Global Gas Report 2025

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RystadEnergy

Foreword

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(IGU)

The Global Gas Report is a consolidated, fact-based reference document on the state of the global Gas markets – which reliably supply more than a quarter of the world's primary energy needs. The report's findings show strong rising energy demand across all regions, but with future demand and supply trajectories subject to considerable volatility. Amidst the geopolitical, economic and regulatory uncertainties, it is critical that investment in Gas and its infrastructure continues to enable Gas' crucial role in reducing global emissions and driving affordable, sustainable development. Progress is also being made in decarbonising the natural gas value chain via greater efficiency and electrification of key processes. However, more supportive and pragmatic policies are urgently needed to support accelerated adoption and scale-up of low and zero-carbon Gas technologies. Alongside the picture of rising overall energy demand, power systems are expanding and becoming more complex to manage as electrification spreads into different parts of the global economy. This year's report therefore spotlights Gas' vital role in supporting intermittent renewables to ensure a secure and reliable electricity supply to power human progress and global growth.

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CEO,
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In an ever-evolving global landscape, natural gas remains essential for energy security and continues to play a pivotal role in the pathway towards a low-emission system. As energy markets remain unsettled, solid and affordable modulation options remain the key to guarantee stability to the system when renewables are not available – that is what energy integration is all about. As the main destination market, Europe – and therefore Italy – needs flexible and redundant infrastructures, as well as a diversification of vectors and sources to cope with unpredictable scenarios. Therefore, we believe it is essential to continue investing in gas infrastructure to achieve long-term goals; in this regard, developing biomethane and carbon capture & storage can contribute to achieving decarbonisation goals by leveraging existing assets, and help mitigate market volatility, in the interest of businesses and households.

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Natural gas demand continued to grow in 2024, with further growth expected this year, underscoring the increasingly important role of natural gas in meeting global energy needs. Power systems are evolving and becoming more complex, driven by increasing electrification and the integration of intermittent renewables sources, while extreme seasonal heatwaves and thunderstorms are becoming more frequent. These trends place additional strain on grid supply. In this context, natural gas serves as a flexible and reliable balancing source, ensuring energy security and system stability amid fluctuations in renewable output. This year's report highlights opportunities for decarbonising the natural gas value chain through efficiency improvements and the adoption of low- and zero-carbon technologies. It also emphasises the critical role the gas industry can play in supporting a sustainable and affordable energy transition. We are pleased and honoured to support IGU and Snam in presenting the latest developments in the natural gas markets, as well as the future direction of the gas industry.

Executive Summary

Natural gas remains essential to energy security in an ever-evolving energy system. It is continually demonstrating its ability to deliver reliable energy supply with lower emissions than oil and coal, while also serving as a stabilising force in future energy mixes amid rising electrification, growing variable renewables penetration and increasing uncertainties such as extreme weather events and technological breakthroughs.

2024 served as a transitional year for the global natural gas and LNG market, marked by limited momentum and tight fundamentals – a contrast to the extreme volatility of recent years. In 2024, global natural gas demand rose to 4,122 billion cubic metres (Bcm), an increase of 78 Bcm (1.9%) from 2023, driven by sustained growth in Asia and North America. Power generation remained the dominant end-use sector, further supported by extreme summer heatwaves that boosted cooling demand. Supply also expanded, increasing by 65 Bcm to reach 4,090 Bcm. LNG trade grew for the 11th consecutive year, reaching 555 Bcm, with the United States, Qatar, and Australia maintaining their positions as leading LNG exporters. Entering 2025, the market has shown regional divergence in natural gas demand. In the first half of 2025, growth was concentrated in Europe and North America, increasing by 6.1% and 1.5% respectively. Meanwhile, LNG trade has continued to expand, supported by a sharp rise in European imports, which grew by 16 Bcm (23.6%) to meet regional demand and storage injection requirements. In contrast, LNG procurement activity in Asia has been more subdued. Higher spot LNG prices, combined with increased competition with Europe, have limited spot purchases from price-sensitive buyers such as China and India. With these dynamics in play, natural gas demand is expected to continue its growth trajectory in 2025, with a projected annual increase of 71 Bcm.

Observed trends suggest global energy demand is expected to follow an upward trajectory over the next decade, especially leading up to 2030. Power consumption is expected to surge in China and India, positioning Asia as the key driver of global energy demand, supported by growth in North America.

Nonetheless, uncertainties from emerging trends are making it increasingly difficult to project and plan for future energy demand growth. Climate change-induced heatwaves and technological breakthroughs like the AI data centres boom are straining power systems globally, requiring reliable and flexible sources as well as infrastructure. Uncertainty surrounding the timing of the next wave of LNG is exacerbating risks of already anticipated supply shortfalls, though this could be mitigated by the ~270 Bcm of approved or under construction liquefaction capacity in the pipeline to be commissioned by 2030. If current trends continue, demand growth will likely outpace scenario pathways proposed by leading institutions, exceeding projections for 2030 by as much as 8-90 EJ. Considering the observed trends of rising demand while planning the optimal energy mix can help ensure greater supply readiness for the future.

Targeted investments in natural gas and LNG supply, infrastructure, and storage are thus required to meet potential shortfalls and mitigate energy uncertainty. Natural gas can act as a force of resilience supporting long-term sustainability and energy security by meeting rising power demand, and enhancing geopolitical stability through reliable, diversified supply.

Furthermore, as variable renewable energy (VRE) becomes central to global power systems, natural gas can play an instrumental role in backing up these evolving systems. The inherent volatility of VRE poses challenges for system planning, grid stability, and supply security, introducing fluctuations across multiple timescales. VRE output is impacted not only on an intra-day basis due to the natural intermittency of wind and solar, but also by longer-term seasonal variations and extreme weather events. While batteries can support intra-day balancing, their capacity limitations constrain their ability to ensure supply security over extended periods, underscoring the need for complementary dispatchable power. Natural gas is the most mature, responsive, and scalable source of flexibility today. With short deployment timelines, modest capital requirements, and integration into global LNG markets, gas-to-power is well placed to support rising VRE penetration alongside battery technology. In the near term, gas provides reliable dispatchability, as seen during periods of dunkelflaute, and can also support power generation during prolonged abnormal weather events such as droughts and heatwaves.

As natural gas becomes increasingly integral to the global energy mix, efforts to reduce emissions and improve efficiency are advancing in parallel. These include electrifying processes along the natural gas and LNG value chain, enhancing leak detection and repair, capturing and utilising gas, and improving operational practices. Carbon capture and storage is emerging as a key decarbonisation pathway, while AI, automation and advanced analytics are being leveraged to enhance system efficiency.

Additionally, the global Gas industry is advancing lower-carbon technologies in response to the need for decarbonisation. Biomethane holds enormous potential, with mature production technologies and drop-in compatibility with existing natural gas infrastructure. Feed-in premiums and feed-in tariffs have driven biomethane production growth in Europe by guaranteeing long-term offtake and price. Similar policy mechanisms could support other low-carbon gases such as clean hydrogen and its derivatives, which continue to face high production costs. Meanwhile, momentum in CCUS is building, with major projects having reached FID and start-up this year. Governments and companies are increasingly viewing CCUS as a vital decarbonisation tool to achieve climate targets. However, a significant proportion of capacity addition is in the pre-FID phase, reinforcing the need for clearer regulations, streamlined permitting, and more mature carbon markets to scale up CCUS. Accelerating low-carbon gas development hinges on incentivising or mandating long-term offtake to provide demand visibility and revenue certainty, as well as ensuring the buildout of readily usable transport and storage infrastructure. This enables developers to secure financing, reach FID, and move faster towards commercial rollout to unlock cost reductions through learning and scale, thereby accelerating decarbonisation.

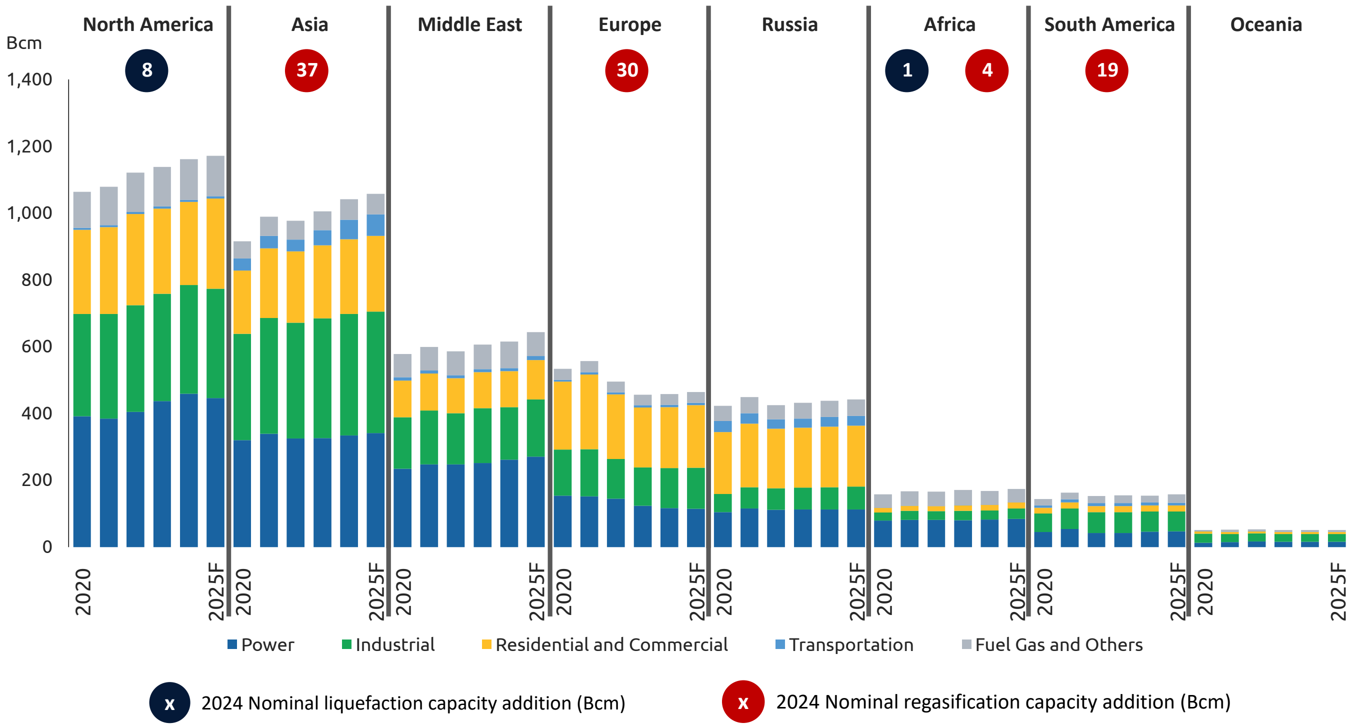
Contents

Key Messages

Key Message 1: Growing gas demand

Chapter 1

Figure 1: Regional natural gas demand by sector and liquefaction/regasification capacity addition



Source: Rystad Energy, IGU

Natural gas demand rose by 78 Bcm (1.9%) in 2024, reaching 4,122 Bcm. The increase was primarily driven by strong gains in Asia and North America. Demand is expected to continue growing in 2025, with an anticipated increase of 71 Bcm (1.7%). Gas-for-power remained a key driver, with heatwaves boosting cooling needs and reinforcing the fuel's role in electricity generation, alongside rising demand from transportation and industrial sectors.

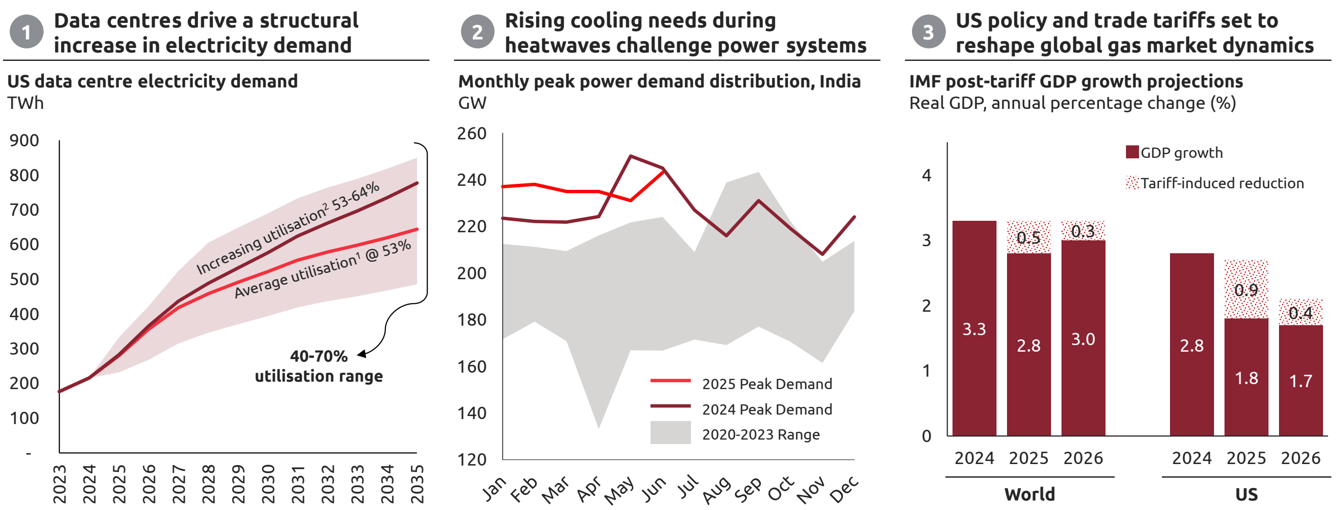
Global natural gas production also increased by 65 Bcm (1.6%) in 2024; however, market fundamentals remained tight. LNG trade expanded for the 11th straight year, rising to 555 Bcm, underscoring its pivotal role in meeting growing demand, enhancing global natural gas trade and improving market connectivity despite ongoing geopolitical uncertainties. Although growth in liquefaction capacity was modest (+9 Bcm) and some projects faced delays, the emergence of new exporters, such as Mexico and Congo, highlights LNG's steadily increasing significance in the evolving global energy landscape. Supporting this momentum in LNG infrastructure development, 64 new LNG carrier vessels were delivered in 2024, with a further 337 under construction at year-end.

2025 started with regional divergence in demand trends. Demand growth was concentrated in Europe and North America during the first half, driven by gas-for-power demand in Europe and strong space heating demand across both regions. LNG trade also grew in H1 2025, with a notable resurgence in European imports, which increased by 23.6% compared to the first half of 2024. This growth offset import declines from more price-sensitive buyers in Asia, particularly China, where LNG imports decreased by 19.4% compared to H1 2024, while domestic supply and pipeline imports remained robust. These trends are expected to persist through 2025, with elevated LNG imports in Europe supporting storage injection needs, while procurement activity in Asia is expected to remain more subdued.

Key Message 2: Rising energy uncertainty

Chapter 2

Figure 2: Rising energy uncertainty due to shifts in technology, climate and geopolitics



Notes: 1) The 'average utilisation' demand line assumes 53% utilisation of the existing project pipeline capacity for all years from 2025-2035, based on the historical average utilisation of data centre capacity in the US. **2)** The 'increasing utilisation' demand line assumes that utilisation of data centre capacity increases from the historical average of 53% in 2025 to 64% in 2035 at a gradual rate to reflect uncertainty around the pace of AI adoption.

Source: Rystad Energy, IMF

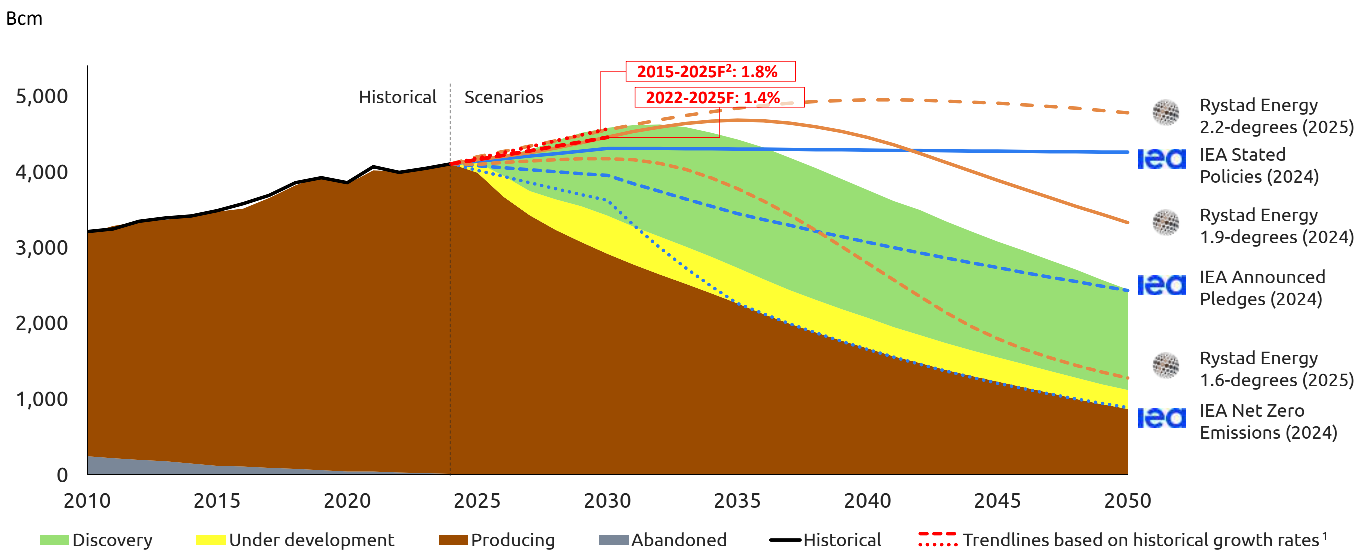
Amid rising uncertainties arising from shifts in technology, climate and geopolitics, the trend of growing energy demand can be clearly observed. Should this trajectory persist, there is a risk of misalignment between continuity of supply and the realities of demand. Recent trends suggest that global energy demand could continue increasing over the next decade, driven by Asia and supported by growth in North America. Yet, uncertainties from global shifts are making it increasingly difficult to project and plan for this growth. **US-led AI data centre boom accounted for ~1.5% of electricity globally in 2024**, with additional capacity in the pipeline set to increase this figure to ~1.7% in 2025, rapidly straining grids. More notably, increased cooling needs in 2024, the hottest year yet, contributed to record peak power demand or significant heat-induced grid disruptions in 80% of countries in Latin America and Asia Pacific. With at least one of the next five years expected to exceed 2024 temperatures, there is a heightened risk of unprecedented peak power demand growth. Geopolitical developments add further uncertainty to projections of growth, with US import tariffs threatening to weaken global LNG demand due to slowing overall economic activity, despite strong support for the oil and gas sector domestically. These challenges are exacerbated by the unpredictable pace of the energy transition with the potential for both rapid acceleration and slowdown.

If recent trends in energy persist, future demand is likely to outpace scenario pathways proposed by leading institutions, exceeding projections for 2030 in most cases by as much as 8-90 PJ. **While planning investment decisions, it is important to also ensure energy system readiness** for higher demand outcomes, avoiding indecision driven by prevailing uncertainties. This can be achieved by aligning energy planning with observed trajectories and **addressing the observed trend of rising energy demand** by scaling up reliable and flexible energy sources such as natural gas.

Key Message 3: Key role of investments in gas and LNG supply and infrastructure

Chapter 2

Figure 3: Global gas demand-supply balance under various scenarios, supply split by lifecycle



Notes:

1) This analysis considers two trendlines based on historical growth rates: the 2022-2025F trendline and the 2015-2025F 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, respectively 1.4% and 1.8%. **2)** The 2015-2025F 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

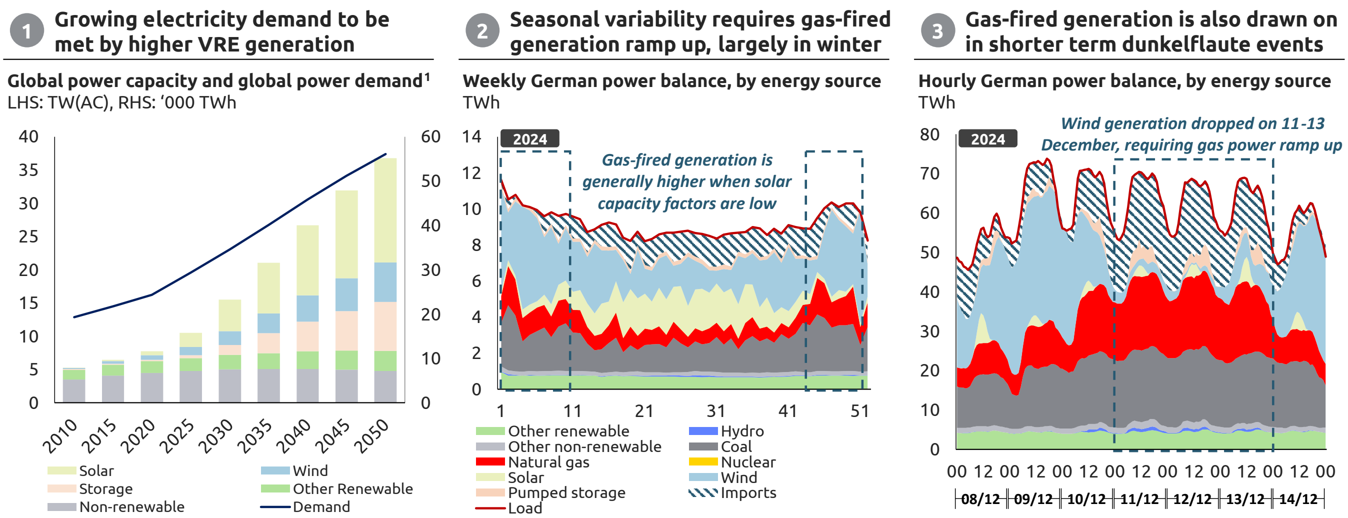
Natural gas is well-positioned as a force of resilience to mitigate energy uncertainty, serving as a key element of a reliable, flexible, affordable and climate-ready energy system. As a lower carbon alternative to coal, especially with the integration of carbon capture technologies, natural gas can offer long-term sustainability while ensuring energy security in emerging economies. It provides system reliability, serving as an insurance for power systems and providing dependable backup as both short- and long-term energy storage when intermittent renewables output falls short. This is especially relevant in the context of growing power demand emanating from data centres and heightened cooling needs, which require stable and dispatchable energy sources, respectively. Gas and LNG also emerge as geopolitical tools, vital for preventing economic and social instability through the provision of secure and diversified supply.

Amid rising demand, LNG projects could face potential delays and cost overruns linked to trade policy shifts, key transit route disruptions, and climate regulations. Despite ~270 Bcm of approved or under construction liquefaction capacity in the pipeline to be commissioned by 2030, there is uncertainty around the timing of the next wave of LNG supply. This can exacerbate the risk of already anticipated shortfalls in global gas supply, highlighting the need for targeted investments in natural gas upstream production and wider infrastructure (LNG, transport, storage) to meet deficits. Investments would be required even if global gas demand were to develop similar to the most ambitious 1.5 degrees-aligned pathway. As the energy transition progresses, risk mitigation measures should focus on building resilience by expanding gas storage to manage supply shocks and seasonal demand, diversifying supply sources to reduce geopolitical dependence, integrating low-carbon gases like hydrogen and biomethane to align with climate goals, and investing in flexible, repurposable infrastructure that can adapt to future energy systems needs.

Key Message 4: Growing electricity need supported by natural gas' balancing role

Chapter 3

Figure 4: Growing electricity needs



Note: 1) This figure considers Rystad Energy's base case scenario. 'Other renewable' includes nuclear, geothermal, solar thermal, bioenergy, and hydro. 'Non-renewable' includes natural gas, coal, and liquids. 'Storage' refers primarily to batteries and pumped hydro storage which, in Rystad Energy's view, are expected to account for nearly 100% of storage capacity through 2050. Other storage solutions (compressed-air energy storage, liquid air energy storage, thermal energy storage) are expected to contribute only marginally.

Source: Rystad Energy, ENTSO-E

Natural gas plays an increasingly critical role in stabilising future power systems amid rising penetration of variable renewables energy (VRE) and growing incidence of extreme weather events. Electricity demand is projected to rise sharply, reaching ~56,000 TWh by 2050, accompanied by a structural shift in which the majority of this demand will be met by variable renewable energy (VRE). Installed renewable capacity, including storage, is expected to grow by a compound annual growth rate (CAGR) of 7.4% in the same period according to Rystad Energy's base case, driven by sustained investment in wind and solar.

However, higher VRE penetration introduces fluctuations in the power system across multiple timescales. In the intra-day timescale, variability is driven by the natural intermittency of wind and solar. While batteries are well-suited for sub-hourly and intra-day balancing, they lack the capacity to buffer supply across multiple days. During such periods, dispatchable generation, primarily gas and hydro, remains essential for maintaining supply security. Recent *dunkelflaute* events in Germany and Australia – marked by prolonged periods of low wind and solar output – have highlighted natural gas' central role in maintaining energy supply, with gas-fired generation surging during peak stress. In the long-term, seasonal patterns can significantly affect generation output, for instance, with solar capacity factors typically peaking during the summer and remaining low for extended periods in the winter.

Furthermore, the growing incidence of extreme weather events has further highlighted the need for reliable power to manage volatility in future power systems. Extreme events, such as heat waves, cold storms and droughts, have intensified longer-term seasonal energy demand peaks, amplifying challenges of higher VRE penetration. In countries such as India, which faced record peak power demand in 2024 and remain reliant on high-emissions, inflexible coal generation, opportunities for coal-to-gas switching have emerged – reflected in a surge in LNG imports during the summer of 2024.

Natural gas already plays a central role in today's global power mix, offering a set of advantages particularly well-suited to respond to future power system challenges. Natural gas remains a competitive, flexible solution due to its technological maturity, lower deployment and spatial constraints, cost-effective capital intensity and broad infrastructure support enabling long-duration energy storage. As such, **natural gas can support the transition to a low-emission power system by providing flexible, dispatchable capacity that complements variable renewables and battery storage**. Realising this potential requires targeted **investment across the gas value chain, including LNG infrastructure and storage**, as well as reform of power market structures to ensure project viability.

Key Message 5: The role of low-carbon gases

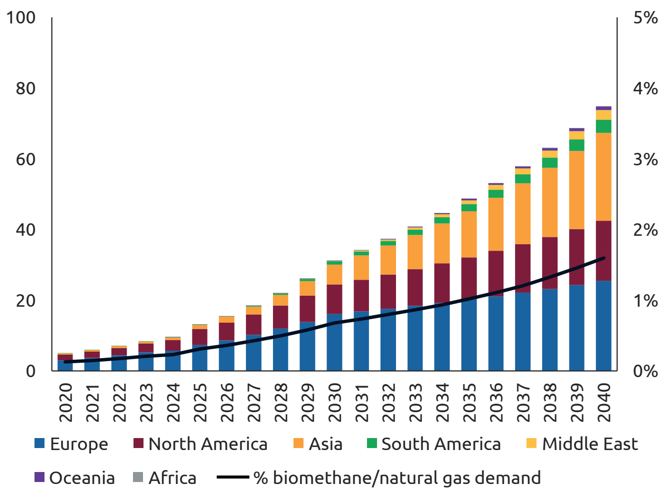
Chapter 4

The global gas industry is increasingly engaging with the decarbonisation challenge, pursuing lower-carbon technologies through innovation and collaboration. Targeted investments in decarbonised molecules are required to unlock decarbonisation options such as biomethane and bio-LNG scale up, CCS-based gas system decarbonisation, and the integration of hydrogen and its derivatives.

Biomethane stands out as the most promising low-carbon gas today, backed by mature production technologies, drop-in compatibility with existing natural gas infrastructure, and strong potential for large-scale deployment. Global production has increased sevenfold over the past decade, reaching 9.6 Bcm in 2024, driven by supply-side incentives such as feed-in premiums and feed-in tariffs that have reduced investment risks for operators and investors. Looking ahead, global biomethane production is projected to grow by 14% annually through 2040, driven by strategic targets in Europe

Figure 5: Biomethane production by region and share of biomethane in global natural gas demand

LHS: Bcm; RHS: Percentage



Note: 'Biomethane production' refers to the total production levels of announced biomethane projects, with adjustments (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, commerciality, and country targets. Historical production levels reflect actual data where available; otherwise, they are estimated based on capacity and utilisation rates. The share of biomethane production in global natural gas demand may vary due to uncertainty in global gas demand in the long run. Biomethane production levels for Europe in 2030 are estimated based on announced capacity additions and expected capacity utilisation rates and are more conservative than REPowerEU's target.

Source: Rystad Energy

and China. Beyond its role in the energy system, biomethane supports broader policy goals by addressing waste management challenges and enhancing energy security. Its role as a flexible and dispatchable source of clean energy also supports the energy transition by being a critical enabler of grid reliability during periods of low renewable output.

Momentum in CCUS is building, with major projects having reached FID and start-up in 2025, despite ongoing delays stemming from project complexity and regulatory challenges. Global unrisked CO_2 capture capacity is expected to grow towards 79 Mtpa in 2025 and could increase by more than seven times to 577 Mtpa by 2030. However, most upcoming capacity additions are in the pre-FID phase, underscoring the need to accelerate progress via clearer regulatory frameworks, streamlined permitting, and more mature carbon markets. Further policy support for CCUS is expected this year, especially for carbon removals, which made up around 55% of announced projects in 2024 targeting startup by 2030, as countries submit their Nationally Determined Contributions (NDCs) ahead of COP30.

Clean hydrogen development has progressed in the past year but cost reductions in production have been lower than expected mainly due to inflationary pressures. In parallel, the low willingness to pay by offtakers has discouraged developers and investors from announcing new projects, underscoring a shift towards greater caution in clean hydrogen development. This highlights the need for stronger policy support to boost market confidence, thereby accelerating investments.

Governments can boost market confidence for low-carbon gases by incentivising or mandating long-term offtake to ensure demand and revenue certainty for producers, thereby enabling financing, commercial rollout and eventual cost reductions that drive wider adoption. Successful policies should be market-based, focusing on lifecycle emissions reduction and prioritising no-regrets investments such as the repurposing of existing natural gas infrastructure for the transport of low-carbon gases and for the storage of CO_2.

Several policies have been implemented globally to directly incentivise or mandate long-term offtake of low-carbon gases. These include book-and-claim systems expanding biomethane producers' reach to offtakers beyond their immediate geography, contracts for differences for CCUS providing revenue certainty, auctions securing long-term clean hydrogen offtake agreements, and the ReFuelEU Aviation regulation mandating SAF uptake till 2050.

1/ Natural Gas Market Fundamentals

Chapter highlights

Global natural gas demand continued to grow in 2024, with further gains expected in 2025

- Demand rose by 78 Bcm (1.9%) year-on-year (y-o-y) in 2024, led by Asia and North America. Power generation accounted for one-third of demand, rising by 39 Bcm (2.8%), partially driven by seasonal heatwaves globally
- In H1 2025, demand growth was centered in Europe (+6.1%) and North America (+1.5%), driven by colder weather boosting residential and commercial demand, and lower renewable generation driving gas-for-power in Europe. Demand is expected to continue growing in 2025, with an anticipated increase of 71 Bcm (1.7%)

Supply growth matched demand gains, keeping global market fundamentals tightly balanced

- Supply rose by 65 Bcm y-o-y in 2024, driven by increase in the Middle East and a rebound in Russia, while US output remained flat amid low prices from high storage levels and mild winters leading to shut-ins and delayed drilling
- Liquefaction capacity grew by ~9 Bcm in 2024, with further addition in H1 2025 from Greater Tortue Ahmeyim and LNG Canada. Further expansion is expected as US LNG projects (Plaquemines LNG and Corpus Christi) continue their ramp up

Global natural gas trade expanded, while prices remained subdued but volatile

- LNG trade rose to 555 Bcm in 2024, with Europe and Asia making up over half of imports. Net trade across LNG and pipeline flows increased by 44 Bcm y-o-y. LNG trade continued to grow in H1 2025, led by a resurgence in Europe, where imports grew by 16 Bcm (23.6%) compared to H1 2024
- In 2024, major benchmark prices averaged below 2023 levels, though early 2025 saw renewed volatility, with Henry Hub reaching a two-year high of 4.3 USD/MMBtu, and TTF rising to 17.6 USD/MMBtu (58.4 €/MWh)

Policy shifts and geopolitical developments continue to reshape gas and LNG markets

- Geopolitical events – including Houthi attacks in Red Sea, end of Russian gas transit via Ukraine, and the more recent escalation in conflict between Israel and Iran are reshaping global trade flows infrastructure and generation capacity
- The recent tariff dynamics related to the Trump administration have brought US LNG into focus as a tool in bilateral trade negotiations with other economic blocs

I. Key changes in the natural gas market

The following chapter explores key developments in the global natural gas and liquefied natural gas (LNG) markets throughout 2024 and early 2025 and provides a near-term outlook for the remainder of 2025. It covers trends and significant developments in supply, demand, trade flows, and pricing.

