere by the biomass plants during their growth. Biomethane can directly replace natural gas and can be readily stored and distributed using existing gas infrastructure. Additionally, biomethane production supports a circular economy by turning waste from other sectors of the economy into energy. The residual by-product (known as 'digestate') from biodigesters can then additionally be used as fertiliser in agriculture. While global biomethane production has been growing more rapidly in the recent years, its scale remains small compared to its massive potential – currently only representing <1% of global gas market share. Synthetic methane or e-methane is another carbon-neutral alternative for natural gas. It is produced from a process that combines CO_2 and hydrogen. To be carbon-neutral, e-methane should be produced from captured CO_2 and green or blue hydrogen.

Biomethane and synthetic methane can directly replace natural gas to be readily stored and distributed using existing gas infrastructure and be used in consumer appliances without any modifications. In the EU, more than 80% of biomethane plants are connected to the grid, allowing for a seamless integration of biomethane into Europe's energy system. This showcases the value of current infrastructure which acts as an enabler for the adoption of biomethane, avoiding additional capital expenditure costs and time spent on building new transmission and utilisation facilities. Currently, most biomethane production is concentrated in Europe and North America, but Asia and South America have been stepping up as well, as illustrated in Map 3.

Map 3: Global biomethane production, split by region



Note: The latest production values in each region are presented, using 2023 data where available; otherwise, 2022 data is used. Combined production value for biogas and biomethane values are provided for Asia where biomethane-only production data is unavailable.

Source: Rystad Energy; WBA; EBA; Argus

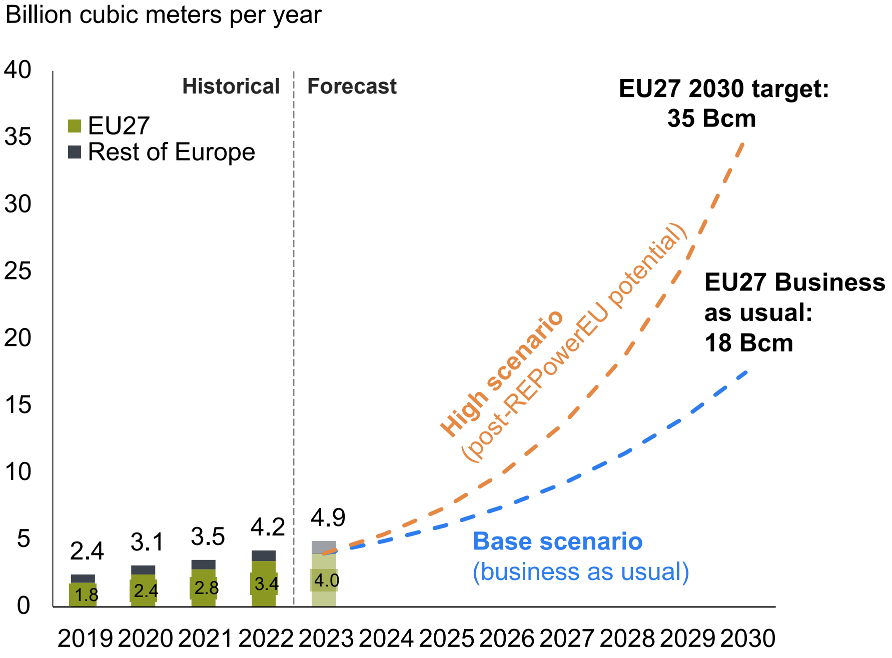
Production is expected to scale up rapidly in both regions alongside Asia, as biomethane is seen as a source of renewable energy and a method to reduce greenhouse gas emissions.

Asia: In 2022, Asia produced over 13 Bcm of biogas and biomethane – most of which is biogas production – with China and India being the main producers, each having set production targets. China is aiming to produce 20 Bcm of biomethane annually by 2030, while India aims to produce 15 million tonnes of compressed biogas by 2025 via implementing 5,000 commercial compressed biogas units. These production targets would be supported by renewable energy policies in China that include state-level subsidies, while India's policies focus on the Sustainable Alternative Towards Affordable Transportation Initiative and the National Policy on Biofuels. Additionally, India plans to boost biogas demand by mandating that 1% of gas consumption must come from compressed biogas starting from 2025. This target will be gradually raised to 5% from 2028 to 2029.

China's biogas industry first emerged via promoting biogas uptake in its residential population through the Chinese Rural Household Biogas State Debt Project. The project successfully led to the installation of approximately 42 million household digestors by 2015. From that year, China gradually shifted its stance from domestic usage to engineered plants for combined heat and power generation. Since 2019, the government has prioritised the development of large-scale bio-natural gas plants with a minimum annual production capacity of 0.01 Bcm. To build its expertise in large-scale biogas plants, the government spurred project development by increasing its subsidy for pilot projects from 25% to 45% in 2009. Strong government support for biogas plants has led to investments into new plants, notably by French company Air Liquide in 2022 and German company EnviTec Biogas AG, which has at least eight biogas plants in China. Recently, China and India have been transitioning from individual household plants to industrial-sized facilities. This strategy enables centralised control and benefits from economies of scale.

Europe: In 2022, Biomethane production in the EU reached 3.4 Bcm, approximately 10 times below the EU's 2030 target of 35 Bcm as outlined in the REPowerEU plan. As illustrated in Figure 37, achieving this goal requires significant commitment from EU countries, with capacity needed to grow at a rate that is 50% higher than historical growth rates. From 2019 to 2022, biomethane production in the EU grew at a CAGR of 24%, but the 35 Bcm target requires production to grow at a CAGR of 36% from 2023 to 2030. To accelerate production, the European Biomethane Industrial Partnership estimates that all EU countries will need to increase production capacities by investing over €83 billion (around US$89 billion[15]) into 5,000 new biomethane projects by 2030. In 2023, the EU funded the Biomethaverse project to boost biomethane potential by diversifying production technologies in Europe, reducing production costs, and promoting the adoption of biomethane

Figure 37: EU27 Biomethane production vs potential pathway to EU27 production target for 2030



Note: 2023 capacity is forecasted based on announced projects. Base scenario is projected based on data available on historical growth rates (2019-2022).

Source: Rystad Energy; EBA

[15] *Assuming exchange rates of €1 = US$1.07, A$1 = US$0.67, JPY1 = US$0.0062 and R$1 = US$0.18.*

technologies. The Biomethaverse project aims to increase European biomethane output by 66% and decrease production costs by 44% by 2030, making pipeline-quality renewable gas more affordable. On the demand side, some European countries are actively promoting biomethane usage to reduce emissions via blending mandates and targets for biomethane injection into gas grids. For instance, the Netherlands will implement its biomethane blending mandate in 2025, while France has set a target for 7% to 10% of renewable natural gas in its gas grid by 2030 in its 2019 Programmation Pluri-annuelle de l'Energie (PPE) that was adopted in 2020. The next revision of the PPE is expected to be adopted in late 2024, which may see revised targets for biogas injection. The country's 2023 draft National Energy and Climate Plan (NECP) was developed based on the latest PPE revisions and may provide some indication of France's revised biogas targets. Under the updated NECP published in July 2024, France has set a target of 50 TWh of annual biogas production, of which 44 TWh is to be injected into the gas distribution network (equivalent to around 15% of biogas injected into the gas network)[16].

To further spur biomethane development, the EU offers multiple investment funds that biomethane projects can leverage. Projects can seek funding and financing from programs such as Horizon Europe (€95.5 billion; around US$102.2 billion[15]), the Innovation Fund (€40 billion; around US$42.8 billion[15]) and the Modernization Fund (€57 billion; around US$52.4 billion[15]). Horizon Europe and the Innovation Fund are direct funding schemes targeted at developing low-CO_2 technologies, while the Modernization Fund targets lower-income EU states to improve energy systems, including biomethane. Overall, the EU benefits from a robust funding system and technology know-how from operational projects.

North America: Biomethane production in the US reached 3.3 Bcm in 2023. The US biogas market has been expanding rapidly, with 96 new projects contributing an additional 1.7 Bcm in 2023, 91% of which were biomethane projects. Although the US does not have a national biomethane target, on a state level, the California Public Utilities Commission has set a goal of procuring 2 Bcm of biomethane annually by 2030 to reduce methane emissions by 40%. Historically, government support in the US for biomethane has focused on the transport sector through policies such as Renewable Fuel Standard and California's Low Carbon Fuel Standard. However, the Inflation Reduction Act provides a more robust funding scheme for biomethane projects through Production Tax Credits, Investment Tax Credits and Clean Fuel Production Credits.

In Canada, biomethane production capacity was roughly 0.2 Bcm annually in 2022, with a goal to increase production to 6.7 Bcm in 2030. To achieve its ambitious goals, the Canadian government will leverage a variety of policies including, but not limited to, carbon pricing, renewable gas mandates for blending fossil fuels with renewable content, clean fuel standards and a government-regulated carbon offset system. In 2019, the government of Quebec introduced a renewable natural gas mandate requiring natural gas suppliers in Quebec to blend a minimum of 1% of renewable natural gas from 2021, gradually increasing to 10% by 2030. This initiative was undertaken with the primary objective of reducing emissions from natural gas consumers.

In the short to medium term, North America will likely continue to be a major producer of biomethane, primarily driven by the US. The extensive availability of government-supported financing programs could spur further developments, as seen in 2023. In Canada, strict government regulations could drive the growth of biomethane plants. However, the high capital investment required for biomethane plants and the lack of direct funding in Canada could make it challenging to achieve the 6.7 Bcm target.

South America: Brazil stands out as the only country with significant biomethane production, reaching around 0.15 Bcm in 2023. Like China and India, Brazil's government is focused on developing the biogas market, which will drive the growth of the biomethane market. Although Brazil has not set a specific biomethane production target, the government has mandated that by 2034, 10% of gas sold in the country must be composed of biomethane under the Fuel of the Future bill. The mandate will be implemented in stages, starting at 1% in 2026 and gradually increasing to 10% in 2034.

To meet the expected demand, Brazil has been actively investing in biomethane plants. In 2024, at least 10 biomethane plants with a capacity of 0.18 Bcm are scheduled for completion. By 2025, Brazil's biomethane capacity is expected to reach 0.44 Bcm annually, a near threefold increase from 2023.

[16] A Source: National energy climate-plan. European Commission. (2024). https://commission.europa.eu/document/download/ab4e488b-2ae9-477f-b509-bbc194154a30_en?filename=FRANCE%20–%20FINAL%20UPDATED%20NECP%202021-2030%20%28English%29.pdf

2 / Evolution of low-CO_2 and decarbonised gas technologies

The rapid growth in biomethane production is supported by government incentives such as the Special Regime of Incentives for Infrastructure Development that exempts new projects from federal taxes for the acquisition of equipment and materials. Additionally, the National Zero Methane Program aims to stimulate the production of biomethane through direct financial support, including specific financing and a line of credit from public banks. Looking ahead, Brazil is well positioned to grow its biomethane production to meet its goals under the Fuel of the Future bill by leveraging its significant agricultural sector for biomass. The rate of added capacity, coupled with government support, could be a strong signal for continued growth in this sector.

Africa: The biogas sector in Africa has seen significant investments in the past, but biogas development has not taken off as expected, with many failed and abandoned biogas projects throughout the continent. This is due to various factors, ranging from poor conceptualisation and implementation of biogas projects to a lack of societal acceptance for the fuel. This, in turn, affects biomethane production, which forms a small subset of the end-uses of biogas produced in Africa, of which most volumes are directly channelled towards power and heat generation, especially at the household level. Supporting policies and programs for biogas and biomethane production have been few, the most significant of which is the Africa Biogas Partnership Program that ran from 2009 to 2019 and was implemented in five countries (Ethiopia, Kenya, Tanzania, Uganda and Burkina Faso) to provide cleaner cooking fuel for Africans. Moving forward, more government support is required for biogas and biomethane production to scale up in Africa, including an examination of the reasons behind project abandonment, with measures put in place to mitigate the risk of that happening in the future. If done successfully, biogas development in Africa has the potential to solve various issues at once, from organic waste management, to meeting increased energy demand with renewable energy sources, to having cleaner cooking fuels to reduce indoor air pollution.

Synthetic Methane / e-Methane

Similarly, the development pace of synthetic methane is also picking up globally as governments see its importance as a decarbonised gas in achieving their CO_2 reduction targets. For example, the Japan Gas Association (JGA) has identified e-methane as an important energy source for Japan to achieve carbon neutrality. The JGA plans to utilise blue hydrogen to produce e-methane in the interim while developing green hydrogen capabilities. Turning ambition into action, Toho Gas began a demonstration project in 2024, with the company's goal of having a production mix of more than 1% synthetic methane by 2030. Pilot projects such as these are important in preparation for the full-scale introduction of synthetic methane in the future, learning from initial experiences to most cost effectively scale up production levels moving forward. Overall, carbon-neutral methane is poised to play an increasingly significant role in the transition to a sustainable and equitable energy system. Apart from its carbon-neutral emissions profile, it offers several notable advantages such as compatibility with existing natural gas infrastructure and versatility in its end-use applications, where it can be utilised in the same applications as natural gas today. Despite limited production capacities today, biomethane and synthetic methane are expected to scale up in production, although it is crucial to ensure that supportive policy frameworks are implemented. Firstly, the carbon-neutral emissions profile of these gases could be more widely recognised in key global emission accounting frameworks, such as the GHG Protocol. Secondly, supply-side measures such as subsidies, technology incentives and financing, alongside demand-side measures such as blending mandates, are important for increasing production while reducing costs, especially in less developed countries.

II. Zero- and low-CO_2 hydrogen and its derivatives

Zero- and low-CO_2 hydrogen can be produced using many methods. The three primary hydrogen production processes used today are the widely commercial "grey" hydrogen, using natural gas reformation, "blue" hydrogen also using the commercially widespread natural gas reformation method, but combining it with carbon capture technology, so the CO_2 emissions of the production process can be eliminated, and "green" hydrogen, produced by combining renewable electricity and water via electrolysis, which releases hydrogen from the water molecule. Currently, hydrogen is mostly produced for use predominantly as feedstock in refineries, fertiliser production, and methanol-based chemical production, while its use as a fuel remains in its infancy, accounting for less than 1% of total hydrogen demand. Consequently, there is limited existing infrastructure and experience for storing, shipping and utilising hydrogen as a fuel. However, the development of hydrogen as energy carrier is beginning to accelerate, with advancements such as hydrogen blending with natural gas and the construction of power plants equipped with dual-fuel turbines capable of combusting a mix of natural gas and hydrogen. This section will primarily focus on blue and green hydrogen, and their derivatives such as low-carbon ammonia, low-CO_2 methanol and sustainable aviation fuel (SAF).

To date, most blue hydrogen developments have been driven by oil and gas players due to synergies with current capabilities and infrastructure. For instance, existing gas infrastructure such as steam methane reformation facilities and onshore pipelines could be repurposed for blue hydrogen production and transportation as players develop their CCUS know-how. Numerous new blue hydrogen projects have been announced with expected start-up dates towards 2030. These projects are set to increase cumulative blue hydrogen capacity by approximately sevenfold, reaching around 29 Mtpa by the end of the decade. However, almost 83% (around 24 Mtpa) of blue hydrogen projects forming 2030's capacity levels are in the pre-FID phase, with another 3% (around 1 Mtpa) of projects having reached FID or being under

Figure 38: Cumulative blue hydrogen capacity, split by status

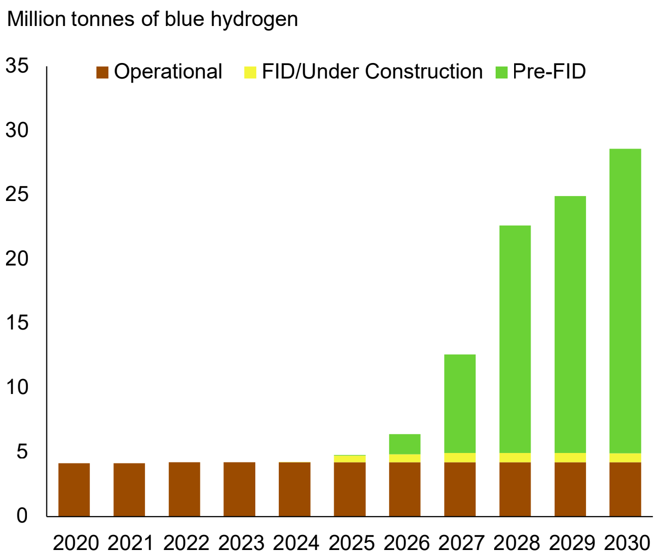
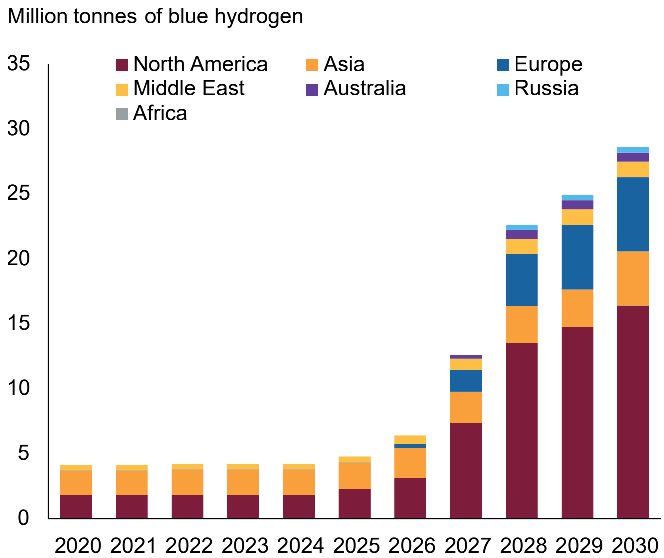


Figure 39: Cumulative blue hydrogen capacity, split by region



Note: 'Cumulative blue hydrogen capacity' refers to the total capacity of announced blue hydrogen projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality.

Source: Rystad Energy

Figure 40: Cumulative green hydrogen capacity, split by status (left)

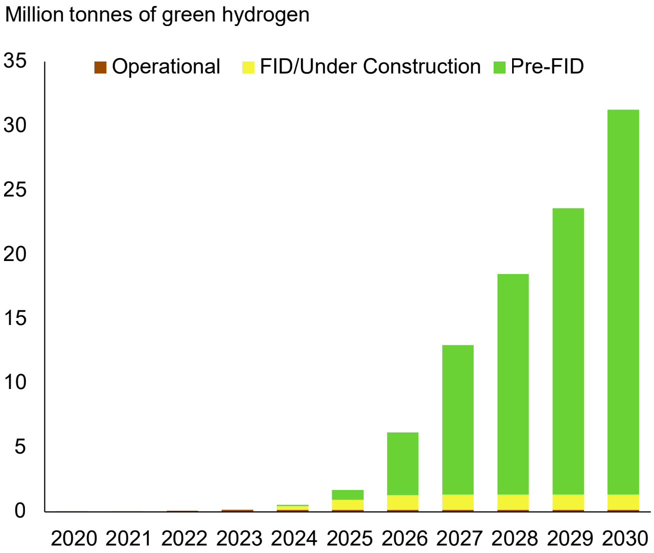
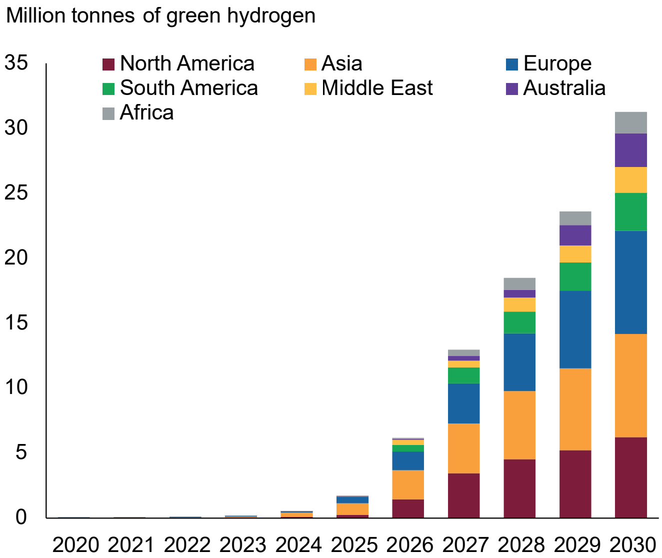


Figure 41: Cumulative green hydrogen capacity, split by region (right)



Note: 'Cumulative green hydrogen capacity' refers to the total capacity of announced green hydrogen projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality.

