GECF

Gas Exporting Countries Forum

MONTHLY GAS MARKET REPORT

February 2026

GECF

Gas Exporting Countries Forum

MONTHLY GAS MARKET REPORT

February 2026

Disclaimer

About the GECF

The Gas Exporting Countries Forum (GECF) is an intergovernmental organization comprising the world's leading gas exporters, aimed at fostering cooperation and collaboration among its members by providing a platform for the exchange of views, experiences, information, and data on gas-related matters. The GECF includes 20 countries — 12 Member Countries and 8 Observer Countries — spanning four continents. Member Countries are Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela, while Observer Countries include Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal.

The GECF Monthly Gas Market Report (MGMR) is a monthly publication by the GECF Secretariat that provides insights into short-term developments in the global gas market, covering areas such as the global economy, gas consumption, gas production, gas trade (both pipeline gas and LNG), gas storage, and energy prices.

Acknowledgements

The Monthly Gas Market Report is prepared by the experts from the Gas Market Analysis Department of the Gas Exporting Countries Forum (GECF).

Project Leader

- Aydar Shakirov, Head of the Gas Market Analysis Department (GMAD)

Expert Team (in alphabetical order)

- Adrian Sookhan, Gas Market Analyst, GMAD
- Hossam ElMasry, Energy Analyst, GMAD
- Imran Mohammed, Gas Transportation and Storage Analyst, GMAD
- Rafik Amara, Senior Gas Market Analyst, GMAD
- Sandy Singh, Market Research Analyst, GMAD

The authors of the report would like to extend their appreciation to HE Dr. Philip Mshelbila, Secretary General of the GECF, for his contribution to the development of the report.

Peer Review

GaffneyCline energy advisory (GCea)

Tornado Tower, 47th & 48th Floors, West Bay, Doha, Qatar

CONTENTS

List of Figures

List of Tables

HIGHLIGHTS

Gas consumption: Major gas-consuming regions have seen divergent demand trends. In January 2026, the EU experienced a significant 10% y-o-y surge to 47 bcm, fuelled by a colder-than-normal month that spiked residential heating needs and gas-fired power generation. Conversely, US demand fell by 1.1% y-o-y to 108.7 bcm, reflecting softened consumption across the residential, commercial and power sectors. Meanwhile, China's gas consumption rose 10% y-o-y to 41.5 bcm in December 2025, with demand projected to hit 450–455 bcm this year and climb to 550 bcm by 2030 according to CNPC's ETRI.

Gas production: Global gas production trends have showed regional variation. In January 2026, US output continued its upward trajectory, rising 2% y-o-y to 93.4 bcm, supported by favourable Henry Hub prices and strong heating demand. China also maintained its growth momentum in December 2025, with production increasing 6% y-o-y to 23 bcm. In contrast, European production declined by 2% y-o-y to 16.7 bcm, hampered by dwindling output from mature fields in the UK and the Netherlands. On the upstream front, Libya, a GECF member, marked a strategic milestone by announcing the results of its first oil and gas licensing round since 2007, signalling a renewed push for exploration and development.

Gas trade: Global gas trade increased in January 2026 driven mainly by LNG imports. Global LNG imports surged to a record 43.0 Mt, rising by 11% y-o-y and marking the largest m-o-m increase since January 2022. Notably, Asia Pacific's incremental LNG imports exceeded Europe's for the first time since August 2025, with China re-emerging as the main driver of import growth in the region. In Europe, higher LNG intake was driven by colder-than-normal weather, stronger gas demand, and lower domestic production, with the region remaining the primary destination for US LNG cargoes. In the meantime, pipeline gas imports showed growth in the EU and China, largely driven by supply from Russia.

Gas storage: The net gas withdrawal season continued across the Northern Hemisphere in January 2026, with major regions recording strong outflows in response to lower-than-average winter temperatures. The EU's monthly average aggregated gas stocks fell to 53 bcm, representing 51% of capacity, a notable decrease compared to the 66 bcm held one year prior. In the US, the monthly average storage stood at 84 bcm, or 63% of capacity, which remains higher than last year's 81 bcm. In Asia, previously high inventories kept the combined LNG storage levels in Japan and South Korea at 13 bcm, marking a 6% y-o-y increase.

Energy prices: Regional gas prices experienced significant upward pressure in January 2026 as extreme weather events triggered supply tightness and intense regional competition. European spot prices led the surge, with TTF averaging $12.00/MMBtu, representing a 27% m-o-m increase that briefly surpassed Asian benchmarks and highlighted the region's acute vulnerability to price volatility. In the US, Henry Hub prices skyrocketed by 75% m-o-m to $7.32/MMBtu as winter storms caused widespread production disruptions. Meanwhile, Asian spot LNG prices saw a more tempered rise, with the average NEA benchmark rising by 5% m-o-m to $10.43/MMBtu, as higher prices tempered spot demand from price-sensitive buyers.

FEATURE ARTICLE:

FSRUs increasingly support global LNG expansion by connecting supply and demand

Between 2026 and 2030, the global LNG market is poised for significant growth, with 235 Mtpa of new liquefaction capacity expected to come online, adding to the existing 551 Mtpa. This expansion will enhance the liquidity and responsiveness of global energy markets, providing a strong foundation for sustained growth in global LNG trade. Successfully absorbing these volumes will depend on robust demand from mature and emerging markets and the continued expansion of gas use in the power and industrial sectors as a reliable, low-carbon energy source.

To bridge the new supply with global gas consumption centers, regasification infrastructure must scale proportionally. While traditional onshore terminals provide the high-capacity backbone of the industry, Floating Storage and Regasification Units (FSRUs) have emerged as the premier solution for agility. By consolidating storage and regasification into a single vessel with minimal shoreside requirements, FSRUs offer a modular, cost-effective pathway to market. This flexibility empowers the midstream sector to circumvent traditional infrastructure constraints, ensuring that incoming LNG supply is seamlessly diverted to high-demand markets with unmatched responsiveness.

When developing an LNG import project, the choice between an onshore terminal and an FSRU is dictated by a complex interplay of strategic and technical factors. Identifying the optimal solution requires a comprehensive assessment to ensure the infrastructure aligns with local demand, facilitates timely market entry, and supports long-term energy security goals. This evaluation centers on several critical pillars: project timelines, regasification capacity, operational flexibility, capital and operational expenditures, siting, storage capacity, and permitting processes. Balancing these variables allows developers to calibrate their investment to the specific needs of the target market.

Project timelines for FSRUs typically range from 12 to 24 months, whether through conversion of existing vessels or new builds, requiring minimal civil works beyond mooring and pipeline connections. In high-priority cases, deployment of existing FSRUs can be even faster; recent projects in Germany reached operational status in seven months, showcasing the technology's potential for rapid market entry. By comparison, onshore terminals take 4 to 7 years to complete, reflecting the scale and complexity of permanent infrastructure. FSRUs therefore provide a fast-track solution for markets seeking timely LNG access and enhanced energy security.

Regasification capacity for onshore terminals is designed for high-volume LNG imports, typically ranging from 3 to 12 Mtpa, with some mega-terminals exceeding 15 Mtpa. These facilities are ideally suited for mature gas demand centers with substantial long-term needs, providing the high throughput necessary to support stable, sustained consumption. In contrast, FSRUs offer more moderate capacity, generally between 0.5 and 5 Mtpa per vessel, making them the preferred choice for small-to-medium and decentralized markets or as bridge solutions for emerging markets.

Operational flexibility is a key strength of FSRUs, which are mobile and redeployable, enabling operators to respond swiftly to shifting market conditions, emerging demand centers, or the conclusion of local contracts. Their modular design allows rapid relocation, making them well-suited for dynamic and transitional markets. In contrast, onshore terminals are permanent, fixed infrastructure. While not relocatable, they provide long-term stability and can be expanded over time to deliver high-volume capacity for established, high-demand markets.

Capital expenditures for onshore regasification terminals are substantial, often exceeding $1 billion due to land acquisition, civil works, storage tanks, and permitting. FSRUs offer a lower-cost alternative, with new-build projects typically costing $400-500 million and vessel conversions requiring $200-350 million. Crucially, total investment for both infrastructure types is heavily influenced by regasification capacity, with FSRUs providing a particularly cost-effective entry point for small-to-medium volumes. This financial profile makes floating solutions ideal for minimizing initial outlay while securing right-sized energy access.

Operational expenditures for onshore terminals are relatively lower, typically ranging from $20–35 million annually due to fixed staffing, maintenance, and regasification costs. In contrast, FSRUs usually follow a leasing model where annual OPEX is significantly higher, often reaching $40–65 million, because the costs are centered on daily charter rates that combine vessel hire, crew, and insurance. However, despite this higher annual operating burden, the FSRU model offers greater agility by converting what would be a massive upfront capital expenditure into predictable operating costs. This financial flexibility allows the industry to respond rapidly to market changes, making leased FSRUs a strategically efficient choice for smaller or emerging markets that prioritize speed and lower risk over long-term operating savings.

Siting is a critical factor in regasification deployment. FSRUs offer versatile positioning in shallow waters, restricted ports, or remote coastal regions, requiring minimal civil engineering beyond basic mooring and pipeline integration. This adaptable architecture enables vessels to serve as high-capacity energy hubs in locations where permanent construction is geographically unfeasible. This manoeuvrability allows for rapid setup and relocation as market dynamics or regional requirements evolve. In contrast, onshore terminals require expansive land, deepwater access, and substantial maritime infrastructure.

Storage capacity differs significantly between the two models. Onshore terminals are designed for large LNG reserves, typically relying on multiple tanks with capacities of 150,000 to 500,000 cubic meters each. This allows major hubs, such as Pyeongtaek in South Korea, to store more than 3 million cubic meters of LNG. By contrast, FSRUs are more compact, with an average storage capacity of 170,000 cubic meters per vessel, suited to handling cargoes from standard LNG carriers. Rather than increasing tank size, the floating model typically expands capacity by deploying additional vessels, allowing operators to match storage closely with local demand.

Permitting processes for FSRUs are generally simpler and faster, as these projects involve limited onshore construction and a smaller environmental footprint, often allowing approvals under existing maritime and port regulations with minimal additional bureaucracy. Onshore regasification terminals, in contrast, require expansive land use, civil works, and permanent facilities, typically involving stringent environmental impact assessments, complex zoning reclassifications, and oversight from multiple national and local construction authorities.

The history of the FSRU industry began in March 2005 with the commissioning of the Excelsior, a purpose-built vessel that served the Gulf Gateway Deepwater Port in the US Gulf of Mexico. This pioneering project proved that LNG could be regasified onboard a ship and discharged directly into subsea pipelines, offering a faster and more flexible alternative to traditional land-based terminals. The industry reached a second major milestone in 2008 with the Golar Spirit in Brazil, which became the first existing LNG carrier to be successfully converted into an FSRU. These projects collectively demonstrated the commercial viability of floating regasification, setting the stage for the rapid global expansion of the fleet.

Since its inception, the global FSRU fleet has undergone a remarkable transformation, evolving from a specialized niche into a central pillar of the international LNG landscape as energy markets prioritize rapid scalability and geographic flexibility. This shift is underscored by the fleet reaching a record 50 operational units by early 2026, representing a combined regasification capacity of 197 Mtpa (Figure i).

As a result of this rapid growth, FSRUs now account for approximately 20% of total global regasification capacity, while permanent onshore terminals maintain the remaining 80%. The floating infrastructure has become the primary tool for rapid-response energy security, particularly in Europe, which currently leads global capacity with 64 Mtpa. This is followed by Latin America and the Caribbean (LAC) at 50 Mtpa, Asia at 41 Mtpa, and the Middle East and Africa, which contribute 21 Mtpa each (Figure ii).

The scale of FSRU expansion is defined by a historic 100 Mtpa capacity surge between 2021 and 2025, which effectively doubled the global footprint in half a decade. This growth was largely catalysed by Europe's urgent pivot toward LNG following the 2022 energy crisis. Because the immediate nature of the crisis precluded the multi-year construction of permanent onshore terminals, the region prioritized floating units to ensure energy security. Consequently, 46 Mtpa of FSRU capacity was brought online within 5 years to partially mitigate the loss of pipeline gas imports, led by Germany (13.2 Mtpa), Italy (7.4 Mtpa), and the Netherlands (6.7 Mtpa).