In 2024, the global natural gas market remained largely stable, with modest growth in both supply and demand. Demand rose by 78 Bcm (1.9%) year-on-year (y-o-y), reaching 4,122 Bcm, driven primarily by Asia and North America, alongside growth in domestic consumption in Russia. Weather remained a key factor, with summer heatwaves boosting cooling demand in Asia, while milder 2023/2024 winters across the Northern Hemisphere reduced space heating needs. On the supply side, global production grew by 65 Bcm (1.6%), reaching 4,090 Bcm, led by gains in the Middle East and Russia, with smaller increases in Asia and North America. However, liquefaction capacity growth underperformed expectations due to project delays, including those affecting the Greater Tortue Ahmeyim FLNG and Golden Pass LNG project.

From late 2024 through June 2025, natural gas demand trends diverged across major markets. Europe experienced a resurgence in LNG imports, while demand growth in Asia slowed, weighed down by relatively higher spot LNG prices and weak macroeconomic conditions that limited spot market activity. LNG imports into Europe grew by 16 Bcm (23.6%) in H1 2025 compared to H1 2024. Meanwhile, China, the world's largest LNG importer, recorded a decline of 19.4% in LNG imports over the same period. Overall global natural gas demand growth in H1 2025 was primarily driven by Europe and North America, which registered increases of 6.1% and 1.5%, respectively. This was largely driven by colder 2024/2025 winter, which increased heating demand in both regions. In Europe, lower renewable generation also necessitated gas-for-power usage during the last winter.

On the pricing front, despite the absence of extreme price shocks like those in 2022, market fundamentals remained tight in 2024. European benchmark Title Transfer Facility (TTF) averaged 11.0 USD/MMBtu (34.7 €/MWh), peaking at 14.9 USD/MMBtu (48.5 €/MWh) amid expiration of the Ukraine Transit Agreement. Meanwhile, Henry Hub fell below 2.0 USD/MMBtu in early 2024 due to mild weather, prompting shut-ins and reduced drilling activity. Low Northeast Asia spot prices of LNG early in the year supported procurement by price-sensitive markets in Asia.

Volatility returned in early 2025, with Henry Hub spiking to a two-year high of 4.3 USD/MMBtu. This surge was driven by well freeze-offs, [when water or hydrates in natural gas wells freeze due to extreme cold, disrupting production], particularly in the Appalachia region, along with stronger demand for heating amid extreme winter conditions, and increased LNG feed gas demand following the start-up of operations at Plaquemines LNG and Corpus Christi Stage 3. TTF similarly surged to 17.6 USD/MMBtu (58.4 €/MWh) in February as a cold snap gripped Europe.

In parallel with these market movements, policy shifts and geopolitical developments continue to shape the global natural gas and LNG markets amid ongoing uncertainty. The return of President Trump

Table 1: Key 2024 year-on-year changes in the global natural gas market

	Consumption		Production		Gross imports		Gross exports	
Regions	Bcm	% change	Bcm	% change	Bcm	% change	Bcm	% change
Asia	+ 36.0	+ 3.6%	+ 17.5	+ 2.5%	+ 36.9	+ 7.9%	+ 3.7	+ 2.2%
Europe	+ 2.2	+ 0.5%	+ 1.7	+ 0.8%	− 13.6	− 2.9%	− 6.9	− 3.0%
North America	+ 22.9	+ 2.0%	+ 4.6	+ 0.4%	− 1.2	− 0.7%	− 3.1	− 1.0%
South America	− 0.9	− 0.6%	− 1.0	− 0.7%	+ 2.0	+ 7.9%	+ 1.1	+ 4.4%
Africa	− 2.6	− 1.5%	− 17.0	− 6.6%	+ 2.3	+ 13.9%	− 9.3	− 9.7%
Middle East	+ 8.8	+ 1.5%	+ 29.6	+ 4.4%	+ 6.0	+ 6.4%	+ 6.1	+ 3.5%
Russia	+ 11.5	+ 2.5%	+ 30.5	+ 5.1%	− 0.7	− 8.8%	+ 14.3	+ 9.9%
Oceania	+ 0.1	+ 0.3%	− 1.1	− 0.7%	− 0.6	− 77.4%	− 2.0	− 1.6%
World	+ 78.2	+ 1.9%	+ 64.8	+ 1.6%	+ 31.0	+ 2.5%	+ 4.0	+ 0.3%

Source: Rystad Energy

Table 2: Key 2025 (forecast) year-on-year changes in the global natural gas market

	Consumption		Production		Gross imports		Gross exports	
Regions	Bcm	% change	Bcm	% change	Bcm	% change	Bcm	% change
Asia	+15.9	+1.5%	+10.1	+1.4%	−2.2	−0.4%	+2.5	+1.4%
Europe	+5.2	+1.1%	−3.4	−1.5%	+23.8	+5.2%	+3.4	+1.6%
North America	+10.4	+0.9%	+40.1	+3.1%	+4.2	+2.3%	+34.8	+11.8%
South America	+3.9	+2.5%	+3.9	+2.6%	+0.1	+0.2%	−4.1	−15.4%
Africa	+5.7	+3.4%	+13.6	+5.7%	+7.9	+41.6%	+26.4	+30.3%
Middle East	+28.2	+4.6%	+21.3	+3.1%	+0.6	+0.6%	−3.5	−1.9%
Russia	+1.7	+0.4%	−0.3	0.0%	−3.6	−47.3%	−10.3	−6.5%
Oceania	−0.4	−0.8%	+1.6	+1.0%	−0.2	−100.0%	−1.4	−1.2%
World	+70.6	+1.7%	+87.0	+2.1%	+30.6	+2.4%	+47.8	+3.8%

Source: Rystad Energy

in office in the US has brought renewed emphasis on domestic natural gas and LNG production, including lifting the LNG export permit freeze. However, the recently introduced tariffs have disrupted global markets, raising concerns about inflation and slowing demand growth.

Geopolitical tensions also escalated. The ongoing Russia-Ukraine conflict, friction between India and Pakistan, and hostilities between Israel and Iran have kept the energy markets on edge. In June, the conflict between Israel and Iran intensified. US airstrikes on Iranian nuclear facilities on 22nd June 2025 heightened fears of a blockade in the Strait of Hormuz - a critical transit route for LNG volumes, including all exports from Qatar and the United Arab Emirates (UAE). These developments impacted global energy markets, pushing both TTF and Northeast Asia spot price for LNG to their highest levels since February 2025. However, price volatility eased toward the end of June, following a ceasefire announcement by Israel and Iran on 24th June 2025.

Overall, natural gas demand in 2025 is expected to grow more slowly than in 2024, impacted by tight market fundamentals and sluggish growth in Asia during the first half of the year. A y-o-y demand growth of 71 Bcm is projected for 2025.

II. Natural gas demand review

Map 1: World map with natural 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
2020	1,063	2020	144	2020	533	2020	157	2020	578	2020	423	2020	916	2020	51
2021	1,078	2021	162	2021	556	2021	167	2021	598	2021	475	2021	988	2021	51
2022	1,120	2022	152	2022	495	2022	165	2022	586	2022	452	2022	976	2022	53
2023	1,138	2023	155	2023	456	2023	171	2023	606	2023	463	2023	1,005	2023	51
2024	1,161	2024	154	2024	458	2024	168	2024	615	2024	474	2024	1,041	2024	51
2025F	1,171	2025F	157	2025F	463	2025F	174	2025F	643	2025F	476	2025F	1,057	2025F	51

Source: Rystad Energy

The global natural gas demand increased by 78 Bcm (1.9%) y-o-y in 2024, reaching an all-time high of 4,122 Bcm. **This growth was primarily driven by rising demand in Asia (+36 Bcm, 3.6%), North America (+23 Bcm, 2.0%)**, Russia (+12 Bcm, 2.5%), and the Middle East (+9 Bcm, 1.5%). Demand in Europe increased modestly by 2 Bcm (0.5%). Although demand declined slightly in Africa (-3 Bcm, -1.5%) and South America (-1 Bcm, -0.6%), both regions are expected to rebound above 2023 levels in 2025. In contrast, demand in Oceania remained flat and is projected to stay largely unchanged through 2025.

In H1 2025, North America and Europe emerged as main growth regions for natural gas demand, driven by stronger space heating needs during the 2024/2025 winter. In Europe, lower renewable output also supported increased gas-to-power demand. In contrast, milder winters and ample storage in China and Japan, coupled with higher spot LNG prices compared to the previous year weighed on price-sensitive demand in Asia. As a result, **global natural gas demand is projected to grow y-o-y in 2025, albeit at a slower pace, increasing by ~71 Bcm (1.7%), led by the Middle East (+28 Bcm, 4.6%), Asia (+16 Bcm, 1.5%), and North America (+10 Bcm, 0.9%)**.

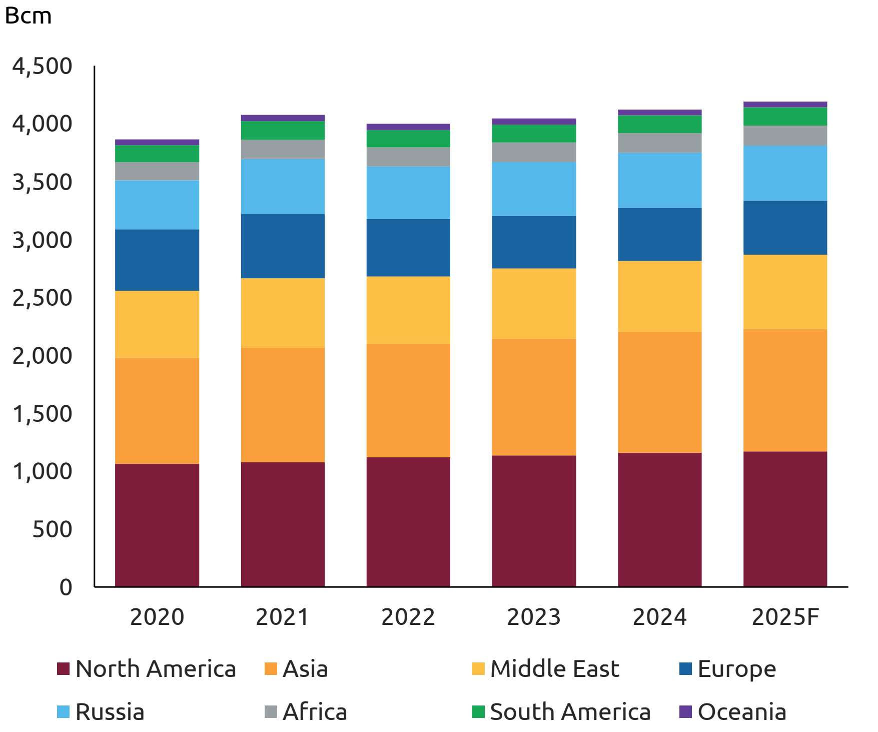
By sector, power accounted for one-third of global demand in 2024, totalling 1,427 Bcm. It also recorded the highest growth, increasing by 39 Bcm

(2.8%) in 2024 y-o-y, partially driven by seasonal heatwaves affecting countries such as China, India, and the United States. Other sectors with notable growth included the transportation sector (+15 Bcm, 14.8%), driven by the rise of LNG fuel-trucking in China, and industry (+7 Bcm, 0.6%), with strong demand observed in Canada and China.

Looking ahead, **demand growth in 2025 is expected to be primarily driven by the residential and commercial sectors**, reflecting trends observed in the first half of the year. Growth in the power sector is expected to be more moderate as the ongoing expansion of renewable generation reduces baseline gas demand in North America, with any additional natural gas needs from the sector becoming increasingly weather-dependent, as seen in Europe.

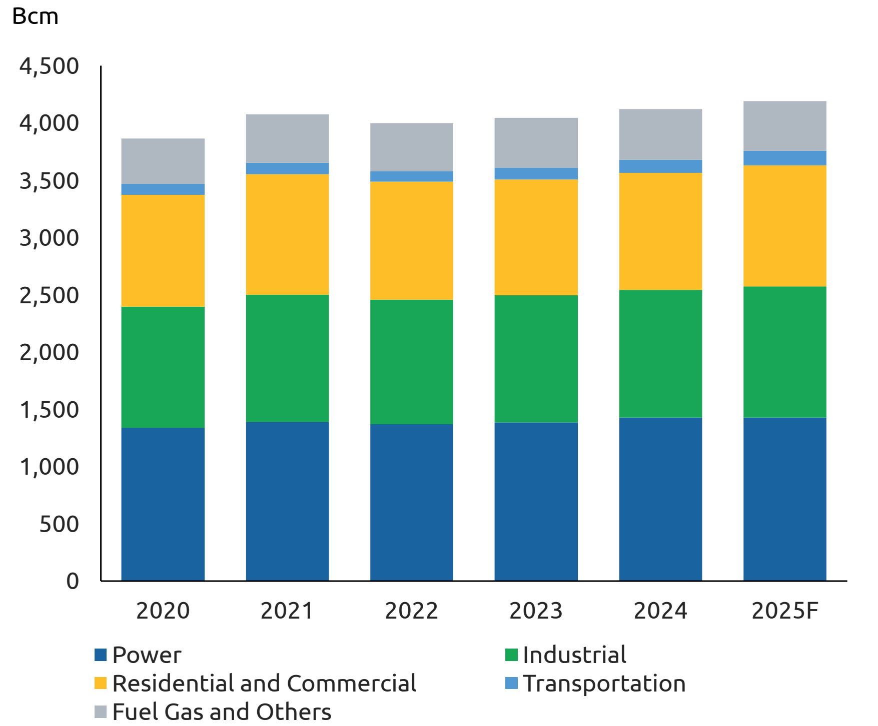
Note:
Power: Gas used as fuel in the electric power sector (including combined heat and power plants).
Industrial: Gas used in manufacturing establishments, refining, mining, mineral extraction, agriculture, forestry, fisheries, chemicals and other industrial activities.
Residential: Gas used in private 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 as fuel in vehicles, ships and other transportation means.
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.

Figure 6: Global natural gas demand, split by region



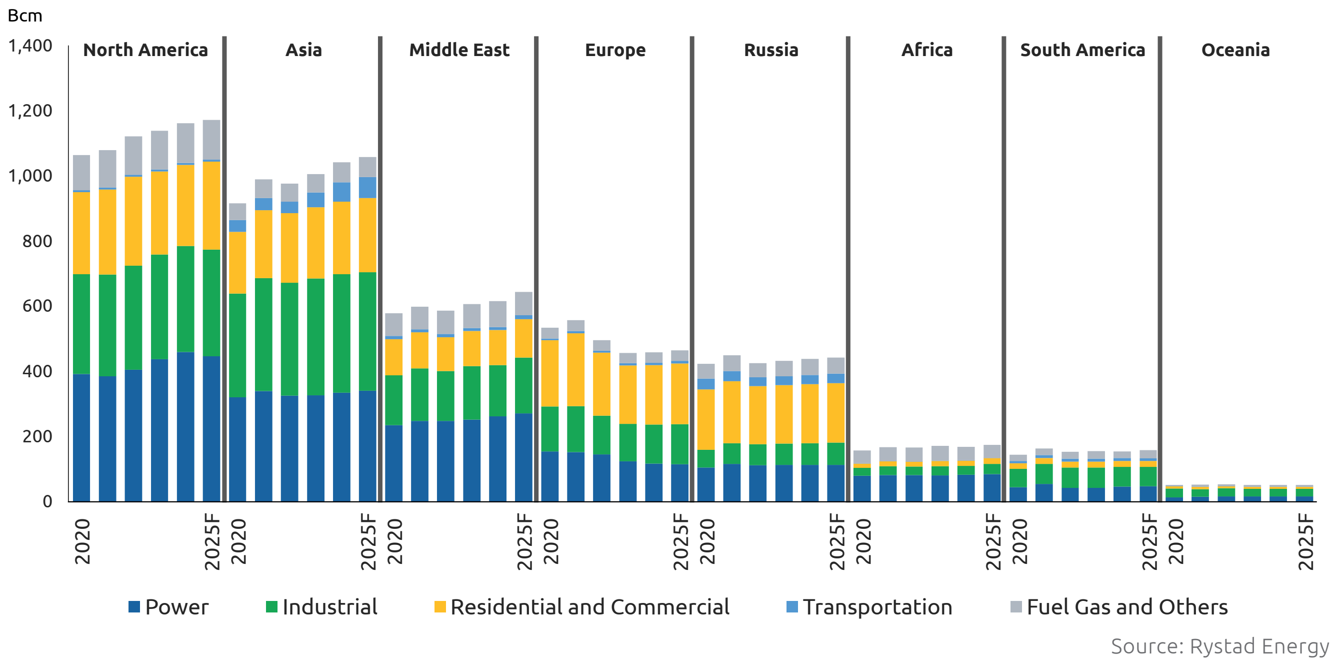
Source: Rystad Energy

Figure 7: Global natural gas demand, split by demand sector



Source: Rystad Energy

Figure 8: Regional natural gas demand, split by demand sector



Source: Rystad Energy

North America

In 2024, natural gas demand in North America increased by 23 Bcm, a 2.0% rise from 2023. This growth was largely underpinned by a 22 Bcm (5.0%) increase in the region's power sector, and a 5 Bcm (1.5%) increase in demand from the industrial sector, whereas the residential sector saw a decline of 6 Bcm (-3.9%).

Within the region, the United States remained the largest consumer, accounting for approximately 80% of North American natural gas demand and driving most of the y-o-y growth. In 2024, gas-for-power in the US benefited from historically low Henry Hub prices as natural gas became more cost-competitive, leading to increased coal-to-gas switching in the power sector. Industrial demand remained flat, while the combined residential and commercial sector saw demand decline, largely driven by milder winters in the beginning of 2024. In Mexico, demand across sectors remained flat while Canada's y-o-y demand grew by 5% with oil sands being a key driver of industrial growth as the Trans Mountain pipeline expansion was completed.

In the first half of 2025, the region's natural gas demand grew by 1.5%, compared to the same period in 2024, driven primarily by residential and commercial sector, where demand increased by 0.4 Bcm (9.2%) due to stronger seasonal space heating needs. In contrast, demand from the power sector declined by 3.9%, impacted by higher solar generation and coal regaining cost-competitiveness. Meanwhile industrial demand remained flat.

Continuing along these trends, North America's total natural gas demand is projected to rise by 10 Bcm (0.9%) y-o-y in 2025, primarily supported by residential and commercial demand. However, a ~12 Bcm decline is expected from the power sector.

Asia

Asia's natural gas demand rose by 36 Bcm (3.6%) in 2024, supported by growth across the transportation (+14 Bcm), power (+8 Bcm), and industrial (+5 Bcm) sectors. **More than 80% of the region's demand growth came from China and India**. China's natural gas demand increased by 32 Bcm (8.0%), and India's rose by 6 Bcm (9.3%), offsetting flat demand in Japan and South Korea.

Heatwaves across the region drove a surge in gas-fired power generation, especially in China and India, where record temperatures significantly increased air conditioning needs. In South Korea and Japan, despite limited overall growth in LNG demand, there were some seasonal increases. South Korea recorded robust spot LNG procurement during the summer, driven by above-average temperatures and curtailments in nuclear power. In Japan, the expiration of long-term contracts led to increased LNG purchasing activity by smaller buyers and traders.

In China, the transportation sector led natural gas demand growth, growing 13 Bcm (45.5%) from 2023. This was driven by expanded LNG use in heavy-duty trucking, driven by lower LNG prices relative to diesel in the first half of the year. Industrial demand rose by 6 Bcm (3.6%) as post-pandemic recovery continued. India's growth was driven by rising demand in the power, industrial and transportation sectors, with Compressed Natural Gas (CNG) remaining a key end-use. Plans are also advancing for the development of LNG-fuelled long-haul trucking infrastructure within the country.

The first half of 2025 has been somewhat subdued for Asia, particularly China. Heating demand was suppressed by a milder winter, while industrial demand faced significant headwinds throughout the first quarter. Initially, the activity was dampened by the Lunar New Year holidays, which expectedly led to lower factory run rates. This was followed by rising economic uncertainty amid ongoing trade tensions with the US. Although industrial demand showed a modest rebound in May, the outlook remains uncertain, as trade-related risks continue to weigh on the sector's recovery.

As a result, natural gas demand in Asia is projected to grow more slowly in 2025, increasing by 16 Bcm (1.5%) for the full year. However, some upside is anticipated from the emerging Southeast Asian markets, such as the Philippines, which has recently integrated LNG into its energy mix.

Middle East

Middle East's natural gas consumption increased by 9 Bcm (1.5%) y-o-y in 2024. This growth was led by a 9 Bcm (3.8%) increase in the power sector and ~2 Bcm gain in the fuel gas (9.8%) sector, which offset a 7 Bcm (-4.0%) decline in the industrial sector gas demand. Natural gas demand grew in Iraq (+7 Bcm, 24.8%), Turkiye (+3 Bcm, 6.3%), and the UAE (+2 Bcm, 2.7%). However, Iran, one of the top five global gas consumers and the largest in the region, experienced a 6 Bcm decline driven by reduced industrial sector consumption. Insufficient natural gas supply during winter months required rationing, leading the government to prioritise residential heating over power generation. This caused power outages and disrupted industrial and commercial operations. Domestic industrial and power demand in Iran is expected to remain constrained by limited gas availability, particularly during the winter months of 2025.

Middle East's natural gas demand is projected to maintain its upwards trajectory, with an estimated 4.6% increase in 2025. This growth is expected to be driven by a rebound in demand in Iran and an approximately 8 Bcm increase in Saudi Arabia. The rising interest in natural gas as a substitute for oil in key end-use sectors, supported by favourable policies such as Saudi Arabia's strategy to phase out oil-fired power generation by 2030 in favour of a renewable and gas-based power mix, is expected to further contribute to the region's growing natural gas consumption.

Europe

In Europe, natural gas demand grew by a modest 2 Bcm (0.5%) y-o-y in 2024, reaching 458 Bcm. Germany, Italy, France and the UK together accounted for over half the continent's consumption, with Germany leading. On a sectoral basis, industrial demand grew moderately by an estimated 5 Bcm (4.5%) but this was offset by declines in other sectors - most notably power, where natural gas demand dropped by 7 Bcm (-5.9%). This decline was notable in major markets such as the UK, Spain, and France, and was driven by continued renewable capacity additions, favourable wind conditions, ample hydropower availability, and increased nuclear output in France. However, several Dunkelflaute[1] events, particularly in November and December 2024, constrained renewable generation, requiring gas-fired power plants to ramp up despite elevated gas prices.

In the first half of 2025, gas-fired power generation exceeded 2024 levels, increasing by 6 Bcm (12.3%), driven by colder-than-average temperatures and reduced wind output. Residential and commercial demand also grew by 4 Bcm (4.7%) as colder weather

[1] Dunkelflaute refers to a period of low winds and limited sunlight, typically occurring in late autumn and winter, which leads to reduced renewable power generation due to unfavourable weather conditions. The impact of Dunkelflaute on power generation is discussed in greater detail in Chapter 3.

2024/2025 winter period boosted seasonal heating needs.

These factors led to increased natural gas withdrawals from storage, a situation further exacerbated by the termination of Russian pipeline flows through Ukraine at the start of 2025. According to the European Commission, storage levels dropped to 34% by 1st April 2025, below the levels observed over the previous two years. Although storage injections in the second quarter increased y-o-y as efforts ramped up to replenish inventories, levels remained an estimated 20 Bcm lower compared to the same period in 2024.

To enhance supply security and reduce market volatility, the EU has extended its gas storage scheme through 2027 and introduced more flexible storage targets. Member states are now required to reach the 90% storage level anytime between 1 October and 1 December, instead of the previously mandated 1 November deadline. The revised regulation was approved by the European Parliament in July 2025.

LNG imports are expected to remain the primary source of natural gas replenishment during the 2025 summer, ahead of the year-end seasonal demand surge. However, the increased flexibility in meeting storage targets is expected to ease upward pressure on prices that typically arises in tight market conditions – when inventories are low and fixed filling deadlines approach – potentially supporting a more stable market environment.

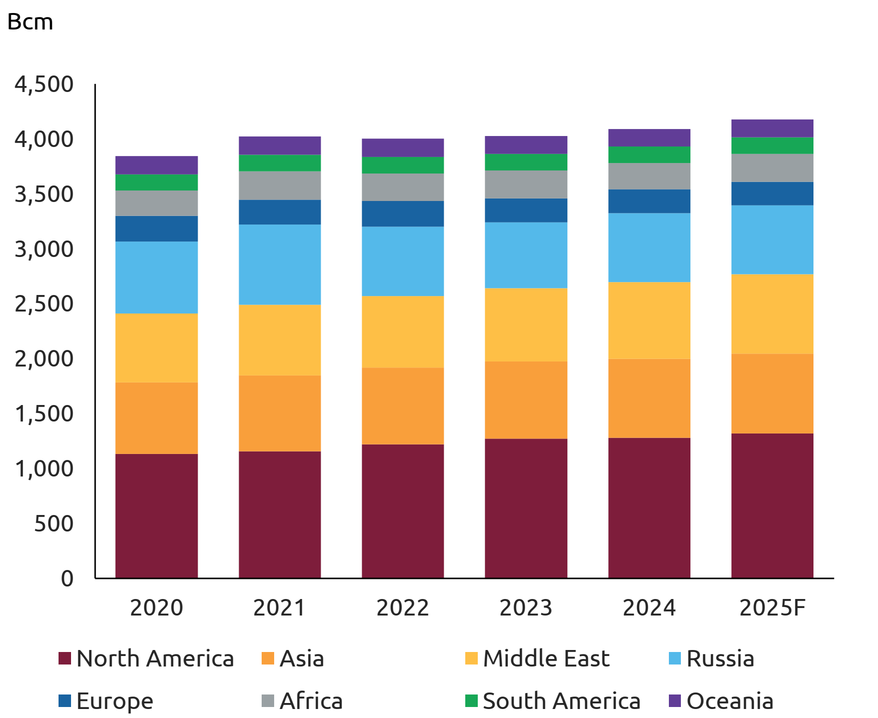
Europe's natural gas demand grew by 13 Bcm (6.1%) y-o-y in the first half of the year, largely shaped by seasonal patterns that reduced renewables output and increased heating demand. However, the higher growth rate in H1 2025 does not necessarily indicate strong full-year demand growth, as much of the increase was weather dependent rather than reflective of sustained market trends. The industrial sector may also face further uncertainty from trade developments that could materialise over the remainder of the year. European gas demand is projected to rise modestly in 2025, by an estimated 5 Bcm (1.1%)

III. Natural gas supply review

Natural gas supply grew by 65 Bcm (1.6%) y-o-y in 2024, reaching 4,090 Bcm, driven by significant production gains in the Middle East (+30 Bcm, 4.4%) and Russia (+30 Bcm, 5.1%). These increases were supported by marginal growth in Asia (+17 Bcm, 2.5%), and North America (+5 Bcm, 0.4%), which collectively offset declines in other regions. This growth was supported by a 9 Bcm increase in global liquefaction capacity. In the US, capacity expanded with the year-end startup of Plaquemines LNG. Congo became an LNG exporter with the commissioning of Congo FLNG, while Mexico – still a net importer - exported its first cargo to Europe from the new Altamira FLNG facility.

Russia saw a strong recovery in natural gas production in 2024, after two consecutive years of decline, led by a 27 Bcm (6.8%) increase in supply from Gazprom's natural gas assets. Higher domestic demand and increased exports to Asian markets, both via pipelines and LNG, supported this resurgence.

Figure 9: Global natural gas production, split by region



Source: Rystad Energy

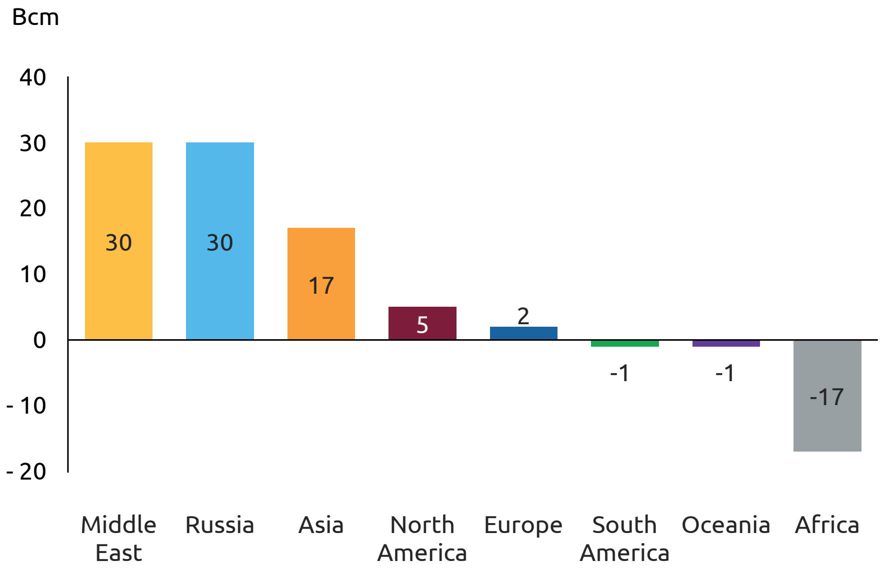
In the Middle East, natural gas production growth was recorded across all major oil and gas producers in 2024, with the UAE leading the increase with a gain of 7 Bcm. Additional regional supply growth came from the Barzan field in Qatar and the South Pars field in Iran. Further increases are expected in 2025, with Saudi Arabia's production projected to rise by 8 Bcm, as the first phase of Jafurah field - the country's largest unconventional natural gas development - is expected to begin operations before the end of the year. The development of Saudi Arabia's gas resources aligns with national plans to replace up to 1 mmbbl/d of oil with natural gas in the power generation sector and to support the expansion of petrochemicals, blue hydrogen and ammonia production.

North American supply saw muted growth in 2024, increasing by 5 Bcm (0.4%), reflecting a slowdown in upstream activity. In the US, production declined from cuts in Appalachia and Haynesville. High storage levels from mild winter weather, and from the shoulder seasons, when natural gas demand eases due to milder weather and reduced residential and commercial consumption, suppressed natural gas prices, leading to production shut-ins throughout the year and significantly delaying drilling activity.

In Asia, gains were led by China, Malaysia, and Azerbaijan. China exceeded its annual domestic natural gas production target of 230 Bcm under the 14th Five-year plan, part of a broader strategy to boost domestic exploration and production and reduce reliance on imports. Notable asset-level growth was also recorded at the Jerun and Timi fields in Malaysia, and the Shah Deniz field in Azerbaijan.

Elsewhere, natural gas production recorded a decline over the past year. In Africa, declining output from producing assets persisted. Algeria, the continent's largest producer and a key supplier to Europe, launched its first upstream bidding round in nearly a decade at the end of 2024, aiming to revitalise development, attract foreign investments, and improve both domestic natural gas supply and its export capacity. In South America, strong growth from Argentina's Vaca Muerta shale play (20.0% y-o-y) was insufficient to offset continued production declines in Bolivia, and minor reductions elsewhere across the continent. Natural gas production also fell by 1 Bcm in both Oceania and South America. In Europe, record production from Norway's Troll field slightly offset declines in the Netherlands, following the complete closure of the Groningen field, which was left partially open in 2023 to supply gas during exceptional circumstances such as extreme winters, and in the UK, where aging North Sea assets drove natural gas output to historic lows.

Figure 10: 2024 Global natural gas production year-on-year change



Source: Rystad Energy

In North America, production activity in H1 2025 was largely driven by operators drawing down their drilled-but-uncompleted (DUC) well inventories, particularly in the Haynesville and Appalachia regions of the US. South America also recorded gains, with Brazil reporting an all-time high in domestic production at 172.3 million cubic meters per day in May. In Asia, China saw production rise by 6 Bcm (6.2%) from January through May, with gains in by coal-bed methane production in the Ordos basin.

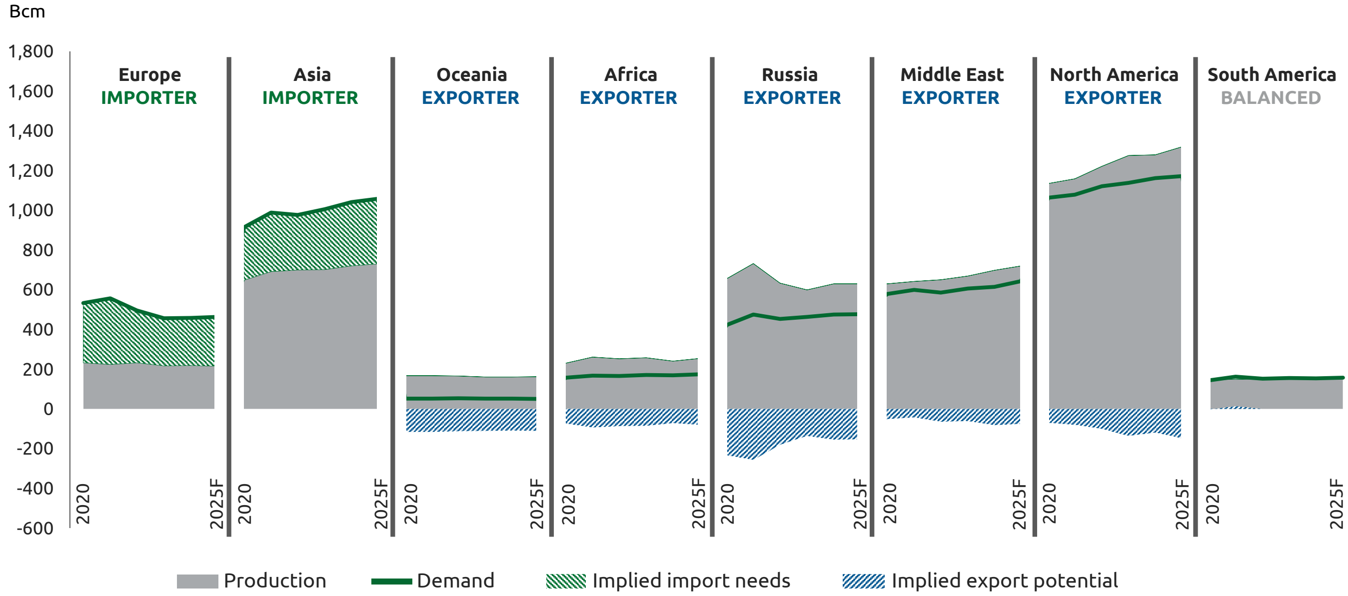
However, geopolitical tensions could impact the supply outlook, as seen during the escalation of the Israel-Iran conflict in June 2025. Israel shut down production at its Leviathan and Karish fields for nearly two weeks, while drone attacks on 14 June targeted Iran's natural gas infrastructure, damaging a processing plant at South Pars Phase 14 and briefly limiting production.