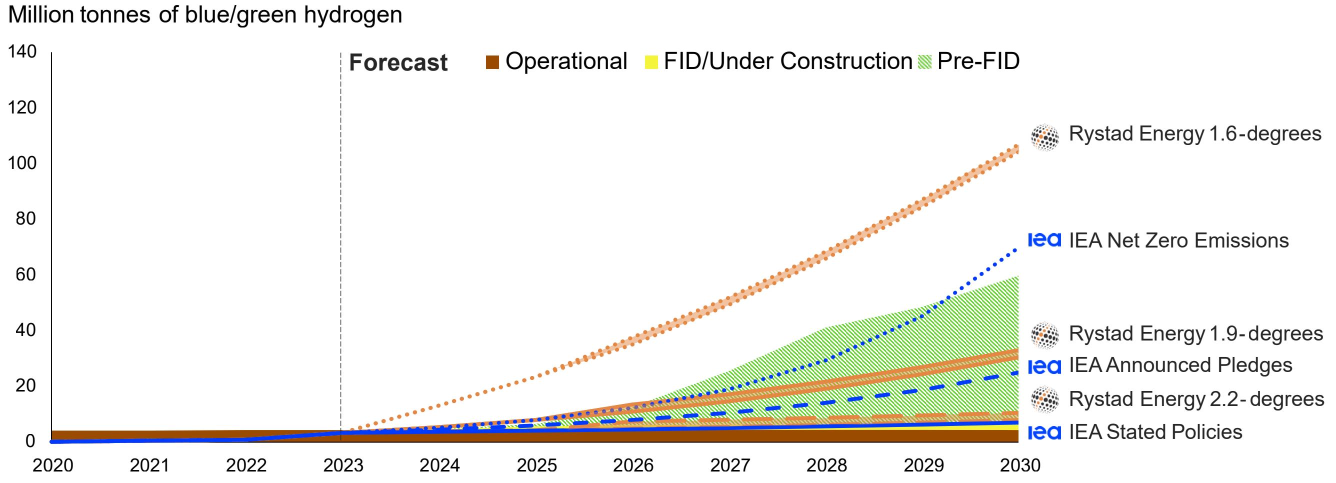
Source: Rystad Energy

construction. Nonetheless, the pace has accelerated: blue hydrogen FIDs taken since 2023 account for around 76% of total blue hydrogen FIDs taken since 2019 (in terms of project capacity). Currently, most operational blue hydrogen production facilities are in North America and Asia, with the US, Canada, India and Pakistan driving blue hydrogen production.

In contrast to blue hydrogen developments, the pace of green hydrogen growth has been slow, with green hydrogen projected to make up only 4% (around 0.2 Mtpa) of total operational blue and green hydrogen production in 2024 (around 4 Mtpa to 5 Mtpa). However, that could change moving forward as governmental policies, incentives and auctions that focus more on green hydrogen production are rolled out across the globe, especially across North America, Europe and Asia. By 2030, the combined capacity for pre-FID, FID and operational green hydrogen projects would reach about 31 Mtpa, exceeding the anticipated 29 Mtpa of blue hydrogen. This underscores the potential for a tremendous growth of green hydrogen within the next few years. However, most projects are currently in the pre-FID phase, with only about 1.2 Mtpa of projects (around 4%) having reached FID. Nonetheless, the pace of FIDs has been increasing rapidly since 2019, accounting for around 92% of cumulative historical green hydrogen project FIDs by capacity. Of this 92%, more than half (57%) is attributed to green hydrogen projects that have reached FID since 2023, highlighting a spike in green hydrogen project development in the last 18 months. As of 2024, zero- and low-CO_2 hydrogen capacity can only fulfill 4% of the total hydrogen demand. Consequently, the majority of ammonia and methanol produced to date still relies on fossil fuels. Nevertheless, this is expected to change moving forward, as more regulatory support for low-carbon ammonia production is being rolled out to decarbonise the agriculture, shipping and power generation sectors.

Currently, about 47% of hydrogen produced is used in its original form, while the remaining 53% is converted into derivatives, including ammonia for fertiliser production, methanol for chemical production and SAF for use in aircrafts. Ammonia and methanol make up the bulk of hydrogen derivative production. Nevertheless, there is an increasing prioritisation of electro-sustainable aviation fuel (eSAF) development to help decarbonise the aviation sector. However, as with all hydrogen derivatives, the cost of eSAF production remains significantly higher than that of conventional alternatives – up to eight times the cost of conventional jet fuel and two to three times the cost of bioSAF. Although the production of eSAF is costlier than that of bioSAF, its development is still necessary due to the limited supply of sustainable

Figure 42: Global unrisked zero- and low-CO_2 hydrogen production capacity, known vs. aspired



Note: 'Global unrisked zero- and low-CO_2 hydrogen capacity' refers to the total capacity of announced zero- and low-CO_2 hydrogen projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality. Ranges for the different degree scenarios reflect variation in zero- and low-CO_2 hydrogen displacement rate in existing uses of grey hydrogen, that include but are not limited to conventional methanol-based chemicals, fertilisers, refineries and plastic.

Source: Rystad Energy; IEA

biomass feedstock that is required for the aviation sector. This is often due to land-use constraints and competing demand from other biofuels, indirectly implying a supply cap on bioSAF that can be used for the aviation sector. To drive the adoption of eSAF, the RefuelEU Aviation initiative was drafted into law in 2023, creating an obligation for aviation fuel suppliers to carry a minimum share of eSAF when supplying fuel to aircraft operators at EU airports. This will start at 1.2% in 2025 and increase to 35% in 2050.

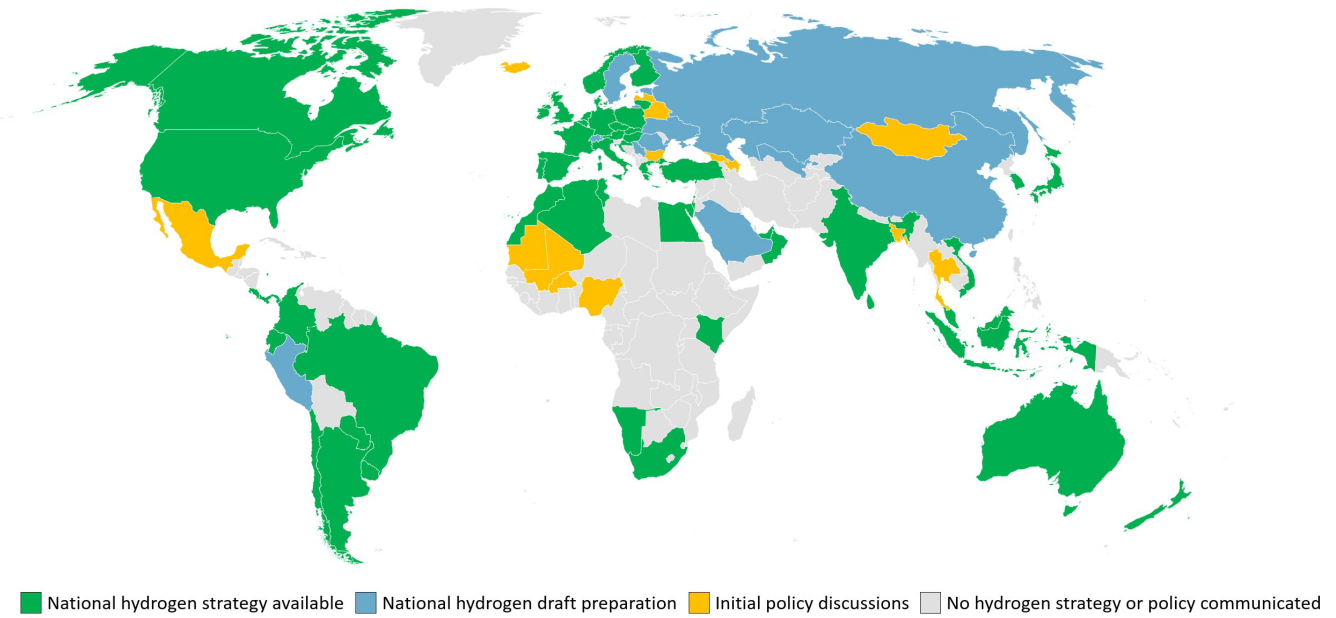
Based on announced project pipelines of zero- and low-CO_2 hydrogen, global unrisked zero- and low-CO_2 hydrogen capacity by 2030 is expected to grow to about 60 Mtpa, exceeding the capacity required by Rystad Energy's 1.9-degree scenario, as illustrated by Figure 42. However, this is still about 10 Mtpa below the capacity called by the IEA's net-zero-degree scenario and about 44 Mtpa below that of Rystad Energy's 1.6-degree scenario, calling for greater regulatory support to fulfil decarbonisation commitments. Governments across the globe are recognising the gap between current actions and ambitions and are starting to develop and enhance policy measures to support zero- and low-CO_2 hydrogen development. In Europe, the UK has completed its first Hydrogen Allocation Round (HAR1) in 2023, providing over £2 billion (US$2.14 billion[14]) of revenue support to 11 green hydrogen commercial projects that are expected to be operational from 2025, totaling 125 MW in capacity. With the UK's goal of 1 GW of green hydrogen in construction or operation by the end of 2025, the second Hydrogen Allocation Round (HAR2) in 2024 would support another 875 MW of green hydrogen projects. Besides that, the European Commission held its first auction under the European Hydrogen Bank, awarding nearly €720 million (US$770.4 million[14]) to seven green hydrogen projects – five located in Spain and Portugal, and two in Scandinavia – with a total production capacity of around 1.6 million tonnes over 10 years.

In the US, the Regional Clean Hydrogen Hubs (H2Hubs) program – under the Bipartisan Infrastructure Law signed in 2021 – would provide US$7 billion of funding to establish seven regional clean hydrogen hubs (blue and green hydrogen) across the country and US$1 billion to firm up demand-side support for those hydrogen hubs. H2Hubs would help jump-start the commercial development of the clean hydrogen value chain by creating networks of hydrogen producers, consumers, and local connective infrastructure to boost the adoption of clean hydrogen. In total, H2Hubs are expected to produce 3 million tonnes of clean hydrogen annually, achieving almost a third of the country's 2030 hydrogen production target of 10 million tonnes of clean hydrogen. In addition, the Inflation Reduction Act's 45V tax credit for clean hydrogen production seeks to further incentivise hydrogen production nationwide regardless of technology used, with credits given based on the lifecycle emissions of hydrogen production, ranging from US$0.60 per kg of H_2 (2.5 to 4 kg CO_2e per kg of H_2) to US$3 per kg of H_2 (<0.45 kg CO_2e per kg of H_2). Currently, blue hydrogen is unlikely to meet the lifecycle emissions criteria for higher tiers of the 45V tax credit due to high methane leakage rates and the carbon intensity of electricity used. As such, the 45Q tax credit for CCUS is often preferred when blue hydrogen is produced. Tax credits[17] under the 45Q vary depending on how CO_2 is captured and stored, ranging from US$60per tonne of CO_2 for enhanced oil recovery applications to US$85 per tonne of CO_2 for geologically sequestered CO_2. If direct air capture technology is used, these provided tax credits would approximately double.

In Asia-Pacific, Australia is investing AU$4 billion (US$2.68 billion[15]) into its Hydrogen Headstart Program, providing production credits for green hydrogen and its derivatives that would be delivered over 10 years. Six applicants have been shortlisted in 2024, representing a total electrolyser capacity of more than 3.5 GW. Japan is taking a similar approach, with plans to launch a contract for difference (CfD) scheme and a hub development support scheme in 2024. Under the CfD scheme, Japan would spend JPY3 trillion (US$18.6 billion[15]) to subsidise clean hydrogen production, transportation and storage. Eligibility for the scheme is based on carbon intensity (<3.4 kg CO_2 per kg of H_2) rather than hydrogen production technology. As domestic hydrogen production would be insufficient to meet Japan's hydrogen supply targets, policy support also encompasses imported hydrogen.Increasingly, many zero- and low-CO_2 hydrogen support policies have become colour agnostic, focusing more on the carbon intensities of hydrogen produced rather than its production methods. For green hydrogen, more stringent requirements regarding the source of energy used by electrolysis plants are starting to be introduced in the form of three criteria – additionality, regionality and time-matching, at least in the US and EU. This seeks to ensure that green hydrogen production would contribute to an increase in renewable energy supplied to the grid without inadvertently increasing fossil fuel usage for power generation.

First, on additionality, increased electricity demand should be met by additional clean power, otherwise the extra demand would likely be met by fossil fuels. Second, on regionality, renewable energy used by the electrolysis plant should ideally be locally generated, otherwise, it might incentivise fossil electricity

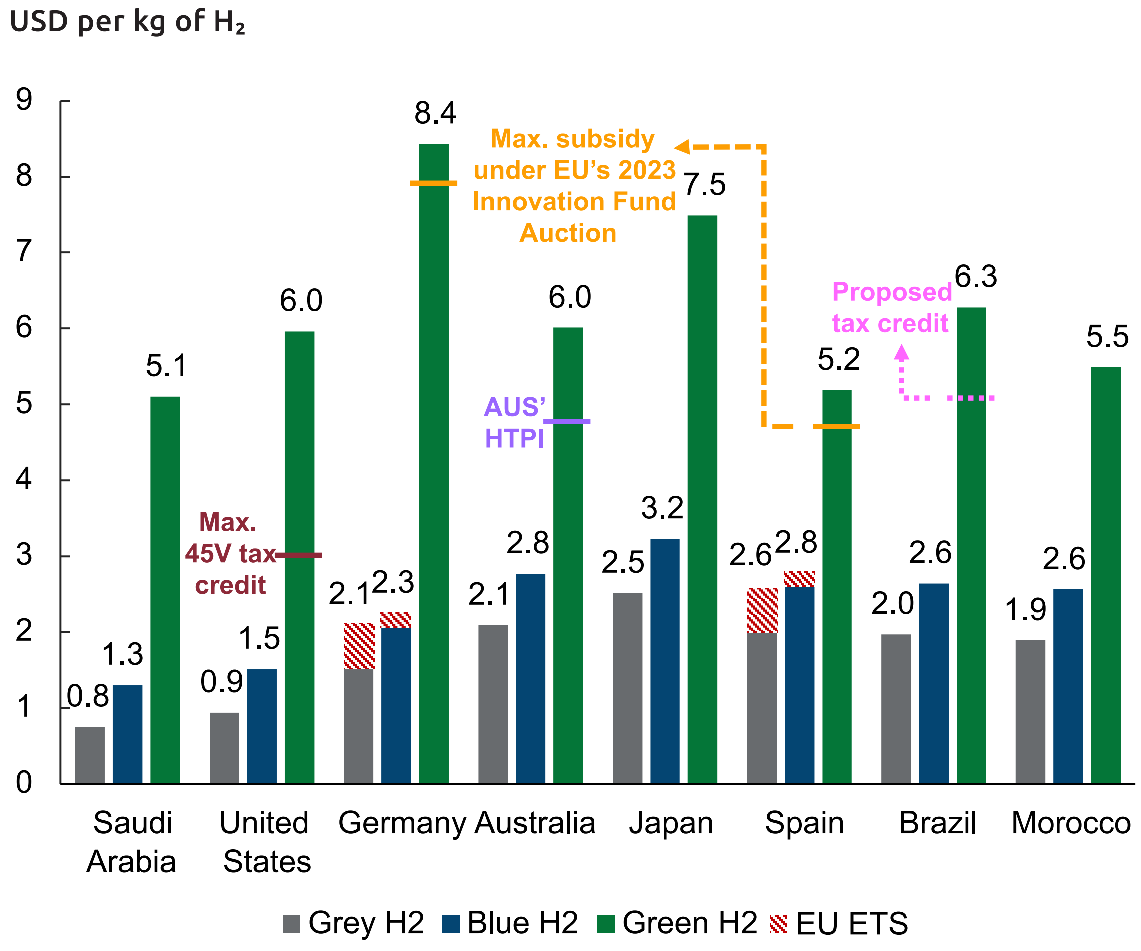
Map 4: Map of countries with national hydrogen strategies



Source: Rystad Energy

[17] *For equipment placed in service after 12/31/2022 and construction beginning prior to 1/1/2033.*

Figure 43: Levelised cost of hydrogen production for selected countries in most cost competitive provinces (2024)



Note: Levelised costs represent modelled real costs of hydrogen production in 2024 for each country based on a set of location-specific assumptions extracted from Rystad Energy's Hydrogen Fuel Cost Analysis. Each country's levelised cost reflects the production cost in the most cost competitive province. Model assumptions cover the prevailing location-specific gas and power prices, a discount rate of 5%, an asset lifetime of 30 years, an electrolyser energy consumption of 54 kWh per kg of H_2, an electrolyser plant size of 125 MW, and a carbon capture rate of 80%. The renewable energy source used for green hydrogen production is assumed to be solar only. Grey and blue hydrogen levelised costs have been adjusted with carbon taxes, where applicable, across countries.

Source: Rystad Energy

generation elsewhere, especially if the renewable electricity generated there is diverted away. Third, on time-matching, hourly matching ensures that electrolysis is occuring when clean energy is generated compared to annual matching, which could result in hydrogen produced during periods of more carbon-intensive power generation, when increased demand for power is likely to be fulfilled by less clean sources. The wave of recent policy support is not limited to the examples mentioned, as many countries are stepping up to develop their own national hydrogen strategies or revising their original strategies to be more ambitious, recognising hydrogen as an important fuel to decarbonise their economies, if produced cleanly.

Furthermore, policy support will be required to enable the development of infrastructure for hydrogen delivery and end-use, as it currently does not exist but is necessary for hydrogen's use as fuel. As the build-out of new hydrogen infrastructure is costly, the usage of existing infrastructure has been considered to mitigate this. Currently, zero- and low-CO_2 hydrogen blending with natural gas or other forms of pipe-quality methane is generally considered feasible at levels up to 20% for use in existing natural gas infrastructure without any major infrastructural modifications. However, this depends on a variety of factors that include the types of material used in existing natural gas infrastructure and the level of operational pressure and flow rates required in local markets, and thus requires a deliberate assessment and planning with policy as a driver. For instance, hydrogen can cause embrittlement in materials like steel. Moreover, since natural gas has a higher energy density than hydrogen, higher hydrogen blends would result in a higher total blended volume for the same energy content to be delivered. Thus, this would require increased operating pressures for necessary flow rates to be maintained. On the other hand, blending hydrogen with natural gas can help with reducing emissions – a 20% hydrogen blend would decrease emissions by about 6% to 7% due to hydrogen's lower energy density. Additionally, retrofitting existing natural gas infrastructure could accommodate pure hydrogen delivery and achieve a reduction in hydrogen delivery cost by 20% to 60% compared to building new hydrogen pipelines, as shown by a research study[18] published in 2020. The same study also showed that more than 80% of the analysed natural gas pipeline network in Germany is technically viable for pipeline reassignment. Thus, leveraging existing infrastructure through modifications could present a promising pathway to alleviate the costs of constructing new networks dedicated solely to zero- and low-CO_2 hydrogen distribution.

Energy infrastructure companies such as Snam, Gasunie and GRTgaz have recognised this and are repurposing existing natural gas pipelines while also building new hydrogen pipelines to advance the widespread use of hydrogen. For instance, Snam has started the engineering of the Italian segment of the SoutH2 Corridor project, which would connect North Africa, Italy, Austria and Germany via 3,300 km of largely repurposed natural gas infrastructure (>60% repurposed) to supply renewable energy to Italian and European demand clusters. Another example is Gasunie's recent FID for the first part (more than 30 km) of the Dutch national hydrogen network, which will connect major industrial regions in the Netherlands and neighbouring countries to import terminals and hydrogen production and storage facilities via a 1,200 km network (about 85% repurposed). As such, natural gas infrastrucuture becomes an enabler of the scale-up of zero- and low-CO_2 hydrogen as it accelerates the integration of zero- and low-CO_2 hydrogen into mainstream energy systems.