Figure i: Trend in FSRUs capacity and number of units

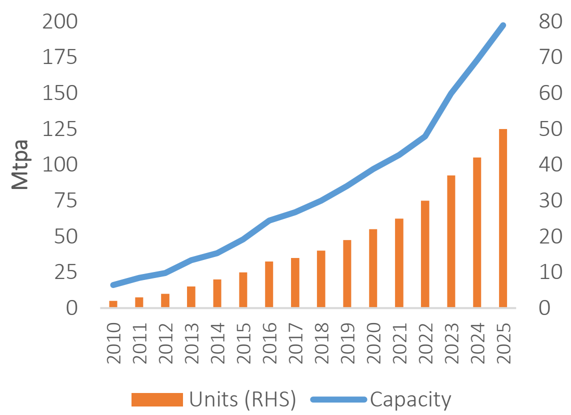
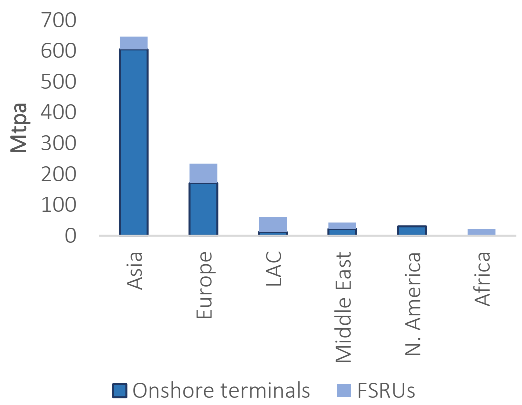


Figure ii: Regional LNG regasification capacity by type



Source: GECF Secretariat based on data from ICIS and Argus

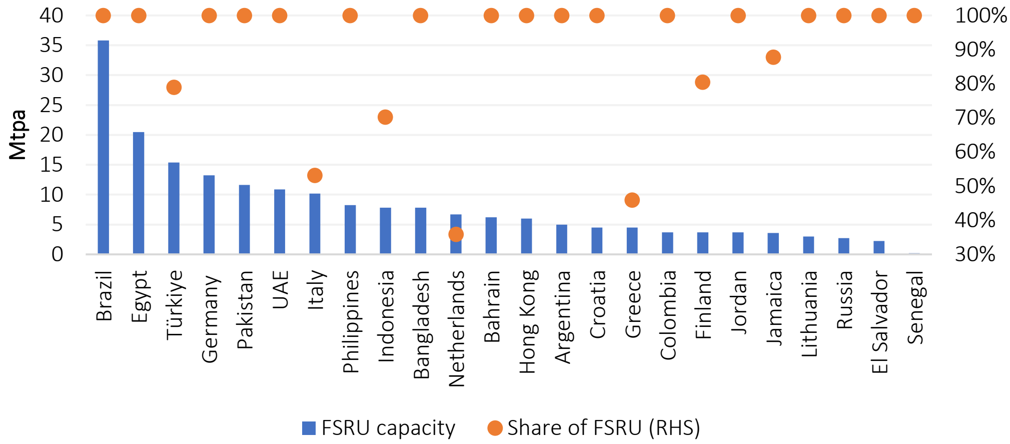
The FSRU has cemented its role as a strategic gateway for emerging gas importers to access the global gas market and meet surging energy demand. By bypassing the logistical hurdles and high capital costs of onshore terminals, this technology provides a permanent solution for markets with small-to-medium demand such as El Salvador, Croatia, and Bahrain, where a floating unit serves as the primary long-term infrastructure. For larger or transitioning markets like Jordan, Colombia, the Philippines, and Brazil, the FSRU acts as a strategic bridge that provides immediate energy security while allowing time to evaluate permanent onshore solutions based on evolving demand dynamics.

Furthermore, in gas-exporting nations such as Egypt, the UAE, and Indonesia, FSRUs serve as critical balancing tools for seasonal or short-term demand surges. This flexibility is essential for managing summer power peaks and drought-driven generation needs when domestic production falls short of localized spikes or unexpected supply deficits. In this capacity, FSRUs enable exporters to honour high-value long-term export contracts while simultaneously safeguarding domestic energy security and ensuring continuous grid stability.

Globally, 24 countries operate FSRU import terminals, with 17 relying exclusively on floating LNG import terminals and the remaining seven operating a mix of offshore and onshore facilities. Brazil, Egypt, Türkiye, Germany, Pakistan, and the UAE account for the largest shares of floating regasification capacity (Figure iii).

Reflecting this broad geographic footprint, LNG imports through FSRUs reached 70 Mt in 2025, accounting for 17% of global LNG imports. Despite massive capacity additions, the average utilization of the FSRU fleet stood at 35%, trailing the total global regasification average of 41%. This disparity reflects the role of FSRUs as strategic insurance across diverse markets, where capacity is held in reserve to manage seasonal volatility or sudden supply shocks.

Figure iii: FSRU regasification capacity by country in 2025



Source: GECF Secretariat based on data from ICIS and project updates

Vessel scarcity has emerged as the primary bottleneck for further market expansion, with the FSRU sector currently facing unprecedented supply constraints. Most of the 50 operational units are locked into long-term charter agreements through 2030, leaving a negligible pool of vessels for prompt redeployment. This supply deficit was exacerbated by the European energy pivot, which absorbed nearly all uncommitted units and prompted the conversion of standard LNG carriers. With major shipyard slots now booked several years in advance, new-build delivery timelines have extended to approximately four years. Consequently, emerging markets must increasingly rely on vessel conversions, which still require 18 to 24 months, forcing new importers to either wait for charter expirations or navigate protracted shipyard schedules to secure market entry.

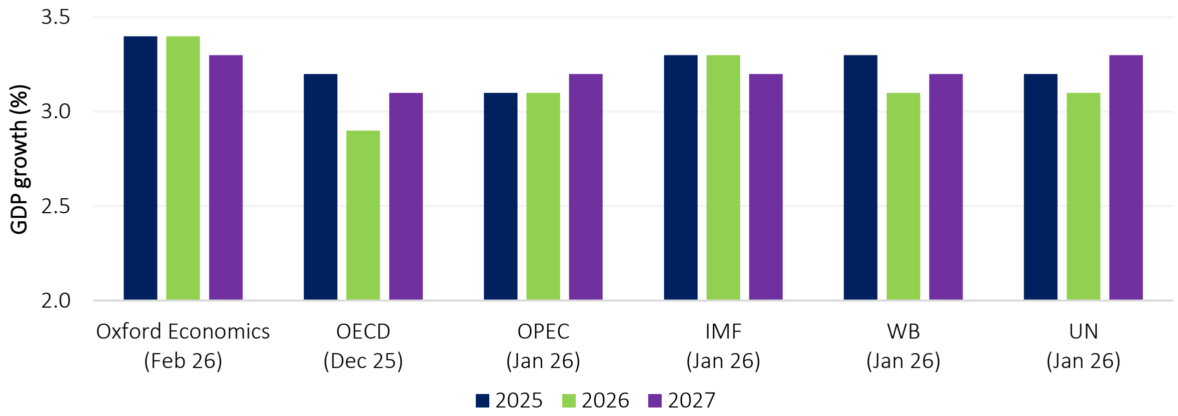
Remarkably, FSRUs hold significant potential to catalyse economic development and social progress across the developing world, particularly in Africa, by offering a financially accessible gateway to the global LNG market. In regions where energy poverty remains a primary barrier to economic growth, FSRUs can provide a vital alternative to the prohibitive capital required for permanent onshore infrastructure. By enabling the rapid deployment of LNG, FSRUs would allow emerging nations to fuel both gas-to-power solutions and heavy industrial sectors. This strategy would facilitate just energy transitions by displacing carbon-intensive coal and liquid fuels with natural gas, resolving chronic energy deficits while simultaneously transforming developing markets into new, long-term demand centers for the global LNG industry.

1 GLOBAL PERSPECTIVES

1.1 Global economy

In February 2026, global GDP growth for 2026, based on purchasing power parity, was estimated at 3.4% by Oxford Economics (Figure 1). With global GDP growth matching the rate of 2025, this outlook suggests a period of sustained economic expansion amidst persistent headwinds. Nevertheless, global economic activity is expected to slow down looking ahead, with GDP growth in 2027 forecast at 3.3%.

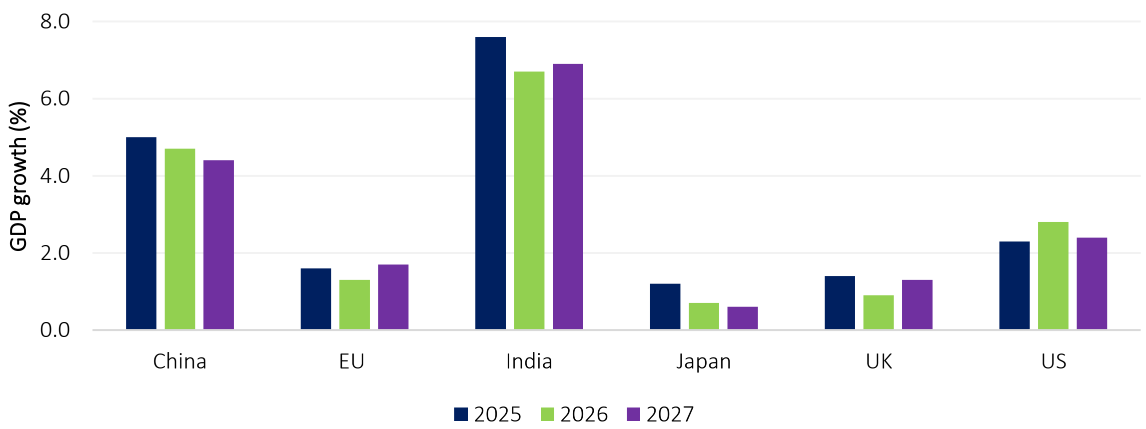
Figure 1: Global GDP growth



Source: GECF Secretariat based on data from Oxford Economics, OPEC, IMF, OECD, WB and UN
Note: Global GDP growth calculated based on purchasing power parity.

At the country level, the estimated GDP growth for the US in 2026 was unchanged from one month ago at 2.8%, reflecting a stabilisation of labour market conditions. Growth is however expected to weaken in 2027, forecasted to be 2.4%, with productivity expected to play a significant role on the outlook. In the EU, GDP growth for 2026 was estimated at 1.3%, an increase of 0.1 percentage points from the previous month. Growth in 2027 is projected to step up to 1.7%, boosted particularly by the effect of Germany's fiscal stimulus. China's GDP growth for 2026 was estimated at 4.7%. Growth is expected to slow further in 2027, with GDP projected to expand by 4.4%, with continued support from state-led investment. India's GDP growth for 2026 was estimated at 6.7%, with the outlook for 2027 rising to 6.9% (Figure 2).

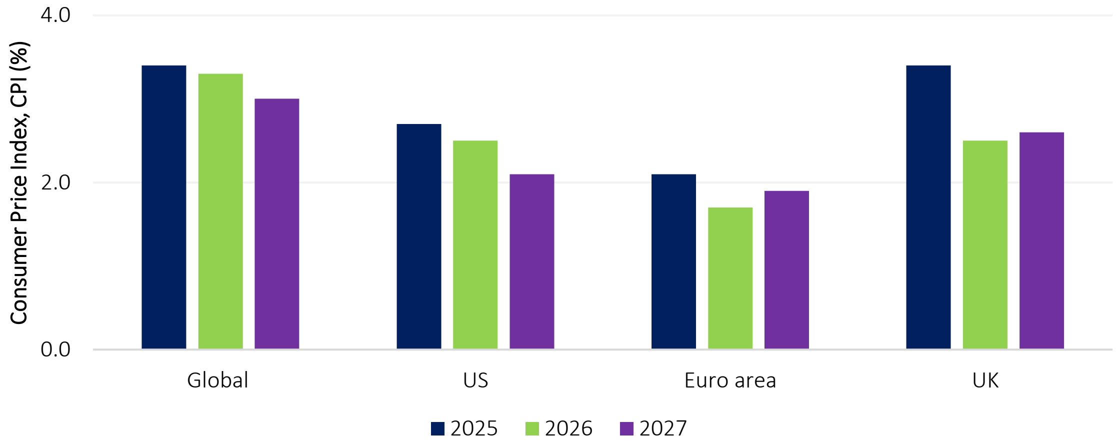
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

Moreover, according to Oxford Economics, global inflation was estimated to fall by 0.1 percentage points in 2026 to 3.3%, and by a further 0.3 percentage points in 2027 to 3.0%. In the Euro area, inflation was estimated at 1.7% in 2026 and is forecast to jump to 1.9% in 2027. Similarly in the UK, inflation was estimated at 2.5% in 2026 and is expected to rise to 2.6% in 2027. On the other hand, in the US, inflation was estimated at 2.5% in 2026, but is however expected to ease to 2.1% in 2027 (Figure 3).