Global liquefaction capacity also expanded in H1 2025 with the startup of Greater Tortue Ahmeyim (GTA) project in Mauritania and Senegal, and commencement of commercial operations at LNG Canada. Further capacity growth is expected later in the year with the ramp-up of remaining trains at Plaquemines LNG and Corpus Christi LNG, the launch of Congo's second facility, Nguya FLNG, and the potential startup of Golden Pass LNG in the US. **Taken together, these trends point to continued production growth through 2025, with a projected increase of 87 Bcm (2.1%), underpinned by a rebound in North America and Africa, and sustained growth in the Middle East, despite recent geopolitical disruptions**.

IV. Natural gas market trade flows and prices

a. Trade Flows

Figure 11: Gas demand, production, and import or export volumes



Source: Rystad Energy

Net global trade grew by 44 Bcm y-o-y across both LNG and pipeline flows, driven primarily by rising demand in Asia. **Europe and Asia collectively accounted for over 50% of global natural gas imports, while Russia remained the largest net exporter** at 151 Bcm (+15 Bcm), followed by Norway (+12 Bcm) and the United States (+6 Bcm). As in 2023, China was the largest net importer in 2024, with a deficit of 175 Bcm (+19 Bcm), reinforcing its position as a key player in global natural gas trade.

Global LNG trade rose to a record 555 Bcm in 2024, underscoring LNG's growing role in the global energy mix as countries prioritise supply security. The top ten net exporters of LNG remained unchanged from 2023, with the US leading at 116 Bcm, followed by Australia (110 Bcm) and Qatar (107 Bcm).

The past year demonstrated the resilience of the LNG value chain amid evolving geopolitical and environmental disruptions. Security risks in the Red Sea escalated following Houthi attacks on foreign vessels beginning in late 2023, increasing volatility around the Bab-al-Mandeb Strait. At the same time,

Table 3: Top 8 gas exporters and importers in 2024

Top 8 Exporters (Bcm)		Top 8 Importers (Bcm)	
Russia	151	China	175
Norway	136	Japan	90
United States	129	Germany	77
Qatar	127	Mexico	68
Australia	110	South Korea	62
Canada	54	Italy	58
Algeria	46	Turkey	50
Turkmenistan	41	France	36

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

Source: Rystad Energy

the Panama Canal, an important link between the Atlantic and Pacific basins, faced drought-induced constraints, with reduced water levels limiting daily vessel transits. These disruptions led to adjustments in trade flow. LNG vessels increasingly avoided the Suez Canal and reduced transits through the Panama Canal, instead opting for the longer but more secure route around the Cape of Good Hope.

China consolidated its position as the world's largest net importer of LNG, receiving 105 Bcm LNG in 2024, an increase of 11 Bcm from the previous year. Japan (90 Bcm) and South Korea (62 Bcm) followed, both increasing spot purchases during the summers due to high temperatures, although demand eased towards the end of the year. Lower LNG prices at the start of 2024 supported import growth across Asia, enabling price-sensitive markets to procure more spot cargoes. Notably, India's imports grew to 36 Bcm, surpassing France to become the fourth largest net importer of LNG. Record-high temperatures and elevated gas-for-power demand for cooling were key drivers of Asia's LNG consumption.

In contrast, Europe's LNG imports declined to their lowest levels since 2021, constrained by high storage levels, milder 2023/2024 winter, and stable pipeline flows from Norway and Russia. However, by year-end, a combination of falling storage levels, multiple dunkelflaute events, and the termination of Russian gas transit through Ukraine contributed to a renewed increase in LNG demand – positioning the region for an LNG import rebound in 2025 that significantly shaped global LNG trade dynamics in the first half of 2025.

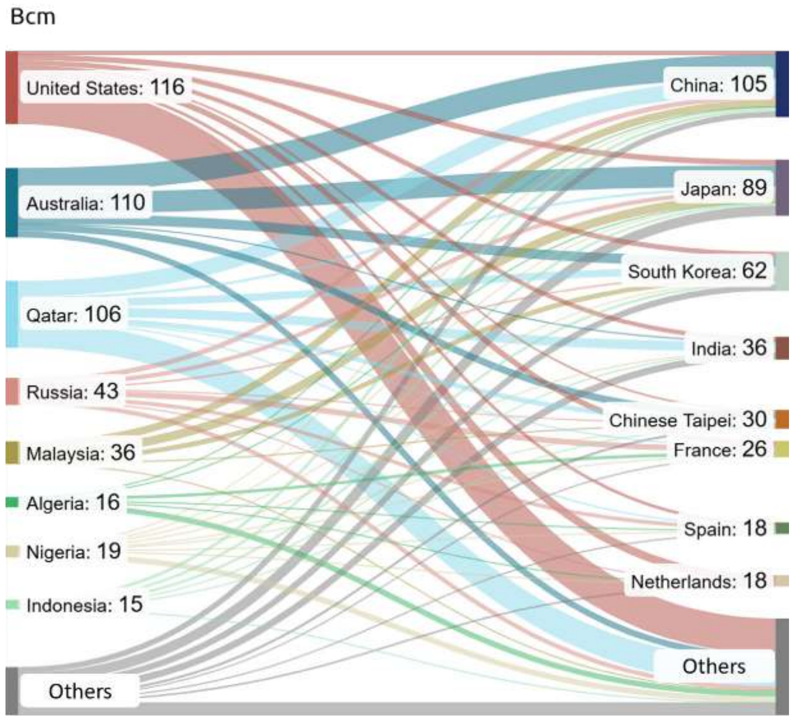
From January through June 2025, the global LNG trade totaled 340 Bcm, representing an estimated 6 Bcm (2.2%) increase compared to the same period last year. LNG imports into Europe rose by 16 Bcm (23.6%), with a record 17 bcm LNG imported in March alone. The US-Europe corridor strengthened significantly, with American LNG volumes accounting for 48 Bcm LNG (57.6%) of total imports. Imports remained elevated throughout the second quarter to support storage replenishment, following substantial drawdowns earlier in the year.

In contrast, import activity in Asia was less robust, declining by 17 Bcm (8.8%). A milder winter, ample storage in key import markets such as China and Japan, and higher spot prices of LNG all contributed to weaker demand. Price-sensitive buyers, including India and Thailand, reduced their LNG purchases compared to 2024 levels. China, in particular, recorded a notable 10 Bcm (19.4%) decline in LNG imports over H1 2025 compared to the same period last year.

Developments in the Middle East also had a material impact on regional trade flows. Israel's shutdown of natural gas production at major fields led to the suspension of pipeline exports to Egypt and Jordan. In response, the importing countries implemented demand curtailments in non-essential end-use sectors to manage the supply gap. Egypt took additional measures to safeguard energy security in the near-term, securing LNG supply agreements for over 150 cargoes. The country is also ramping up its regasification capacity and is expected to launch two new FSRUs starting in August 2025.

Net pipeline gas trade rose by

Figure 12: Global LNG trade flows for 2024 for top net importers and exporters



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

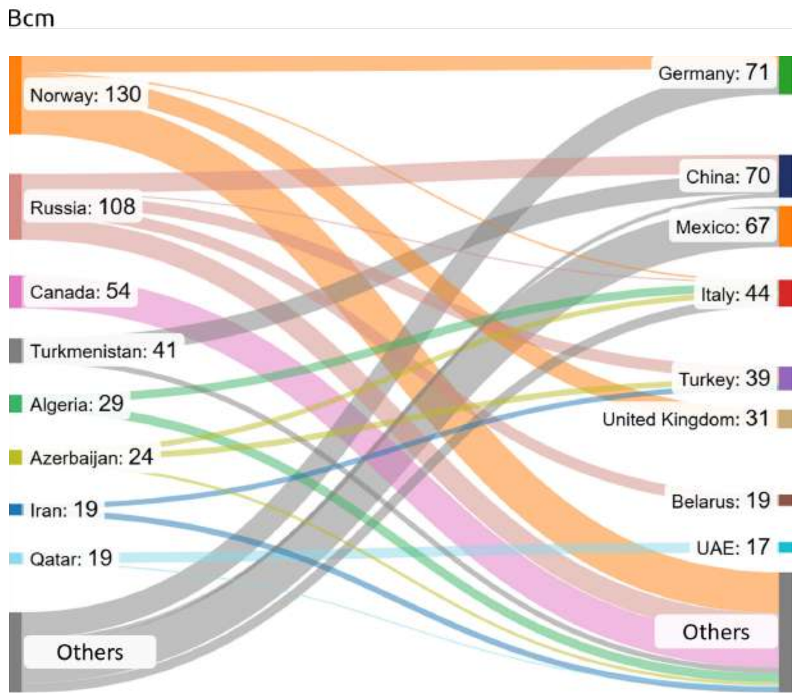
Source: Rystad Energy

46 Bcm y-o-y in 2024, led by Norway (+11 Bcm) and Russia (+14 Bcm). Norway's net pipeline exports grew to a record 130 Bcm, supported by stable upstream production, expanded capacity at the Kollsnes gas processing plant (now 156 million standard cubic meters per day), and no significant infrastructure outages. All volumes were delivered to other European countries as they continued to reduce their dependence on Russian gas. In contrast, Russian pipeline flows to Europe declined further, with limited intake by Central and Eastern Europe. Despite this, Russia's total pipeline exports still grew, with China emerging as its largest offtaker, receiving a record 31 Bcm gas via the Power of Siberia pipeline.

Germany, China and Mexico remained the global top pipeline gas importers, with China seeing the largest increase due to rising domestic demand. Iraq, which imports pipeline gas from Iran under a US-issued waiver, also saw imports rise by 3 Bcm in 2024. However, uncertainty around the continuation of the waiver has prompted Iraq to seek alternative sources of natural gas in 2025. On January 1, 2025, Russia's natural gas transit through Ukraine ceased with the expiration of the Ukraine transit agreement. Since then, Russian pipeline gas imports to Europe have fallen to 8 Bcm. Pipeline gas supply from Norway also trended lower this year, declining by 3 Bcm (4.7%) due to unscheduled maintenance that extended into June, reducing natural gas availability. Meanwhile, although LNG imports declined, pipeline imports to China remained steady, growing by 4 Bcm (10.4%) in the first half of 2025. Further growth is expected as flows through the Power of Siberia pipeline, which supplies Russian gas, continue to ramp up.

In 2025, considering both pipeline flows and LNG, global net exports of natural gas are projected to

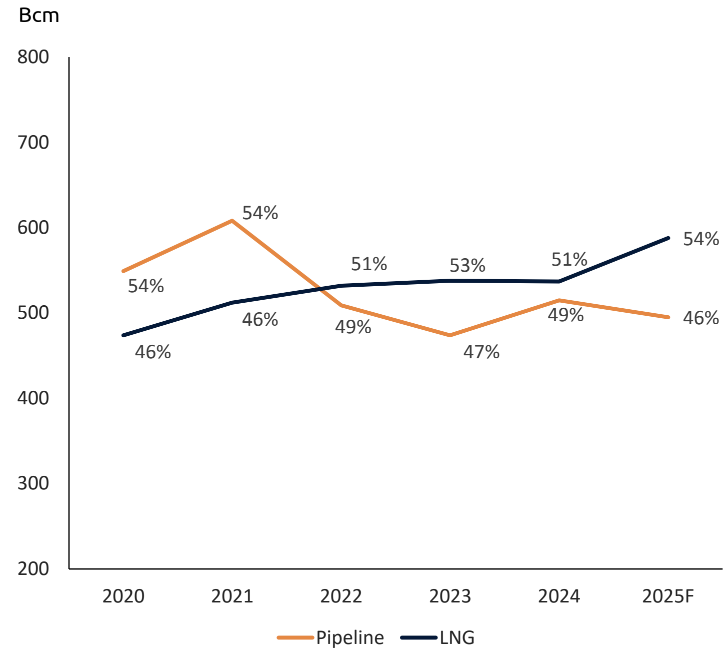
Figure 13: Global pipeline trade flows for 2024 for top net importers and exporters



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

Source: Rystad Energy

Figure 14: Global net natural gas export volumes, split by flow type



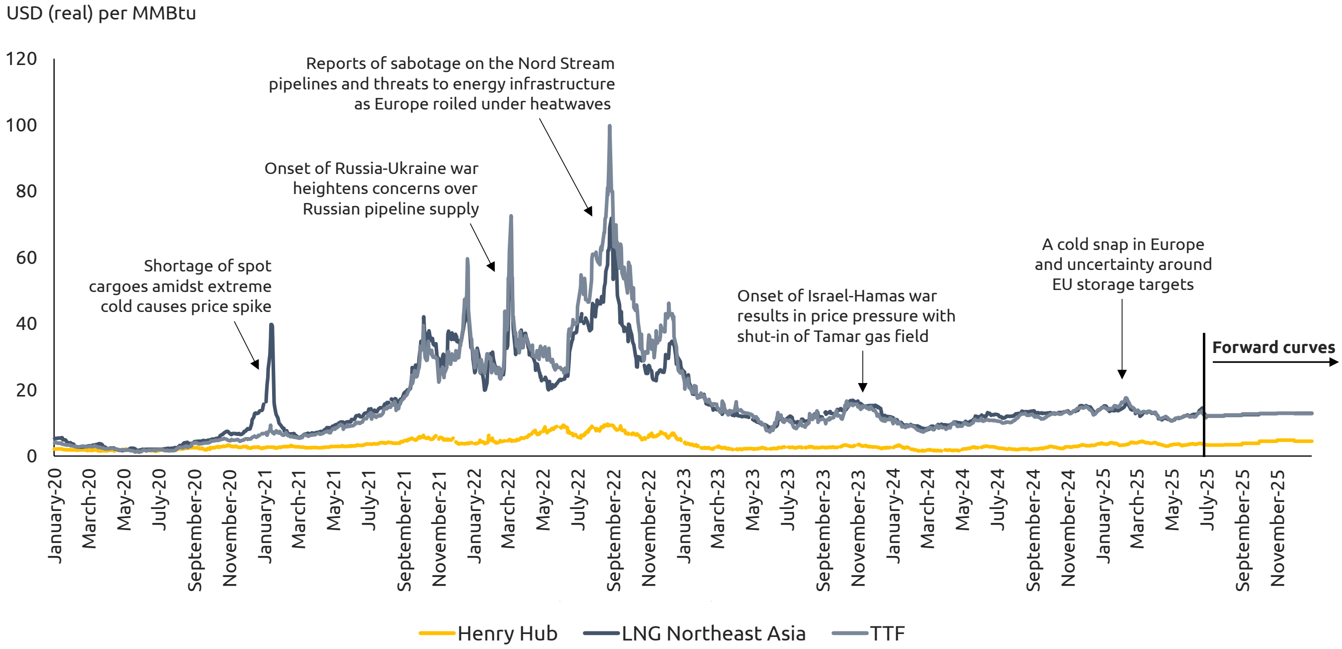
Note: Global gas export volumes are calculated on a country-by-country basis, aggregated at a global level. They are also net, subtracting imports from exports at a country level.

Source: Rystad Energy

grow by 23 Bcm, driven primarily by LNG. Despite persistent geopolitical uncertainty and risks at key maritime chokepoints, LNG trade has remained stable, underscoring the sector's adaptability. In Europe, LNG continues to play a central role in supporting energy security. In parallel, natural gas is being positioned as a strategic fuel within the energy strategies of key developing economies such as China, India, and Indonesia. LNG, with its ability to connect remote supply with high-growth demand centres, is expected to remain an instrumental enabler in this transition.

b. Prices

Figure 15: International natural gas prices



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

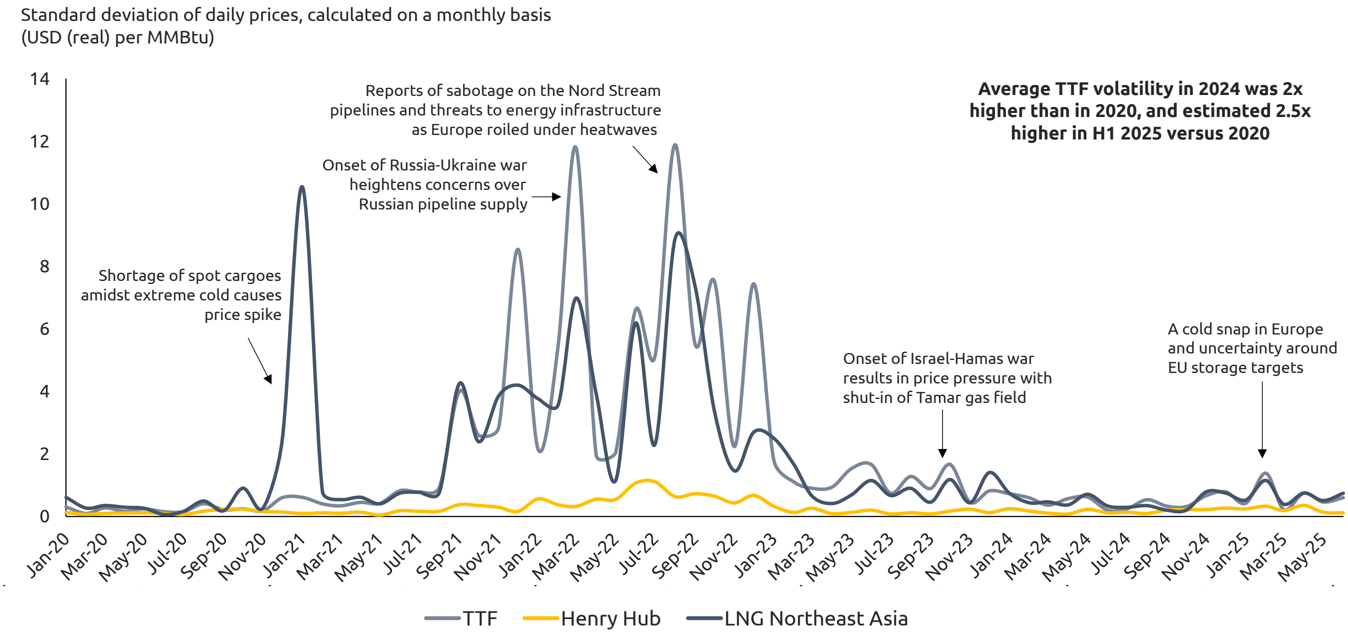
Source: Rystad Energy, Argus (LNG Northeast Asia)

Natural gas prices across major benchmarks remained somewhat subdued throughout 2024. While the year did not see pricing shocks on the scale of 2022, however, the markets remained responsive to evolving geopolitical developments and weather patterns.

In contrast, during the first half of 2025, natural gas prices trended higher than the same period last year and were more volatile. The TTF benchmark remained elevated, underpinned by strong demand in Europe, which also drove up Northeast Asia spot price for LNG - reducing spot procurement activity in Asia in the process. Henry Hub prices similarly trended higher, avoiding the 2 USD/MMBtu range seen in 2024 and recording a two-year high earlier in the year. In 2024, TTF averaged 11.0 USD/MMBtu (34.7 €/MWh), marking a 17.0% y-o-y decrease from 2023. Prices fell to 7.0 USD/MMBtu (22.1 €/MWh) in late February, driven by warmer-than-normal temperatures and robust storage levels, before rebounding in March amid reduced Norwegian natural gas output. From March to May, TTF traded in the 8.0-10.0 USD/MMBtu (25.3-31.7 €/MWh) range. Supply disruptions in Norway, LNG outages in the US, and rising tensions between Iran and Israel later pushed prices above 10.0 USD/MMBtu (31.7 €/MWh). By mid-August, the benchmark exceeded 12.0 USD/MMBtu (37.2 €/MWh), driven by maintenance on the Norwegian Continental Shelf (NCS), forecasts of colder-than-average winters, and intensifying Middle East tensions. The 2024 peak of 14.9 USD/MMBtu (48.5 €/MWh) was reached in December amid heightened supply security concerns following Ukraine's announcement to halt Russian gas transit through its territory starting from January 2025.

The year 2025 has begun with heightened volatility. TTF remained elevated through January, then surged to 17.6 USD/MMBtu (58.4 €/MWh) in mid-February driven by a cold snap and uncertainty around EU storage targets. Prices fell back to 13.5 USD/MMBtu (44.7 €/MWh) following reports of a possible

Figure 16: International natural gas prices volatility



Source: Rystad Energy, Argus (LNG Northeast Asia)

US-brokered Russia-Ukraine peace deal and discussions to relax EU's storage refill targets. By April, with Europe entering its shoulder season, prices settled in the 10.0–13.0 USD/MMBtu (29.7-38.6 €/MWh) range. This was relatively higher than last year, as elevated prices were supported by Europe's ongoing storage injection needs that kept LNG import demand strong.

Volatility returned in June 2025 amid escalating geopolitical tensions in the Middle East. TTF prices spiked to 13.7 USD/MMBtu (40.6 €/MWh) as markets speculated on the conflict's scale, duration, and the potential closure of the Strait of Hormuz. However, prices eased following announcements of a ceasefire.

Throughout 2024, the Northeast Asia spot price for LNG closely tracked TTF, averaging an estimated 1.0 USD/MMBtu higher. Softer demand in Europe kept spot LNG prices below 2023 levels, enabling greater procurement by price-sensitive buyers such as India and Thailand in Asia. Northeast Asia spot LNG prices rose to 12.0 USD/MMBtu around July, driven by heatwaves in Japan and South Korea in East Asia, and supply outages at LNG plants in APAC and the US. Towards year-end, spot LNG prices were tracking TTF at a slight discount, fluctuating between 12.0-15.0 USD/MMBtu before closing the year at 14.1 USD/MMBtu. This trend continued in 2025, with Northeast Asia spot price for LNG directionally following TTF. Prices briefly surged past 17.0 USD/MMBtu in February but ended the month around 13.6 USD/MMBtu, as high inventories in Japan and South Korea tempered spot buying activity despite cold weather. Unlike the previous year, Northeast Asia spot prices for LNG did not fall below 10 USD/MMBtu during the shoulder season, settling in the 11-13 USD/MMBtu range, which impacted the spot LNG procurement activity in Asia. In June, prices temporarily spiked to 14.5 USD/MMBtu amid escalating conflict in the Middle East that unsettled global energy markets.

In the US, Henry Hub traded below 2.0 USD/MMBtu from February to April 2024, suppressed by mild winter weather, which caused operators to shut in production and scale back drilling activity. Prices rose to 3.0 USD/MMBtu in June, supported by increased cooling demand and higher feed gas consumption as Freeport resumed operations. In early 3rd quarter, Henry Hub prices dipped again following disruptions to LNG facilities caused by Hurricane Beryl. Prices remained subdued through summer and fall, delaying any recovery in drilling until late 2024 and into the peak winter period of January and February 2025. However, Henry Hub has trended higher since the start of 2025, with prices ranging between 3.5-4.5 USD/MMBtu through most of the first quarter. The benchmark reached a two-year high of 4.3 USD/MMBtu in March 2025, as extreme weather caused well freeze-offs and increased heating demand, and increased liquefaction capacity came online. In June 2025, geopolitical developments in the Middle East also impacted Henry Hub prices, which briefly climbed to 3.9 USD/MMBtu at the end of June before returning to pre-crises levels. Looking ahead, prices are expected to remain buoyed through 2025 by growing feed gas demand, with Plaquemines LNG (Phase 1) nearing full capacity by year-end, while Corpus Christi Stage 3 continues its ramp up, albeit at a slower pace.

2/ Operating in an Uncertain Future - Mitigating Risk

Chapter highlights

Recent trends suggest that global energy demand is expected to trend upwards over the next decade

- Power consumption is expected to surge in China and India, positioning Asia as the key driver of energy demand, supported by North America
- Despite economic headwinds and mounting pressure on energy-intensive industries, European energy demand is likely to remain steady until 2030, amid the unpredictable pace of energy efficiency improvements

Uncertainties from shifts in technology, climate and geopolitics are risking misalignment between planned supply and demand

- Rising heatwaves are driving higher cooling demand, with 80% of countries in Asia Pacific facing peak power loads or disruptions in 2024
- Accelerating US-led AI data centre growth, accounting for ~1.5% of global electricity demand in 2024 and expected to rise to ~1.7% in 2025, is making it difficult to project future energy demand

If current trends continue, energy demand growth will likely outpace scenario pathways

- Energy demand growth could exceed most scenario projections for 2030 by as much as 8-90 EJ if recent trajectories persist
- While making investment decisions, it is important to align energy planning with observed trends and ensure system readiness for higher demand outcomes, especially by scaling up reliable and flexible energy sources

Targeted investments are required in gas supply, infrastructure and storage to mitigate the risk of energy shortfalls

- Natural gas is well-positioned as a force of resilience serving as a key element of a reliable, flexible, affordable and climate-ready energy system, especially when integrated with carbon capture
- Despite ~270 Bcm liquefaction capacity planned to come online by 2030, risks of delays to the next LNG wave exacerbate supply shortfall risks

Based on recent trends, global energy demand is likely to rise over the next decade, with particularly strong growth expected towards 2030. Asia, currently the largest contributor to global energy demand, is projected to remain the key driver of growth boosted by growing power demand in markets such as China and India. This is especially relevant in the context of the rising frequency of heatwaves, which are increasing energy demand in the buildings sector through increased cooling needs. Notably, China's power demand has been growing faster than GDP since 2020, currently standing at almost twice that of US and eighteen times Germany's.

Similarly, North America's growing power demand, supported by data centre expansion in the US, is also likely to contribute to global energy demand growth. Moreover, Trump's re-election has resulted in the active promotion of the oil and gas industry, potentially giving new impetus to the sector.

Europe's energy-intensive industries remain under pressure, due to sluggish economic growth domestically and growing competition in export markets. If not addressed, high energy prices could pose a risk to the EU's competitiveness, potentially lead to a gradual decline in industrial activity, and ultimately dampen future energy demand growth in Europe. However, the pace of electrification and energy efficiency improvements remains unpredictable with European energy demand likely to stay robust towards 2030.

The observed trend of rising global energy demand suggests that there may be certain unfolding risks, threatening to disrupt supply security and alter demand dynamics with markets being compelled to adapt, often at a higher cost. The difficulty in accurately estimating the momentum with which demand will develop, especially given the evolution of economies, politics, technologies and climate around the world, heightens global energy uncertainty.

To mitigate these risks, it is essential to implement targeted investments throughout the supply chain, complemented by appropriate policy measures designed to ensure future readiness, as detailed later in this chapter.

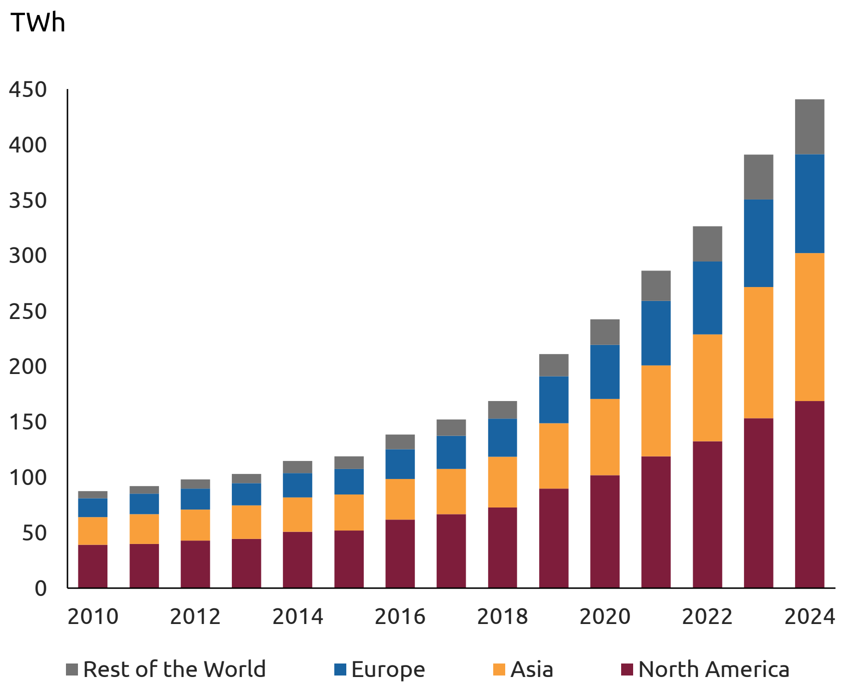
I. An age of uncertainty: examining shifts in technology, climate and geopolitics

The pace of the energy transition remains unpredictable, with potential for both rapid acceleration and slowdown, complicating energy planning, especially for systems reliant on stable, long-term projections of demand and capacity. Technological shifts, such as the rapid rise of Artificial Intelligence (AI), are reshaping consumption patterns while straining power grids, making it increasingly difficult to project their future growth. External uncertainties also arise from climate-related events with the pace of the transition determining the levels of global warming and resulting in hard-to-anticipate extreme weather events. These developments are occurring against the backdrop of major geopolitical events, which are themselves disrupting traditional energy trade flows and complicating global demand and supply dynamics, especially in the case of natural gas (and LNG). Prevailing uncertainties may result in indecision regarding the optimal future energy mix and corresponding investment strategies. The lack of visibility on how demand, policy, technology, climate and the energy transition will evolve increases the perceived risk of costly long-term commitments, hindering decision makers' ability to identify and prioritise the necessary technologies at the right time. This indecision, in turn, can delay progress on energy infrastructure development, technology planning, and emissions reduction efforts. Thus, understanding and planning for these shifts is crucial for ensuring preparedness for the future of energy demand.

a. Data centre boom as a key driver of structural increases in electricity demand

AI has rapidly evolved into a transformative, general-purpose technology, reshaping industries and economies with trillions in market value driven by technological breakthroughs, data growth, and declining computing costs. AI has the potential to significantly impact the energy sector, particularly through heightened electricity demand from data centres. According to the IEA, a conventional AI-focused data centre consumes as much electricity as 100,000 households, with some of the largest ones under construction today having the potential to consume 20 times as much[2]. In 2024, data centres consumed ~1.5% of global electricity, and this is projected to grow even further to ~1.7% in 2025. The US contributes the largest share of global data centre electricity consumption at 35% in 2024, followed by

Figure 17: Global electricity consumption of data centres by region



Source: Rystad Energy

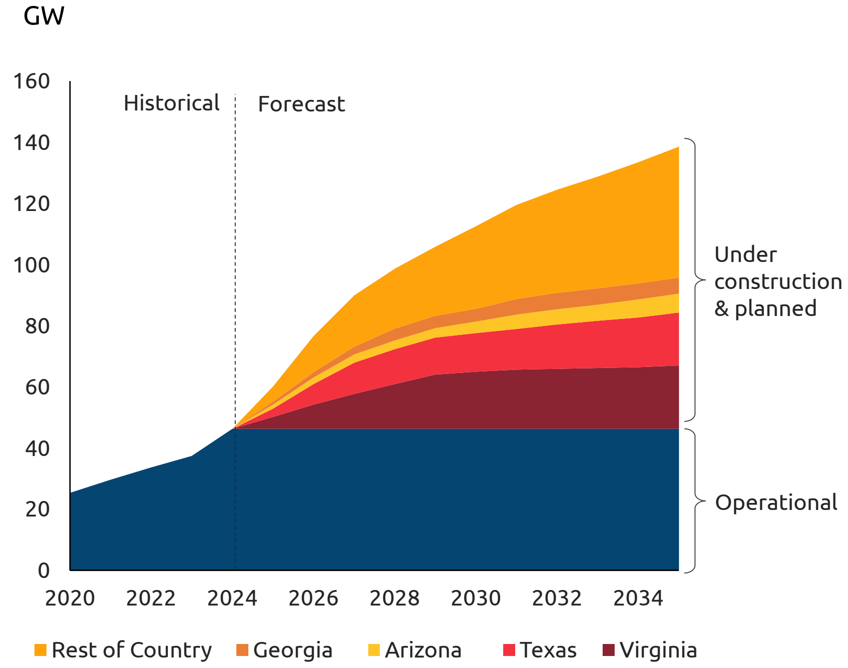
[2] *Source: Energy and AI, IEA (April 2025); https://www.iea.org/reports/energy-and-ai.*

China and Europe. The country leads the charge in the rapidly evolving data centres boom, with data centres projected to account for an increasingly larger share of its power demand. The US is estimated to host around 40% of globally installed data centre capacity, with operational capacity reaching close to 45 GW in 2024, and most of the facilities concentrated in three states – Virginia, Texas and Arizona.