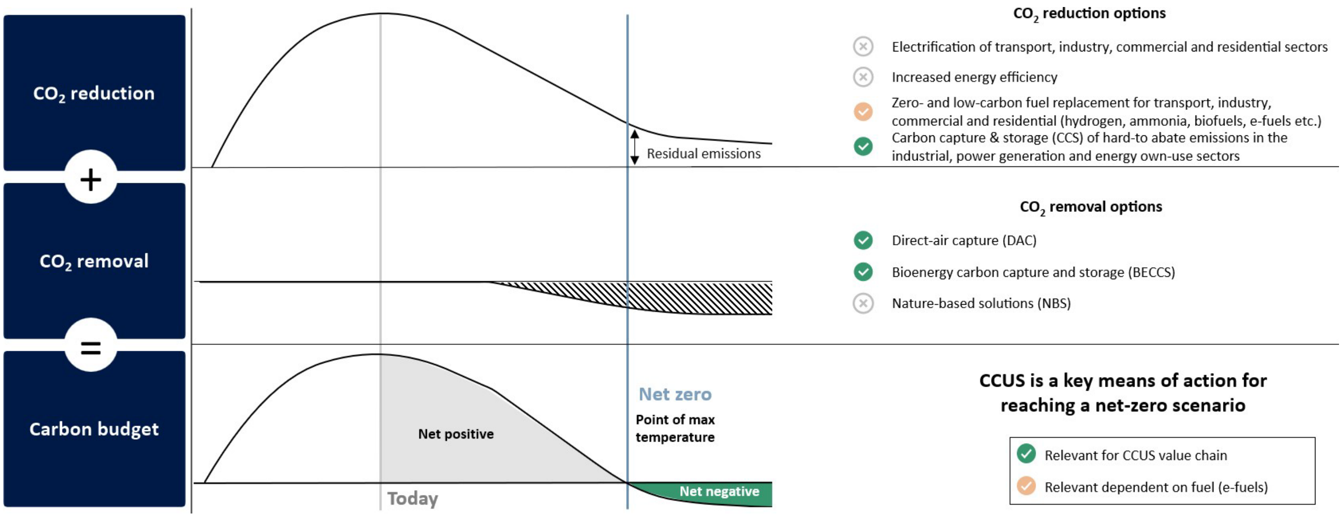
On production costs, the adoption of green hydrogen is still challenged by its high cost as illustrated in Figure 43, as it is around three to six times more expensive than grey hydrogen in the highlighted countries. However, significant cost reductions are expected from scaling effects and learning rates as electrolyzer technology advances. Costs could be further lowered via access to competitive low-carbon electricity, which comprises over 70% of cost for some locations. Government interventions like tax credits and subsidies, coupled with mechanisms that escalate carbon taxes overtime, would be key for zero- and low-CO_2 hydrogen's acceleration towards cost parity with emissions intensive fuel alternatives in existing and new hydrogen end-use segments such as fertilizers, refining, steel and shipping. This is crucial as blue hydrogen averages to about US$20 per GJ, more than twice the average cost of natural gas (US$8 per GJ) and more than three times the average cost of coal (US$6 per GJ)[19]. The cost parity gap against natural gas and coal is even wider for green hydrogen, which costs more than two times blue hydrogen, having an average cost of about US$52 per GJ. Thus, production tax credits or governmental subsidies, as well as carbon taxes or quotas, will be required to close the gap in cost and economically justify the switch to zero- and low-CO_2 hydrogen.

[18] *Source: Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a Germany case study. International Journal of Hydrogen Energy. (2020. April 17). https://doi.org/10.1016/j.ijhydene.2020.02.121*

[19] *Prices of natural gas and coal are based on latest price benchmarks (Henry Hub, TTF, Asia LNG Spot, Coal Newcastle and Coal ARA) in real 2023 terms. Hydrogen prices used are from Figure 43. Conversion factors used are 120.21 MJ per kg of hydrogen (LHV), 1.055 kJ per Btu of natural gas and 6,000 kcal per kg of coal (where 1 kcal equals to 4.1868 kJ).*

III. Carbon capture utilisation and storage (CCUS)

Figure 44: Overview of CCUS' key role in reaching a net-zero scenario



Source: Rystad Energy

CCUS plays a key role in decarbonization via two levers – CO_2 reduction and CO_2 removal. For CO_2 reduction, CCUS addresses hard-to-abate emissions in sectors such as cement production, petrochemicals production and dispatchable fossil fuel-based power generation, where alternatives are few and can be more costly than CCUS. Moreover, low-carbon replacement fuels such as blue hydrogen can be produced by reducing emission from conventional production. While traditional CCUS can help with CO_2 emission reduction, residual and legacy emissions[20] would still be present, requiring carbon removal technologies such as direct air capture (DAC) of atmospheric CO_2 and bioenergy carbon capture and storage (BECCS) of biogenic CO_2 to address the shortfall in reaching a net-zero scenario. Without carbon removal technologies to remove residual emissions, the path to net zero would be more complex and costly. Once atmospheric or biogenic CO_2 is captured, it can either be permanently stored (carbon dioxide removal, CDR) or utilised in various applications such as in producing e-fuels or construction materials (carbon capture and utilisation, CCU). Although the concept of CCUS is not new, it has only started to gain meaningful traction recently and requires more policy support for rapid development.

[20] *Residual emissions refer to CO_2 emissions that remain even after CO_2 reduction measures have been taken, while legacy emissions refer to accumulated CO_2 emissions in the atmosphere from past activities.*

Figure 45: Cumulative capacity of CO_2 capture projects, split by lifecycle detail

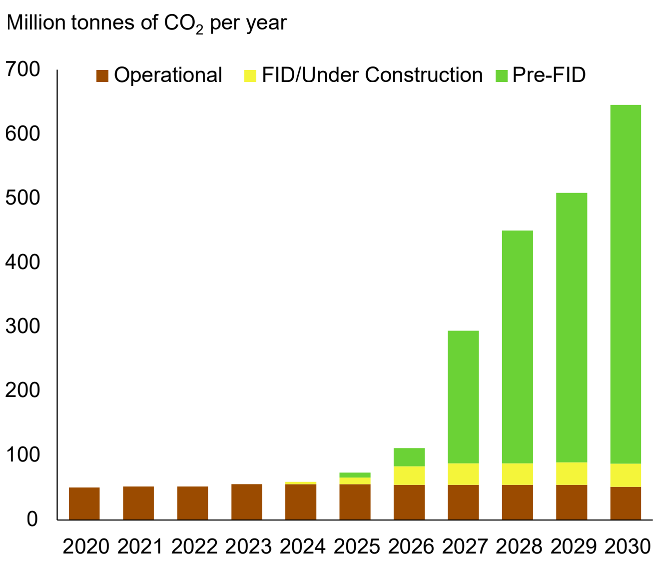
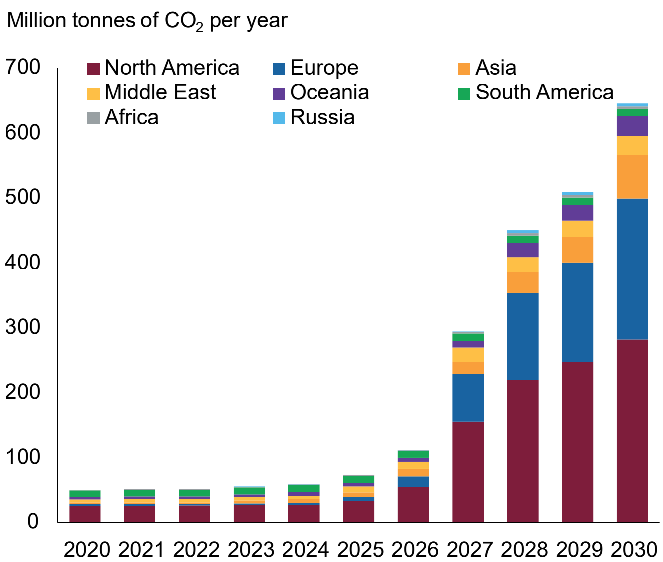


Figure 46: Global CO_2 capture capacity, split by region



Note: 'CO_2 capture capacity' refers to the total capacity of announced CO_2 capture projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality.

Source: Rystad Energy

In 2024, global CO_2 capture capacity is expected to grow towards 59 Mtpa of CO_2, with North America contributing to nearly half of total global capacity.

Moving towards 2030, global CO_2 capture capacity is estimated to grow by nearly 11 times, mainly driven by North America and Europe.

Figure 47: Cumulative capacity of CO_2 storage projects, split by lifecycle detail

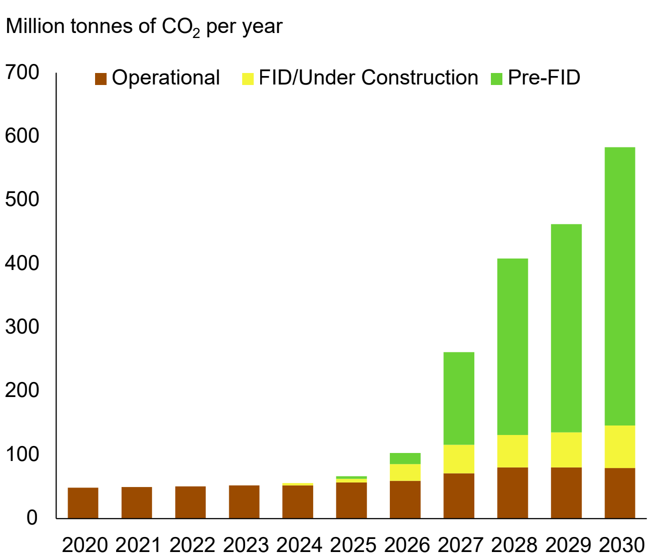
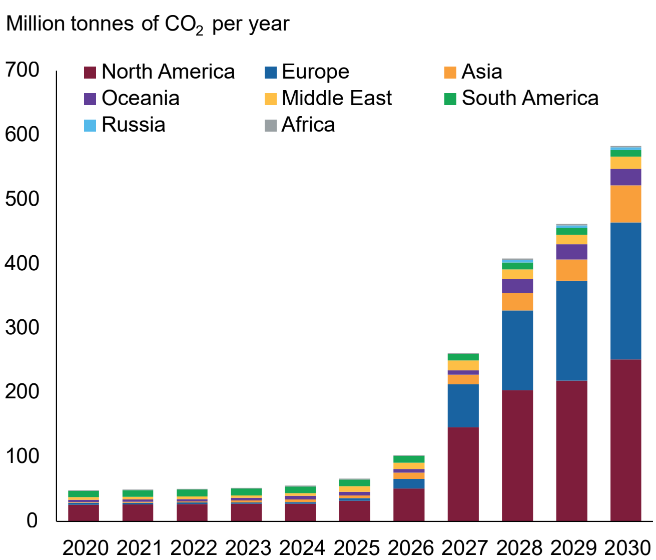


Figure 48: Global CO_2 storage capacity, split by region



Note: 'CO_2 storage capacity' refers to the total capacity of announced CO_2 storage projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality.

Source: Rystad Energy

Similarly, CO_2 storage capacity is expected to grow towards 55 Mtpa of CO_2 in 2024, and multiply by over 10 times in 2030. The difference in current CO_2 capture and storage capacities is mainly due to CO_2 capture projects that have been announced but have yet to determine the storage site of their captured CO_2.

While both CO_2 capture and storage announced capacities are anticipated to scale rapidly by 2030, most of the announced projects are still in the pre-FID phase, with progress towards FID being slow due to internal delays like prolonged FEED studies as well as external delays like permitting and financing. Mature markets in Europe and North America have been focusing on overcoming challenges in announced projects, while the Asia-Pacific market, which was previously lagging, leapt forward. The Asia-Pacific market saw a boost in CCUS driven by favourable policies developments such as national target announcements in Japan and South Korea and the amended safeguard mechanism in Australia. In Southeast Asia, countries such as Indonesia and Malaysia continued to take significant strides in developing critical regulatory frameworks.

Increasingly, oil and gas players are stepping in to function as infrastructure service providers in the CO_2 transport and storage business, leveraging on adjacent capabilities in field developments and infrastructural synergies by reusing existing gas systems such as pipelines for CO_2 transport and depleted oil and gas fields for CO_2 storage. For example, the UK's Acorn CCUS project, jointly owned by Storegga, Shell, Harbour Energy and North Sea Midstream Partners, plans to repurpose existing oil and gas infrastructure to transport up to 20 Mtpa of CO_2 to storage sites. Specifically, it plans to repurpose the Goldeneye pipeline to transport CO_2 offshore to the North Sea storage site, and further develop the gas separation plant at St Fergus terminal to capture emissions from other sources. This reuse of natural gas infrastructure is anticipated to save approximately £648 million (around US$693 million[16]), enhancing the project's commercial viability.

Figure 49: Current DAC and BECCS project pipeline by count

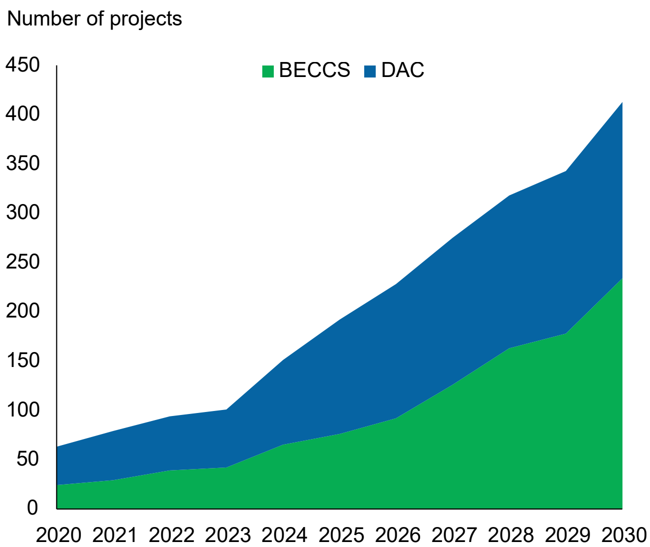
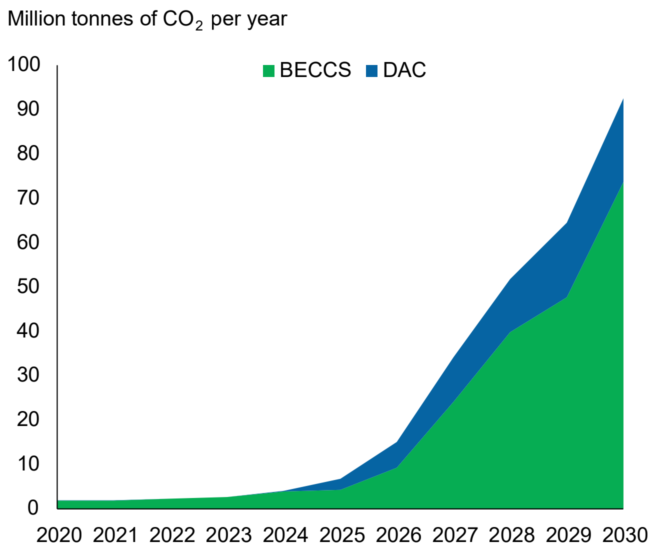


Figure 50: Current DAC and BECCS project pipeline by capacity



Source: Rystad Energy

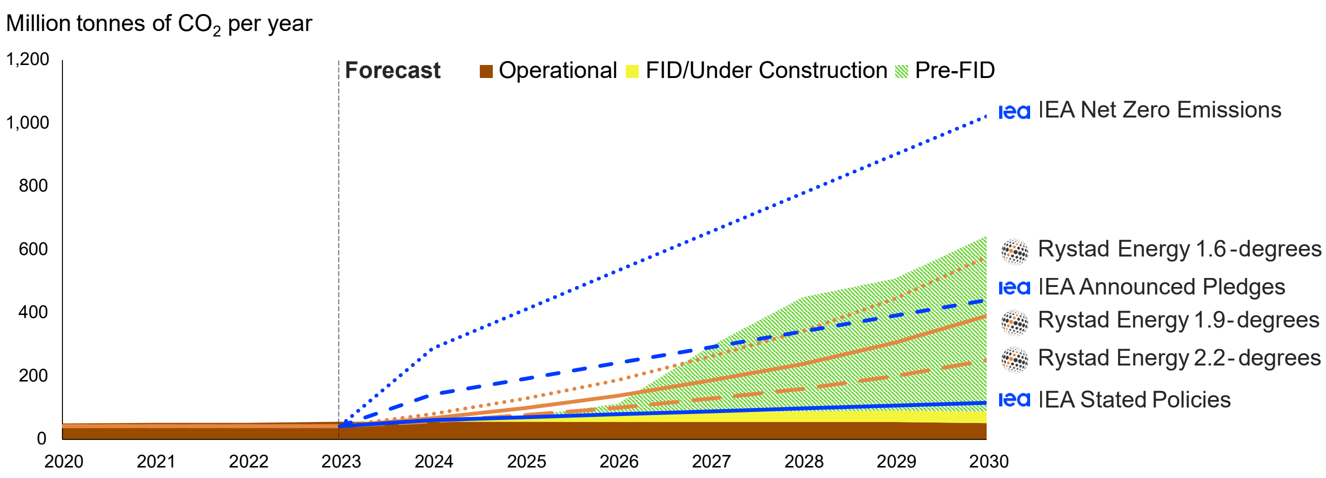
On the side of carbon removal technologies, DAC and BECCS are expected to scale quickly by 2030, with total project count tripling from 2024 to 2030. However, as seen in Figure 49, BECCS projects are scaling at a faster pace annually (at 24%) than DAC projects (at 13%), due to the intrinsic lower entry barriers (more developed technology) and lower initial costs. Although the numbers of DAC and BECCS projects are comparable, BECCS is estimated to boast about 24 times the carbon capture capacity to DAC in 2024, as seen in Figure 50. This is primarily because most DAC projects are small-scale proof-of-concept endeavours with minimal, if any, carbon capture capacity, that are often affiliated with universities and research institutions. In contrast, BECCS stands as a more established set of technologies, where the focus lies in deflating unit costs with large-scale projects. With large investments continuing to be made in CCUS, a surge in the deployment of both DAC and BECCS technologies is predicted, increasing capture capacity by over 22 times from roughly 4 Mtpa in 2024 to about 93 Mtpa by 2030. Most recently, the demand for these technologies has been partly driven by Big Tech to manage emissions arising from the power-intensive infrastructure used in artificial intelligence development, that is unlikely to be fully mitigated by clean power in the short term due to supply shortages. One example is Microsoft's deal with Occidental Petroleum in July 2024 to offset emissions via 500,000 carbon credits that would be captured by Occidental's first DAC project, Stratos.

With growing traction for CCUS in the market, total unrisked carbon capture capacity globally would grow rapidly from 55 million tonnes of CO_2 in 2023 to about 645 million tonnes of CO_2 in 2030. This is the result of many supportive CCUS policies being introduced successively in the past, primarily across Europe, the US and in Asia-Pacific countries such as Australia, China and Japan.

For countries in the EU, the implemented EU Emissions Trading System (ETS) effectively sets a price on greenhouse gas emissions, which in turn, helps to reduce emission levels and finance Europe's green transition. Complementing the ETS' outcome of ensuring CO_2 demand are two funding avenues for CCUS projects, namely by the European Commission Innovation Fund and the EU Connecting Europe Facility (CEF). The goal of the Innovation Fund is to support the commercial demonstration of innovative low-carbon technologies – including carbon capture and storage, carbon direct removal, and carbon capture and utilisation projects – with around €38 billion (US$40.66 billion[16]) from 2020 to 2030, that can bring about significant reductions in emissions. In comparison, the EU CEF aims to promote jobs and growth through infrastructure investment in Europe, which includes funding cross-border energy infrastructure projects. In 2023, eight such projects have been endorsed with a funding of €594 million (US$634.58 million[16]), with five of the projects being CO_2 network projects. In addition to these policies, in May 2024, the European Council has adopted the Net Zero Industry Act – a legislative initiative to bolster EU's manufacturing capacity for net-zero technologies – which includes a target to achieve 50 million tonnes of CO_2 sequestration capacity by 2030 in subsurface reservoirs within the EU. For the rest of Europe, countries are also setting their own policies to support CCUS development. One example is the UK, which introduced a clustering sequencing program to establish four CCUS clusters by 2030, alongside various funding mechanisms such as the CCUS Infrastructure Fund and the CCUS Innovation 2.0 programme, to reach a capture capacity of between 20 Mtpa and 30 Mtpa of CO_2 by 2030.

In the US, the Inflation Reduction

Figure 51: Global unrisked CO_2 capture capacity, known vs aspired



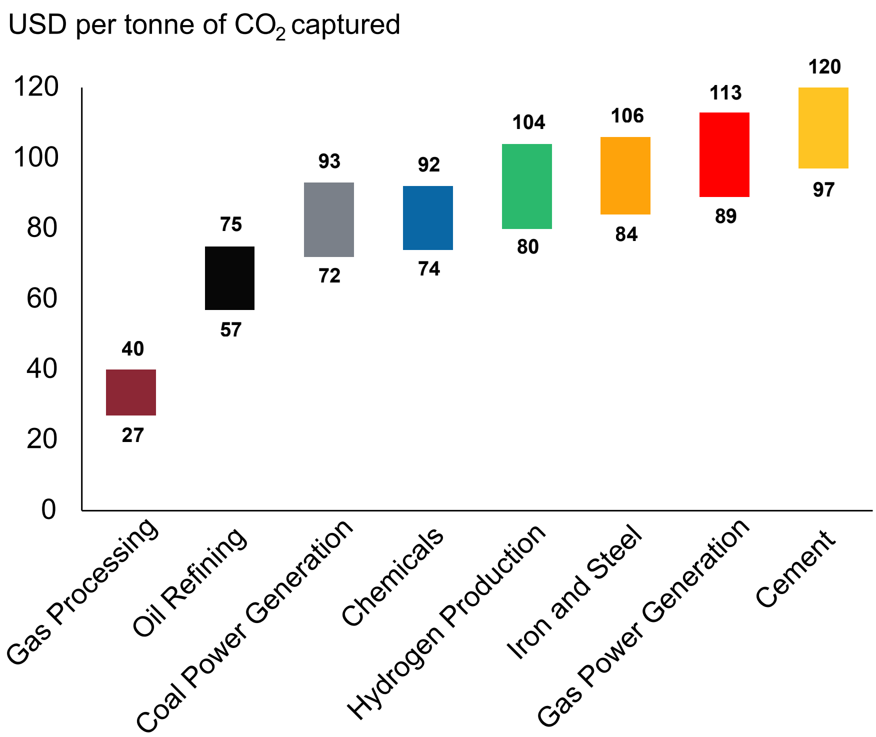
Note: 'Global unrisked CO_2 capture capacity' refers to the total capacity of announced carbon capture projects based on project owners' communicated capacity and start-up date, without adjusting for the risk related to project delays, regulatory permits and commerciality.