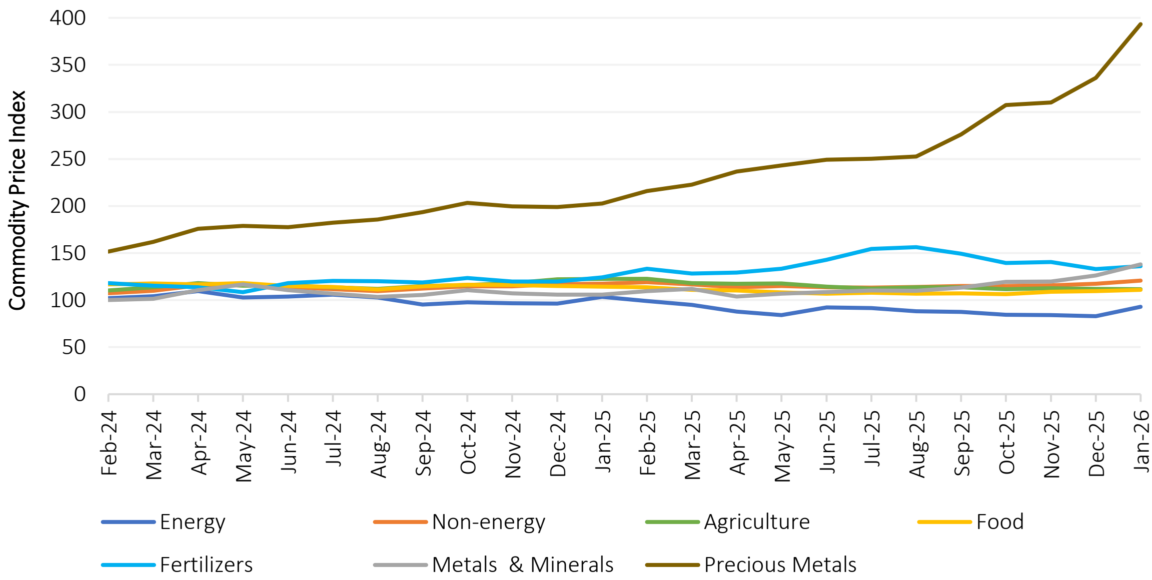
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In January 2026, commodity prices in the energy sector increased from the level of the previous month, driven by seasonal energy demand, and particularly by the surge in Henry Hub prices. As a result, the energy price index rose by 12% m-o-m, but was still 10% lower than one year prior. There were increases in the non-energy price index by 3% m-o-m as well as y-o-y. The fertilizer price index rose by 2% m-o-m and also by 9% y-o-y. The precious metals price index climbed yet again, surging by 17% m-o-m and 94% y-o-y (Figure 4).

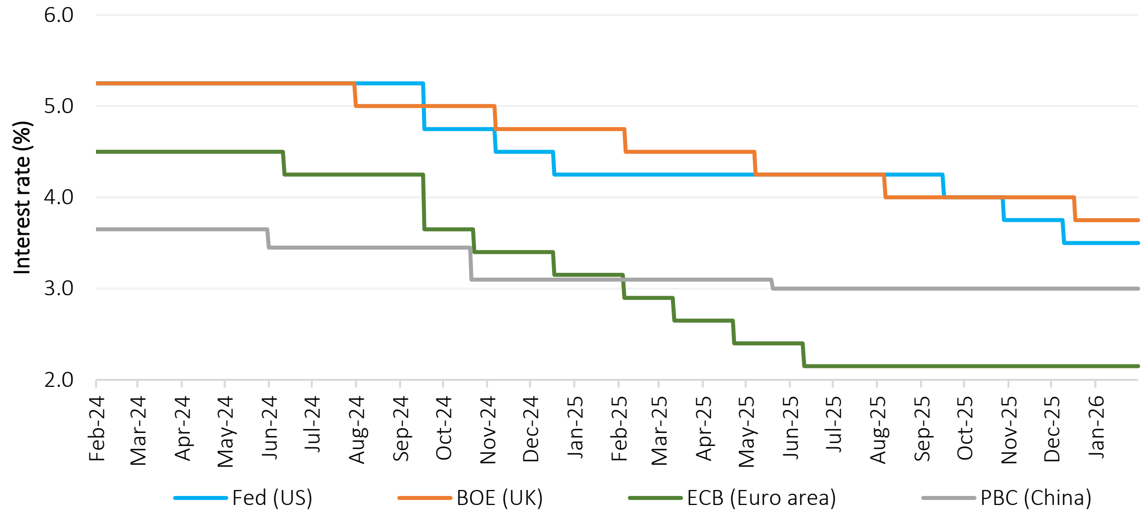
Figure 4: Monthly commodity price indices



Source: GECF Secretariat based on data from World Bank Commodity Price Data
Note: Monthly price indices based on nominal US dollars, 2010=100. The energy price index is calculated using a weighted average of global crude oil (84.6%), gas (10.8%) and coal (4.7%) prices. The non-energy price index is calculated using a weighted average of agriculture (64.9%), metals & minerals (31.6%) and fertilizers (3.6%).

In January 2026, the major central banks all maintained their benchmark interest rates, compared to the previous month. The US Federal Reserve (Fed) maintained its benchmark interest rate within the range of 3.5% to 3.75%, which was most recently adjusted in December 2025. The Bank of England (BOE) kept its benchmark interest rate at 3.75%, also having adjusted during the previous month. Meanwhile, the main refinancing operations rate of the European Central Bank (ECB) has held steady at 2.15% since mid-June 2025. Similarly, the People's Bank of China (PBC) kept its one-year Loan Prime Rate (LPR) at 3.0% (Figure 5).

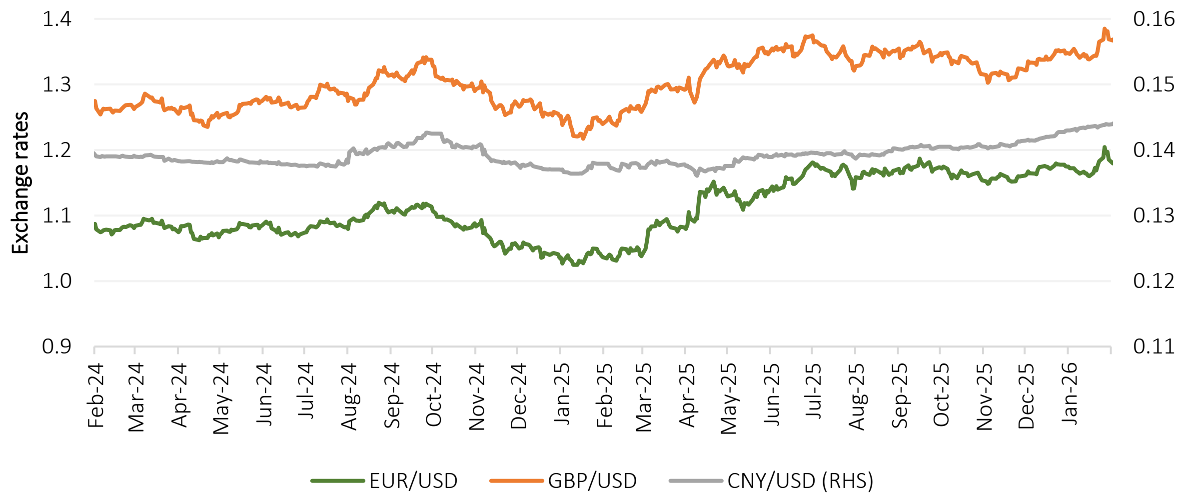
Figure 5: Interest rates in major central banks



Source: GECF Secretariat based on data from US Federal Reserve, Bank of England, European Central Bank and People's Bank of China

In January 2026, the US dollar continued to weaken in comparison to major global currencies. The euro recorded an average exchange rate against the US dollar of $1.1744, representing an increase of 0.2% m-o-m and 13% y-o-y. The British pound also reflected increases of 1% m-o-m and 9% y-o-y against the US dollar, with an average exchange rate of $1.3532. The average exchange rate of the Chinese yuan the US dollar was $0.1435, representing increases of 1% m-o-m and 5% y-o-y (Figure 6).

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

World Economic Forum: The World Economic Forum 2026, held in Davos, Switzerland, on January 19–23, was defined by a widening ideological rift between proponents of traditional energy expansion and architects of the green transition. While European and Asian delegates reaffirmed the commitment to the European Green Deal and the scaling of renewable manufacturing, the summit's discourse shifted noticeably toward energy pragmatism and industrial sovereignty. Natural gas was repositioned as an essential reliability partner for aging power grids, alongside a burgeoning "nuclear renaissance" intended to fuel the electricity-hungry expansion of AI and data centres. The US President Trump signalled a decisive break from international climate frameworks, championing a fossil-fuel-centric, pro-growth agenda while sharply criticizing the "radical" energy policies of several European nations.

African Union: The 39th Ordinary Session of the African Union Assembly, held in Addis Ababa, Ethiopia, on February 14–15, took note of continental development initiatives aimed at mobilizing resources for infrastructure, energy, water and sanitation, and climate adaptation programmes. In his statement, HE Mahmoud Ali Youssouf, Chairperson of the African Union Commission, highlighted that "it is crucial to accelerate the industrialisation of the Continent and the transformation of agriculture. And this will only be possible by developing the energy potential of Africa. And by providing the Continent with high-performing infrastructure. These are the sine qua non conditions for the anticipated economic growth."

LNG2026 Conference: The LNG2026 conference took place in Doha, Qatar from February 2-5. HE Saad Sherida Al-Kaabi, Qatar's Minister of State for Energy Affairs, warned that the global market could shift from a projected supply glut to a significant shortage by 2030, driven by the sustained, baseload power requirements of artificial intelligence and data centres, together with European and Asian demand. HE Dr Philip Mshelbila, the GECF Secretary General, underscored the importance of collective action in addressing methane emissions, highlighting the need for balanced and pragmatic approaches that safeguard energy security while advancing global climate objectives.

Libya: The 2026 Libya Energy & Economic Summit, convened in Tripoli on January 24–26, served as a strategic milestone for the nation's energy sector. Prime Minister Abdul Hamid Dbeibeh framed the event as a "pivotal turning point," underscoring the government's focus on international partnerships to drive long-term economic stability. On the sidelines of the Summit, Libya and Egypt signed a gas cooperation agreement to expand technical collaboration, enhance infrastructure for transporting crude oil and natural gas, and strengthen regional energy security across the oil, gas, and mining sectors. HE Dr Philip Mshelbila, the GECF Secretary General, emphasized Libya's geographic advantage, noting its vital role in enhancing European energy security through the Greenstream pipeline and its proximity to high-demand markets.

Nigeria: The 2026 Nigeria International Energy Summit, convened in Abuja from February 2–5, showcased an industry in the midst of an accelerated recovery, evidenced by a significant rebound in rig activity and the securing of over $8 billion in FIDs. In an address delivered on his behalf by Vice-President Kashim Shettima, President Bola Ahmed Tinubu framed the energy sector as a vital stabilizer for national development. This vision was echoed by HE Dr Philip Mshelbila, the GECF Secretary General, who lauded Nigeria's policy trajectory and emphasized that Africa's gas reserves are the fundamental bedrock for industrialization, energy security, and sustained economic resilience.

2 GAS CONSUMPTION

In December 2025, aggregated gas consumption across some of the major gas consuming countries, which collectively account for 75% of global gas demand, increased by 4.5% y-o-y to reach 358 bcm. Growth was recorded in all regions, including the EU, North America, and Asia.

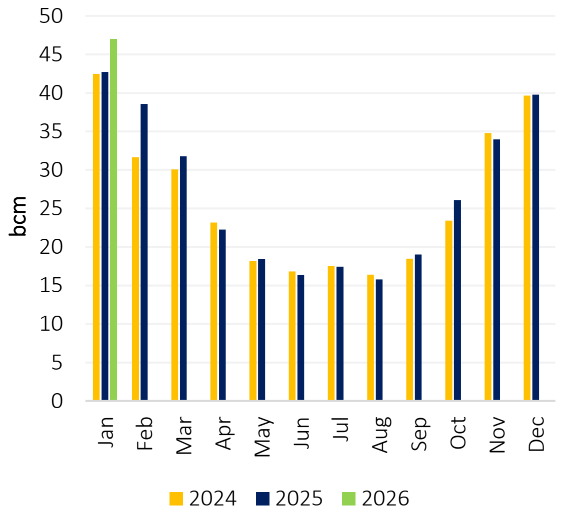
2.1 Europe

2.2.1 European Union

In January 2026, natural gas consumption in the EU surged, rising by 10% y-o-y to 47 bcm (Figure 7). This increase largely reflected stronger space-heating requirements in the residential sector, alongside a rebound in gas use for power generation following a colder-than-normal month. Average temperatures across the region were about 0.9°C below those recorded a year earlier, with Eastern Europe experiencing particularly harsh conditions. Early snowfall in several countries further intensified heating needs. While wind generation improved during the month, renewable output remained insufficient to fully accommodate the additional demand associated with colder weather. Consequently, natural gas assumed a central role in balancing the energy system, meeting elevated seasonal demand for both heating and electricity and supporting system stability during peak load periods.