Moreover, favourable conditions such as low-cost energy, tax incentives and robust fibre infrastructure position the US as one of the most attractive markets for data centres development globally. US data centre capacity is expected to continue growing at a swift pace, with around 73 GW in new capacity planned for the next five years. Amazon, Google, Microsoft and Meta are driving near-term US data centres growth, with joint ventures likely to shape long-term expansion. In Q4 2024, Google announced a substantial increase in its capital expenditure (CAPEX) plans, projecting a USD 75 billion investment for 2025, up 43% from 2024. This amount is comparable to Microsoft's USD 80 billion CAPEX for its current fiscal year and exceeds Meta's expected USD 60–65 billion. Additionally, Project Stargate, which aims to invest USD 500 billion in new AI infrastructure over four years led by OpenAI, SoftBank, Oracle and MGX, has extensive policy and regulatory support from the Trump administration.

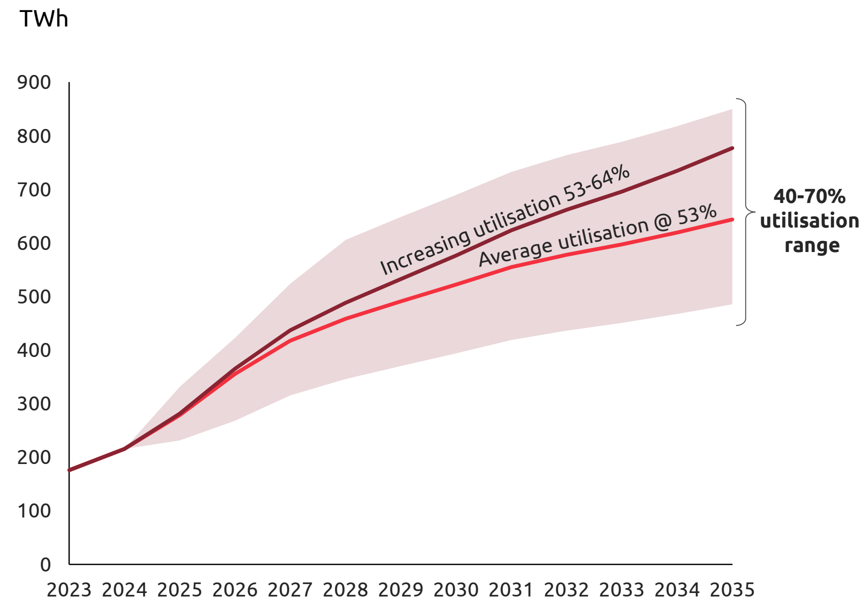
These trends point towards sustained growth even though the extent may vary. US data centres capacity could reach ~140 GW by 2035, driving demand to nearly 650 TWh based on an average assumed utilisation rate of 53%. The likelihood of rising infrastructure utilisation and an expanding project pipeline poses upside risks to this demand forecast. Yet, uncertainty remains

Figure 18: Operational US data centres capacity and project pipeline



Source: Rystad Energy

Figure 19: US data centres electricity demand based on existing project pipeline



Note: 1) The 'average utilisation' demand line assumes 53% utilisation of the existing project pipeline capacity for all years from 2025-2035, based on the historical average utilisation of data centre capacity in the US. 2) The 'increasing utilisation' demand line assumes that utilisation of data centre capacity increases from the historical average of 53% in 2025 to 64% in 2035 at a gradual rate to reflect uncertainty around the pace of AI adoption.

Source: Rystad Energy

around the pace of AI adoption, its productivity gains, efficiency improvements, and resolution of energy sector bottlenecks. Notably, the development of large data centres will depend on three key factors – stable energy supply, transmission availability and fibre network connectivity, especially in American states emerging as AI data centre hubs.

Outside of the US, regulatory complexities further contribute to uncertainty regarding the ultimate demand potential of data centres. For instance, data sovereignty rules and cross-border restrictions such as the EU's General Data Protection Regulation (GDPR) and China's cybersecurity law are limiting the use of global data centres by forcing local data storage. Nordic countries offer attractive conditions for data centres development due to their abundant emission-free energy, low electricity prices, and cold climates that naturally reduce cooling costs. Yet, development in the region also faces risks; notably, Finland's proposal to abolish electricity tax breaks for data centres could stall future growth.

Despite uncertainties around operating data centres at scale, there is an evident increase in their demand globally. Power grids are being strained by data centre expansions due to their constant, high electricity demand and grid integration challenges. This has encouraged the integration of alternative energy sources and development of microgrids to ensure energy security and sustainability. Some regions such as Western Australia, where data centres could double power demand, are increasingly exploring behind-the-meter power generation to tap on-site renewable energy, boosting resilience to grid disturbances. Similarly, data centres in the US are exploring off-grid options such as mobile gas turbines, nuclear small modular reactors (SMRs), renewables, and storage. Yet, few developments are expected to fully disconnect from the grid, leaving grid-based generation, particularly from natural gas, as the dominant power source for the sector. Natural gas is a reliable and affordable energy source for powering data centres helping grid operators and developers stay competitive. Aided by its high dispatchability and flexibility to meet both steady and dynamic demands, natural gas is essential for navigating the volatile energy demands of AI applications. While renewables and storage continue to simultaneously scale, energy-intensive data centres will require a dependable energy source such as natural gas to mitigate operational disruptions.

b. Rising cooling needs during heatwaves challenge power system reliability

2024 saw a number of extreme weather events, including intense heatwaves, in the northern hemisphere summer, extreme pre-monsoon heat across continents and a strong El Niño, culminating in the warmest year on record. In Europe, the fastest warming continent, record-high annual temperatures were experienced in almost half the region alongside severe storms and widespread flooding. According to the World Meteorological Organization, there is 80% chance that at least one of the next five years will exceed 2024 as the warmest on record and 86% chance that at least one of next five years will be more than 1.5°C above the 1850-1900 average[3]. This indicates a persistent risk of increasingly hot weather in the coming years, with rising pressure on electricity grids, driven by heightened cooling demand during heatwaves.

In 2024, over 40 countries representing almost 70% of the world's electricity demand, including Brazil, China, India, Mexico, and the US hit new peak electricity demand during heatwaves. Close to 80% of countries in both Latin America and Asia Pacific saw either record peak demand during heatwaves or significant heat-induced grid disruptions. The Middle East and North African regions closely followed with 70% of countries in the region experiencing one of the two phenomena. There is a clear relationship between peak power demand and average temperatures during seasons with higher cooling needs, wherein an increase in the latter is exerting upward pressure on peak demand, straining grids, and resulting in outages. For instance, in Brazil and Türkiye, a 1°C temperature rise results in an additional 3.6 GW and 2 GW of electricity demand, respectively[4].

A closer examination of selected countries in South and Southeast Asia highlights the significant impact of heatwaves in 2024 on monthly peak power demand, which reached record highs across the region during the year. In India, while the year-on-year growth in 2024's monthly peak demand was 3%, the increase was particularly pronounced during the summer months of April to June, with a 9% rise since the same period in 2023. By April 2025, peak demand levels had already exceeded those of 2024,

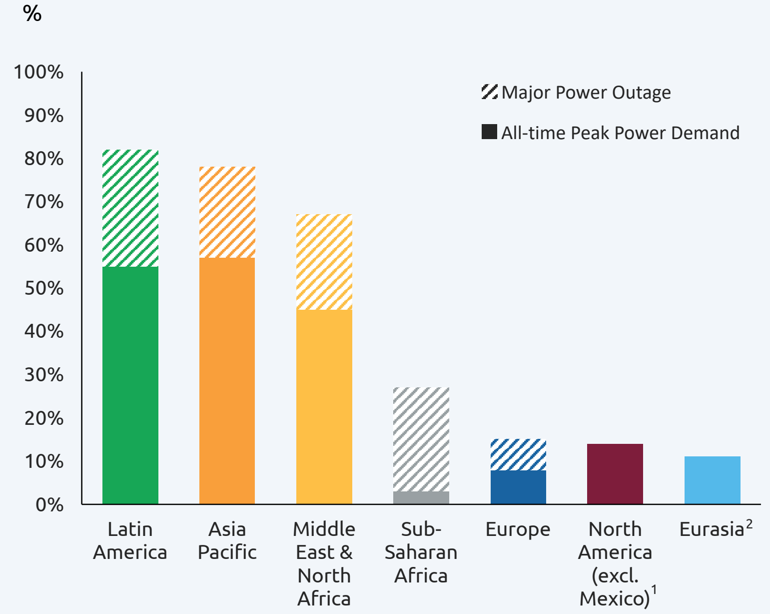
[3] *Source: Global climate predictions show temperatures expected to remain at or near record levels in coming 5 years, World Meteorological Organization (May 2025); https://wmo.int/news/media-centre/global-climate-predictions-show-temperatures-expected-remain-or-near-record-levels-coming-5-years*

[4] *Source: Energy Efficiency 2024, IEA (November 2024); https://www.iea.org/reports/energy-efficiency-2024*

with the government forecasting a summer peak of 277 GW. In contrast, May 2025 saw relatively subdued peak demand, attributed to unseasonal rainfall and a slowdown in industrial activity. Nonetheless, in June 2025, peak demand is reported to have reached 243 GW – just short of the record set in June 2024, a year marked by unprecedented electricity demand.

In April 2024, the typical season of high temperatures in Thailand, the country witnessed a 13% year-on-year growth in peak power demand. Moreover, high temperatures in April caused power demand to peak earlier than usual in 2024, compared to the previous five years. As of April 2025, temperatures hit 40°C, pushing peak demand close to last year's record of ~36 GW. In Philippines, intensifying heat during the dry season and effects of the El Niño drove 2024's first quarter peak demand to the highest in a decade (~19 GW). While peak demand rose across the year, the months of April-June saw ~12% year-on-year

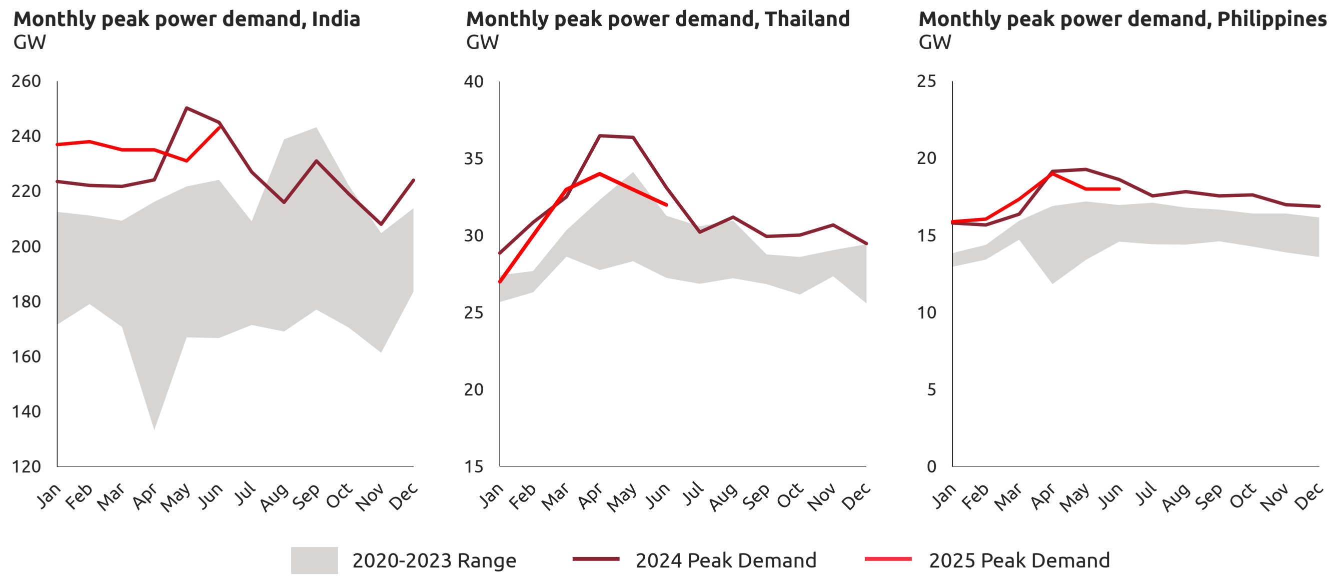
Figure 20: Share of countries in a region that reached all-time peak power demand or faced major demand outages due to extreme heat events, 2024



Notes: **1)** North America's share is based on 14 major regional transmission organizations (RTOs) and independent system operators (ISOs) across the United States and Canada. **2)** Eurasia includes Russia, Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan. **3)** Countries that experienced both electricity demand records and outages are counted in only one category

Source: IEA[5]

Figure 21: Distribution of monthly peak power demand in India, Thailand and Philippines



Source: Rystad Energy

[5] *Source: Energy Efficiency 2024, IEA (November 2024); https://www.iea.org/reports/energy-efficiency-2024*

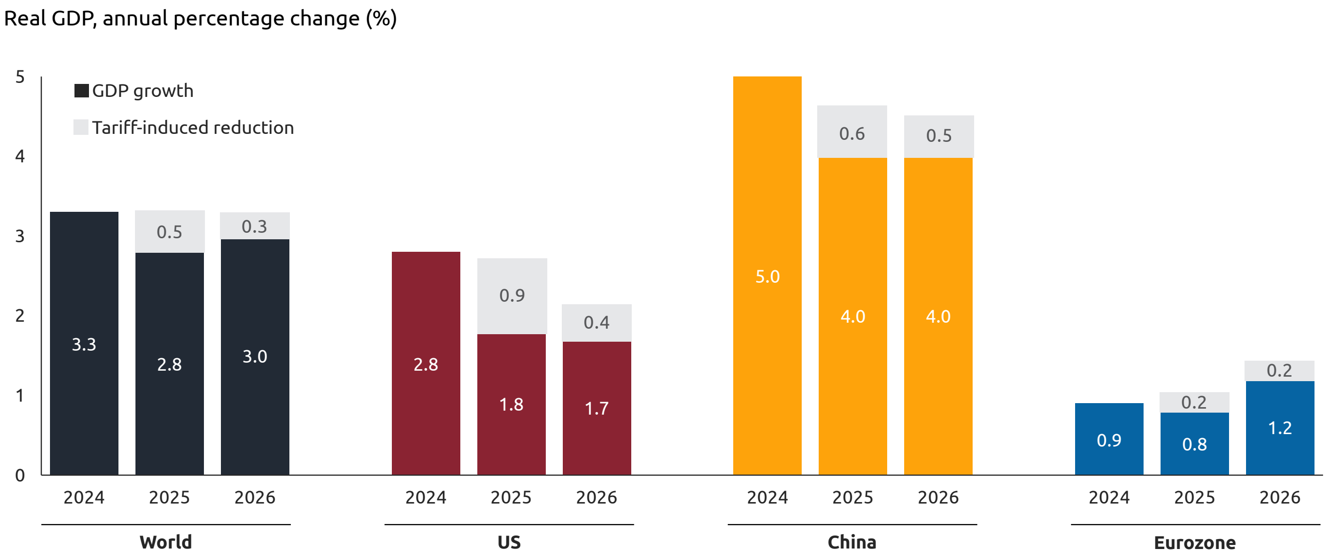
growth, which was higher than the annual average of 8%. This year, in March 2025, yellow alerts were issued as demand-supply imbalances re-emerged with early-season surges and demand inching towards 2024 levels, before witnessing a slight decline in May.

Higher maximum daily temperatures go hand-in-hand with rising air conditioner (AC) ownership, incentivised by countries' economic conditions and people's growing purchasing power. AC sales are on the rise with sales volumes in India increasing 25% year on year between 2021 and 2023, while 2024 witnessed the country's highest ever sales[6]. In developing nations of sub-Saharan Africa and Brazil, sales are set to grow further with increasing income levels. Yet, most air conditioners being sold display low levels of efficiency, requiring more electricity than higher-efficiency models to deliver the same level of cooling. If households do not make the choice of switching to higher-efficiency models, there is a risk of significantly greater strain being placed on power systems, with the upcoming years experiencing unusually high peaks in demand, especially during heatwaves.

Countries are increasingly trying to scale up renewables, especially solar power, to meet heatwaves-induced power demand. For instance, in the month of June 2024 alone, solar powered generation in China witnessed a 28% year-on-year increase. However, prominent Asian regions that faced heatwaves continue to rely on coal, driven mainly by its cost effectiveness. As such, countries including China, India and Philippines ramped up production from the highly emissions-intensive fuel during peak summer, contributing towards global coal demand increasing by 1% in 2024. Natural gas can offer a lower carbon and more flexible alternative to coal-based generation, suitable for both environmental considerations and peaking needs of high summer demand, respectively.

c. US policy and trade tariffs set to reshape global natural gas market dynamics

Figure 22: International Monetary Fund GDP growth projections



Source: Rystad Energy, IMF

Regional energy demand and supply growth is also susceptible to cross-border political strains, which can shift demand trajectories with little notice. For instance, ongoing US-China trade negotiations have the potential to significantly influence the global oil demand outlook. Easing tensions may spur manufacturing activity, boosting petrochemical feedstocks demand, while gasoline and diesel demand would likely decline as EVs continue to gain larger market share. Furthermore, trade tariffs, sanctions, and domestic regulatory constraints add layers of complexity to demand and supply outlooks, reinforcing the need for diversified supply strategies and robust contingency planning in the natural gas and LNG sectors, as elaborated in the case study presented in this section.

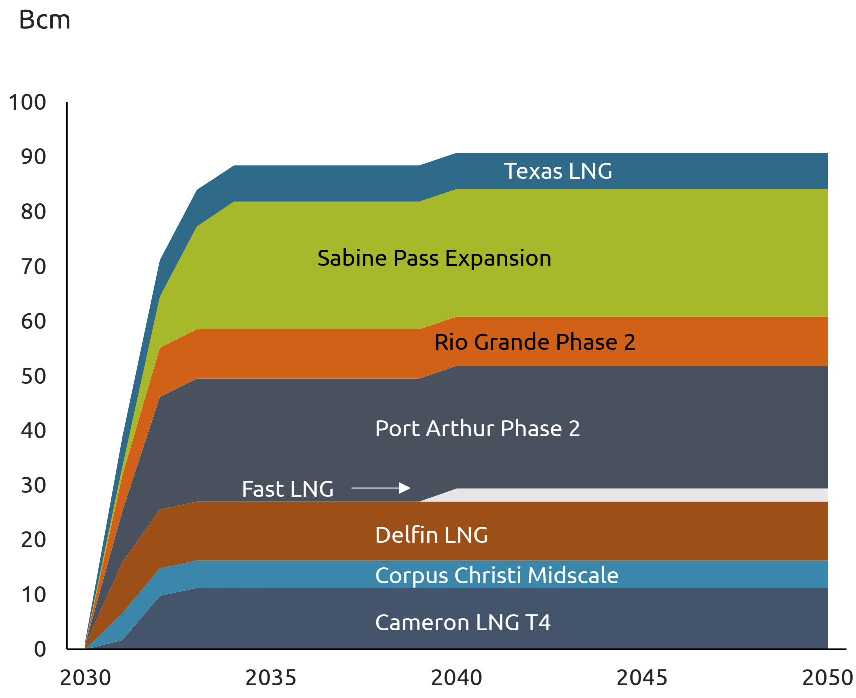
A key development has been the imposition of tariffs on US imports on April 2, 2025, by the Trump administration. These broad and escalating tariffs, which currently vary by country, are expected to dampen global LNG demand by slowing overall

[6] *Source: Energy Efficiency 2024, IEA (November 2024); https://www.iea.org/reports/energy-efficiency-2024*

economic activity, particularly in export-driven sectors outside of the US. Alternatively, tariffs could possibly lead to new US LNG volumes coming online if they help in securing long-term export contracts that incentivise additional Final Investment Decisions (FIDs), which might not have materialised under normal market conditions.

Reputable institutions such as the International Monetary Fund (IMF) have revised global GDP growth projections downwards expecting US trade policy to translate into a 0.5 percentage point reduction in global GDP growth in 2025 and a 0.3 percentage point reduction in 2026. The projections for China, one of US' largest trading partners, show an even more severe dip at 0.6 percentage points in 2025 and 0.5 in the subsequent year. While the link between GDP and natural gas demand varies by region and sector, **slower economic growth typically reduces gas consumption, particularly in LNG-importing countries, thereby shrinking global LNG demand and US export potential**. The industrial sector is most exposed, with gas-intensive industries like chemicals and steel directly cutting usage during downturns. In the EU, a 1% GDP decline could reduce industrial gas demand by 3.3 Bcm in 2025, based on past elasticities. **Additionally, tariffs pose a targeted risk to export-oriented sectors**; for instance, US-bound exports account for 12-16% of China's steel, glass, and ceramics output, with tariffs potentially resulting in gas demand losses of 2.7 Bcm in these sectors in 2025.

Figure 23: US LNG pre-FID production outlook



Source: Rystad Energy

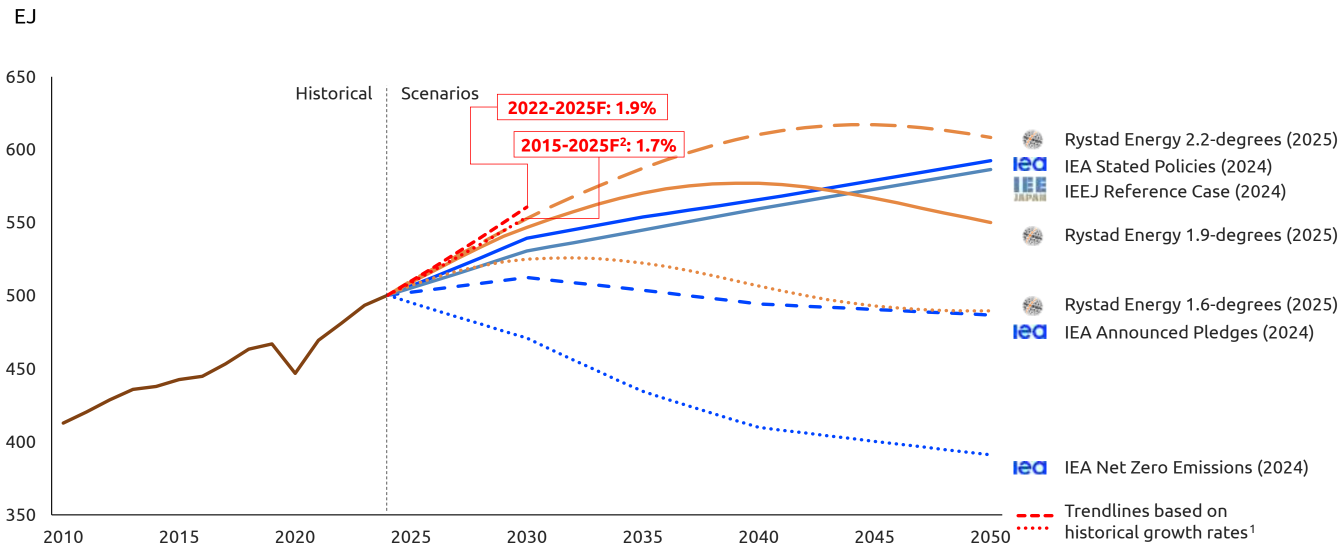
US tariffs appear to influence the structure and timing of Sale and Purchase Agreements (SPAs), raising uncertainty about how project FIDs and eventually global LNG trade could be affected. Exports from pre-FID US projects were already forecasted to rise rapidly, positioning US projects as crucial for balancing the global LNG market. The high expected utilisation rates of US facilities leave limited room for incremental exports. As such, SPAs linked to projects already expected to reach FID largely represent a shift from spot sales to long-term contract sales, rather than new volumes. However, SPAs tied to projects with weaker prospects could prove pivotal if they help trigger an unexpected FID, though they remain inconsequential if they fail to alter the project's trajectory.

II. Readiness in an era of high energy uncertainty: scenarios vs. forecasts

Amid a world increasingly shaped by climate change, evolving geopolitical dynamics, and rapid economic and technological progress, **global energy demand is experiencing a significant and sustained rise. This upward trajectory is expected to persist across regions**. While certain areas may face long-term structural declines, emerging sources of demand, particularly within the power sector, are poised to offset these trends. Factors such as the expansion of data centres and rising cooling needs are anticipated to be key drivers of continued energy consumption growth.

Many institutions, such as Rystad Energy, the International Energy Agency (IEA) and the Institute of Energy Economics, Japan (IEEJ) among others, project the future of energy demand using a myriad of scenarios. Some projections, such as IEA's Net Zero Emissions by 2050 scenario (NZE) and Rystad Energy's pathways, are back-casted from the assumed

Figure 24: Global final energy demand scenarios from various institutions



Notes: 1) This analysis considers two trendlines based on historical growth rates: the 2022-2025F trendline and the 2015-2025F 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, respectively 1.9% and 1.7%. **2)** The 2015-2025F 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

attainment of specific decarbonisation or climate goals. Others, such as IEA's Stated Policies scenario (STEPS), are exploratory in nature assuming different sets of starting conditions. This implies that scenarios are designed not as forecasts, but as analytical tools to explore how varying trends may shape the global energy landscape. As such, they may differ from the actual growth trajectory observed in recent years and, should current geopolitical and trade tension resolve and Asian growth continue, they may fall short in accurately anticipating future energy demand, with dire consequences for energy systems globally if proper supply security investments are not realised.

The figure above illustrates that most scenarios understate the trend of energy demand growth observed in recent years. For instance, IEA's STEPS, which reflects the trajectory of demand based on governments' adopted measures, projects 1.3% growth on average towards 2030. Similarly, Rystad Energy's base case scenario, which is consistent with a 1.9°C temperature increase compared to pre-industrial levels, projects demand to grow at a rate of 1.4-1.5% towards 2030. If energy demand continued to develop at the 1.7% growth rate observed over the past ten years, it would outpace the more conservative projections of these scenarios. The gap becomes even more pronounced when considering the 1.9% average annual growth recorded over the past three years, as represented by the 2022-2025F trendline. To put this in perspective, this trendline could exceed scenario projections by as much as 8-90 EJ when compared against the different scenarios assessed. As such, even Rystad Energy's more extreme climate scenario, which assumes that global warming will be limited to 2.2°C, underestimates recent demand growth by 8 EJ.

Thus, if recent trends in energy were to persist, future demand would outpace the projections embedded in many leading scenarios, exceeding the demand expectations for 2030. Consequently, demand declines projected in Rystad Energy's scenarios and IEA's Announced Pledges Scenario (APS) and NZE could be pushed further into time than what is currently projected. As such, relying on back-casted scenarios alone for energy supply and investment planning can significantly heighten the risk of misalignment between planned supply of low-carbon energy and the realities of demand. Given actual growth trajectories from the past few years, it is instrumental to also plan for a high demand outcome in order to mitigate the risk of increased market volatility and full-blown energy crisis. While deciding the optimal energy mix, governments must adopt an approach balancing considerations such as long-term emissions reduction goals with recently observed growth trends.

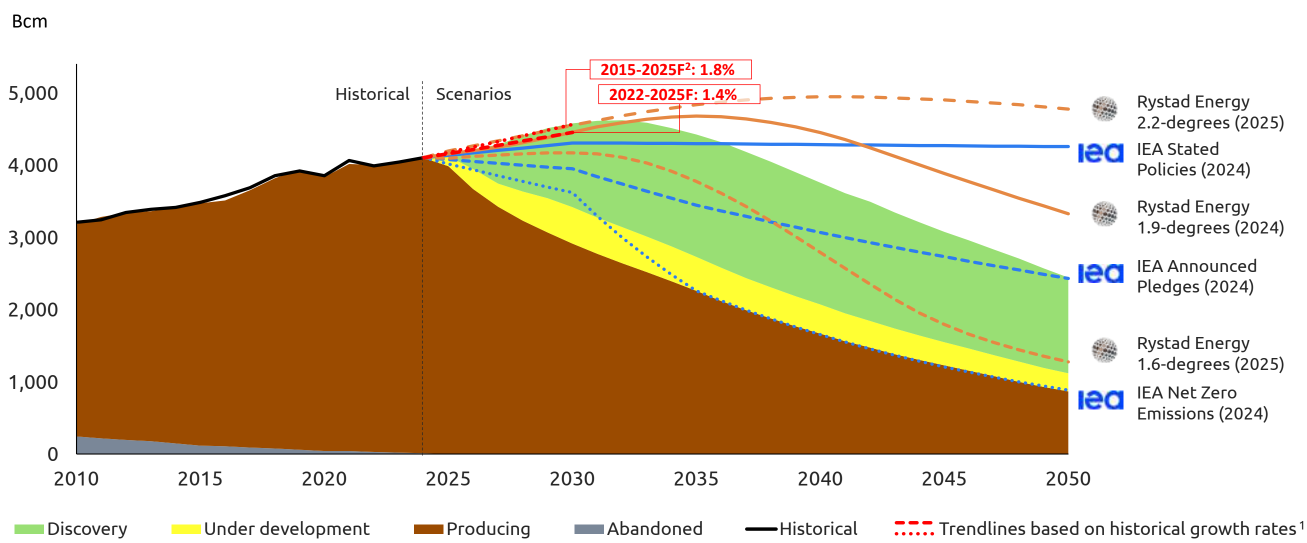
III. Mitigating risk through strategic investment in natural gas

As energy demand continues to grow in the coming years, potentially exceeding projections in target-oriented scenarios if current trends persist, there is a pressing need to ensure preparedness for the future. To meet rising needs driven by emerging trends and expanding economies, while also progressing toward decarbonisation goals and safeguarding national interests, it is essential to balance energy sustainability, security, affordability, and flexibility. This balance is critical in planning robust energy systems capable of navigating the complexities of an uncertain future.

Gas is well-positioned as a force of resilience to mitigate the ongoing and impending energy uncertainty. As a lower carbon alternative to coal, natural gas can step in to increase energy security in emerging economies, especially for use in industrial processes. **The integration of natural gas with carbon capture and low and zero-CO_2 gases has the potential to further reduce the carbon intensity** of gas-fired power generation as well as other gas uses, such as consumption in buildings, industry and shipping. **Gas infrastructure built today can be future-proofed and repurposed for low-carbon gases** such as biomethane or hydrogen, thus ensuring long-term sustainability through current investment.

Offering system reliability, gas-fired power plays a vital role in supporting intermittent renewables like wind and solar, ensuring grid stability during periods of low generation due to its flexible nature. In this context, natural gas increasingly serves as an insurance for power systems, providing dependable power when renewable output falls short. This is becoming particularly relevant as natural gas is helping balance systems in regions with growing renewables capacity, as is explored in depth in Chapter 3.

Figure 25: Global gas demand-supply balance under various scenarios, supply split by lifecycle



Notes:

1) This analysis considers two trendlines based on historical growth rates: the 2022-2025F trendline and the 2015-2025F 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, respectively 1.4% and 1.8%. **2)** The 2015-2025F 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

Further, natural gas possesses fast ramp-up capability and dependable dispatchability to meet new loads from emerging demand drivers such as data centres. In line with this, the US is expected to ramp up natural gas production to meet fluctuating data centres demand using an energy source that offers reliability.

Gas has also proved itself a vital component of global energy security. LNG trade has historically offered cross-border flexibility to respond to shifting demand-supply dynamics during market uncertainties. For instance, the 2022-2024 European energy crisis following the reduction of Russian piped gas supply was stabilised using LNG imports from the US and Qatar. Similarly, East Asian countries like Japan and South Korea rely on spot LNG purchases to balance seasonal fluctuations, establishing natural gas and LNG as geopolitical tools for preventing deeper economic or social fallout through resilient and diversified supply.

Amid rising demand, there is indication of growing LNG supply reinforcing natural gas' role as a reliable fuel to meet expected shortfalls. Despite tightness in the near term, the global LNG market is expected to gradually ease over the next few years, and move into surplus as new supply comes online toward 2030. Around 270 Bcm of approved or under construction liquefaction capacity is currently in the pipeline to be commissioned by 2030, primarily driven by projects in the US and Qatar. This marks a new growth phase following a prolonged period of stagnation, reflecting the inherently cyclical nature of the liquefaction sector. These cycles are driven by the capital-intensive nature of projects – typically costing around $0.75 billion per Bcm – and long development timelines, often spanning 4–5 years from FID to operation. To manage market risk, developers usually secure most of their capacity through long-term contracts. Due to these factors, the LNG market is expected to remain broadly balanced, with limited opportunity for new developments in the short term and ample supply by 2030.

Uncertainty surrounding the timing of LNG supply persists despite the expected surge associated with the next wave of LNG projects. In October 2024, TotalEnergies revised its forecast, now anticipating that the next wave of LNG supply will only come to market from 2027, two-years after the previously projected 2025 timeline. The supply outlook remains uncertain due to potential delays as well as regulatory, technical and financial risks to projects. While there is a potential for increased project FIDs as a result of US import tariffs, policies such as the sanctions on Russian LNG are set to strike a blow to global LNG supply as upcoming projects' ability to acquire necessary equipment, secure vessels and find buyers is becoming increasingly limited. Disruptions to key LNG transit routes, such as the Strait of Hormuz, increase shipping times and costs, undermining project economics and investor confidence. This may lead to slower FIDs for projects dependent on long-distance or chokepoint-exposed routes.