Source: Rystad Energy; IEA

Act 45Q provides a tax credit of US$85 per tonne of CO_2 captured and permanently stored in geological formations and US$180 per tonne of CO_2 if DAC is used. This tax credit was revised[21] upwards from a previous maximum credit amount of US$50 per tonne of CO_2, benefitting many hard-to-abate sectors that face high CO_2 capture costs, as seen in Figure 52. Similarly, tax credits were raised for other qualified uses of CO_2 storage applications, including EOR.

In Asia, CO_2 taxes are being gradually rolled out across various countries such as Singapore and Australia, with Indonesia taking the lead in CCUS regulations with its first legal framework for CCUS being introduced in March 2023. In China, the national ETS was introduced back in 2021 and is currently the largest carbon market in the world in terms of emissions covered. The ETS currently covers the power generation sector, which represents over 40% of China's total emissions, with plans for other sectors to be covered in future. However, China's ETS differs from the EU ETS in one major aspect: instead of setting a CO_2 emissions cap, China's ETS allocates allowances based on the verified emissions intensity of individual emitters. Power plants in China are granted a certain quantity of free allowances for their annual emissions but if they surpass this allocated amount, they are required to acquire extra allowances from the open market. Compliance rate for the first compliance period reached 99.5%, with most companies meeting their obligations. However, there have been concerns over its effectiveness due to low market liquidity and traded volumes. Carbon prices are also relatively low compared to global markets, averaging around US$10.8 per tonne of CO_2 in the past 12 months.

Figure 52: Levelised cost of CO_2 capture across industrial sectors (2023)



Note: Results and calculations are based on assumptions extracted from Rystad Energy's CCUS Levelised Cost dashboard, with selection of costs based on a power price of US$100 per MWh and a CO_2 capture rate of 1 Mtpa to 5 Mtpa. An open-cycle gas turbine plant is assumed for the levelised cost of capture for gas power generation. All figures are rounded to the nearest whole number.

Source: Rystad Energy

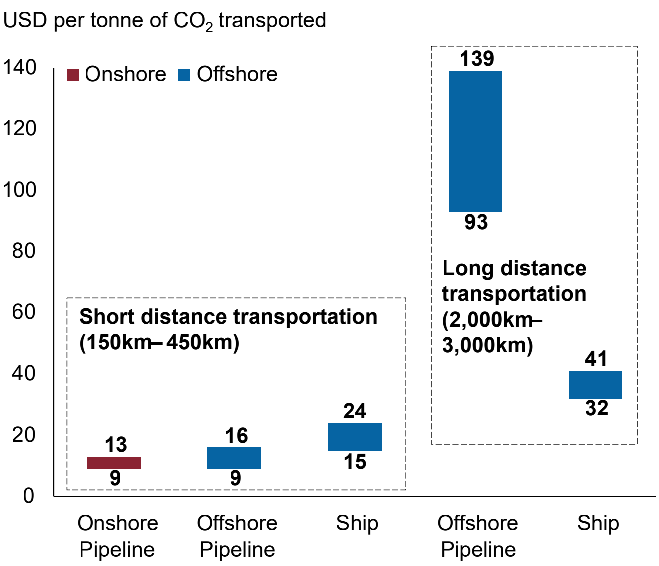
While the announced growth in carbon capture capacity towards 2030 may seem promising as illustrated by Figure 51, achieving the capacity required under a 1.6-degree scenario remains uncertain. This is due to a high likelihood of project delays moving forward, like those experienced in 2022 and 2023, which are often caused by project development issues, and regulatory and economic factors. A prolonged FEED study phase has been the primary cause of significant project delays and is expected to affect one-third of projects this decade as most commercial CCUS projects are still in the early stages of development. Medium and large CCUS hub projects would be particularly impacted as they require extensive early assessment studies due to their scale and complexity. This also applies to standalone or multi-asset projects deploying innovative and relatively immature capture technology or utilizing large cross-network transportation routes or underexplored storage reservoirs.

[21] *For equipment placed in service after 12/31/2022 and construction beginning prior to 1/1/2033.*

Furthermore, regulatory hurdles that include obtaining approvals for pipeline routes and storage sites can be a lengthy and iterative process, especially if permits are rejected and require resubmission. For example, the Class VI permit application to operate wells for geological CO_2 sequestration in the US involves a detailed five-step review process, which can take approximately two to three years for approval. A resubmission could result in a delay of another two to three years. In addition, economic challenges that include the high and persistent inflation seen in 2022 and 2023, along with high borrowing costs, has made CCUS projects more expensive than anticipated, delaying funding and slowing down the development of CCUS projects. As such, a substantial increase in CCUS capacity is likely to become more evident in the next decade rather than by 2030.

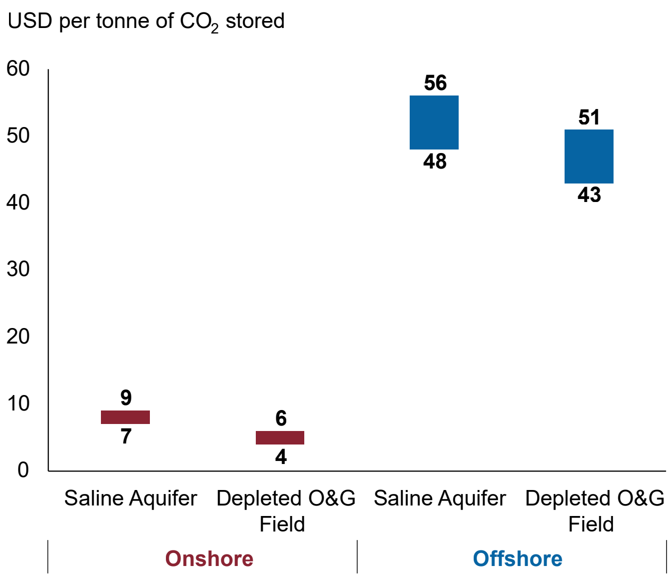
To close the gap between current and targeted CCUS capacity levels, governments worldwide need to collaborate more closely with industry players on two main issues: lowering the risk of project delays and increasing project bankability. First, project delays can be mitigated by accelerating permit approvals and sharing best practices in permit applications. Governments should lead these efforts, and companies should allocate more resources to the initial assessment phases of CCUS projects, which are often delayed by funding issues. Second, governments can enhance the bankability of CCUS

Figure 53: Levelised cost of CO_2 transport (2023)



Note: Results provide a representative view of the average range for the levelised cost of CO_2 transport (LCOT) across global projects. These findings are based on a specific set of assumptions, set to reflect actual project parameters. Data is extracted from Rystad Energy's CCUS Levelised Cost dashboard, with selection of costs based on a power price of US$100 per MWh, a ship capacity of 25,000 tonnes of CO_2, transport distances that range from 150 km to 3,000 km, and a CO_2 transport amount of 2 Mtpa. All figures are rounded to the nearest whole number.

Figure 54: Levelised cost of CO_2 storage (2023)



Note: Results provide a representative view of the average range for the levelised cost of CO_2 storage (LCOS) across global projects. These findings are based on a specific set of assumptions, set to reflect actual project parameters. Data is extracted from Rystad Energy's Levelised Cost dashboard that varies depending whether CO_2 is stored onshore or offshore. For onshore storage, assumptions are based on a storage depth of 1,500 m, and a storage rate of 1 Mtpa. For offshore storage, assumptions are based on a storage depth of 2,500 m, a water depth of 1,500 m, and a storage rate of 1 Mtpa. Both onshore and offshore storage use US$100 per MWh as the power price. Levelised cost of storage data only includes injection and storage costs and does not include monitoring and verification costs. All figures are rounded to the nearest whole number.

Source: Rystad Energy

projects, giving developers and investors more confidence. This requires a range of measures, including increased government funding, a well-regulated carbon credit compliance market, and progressive regulations that penalize industries lagging in emissions reductions.

On CCUS costs, capture costs form the bulk of total CCUS costs (around 33% to 62%), meaning that capture technology advancement could accelerate the cost competitiveness of CCUS. Capture cost varies on the capture source, scale and capture technology. In general, capture costs tend to fluctuate according to the concentration of CO_2 in emission streams – the lower the CO_2 concentration in resulting emissions, the higher the capture cost, due to higher energy requirements and more complex capture equipment required. For instance, as shown in Figure 52, natural gas processing facilities typically produce gas streams with much higher CO_2 concentration compared to power and cement plants, which makes separation easier and more energy efficient, thereby reducing capture costs.

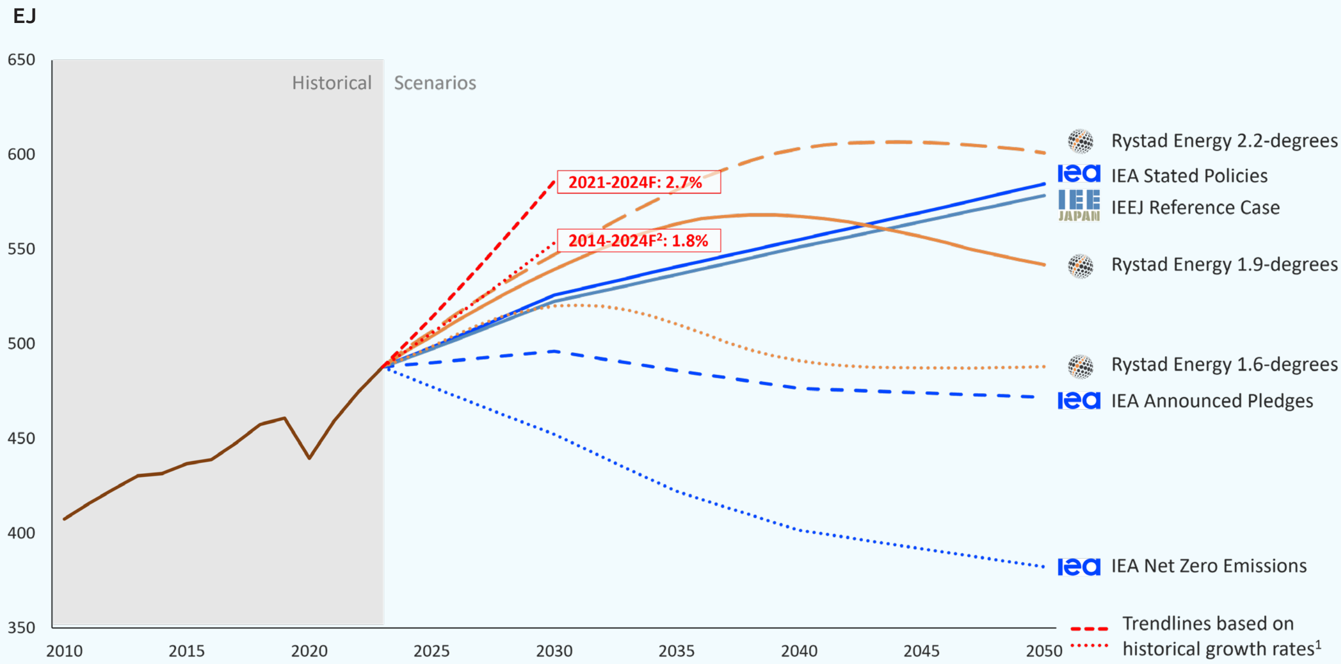
Transport and storage cost varies widely across projects depending on factors such as scale, transport distance, and storage conditions, with transport cost ranging from US$9 per tonne of CO_2 to US$139 per tonne of CO_2 and storage cost ranging from US$4 per tonne of CO_2 to US$56 per tonne of CO_2. The actual cost range could be broader across various CCUS projects, reflecting differences in geographical, geological, and institutional context. For longer distance CO_2 transport beyond 600 km to 800 km, the use of ships may be more economical while providing additional advantages over offshore pipelines such as destination flexibility and decreased sensitivity towards capital cost as distance scales. These are positive accelerants for the development of 'open-source' CCUS hubs and cross-border CO_2 trading. However, CO_2 shipping technology is still in its infancy today with underdeveloped infrastructure. Only a few liquefied CO_2 vessels are in operation, primarily for the food and beverages industry, while vessels built for CCUS-purposes are still in trial phase. Furthermore, there are indirect costs associated with shipping such as port infrastructure requirements that could shave away its cost advantages. As such, many project developers still prefer pipelines to ships (sometimes to complement shipping), especially for larger volumes and shorter distances, due to their cost efficiency, established technology, and steady flow. Moving forward, cost reduction in pipeline transport will likely be achieved from access to cheaper power sources, economies of scale through hub-models, and via a clustering of emissions sources.

For CO_2 storage, depleted oil and gas fields are generally more cost-competitive than saline aquifers due to the presence of existing infrastructure such as wells and pipelines that can be reused. This cost advantage and the availability of extensive data and proven integrity, explains why most captured CO_2 has been stored in these fields or used in enhanced oil recovery. However, the use of saline aquifers is expected to increase due to their wider availability and greater potential for CO_2 storage, which is essential to meet the growing global demand for CCUS.

3 / Operating in an era of high energy uncertainty

Highlight

Figure 55: Global final energy demand growth trends, historical vs. aspired



Gap between trendlines and 2030 scenario targets: *For reference, Europe energy demand was 65 EJ in 2023*

Scenario	IEA Net Zero Emissions	IEA Announced Pledges	IEA Stated Policies	RE 1.6-degrees	RE 1.9-degrees	RE 2.2-degrees	IEEJ Reference Case
2021 – 2024F trendline gap	134 EJ	90 EJ	60 EJ	66 EJ	48 EJ	39 EJ	64 EJ
2014 – 2024F[2] trendline gap	101 EJ	57 EJ	27 EJ	33 EJ	14 EJ	6 EJ	31 EJ

Note: [1] This analysis considers two trendlines: the 2021-2024F trendline and the 2014-2024F trendline. Each trendline uses a consistent annual growth rate towards 2030, which is calculated as the average of the annual growth rates of the historical years considered.
[2] The 2014-2024F trendline excludes Covid-19 impacted years 2020 and 2021 from the average growth rate calculation to adjust for the unusually low and high growth rates observed in the respective years.

Source: Rystad Energy, IEA, IEEJ

The world is demanding more energy. Developing regions need more energy for urbanisation and industrialisation, while developed regions are maintaining energy consumption growth despite energy efficiency gains and structural declines of certain sectors (such as industry). Recent trends like the spread of power-intensive technologies and increasing average temperatures (driving higher cooling demand), alongside the continuing electrification of transport and buildings, are causing an unexpected surge in power and overall energy demand. This rise in demand is challenging a multitude of assumptions surrounding future energy needs made by target-oriented scenarios from institutions like the IEA, IEEJ and Rystad Energy[22], with 2030 targets already seeming far from reach. If energy use continues to evolve as it has in recent years, actual demand will significantly diverge from scenario pathways, potentially leading to a significant gap between demand and planned supply of gas and low-CO_2 energy. Living in an era of high energy uncertainty has profound implications for investment decisions, energy infrastructure development and technology planning, and reconciling scenarios with forecasts is necessary to inform prudent policy.

Uncertainty complicates decisions about the optimal energy mix and poses risks to achieving global emissions reduction goals, requiring a more realistic approach balancing current growth trends with long-term sustainability goals.

To mitigate the risk of further crisis and volatility, natural gas plays a crucial role, providing the necessary flexibility to accommodate increasing demand while supporting the transition towards a lower-carbon future.

[22] *This analysis considers 7 energy demand scenarios from 3 institutes: IEA's Stated Policies, Announced Policies ad Net Zero Emissions by 2050 scenarios from the 2023 Outlook, IEEJ's Reference Case scenario from the 2024 Outlook and Rystad Energy's latest 1.6-degrees, 1.9 degrees and 2.2-degrees scenarios. Rystad Energy's degree scenarios assume that global warming will be limited to the specified degree Celsius.*

I. Mitigating risk in an era of high energy uncertainty: scenarios vs. forecasts

The world is in an era of high energy uncertainty, fuelled by rising energy demand, economic development pressures, the pursuit of affordability, the energy transition, and the urgent need to reverse the ongoing growth of emissions. These factors create competing priorities for energy supply and investment planning.

Following a period of turbulent energy demand through the pandemic bust and boom cycle, 2023 continued to see opportunities and challenges unfold in global energy and gas markets. The global supply crisis gradually stabilised, but markets remain fragile. As the world is moving to electrify energy end-use, significant new trends are shaping the evolution of energy demand and creating potential implications for future gas demand. This section will dive to explore these new trends in the context of historical energy demand evolution, and to extrapolate implications for investment planning in gas. The wider focus on energy demand in this section provides an opportunity to assess the role of gas in the context of the evolving energy system, the purpose of which is to provide sustainable, affordable, and reliable energy to the consumers who need it.

Looking at historical trends, the demand for energy has evolved differently across regions, reflecting different social, technological, and economic trajectories. Charting possible pathways from these historic trends toward a low-emissions future requires creating scenarios. Scenarios are sophisticated economic modelling exercises which apply and assess numerous assumptions of potential technological and behavioural changes that could shift the historic trend. As such, many prominent analytical institutions have developed a myriad of scenarios for the future of energy demand, creating back-casted pathways based on targets and assumptions over decarbonisation, achieved degree of climate warming, or policy implementation. Scenarios are not forecasts, because significant assumptions around policy's ability to impact energy consumption patterns, behavioural changes, and technology adoption rates are made when formulating them. Uncertainty about the relative likelihood of different scenarios can add to overall uncertainty in energy systems.

Scenarios are analytically informed proposals of a possible future. Forecasts, on the other hand, project energy demand based on research into trends observed in actual historical demand to determine the most likely outcome for the future. Neither of those instruments are a perfect predictor of the future, but when planning investment, it is critical to consider both.

If energy demand continues to evolve as it has in recent years, future demand is likely to diverge from many major scenario assumptions, overshooting the 2030 demand reduction targets under most scenarios. In this context, using scenarios as an energy supply and investment planning tool without cross-checking against forecasts enhances the risk of a significant gap between actual demand and the planned supply of gas and low-CO_2 energy. This can lead to an increased propensity of further energy crises and market volatility. Avoiding it requires a balance between the priorities of sustainability, security, and affordability to create a more resilient and adaptable energy system. In the historically unprecedented attempt to change the pattern of energy system evolution, flexibility may become the single most important determinant of success or failure. Gas is an essential energy source of flexibility for navigating this energy uncertainty and ensuring that the energy system is nimble enough to manage growing demand, while decarbonising.

This chapter begins with a regional overview of energy demand trends over the past five years, highlighting key energy demand drivers and the gap between actual trends and demand scenarios. Following this, the chapter zooms into examples of new global energy use trends and assesses their impact on projected energy and electricity demand. These trends include rapidly growing demand from data centres due to widespread artificial intelligence (AI) integration, and an uptick in cooling demand caused by higher average temperatures, as well as continual electrification of different sectors through rising

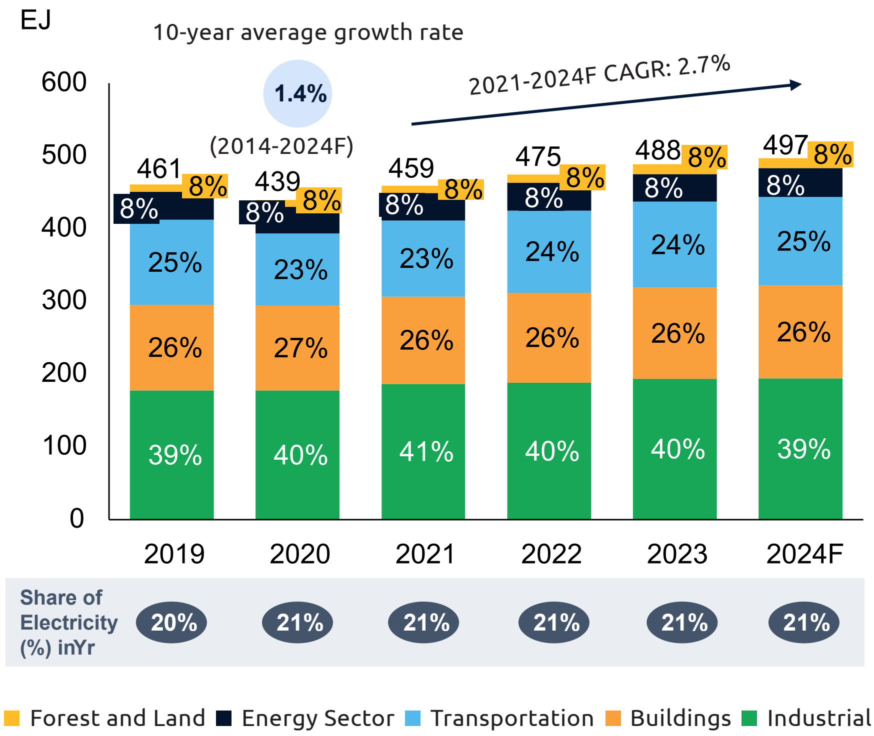
heat pump adoption in buildings and growing electric vehicle (EV) sales. These growing demand trends have been adding to energy emissions and compounding increase in the risk of missing ambitious climate and energy demand reduction targets, particularly as coal continues to supply two-thirds of the world's electricity, and the rate of growth of renewable sources has not been able to catch up to the rate of power demand growth.
The chapter concludes with a comparison of actual demand trends with scenario pathways set by various institutions, demonstrating that the gap between them is still prominent. This points to a risk of a potential supply and investment gap in gas and other low-CO_2 energy, which requires urgent mitigation.