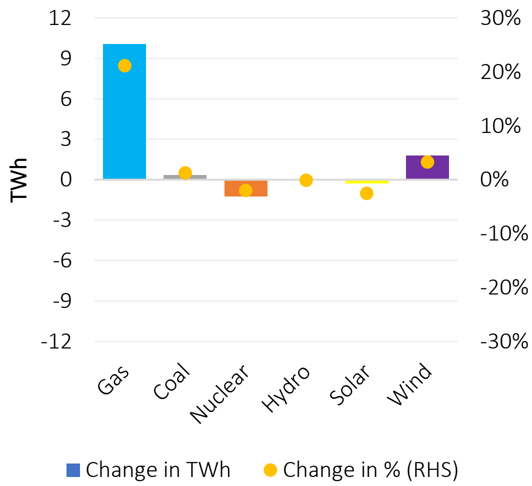
EU electricity generation saw a y-o-y increase of 4.4% to reach 254 TWh. Notably, gas-fired power surged by 21% y-o-y, reflecting gas's continued importance in balancing the grid, particularly during the recent cold spell. Wind and coal generation also expanded, by 3% and 1% y-o-y, respectively (Figure 8). In the overall power mix, non-hydro renewables remained the largest source at 30%, followed by nuclear (24%), gas (23%), hydro (12%) and coal (11%). These developments illustrate the ongoing evolution of Europe's power sector, where renewables dominate, while natural gas remains vital for system reliability.

Figure 7: Gas consumption in the EU



Source: GECF Secretariat based on data from Entsog and LSEG

Figure 8: Trend in electricity production in the EU in January 2026 (y-o-y change)



Source: GECF Secretariat based on data from Ember

2.1.1.1 Germany

In January 2026, Germany's natural gas consumption continued its upward trend, marking the fifth consecutive month of growth and reaching 12.2 bcm, up by 10% y-o-y (1.1 bcm) (Figure 9). The increase was mainly driven by stronger demand from the residential and industrial sectors. Residential gas consumption rose by 8.4% y-o-y, reflecting notably colder weather conditions: the average temperature in January stood at –0.9°C, compared with 2.1°C in 2025 and 1.7°C in 2024, making the month around 3.0°C and 2.6°C colder, respectively. Industrial gas demand also remained on an upward trajectory, increasing by 8% y-o-y and extending the ongoing growth trend (Figure 10).

Figure 9: Gas consumption in Germany

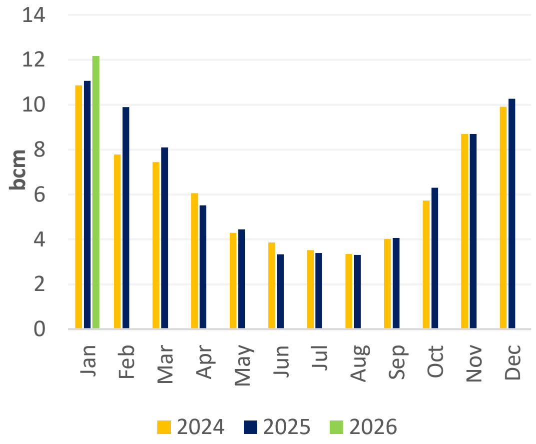
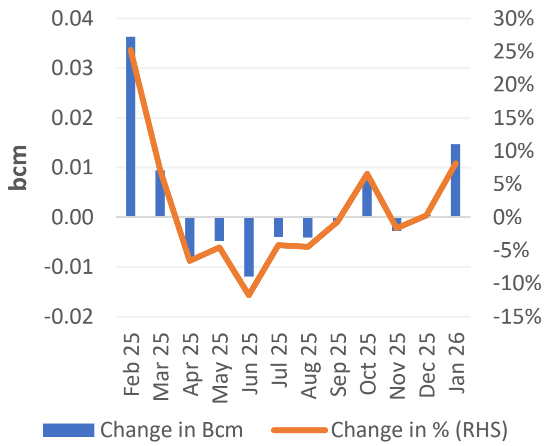


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Total electricity generation rose by 11% y-o-y in January, reaching 45.3 TWh. Gas-fired power production recorded a sharp increase of 33% y-o-y, largely compensating for a pronounced contraction in hydropower output, which declined by 32% (Figure 11). At the same time, wind generation strengthened, expanding by 11% y-o-y. In Germany's power mix, non-hydro renewables remained the dominant source, accounting for 48% of total electricity generation, followed by natural gas at 25% and coal at 24% (Figure 12).

Figure 11: Trend in electricity production in Germany in January 2026 (y-o-y change)

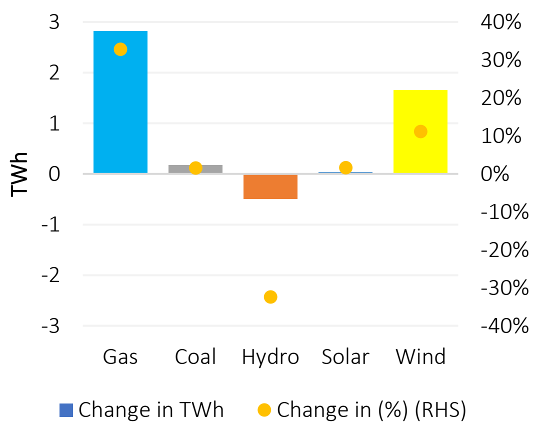
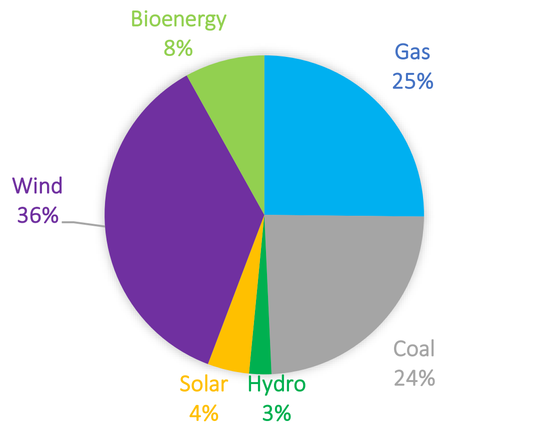


Figure 12: German electricity mix in January 2026



Source: GECF Secretariat based on data from LSEG and Ember

2.1.1.2 Italy

In January 2026, Italy's natural gas consumption increased by 11% y-o-y to 9.1 bcm (Figure 13), primarily driven by colder weather conditions across the country. Residential gas demand rose by 8% y-o-y to 5.1 bcm, supported by significantly lower temperatures, with the monthly average falling to 3.9°C, compared with 6.1°C in January 2025 and 4.7°C in January 2024, thereby intensifying heating requirements in households and commercial buildings. In contrast, industrial gas consumption declined marginally by 0.5% y-o-y to 0.98 bcm, marking the first contraction in manufacturing-related demand after two consecutive months of growth (Figure 14). Meanwhile, the renewed increase in gas use for power generation highlighted its critical role in ensuring supply adequacy during periods of colder weather.

Figure 13: Gas consumption in Italy

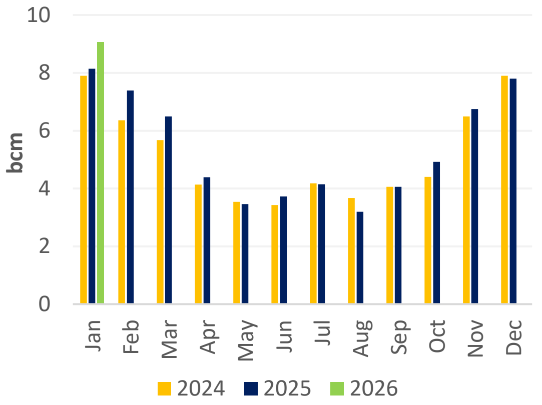
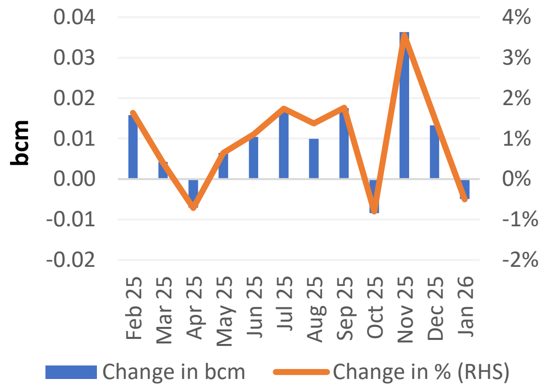


Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change)



Source: GECF Secretariat based on data from Snam

Total electricity generation in Italy increased by 19% y-o-y to 22.9 TWh, reflecting higher power demand amid colder-than-normal weather conditions. Gas-fired electricity generation rose by 25% y-o-y to 2.7 bcm, supported in part by a sharp reduction in coal output, which declined by 37% (Figure 15). As colder temperatures boosted both heating and electricity needs, natural gas remained central to balancing the power system, accounting for 64% of total electricity generation. Meanwhile, non-hydro renewable sources contributed 25% of output, underscoring Italy's continued reliance on gas as a key pillar for ensuring power system stability during periods of elevated demand (Figure 16).

Figure 15: Trend in electricity production in Italy in January 2026 (y-o-y change)

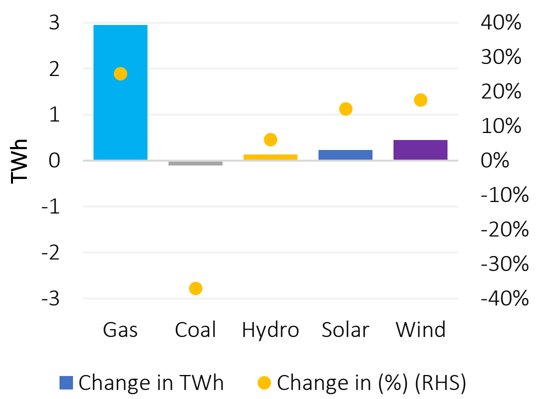
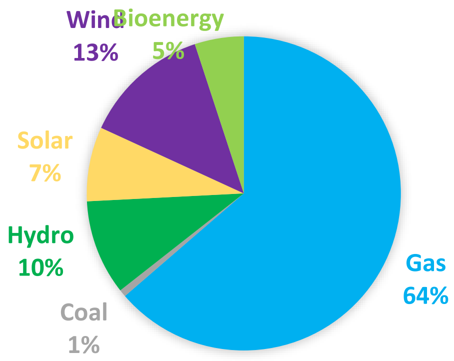


Figure 16: Italian electricity mix in January 2026



Source: GECF Secretariat based on data from Terna, LSEG and Ember

2.1.1.3 France

In January 2026, France's gas consumption declined by 1.4% y-o-y to 4.8 bcm (Figure 17), driven by lower demand in the industrial and residential sectors. Residential consumption declined by 33% y-o-y to 3.4 bcm, supported by less gas use for heating despite cold temperature during the month, with average temperatures at 5.6°C — 0.6°C lower than the same month last year. The industrial sector recorded a decline of 1.8% to reach 0.96 bcm (Figure 18).

Figure 17: Gas consumption in France

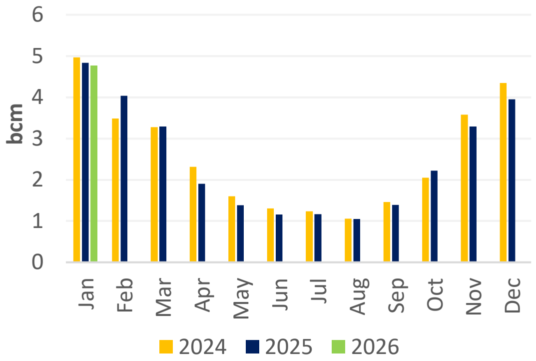
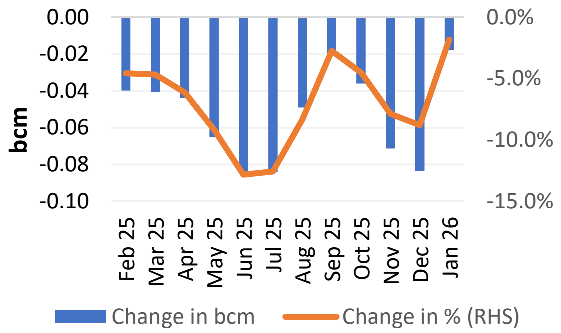


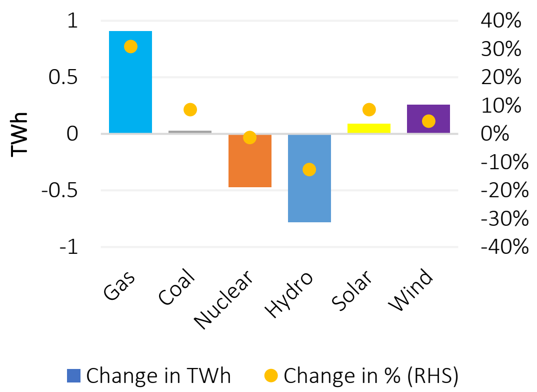
Figure 18: Trend in gas consumption in the industrial sector in France (y-o-y change)



Source: GECF Secretariat based on data from GRTgaz

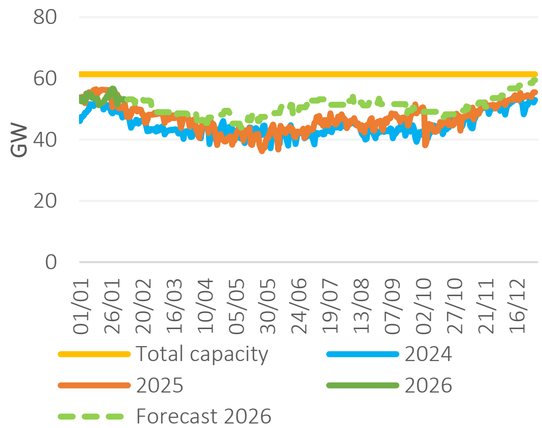
Total electricity generation in France recorded the same level of last year reaching 55 TWh. Natural gas generation soared by 31% y-o-y, as hydropower and nuclear output fell by 13% and 1% y-o-y respectively. In contrast, wind and solar generation continued to grow over the period (Figure 19). French nuclear capacity availability grew by 1% m-o-m but declined by 2% y-o-y (Figure 20). EDF has confirmed nuclear generation targets of 350–370 TWh for both 2026 and 2027, while introducing a first estimate for 2028 in the range of 345–375 TWh, reflecting increased uncertainty around demand and reactor modulation. Output in 2025 exceeded 370 TWh for the first time since 2019, supported by improved reactor availability despite rising curtailment during periods of oversupply. In the overall power mix, nuclear energy continued to dominate, representing 69% of total electricity supply, followed by non-hydro renewables (13%), hydro (10%) and natural gas (8%).