While natural gas is essential for navigating today's world and an uncertain future, there is a looming shortfall in its supply. **To address this gap, there is a need for continued targeted investment in gas**. The above figure shows that all three IEA scenarios – STEPS, APS and NZE – as well as Rystad Energy's 1.6-degrees scenario undershoot the demand growth trends observed in recent years. Notably, if demand progress were to be similar to even the most ambitious scenarios such as IEA's NZE, there would be investment needed beyond producing and sanctioned projects towards 2030. This was reaffirmed in a 2025 statement by the IEA, who made it unequivocally clear that upstream oil and gas investments would still be necessary[7].

It is key to note that investment in natural gas needs to be in parallel with, not instead of, continuing to drive deployment of renewables. There has been growing support for the concept of "energy addition", reflecting the current global reality where rising energy demand, particularly in emerging economies, often requires new energy investments to supplement rather than replace traditional sources. In this context, natural gas can play a critical role in meeting incremental demand while supporting energy access and reliability. However, this dynamic may evolve over time, and energy addition should not be assumed as a long-term structural trend. **As the energy transition progresses, risk mitigation measures should include expanding natural gas storage to manage supply shocks and seasonal demand, diversifying supply sources to reduce geopolitical dependence, integrating low-carbon gases like hydrogen and biomethane to align with climate goals, and investing in flexible, repurposable infrastructure that can adapt to future energy systems**.

To conclude, given the great uncertainty surrounding the future of energy, it is essential to stay focused on the underlying fundamental of uncertain evolution of rising energy demand and the corresponding imperative to continue investing in natural gas as a flexible and reliable source to meet the growing needs and ensuring stability of energy systems globally.

[7] *Source: 'A huge issue': IEA head says upstream investments needed to offset fields' decline, Upstream (March, 2025); https://www.upstreamonline.com/field-development/a-huge-issue-iea-head-says-upstream-investments-needed-to-offset-fields-decline/2-1-1790533*

3/ The Role of Gas in Power System Flexibility and Renewables Integration

Chapter highlights

Large-scale variable renewable energy (VRE) integration challenges grid stability

- Electricity demand is projected to double by 2050, with VRE forming majority of the capacity, signalling a shift toward a low emission power mix
- VRE faces integration challenges from intermittency across time and seasons, disruption during extreme weather events, and grid congestion issue

Recent events highlight need for dispatchable capacity to balance VRE and limit price volatility

- Dunkelflaute events worldwide have necessitated reliance on natural gas and coal to offset low output in markets with high VRE penetration
- Such conditions have historically driven price spikes, as seen in Australia on 30 July 2024, when very low wind output during high demand contributed to wholesale 30-minute electricity prices exceeding 5,000 AUD/MWh in nine instances across all National Energy Market (NEM) zones

Natural gas is well-suited to complement VRE and provide grid stability

- Gas-to-power is mature, dispatchable, and stands out for its operational flexibility in responding to short-term and seasonal long-term fluctuations
- Natural gas benefits from a global LNG value chain, existing infrastructure, and extensive storage facilities, ensuring supply availability alongside batteries to buffer power system variability

Unlocking natural gas' full potential requires targeted measures

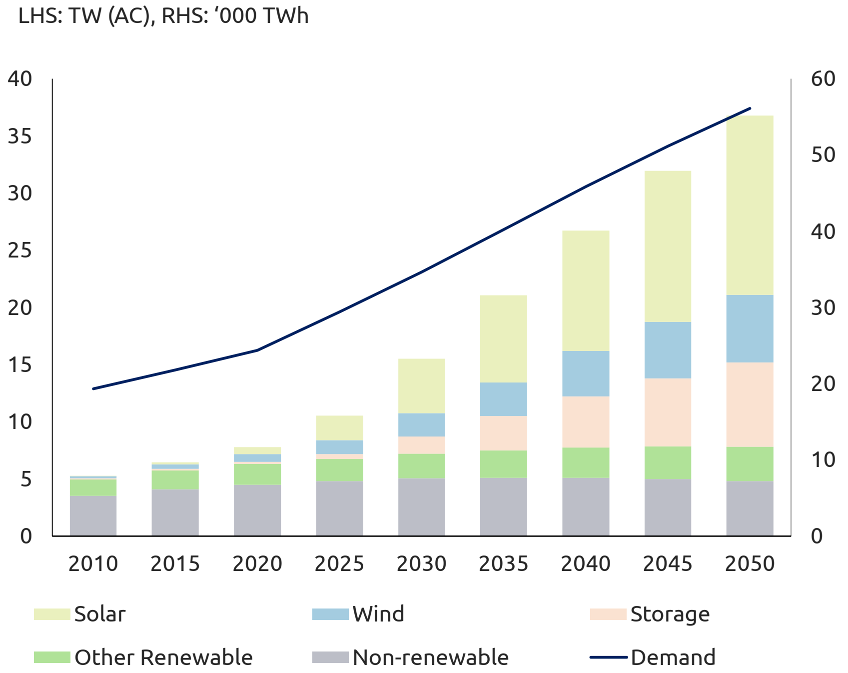
- Integrating natural gas into power systems requires strategic investment across the entire value chain, from new upstream supply to midstream infrastructure and generation capacity
- As natural gas shifts from baseload power to flexible backup, market reforms are needed to support viability of flexible gas-fired capacity projects

I. Large-scale integration of variable renewable energy challenges system stability and electricity supply

The global power system is undergoing a fundamental transformation as large-scale renewables gain ground, driven by supportive policies and increasingly competitive economics. In Rystad Energy's base case scenario, electricity demand is projected to rise sharply, reaching ~56,000 TWh by 2050, accompanied by a structural shift in which most of this demand is likely to be met by variable renewable energy (VRE). The installed renewable capacity including storage is projected to grow from around 5 TW in 2024 to roughly 32 TW by 2050, representing a CAGR of 7.4%. This shift signals a move toward a low-emissions future, with wind and solar set to dominate global power capacity through sustained investment and capacity expansion.

Energy sources can broadly be classified as dispatchable or non-dispatchable. Coal, natural gas, and hydropower are key examples of controllable, dispatchable sources. They can produce electricity on demand and have historically served as baseload in many power markets. **Among these, natural gas and hydropower stand out for their operational flexibility, as they can ramp up quickly, respond**

Figure 26: Global power capacity, split by energy source and global power demand



Note:

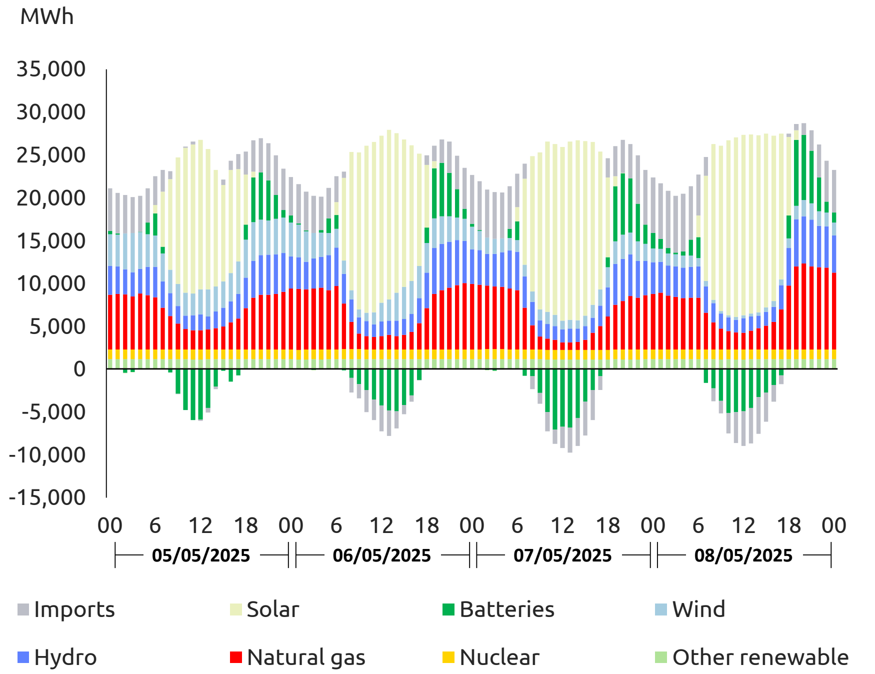
'Other renewable' includes nuclear, geothermal, solar thermal, bioenergy, and hydro. 'Non-renewable' includes natural gas, coal, and liquids. Storage refers primarily to batteries and pumped hydro storage, which, in Rystad Energy's view, are expected to account for nearly 100% of storage capacity through 2050. Other storage solutions (compressed-air energy storage, liquid air energy storage, thermal energy storage) are expected to contribute only marginally.

Source: Rystad Energy base case scenario

to short- and long-term fluctuations, and operate without the need for external energy storage. Non-dispatchable sources, primarily VRE such as wind and solar, are influenced by weather and other unpredictable factors. Their output varies due to predictable patterns, such as the day-night cycle and seasonal shifts, as well as less predictable factors like cloud cover or varying wind speeds. This variability creates a fundamental mismatch between power supply and demand, which can compromise system reliability and long-term supply security. Additionally, VRE assets are often decentralised and located far from major demand centres, leading to congestion and added strain on the power grid.

The state of California in the US offers a prominent example of a power system with large-scale VRE integration. California has one of the highest shares of VRE in the world and is targeting a 60% renewable share in its energy mix by 2030. Currently, the system relies on a mix of nuclear and natural gas for baseload electricity generation, with natural gas – along with hydropower – also providing additional flexibility needed to adjust for fluctuations in solar and wind output. The power system also utilises

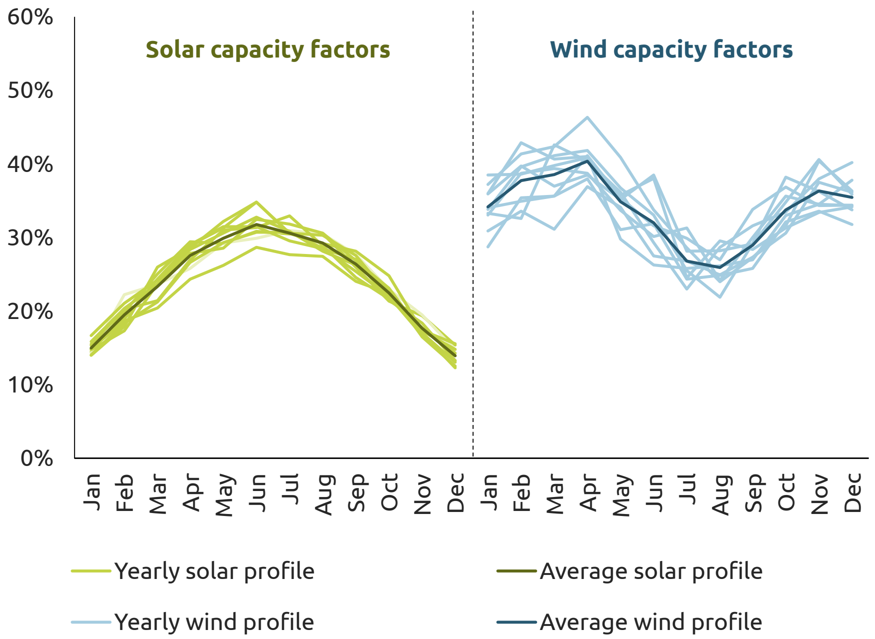
Figure 27: Hourly power supply in California, 5th to 10th May 2025, split by energy source



Source: CAISO

large-scale battery storage to enhance grid stability by charging during periods of high solar generation and discharging in the evenings when solar output declines. These measures effectively reduce energy curtailment and increase the availability of flexible capacity in the system. Natural gas, hydropower, and batteries collectively maintain grid integrity during periods of high renewable output and ensure demand is met when renewable generation declines. **California's energy mix highlights how natural gas remains a proven technology partner to batteries**, providing reliable dispatchable power. Over the first six months of 2025, solar and wind accounted for about 35% of total power generation in California, with the share surpassing 50% on average during peak VRE production hours, recorded daily across this period.

Figure 28: Monthly wind and solar capacity factors[1] in the United States, 2015-2024, split by year



Note: 1) Actual generation as a percentage of maximum possible output over a given time.

Source: Rystad Energy

VRE introduces fluctuations across multiple timescales. In the short term, reduced system inertia can lead to frequency instability. System inertia refers to the automatic frequency stabilisation provided by the rotating masses of synchronous generators, such as gas-fired turbines. This property cushions the grid against power imbalances by limiting the rate of change of frequency in the event of sudden spikes in demand or dips in supply. While the technology exists to provide synthetic inertia (also known as virtual inertia), renewables have been typically connected to the grid in a way such that contributes little to system inertia. With synchronous rotors, existing gas-fired power plants inherently provide both inertia and rapid ramping ability to counteract VRE variability, making them crucial to support system stability.

In the medium-term, variability emerges on intra-day timescales, driven by the natural intermittency of wind and solar. Solar output follows a diurnal pattern and is highly sensitive to cloud cover, while wind generation can also fluctuate during the day depending on regional weather systems. While batteries are well-suited for sub-hourly and intra-day balancing, they lack the capacity to buffer supply across multiple cloudy or calm days. During multi-day variability, dispatchable generation, primarily natural gas and hydro, remains essential for maintaining supply security. In the long-term, seasonal patterns and extreme weather events can significantly affect generation output. Solar capacity factors typically peak during the summer and remain low for extended periods in the winter. Wind generation increases through autumn and winter, peaking in spring, but exhibits greater year-to-year variability than solar. Extreme weather events, such as heat waves, cold storms and droughts, have intensified longer-term seasonal energy demand peaks, amplifying the challenges faced as countries worldwide adopt higher shares of VRE.

Another key consideration with increasing VRE penetration is grid congestion. Traditional power grids are designed for centralised, one-directional power flows, with large-scale power plants feeding electricity into transmission and distribution networks. **The integration of VRE, particularly from remote sites with favourable wind or solar resources, can overload transmission corridors and create congestion in regions with limited grid capacity**. This pushes transmission infrastructure closer to operational limits and demands enhanced coordination across the power system. This is evident in Great Britain, where wind farms in Scotland - located in regions with low electricity demand - struggle to supply power to higher

Table 4: Key challenges of high VRE integration

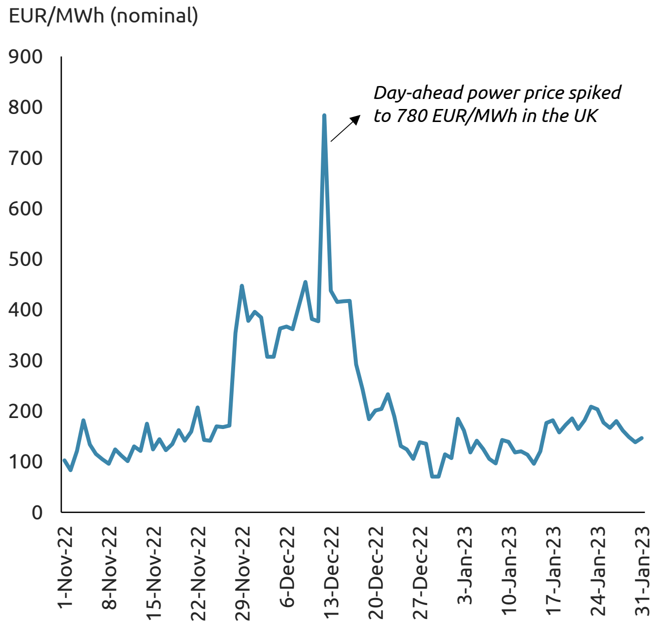
Challenges		System requirement and responses	
Intermittancy and unpredictablity	Fluctuating VRE output complicates real-time balancing of power supply and demand	Fast-ramping resouces	Deploy responsive, flexible generation to manage volatility of VRE output
Extreme weather and seasonal impact	Seasonal variation and extreme weather events can contribute to imbalances and curtailment	Energy procurement	Strengthen procurement and storage to address both expected and unexpected imbalances
Grid stability concerns	Low system inertia weakens frequency and voltage stability, increasing vulnerability to disturbances	Synthetic inertia	Use grid-forming inverters to stabilise frequency under low-inertia conditions
Grid congestion	High concentration of VRE can overload transmission corridors leading to congestion	Grid-scale storage	Deploy strategically located storage to reduce congestion and enhance grid reliability
Curtailment	VRE curtailment can impact market pricing, increase grid balancing costs, while excess generation can strain the grid	Automated generation control	Coordinate VRE, storage and demand to manage imbalances and maintain frequency regulation

demand regions further south in England due to grid constraints that limit transmission capacity. In its 2025 Annual Balancing Costs Report, Great Britain's National Energy System Operator estimated that 13% of potential wind generation was curtailed in 2024/2025 and separately identified wind curtailment as a major driver of rising grid balancing costs. Grid upgrades, including the expansion of the electricity network, are needed to address these growing costs and fully utilise the renewable buildout.

Grid congestion issues are further compounded by small-scale distributed VRE, which introduces localised injections into the grid and increases volatility due to weather-driven variability, adding costs and complexity to local power distribution networks. Temporal fluctuations in VRE output, combined with bidirectional power flows between grid and end-users who also generate electricity, further add operational complexity, requiring greater system flexibility and control, real-time balancing, short-term dispatch, infrastructure investments, and long-term system planning.

As the table above shows, appropriate system responses can help address key challenges associated with high VRE integration. Notably, co-deployment of batteries has the potential to mitigate investment risk in VRE by increasing revenue certainty. Batteries can reduce curtailment by storing excess power, especially during low-price periods, and discharge it during periods of low generation and high demand, thus firming up VRE output and boosting system reliability. As batteries can only cater to short-term and intra-day variability, co-deployment is a partial solution best used in combination with demand-side responses, grid infrastructure upgrades and, importantly, sustained investment in other sources of dispatchable capacity.

Figure 29: UK day-ahead price of electricity November 2022 - January 2023

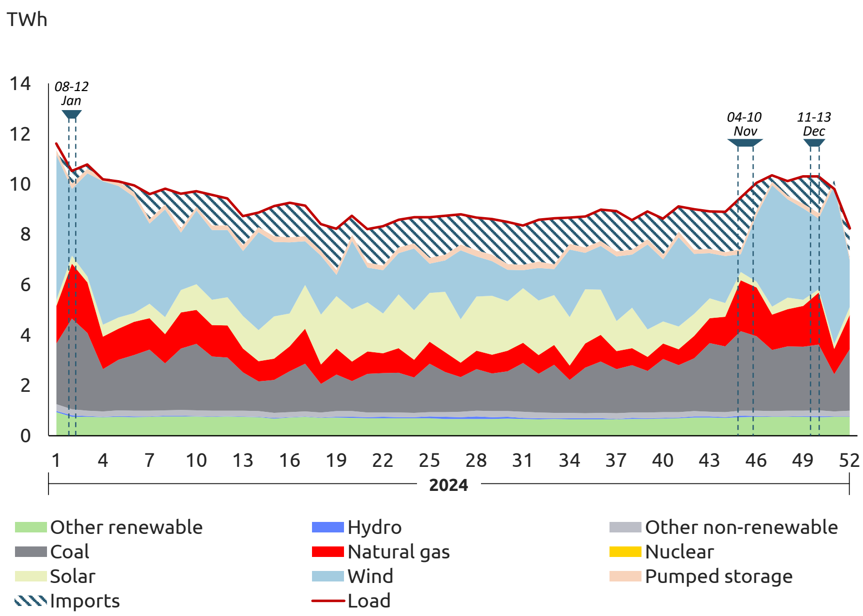


Source: Rystad Energy, RTE

Several large-scale dunkelflaute events have been observed in power systems with high VRE penetration, underscoring the challenge of managing extended periods of low wind and solar output.

In December 2022, gas-fired power plants in the **United Kingdom** ramped up production, supplying more than 73% of the country's total electricity due to weak wind conditions. High energy demand, driven by low temperatures, pushed up wholesale electricity costs, with the day-ahead price for power on 12 December 2022 rising to 675 £/MWh (~780 €/MWh).

Figure 30: Weekly power balance in Germany, 2024, by energy source



Dunkelflaute events in Germany in 2024

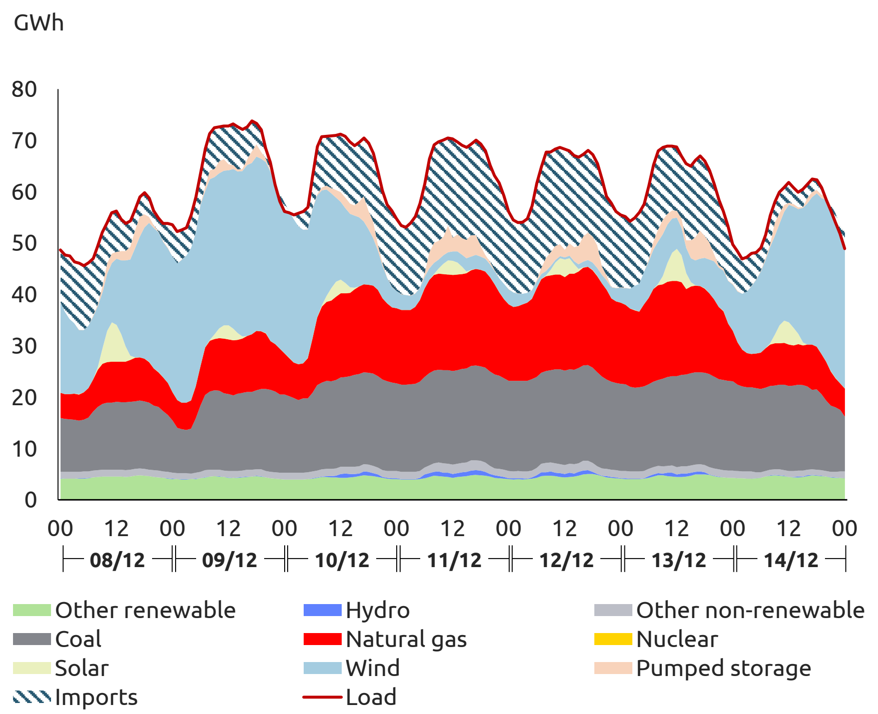
8 - 12 Jan 2024	*Low wind power output triggered ramp-up of natural gas, coal, and imports, briefly pushing balancing prices above 2,000 €/MWh*
4 - 10 Nov 2024	*Wind generation declined in late October, falling 25% below normal levels for two consecutive months* *Resulted in a record 79% monthly increase in gas-fired power generation, with fossil fuels making 70% of Germany's power mix*
11 - 13 Dec 2024	*Wind generation fell below 15% of expected levels; natural gas covered ~27% of demand during the period - over twice the 2024 average* *Intraday spot prices briefly exceeded 1,000 €/MWh - 10 times the annual average*

Source: ENTSO-E

Similarly, **Germany** experienced multiple dunkelflaute incidents across 2024, which required significant ramp-up of coal and natural gas, along with increased imports, to compensate for high demand and low VRE output. German energy authorities and the Ministry for Economic Affairs publicly warned that such "unusual doldrums" underscore the importance of dispatchable capacity, especially as the country phases out coal and nuclear.

Australia presents a similar case, with one of the world's most volatile power markets. This volatility stems from high VRE penetration combined with limited flexible capacity to manage dunkelflaute conditions. The National Electricity Market (NEM), which serves the eastern and southern states, operates in isolation from other Australian power markets and cannot rely on inter-regional imports during supply-demand imbalances, unlike Germany. NEM is particularly vulnerable during the southern hemisphere winter months when still weather coincides with seasonally high demand. On the

Figure 31: Hourly power balance in Germany, 8th to 14th December 2024, by energy source



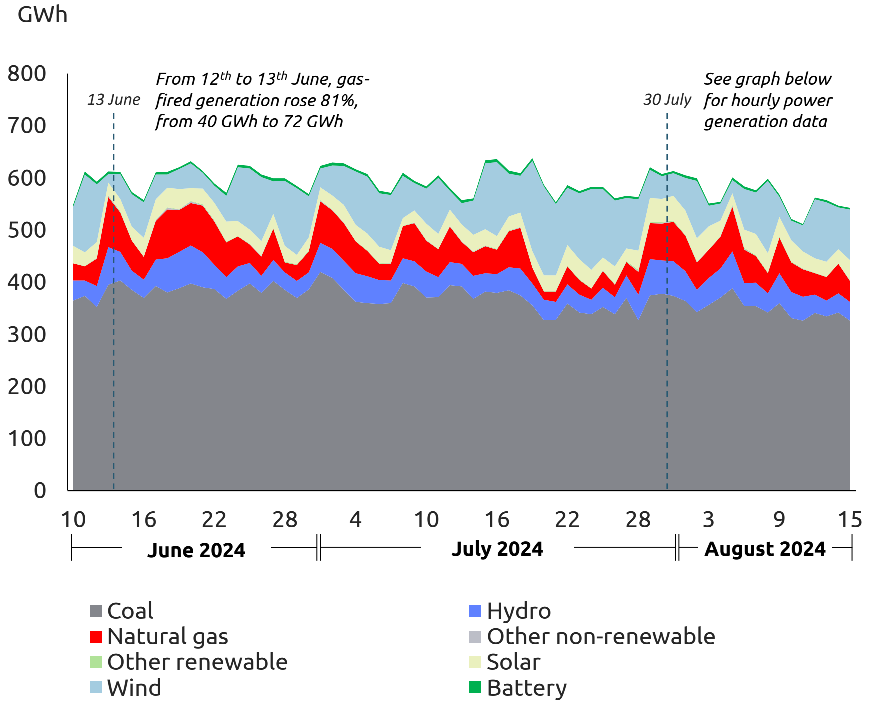
Source: ENTSO-E

afternoon of 13 June 2024, wind output dropped below 1% of installed capacity. Dispatch prices were driven above 500 AUD/MWh (280 €/MWh) in southern regions, more than five times higher than the regional average spot prices in 2024. On 30 July 2024, a combination of low wind output and elevated demand pushed wholesale power prices above 5,000 AUD/MWh (2,800 €/MWh) across all NEM pricing zones. The Australian Energy Regulator (AER) reported five instances of 30-minute electricity prices exceeding 5,000 AUD/MWh across NEM regions at 6pm, attributing the spikes largely to limited wind generation, which averaged just 6% of total installed capacity. Separately, four additional high price events were recorded in South Australia, where wind output averaged only 280 MW out of possible 2,763 MW during the peak pricing period. These events underscore the sensitivity of wholesale electricity prices to fluctuations in VRE output during peak demand periods.

Beyond short-term fluctuations, such as dunkelflaute events, the growing frequency of extreme weather events, such as heatwaves, storms, and droughts, has further highlighted the need for reliable power to manage volatility in future energy systems. According to the World Meteorological Organization (WMO), the world saw over 600 extreme weather events in 2024, of which more than 70% were classified as unprecedented or unusual, in terms of magnitude, location or extent. In fact, it confirmed that 2024 is the warmest year on record, and the past ten years (2015-2024) marked the hottest decade ever recorded. Hotter summers and colder winters result in demand-side volatility by exerting upwards pressure on peak demand, straining grids and causing outages, especially during high-load periods.

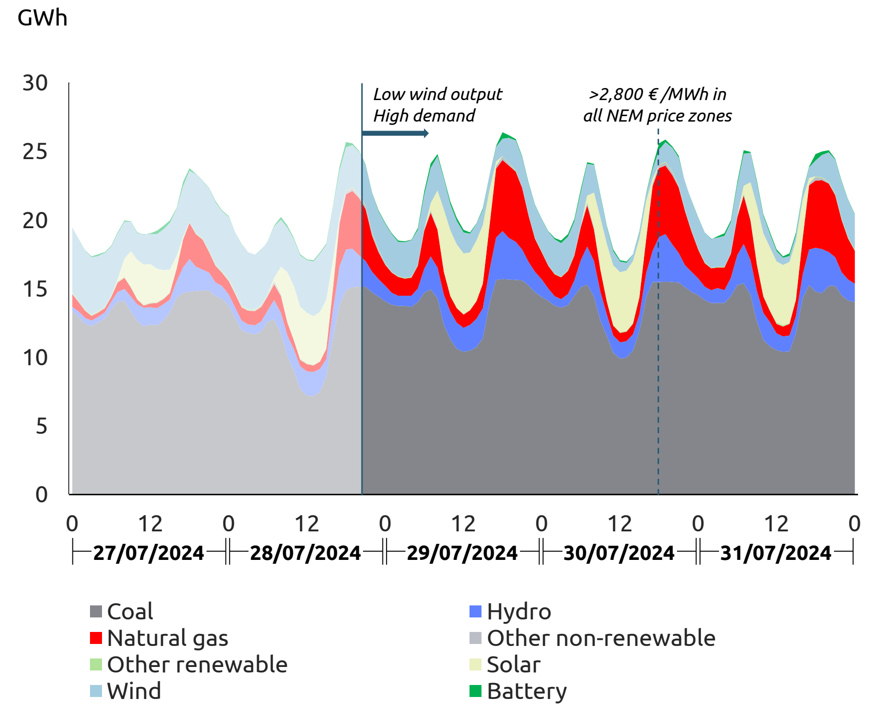
Heat waves across China and India are becoming more frequent, arriving earlier and lasting longer, further driving up energy demand for cooling. Driven by high summer temperatures, China's peak power demand hit a record 1,450 GW in 2024. Resulting grid strains led state operators to promote nighttime charging of electric vehicles and limited air conditioner (AC) use during cooler periods to stagger demand from daily peak hours. With 2025 already surpassing 1,500 GW of peak power demand in July, rising heat in coming years is set to intensify these challenges.

Figure 32: Daily power generation in NEM, 10th June to 15th August 2024, by energy source



Source: AEMO; NEM

Figure 33: Hourly power generation in NEM, 27th to 31st July 2024, by energy source

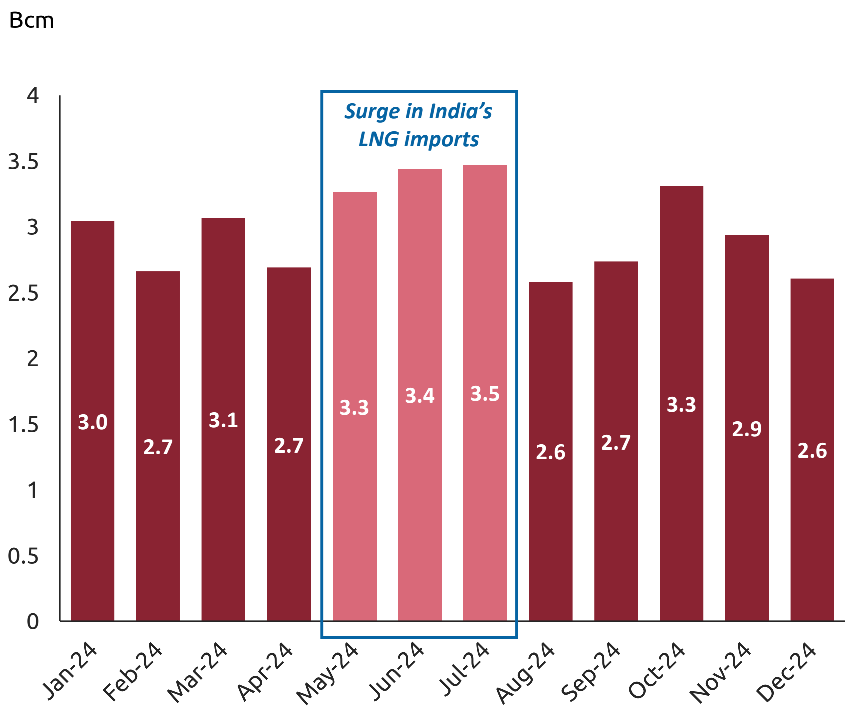


Source: AEMO; NEM

Similarly, extreme heat has prompted growing AC ownership in India, which contributed to the country achieving its highest ever peak power demand in May 2024, exceeding 250 GW (*for more details, see Chapter 2*). These countries are ramping up renewable energy to meet rising power demand from heatwaves, with China's solar generation increasing 28% y-o-y in 2024. However, both nations still rely heavily on coal for its cost efficiency, announcing plans to increase coal-fired capacity in 2024. As such, gas-fired generation in these key economies remains limited, presenting opportunities for coal to gas switching. Natural gas offers strong potential to balance energy system flexibility with environmental concerns due to its quick ramp-up capabilities and lower emissions intensity as compared to coal – an advantage as extreme weather events become more frequent. In this context, India has begun to increasingly draw on LNG to meet elevated summer power demand. LNG imports peaked between May and July 2024, achieving the highest monthly volume of ~3.5 Bcm in July, highlighting India's growing dependence on LNG to meet rising power needs during extreme temperatures.

Similarly, winter storms in the US have led to significant spikes in energy demand for heating, thereby elevating natural gas demand. For example, during Winter Storm Enzo earlier this year (2025), peak hour gas-fired power generation reached a record level of 291 GW. This was 72% higher than typical winter hours, surpassing output seen during previous winter storms, according to a report by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. These effects are especially pronounced in regions

Figure 34: Monthly LNG import volumes to India, 2024



Source: Rystad Energy

reliant on solar generation during winters with low solar output, or in wind-dependent areas facing poor wind conditions during heatwaves. Supply-side volatility can also stem from extreme weather events that disrupt renewable energy output.