II. Regional energy demand trends vs. scenarios

a. Global

Global energy demand has been consistently increasing after the Covid-19 pandemic, with growth in recent history above 10-year average rates. The world has been increasing its energy consumption by 2.7% annually, between 2021 and 2024F[23], at almost double the 2014-2024F rate of 1.4%. Should the world continue to develop in a similar dynamic, with an increase in access to energy-intensive lifestyles in developing countries alongside new demand drivers such as AI-focused data centres and higher cooling demand from extreme weather events, this growth can be expected to continue its steady trajectory. This is in contrast with energy demand outlined by back-casted scenarios targeted to reach ambitious climate objectives. For example, a Rystad Energy scenario anticipates a 1.8% average global energy demand growth rate assumption between 2021 to 2030, to keep a global warming limit of 1.9 degrees within reach. The IEA assumes a 1.1% growth rate globally over the same period in the Stated Policies scenario, a 0.3% rate in Announced Pledges, and -0.2% in Net Zero. Japan's Energy and Economics Institute (IEEJ) applied a 1.4% growth rate for its reference case over the same 2021-2030 period. The departure of these growth rates from the global 2021 to 2024F Compounded Annual Growth Rate (CAGR) of 2.7% outlines the difficulty in reaching 2030 targets should energy demand continue to evolve as it has in the information age, including the most recent years.

Figure 56: Global final energy demand split by sector, and share of electricity in total demand



Source: Rystad Energy

Global energy demand growth from 2021 – 2024F has mainly been driven by three key segments: transportation demand with 17 Exajoules (EJ) (5.3% CAGR), buildings demand with 8 EJ (2.0% CAGR), and industrial demand with 8 EJ (1.4% CAGR) over the four-year period. Transport energy demand has seen the most significant growth, driven by an overall increase in passenger and

[23] *Period chosen to reflect growth rates after energy demand recovery to pre-pandemic levels.*

freight transportation across road, aviation, and shipping sectors. The International Air Transport Association (IATA) expects a 10.4% increase in total passenger numbers in 2024, outlining a recovery from the pandemic with growth in all continents except for Africa. A key trend to monitor in the transportation space is strong momentum for EV adoption supporting large-scale road transport electrification, swinging the demand for oil-products to demand for electricity.

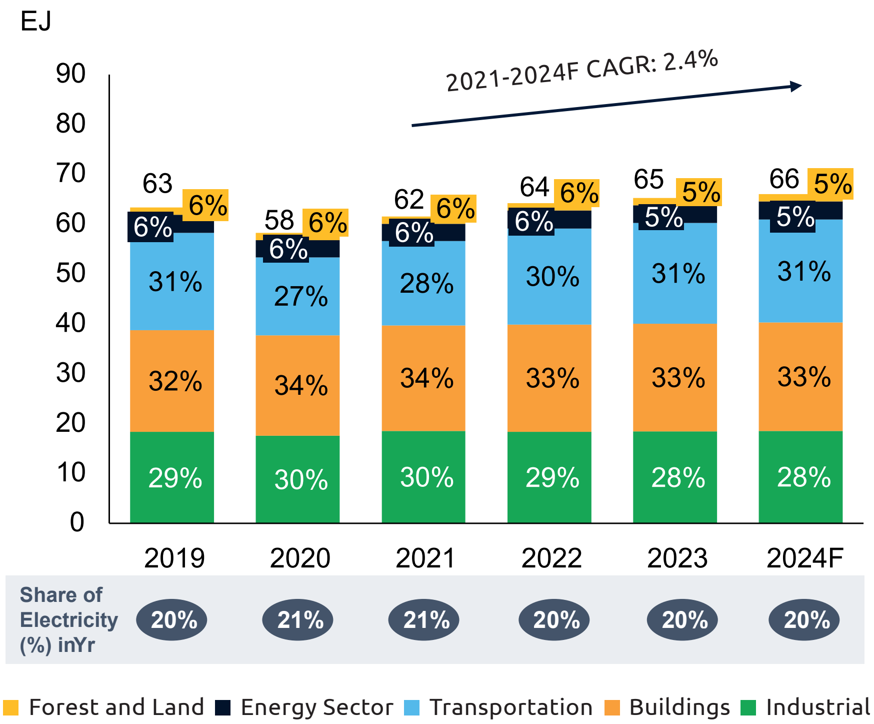
Energy demand growth in the buildings sector is largely attributed to increase in building stock globally, particularly in emerging economies, as population growth continues alongside a shift towards more energy-intensive lifestyles – an International Monetary Fund study[24] in 2020 outlined that for middle income countries, energy consumption and incomes move in lockstep. In addition, the building sector is undergoing substantial changes, with growing AI-focused data centres expected to drive energy demand growth. The increasing frequency of extreme weather events is also driving higher cooling demand, in both residential and commercial buildings.

The International Monetary Fund (IMF) expects global economic growth to reach 3.3% in 2024, up from 2.9% in 2023. This has driven a resurgence in activity as supply chains stabilise, especially in industrial powerhouses such as China and India, where industrial demand accounts for over half of total energy demand. This has resulted in an uptick of industrial energy demand globally, seeing a 1.3% CAGR over the 2021-2024F period.

b. Europe

Energy demand in Europe is expected to see a CAGR of 2.4% from 2021 to 2024F, reaching 66EJ in 2024. In contrast, based on scenario assumptions, Rystad Energy's 1.9-degrees scenario calculates a 1.0% rate of demand growth required between 2021 to 2030 on a pathway to limit warming to 1.9-degrees. The IEA anticipates a rate of -0.7% in the Stated Policies scenario over the same period, which is notably a contraction, in opposite direction of that of the current 2021-2024F trend. The institution's Announced Pledges scenario is even further away, seeing a rate of -1.3%. The departure of these growth rates, from the aforementioned 2021 to 2024F CAGR in Europe outlines the difficulty in reaching 2030 targets should energy demand continue to evolve as it has in the recent past.

Figure 57: Europe final energy demand split by sector, and share of electricity in total demand



Source: Rystad Energy

Recently, the EU has put forward policies to increase energy efficiency and decrease overall energy demand. The 2021 European Green Deal revision set legally binding targets to reduce emissions by 55% by 2030, compared to 1990 levels, with regulations around reducing energy consumption. Goals to enhance energy efficiency were later reinforced in the REPowerEU plan which aimed to reduce Europe's dependence on Russian fossil fuel imports. In latest developments, the EU Parliament announced a target in July 2023 to reduce both primary and final energy consumption in the EU by at least 11.7%[25] by 2030, compared to 2030 baseline projections contained in the 2020 EU Reference Scenario. These

[24] *Source: Energy, Efficiency Gains and Economic Development: When Will Global Energy Demand Saturate? https://www.elibrary.imf.org/view/journals/001/2020/253/article-A001-en.xml*

[25] *Source: Parliament adopts new rules to boost energy savings. https://www.europarl.europa.eu/news/en/press-room/20230707IPR02421/parliament-adopts-new-rules-to-boost-energy-savings*

policies place great emphasis on consumption reduction from the buildings sector which accounted for the largest share of energy consumption in Europe in 2023 at 33%. The March 2024 revision of the Energy Performance of Buildings Directive aims to reduce emissions as well as energy consumption, also helping bring down energy bills. In the industrial sector, which has contributed between 28% and 30% of energy demand in the past 5 years, energy market experts argue that industrial demand destruction through deindustrialisation rather than an increase in energy efficiency has caused an apparent reduction in energy demand. This is a result of energy-intensive industries not recovering from 2022's production slowdown caused by high energy prices and reduced supply availability.

On the side of Europe's power demand, there has been a decline with March 2024 recording numbers 2.4% lower than in March 2023, 7% lower than in March 2022 and 8% lower than in the five years between 2016 and 2021. The drivers of this include relatively low industrial and commercial activity across Europe and low residential demand. Demand across all sectors has remained low, despite prices falling dramatically over the last year, indicating that price sensitivity is not the only driver for the reduced demand we are observing. Among key regions, France has seen the largest percentage decline in demand, while the Nordic region has recorded the largest increase. Sweden and Norway experienced frigid temperatures in January this year, resulting in surging power demand, while their economic activity also remains at a more normal level compared to the rest of Europe.

Europe is leading in terms of share of renewables for power generation, having seen strong growth in recent years and occupying a share of 48.1% in 2023 (up from 43.3% in 2022). Solar and onshore wind generation increased from 6.2% and 12.0% in 2022 to 7.5% and 13.4% in 2023, respectively, and are expected to see the largest growth in the share of total generation in 2024. Nuclear and gas power generation were the two largest energy sources in Europe at the end of 2023, accounting for 20.9% and 17.9% of total power generation. While the share of nuclear power changed negligibly since 2022, the share of gas dipped from 20.3% in 2022 to the current level. Coal power generation also dipped from 14.6% in 2022 to 11.7% in 2023.

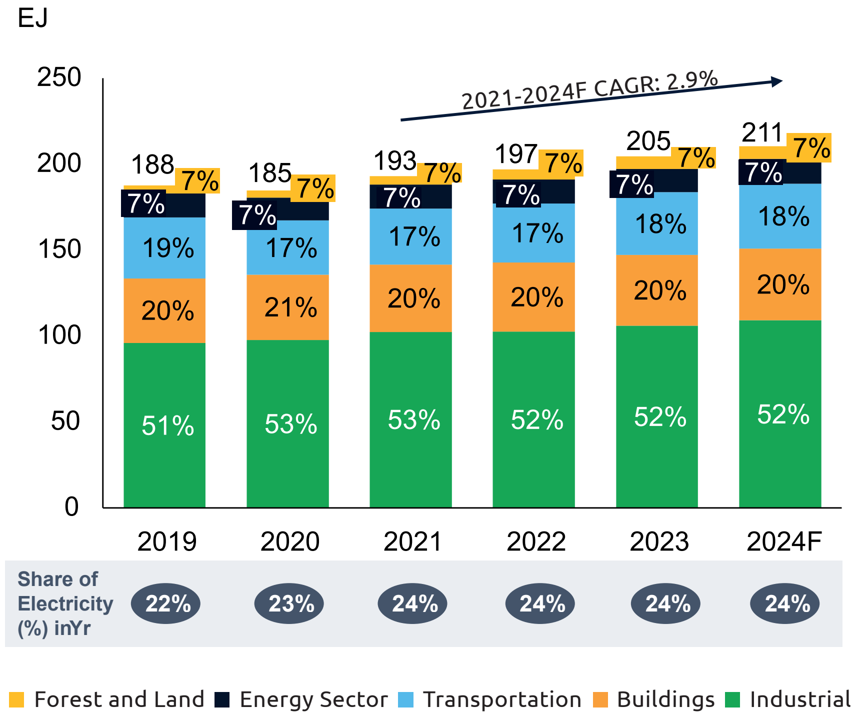
On a country-level, renewables account for more than half of total power generation in Germany and Spain at 52.7% and 50.4% in 2023 respectively. The UK closely follows the leading countries with a 47.6% share of renewables, driven by wind, in addition to nuclear power. France has a relatively low share of renewables at 27.9%, but nuclear occupies a large component of its power mix bringing the combined power generation from coal, gas and oil to well under 10%.

c. Asia

Energy demand in Asia is expected to see a CAGR of 2.9% from 2021 to 2024F, reaching 211EJ in 2024. In contrast, based on scenario assumptions, Rystad Energy's 1.9-degrees scenario calculates a 2.2% rate of demand growth required between 2021 to 2030 on a pathway to limit warming to 1.9-degrees. The IEA anticipates a rate of 1.5% in the Stated Policies scenario over the same period, which is also notably lower than growth in the current 2021-2024F trend. The Institution's Announced Pledges scenario is even further away, seeing a rate of growth at one-fourth the pace of the current trend at 0.7%. The departure of these growth rates, from the aforementioned 2021 to 2024F CAGR in Asia outlines the difficulty in reaching 2030 targets should energy demand continue to evolve as it has in the recent past.

The industrial sector consistently accounted for over half of Asia's final energy consumption in the 2019-24 period. China and India are the major drivers of demand growth. Given the consistent growth the sector has seen in recent years, China's industrial activity is expected to remain strong in the future and further the uptick in global energy demand. Industry and manufacturing saw a 6% growth rate in the first quarter of 2024. In India, industrial growth is expected to continue, supported by economic development and population growth. Manufacturing output rose 9% year-on-year in the first quarter of 2024. Electricity demand in India and China notably influences global energy demand growth. China has by far the largest power sector in the world, with higher power demand than the rest of Asia combined, representing roughly 32% of global power demand in 2024. In 2023, China's total electricity consumption reached 9,220 TWh, marking a 6.7% year-on-year increase from the previous year. Amongst other factors, this significant jump was driven by electrification across the energy sector, including buildings and road transportation, facilitated by the low base in 2022 due to pandemic-related restrictions and economic downturns. Though household electrification has been slower to grow in India, its industrial sector is a key driver for power demand. India's peak power demand is rising each year with a record maximum daily power demand of 250 GW being recorded in May 2024. This was largely attributed to weather-related loads such as heatwaves, alongside increasing industrial and residential power consumption and has caused significant challenges to reliability, power shortages, and strain on the electricity network. India and China are also emerging as major sources of renewables power generation. Of the total 340 GW of solar PV installed last year globally, 217 GW was installed in China, representing more than 60% of the global share. In India, rapid expansion in solar capacity through government-led initiatives has also spurred demand for solar modules. Asia is expected to remain the main driver of power demand growth globally during the next decades. Demand in the region is expected to total more than 24,000 TWh by 2050, representing 54% of the world's total, with China being responsible for most of this growth.

Figure 58: Asia final energy demand split by sector, and share of electricity in total demand



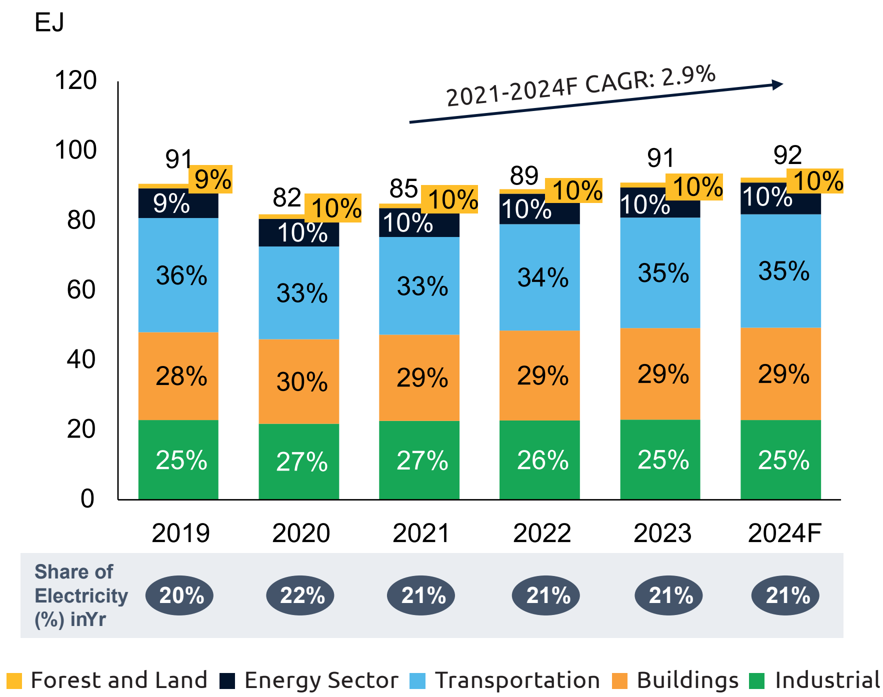
Source: Rystad Energy

Moreover, macroeconomic factors are at play in increasing Asia's topline electricity demand and further energy demand. India is growing in terms of population and development while China's standard of living is rising, despite slowing population growth. Additionally, insights from the ASEAN Centre of Energy show that energy consumption is expected to increase across all end-use sectors in 2024 due to an uptick in population and economic growth in the region.

d. North America

Energy demand in North America is expected to see a CAGR of 2.9% from 2021 to 2024F, reaching 92EJ in 2024. In contrast, based on scenario assumptions, Rystad Energy's 1.9-degrees scenario calculates a 1.2% rate of demand growth required between 2021 to 2030 on a pathway to limit warming to 1.9-degrees. The IEA anticipates a rate of 0.1% in the Stated Policies scenario over the same period, which is a much lower rate of growth relative to the current 2021-2024F trend. The Institution's Announced Pledges scenario is even further away, seeing a rate of -0.5%, in the opposite direction. The departure of these growth rates, from the 2021 to 2024F CAGR in North America outlines the difficulty in reaching 2030 targets should energy demand continue

Figure 59: North America final energy demand split by sector, and share of electricity in total demand



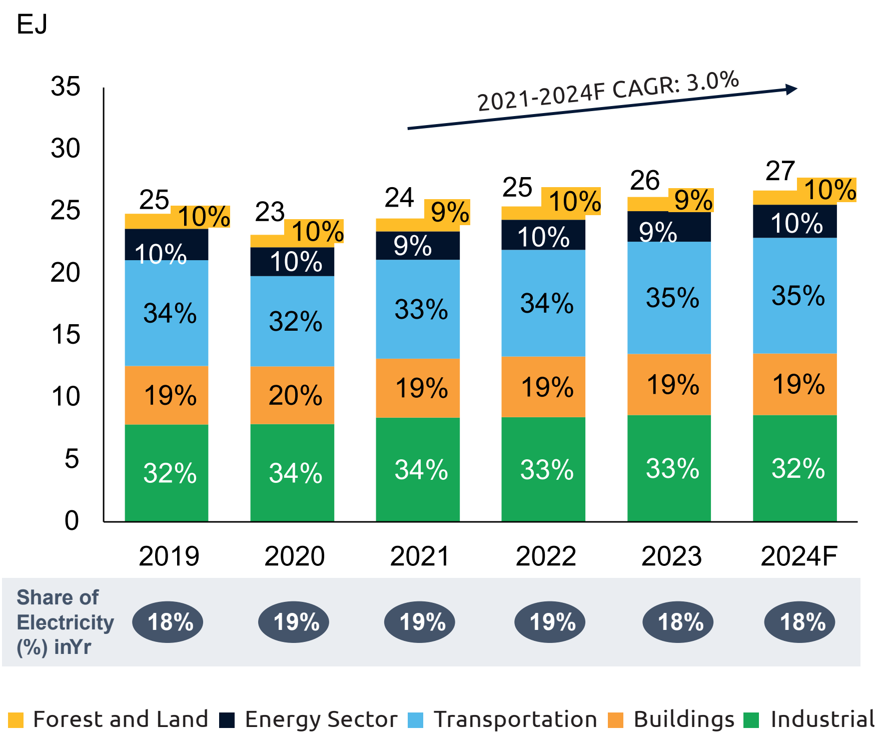
Source: Rystad Energy

to evolve as it has in the recent past. The transportation sector has consistently been the largest contributor to energy demand, constituting 37% and 36% of total consumption in the US and Mexico in 2023. In 2022, EIA reported that overall gasoline consumption from transportation in the US increased despite improvement in the fuel economy of light-duty vehicles. This rise was attributable to a simultaneous rise in the number of vehicles and distance travelled per vehicle. A key trend in the transportation sector is electrification, with power demand from electric vehicles (EVs) tripling between 2021 and 2023. The buildings sector in North America also contributes heavily to total energy demand with the US' residential and commercial buildings holding a 30% share of total consumption in 2023. One of the trends to note in this sector is the growing demand for heat pumps in the US, especially in the residential sector, which overtook gas furnace sales in 2023. Industry occupies a relatively lower share of total energy demand in North America, with industrial consumption expected to reach lower levels in 2024 relative to 2019.

e. South America

Energy demand in South America is expected to see a CAGR of 3.0% from 2021 to 2024F, reaching 27EJ in 2024F. In contrast, based on scenario assumptions, Rystad Energy's 1.9-degrees scenario calculates a 1.9% rate of demand growth required between 2021 to 2030 on a pathway to limit warming to 1.9-degrees. The IEA anticipates a rate of 1.8% in the Stated Policies scenario over the same period, a lower rate of growth relative to the current 2021-2024F trend. The Institution's Announced Pledges scenario is similar, seeing a rate of 1.2%. The departure of these growth rates, from the aforementioned 2021 to 2024F CAGR in South America outlines the difficulty in reaching 2030 targets should energy demand continue to evolve as it has in the recent past.