Figure 19: Trend in electricity production in France in January 2026 (y-o-y change)



Source: GECF Secretariat based on data from Ember

Figure 20: French nuclear capacity availability



Source: GECF Secretariat based on LSEG and RTE

2.1.1.4 Spain

In January 2026, Spain's gas demand increased by 10% y-o-y to 3.3 bcm, extending its growth streak to twelve consecutive months (Figure 21). The rise was largely driven by stronger gas use in the power sector, where gas-fired generation played a key role in offsetting reduced output from coal, hydropower, and solar. In parallel, industrial gas demand continued its downward trend, declining marginally by 0. 1% y-o-y and signalling softer industrial activity. The downtick was largely driven by lower consumption in the textile sector (-16%), agro-food sector (-12%), the paper industry (-10%) and metallurgy sector (-6.7%) (Figure 22).

Figure 21: Gas consumption in Spain

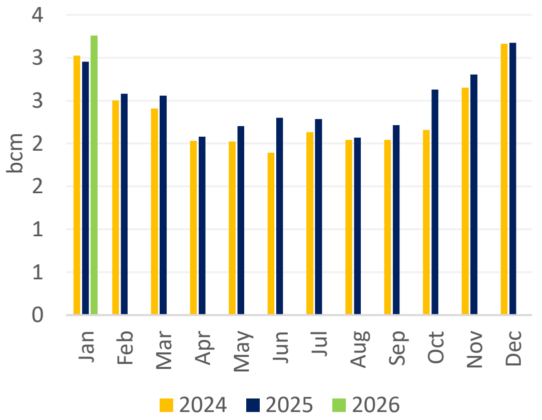
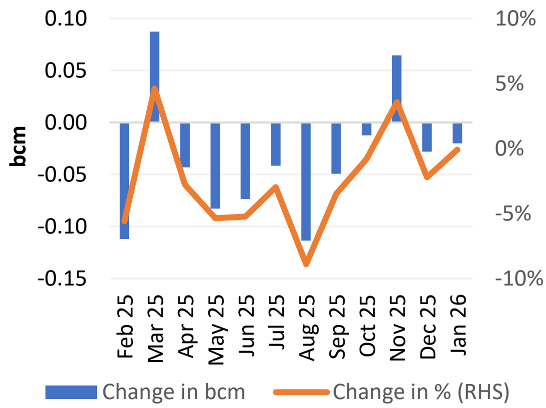


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Spain's total electricity generation increased modestly by 2% y-o-y in January, reaching 23.1 TWh. Within this context, gas-fired power output rose sharply by 17% y-o-y, as natural gas was increasingly deployed to compensate for weaker hydropower and solar generation under unfavourable weather conditions (Figure 23). Coal-fired generation continued its structural decline compared with the previous year. In the generation mix, non-hydro renewables remained the leading source, accounting for 45% of total output, while natural gas represented 20%, highlighting its key role in balancing the power system amid fluctuations in renewable supply (Figure 24).

Figure 23: Trend in electricity production in Spain in January 2026 (y-o-y change)

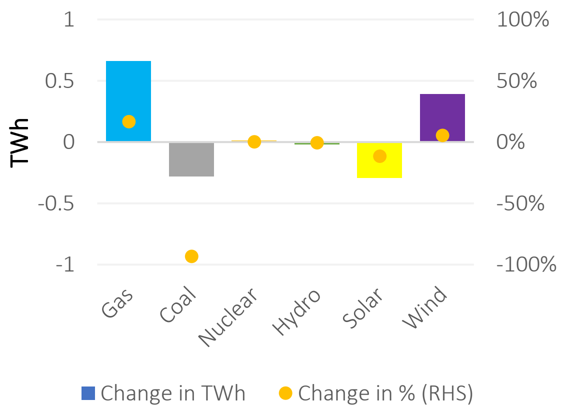
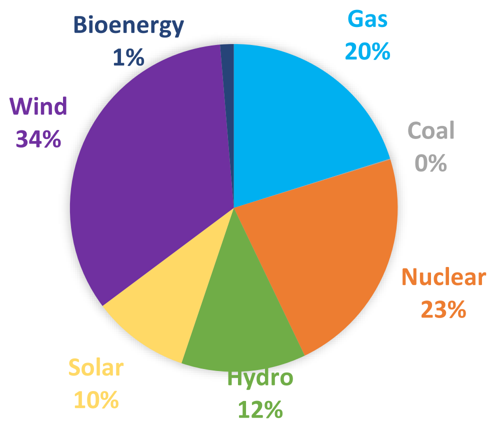


Figure 24: Spanish electricity mix in January 2026



Source: GECF Secretariat based on data from Ember and Ree

2.1.2 United Kingdom

In January 2026, natural gas consumption in the UK declined by 6% y-o-y to 8.2 bcm (Figure 25), largely reflecting strong wind generation in the power sector, which reduced the need for gas-fired output. This contraction was driven by a warmer-than-normal weather conditions during the month. Residential gas demand fell by 2.3% y-o-y to 6.6 bcm, average temperatures eased to 4.4°C, around 0.9°C higher than a year earlier. In contrast, industrial gas consumption recorded a sharp decline of 40% y-o-y, pointing to persistently weak demand across energy-intensive industries (Figure 26).

Figure 25: Gas consumption in the UK

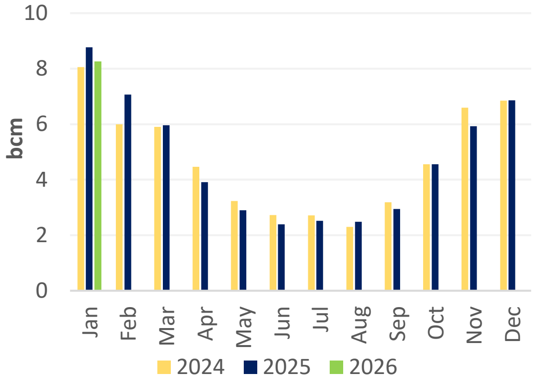
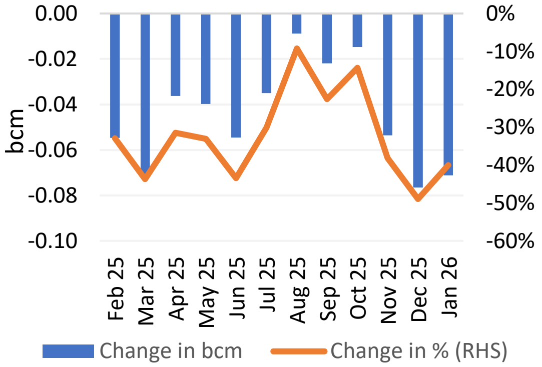


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Total electricity generation in the UK increased by 6.4% y-o-y to 25 TWh. However, gas-fired power generation declined by 17% y-o-y, largely offset by strong wind and solar output driven by favourable weather conditions. Wind and solar generation rose by 54% and 4% y-o-y, respectively (Figure 27), whilst nuclear power-generation output decreased compared to last year. Non-hydro renewables remained the largest contributor to the power mix, accounting for 51%, while natural gas made up 36%, highlighting its role in balancing the electricity grid amid fluctuating renewable output (Figure 28).

Figure 27: Trend in electricity production in UK in January 2026 (y-o-y change)

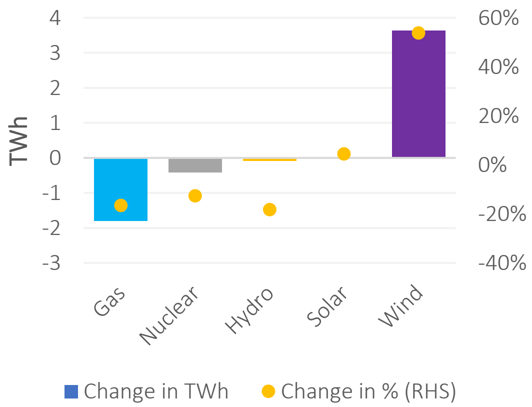
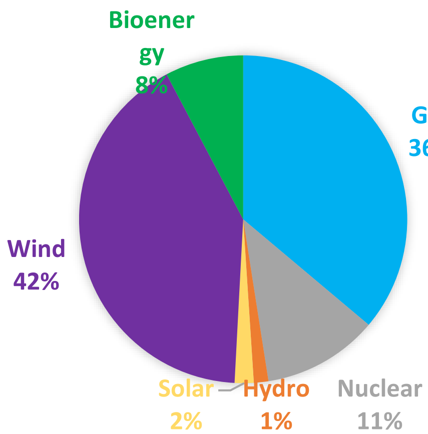


Figure 28: UK electricity mix in January 2026



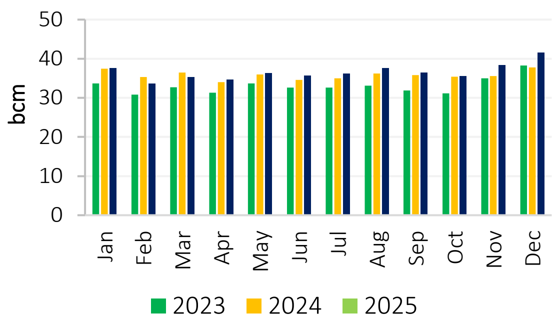
Source: GECF Secretariat based on data from Ember

2.2 Asia

2.2.1 China

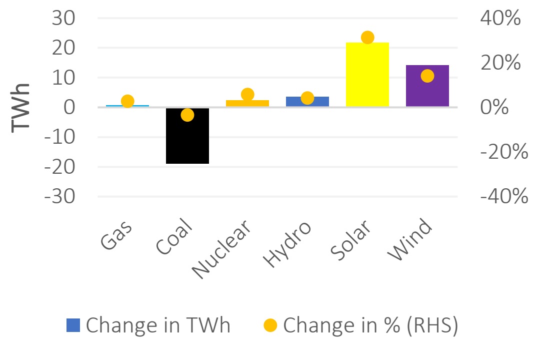
In December 2025, China's apparent gas demand (production + LNG and pipeline gas imports) recorded a growth of 10% y-o-y to reach 41.5 bcm (Figure 29). China's gas consumption is projected to continue rising, reaching around 450–455 bcm in 2026 and increasing to about 550 bcm by 2030, according to CNPC's ETRI. Industrial demand is expected to be the main driver of growth, supported by coal-to-gas policies and efforts to peak coal consumption, alongside expanding gas use in power generation and LNG-fuelled transport. Overall gas demand growth of around 5% per year over 2026–2030 broadly aligns with China's medium-term GDP growth outlook. China's electricity generation reached 919 TWh in December, a rise of 2.7% y-o-y (Figure 30).