In South America, prolonged droughts have repeatedly constrained hydropower generation, prompting an increased reliance on fossil fuel-fired generation to replace lost hydroelectric generation. For instance, Brazil's LNG imports surged by 112% during the first nine months of 2024, driven in part by a sustained drought that necessitated the ramp up of gas-fired generation to offset lost hydroelectric generation.

Together, these extreme weather patterns compound power system stress: extreme temperatures trigger large spikes in energy demand, while the volatile and unpredictable nature of extreme weather such as droughts and storms, could disrupt VRE supply. This leaves VRE-dependent regions exposed to mismatches between supply and demand.

As these extreme weather events become more frequent and persistent, they highlight the critical need for weather-resilient, dispatchable energy sources capable of rapidly scaling to maintain grid reliability under stress. Power systems with high shares of VRE are particularly vulnerable to sustained periods of low generation without adequate backups. Future power systems will need to balance both short-term and long-term fluctuations in VRE output, with batteries being well suited for managing ordinary, intra-day variability and gas-fired power generation offering flexibility across both short term and long-term VRE fluctuations.

II. Natural gas plays an important role as a flexible solution in balancing VRE variability

As VRE continues to scale, power systems face a growing need for flexibility. Intermittent supply from wind and solar must be balanced by technologies that can reliably manage short-term fluctuations and longer-term seasonal intermittency and maintain grid stability.

There are several pathways to developing a resilient long-term power mix, each shaped by regional and local conditions that affect both the intermittency of VRE, and the scale of flexibility required. The right combination of flexibility measures will depend on system-specific factors, including generation mix, grid infrastructure, and demand patterns. As systems evolve, a balanced mix of grid investments, energy storage, and dispatchable generation – both short- and long-duration – will be essential.

As illustrated in the table below, the main energy solutions available to mitigate VRE-related challenges vary in their technical and economic performance, emissions impact, and decarbonisation potential.

Table 5: Key characteristics of main flexibility solutions for balancing VRE generation

	Technical performance		Economic performance		Adoption feasibility		Emissions impact
	Baseload	Flexibility	Capex	Opex	Technology	Infrastructure	Intensity
Gas (peaker)	◐	●	●	○	●	●	◐
Gas (baseload)	●	◐	◐	◐	●	●	◐
Batteries	○	●	○	●	◐	◐	●
Coal	●	○	◐	◐	●	◐	○
Nuclear	●	○	○	◐	◐	○	●
Pumped storage	◐	●	◐	●	●	○	●
	Steady / stable generation	*Unplanned start and ramp-up*	*Build cost*	*Driven by per unit fuel cost*	*Technical maturity*	*Deployment readiness*	*Per unit carbon emissions*

High VRE co-deployment suitability (Gas (peaker), Gas (baseload))

● Favourable ◐ Neutral ○ Unfavourable

Source: Rystad Energy

Among the available options, gas-to-power stands out for its maturity, responsiveness and suitability for integration into existing systems. Natural gas already plays a central role in today's global power mix, offering a set of advantages particularly well-suited to respond to VRE-related challenges. In many systems, gas-to-power solutions deliver high systemic value by complementing variable renewables with responsive, dispatchable generation.

Natural gas is a technologically mature energy source that provides generation flexibility

Natural gas and gas-to-power solutions have historically contributed both baseload and flexible capacity, offering proven and mature technologies. The two dominant gas-to-power technologies are open-cycle gas turbines (OCGT) and combined-cycle gas turbines (CCGT), each serving distinct roles. Both technologies are characterised by decades of global deployment with standardised designs and well-established maintenance practices. As VRE penetration increases, power systems will face mounting pressure to maintain reliability. This reinforces the need for fast, scalable deployment of technologies that can respond to short-term volatility and long-term structural shifts, such as gas-fired generation.

Natural gas has lesser deployment and spatial constraints than other alternatives

One of the key advantages of gas-fired power is its short build time relative to alternatives such as hydropower and nuclear power. This enables rapid scaling of flexible capacity in parallel with accelerated VRE deployment. In contrast, large-scale hydropower is constrained by geography and environmental considerations, and while pumped hydro storage can provide flexibility, it is not universally deployable. Although modern nuclear power plants are developing stronger peaking capabilities, the sector continues to face political resistance, lengthy permitting processes, and construction timeline. These factors increase deployment time and make nuclear less suited to provide peaking capacity in energy systems that aim to undergo rapid VRE deployment in the coming years. These challenges highlight the role gas-fired generation can play in the evolving power mix.

The low capital intensity of natural gas makes gas-fired power cost competitive against other flexibility solutions, especially in the current context of reduced capacity factors for dispatchable sources

Gas power plants benefit from relatively low upfront investment costs and short deployment times, making them a cost-effective option for adding flexibility. The capital expenditure (CAPEX) of gas-fired power plants, compared to capital intensive technologies such as nuclear and coal, is relatively low, enhancing its overall competitiveness, despite its relatively higher operational expenditure (OPEX) which is mainly tied to natural gas prices. This is especially relevant in a system where dispatchable power plants are increasingly shifting from baseload to mid-merit and peaking roles due to growing VRE expansion, and capacity factors for dispatchable sources, including natural gas, are declining. From an economic standpoint, technologies with low OPEX but high CAPEX are less viable at low-capacity factors, as capital costs become harder to recover over the project's lifetime.

However, the lower capital intensity of gas-fired power helps offset reduced utilisation or higher per-unit operating costs, maintaining competitiveness in flexible and peaking roles compared to more capital-heavy alternatives. Consequently, natural gas-fired power can play a significant role in improving energy access in developing economies, where it can be deployed more rapidly and reliably than the more expensive technologies. Especially in regions where electricity demand is rising rapidly and grid infrastructure is often limited or unevenly developed, gas-fired power plants offer a scalable, dispatchable solution, which can assist in reducing reliance on imported fuels and enhancing energy security.

Natural gas is supported by widespread infrastructure, unlocking unique opportunities to address long-duration energy storage needs

Gas-to-power systems benefit from a well-established global value chain that includes both LNG and pipeline infrastructure, which underpins high supply security. In addition, the widespread availability of physical gas storage facilities enables natural gas to address both short-term imbalances caused by variability of renewable generation, and long-duration supply shortfalls. Storage technologies such as pumped hydro and batteries require prior energy input, ideally from surplus renewable generation that would otherwise be curtailed. However, during extended periods of low VRE output, these storage reserves are quickly depleted and cannot be easily replenished, which limits their reliability in prolonged shortfall scenarios. In contrast, natural gas storage offers a dependable form of long-duration energy storage, which batteries and other storage options cannot match, providing a valuable hedge against the inherent volatility of VRE.

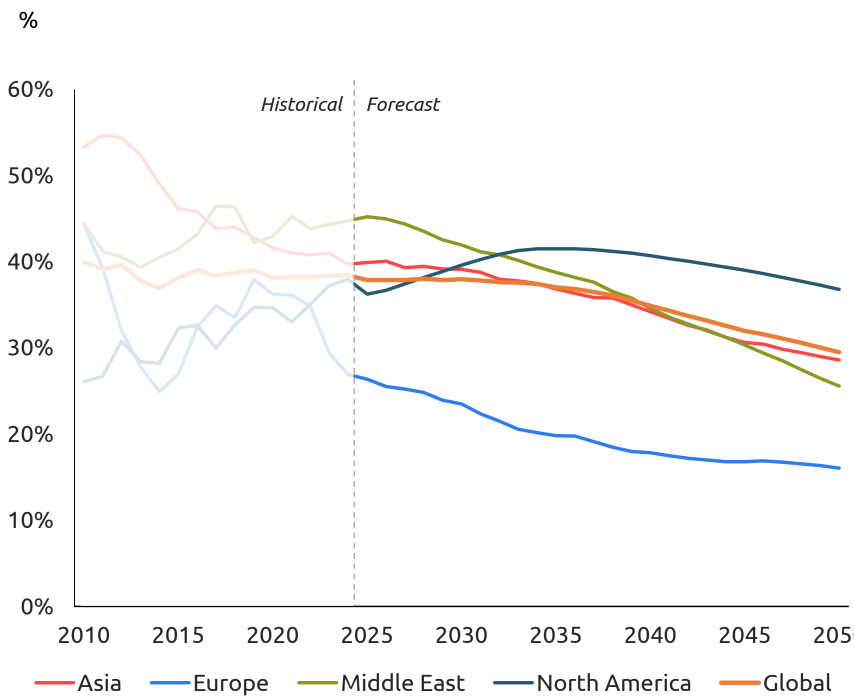
Natural gas can contribute meaningfully to the flexibility needed in power systems with high shares of VRE. Its technical maturity, adaptability, and global supply infrastructure position it as a practical complement to renewables in many settings. By offering dispatchable capacity, supporting grid stability, and providing responsiveness during periods of variability, gas-to-power solutions can help enable the continued integration of VRE. While the long-term role of natural gas will depend on future decarbonisation strategies and market developments, it remains a robust option for addressing near- to medium-term challenges in the evolving power mix.

III. Market and value chain developments needed to support natural gas as flexible power source

Globally, policy and market developments are supporting a shift in the role of natural gas within power systems. As natural gas transitions from primarily serving as a baseload source to acting as a flexible and responsive power source, it increasingly provides a form of insurance and stability for power markets facing high VRE integration. By 2050, the global capacity factor of natural gas-fired generation is expected to decrease from the current level of ~38% to ~30%, reflecting its evolving role as a complement to renewables rather than a pure baseload.

Recognising that natural gas provides valuable inertia and stability to power grids, countries are rolling out policies aimed at creating favourable market conditions for gas-fired power as its role in the energy system adapts to the energy transition.

Figure 35: Capacity factor of natural gas-fired generation, 2010-2050, by geography



Source: : Rystad Energy base case scenario

Germany is introducing capacity-based subsidies to ensure stable supply and backup capacity for renewable power amid the coal phase-out. The country's energy minister recently announced plans to tender "at least" 20 GW of new gas-fired capacity through a series of competitive auctions. Despite delays due to political reasons, at least 5 GW of capacity is scheduled to be put up for auction before the start of 2026. Earlier in 2024, the government also communicated plans to provide EUR 17 billion worth of subsidies for gas power plants that can switch to hydrogen. From 2028, Germany also plans to introduce a formal capacity market, which – unlike energy-only markets – ensures reliable electricity supply by paying providers to be available during peak demand, regardless of how often they generate. These mechanisms together offer revenue certainty to gas-fired capacity, ensuring its availability to stabilise the power grid.

In **Ireland**, under the country's DS3 Flexibility Program, new grid codes and market incentives have been introduced to encourage the deployment of flexible natural gas plants, batteries and demand response to support VRE. As a result, Ireland operates its grid without significant stability issues, with wind providing close to 40% of annual generation. The country plans to add at least 2 GW of new highly flexible natural gas capacity by 2030 to further enhance system resilience.

In the **EU**, under the region's Taxonomy Label for Gas, natural gas power projects are classified as *sustainable investments* given that they replace coal-to-power generation. The EU framework recognises the role of natural gas in supporting grid reliability and stability amid increasing VRE integration.

North America is one of the key regions where natural gas is still expected to play a more traditional role, with the phase-out of coal driving continued development of gas power plants. Many of these plants are intended to operate as baseload rather than purely as VRE support. In the US, the EPA's Carbon Standards for Gas Plants require new baseload natural gas power plants to be either equipped with CCS or be hydrogen-ready. The framework, along with retrofitting of gas turbines, solidifies natural gas' role as a flexible source to complement high integration of renewables. However, in June 2025, the EPA announced plans to repeal existing GHG standards, following directives from President Trump aimed at promoting energy independence and reducing regulatory burdens.

The future role of natural gas in power systems will vary widely depending on feasibility considerations, best practices, and regional integration strategies. Existing infrastructure, current power mixes, and policy environments will determine how extensively gas-to-power can contribute to system flexibility. Therefore, unlocking the full potential of natural gas as a dispatchable and balancing power source will require a set of targeted measures at both national and global levels.

Value chain infrastructural investment requirements

Realising the contribution of natural gas in future power systems demands coordinated investment across the entire natural gas value chain. This includes new upstream supply, midstream infrastructure, and downstream gas-to-power capacity. Midstream needs, such as pipelines and storage, vary significantly across regions and are shaped by existing and future patterns of production and consumption. The addition of new gas-fired power capacity can itself trigger investment in transport and storage infrastructure, while sourcing natural gas via LNG may require regasification terminals (as well as liquefaction capacity in exporting regions). Regardless of delivery mechanisms at the local level, the growing role of natural gas in flexible power systems implies continued global demand for upstream development and exploration activity.

Economics and market design

As natural gas shifts from baseload to flexibility, the economics of gas-to-power are increasingly challenged. Natural gas plants operating in a flexible, peaking role face a reduced number of operating hours and lower revenues, especially as VRE suppresses wholesale and spot prices. This weakens life-time project economics and raises investment risk.

To ensure sufficient future natural gas capacity, market reforms are needed. These include capacity payments for standby availability, monetisation of flexibility services, and long-term contracts to ensure revenue certainty. Japan held its first capacity market auction in 2020 for capacity obligations in 2024/2025, allowing the country to maintain a buffer of gas-fired flexible capacity amid VRE expansion. Italy launched a central capacity market in 2019, with initial auctions held for 2022-2023 delivery and offering long-term contracts of up to 15 years for new capacity. The scheme aims to secure dispatchable capacity during peak demand while supporting VRE integration and maintaining system reliability. Such reforms will become even more important as CCUS is introduced to meet emission targets, further increasing costs and reducing margins.

Without adjustments to market design, the business case for flexible gas power risks becoming unviable, despite its potential contribution to system reliability and VRE integration.

Natural gas can support the transition to a low-emission power system by providing flexible, dispatchable capacity that complements variable renewables. Realising this potential requires more than technological readiness. It demands targeted investment across the natural gas value chain, careful alignment of technology choices with system needs, and reform of power market structures to ensure project viability. While broader decarbonisation efforts continue to evolve, natural gas is expected to continue to play a stabilising role in future power systems.

Spotlight

Value chain emissions reduction and industry action on methane abatement

Emissions in the natural gas and LNG industries

Natural gas can play a critical role in the global energy transition as a companion fuel to renewables. With lower emissions than coal and oil, well-established infrastructure, and a mature global value chain, it offers a reliable and flexible alternative. However, to fully realise this potential, the sector needs to prioritise emissions management and system efficiency through targeted investments and innovation.

Every natural gas value chain begins with upstream production, followed by processing to remove impurities and separate liquids. The gas is then transported for various end-uses. In the case of LNG, additional steps include liquefaction, shipping via purpose-built LNG carriers, and regasification. Each stage of the value chain contributes differently to total emissions, with varying levels of carbon dioxide and methane. Methane emissions, for example, are primarily concentrated in upstream production, processing, and transmission, escaping into the atmosphere through leaks, inefficient flaring, or venting. Emissions intensity also varies by supply route and facility location, impacted by country- or region-specific environmental regulations. Transportation-related emissions depend on the condition of infrastructure, as older equipment is more prone to leaks, and on the distance travelled, whether by pipeline in the case of piped gas, or by ship in the case of LNG.

Through the deployment of appropriate decarbonisation technologies, improved operational practices, and greater system efficiency, emissions across the full natural gas value chain can be substantially reduced - or in some cases, eliminated.

Emissions reduction and efficiency improvement measures

Efforts to reduce greenhouse gas emissions reduction across natural gas and LNG value chains are intensifying, particularly in high-emission, energy-intensive processes.

Upstream emissions in the natural gas value chain are primarily associated with process emissions from on-site equipment, flaring and fugitive methane leaks. Fugitive emissions refer to methane that escapes into the atmosphere due to equipment leaks or intentional venting during maintenance or emergencies. Incomplete combustion during flaring can also result in methane release. These emissions can be effectively mitigated through robust methane **leak detection and repair (LDAR)** programs, combining continuous monitoring combined with periodic aerial surveys to identify and address emissions. Replacing flaring and venting with **gas capture and utilisation** methods has the dual benefit of reducing emissions while enabling the gas to be used for on-site energy needs or sold to market.

Liquefaction, the most energy intensive stage in the LNG value chain, generates carbon dioxide emissions mainly from the treatment of feed gas, combustion in gas turbines, and power generation for plant operations. **Electrification** of liquefaction operations is a key lever for emission reduction, and upcoming projects are increasingly incorporating it into the development of new LNG facilities. For example, among projects that reached final investment decision (FID) in 2024, Oman's Marsa LNG is planned to be powered entirely by a solar farm, while the UAE's Ruwais LNG is expected to be fully operated on grid electricity. Among operational facilities, Norway's Hammerfest LNG plans to replace gas-fired turbines with grid electricity by 2030, reducing annual CO_2 emissions by 850,000 tonnes. These initiatives reflect a broader industry pivot toward low-emission facility design.

Carbon Capture and Storage (CCS) provides another decarbonisation pathway, capturing CO_2 at the source for storage or potential utilisation (e.g. enhanced oil recovery). Currently, three operational

LNG plants have integrated CCS: Hammerfest LNG (Norway), Ras Laffan (Qatar), and Gorgon LNG (Australia), although the latter has faced challenges achieving full capture capacity. More than 35 MTPA of LNG-linked CCS capacity is in the project pipeline through 2030.

Within midstream, which refers to the transportation and storage of natural gas, emissions can occur from gas-powered pneumatic controllers and pumps. These emissions can be reduced by retrofitting or replacing them with **low-bleed or zero-emission electrical and mechanical alternatives**, technologies that are commercially available and offer similar functionality. European transmission operators such as Gasunie (Netherlands), Enagas (Spain) and Snam (Italy) have initiated plans to transition away from gas-operated pneumatics. Increasingly, midstream operators are also pursuing **full or partial electrification of transportation and storage operations**, including the use of dual-fuel compressors powered by low-carbon electricity (wind, solar etc.) to cut emissions further. Pipeline leakages caused by wear and tear in transmission infrastructure and auxiliary equipment, represent another source of emissions. These can be mitigated through more robust LDAR programs, similar to those implemented in upstream fields and natural gas processing facilities.

In the case of LNG carriers, natural boil-off gas generated during voyages can contribute to emissions if released directly into the atmosphere. However, LNG carrier technology has advanced significantly to manage this and reduce boil-off rates. Modern vessels are equipped with pressure control systems that manage boil-off gas using **re-liquefaction systems or gas combustion units for onboard utilisation**. Increasingly, boil-off gas is also being used as secondary fuel for ship propulsion or electricity generation, helping to reduce emissions and minimise energy wastage.

In the maritime domain, new International Maritime Organization (IMO) rules and EU regulations are shaping the LNG shipping landscape. Since 2023, all ships must report their **Energy Efficiency Existing Ship Index (EEXI)** and **Carbon Intensity Indicator (CII)** scores. In 2024, the IMO also banned use of heavy fuel oil in vessels operating in the Arctic, requiring operators to switch to cleaner alternatives. The EU Emissions Trading System (ETS) began including maritime shipping in 2024, and the **FuelEU Maritime Regulation**, effective 1 January 2025, mandates a reduction in the GHG intensity of energy used by ships operating within the EU.

Ship operators must increasingly consider propulsion efficiency, fuel switching, and onboard emission reduction technologies to remain competitive and compliant. More stringent regulations are also supporting the uptake of LNG as a marine fuel. In 2024, the global operational LNG bunkering vessel fleet expanded to 56 units. Growth has been underpinned by regulatory drivers, an expanding LNG bunkering supply chain, and rising interest in LNG for dual-fuel vessels, with non-LNG carrier fleet capable of running on LNG expected to exceed 1,500 vessels by 2030.

Digital innovation is also enabling emission reductions. **AI, automation, and data analytics** are being used to optimise LNG plant operations, detect potential leaks, and improve equipment efficiency. Technologies like **digital twins** - virtual replicas of physical LNG facilities - support predictive maintenance, real-time asset monitoring, and more informed decision making. These tools reduce unplanned downtime, improve operational efficiency, and contribute to lower emissions. Major international oil companies (IOCs) and national oil companies (NOCs) have begun investing in digital twin technology to support analytics and oversight of their natural gas and LNG assets.

Industry action on methane abatement

Methane's high global warming potential makes its reduction a critical component of climate action strategies. Robust methane measurement, monitoring, reporting and verification (MMRV) is the essential first step in accurately quantifying and addressing both fugitive and process-related emissions. While technically achievable with existing sensors and LDAR systems, methane has historically been severely underreported.

Encouragingly, progress is underway. Voluntary initiatives such as the Oil and Gas Methane Partnership (OGMP 2.0) are driving transparency and accountability in methane reporting. As of 2024, the initiative includes 140 members, collectively representing 42% of global oil and gas production and over 80% of global LNG flows. Their adoption of measurement-based MMRV frameworks and asset-level reporting is laying a foundation for widespread adoption of best practices.

In January 2024, the International Methane Emissions Observatory (IMEO) launched the Methane Alert and Response System (MARS), the world's first public, satellite-based methane detection and alert system. MARS notifies government agencies when leaks are detected at oil and natural gas sites. However, on-site mitigation remains the responsibility of operators and regulators. To date, only around 1% of MARS notifications have received a meaningful response, underscoring a critical gap between detection and industry-driven action. An overview of these and other methane abatement and reduction initiatives is provided in the table below.

Table 6: Overview of methane abatement and reduction initiatives in the energy industry

	Lead Organisation	Programme	Start Year	Participants	Description	Programme Contributions
Global	World Bank	Global Flaring and Methane Reduction Partnership	2023	Multiple governments and companies	Supporting developing countries in reducing routine flaring and methane emissions through policy, investment, and technical support	• Zero Routine Flaring by 2030 • Global Gas Flaring Tracker Report
Global	Oil and Gas Climate Initiative (OGCI)	Aiming for Zero Methane Emissions	2022	22 signatory companies	Targeting near-zero methane emissions from operated oil and gas assets by 2030, with focus on annual reporting, MRV intergration, and advocacy	• Annual progress reports
Global	European Union and the United States	Global Methane Pledge	2021	159 countries and European Commission	Countries commit to reducing global methane emissions by at least 30% below 2020 levels by 2030 through collaboration and national action	• Advanced Global Methane Reductions (AGMR)
Global	United Nations Environment Programme (UNEP)	Oil and Gas Methane Partnership 2.0	2020	65 upstream companies[1]	Voluntary reporting and mitigation programme with the industry's most comprehensive methane reporting framework; aspiring for a 60-75% reduction by 2030	• Gold Standard framework for MRV of methane emissions
Global	United Nations Environment Programme (UNEP)	Climate and Clean Air Coalition (CCAC)	2012	97 countries	Voluntary partnership focused on reduction of short-lived climate pollutants, including methane, through policy, advocacy, and funding support	• Global Methane Assessment • Global Methane Pledge (Secretariat services)
Regional	JERA, Kogas	Coalition for LNG Emission Abatement Toward Net Zero (CLEAN)	2023	27 gas/LNG companies	Industry-led programme initiated by key LNG buyers focusing on emission reduction in the LNG value chain	• CLEAN Annual Report
Regional	PETRONAS	ASEAN Methane Leadership Program 2.0	2024	18 members	18-month regional programme focused on methane mitigation capacity building, and MRV training	• Southeast Asia Methane Emissions Technology Evaluation Centre (planned)
Data-focused	United Nations Environment Programme (UNEP)	International Methane Emissions Observatory (IMEO)	2021	-	Global methane emissions platform integrating data from MARS, OGMP 2.0, and various independent methane studies for analysis and thought leadership	• Annual Eye on Methane report
Data-focused	International Energy Agency	Global Methane Tracker	2020	-	Comprehensive assessment of global methane emissions with country- and sector- level data, tracking progress on pledges and other industry action	• Annual Global Methane Tracker report

Notes: [1] *OGMP 2.0 members include companies from downstream and midstream sectors, as well as non-company organisations such as the World Bank and the European Commission.*
[2] *List is not exhaustive.*

The Coalition for LNG Emission Abatement Toward Net Zero (CLEAN) initiative, which was spearheaded by JERA and Kogas in 2023 with support from the Japan Organisation for Metals and Energy Security (JOGMEC), with the aim to reduce methane emissions across the LNG value chain, further grew its network in 2025. To date, 27 companies have joined the initiative, representing a growing number of LNG producers and consumers committed to driving dialogue and action on emissions reduction.

Additionally, JOGMEC, along with Ministry of Economy, Trade and Industry (METI) of Japan, IEA, UNEP-IMEO, the International Group of Liquefied Natural Gas Importers (GIIGNL), the Environmental Defense Fund (EDF), and methane emissions certification body MiQ, supported by the Government of Canada, issued a joint statement to accelerate reduction of emissions across the LNG supply chain. The parties plan to jointly assess emission reduction opportunities, cooperate with METI and IEA on developing an emission reduction roadmap, and collaborate further on emissions verification mechanisms tailored to reduce emissions within the LNG value chain. Policy efforts are also advancing. In August 2024, the European Union (EU) adopted the Regulation EU/ 2024/1787 on the reduction of methane emissions in the energy sector. Building upon the OGMP 2.0 framework, the regulation mandates LDAR, prohibits routine venting and flaring, and introduces stricter reporting requirements for both domestic producers and imported volumes, with penalties for non-compliance, effectively extending EU methane standards across international natural gas and LNG value chains.

Momentum from industry, regulators, and policymakers signals growing alignment around reducing the emissions intensity of natural gas and LNG value chains. For producers, investing in methane abatement and emissions management will become increasingly essential - not only for compliance with evolving regulations, but also to maintain market access and strengthen the long-term resilience of their operations.

4/ Decarbonisation and Low-carbon Gas Technology Evolution

Chapter highlights

Biomethane stands out as one of the most promising low-carbon gases today

- Backed by mature production technologies, drop-in compatibility with existing infrastructure and its ability to tackle global challenges such as waste management and energy security, biomethane production is projected to grow 14% yearly from about 10 Bcm in 2024 to 75 Bcm by 2040
- Feed-in premiums and tariffs have driven production growth in Europe by guaranteeing long-term offtake and price

Record clean hydrogen FIDs mark execution focus amid lower-than-expected volumes and cost reductions, underscoring need for policy support

- While 2024 has seen lower-than-expected cost reductions and cautious uptake of clean hydrogen by customers, progress has been made with a focus on project executions, as reflected by a record number of FIDs (1.9 Mt) and an almost threefold increase in post-FID volumes (0.8 Mt)
- Clean hydrogen derivatives also face similar challenges, requiring strengthened policy frameworks to increase demand certainty

Momentum in CCUS is building, with major projects having reached FID and start-up

- Global unrisked CO_2 capture capacity is projected to reach 577 Mtpa by 2030, but over 80% is still pre-FID, requiring clearer regulations, faster permitting, and more mature carbon markets to accelerate progress and address delays from project complexity and regulatory challenges
- Further policy support is expected as countries submit their NDCs, especially for carbon removals

Incentivising long-term offtake of low-carbon gases is key in accelerating decarbonisation

- With long-term offtake guaranteed, investment risks decrease, accelerating FIDs and commercial deployment, which in turn enables cost reductions through learning and economies of scale
- Several policies have been successful, such as ReFuelEU Aviation, hydrogen auctions, biomethane book-and-claim systems and CfDs for CCUS

I. The current state and development trajectory of low-carbon gases

a. Biomethane

Biomethane[8] holds **untapped potential in addressing a range of global challenges**, from waste management and energy security to sustainability and soil management. As a **drop-in fuel**, it can be **seamlessly integrated** into existing natural gas infrastructure and end-use applications with **minimal modifications**. It also serves as a **flexible and dispatchable source of clean energy** that provides **critical grid-balancing support during periods of low renewable generation**. Biomethane production technologies are mature, making them a **readily available lever to accelerate global decarbonisation efforts**.

Driven by supportive policy frameworks, global biomethane production has grown sevenfold over the past decade – from 1.5 Bcm in 2014 to 9.6 Bcm in 2024. Europe accounted for almost 60% of total production in 2024 (5.7 Bcm), driven by Germany (1.7 Bcm), France (1.1 Bcm), Italy (0.4 Bcm). This growth was largely supported by supply-side incentives, such as **feed-in premiums and feed-in tariffs**,

[8] Biomethane is a near-pure source of methane (>97% CH_4) produced by purifying biogas.

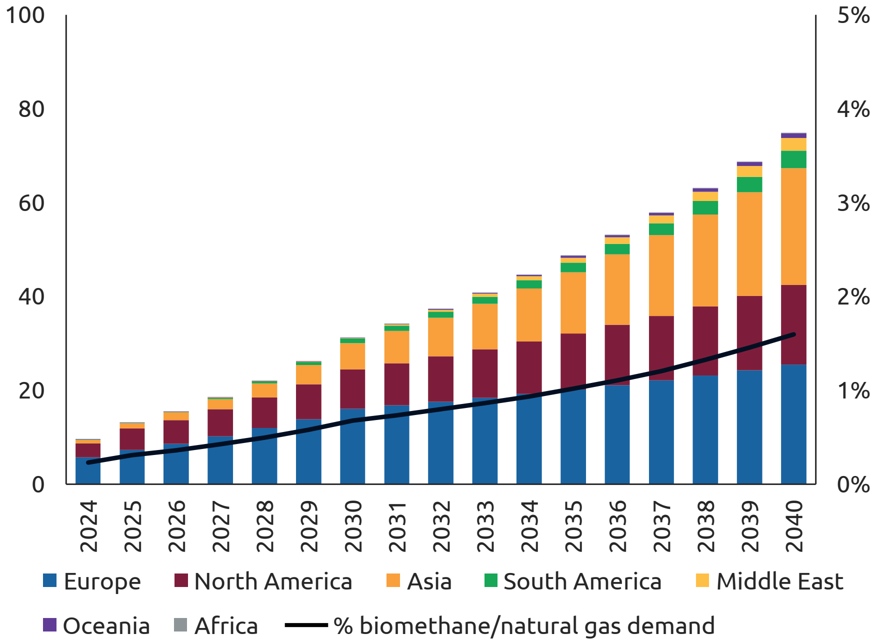
which either **guaranteed a price premium to natural gas, ensured offtake or provided both**, significantly **reducing the investment risks** for operators and investors. In contrast, the US, that was responsible for the majority of the remaining biomethane production in 2024 (about 27%, or 2.6 Bcm), relied on a **cap-and-trade system** to drive low-carbon fuel uptake in the transportation sector. This allows producers of renewable fuel to generate credits for each gallon of qualifying fuel, which is acquired by fuel refiners and importers to comply with their blending or carbon intensity obligations. This boosted biomethane demand, with biomethane accounting for about 79% of on-road fuel used in natural gas vehicles in 2023[9].

Looking ahead, global biomethane production is projected to grow by about 14% annually, rising from 9.6 Bcm in 2024 to 74.8 Bcm by 2040, **driven largely by China's target of reaching 20 Bcm of annual production by 2030 and the EU's 35 Bcm target by 2030**. In China, biogas has historically been prioritised over biomethane, but the country has recently shifted towards industrial-scale facilities focused on producing biomethane for urban applications and transportation. However, margins for biomethane producers in China are often slim, without subsidies, as many incentives still favour biogas production, making it challenging to scale up biomethane production to meet national targets. Meanwhile, the EU is advancing the production and uptake of waste-based biomethane via the Renewable Energy Directive (RED) III. The directive's double-counting mechanism for advanced biofuels from waste and residue streams, such as used cooking oil, allows their energy contribution to count twice towards renewable energy targets. This regulatory shift would **help drive investment in sustainable feedstock supply chains while reducing the sector's dependence on food-grade crops**, thereby boosting the resilience of the European biomethane supply chain. In the US, biomethane production will continue to be driven by blending mandates and carbon intensity requirements in the transportation sector, alongside state-level policies that mandate an increasing use of biomethane in utility gas supplies.