Figure 60: South America final energy demand split by sector, and share of electricity in total demand



Source: Rystad Energy

The transport sector occupies the largest share of total energy demand at 35% in 2024F with road transport primarily driving consistent growth in demand since the pandemic. Passenger vehicle ownership in the region, including cars and two-wheelers, is expected to rise with economic development and urbanisation alongside limited public transportation connectivity. Industry is a close second, with the sector expected to drive 32% of the continent's total demand in 2024F. Buildings are expected to drive 19% in 2024F, with electricity accounting for 45% of building demand.

f. Africa

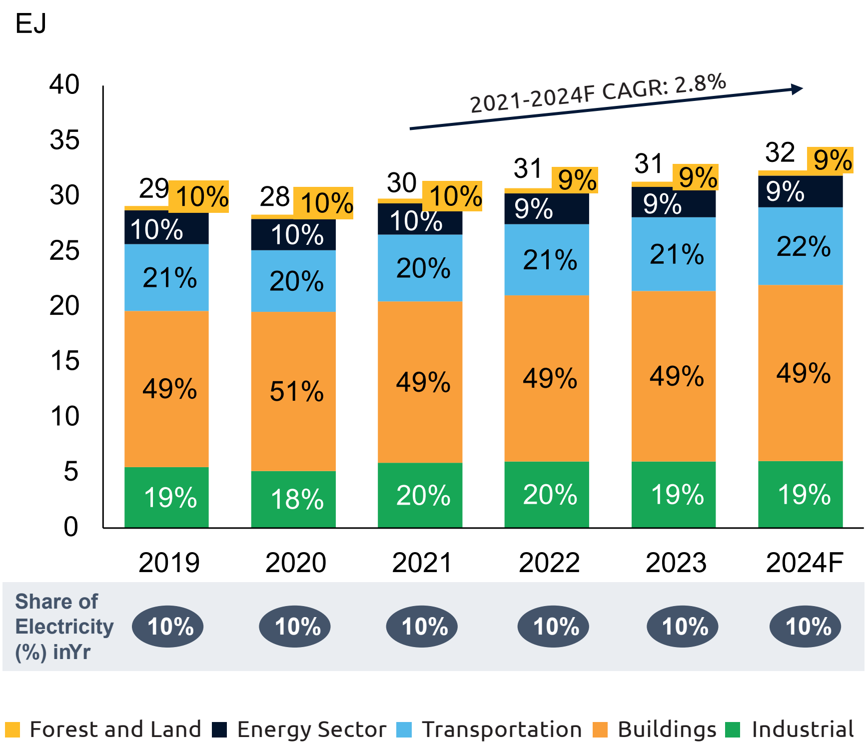
Energy demand in Africa is expected to see a CAGR of 2.8% from 2021 to 2024F, reaching 32EJ in 2024. In contrast, based on scenario assumptions, Rystad Energy's 1.9-degrees scenario calculates a 2.5% rate of demand growth required between 2021 to 2030 on a pathway to limit warming to 1.9-degrees. The IEA anticipates a rate of 1.8% in the Stated Policies scenario over the same period, a lower rate of growth relative to the current 2021-2024F trend. The Institution's Announced Pledges scenario is flat, seeing a 0% rate over the 2021-2030 period. The departure of these growth rates, from the aforementioned 2021 to 2024F CAGR in South America outlines the difficulty in reaching 2030 targets should energy demand continue to evolve as it has in the recent past.

The World Economic Forum estimates that Africa's population is set to double by 2050 to exceed two billion people. With growing urbanisation, by the end of the century, 15 of the 20 largest cities in the world are set to be in Africa. As the continent develops, energy consumption per capita will rise with incomes, as lifestyles improve to increase appetite for demand segments such as cooling, transportation and food, and as Africa accomplishes its goal of reaching full energy access. Today, over half of Africa's population lives without electricity, and the continent shows the lowest energy use per capita. According to bp's 2022 Statistical Review of World Energy, Africa consumed 15 GJ of primary energy per capita in 2021, in sharp contrast to North America's 227 GJ per capita. Maintaining energy affordability driven by policy action and investments will remain key to alleviating energy poverty and making modern energy readily available and accessible.

Buildings have consistently occupied Africa's largest share of energy consumption, driving nearly 50% of demand since 2019. As the continent is set on urbanising amidst a growing population, the residential building stock is projected to reach 50 billion square meters by 2050. To meet growing demand from this sector, it will become increasingly important to ensure resource efficiency, especially in urban areas, where most new construction is expected.

Transport is the next largest demand segment in the region, accounting for 7EJ or 22% of demand in 2024F. Road transport dominates this demand, with growth expected to remain following the continuation of increasing urbanisation and a population boom.

Figure 61: Africa final energy demand split by sector, and share of electricity in total demand

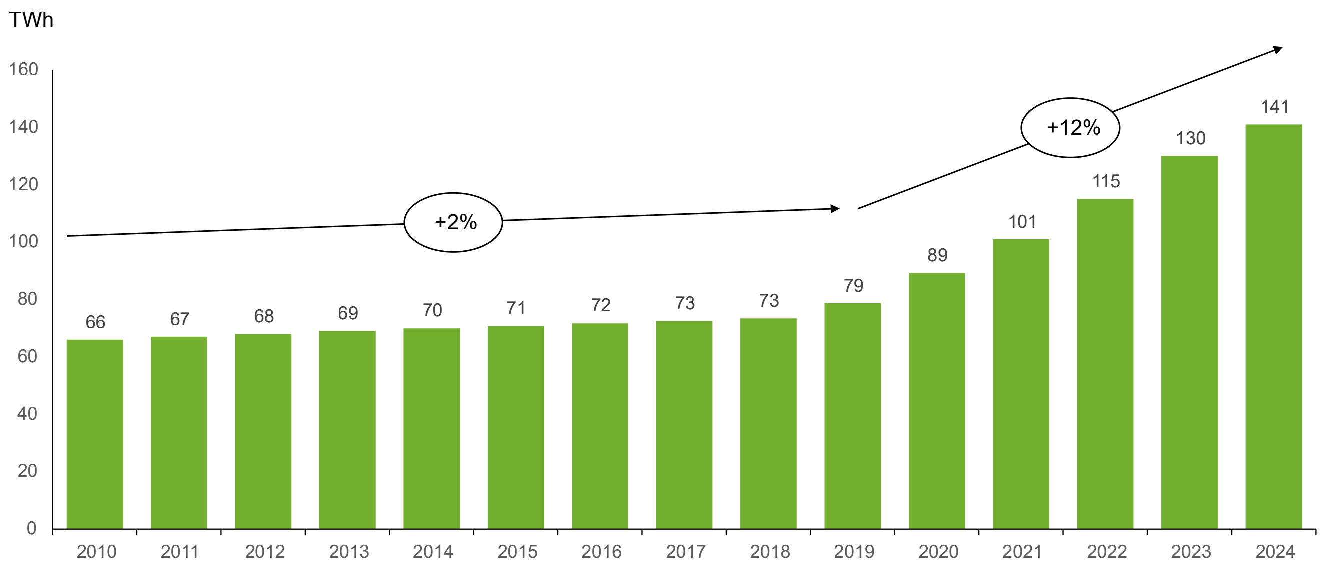


Source: Rystad Energy

IV. Electrification and new energy demand trends

a. Case 1: Growing AI-focused data centres contribute to electricity demand surge

Figure 62: Electricity demand from US data centres



Source: Rystad Energy

Recent strong growth in data centres and chip manufacturing to support the growing needs of rapidly evolving artificial intelligence (AI) have resulted in significant electricity demand growth. In 2023, US data centre demand was around 130 TWh annually, representing a small but significant share of total US power demand at 3.3%, largely originating from 'traditional' data centres. Goldman Sachs estimates that the data centres share of total US power demand will grow to 8% by 2030. Data centres focused on AI are expected to drive most of this growth due to the increasing integration of AI into daily applications. Going forward, domestic chip production, bolstered by the US' 2022 CHIPS and Science Act[26], will also spur demand. Considering this upward trajectory, system operators such as PJM, the Electric Reliability Council of Texas (ERCOT), and utilities Duke Energy and Georgia Power have increased their demand growth assumptions in 2023.

The increase in electricity demand from AI operations is evident. For instance, a single ChatGPT query consumes 10x the energy compared to a conventional search: 2.9 watt-hours of electricity, compared to 0.3 watt-hours for a Google search[27]. Notably, electricity demand from US data centres has grown at a CAGR of 12% from 2019 to 2024, reflecting a recent uptick in AI-focused data centres. This marks a 6x acceleration from the 2% rate observed in the decade preceding 2019. Moreover, between 2010-2019, improvements in efficiency helped limit the growth in energy demand from data centres globally. This was achieved through advancements in IT hardware, cooling systems, and a shift towards more efficient cloud and hyperscale facilities. However, since 2020, efficiency gains have slowed, and AI's widening use has led to increased power consumption. While some AI innovations may enhance computing efficiency, the overall expansion of AI applications is expected to drive up energy demand. The immense new

[26] *The CHIPS and Science Act of 2022 incentivizes research, development and domestic manufacturing of semiconductors.*
[27] *Source: AI is poised to drive 160% increase in data center power demand. Goldman Sachs. (2024, May 14). https://www.goldmansachs.com/intelligence/pages/AI-poised-to-drive-160-increase-in-power-demand.html*

power demand from data centres is straining existing energy infrastructure and threatening to outpace supply build-out. This impending power crunch poses significant challenges for utilities and electrical grids, highlighting the need for robust forecasting, planning, and acceleration of efficient, clean technologies, and sustainable energy sources to meet the growing power requirements of the digital economy.

As such, the expansion of renewables and grid infrastructure must continue to accelerate, but the current pace of build-out lags the growth in energy and power demand. Gas-fired power plants will be crucial to support renewables by providing flexibility and ensuring the provision of dispatchable and uninterrupted electricity supply that data centres critically need. Given that grid capacity will need to undergo swift expansion, gas will also act as the economically viable option due to the cost-effectiveness of building and operating gas power plants. Prominent players from the US natural gas industry such as EQT and TC Energy are positioning themselves to capitalise on this opportunity with the latter estimating that data centre operations could increase natural gas demand by 0.2-0.3 Bcm per day by 2030.

While roughly 40% of the world's data centres are located in the US[28], they are on the rise globally, indicating significant future power demand growth. Global data centre power consumption currently accounts for 1%-2% of total power demand at roughly 411 TWh, but this figure is projected to increase to 3%-4% at around 1,063 TWh by 2030[29]. Europe houses 15% of all data centres, and there is an anticipation of growth in countries with cheap and reliable electricity, as well as economies with technology services that offer tax incentives. With the oldest power grid in the world, Europe must invest in upgrading the grid to support significant demand growth. In emerging AI hubs such as Australia, Rystad Energy analysis has identified 124 data centres at various stages of development with a combined capacity of 4.4 GW. This translates into an annual energy demand of up to 30 TWh through 2027, which is equivalent to three times the annual consumption of Tasmania, highlighting the significant investment that will be required to provide stable power supply to data centres. The digital economy's growth in Southeast Asia is also driving investments in data centres due to rising demand for digital services and technologies like 5G, AI, and cloud computing, making it a hub for such facilities. Localization of data centres is increasing, extending beyond major cities to tier-two and tier-three cities. Despite high costs and limited land, Singapore is one region that exemplifies overcoming regulatory and structural barriers through technological innovation. It hosts high-capacity data centres for major tech companies by implementing innovative solutions like floating data centres. As of today, Singapore boasts over 70 data centres with over 1.4 GW of capacity. Having lifted the moratorium that had been placed on data centres due to concerns regarding their increased energy consumption, Singapore's facilities are set to increase with plans to add nearly 300 MW of additional data centre capacity in the next few years. Neighbouring countries like Malaysia, Thailand and Indonesia are also providing a goldmine of opportunities for growth.

Observing the US' AI data centre boom and plans for their development across regions, these facilities are poised to become a major contributor of emerging power demand. Data centres would inevitably act as a new source of energy demand having extensive ramifications on power grids globally and creating a pressure to plan and ensure sufficient supply in time to meet growing demand.

[28] *US data centre power demand will be felt mostly in its primary market, which is concentrated in Loudon County, Virginia, with Texas, Arizona, the Midwest, and Ohio comprising secondary markets.*

[29] *Source: AI is poised to drive 160% increase in data centre power demand. Goldman Sachs. (2024, May 14). https://www.goldmansachs.com/intelligence/pages/AI-poised-to-drive-160-increase-in-power-demand.html*

b. Case 2: Higher cooling demand driven by extreme weather events challenges power systems

Extreme weather events are increasing in frequency and challenging the reliability of energy systems worldwide. In 2023, record-high temperatures tested the governments, generators, and grid operators in their ability to meet the rising demand for cooling.

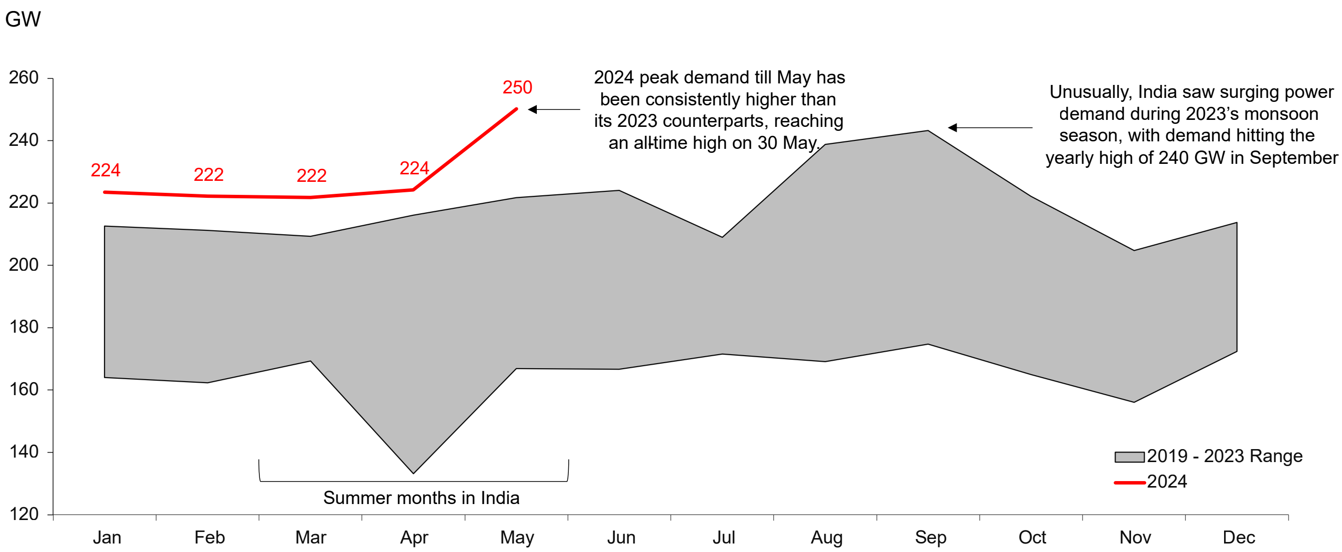
Throughout India's 2023 summer period (March to June), monthly peak power demand consistently surpassed 215 GW, a robust increase compared to the previous five-year period. This is higher than in June 2022 when overall peak power demand was approximately 212 GW. Heatwave conditions during the 2023 summer in India led to a seasonal peak power demand of 223 gigawatts (GW) in June, putting a major strain on India's power system. This represents a year-on-year increase of 5.4%.

Unusually, India saw surging power demand during last year's monsoon season, with demand reaching 236 GW in August and hitting the yearly high of 240 GW on 1 September 2023. This period, marked by the hottest-ever temperatures for August and September, was affected by very low rainfall driving electricity demand especially through cooling technologies such as fans and air conditioning units. This year, the summer peak demand has already reached an all-time high of 250 GW on 30 May 2024. As India's peak power demand surpassed the forecasted 235 GW for May 2024, Bloomberg reported long blackouts in some areas, lasting up to 12 hours[30]. Yet, widespread outages were avoided during 2024's election period, unlike in past years which have observed significant power disruptions[31].

This is mainly because India is readily drawing on coal to meet increased demand, with coal power generation reaching record high levels in May[32]. Peak demand recorded between March and May has been consistently higher than the 2023 counterparts showing an increasingly growing trend, with uncertainty around what the following months will hold.

Given these extreme weather conditions, the impact on cooling demand is growing most significantly in developing countries that are marked by lower air conditioner ownership. In 2022, 90% of the US population had access to air conditioning, compared to 9% in Indonesia and just 5% in India, according to a Harvard study[33]. Air conditioner ownership is on the rise in India, as before 2019 only 10% of rural and

Figure 63: Distribution of monthly peak power demand in India



Source: Central Electricity Authority, Ministry of Power, India

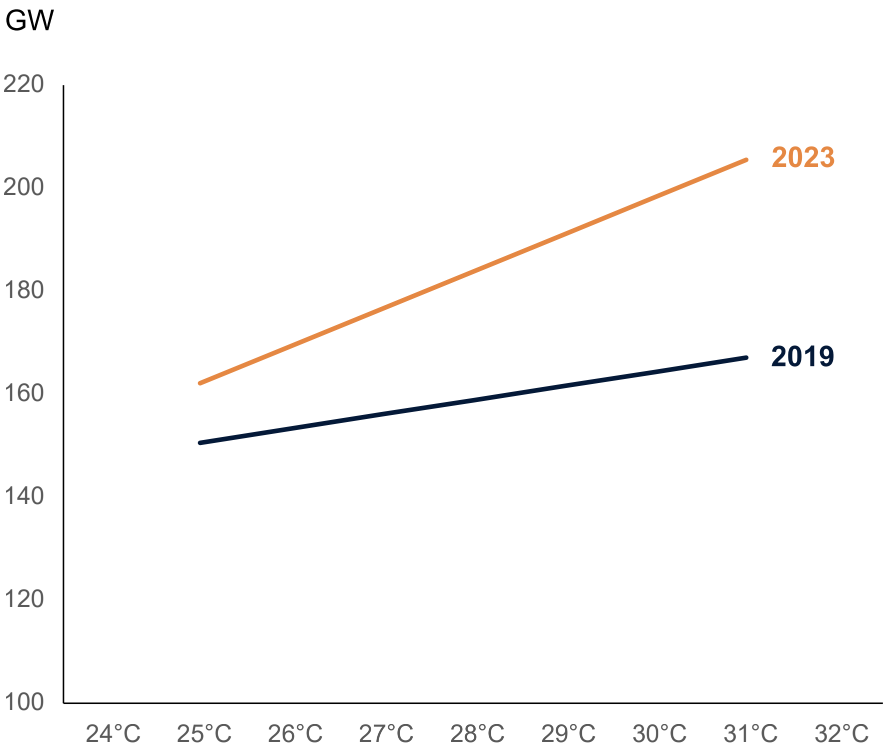
[30] *Source: Singh, R. K. (2024, May 23). Long blackouts hit India as heatwave stokes power use. Bloomberg.com. https://www.bloomberg.com./news/articles/2024-05-23/long-blackouts-hit-india-as-heatwave-stokes-power-consumption*
[31] *Source: India runs power plants flat out to keep cool in heatwave and election | Reuters. (2024, June 3). https://www.reuters.com/world/india/india-runs-power-plants-flat-out-keep-cool-heatwave-election-kemp-2024-05-31/*
[32] *Source: India: Electricity trends. Ember. (2024, May 7). https://ember-climate.org/countries-and-regions/countries/india/*
[33] *Source: In a hotter world, air conditioning isn't a luxury, it's a lifesaver. Harvard SEAS. (2022, July 20). https://seas.harvard.edu/news/2022/07/hotter-world-air-conditioning-isnt-luxury-its-lifesaver*

urban households had access to an air conditioner, but the National Family Health Survey reported that by 2021, 24% of households owned either an AC or evaporative air cooler[34,35]. This upward trend is expected to continue as the government projects that AC ownership alone is expected to increase to 50% of households by 2050.

As such, a rise in temperatures together with increasing ownership of cooling equipment is resulting in higher electricity loads, which are evidently growing with each year. In 2019, every 1°C increase in the average daily temperature added less than 3 GW of electricity load to the system in the months of May and June. During the same months in 2023, the electricity load increased by over 7 GW with every 1°C rise in temperature. Low energy efficiency can put further pressure on the electricity load. The IEA reported that the average efficiency of air conditioners sold in most markets is significantly lower than the highest efficiency models available, even though these more efficient products are not necessarily more expensive[36]. As such, lack of consumer awareness could influence the efficiency of the models people buy, and these preferences eventually affect overall power demand from cooling.

This surge in cooling demand has significant long-term implications for energy demand with cooling being acknowledged as the fastest-growing use of energy in buildings. Cooling also puts upward pressure on electricity demand as it represents 10% of global electricity demand[37].