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

Figure 30: Y-o-y electricity variation in China

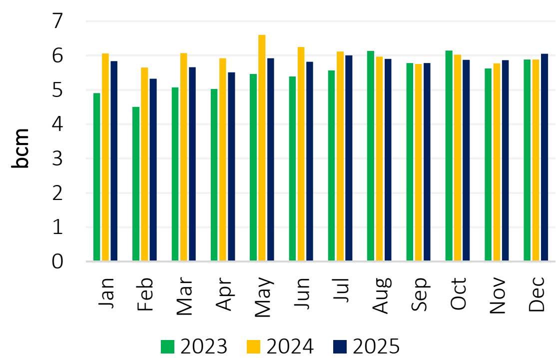


Source: GECF Secretariat based on data from Ember

2.2.2 India

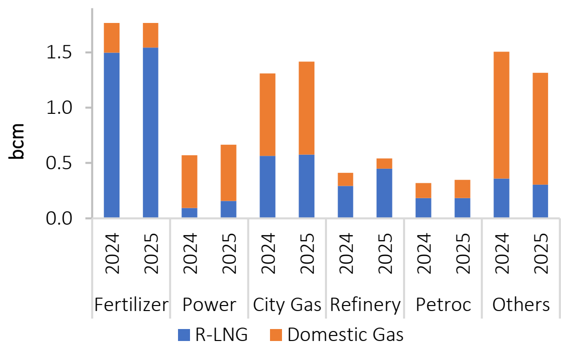
In December 2025, India's gas consumption increased by 3% y-o-y to 6.1 bcm, extending the recovery for a second consecutive month following the contraction recorded in October (Figure 31). The rise was largely supported by stronger gas demand across the power generation, city gas distribution, refinery, and petrochemical sectors, which posted y-o-y increases of 17% (0.2 bcm), 8% (0.1 bcm), 31% (0.1 bcm), and 9% (0.03 bcm), respectively. Fertilizer production remained the dominant source of gas demand, accounting for 29% of total consumption, followed by city gas distribution with a 23% share (Figure 32).

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

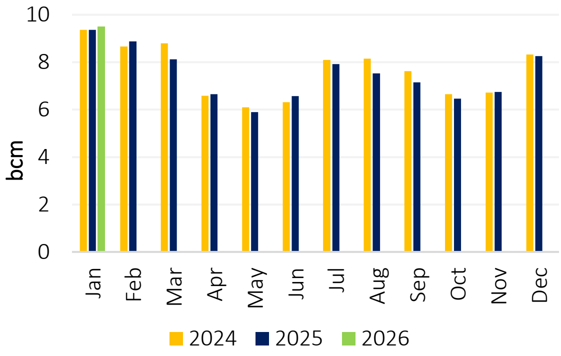
Figure 32: India's gas consumption by sector in December 2025



2.2.3 Japan

In January 2026, Japan's gas consumption increased by 10% y-o-y to 9.5 bcm (Figure 33). Colder-than-normal weather pushed Japan's electricity demand up by 3% y-o-y, leading to higher utilisation of gas-fired power plants. Gas-fired generation rose by 5% y-o-y, increasing LNG consumption and imports, despite a rise in nuclear output, as lower coal-fired generation and declining coal capacity further reinforced reliance on natural gas.

Figure 33: Gas consumption in Japan

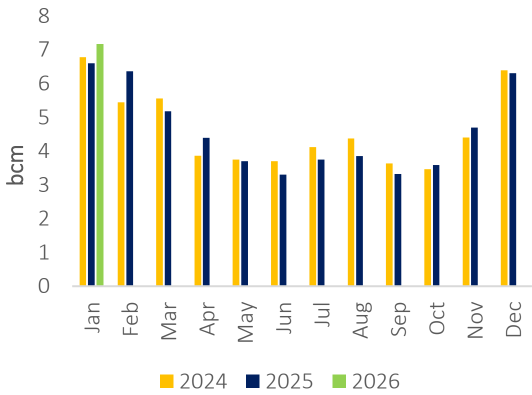


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In January 2026, S. Korea's gas consumption increased by 8.6% y-o-y to reach 7.2 bcm (Figure 34). S. Korea aims to increase nuclear plant utilisation in 2026 to secure stable baseload power and reduce generation costs, with KHNP targeting an average utilisation rate of 89%, up from 85% in 2025. Planned restarts, licence extensions, and new capacity commissioning are expected to support nuclear output, even as the government continues to reassess its long-term nuclear strategy amid a broader policy debate.

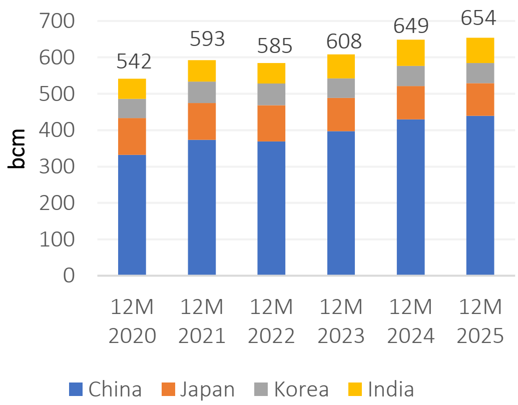
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

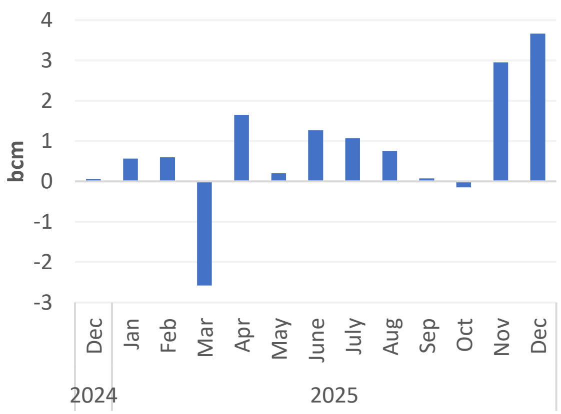
Aggregated gas consumption in major Asian gas consuming countries, namely China, India, Japan and South Korea, rose by 6.5% y-o-y (3.7 bcm) to reach 62.2 bcm (Figure 35), driven mainly by a rise of 3.8 bcm in China (Figure 36).

Figure 35: YTD gas consumption in North East Asia and India



Source: GECF Secretariat based on data from PPCA, LSEG and Chinese custom

Figure 36: Y-o-y variation in aggregated gas consumption of North East Asia and India

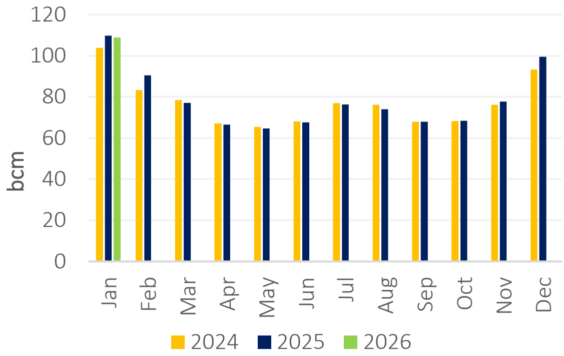


2.3 North America

2.3.1 US

In January 2026, US gas consumption edged down by 1.1% y-o-y to 108.7 bcm (Figure 37), reflecting weaker demand in the residential, commercial, and power sectors, despite the cold spell experienced across parts of the country. Residential and commercial gas use declined by 1.4% y-o-y each. Industrial gas demand also slipped marginally by 0.1% y-o-y (–0.03 bcm), in line with softer manufacturing activity during the month, indicating that economic fluctuations are increasingly influencing overall seasonal energy requirements.

Figure 37: Gas consumption in the US



Source: GECF Secretariat based on data from EIA and LSEG

Total electricity generation in the US decreased by 0.2% y-o-y to 400 TWh. Natural gas-fired power generation declined by 1.4% y-o-y (Figure 38). Natural gas remained the largest contributor to the power mix, accounting for 39%, while nuclear, coal and non-hydro renewables made up 18.5%, 18.7% and 18% respectively (Figure 39).

Figure 38: Electricity production in US in Jan 2026

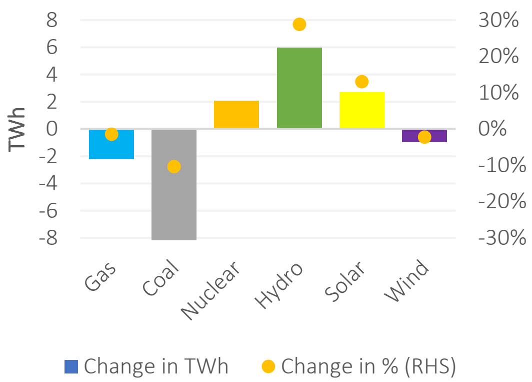
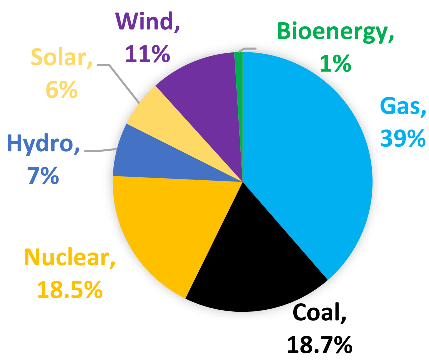


Figure 39: US electricity mix in Jan 2026

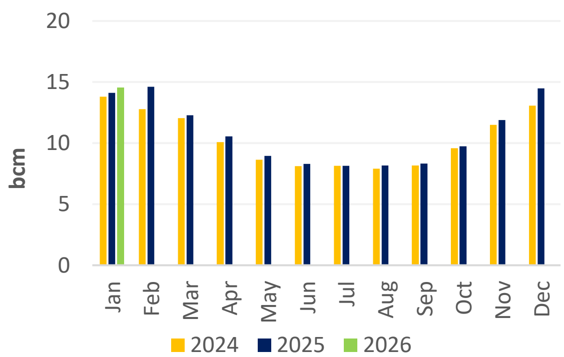


Source: GECF Secretariat based on data from EIA and LSEG

2.3.2 Canada

In January 2026, Canada's natural gas consumption rose by 3% y-o-y to 14.5 bcm (Figure 40), largely reflecting colder-than-normal weather conditions across the country. Residential and commercial gas demand increased by 2.8% and 3.3% y-o-y, respectively, as lower temperatures boosted space-heating requirements. Gas use in the industrial and power generation segment also edged up by 3% y-o-y, supported by higher heating-related and electricity demand during the cold spell.

Figure 40: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.4 Other developments

2.4.1 Sectoral developments

Japan's Osaka Gas launches gas-fired Himeji Unit 1: Osaka Gas officially commenced commercial operations of the No. 1 unit at its newly constructed Himeji Natural Gas Power Plant in western Japan. This 622.5-MW combined-cycle gas-turbine unit represents the first phase of a 1.25-GW facility designed to bolster regional power stability and meet rising electricity demand driven by data centers and AI expansion. The launch is a key milestone for Osaka Gas, marking its first new fossil-fired project since 2017 and increasing its domestic thermal capacity toward a target of 3.2 GW. With Unit 2 scheduled to come online in May 2026 and a third unit planned for 2030 featuring future compatibility with e-methane, this start-up solidifies a long-term strategy for bridging Japan's current energy needs with its 2050 net-zero carbon goals.

Cambodia's first 900MW LNG power plant set for 2026 operational launch: The Government of Cambodia has confirmed that the first phase of its historic 900MW LNG power project in Koh Kong province is on track to begin operations by the end of 2026. Following an on-site inspection on 5 January 2026, Minister of Mines and Energy Keo Rottanak announced that the $1.35 billion facility will be completed in two stages: a 450MW first phase in late 2026 and a second 450MW phase in 2027. Once fully operational, the project is set to generate 6,000 GWh of electricity annually, or roughly one-fourth of Cambodia's total output, strengthening national energy security and supporting the country's goal of reaching 70% clean energy by 2030.

Data centres to drive massive surge in global gas demand through 2035: According to the International Gas Union (IGU), electricity consumption from data centres is projected to double to 1,000 TWh by 2030, potentially triggering an additional 60 bcm of gas demand by 2035 to support AI-driven workloads. This reliance on gas is fuelled by a "time-to-power" crisis; while data centres can be built in under two years, traditional grid and transmission infrastructure often take five or more, forcing hyperscalers to deploy on-site or "behind-the-meter" gas solutions for immediate, reliable power. This shift is reshaping digital geography, positioning gas as an essential backbone for AI hubs in the US, the Middle East, and Asia-Pacific, where high-efficiency gas-fired generation is expected to meet up to 22% of total data centre power demand.