Recently introduced legally binding frameworks, such as the International Maritime Organization's (IMO) net-zero regulations for global shipping by or around 2050, are expected to further accelerate the scale-up of biomethane production, which can be liquefied into bio-LNG for marine use. As a low-carbon alternative to conventional marine

Figure 36: Biomethane production by region and share of biomethane in global natural gas demand

LHS: Bcm; RHS: Percentage

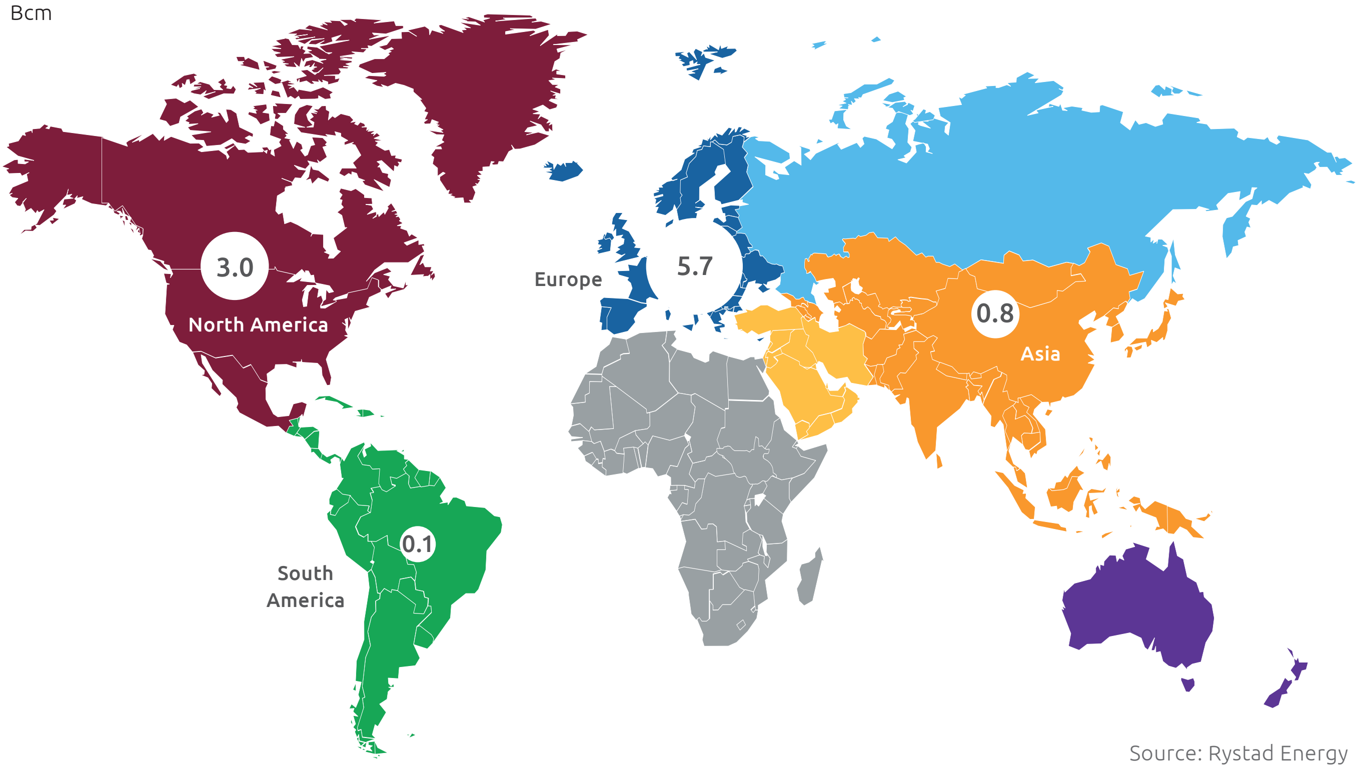


Note: 'Biomethane production' refers to the total production levels of announced biomethane projects, with adjustments (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, commerciality, and country targets. Historical production levels reflect actual data where available; otherwise, they are estimated based on capacity and utilisation rates. The share of biomethane production in global natural gas demand may vary due to uncertainty in global gas demand in the long run. Biomethane production levels for Europe in 2030 are estimated based on announced capacity additions and expected capacity utilisation rates, and are more conservative than REPowerEU's target.

Source: Rystad Energy

[9] *Source: RNG Coalition: RNG breaks motor fuel usage records in 2023, RNG Coalition (April 2024); https://www.rngcoalition.com/news/2024/4/25/rng-coalition-rng-breaks-motor-fuel-usage-records-in-2023*

Map 2: Biomethane production in 2024, split by region



Source: Rystad Energy

fuels, **bio-LNG offers compatibility with existing dual-fuel LNG marine engines, avoiding the need for major retrofits**.

Despite this growing policy support, biomethane fulfilled only 0.23% of global natural gas demand in 2024. Several challenges have slowed its growth, including **feedstock availability, cost competitiveness to natural gas, and permitting delays**.

The type of feedstock used for biomethane production varies per region, dependent on regulations, cost, and availability. **Increasingly, waste-based feedstocks have become attractive in many regions, supported by competitive costs, consistent year-round availability and strong policy support**. For instance, the EU has encouraged biomethane production from non-food and waste-based sources by allowing biomethane produced from these sources to be **double-counted** towards renewable energy targets. Furthermore, the EU has set a **7% cap on food- and feed-based biofuels** that can contribute to the renewable energy target in the transportation sector. In the US, organic municipal waste is primarily used for biomethane production due to its **low cost and high methane yield potential**. This allows biomethane prices to be competitive with natural gas prices in the US. Waste-based feedstocks also tend to be **available year-round**, in contrast to agricultural feedstocks which often **exhibit seasonal variability**. However, waste-based feedstocks have limited scalability, as waste generation cannot increase proportionally with biomethane demand. To address these limitations, **sequential cropping** is gaining attention as a complementary and scalable feedstock solution. Unlike waste-based sources, sequential crops are purpose-grown energy crops, not residues or by-products, and as such, they **offer greater flexibility and responsiveness to market demand**. Their availability is elastic rather than fixed, meaning that production can be scaled up as needed, albeit within the limits imposed by water availability, which remains a critical factor for its feasibility. Importantly, sequential cropping is **not in competition with food and feed production**, as these crops are cultivated between main food crop cycles, making better use of existing agricultural land without displacing food crops. This practice not only boosts biomethane production potential, particularly in countries with extensive arable land and strong agricultural sectors like Italy, India, and the US, but can also contribute to soil regeneration. Therefore, ensuring a **diverse feedstock mix** is crucial to **minimising seasonal fluctuations** in biomethane output, enhancing its value as a **flexible and dispatchable complement** to intermittent renewables in the energy mix.

Biomethane production costs through anaerobic digestion vary widely depending on feedstock type, project location, technology choice, and plant scale. **Waste feedstocks such as manure or municipal solid waste often come at low costs**, while other sources such as agriculture waste, typically trade at higher prices. Proximity to feedstock sources is also a key cost driver, as shorter transport distances help minimise transportation costs. Several upgrading technologies exist for biomethane, with membrane separation and water scrubbing being commonly deployed and cost-effective today. Larger-scale plants benefit from **economies of scale**, with capital costs spread over higher production volumes. Taking these factors into account, global biomethane production costs can vary widely from 11 USD/MMBtu for large plants[10] to 33 USD/MMBtu for smaller-scale facilities, depending on country-specific factors such as feedstock availability. On average, biomethane continues to carry a **cost premium** over natural gas, with benchmark prices at Europe's TTF and Northeast Asia spot markets ranging from 7.5 to 15.0 USD/MMBtu in 2024. **Bridging this cost gap will require continued policy support, including feed-in tariffs and investment incentives, ensuring competitiveness with natural gas**.

While permitting timelines for biomethane plants vary across regions, they are often prolonged by complex and multilayered regulatory processes. According to a survey by the Biomethane Industrial Partnership, a European Commission-led initiative, **permitting can take two to three years on average**, with some projects facing delays of up to five to seven years. In contrast, plant construction typically takes just 18 months in Europe. Delays stem, among other factors, from the **growing decentralisation of the system**, which involves a rising number of smaller production sites compared to traditional natural gas infrastructure. These sites are often located in densely populated areas, where space is limited and permitting particularly complex. Each project requires a high number of permits, each involving time-intensive tasks that could be under the purview of different agencies such as environmental impact assessments and grid connection applications. Rejected permits and appeals further compound delays, creating uncertainty and holding back investment. To address this, the industry has proposed a **zoning based permitting approach**, prioritising pre-identified areas with access to sustainable feedstock and natural gas infrastructure. In these zones, **permitting could be expedited or even automatic**, accelerating project delivery while ensuring alignment with environmental and infrastructure criteria.

While biomethane is widely regarded as a low-carbon alternative to fossil fuels, its **emissions profile depends heavily on its production pathway**. Biomethane production from waste-based feedstock can result in **negative emissions** by capturing methane that would otherwise be released into the atmosphere. Nevertheless, methane leaks during biomethane production can undermine its emission reduction benefits. IEA estimates that the methane leakage rate of agricultural biogas plants is between 2.0% and 5.5%, about **two to five times above** the global average methane emissions leakage rate for oil and gas production, which stood at 1.2% in 2024[11]. To ensure biomethane retains its low-carbon credentials, operators must adopt best practices such as optimising digester loading, using covered digestate storage, and capturing off-gases for combustion or utilisation. If used in ships as bio-LNG, methane slips must be effectively mitigated though methane slip monitoring technology, boil-off gas management systems and low-slip engine designs. The importance of managing the emissions of low-carbon fuels has been reflected in regulations such as the EU's RED II and III, which have established emissions intensity caps for low-carbon fuel eligibility.

Biomethane offers one of the most **immediate and scalable** solutions **for accelerating global decarbonisation**, particularly in sectors **dependent on molecule-based energy sources**. Unlocking its full potential will require **incentives to lower investment risks**, alongside **robust policy frameworks that mandate methane mitigation** across the value chain.

b. Clean hydrogen and its derivatives

Clean hydrogen[12] is another promising low-carbon gas in the energy system, decarbonising hard-to-abate sectors such as the chemical, iron and steel, aviation, and shipping sectors, that collectively accounted for around 25% of global greenhouse gas emissions in 2024. Despite its GHG emission reduction potential, the clean hydrogen sector **concluded 2024 with a more subdued outlook**, as developers

[10] *Based on assumptions such as a low discount rate and readily available waste-based feedstock that in some cases, may have zero or even negative costs.*

[11] *Source: Key issues affecting biogas and biomethane projects, IEA (May 2025); https://www.iea.org/reports/outlook-for-biogas-and-biomethane/key-issues-affecting-biogas-and-biomethane-projects*

[12] *Clean hydrogen, as defined in this report, refers to hydrogen that is produced with low, near-zero and zero lifecycle greenhouse gas emissions, specifically encompassing green hydrogen (from renewable-powered electrolysis) and blue hydrogen (from fossil-based production with carbon capture and storage).*

Figure 37: Clean hydrogen capacity, split by lifecycle detail vs. hydrogen demand

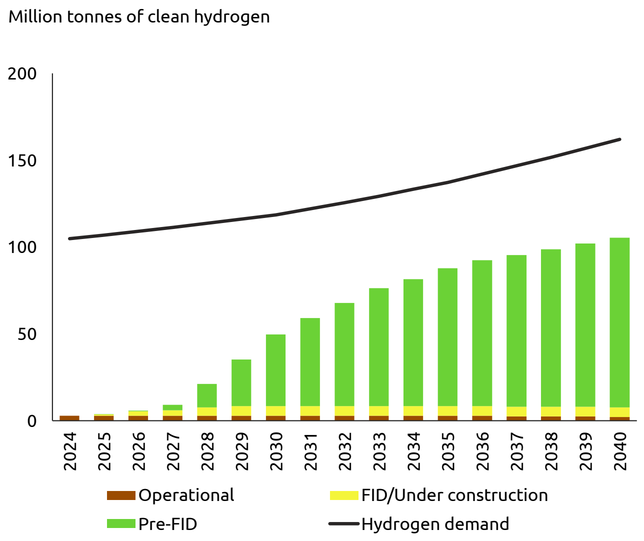
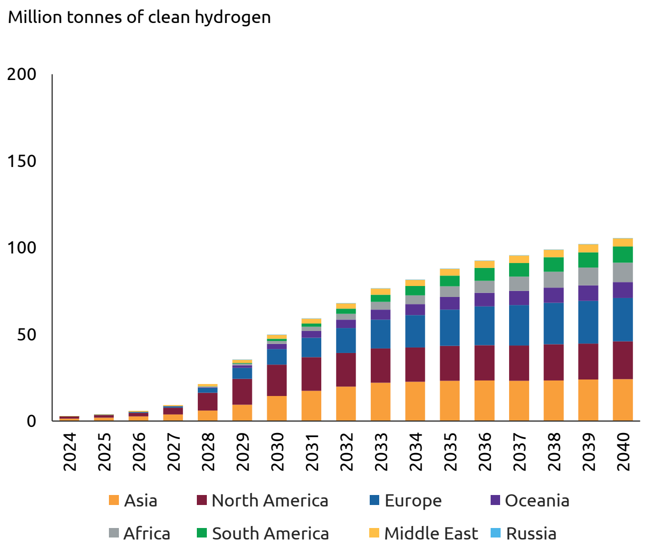


Figure 38: Clean hydrogen capacity, split by region



Note: 'Clean hydrogen capacity' refers to the total unrisked capacity of announced clean hydrogen projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

and investors reassessed the pace and scope of its development. Progress continues, with the project pipeline maturing, as reflected by an almost threefold increase in post-FID volumes (about 0.8 million tonnes of production capacity) compared to last year. However, the combination of **lower-than-expected cost reductions** in production and **limited willingness to pay** from customers, has discouraged the announcement of new projects and led to a more cautious market sentiment. Instead of announcing more early-stage plans, developers and investors are **shifting focus towards project execution** and progressing previously announced developments to final investment decisions (FIDs). This strategic pivot aims to **capitalise on learning curve effects and reduce costs**, resulting in a **record number of FIDs in 2024** (about 1.9 million tonnes of production capacity) and a **more mature project pipeline**. While this is set to accelerate the scale-up of clean hydrogen, **near-term momentum remains below earlier expectations**.

Policy frameworks in the US and the EU have played a critical role in driving early momentum by narrowing the cost gap between green and grey hydrogen, subsidising clean hydrogen production and internalising the cost of CO_2 emissions from conventional grey hydrogen production. In the US, the 45V tax credit significantly lowers the cost of green hydrogen production, while the EU supports projects through Innovation Fund subsidies and carbon pricing under the Emission Trading Scheme (ETS), helping drive cost convergence critical for investment decisions in clean hydrogen. Nonetheless, realising the full value of these cost improvements will require investments in infrastructure to be made simultaneously, ensuring that hydrogen can be delivered efficiently to end users at scale.

However, **inflationary pressures** from higher material, equipment, and labour costs have limited the effectiveness of these policy support measures, contributing to the slower pace of cost reduction in clean hydrogen production seen in 2024 (figure 39). In parallel, project delays have hindered deployment at scale, preventing cost reductions that typically arise through learning curve effects and economies of scale. This highlights the need for stronger and more adaptive policy support to boost market confidence and accelerate investments to scale up the sector.

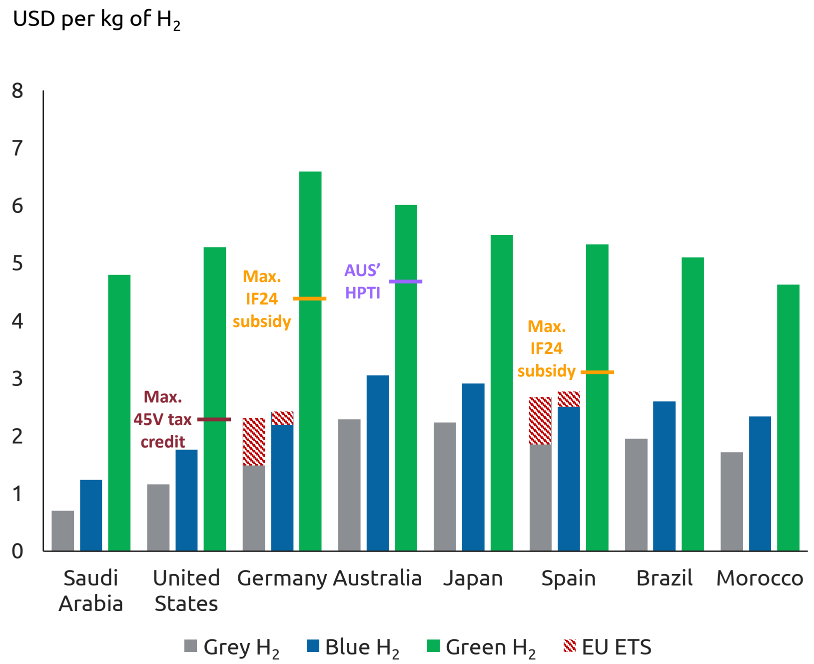
Hydrogen **infrastructure** development is **progressing**, though at a **slower-than-expected pace**, as high costs and insufficient demand have led to delays and cancellations of several network projects. For example, Gasunie has postponed the completion of the Dutch hydrogen network to 2033, citing permitting and labour challenges. Nevertheless, **recent developments suggest**

renewed momentum. In 2024, Germany committed EUR 18.9 billion to build a national hydrogen network, while 20 companies across France, Germany, Portugal and Spain launched the H2Med Southwestern Hydrogen Corridor alliance to accelerate a pipeline linking Iberian producers to northern Europe by the early 2030s. Separately, a Joint Declaration of Intent was signed to advance the Southern Hydrogen Corridor project, establishing a direct hydrogen pipeline connecting North Africa with Italy, Austria, and Germany.

While Asia has not been at the forefront of hydrogen pipeline development, **key projects are now taking shape**. In China, construction is advancing on the 973 km Zhangjiakou Kangbao-Caofeidian pipeline, set to become the longest dedicated hydrogen pipeline globally. In Southeast Asia, Gentari and City Energy have launched a joint feasibility study for a cross-border hydrogen pipeline linking Malaysia and Singapore, while Sembcorp, Pertamina Persero, and Transportasi Gas Indonesia are exploring a similar pipeline between Indonesia and Singapore. In contrast, North America has seen limited new-build activity in 2024 despite operating the world's largest installed hydrogen pipeline network, largely due to shifting policy priorities and regulatory uncertainty.

Hydrogen infrastructure advancements also included hydrogen storage**. Underground hydrogen storage** is the most promising storage technology for the large-scale and seasonal storage of hydrogen, with salt caverns emerging as the most popular option, with ongoing studies on other solutions, such as depleted fields and aquifers. Currently, there are around 60 underground storage facilities in development globally, of which only 20 are operational, primarily at pilot scale and located mainly across the US, the UK, Germany, and Austria.

Figure 39: Levelised cost of hydrogen production for selected countries in the most cost competitive provinces, 2025



Note: Levelised costs represent modelled real costs of hydrogen production in 2025 for each country based on a set of location-specific assumptions extracted from Rystad Energy's Hydrogen and Alternative Fuels Economic Analysis dashboard. Each country's levelised cost reflects the production cost in the most cost competitive province. Model assumptions cover the prevailing location-specific natural gas and power prices, a discount rate of 7%, an asset lifetime of 30 years, an electrolyser energy consumption of 54 kWh per kg of hydrogen, an electrolyser plant size of 20 MW, and a carbon capture rate of 80%. The renewable energy source used for green hydrogen production is assumed to be solar and wind only. Grey and blue hydrogen levelised costs have been adjusted with carbon taxes, while green hydrogen levelised costs have been adjusted with the maximum subsidies that projects can qualify for, where applicable, across countries. Thus, hydrogen production costs can be more realistically compared, showcasing how policies have driven clean hydrogen closer to cost parity with grey hydrogen, encouraging production and uptake.

Source: Rystad Energy

Ammonia production remains the **largest end-use sector for hydrogen** in producing hydrogen derivatives, accounting for 32% of global hydrogen demand in 2024 (about 33 million tonnes). As decarbonisation efforts intensify, the transition to clean hydrogen is critical for reducing emissions in ammonia production, particularly given its role as both a **fertiliser feedstock and an emerging energy carrier**. However, in 2024, **less than 5%** of global ammonia production capacity utilised clean hydrogen, highlighting an urgent need to accelerate decarbonisation efforts across the sector. This is essential in the context of population growth and economic development in developing regions, which are expected to fuel ammonia demand as fertilisers are a key input to the agricultural sector. As the energy transition accelerates, ammonia's role is expanding

Figure 40: Clean ammonia capacity, split by hydrogen type vs. ammonia demand

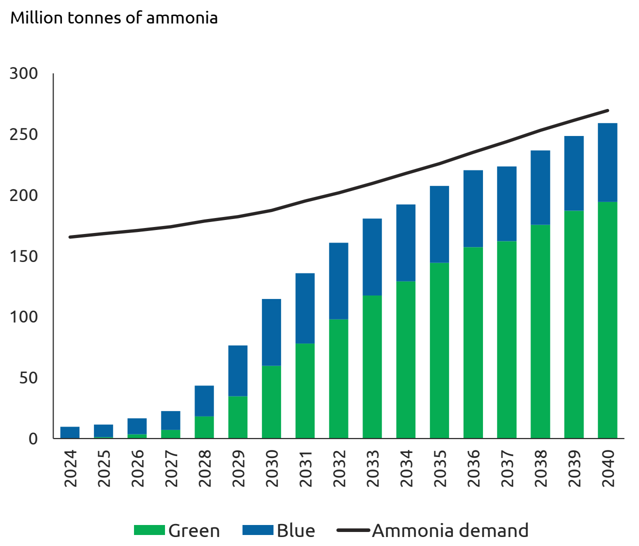
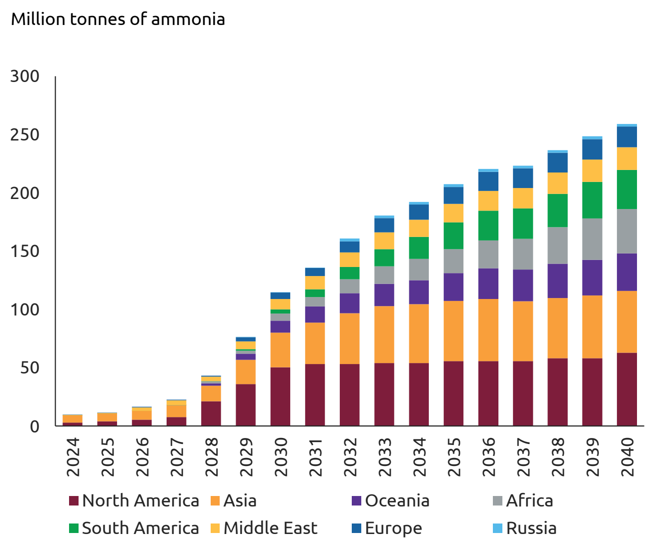


Figure 41: Clean ammonia capacity, split by region



Note: 'Clean ammonia capacity' refers to the total unrisked capacity of announced clean ammonia projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

beyond its conventional uses, with clean ammonia emerging as a **versatile low-carbon solution for hard-to-abate sectors** such as shipping and heavy-duty transport, while also **supporting emissions reduction efforts** in coal-fired power generation. Traditional end-use sectors such as fertiliser production and refinery operations are also expected to contribute to clean ammonia demand, alongside the power sector emerging as a key demand source through co-firing applications. This trend is being driven by supportive policy frameworks, particularly in Europe. In the EU, the RED III requires 42% of the hydrogen used in industry to be renewable by 2030, increasing to 60% by 2035, implying that existing ammonia producers must begin integrating green hydrogen into their operations within this decade.

Supported by an earlier wave of project FIDs, blue ammonia[13] is expected to lead near-term capacity additions relative to green ammonia[14] developments. However, green ammonia is anticipated to dominate in the longer horizon due to global policy support. Clean ammonia has the potential to meet most of the global ammonia demand by 2040, assuming current project pipelines materialise as planned. Nevertheless, delays and cancellations in project execution could defer this timeline.

Realising the potential of clean ammonia will depend on **overcoming cost, demand, and financing challenges, which are deeply interlinked, in addition to infrastructure and supply-chain risks**. High production costs limit the price competitiveness of clean ammonia, leading to uncertain offtake, particularly from the fertilisers sector. Infrastructure and supply-chain challenges such as port readiness, electrolyser supply, and renewable power availability will also need to be contended with for the commercialisation of clean ammonia.

Besides ammonia, **methanol** stands as one of the most important chemicals for the hydrogen industry, playing a key role in various applications such as methanol-gasoline blending and heat and power generation. It is also widely used as a feedstock for chemicals such as formaldehydes, acetic acids, and olefins which are used in the production of everyday products. While the role of methanol in chemical production remains dominant, its **potential as a clean marine fuel is drawing increasing attention**.

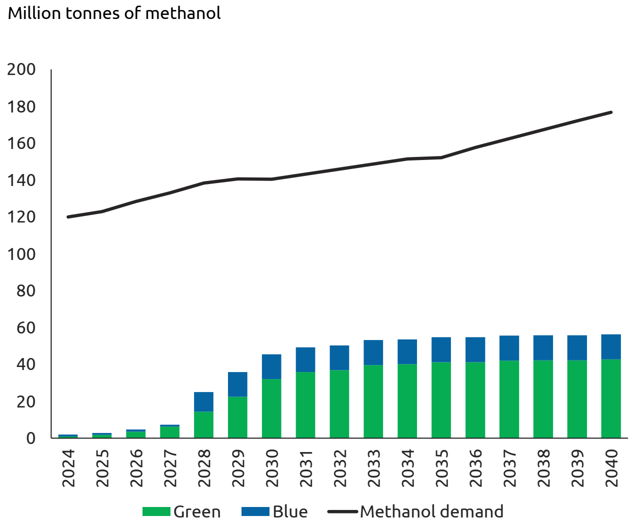
[13] *Blue ammonia is produced by combining nitrogen separated from air with hydrogen derived from natural gas, with CO_2 emissions mitigated by carbon capture and storage.*

[14] *Green ammonia is produced by combining nitrogen separated from air with hydrogen generated through water electrolysis powered by renewable energy.*

For instance, both FuelEU Maritime and the IMO are promoting the adoption of e-fuels as cleaner alternatives to traditional shipping fuels. However, methanol-fuelled vessel orders experienced a slight slowdown last year, with 130 new orders placed compared to 149 in 2023. Based on the current order book, the dual-fuel methanol fleet is projected to reach 455 by 2030, roughly a third of the number of dual-fuel LNG vessels on order for delivery that year (excluding LNG carriers). Even with tighter regulations and incentives favouring cleaner fuels, **green methanol is not expected to reach cost parity with traditional shipping fuels such as very low sulphur fuel oil (VLSFO) before 2050**. Meanwhile **blue methanol may not meet the IMO's zero- and near-zero-emission fuel standard for lifecycle emissions**, thereby creating uncertainty in shipping's long-term offtake potential for clean methanol.

Currently, methanol is mostly produced via fossil fuels, with China accounting for almost 60% of global methanol production in 2024, primarily via coal gasification due to its abundant coal reserves. In contrast, clean methanol production capacity **made up less than 2% of global methanol production in 2024**. Similar to challenges faced in the scale-up of clean ammonia production, high

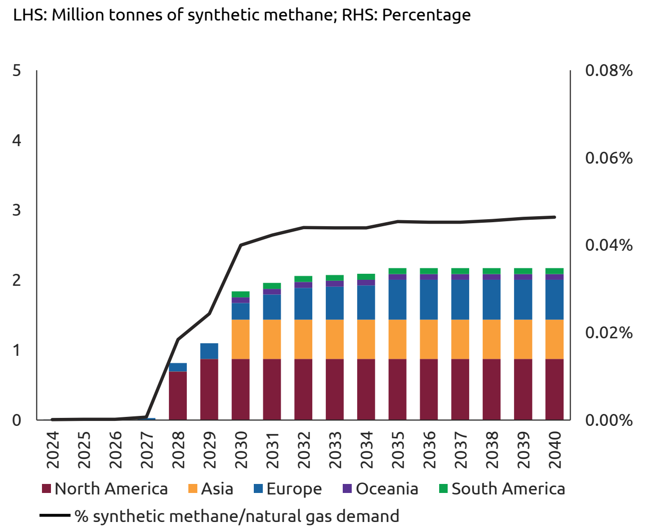
Figure 42: Clean methanol capacity, split by hydrogen type vs. methanol demand



Note: 'Clean methanol capacity' refers to the total unrisked capacity of announced clean methanol projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

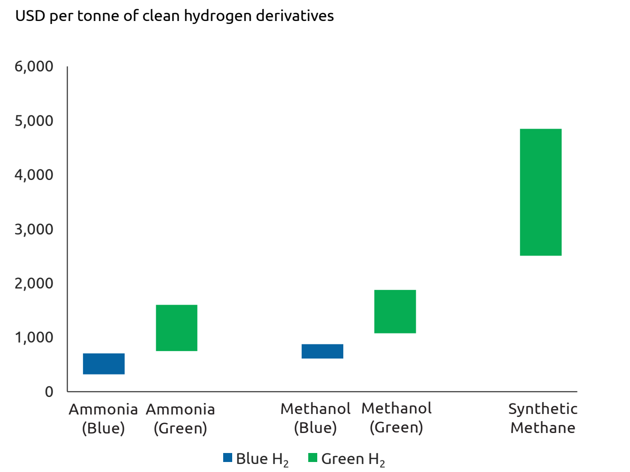
Figure 43: Synthetic methane capacity and share of synthetic methane in global natural gas demand



Note: 'Synthetic methane capacity' refers to the total unrisked capacity of announced synthetic methane projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

Figure 44: Levelised cost of clean hydrogen derivatives, split by hydrogen type, 2024



Note: The range of levelised costs represent modelled real costs of clean hydrogen derivatives in 2024 across North America, Europe, and Asia based on a set of location-specific assumptions extracted from Rystad Energy's Ammonia Market and Methanol & Synthetic Fuels Market dashboards. Model assumptions include a discount rate of 10%, blue hydrogen cost ranging from 1.5 USD/kg to 3 USD/kg, and green hydrogen costs ranging from 6 USD/kg to 8 USD/kg.

Source: Rystad Energy

production costs and demand uncertainty have slowed down the development of clean methanol. Furthermore, **policy support for clean methanol is geographically limited** to Europe and the US, who currently account for less than 9% of methanol production globally. To accelerate the development of clean methanol, regions with significant methanol production must implement stronger supply-side and demand-side policy levers.

Another promising hydrogen derivative is **synthetic methane**, fully compatible with existing natural gas infrastructure and end-use applications. In addition to being a **clean fuel**, it **retains all the benefits of natural gas**, including energy storage and dispatchability for power generation, making it a **flexible complement to variable renewable energy** in a decarbonised energy system. However, synthetic methane remains **four to eight times more expensive** than Asian spot LNG prices in 2024, underscoring the need for substantial cost reductions enabled by robust policy support. Japan is addressing this challenge by pursuing overseas synthetic methane production projects, capitalising on lower renewable electricity and green hydrogen costs abroad. For example, several Japanese utilities firms have partnered with Sempra Infrastructure to produce synthetic methane in the US Gulf Coast for export to Japan by utilising the Cameron LNG terminal. In Europe, Finland is driving the scale-up of e-methane production capacity to accelerate the decarbonisation of heavy road freight and maritime transport. Nordic Ren-Gas is at the forefront of this effort, developing six e-methane projects with EUR 115 million in cumulative funding support from the first EU Hydrogen Bank auction, the EU Innovation Fund, and the Finnish government.

c. SAF

In the aviation sector, **sustainable aviation fuel (SAF)** is widely recognised as a critical lever for decarbonising air travel at scale, with the **potential to deliver lifecycle emissions reductions of up to 99% compared to conventional jet fuel**. However, this is dependent on the production technology and feedstock used. SAF can be produced via various pathways, with the hydroprocessed esters and fatty acids (HEFA) pathway being the most widely deployed, as it leverages existing refinery infrastructure and mature hydrotreating technology, while also benefiting from established feedstock supply chains. This pathway uses waste and residue lipids such as used cooking oil, which are processed with hydrogen to produce SAF. Production pathways that utilise biogenic feedstocks would produce bio-SAF, such as HEFA and

Figure 45: SAF capacity, split by region vs. SAF demand

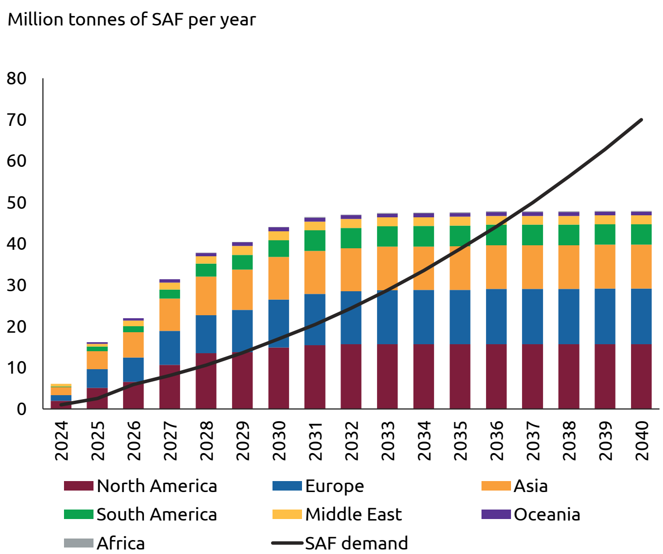
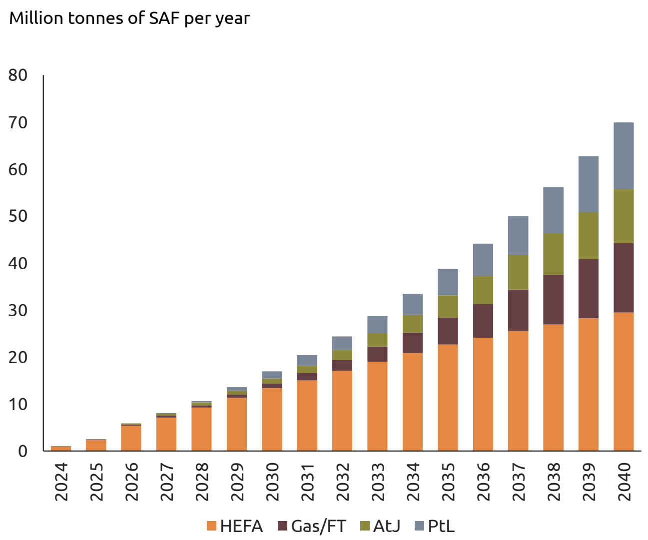


Figure 46: SAF demand, split by technology



Note: 'SAF capacity' refers to the total unrisked capacity of announced sustainable aviation fuel projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

emerging pathways such as gasification/Fischer-Tropsch (Gas/FT) and alcohol-to-jet (AtJ). These pathways are compatible with a range of inputs, but only SAF derived from sustainably sourced biomass or biogenic waste qualifies as bio-SAF. In contrast, e-SAF is produced via the nascent power-to-liquid (PtL) pathway, which uses green hydrogen and captured carbon dioxide as feedstock. These emerging pathways are nearing commercial status and are **expected to rival the HEFA pathway by 2040**, driven by tightening regulations.