Figure 64: Average daily electricity load versus temperature in India during May and June



Source: International Energy Agency (IEA)

Increased electricity generation required to meet cooling needs can affect gas consumption, especially in regions where natural gas is a significant source of power generation. Greater-than-expected pressure on power systems due to unusually high electricity loads, and shifting or expanding peaks, also directly impact emissions. Even though solar capacity is increasingly reducing coal's share during the daytime, India has continued to rely on coal-fired generation to ensure supply during demand spikes which occur during late evenings and at night.

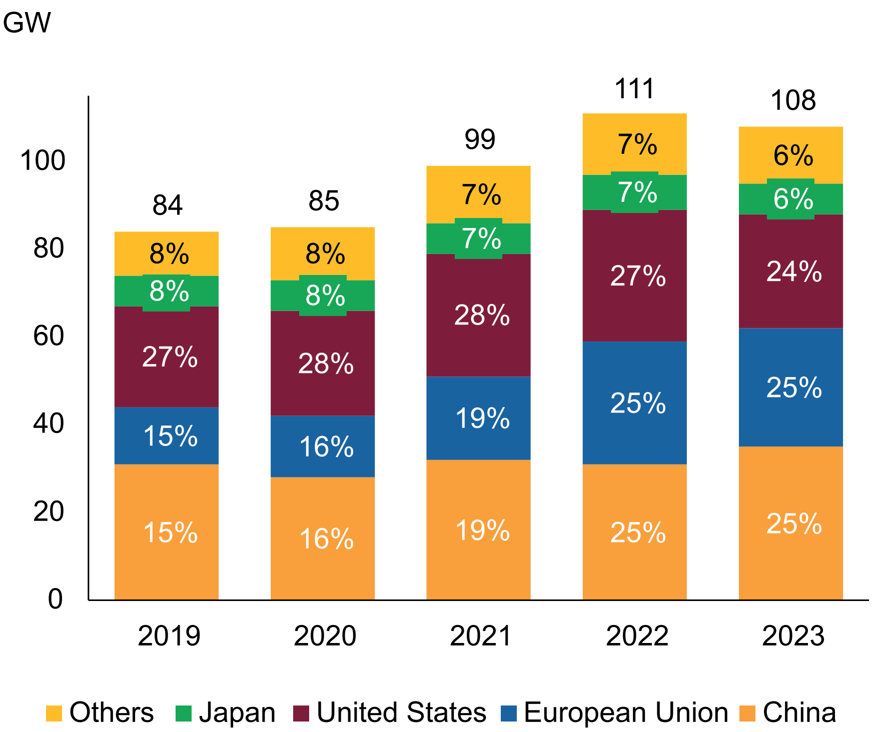
Outside of India, power systems have been challenged across regions due to increased cooling demand especially in Asia-Pacific. In 2023, countries such as China, South Korea and Japan faced heatwaves, resulting in similar spikes in power demand. The recent El Nino phenomenon, which is typically associated with higher temperatures across South America, is also set to challenge several power markets by pushing up power demand for cooling. Looking ahead, there is a likelihood that heatwaves will become more prevalent and last longer requiring countries to address several challenges, including meeting rising energy demand with a resilient and scalable electricity generation system and mitigating emissions from the generation process.

[34] *Source: 2019-21 India National Family Health Survey [FR375]. https://dhsprogram.com/pubs/pdf/FR375/FR375.pdf*
[35] *Source: India Cooling Action Plan. https://ozonecell.nic.in/wp-content/uploads/2019/03/INDIA-COOLING-ACTION-PLAN-e-circulation-version080319.pdf*
[36] *Source: The Future of Cooling: Opportunities for energy-efficient air conditioning. IEA. (2018). https://www.iea.org/reports/the-future-of-cooling*
[37] *Source: Keeping cool in a hotter world is using more energy, making efficiency more important than ever – analysis. IEA. (2023. July 21). https://www.iea.org/commentaries/keeping-cool-in-a-hotter-world-is-using-more-energy-making-efficiency-more-important-than-ever*

c. Case 3: Heat pump adoption set to spike winter peak electricity demand

Heat pump adoption has seen great momentum in recent years with global sales increasing by 28% between 2019 and 2023[38]. Europe has seen the sharpest increase since 2019, with yearly sales in the EU alone increasing by over 100%. 2022 marked a record year for heat pump sales in Europe, with a growth rate of nearly 40% since the year before[39]. Despite an overall decline in 2023, the leading European countries exhibited diverse adoption trends. While France and Italy saw declining sales[40], with the latter dipping more dramatically, Germany and the Netherlands saw a rise of over 50% in 2022 sales[41]. Yet, guided by the EU's ambitious Energy Performance of Buildings Directive (EPBD) and goal to reach the Paris Agreement climate targets, electrification in buildings through renovation incentives is being promoted through country-level policies which are expected to continue garnering support in the future.

Figure 65: Annual heat pump sales split by region



Source: International Energy Association (IEA)

Space heating is the largest contributor to energy consumption in European buildings, consistently constituting approximately 50% of buildings' energy demand over the past five years. As such, it is being targeted for electrification faster and harder than other areas. Moreover, incentives to reduce high upfront costs of heat pumps, coupled with similar or lower running costs than traditional boilers, are propelling a ramp-up of heat pumps in Europe. Some countries like Denmark, Germany, Norway, and the Netherlands have introduced policies banning the installation of new fossil fuel-based systems in households. In markets with considerable market penetration of heat pumps, we note a displacement of oil and gas boilers, and adoption is expected to rise further as heating electrification advances in OECD countries.

Heat pumps are understood to be the energy-efficient alternative to oil and gas boilers, which may result in an overall reduction of energy demand for heating. However, this shift causes a substantial increase in electricity demand, with the major trend of electrification of heating potentially contributing to a spike in peak electricity demand during the winter months, making this an important consideration for planning and grid reliability. This is because winter temperatures generally require more energy for heating than summer temperatures do for cooling, compelling regions to transition from summer to winter peaking systems and necessitating adjustments in grid planning and infrastructure[42]. Moreover, heating demand significantly impacts grid variability due

[38] *While 2022 and 2021 showed double-digit growth since the previous years, there was a small decline of 3% in 2023 due to a shift in energy prices, sectoral slowdowns, high interest rates and policy uncertainty.*

[39] *Source: The Future of Heat Pumps, WEO Special Report. IEA. (2022, December). https://www.iea.org/reports/global-ev-outlook-2024/outlook-for-battery-and-energy-demand*

[40] *Factors for the adoption rate decline in France include lack of clarity around government incentives for renovation. In Italy, the decline was driven by the end of a free tax credit market, removing a 110% tax relief on heat pump installation.*

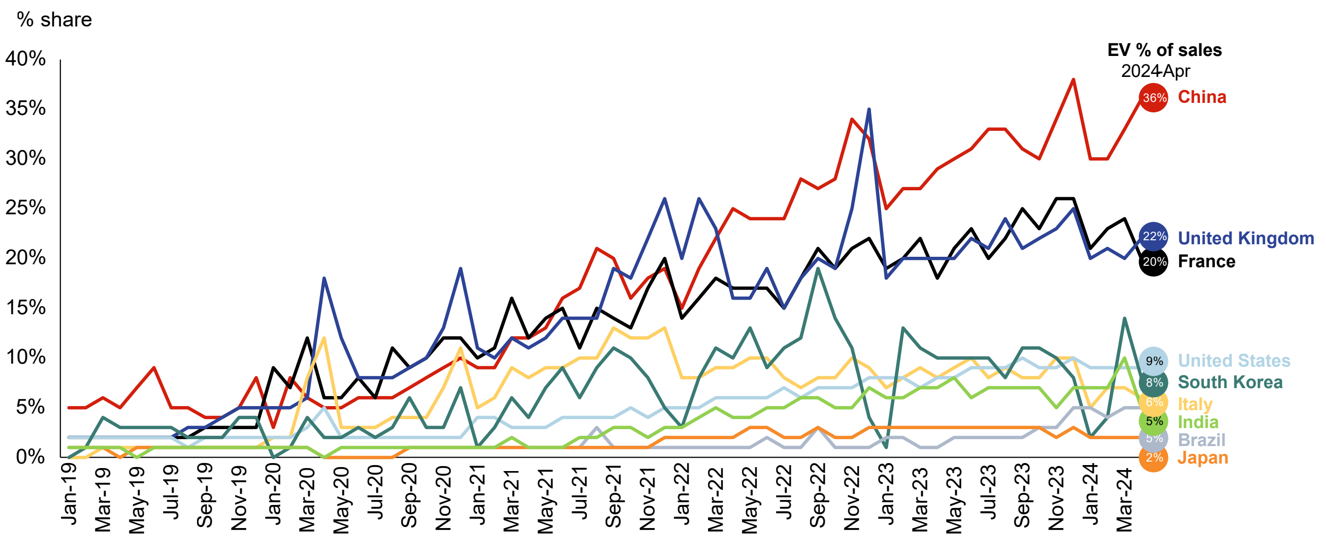
[41] *The share of heat pumps for space heating in households increased from 8% to 24% in Germany and from 2% to 19% in the Netherlands in the past ten years (Source: IEA, The Future of Heat Pumps, 2022).*

[42] *Source: Amonkar, Y., Doss-Gollin, J., Farnham, D. J., Modi, V., & Lall, U. (2023). Differential effects of climate change on average and peak demand for heating and cooling across the contiguous USA. Communications Earth & Environment, 4(1). https://doi.org/10.1038/s43247-023-01048-1*

to its rapid ramp-up nature, especially in commercial and residential buildings. These sharp increases in power demand can cause voltage disturbances, requiring quick adjustments in power plant operations. As such, flexible gas generation could play a role in responding to demand fluctuations, as opposed to inherently less flexible renewables, ensuring grid stability. Other than Europe, countries like the US and China are also driving the growth of heat pumps. In 2023, despite sales being down from the previous year in the US, heat pumps outsold gas furnaces for two years in a row. In 2022, heat pumps represented 8% of heating equipment sales for buildings in China, and in 2023 heat pump sales grew by 12%[43]. Power demand from electrified heating equipment is expected to grow globally, challenging grids to meet the increasing peak

d. Case 4: Strong momentum for EV adoption increases power demand

Figure 66: Monthly EV share of sales per country for selected countries



Source: Rystad Energy

After facing a sales slowdown in the first six months of 2023 as various subsidies were repealed, the year concluded with global EV new car sales exceeding 25%. The global adoption rate[44] of EVs reached 19.8% in 2023, with China as the main driver of EV adoption rates globally in recent years. In 2023, China reached all-time high sales with battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) exceeding 9 million units sold and dominating automobile sales. Initiatives such as China's EV purchase tax reduction policy and increased production from local manufacturers have assisted consistent sales growth in the country. In 2024, the global EV sector is anticipated to enter a period of slower growth, following a deceleration in 2023 and intensified by macroeconomic factors. Yet China will maintain its position as a leader in EV adoption, with EVs comprising a 36% share of vehicle sales in the country as of April 2024.

EV adoption is certain to increase electricity demand globally. According to Rystad Energy analysis, EVs, along with data centres, are projected to be key drivers of power demand growth in the US market through 2030. In 2023, electricity consumption from the US road transportation sector amounted to 18.3 TWh and is expected to grow to 131 TWh by 2030, with most of the power demand coming from passenger BEVs. More broadly, in 2023, the global EV fleet consumed approximately 130 TWh of electricity, which is roughly equivalent to Norway's total electricity demand for that year[45]. This represented about 0.5% of the world's total final electricity consumption but is expected to grow with consistent

[42] *Source: The Future of Heat Pumps in China. IEA. (2024, March). https://www.iea.org/reports/the-future-of-heat-pumps-in-china/executive-summary*

[43] *Adoption rate here refers to the percentage share of new car sales accounted for by a drive-train type.*

[44] *Global EV Outlook 2024. IEA. (2024, April). https://www.iea.org/reports/global-ev-outlook-2024/outlook-for-battery-and-energy-demand*

adoption. Electric vehicles charging is energy intensive, although this varies by vehicle type. A Tesla Model 3 driven in the US averages 14,000 miles per year, using approximately as much electricity as a home's water heater annually, and roughly ten times more than an energy-efficient refrigerator. Larger EVs, like the Ford F-150 Lightning, can exceed the electricity consumption of a large home's central air conditioning system[46]. Charging, especially fast-charging, can also become a strain on the power grid, as deployment increases. Planning, timely investment, and flexibility will again be critical to manage the wave of transport electrification without compromising power supply.

As EV adoption grows, the demand for gasoline is expected to decrease. Some expect overall reductions in primary energy consumption due to the higher efficiency of electric power trains compared to internal combustion engines. However, the overall impact on energy demand would depend on the efficiency of the power generation source and the electrical grid. Moreover, the broader implications for energy systems will be influenced by several key factors such as the pace of EV adoption, improvements in EV efficiency, and the development of charging infrastructure.

The demand drivers discussed above highlight two distinct trends shaping the power and energy landscape: the continual progression of electrification across various sectors raising power demand and the unexpected surge in power and overall energy demand from emerging sources such as data centres and cooling systems. While the former represents a gradual and anticipated shift, the latter has emerged more abruptly, driven by factors such as the rapid adoption of AI technologies and extreme weather events. Energy institutions, in their scenario modelling, likely accounted for foreseeable trends like the already growing adoption of electric vehicles and heat pumps. However, the recent increase in energy consumption from data centres and cooling might not have been fully accounted for. Consequently, the current demand trajectory, which incorporates these recent developments, may deviate significantly from the established scenario pathways. These scenarios are likely to underestimate the actual rate of demand growth creating imminent pressure for planners to ensure sufficient supply to meet demand. This also underscores the need for a realistic approach towards planning, which accounts for the scalability, reliability and affordability requirements of altering consumption patterns spurred by rapidly evolving technological and environmental factors.

IV. Filling the supply and investment gap in an era of energy uncertainty

Future energy demand presents a spectrum of potential implications on the supply mix and infrastructure needed to satisfy this demand. Scenarios from institutions like the International Energy Agency (IEA), the Institute of Energy Economics, Japan (IEEJ), and Rystad Energy among others offer a variety of possible pathways for future energy demand using a multitude of assumptions regarding the future trajectories of economic growth, technological advancements, adoption rates, policy, and consumer behaviour. All the diverse energy demand scenarios examined in this report assume that the growth rate of global energy demand will significantly decelerate toward 2050[47]. Furthermore, most of these scenarios also indicate a flattening and eventual decline in demand[48] – something that would mark a significant shift from the period following the Industrial Revolution, which has consistently seen an increase in energy demand other than during years marked by tragic global events such as the recent Covid-19 pandemic. This flattening trajectory is largely attributed to anticipated improvements in energy efficiency and assumptions regarding the rate of growth in energy consumption across economies.

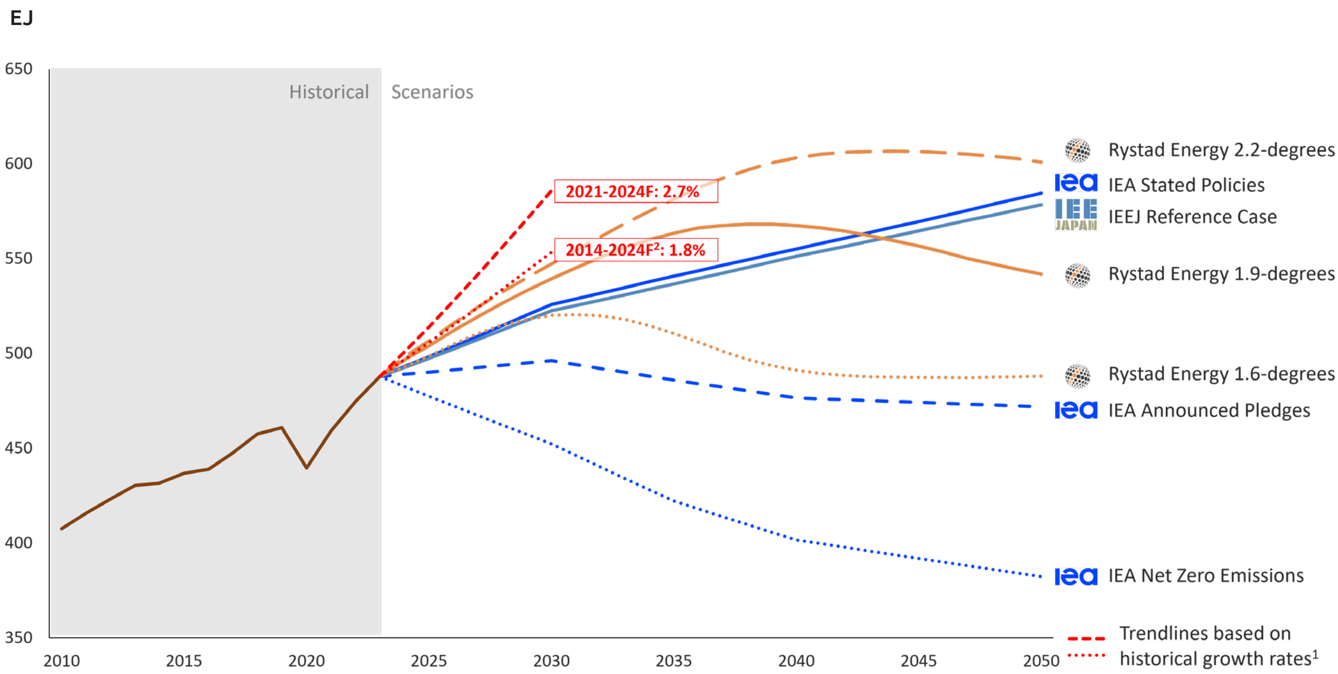
However, it is noted that most scenarios understate the trend of energy demand growth observed in recent years. In IEA's Stated Policies Scenario (STEPS), which is designed using assumptions around how the energy system will progress based on the current

[46] *Source: Why the electric vehicle boom could put a major strain on the U.S. Power Grid. CNBC. (2023, July 7). https://www.cnbc.com/2023/07/01/why-the-ev-boom-could-put-a-major-strain-on-our-power-grid.html*

[47] *This analysis primarily considers 7 energy demand scenarios from 3 institutes: IEA's Stated Policies, Announced Policies ad Net Zero Emissions by 2050 scenarios from the 2023 Outlook, IEEJ's Reference Case scenario from the 2024 Outlook, and Rystad Energy's latest 1.6-degrees, 1.9 degrees and 2.2-degrees scenarios. Rystad Energy's degree scenarios anticipate energy demand trajectories required to limit global warming to the specified degree (Celsius) stated.*

[48] *All scenarios except IEA's Stated Policies Scenario (STEPS) and IEEJ's Reference Case Scenario (REF) make this assumption.*

Figure 67: Global final energy demand scenarios from various institutions



Gap between trendlines and 2030 scenario targets:

For reference, Europe energy demand was 65 EJ in 2023

Scenario	IEA Net Zero Emissions	IEA Announced Pledges	IEA Stated Policies	RE 1.6-degrees	RE 1.9-degrees	RE 2.2-degrees	IEEJ Reference Case
2021 – 2024F trendline gap	134 EJ	90 EJ	60 EJ	66 EJ	48 EJ	39 EJ	64 EJ
2014 – 2024F[2] trendline gap	101 EJ	57 EJ	27 EJ	33 EJ	14 EJ	6 EJ	31 EJ

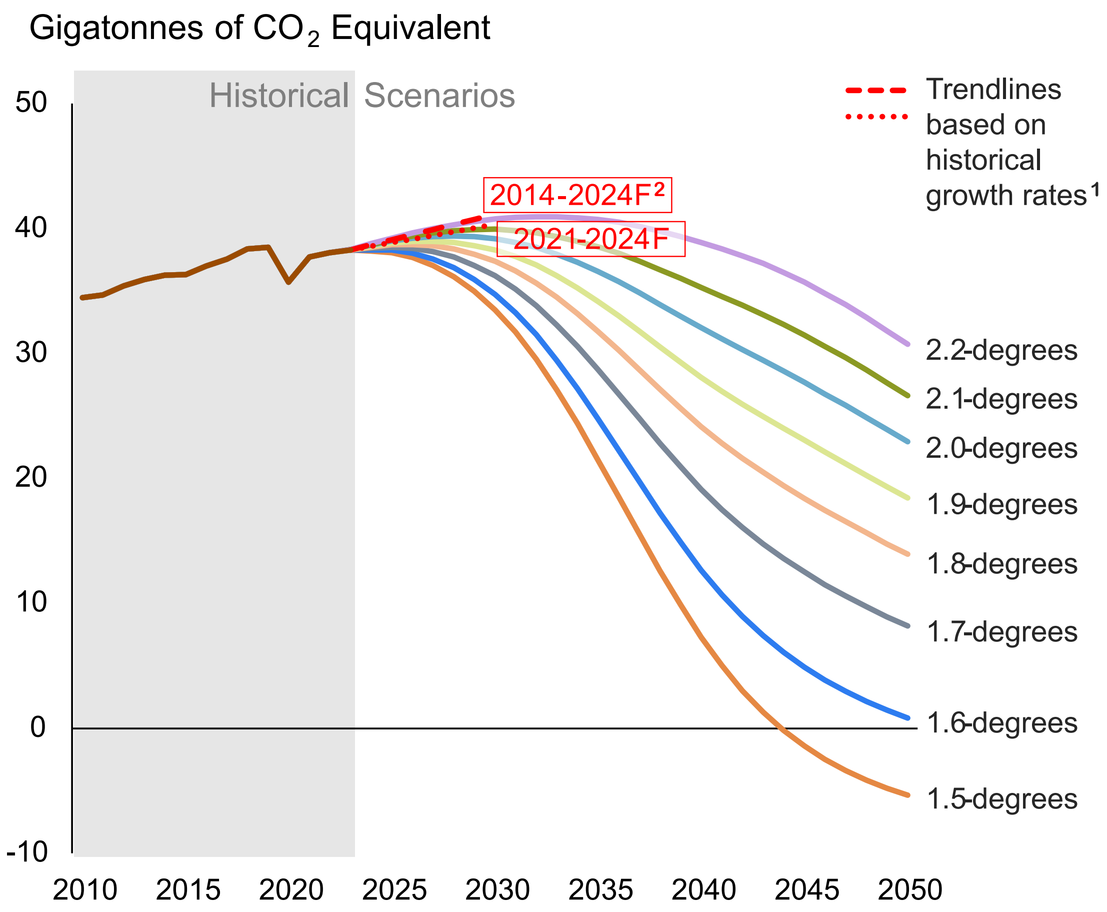
Note: [1] This analysis considers two trendlines: the 2021-2024F trendline and the 2014-2024F trendline. Each trendline uses a consistent annual growth rate towards 2030, which is calculated as the average of the annual growth rates of the historical years considered.
[2] The 2014-2024F trendline excludes Covid-19 impacted years 2020 and 2021 from the average growth rate calculation to adjust for the unusually low and high growth rates observed in the respective years.