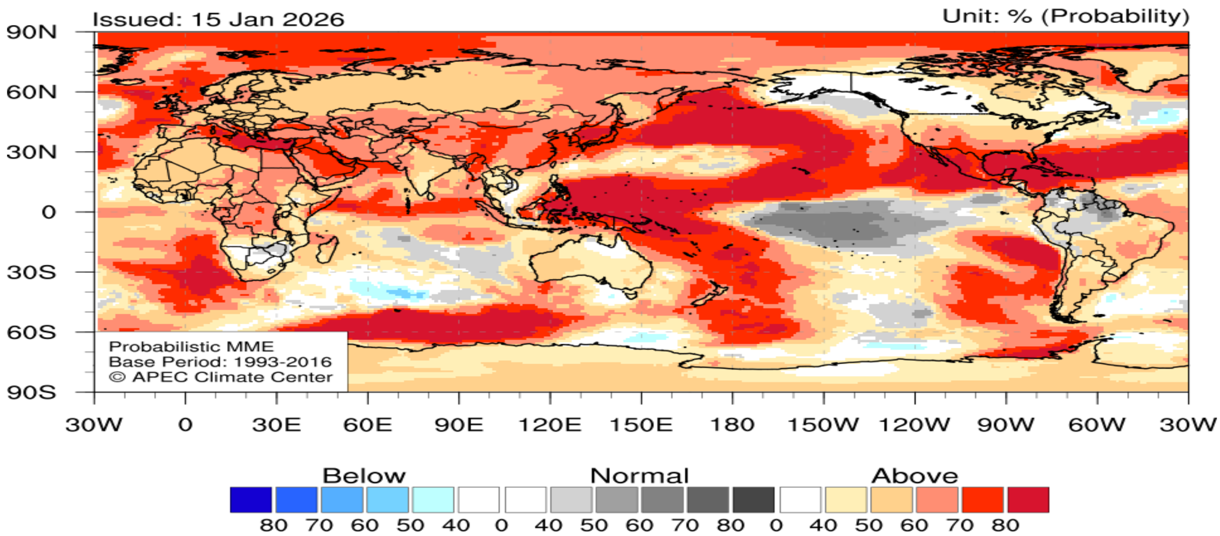
Kuwait plans large-scale gas-fired CHP plant to boost oil production and grid capacity: Kuwait Petroleum Corporation (KPC) and the Ministry of Electricity have signed a Memorandum of Understanding to develop a 1.2 GW to 1.5 GW gas-fired combined heat and power (CHP) plant at the Ratqa oil field. This strategic project aims to optimize domestic gas resources by simultaneously strengthening the national power grid and providing the essential steam required for heavy oil extraction. By integrating power generation with industrial steam production, the facility is expected to significantly lower costs while enabling Kuwait to ramp up heavy oil production at the South Ratqa field to approximately 120,000 barrels per day.

LNG bunkering infrastructure expands to 222 ports globally: The maritime industry's transition to cleaner fuels has reached a new milestone with SEA-LNG reporting that LNG bunkering infrastructure is now available at 222 ports worldwide, a significant increase from 198 ports just a year prior. LNG-fuelled vessels now dominate the alternative-fuel orderbook, accounting for 79% of total tonnage as shipowners prioritize its higher energy density and lower regulatory costs compared to ammonia or methanol. While overall orders for LNG-fuelled ships in 2025 saw a market recalibration to 188 vessels due to regulatory uncertainty, the operational fleet of bunkering vessels has grown to 62 units, ensuring a reliable supply chain at major global hubs.

2.4.2 Weather forecast

According to the APEC Climate Center, from February to April 2026, temperatures are likely above average across most regions, including the Arctic, the southern U.S., Europe and Asia, while below-average conditions are expected in the southern part of the western Indian Ocean and North Atlantic. (Figure 41).

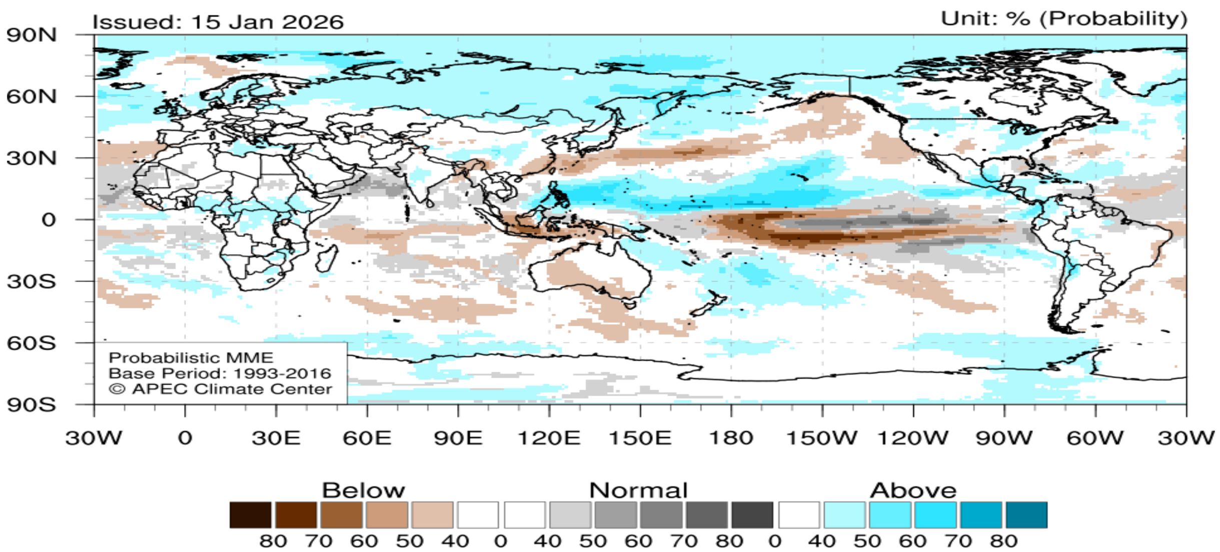
Figure 41: Temperature forecast for February to April 2026



Source: APEC Climate Center

According to the same source, precipitation is expected to be above average in parts of the subtropical North Pacific region, the Arctic Ocean, Russia, Central Africa, the Southwest Pacific, and northeastern North America and Central America. Rainfall is likely near normal in North Indian Ocean and the coast of West Africa, while below-average precipitation is forecast for the equatorial central Pacific region, East China Sea, the Northwest Pacific Ocean, and Indonesia, the tropical Indian Ocean and western Australia (Figure 42).

Figure 42: Precipitation forecast February to April 2026

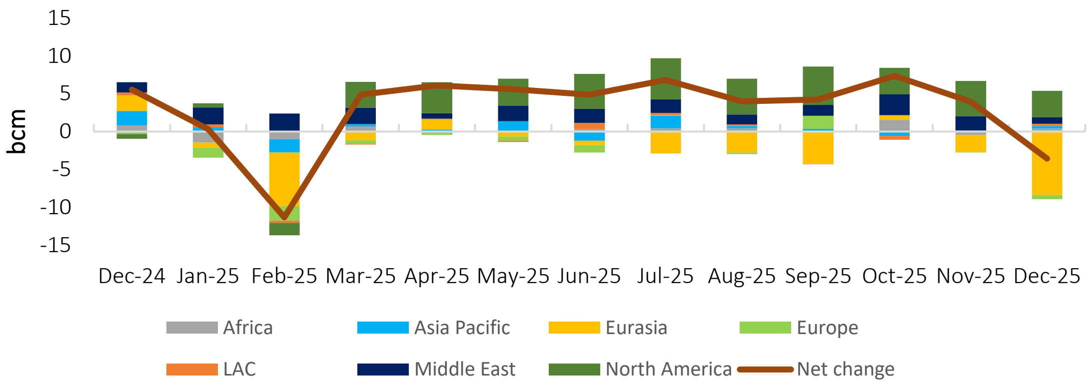


Source: APEC Climate Center

3 GAS PRODUCTION

In December 2025, global gas production growth was estimated to have declined by 1.2% y-o-y to stand at 363 bcm (Figure 43). All gas producing regions, except Eurasia and Europe, witnessed positive production variation, with North America, specifically in the US, leading the growth. On the other hand, Eurasia witnessed the highest output decline in December, with about 10% y-o-y reduction. From a regional perspective, North America kept its leading position as the frontrunner producing region (dominated by the US), accounting for 31% of global gas production, followed by Eurasia with 19% (led by Russia), the Middle East with 18% (led by Iran and Qatar), and Asia Pacific with 17%, while Africa, Europe, Latin America and the Caribbean (LAC) held shares ranging from 4% to 6%.

Figure 43: Y-o-y variation in global gas production



Source: GECF Secretariat estimation

3.1 Europe

In December 2025, gas production in Europe witnessed a 2% y-o-y decline, with a total output of 16.7 bcm (Figure 44). Over the whole 2025, European output has consistently decreased year-on-year in 11 months, mainly driven by lower gas production in the UK and the Netherlands. However, the magnitude of the overall European production decline was limited by the rise in Denmark's gas output, mainly from Tyra phase II gas field in the North Sea, along with the healthy supply from Norway's gas production (Figure 45). Notably, monthly gas production in the EU stood at 2.5 bcm, with the Netherlands and Romania maintaining their positions as top producers.

Figure 44: Europe's monthly gas production

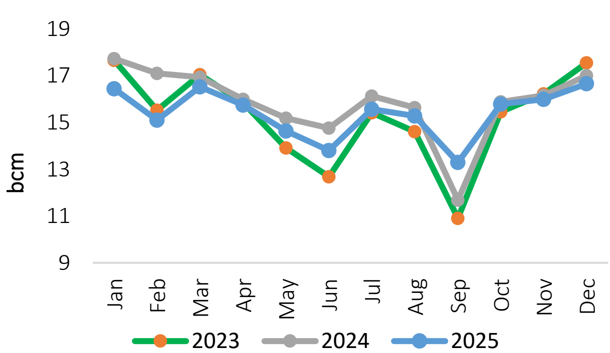
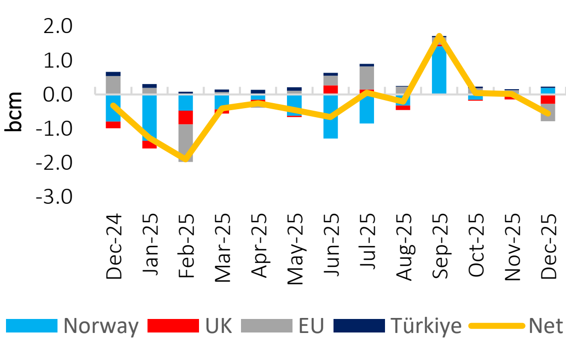


Figure 45: Y-o-y variation in Europe's gas production



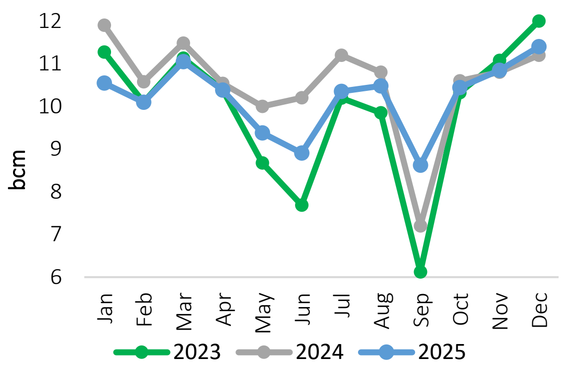
Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

3.1.1 Norway

Norway's gas output witnessed its largest monthly rise during 2025 in December, to stand at the level of 11.4 bcm (+1.7% y-o-y) to compensate some part of its decline during the other months (Figure 46).

This was mainly driven by lower planned and unplanned maintenance duration. Notably, the 124 mcm/d Troll field witnessed reduced production for just one day. In addition, the 28.3 mcm/d Oseberg gas field underwent a planned outage, which slashed its output by 5 mcm/d for a period of 3 days.

Figure 46: Trend in gas production in Norway



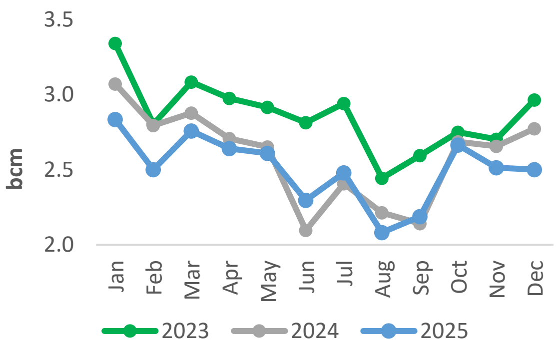
Source: GECF Secretariat based on data from the Norwegian Offshore Directorate

3.1.2 UK

UK gas production declined by 5.3% y-o-y to stand at 2.5 bcm in December 2025 (Figure 47). This is the second highest decline rate during the whole 2025, driven by the reduced output from the UK mature fields, lack of new gas projects and longer-than-expected maintenance periods.

Multiple unplanned maintenance activities took place at the 24 mcm/d Vesterled terminal that decreased its production by 10 mcm/d for a period of 4 days.