SAF production volumes have demonstrated strong growth rates over the past five years, increasing by 10 times from 0.1 million tonnes in 2020 to 1 million tonnes in 2024. **Production levels in 2024 are also double that of 2023**, which accounted for 0.5 million tonnes of SAF. However, **low demand and limited willingness to pay** for SAF have **discouraged further investment** into the sector, reflected in the continued reliance on non-binding memoranda of understanding rather than bankable, long-term offtake contracts that can underpin project financing. Nonetheless, this is beginning to shift with the implementation of the ReFuelEU Aviation regulation, which sets legally binding blending targets for the use of SAF in all flights departing from airports in the EU starting in 2025. The regulation covers both bio-SAF and e-SAF, with a minimum 2% blend of SAF required in 2025 and no sub-target for e-SAF in the initial years. Mandatory e-SAF blending begins in 2030 at 1.2% and rises progressively to 35% by 2050. These binding SAF blending targets are expected to drive sustained demand for both types of SAF, thereby encouraging investments across the SAF value chain. The effectiveness of this regulation is already being seen, with a temporary oversupply observed in early 2025, driven by producers ramping up HEFA co-processing output after the mandate's implementation.

II. The growing role of CCUS in the energy transition

2025 marks a pivotal year for the **carbon capture, utilisation and storage (CCUS)** industry, with various **major projects having reached FID** (around 8 Mtpa of CO_2 capacity from five projects within the first four months of 2025) and **major infrastructure nearing completion or commencing operations**. The year

Figure 47: Capacity of CO_2 capture projects, split by lifecycle detail

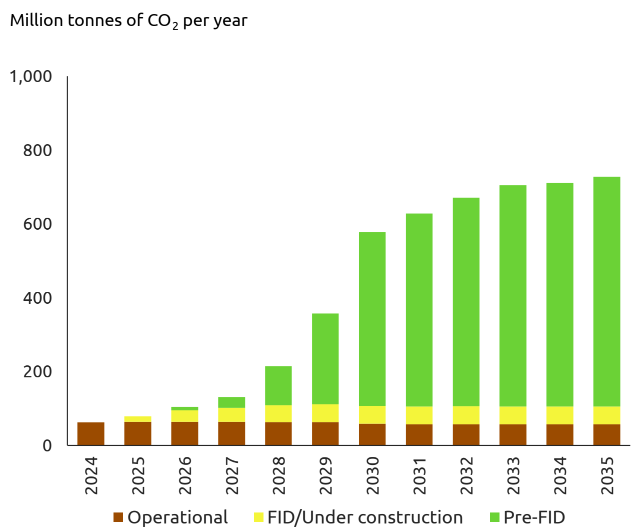
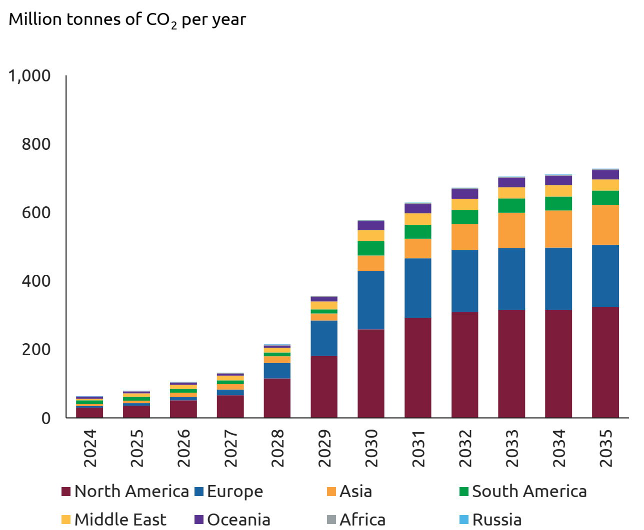


Figure 48: Capacity of CO_2 capture projects, split by region



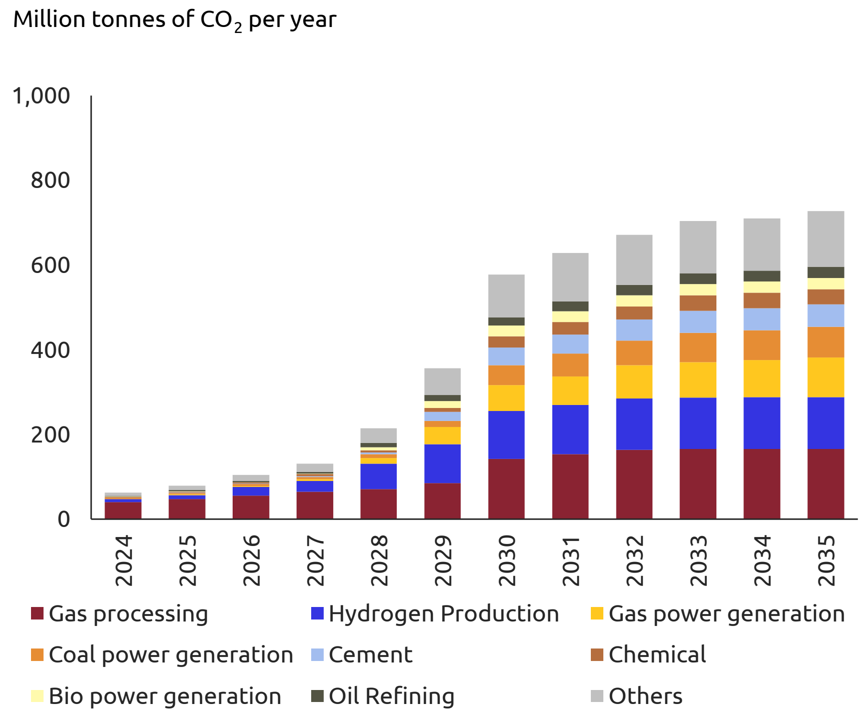
Note: 'Capacity of CO_2 capture projects' refers to the total unrisked capacity of announced CO_2 capture projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

could also see **inclusions of CCUS by countries in their submission of 2035 targets under their third National Determined Contribution (NDC)** required under the Paris Agreement, as governments and companies increasingly view CCUS as a vital decarbonisation tool to achieve climate targets. This is reflected in the acceleration of CCUS projects in developing regions such as Asia, with countries like Malaysia and Indonesia scaling up plans to be regional leaders in CCUS.

Global unrisked CO_2 capture capacity is expected to grow towards 79 Mtpa in 2025 and could increase by more than seven times to 577 Mtpa by 2030. However, most of the upcoming CO_2 capture capacity is in the **pre-FID phase** and many projects have **yet to secure the commercial, technical, and regulatory certainty required to move forward**, putting them at risk of delays and cancellations. Project delays have **intensified** in recent years, with the percentage of delayed projects rising from 32% in 2022 to 42% in 2024, reflecting **growing challenges in navigating project complexity and regulatory hurdles as projects progress from planning to implementation**. One example is Kairos@C, the largest cross-border CCUS project in the EU, which aims to capture and store 14 million tonnes of CO_2 over its first decade of operations. The project had initially targeted an FID in 2023 with operations set to begin in 2025, but that timeline has slipped. As of early 2025, no investment decision has been confirmed due to insufficient financial support. Another example is the Summit Carbon Solutions pipeline project, which has faced significant delays due to public concerns over environmental safety and cultural preservation, as well as the complexities of securing

Figure 49: Capacity of CO_2 capture projects, split by carbon source category



Note: 'Capacity of CO_2 capture projects' refers to the total unrisked capacity of announced CO_2 capture projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

permits across multiple states. Accelerating the progress of CCUS has become critical to meeting national climate targets, underscoring the need for clearer regulatory frameworks, especially for CO_2 transport and storage, alongside faster permitting processes and more developed carbon markets to support offtake certainty.

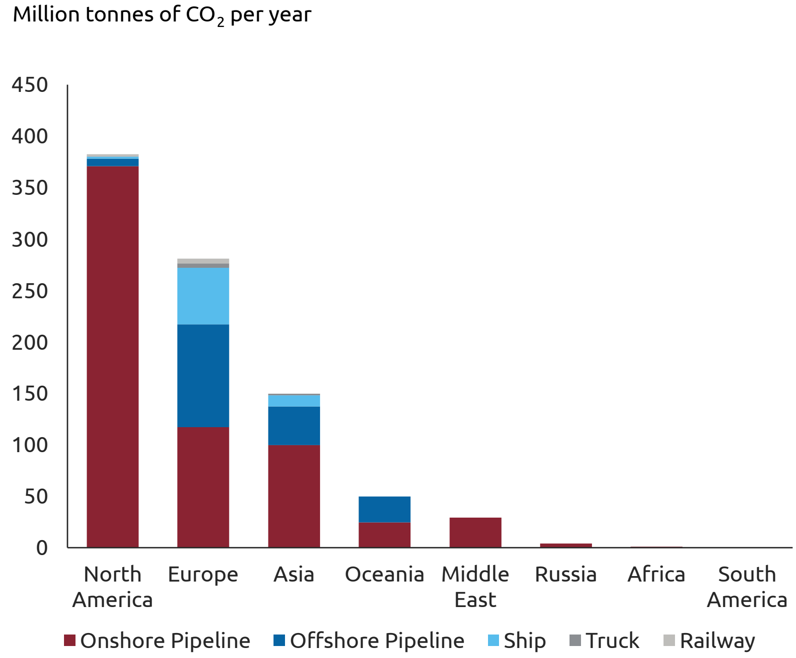
Historically, North America has driven the development of CO_2 capture projects, contributing to nearly half of total global capacity due to incentives from the 45Q tax credit and the Inflation Reduction Act, alongside widespread oil and gas infrastructure that can be repurposed for CO_2 transport and storage.

By 2030, Europe is set to join North America as a key driver of CO_2 capture capacity growth, cumulatively accounting for more than 74% of global CO_2 unrisked capture capacity, with **Europe alone making up almost 30%**. This is enabled by policies such as the ETS, the Green Deal Industrial Plan and REPowerEU, and regulatory frameworks such as the Net-Zero Industry Act and the Industrial Carbon Management Strategy. These policies help scale early-stage projects by stimulating CO_2 demand, streamlining permitting, providing funding support, and guaranteeing CO_2 storage safety.

As policy support for CCUS strengthens and becomes more certain in Asia, the continent is expected to account for **almost 20% of global CO_2 capture capacity by 2040**, driven by China, India, Japan, Malaysia, and Indonesia. Malaysia passed its CCUS bill in early 2025, establishing a comprehensive legal framework and central regulatory agency, inching closer to its goals of developing three regional CCUS hubs by 2030. Similarly, over 2023 and 2024, Indonesia released guidelines for CCUS activities in the country. Site characterisation efforts for CO_2 storage are underway in Indonesia, helping determine storage capacity, injectivity, and overall reservoir integrity, which are essential to de-risking long-term CO_2 containment. Key activities such as reservoir characterisation, fault and borehole integrity assessments, and the identification of potential migration pathways are still in the early stages, indicating that readiness for commercial-scale deployment may require significant time and investment.

Historically, CO_2 capture was first deployed at scale in natural gas processing plants, where CO_2 removal is required to meet pipeline specifications. As CCUS became increasingly established as a critical pathway for decarbonising hard-to-abate sectors and achieving net-zero CO_2 emissions, pilot and commercial-scale projects began to come online globally across all industrial sectors. Towards 2040, growth in CO_2 capture capacity is expected to be **driven by blue hydrogen and power generation**. This momentum is supported by a myriad of clean hydrogen production incentives in the US, Canada, and Europe. In parallel, emissions regulations for the power sector were finalised in Canada, where the operation of unabated fossil fuel-fired power plants is prohibited after 2035. These regulations reinforce the role of CCS in enabling compliance and supporting the long-term viability of fossil-based power generation.

Figure 50: Capacity of CO_2 transport project announcements until 2025, split by CO_2 transportation mode



Note: 'Capacity of CO_2 transport project announcements till 2025' refers to the total unrisked capacity of historically and currently announced CO_2 transport projects based on project owners' communicated capacity, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

CO_2 transport is undergoing a strategic shift, with **more projects relying on offshore pipelines and shipping, as an increasing number of CCUS hubs are developed**. While pipelines continue to dominate due to their cost-effectiveness and scale, the diversification of CO_2 transportation modes reflects the **evolving maturity and growing complexity of the CCUS landscape**. This development is most **prominent in Europe and gaining traction in Asia**, where fragmented geography and limited domestic carbon storage in some countries are making cross-border CO_2 trading and transport increasingly essential for scaling up CCUS deployment.

The outlook for CO_2 storage capacity **broadly mirrors** that of CO_2 capture, with **most projects still in the pre-FID phase**. Near-term growth is expected to be led by North America, which continues to dominate global storage development through the end of the decade, with Europe and Asia playing a more prominent role after 2030. However, not all captured CO_2 is stored, with a portion of CO_2 being utilised in enhanced oil recovery, chemical production, and e-fuel production.

Major CO_2 storage hubs are advancing globally, with **key developments underway** in Europe and North America. A notable milestone was achieved

Figure 51: Capacity of CO_2 storage projects, split by lifecycle detail

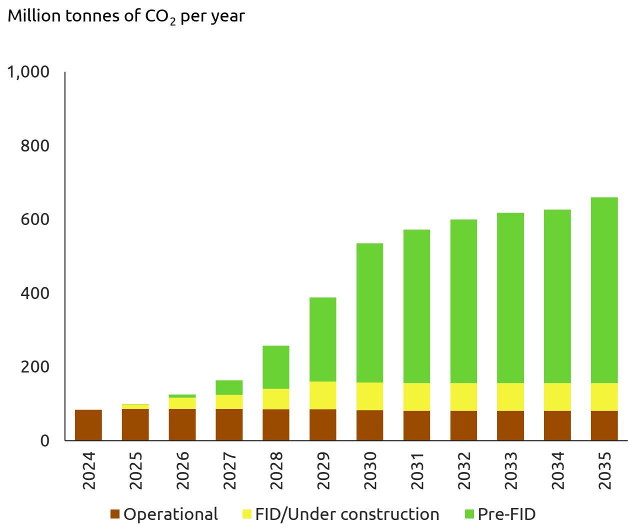
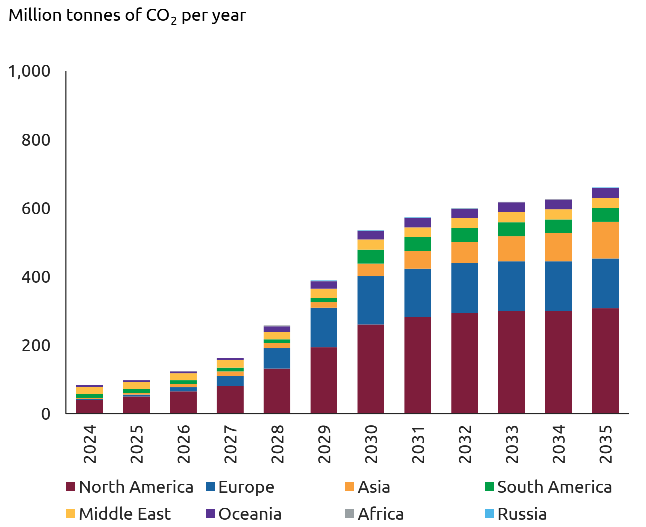


Figure 52: Capacity of CO_2 storage projects, split by region



Note: 'Capacity of CO_2 storage projects' refers to the total unrisked capacity of announced CO_2 storage projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

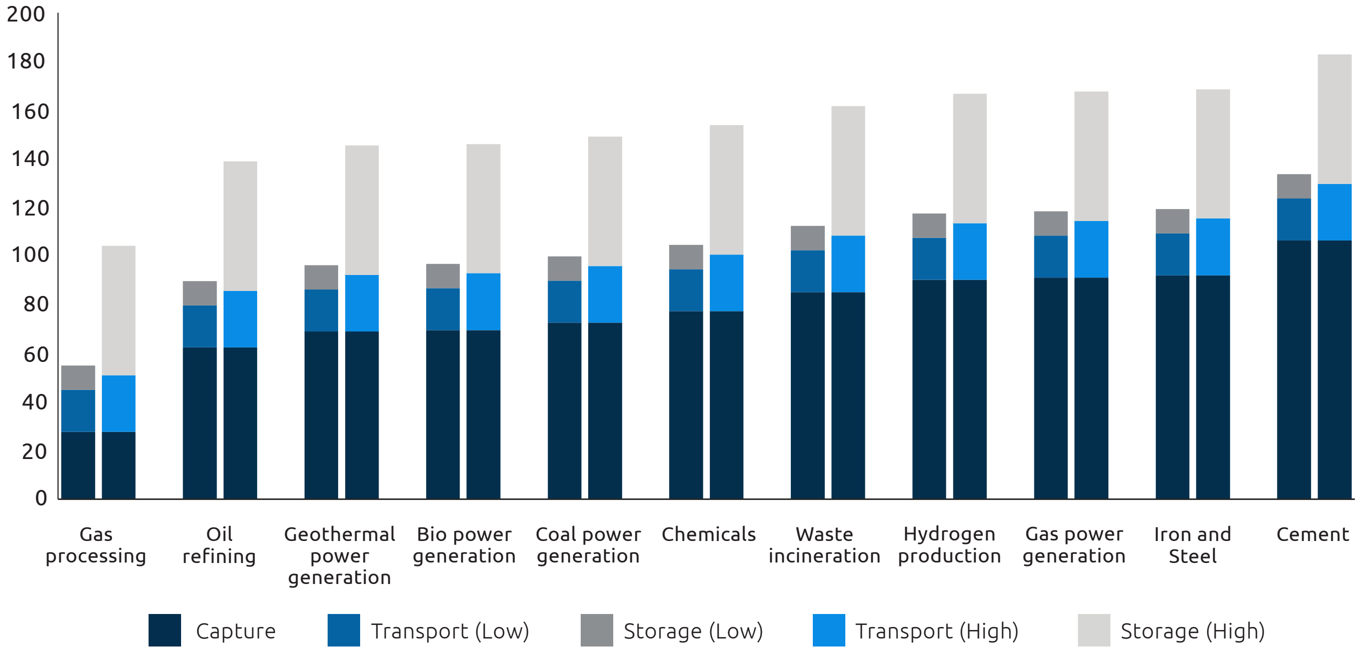
in 2024 when the Northern Lights project in Europe commenced operations, receiving its **first shipment of liquefied CO_2** from the Heidelberg Materials cement plant in Brevik in early June this year. Furthermore, an FID for phase 2 of Northern Lights was announced in March 2025, following the signing of a 15-year CO_2 offtake agreement with Stockholm Exergi for 0.9 Mtpa of CO_2. This translated into a CO_2 transport and storage capacity for the project of 5 Mtpa of by 2028. At the same time, 1PointFive's STRATOS direct air capture (DAC) facility in the US, the **world's largest DAC plant**, achieved a key regulatory milestone in 2025 with the approval of its Class VI permits for CO_2 sequestration. This approval represents a critical step towards commercial operations, remaining on track to begin operations in the second half of 2025 which could see up to 0.5 Mtpa of CO_2 captured.

However, each region has faced vastly different challenges. **North America:** Securing CO_2 offtake from local emitters has been a critical barrier to FIDs for North American hub developers intending to provide transportation and storage as a service, with only 27% of the storage hubs announced in North America having secured offtake agreements. Of the 27%, around half are tied to a single CO_2 emitter project, making them fully reliant on the progress of a single CO_2 capture project and more exposed to risks associated with delays or cancellations. As such, developers are unable to proceed with FIDs without sufficient offtake to cover project costs. **Europe:** Strong demand for storage hubs in Europe is anticipated to exceed available announced capacity by around 50%. This is primarily due to the slower development of storage sites which is typically carried out in phases, requiring long lead times for capacity to come online. In response, governments are stepping up support to accelerate development. For example, the UK has committed GBP 21.7 billion to advance the development of large-scale CCUS clusters such as the East Coast and HyNet clusters. By de-risking early-stage developments, initial government funding is expected to attract an addition GBP 8 billion in private capital, accelerating decarbonisation in the UK. **Asia:** While storage hub development is picking up pace in countries like Malaysia, these projects are likely to face delays. The planned storage hubs would primarily store CO_2 from domestic emitters and key international customers from Japan and South Korea. However, these projects are likely to face challenges with alignment on regulations, financial support, royalty fee structure, and primacy in permit issuance, which are ironed out between the federal government and state authorities.

CCS costs remain weighted towards the capture component, with significant variation depending on the CO_2 concentration in the emission source stream, where **higher CO_2 concentrations generally result in lower capture costs**. Initially, most carbon capture technologies were designed for acid gas removal

Figure 53: Levelised cost of CO_2 capture, transport and storage, 2024

USD per tonne of CO_2 captured, transported and stored



Note: Results and calculations are extracted from Rystad Energy's CCUS Levelised Cost dashboard, based on assumptions to provide a representative view of the average range of the levelised cost of CO_2 capture, transport, and storage across global projects. CO_2 capture costs are based on a power price of 50 USD/MWh and a CO_2 capture rate of 1 Mtpa. An open-cycle gas turbine plant is assumed for the levelised cost of capture for gas power generation. CO_2 transport costs are based on transport distances that range from 150 km to 200 km, a CO_2 transport amount of 2 Mtpa, and transport modes that include both onshore and offshore pipelines. CO_2 storage costs are based on a storage depth of 1,500 m, a storage rate of 1 Mtpa, storage types that include both onshore and offshore storage, and reservoir types that include both depleted oil and gas fields and saline aquifers. Levelised cost of storage data only includes injection and storage costs and does not include monitoring and verification costs.

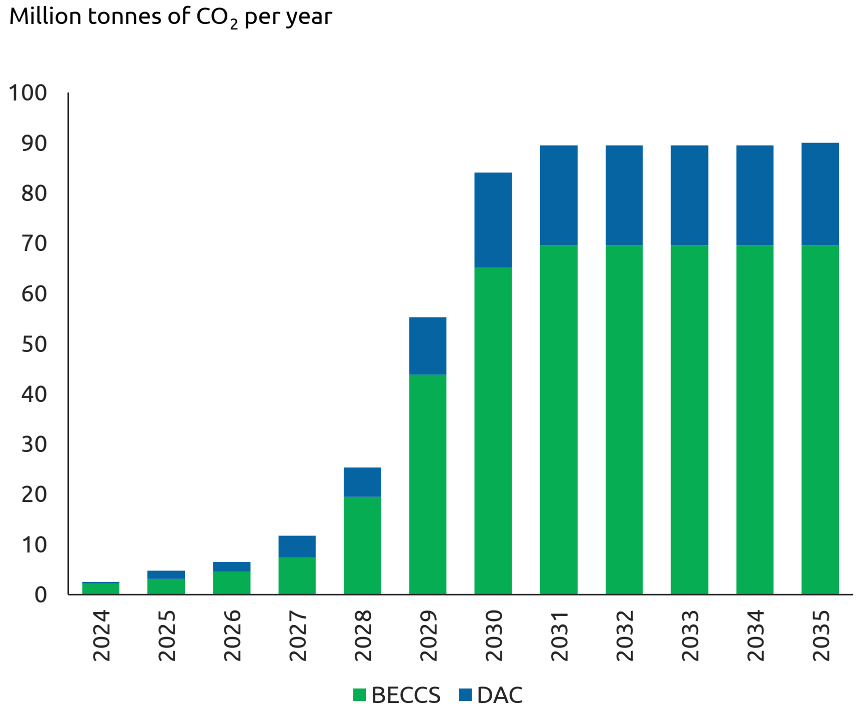
Source: Rystad Energy

during natural gas processing but were later modified for carbon capture from other industry processes. These modifications have helped to reduce energy consumption, improve durability, and lower the costs of carbon capture, driven by innovations from both startups and incumbent players. While carbon capture technologies have seen improvements in energy efficiency and increases in technology readiness level, the **expected learning curve and cost reductions have not materialised at the anticipated pace due to project delays**. On CO_2 transport costs, onshore pipelines remain the most cost-effective option, but the **development of new onshore pipelines have been increasingly hindered by public opposition** (especially across states in the US) and regulatory challenges. This has resulted in a heavier reliance on offshore pipelines which cost more, partially due to longer transport distances to access CO_2 storage sites, especially in Europe where most sites lie in the North Sea. While CO_2 shipping has emerged as an alternative, its development requires long lead times, thus delaying large-scale adoption. On CO_2 storage costs, onshore storage in depleted oil and gas fields remain the lowest-cost option, largely because **existing infrastructure such as wells and pipelines can be reused**. However, legal restrictions can prevent onshore CO_2 storage, forcing the transport of CO_2 over longer distances to more costly offshore sites, thereby raising the overall cost of CCS. For instance, Germany, one of Europe's largest industrial emitters has historically prohibited onshore CO_2 storage due to environmental and safety concerns. However, Germany (which is targeting carbon neutrality by 2045) announced in 2024 the development of a national carbon management strategy. This strategy aims to support

CCUS in hard-to-abate industrial sectors, including a revision of the storage regulation to allow operations both offshore and, potentially, onshore.

Carbon dioxide removal (CDR) projects, notably bioenergy with carbon capture and storage (BECCS) and DAC projects **took centre stage in the CCUS landscape last year**. Approximately 55% of the CCUS projects announced in 2024 set for startup by 2030 are categorised as carbon removal, driven by the **growing demand for high-quality, technology-driven carbon dioxide removal solutions**. The retirement of CDR credits generated from both nature and tech-based projects also grew by 30% in 2024, accounting for 10% of total credit retirements. The CDR market is **expected to continue its growth trajectory in 2025** due to the growing investment appetite for both nature- and tech-based CDR credits and the startup of major CDR projects such as Occidental's long-awaited Stratos DAC facility.

Figure 54: Capacity of BECCS and DAC projects



Note: 'Capacity of BECCS and DAC projects' refers to the total unrisked capacity of announced BECCS and DAC projects based on project owners' communicated capacity and start-up date, with adjustments in start-up date (where relevant) based on analysts' assessment of project delays, time required for regulatory permits, and commerciality.

Source: Rystad Energy

III. Lessons learned and the way forward in accelerating decarbonisation globally

All low-carbon gas technologies have grappled with the fundamental challenge of determining who will ultimately bear the cost of deployment and scale-up. At the heart of this lies the fact that **CO_2 emissions remain an unpriced externality in many markets**, leading to uncertainty in commercial viability without policy intervention. However, **momentum has progressed on this front, with both OECD and non-OECD countries worldwide piloting voluntary carbon markets** before moving towards full-scale implementation of mandatory carbon pricing mechanisms. Developed countries have historically taken the lead in carbon markets, complementing them with policy incentives to drive emissions reduction.

While carbon pricing helps internalise the cost of emissions and narrow the gap between fossil-based fuels and low-carbon alternatives, it remains insufficient on its own to drive widespread adoption of low-carbon gases. Targeted policy measures are essential to enhance their cost competitiveness and accelerate market penetration. Governments play a critical role by providing **clear and consistent policy signals, financial incentives and long-term regulatory frameworks** to de-risk investment in low-carbon gas technologies. Successful policies should be **market-based**, focusing on **lifecycle emissions reduction**, and prioritising **no-regrets investments** such as in refurbishing existing gas infrastructure for the transport of low-carbon gases and for the storage of CO_2.

Mechanisms that incentivise or mandate the long-term offtake of low-carbon gases are crucial, providing demand visibility and revenue certainty to project developers, enabling them to secure financing, reach FIDs and move faster

towards commercial rollout. Once deployed, these low-carbon gas technologies can then be **tested under real-world commercial conditions**, thereby **unlocking cost reductions through learning and scale**. Several policies have been implemented globally to directly incentivise or mandate long-term offtake of low-carbon gases. These include the ReFuelEU Aviation regulation mandating SAF uptake till 2050, auctions securing long-term clean hydrogen offtake agreements, book-and-claim systems expanding biomethane producers' reach to offtakers beyond their immediate geography, and contracts for difference (CfDs) for CCUS providing revenue certainty.

Key policies to help decarbonise gaseous energy molecules

ReFuelEU Aviation

The ReFuelEU Aviation regulation mandates a rising minimum blend of SAF into all jet fuel supplied at EU airports through 2050. Complementing this, aircraft operators are required to uplift at least 90% of their fuel needs in the EU for EU-departing flights, with **non-compliance triggering penalties of at least twice the price difference between SAF and fossil kerosene**. Together, these provisions **secure long-term demand visibility and a strong willingness to pay for SAF**, reducing revenue risk for fuel producers which, in turn, unlocks investment in production capacity as projects become bankable. With offtake certainty and financing in place, project deployment becomes less vulnerable to delays and can proceed at pace. Faster deployment also enables producers to move down the cost curve through operational learning and economies of scale, improving SAF's cost competitiveness and accelerating its displacement of conventional jet fuel. The effectiveness of this regulation is already being seen, with an oversupply of SAF emerging after the mandate's implementation.

Offtake Auctions

Auctions are also effective in encouraging long-term offtake. Germany's H2Global (a non-profit initiative with the goal of accelerating the development of clean hydrogen and clean hydrogen derivatives) took it a step further by introducing a **double-sided auction** to **match green hydrogen producers offering the lowest production costs with buyers demonstrating the highest willingness to pay**, significantly reducing the residual price gap that must be covered by public subsidies. Under this auction, all stakeholders stand to benefit as producers gain revenue certainty to support investment and scale-up, offtakers gain access to green hydrogen at reduced cost without absorbing the full price premium, and governments can facilitate market development while keeping subsidies minimal through competitive price discovery. **Given that many low-carbon gases face the same fundamental challenge of high production costs coupled with limited market willingness to pay, the double-sided auction mechanism presents a scalable solution**. By simultaneously stimulating supply and demand, it can accelerate the commercial rollout of low-carbon gases, driving faster cost reductions through economies of scale and learning, ultimately supporting broader market adoption.

Book-and-claim systems

Another mechanism driving low-carbon gas offtake is the **growing adoption of book-and-claim systems**, which enable producers to **monetise the environmental attributes of their fuels independently from the physical commodity**. This approach **addresses accessibility barriers faced by hard-to-abate sectors** that often have **limited direct access to low-carbon alternatives**, allowing them to advance decarbonisation targets by purchasing fuel attribute certificates without needing to physically consume the fuel. This model is well established in the power sector, where renewable energy certificates represent the rights to claim green electricity produced and fed into a shared grid, despite all customers receiving the same electricity mix. Similarly, this has been implemented in the biomethane sector, with the European Renewable Gas Registry serving as an example of a book-and-claim system that facilitates cross-border trade of biomethane guarantees of origin in the EU. The maritime sector, among others, is now adapting this concept to emerging alternative fuels that are difficult to source physically, **enabling them to meet emissions reduction commitments while providing clear demand signals to producers**. This creates revenue visibility and de-risks investment, supporting the scale-up of low-carbon fuel production capacity.

Contracts for Difference (CfDs)

In the UK, the government uses **long-term CfDs to guarantee a fixed price for capturing, transporting, and storing CO_2**, providing revenue certainty and predictability for CO_2 capture and storage projects. This fixed price is compared against the market value of CO_2, such as allowance prices in the UK ETS. If the market price falls below the agreed price, the government pays the operator the difference. Conversely, if the market price rises above the agreed price, the operator returns the excess amount to the government. This two-way payment structure **reduces financial risk and makes CCUS more attractive for investors**, thereby unlocking capital needed to advance towards FIDs. **As CO_2 prices increase over time, the need for government support is expected to decline, allowing CfDs to act as a transitional mechanism that encourages market growth while avoiding over-subsidisation by the government**.

Capital Grants

In many instances, upfront capital grants are also given to indirectly incentivise offtake by lowering the cost of production of low-carbon gases. This eases the high initial investment burden, particularly for first-of-a-kind or early commercial-scale projects, accelerating FID timelines and helping improve project economics in the early years. For instance, the Net Zero Hydrogen Fund in the UK subsidises the development of low-carbon hydrogen production, thereby de-risking investments made by developers and investors and moving projects quicker to FID. Funding support has also been given to CCUS projects such as the East Coast and HyNet (Liverpool Bay) CCS clusters, fast-tracking the development of new carbon capture and CCUS-enabled hydrogen projects.

Low-carbon gas technologies have advanced significantly in recent years, but numerous challenges remain. Scaling production capacity, attracting investment through revenue certainty, and fostering market demand by increasing willingness to pay are all critical areas that require further progress. At the same time, costs must be driven down through targeted policies and technological innovation. As the urgency to meet net-zero targets by 2050 grows, proactive government action is essential this decade to accelerate cost reductions and enable large-scale deployment. Continued policy innovation and market mechanisms will be crucial to unlock the full potential of low-carbon gases and ensure the energy transition delivers lasting economic, environmental, and energy security benefits on a global scale.

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