Source: Rystad Energy, IEA, IEEJ

policy commitments, demand rises at an average annual growth rate of around 1% through 2030. From 2030 to 2050, demand continues to rise at a slower rate of less than 0.6% led by growth in emerging economies which offsets a slow decline in developed economies. Similarly, in the IEEJ's Reference Case Scenario REF, global energy demand increases at a rate of roughly 1% towards 2030. After 2030, the growth rate decelerates to around 0.5% but 2050 levels remain significantly higher than 2023. If energy demand were to maintain the robust growth rate observed between 2021-2024F as shown in Figure 67, the approximately 2.7% annual increase would significantly outpace the more conservative growth projections posited in the IEA's STEPS and IEEJ's REF, which suggest a more modest annual growth of about 1%. Even if global energy demand continued to develop at the relatively lower rate of growth observed in the past 10 years, the 1.8% annual increase would surpass scenario assumptions.

Rystad Energy's base case scenario uses a different set of assumptions limiting global warming to 1.9 degrees, wherein there is an approximate 1% rise in global energy demand towards the peak in 2039 followed by a deceleration of less than 0.5% to 2050. If the current demand trends continue to 2030 using the same rate as the 2021-2024F trendline, global energy demand in the year will be higher than Rystad Energy's base case assumption by around 47 EJ (9%) in 2030. When considering the trendline based on growth between 2014-2024F, this gap decreases to 14 EJ (3%) in 2030 but remains significant. As a point of reference, Europe's energy demand in 2023 was 65 EJ. In the 2.2-degrees scenario, Rystad Energy posits that total demand grows at a rate of close to 1.7% towards

Figure 68: Global GHG emissions, split by scenario



Note: [1] This analysis considers two trendlines: the 2021-2024F and the 2014-2024F trendline. Each uses a consistent annual growth rate towards 2030, which is calculated as the average of the annual growth rates of the historical years considered.

[2] The 2014-2024F trendline excludes Covid-19 impacted years 2020 and 2021 from the average growth rate calculation to adjust for the unusually low and high growth rates observed in the respective years. Negative emissions are due to removal of carbon such as carbon sinks and carbon capture, utilisation and storage (CCUS) technology.

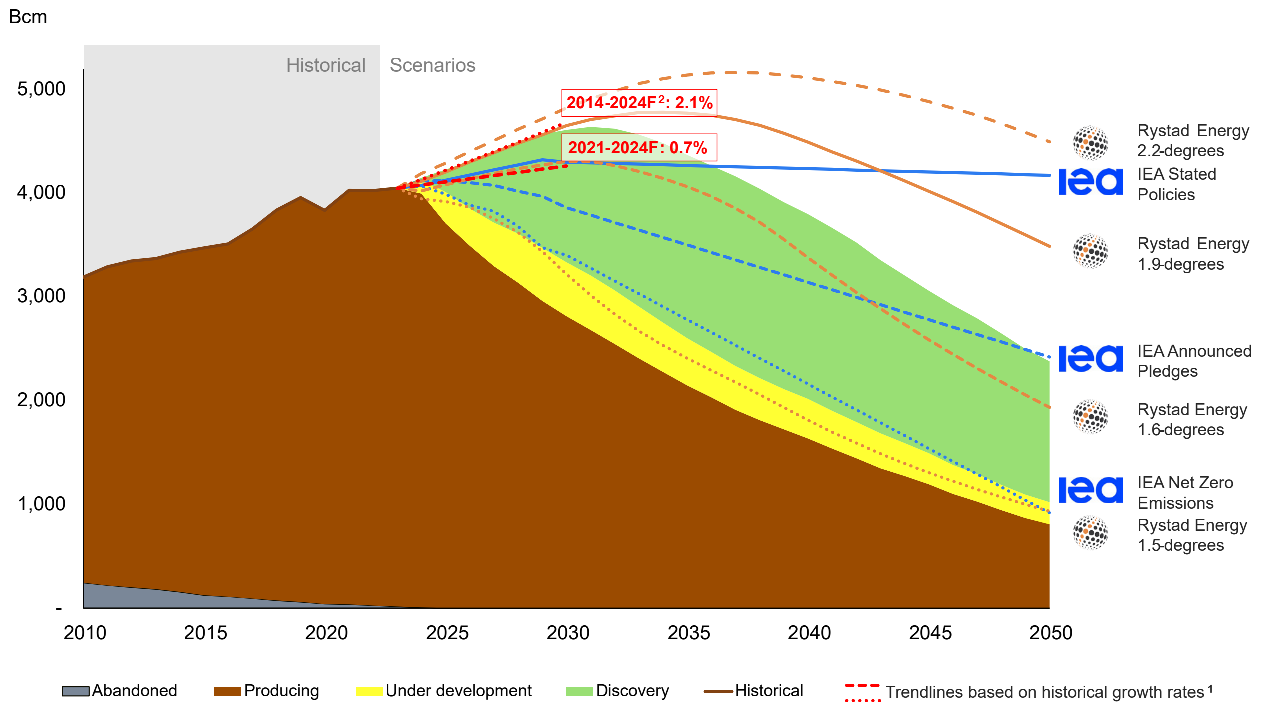
Source: Rystad Energy

2030 and peaks in the early 2040's before switching to a decline towards 2050. Future projections of demand based on 2021-2024F trends show that actual demand may also exceed 2.2-degrees scenario energy demand targets by almost 39 EJ (7%) in 2030. When comparing against the 2014-2024F trendline, this gap in 2023 is significantly lower at only 6 EJ (1%). Given these discrepancies, it is safe to assume that based on the current trajectory the world is on, 2030 energy targets of even the relatively less ambitious scenarios are unlikely to be achieved.

When examining the lower-degree and more ambitious policy scenarios, reaching targets as set by these scenario assumptions seems even less probable. In Rystad Energy's scenario where warming is limited to 1.6-degrees, demand grows initially, peaking in the early 2030s before starting its decline at less than 1% towards 2050. By 2050, the energy demand reaches similar levels to those of 2023. This assumes a substantial shift from the trends from the past years (based on the 2021-2024F trendline), following which there is excess demand of 66 EJ, or 13% of the 1.6-degrees scenario targets in 2030. When considering trends in the 2014-2024F trendline, a significant gap of 33 EJ (6%) remains.

In IEA's Announced Pledges Scenario (APS), which

Figure 69: Global gas demand-supply balance under various degree scenarios, supply split by lifecycle



Note: [1] This analysis considers two trendlines: the 2021-2024F trendline and the 2014-2024F trendline. Each trendline uses a consistent annual growth rate towards 2030, which is calculated as the average of the annual growth rates of the historical years considered.
[2] The 2014-2024F trendline excludes Covid-19 impacted years 2020 and 2021 from the average growth rate calculation to adjust for the unusually low and high growth rates observed in the respective years.
Definitions: (a) Abandoned denotes all abandoned fields which have stopped producing or where production was suspended by owners. (b) Producing includes all the assets that are currently producing. Also, refinery gains are included. (c) Under development denotes assets for which development has been approved by companies & government, but production has not yet started. (d) Discovery includes assets where discoveries have been made but are not yet in a phase of further development (appraisal, field evaluation).

Source: Rystad Energy, IEA

assumes that all government targets will be completely met in the announced timeline, total energy demand increases towards 2030 at a rate of 0.2% – less than a tenth of what we have seen in actual annual consumption growth rates up to the time of writing this report. Peak energy demand in the APS is reached by 2030, slightly earlier than the 1.6-degrees scenario due to faster renewables deployment, improved energy efficiency and more rapid electrification. These trends are even more accelerated in IEA's Net Zero Emissions by 2050 (NZE) Scenario leading to a gradual and steeper decline towards 2050 with energy demand declining by more than 1% towards 2030. The NZE scenario presents the most dramatic reversal from current trends. While actual demand is exhibiting rapid growth, in the NZE scenario this growth is inverted into a swift decline in energy consumption. As such, energy demand based on recent trends is growing at a rate faster than what most scenarios indicate and, in most cases, challenging assumptions around growth deceleration.

Throughout recent history, global annual emissions have been rising except for 2020 due to the Covid-19 pandemic, as illustrated in Figure 68. Rystad Energy has charted out possible emissions profiles to meet a spectrum of climate change scenarios, all of which have emissions peaking before 2035. However, taking the recent historical trend after the Covid-19 recovery, a continuation of the 2021-2024F growth rate shows a divergence between scenarios and reality, where emissions are still increasing. Quantitatively, a continuation of the 2021-2024F trendline implies a 20% gap with Rystad Energy's 1.5-degrees scenario and a 3% gap with the 2.0-degrees scenario by 2030, showing the difficulty in meeting the Paris Agreement's targets. If emissions progress at the same pace as the past 10 years, this gap will increase further, with GHG emissions even surpassing the assumptions of the 2.2-degrees scenario. Despite current decarbonisation pledges made under the Paris Agreement, the United Nations Environmental Programme (UNEP) estimates that the world is on track to warm between 2.5 to 2.9°C above pre-industrial levels. The United Nations Framework Convention on Climate Change (UNFCC) estimates that the full implementation of the latest Nationally Determined Contributions (NDC), including conditional elements, would only achieve a ~3.6% reduction of greenhouse gas emissions by 2030 relative to the 2019 level. However, if conditional elements are excluded, greenhouse gas emissions are expected to grow 3.1% higher in 2030 than in 2019.

Given the current trajectory of global emissions to exceed 2.5°C of warming, this highlights the need and the urgency for increased action and ambition to reduce emissions. As such, decreasing the usage of coal would be vitally important to reduce emissions as coal has the highest emissions factor of any energy source. **Switching from coal to natural gas is a readily- available, cost-effective, affordable action that can be taken to reduce emissions by ~50%, immediately**. The natural gas ecosystem can also be further decarbonised by tapping into the low-carbon technologies discussed above, including biomethane, hydrogen blending, and carbon capture utilisation and storage. **It is important to stress that this is an action that should happen in parallel with, not instead of, continuing to drive deployment of renewables**, doubling down on efficiency, and seeking to scale all the emission-free energy sources that make technological and economic sense. As the analysis above demonstrates, **the world is short on energy and long on emissions**, with coal still being the source of ~40% of energy-sector emissions. Gas will be a critical resource to ensure that global energy transitions are able to move at the scale and speed necessary to limit global warming. **Gas will be a crucial flexibility and grid balancing assurance**; however, for that to occur, investment in its supply needs to be considered, as today there is a shortfall.

Natural gas plays a crucial role as a reliable and scalable energy source, especially in power generation. Its ability to provide a stable energy supply complements the intermittent nature of renewables like wind and solar, making it a well-suited source to mitigate rising energy demand needs. Across all Rystad Energy degree scenarios above 1.5-degrees and IEA's NZE, STEPS and APS scenarios (as seen from Figure 69) additional investment in natural gas supply development will be needed towards 2030 to meet demand and avoid a cliff where production drops off and is not replaced. Based on assumptions of the IEA's APS and STEPS as well, supply would need to scale up significantly to meet 2030 demand. If gas demand continues to grow at the historical rate of about 0.7% as the 2021-2024F trendline towards 2030, this will proceed in opposition of the demand decline trend indicated in IEA's APS, IEA's NZE and Rystad Energy's 1.5-degrees scenarios. When considering the longer 2014-2024F trendline 2.0% growth rate, there is a further departure from the IEA STEPS and Rystad Energy's 1.6-degree scenarios, further highlighting supply planning issues. Between projected demand based on the 2021-2024F trendline and volumes from current gas supply without further investment, there is a supply gap of around 927 Bcm (22%[49]) in 2030. When considering trendline from 2014-2024F, this gap increases to around 1300 Bcm (29%[49]) in 2030 highlighting the need to scale up supply to a greater magnitude.

Thus, we see how scenario assumptions of gas and energy demand stand in stark contrast to the observed trend of growing energy demand, driven by the economic development and improving standards of living in the developing world, but also by new demand trends and continued growth in the developed world. This underscores the critical importance of differentiation between scenarios and forecasts, as both are critical to plan energy investments and assure near and medium-term security of supply. Energy systems cannot be designed on scenarios alone, because scenario assumptions always face a risk of diverging from reality, even if the outcome they are aiming to achieve is the most desirable.

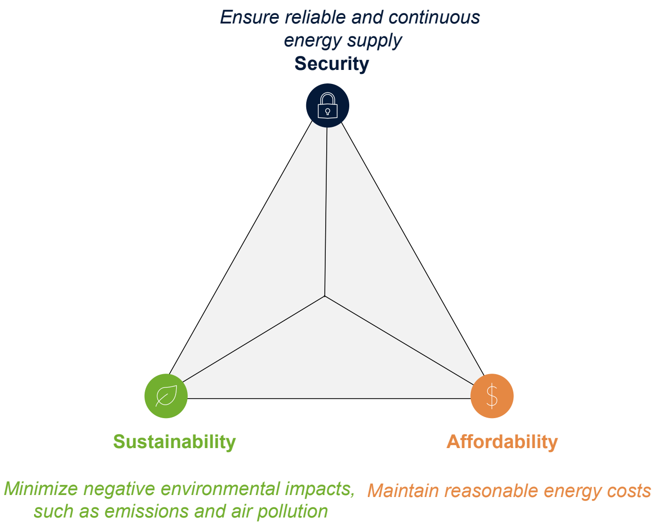
Living in an era of high energy uncertainty, as the world finds itself in 2024, has profound implications for investment decisions, energy infrastructure development and technology planning. Managing this uncertainty requires reconciling scenarios with forecasts to inform prudent policy and good planning. Uncertainty complicates decisions about the optimal energy mix and poses risks to the security of supply and to achieving global emissions reduction goals. A more realistic approach balancing current growth trends with long-term sustainability goals highlights the need for innovative solutions and flexible policies. It also emphasises the importance of continuous monitoring and adjustment of energy strategies to align with evolving global conditions and technological advancements.

[49] *This percentage refers to the gap between the historical trendline and 2030 production volumes given no new investment in gas supply, i.e. the shortfall in gas production volumes from currently operational and sanctioned projects in 2030, against the historical trendline.*

V. Conclusion: Solving uncertainties by addressing the energy trilemma

The future of energy demand is fraught with uncertainties, influenced by a myriad of regional and global factors. Regional demand drivers, such as economic and population growth, urbanisation, industrialisation, resource availability, and many others significantly impact energy consumption patterns. For example, Europe's overall energy demand has increased over the past five years, despite policy incentives to increase energy efficiency and a structural decline in industrial demand. Asia has robust energy demand growth, especially driven by India and China, with the latter boasting the largest power market in the world. North American energy demand has slowly grown to surpass 2019 levels, led by the transport sector, while the growth of data centres and increased electricity consumption for cooling give impetus to new power demand, which is set to grow at a pace not seen in decades. Energy demand in Africa has grown faster than most regions since 2019, led by economic development and the desire to reach full energy access for its inhabitants. In Africa and South America, equitable access to electricity and clean cooking technologies remains a challenge.

Figure 70: The energy trilemma



Source: Rystad Energy

Considering these trends and context, a decarbonized energy mix that balances the dispatchable potential of gases—including zero- and low-CO_2 gases and natural gas with CCUS—along with renewables is a more realistic solution compared to solely relying on intermittent renewables and gas storage. To combat longer-duration intermittency, gaseous energy is necessary in order to meet peaking demand and provide operating reserves to prevent system failures. Repurposing existing gas infrastructure, such as power plants, pipelines, and LNG terminals, for zero- and low-CO_2 molecules represents a substantial cost advantage in the path towards a sustainable transition. Biomethane, hydrogen or natural gas with CCUS can ensure affordable energy for hard-to-abate industrial sectors, such as steel and cement, which are challenging to electrify. Achieving this requires continued investments in gas supply and infrastructure, which in turn brings the additional benefit of minimising the impact of external shocks, such as geopolitical tensions, on gas prices, avoiding gas-to-coal switch in both developed and developing countries and thus helping to reduce the correlation between carbon emissions and the state of the economy.

As renewables are expected to take on an increasing share of power generation, the future role of natural gas will be to ensure a stable energy supply. Gas provides grids with a flexible energy, complementing renewables during periods of intermittency. Gas markets and distributed global abundance provide flexible energy available globally and at scale that can be delivered anywhere in the world by ship or pipeline. LNG's role in keeping energy supply and lights on in Europe after the onset of the Russia-Ukraine conflict demonstrated its criticality of being a force of unprecedented change, replacing two thirds of European gas imports in one year.

Compared to coal and oil, natural gas combustion emits substantially less (~50% and ~30% respectively) CO_2, making it a crucial component in global efforts to achieve emissions targets and mitigate climate change. Use of gas relative to coal also improves local air quality by emitting almost no pollutants such as sulphur dioxide and particulate matter. The future integration of natural gas with carbon capture and low and zero-CO_2 gases would reduce further the carbon intensity of gas generation and use in industrial processes.

It is also pivotal to stress that continued momentum and strengthened efforts towards elimination of methane emissions along the supply chain are essential to maximise the contribution of gas to the energy transition and maximising the value of natural gas infrastructure investments. For this reason, the

IGU is calling for its members and all gas sector players to adopt a zero-methane-emission culture.

Furthermore, it is also critical to continue accelerating efforts to scale decarbonisation technologies such as zero- and low-CO_2 gases and CCUS. Zero- and low-CO_2 gases like biomethane can leverage existing natural gas infrastructure and be used in end-use applications that rely on natural gas without requiring any modifications to be made. On the other hand, zero- and low-CO_2 hydrogen can help decarbonise natural gas streams through blending while also utilising existing natural gas infrastructure. Zero- and low-CO_2 hydrogen can also help with decarbonising refineries, fertiliser production and methanol-based chemical production, which use hydrogen as feedstock and collectively consume more than 90% of grey hydrogen produced today.

Further opportunities are in sight as hydrogen is increasingly being used in new demand segments such as fuel for transportation and heating. In addition, decarbonised gases can contribute greatly to the energy security of countries with large endowments of sustainably sourced biomass and renewables. Nonetheless, some sectors have CO_2 process emissions that are hard-to-abate – such as in cement and petrochemicals production – requiring CCUS technology to reduce emission levels. In addition, inevitably, there will be residual and legacy emissions left that would need to be removed for a net-zero world to emerge. Negative emission technology like BECCS and DAC can help facilitate CO_2 reduction.

In conclusion, the findings outlined in this chapter underscore the complexities and uncertainties that characterise the current global energy landscape. **As regions around the world navigate the dual challenges of decarbonisation and increasing energy demand, it becomes clear that a nuanced approach is essential**. The examination of recent energy demand trends reveals a significant gap between actual consumption patterns and scenario assumptions. To mitigate these risks and create a more resilient energy system, it is crucial to balance the energy trilemma: sustainability, security, and affordability. Natural gas, decarbonized molecules and low-CO_2 molecules, as discussed, play a pivotal role in this balancing act. The flexibility and relatively low emissions intensity of gaseous energy compared to coal make them a key component of the energy mix, especially as we strive to meet ambitious climate targets while ensuring reliable energy supply. As we look ahead, the potential supply and investment gap in gas and other low-CO_2 energies calls for immediate attention. It is essential to cross-check scenario pathways with actual forecasts to avoid misalignment and ensure that the energy supply keeps pace with evolving demand.

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