Figure 47: Trend in gas production in the UK



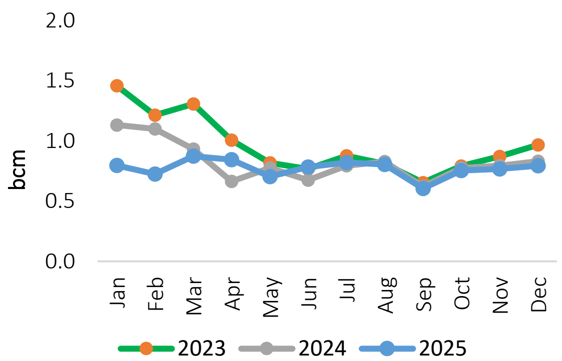
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' gas production maintained a decreasing trend, with a 4.6% y-o-y decline, to stand at 0.79 bcm (Figure 48).

This represented a continuation in output declines observed recently for Dutch production, reflecting a continued negative outlook. With the absence of new field development or rejuvenation, this production drop from the ageing Dutch fields is likely to continue in the coming years.

Figure 48: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In December 2025, gas output in Asia Pacific was estimated to stand at 61 bcm representing a 0.5% y-o-y growth. This increase was driven by the continuous rise in the Chinese gas production, which offset the declining output in some other main Asia Pacific producers.

3.2.1 China

In December 2025, China's gas production maintained its growth trend to stand at 23 bcm, representing a 6% y-o-y uptick (Figure 49). This is a new high record output of the Chinese monthly production, representing new evidence of the consistent gas development track. Coal bed methane production continued its annual growth as well, with 14% y-o-y rise, to stand at 1.5 bcm (Figure 50). Notably, China's largest shale gas production base in the southern Sichuan Basin, southwest China's Sichuan Province, has achieved a cumulative output exceeding 100 bcm, making it the country's first shale gas region to reach this milestone, despite the complex geological conditions.

Figure 49: Trend in gas production in China

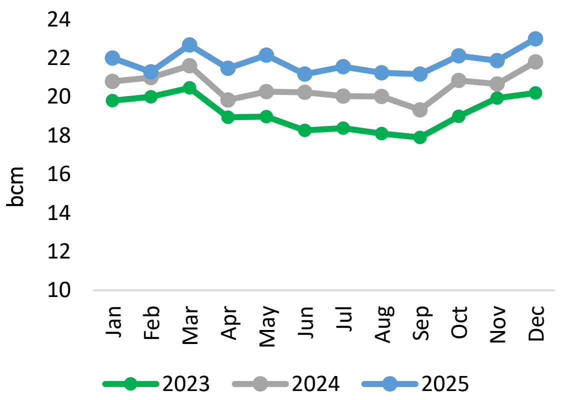
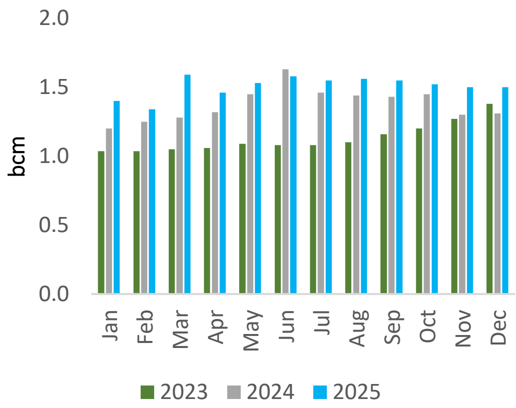


Figure 50: China's CBM gas production

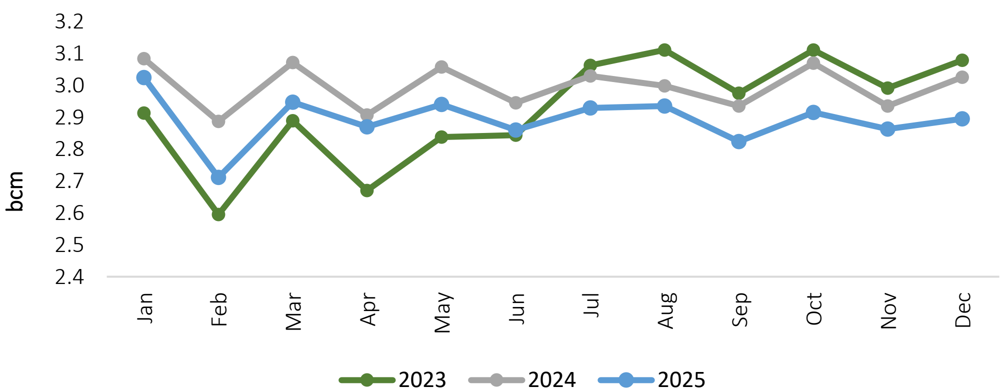


Source: GECF Secretariat based on data from the National Bureau of Statistics of China (NBS)

3.2.2 India

In December 2025, India's gas production continued its negative trend, declining by 4.3% y-o-y to stand at 2.9 bcm (Figure 51). The decrease was driven by a reduction in offshore gas output, which represented 74% of Indian production, along with the decreased output from the onshore Assam field, which recorded an 8% y-o-y decline. Meanwhile, the CBM gas fields witnessed a 4% y-o-y rise, mainly from the West Bengal fields.

Figure 51: Trend in gas production in India



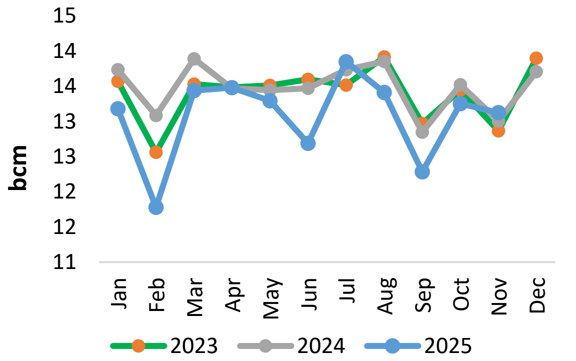
Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In November 2025, Australia's gas production increased by 0.9% y-o-y to stand at 13.1 bcm (Figure 52). Gas production from CBM fields amounted to 3.4 bcm, representing a 1.2% y-o-y reduction and accounting for 26% of the total domestic production. Notably, Australia kept its leading position related to CBM production globally, with consistent growth in the past years, and CBM being used as feedstock for LNG export terminals.

For the period Jan-Nov 2025, the cumulative production dropped by 3% to 143.8 bcm.

Figure 52: Trend in gas production in Australia



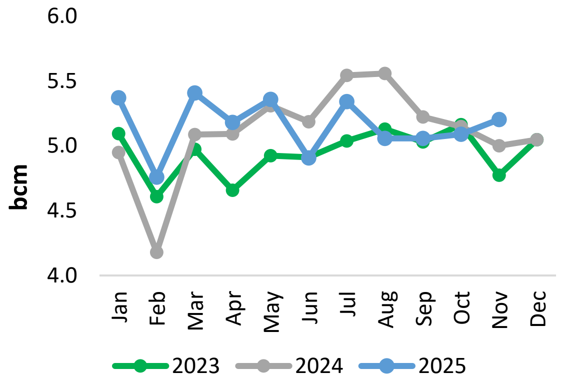
Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In November 2025, Indonesia's gas output rose by 4% to stand at 5.2 bcm (Figure 53). This was driven by an extensive development drilling campaign, with 172 new development wells have been drilled during the month. Their incremental production was able to counterbalance the natural decline in the producing fields.

For the period Jan-Nov 2025, cumulative production rose by 0.8% to 56.7 bcm. This was driven by the startup of multiple gas projects, with 873 new development wells drilled, in addition to 29 new exploration wells.

Figure 53: Trend in gas production in Indonesia



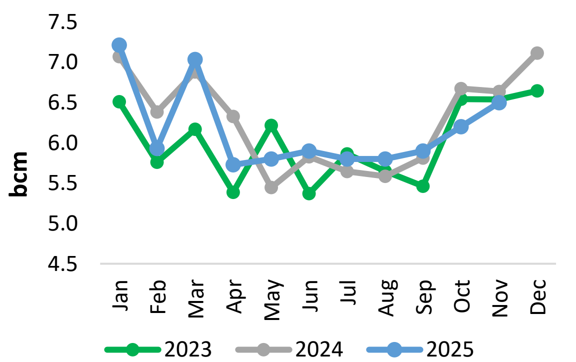
Source: GECF Secretariat based on data from Indonesia's upstream regulator (SKK Migas) and JODI Gas

3.2.5 Malaysia

In November 2025, Malaysia's gas output was estimated at 6.5 bcm, representing a production decline of 2.1% y-o-y (Figure 54). Notably, Petronas is making strategic moves to expand Malaysia's hydrocarbon resources with the award of two key technical evaluation agreements.

For the period Jan-Nov 2025, cumulative production in Malaysia reached 67.8 bcm, representing a 0.7% reduction y-o-y.

Figure 54: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

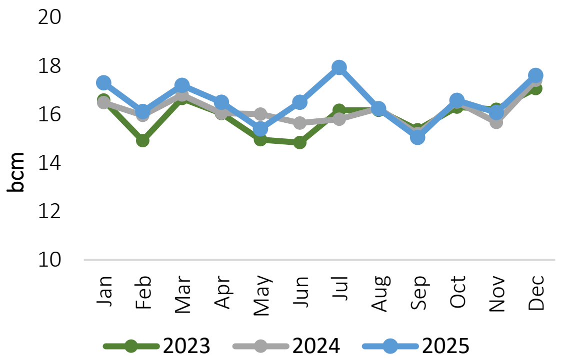
In December 2025, gas production in North America (including Mexico) rose by 3.1% y-o-y to reach 115.6 bcm, driven by strong gas supply growth in the US and Canada.

3.3.1 Canada

In December 2025, Canada's gas production recorded a rise of 1.1% y-o-y, to stand at 17.6 bcm (Figure 55), mainly driven by the increase in the output of shale gas in Alberta and tight gas in British Columbia (BC), coupled with the LNG export startup. From a regional perspective, Alberta was responsible for 10.3 bcm of the production, mainly originating from the Bakken shale production, while BC accounted for 6.9 bcm, with tight gas production from the Montney basin being the main contributor. In this context, Canada is well poised to continue the strong production growth, driven by the start of LNG exports, however the projected growth will be in a slower pace.

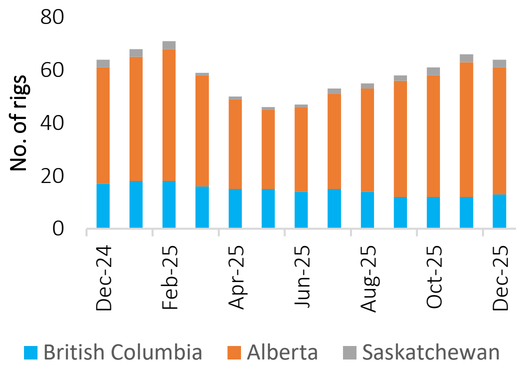
In terms of gas drilling activity, there was a 2-rig-decrease in December 2025, specifically in Alberta, which released 3 more drilling rigs, while BC added one additional gas rig and Saskatchewan kept the same level. Overall, this mirrored the same level of drilling rigs, as compared to December 2024 (Figure 56).

Figure 55: Trend in gas production in Canada



Source: GECF Secretariat based on data from CER, Alberta and British Colombia Energy Regulators

Figure 56: Gas rig count in Canada



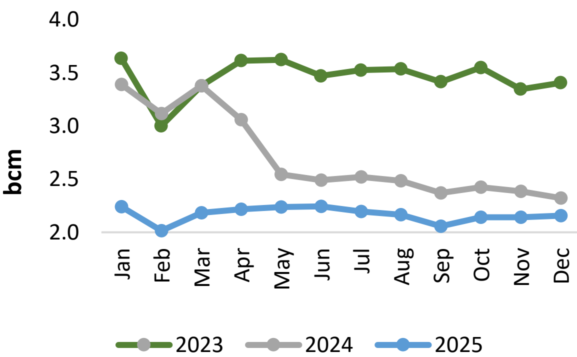
Source: GECF Secretariat based on data from LSEG

3.3.2 Mexico

In December 2025, Mexico's gas output was estimated at 2.15 bcm, representing a production reduction of 7% y-o-y (Figure 57).

For the full year of 2025, Mexico's gas production was estimated at 26 bcm, representing a considerable decline rate of 20% y-o-y. This was driven by the absence of new major gas field startups in 2025.

Figure 57:Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In January 2026, US total gas production maintained its growth trend it witnessed in 2025, with a monthly output rising by 2% y-o-y to 93.4 bcm (Figure 58). This growth reflected the favourable market dynamics, driven by the increased Henry Hub gas prices, rising gas demand for the cold wave, along with the increased feed gas directed to LNG exports terminals.

In terms of supply distribution, shale dry gas production maintained its position as the frontrunner, with 81% share, and it was the main driver for the growth, with 2.3% rise, while conventional gas and associated gas production from shale oil, represented the remaining 19%. In terms of field type, associated gas production represented 26% of the total gas output. From a regional perspective, the Appalachian region accounted for 31% of total gas production, followed by the Permian region output with 24%, and Haynesville with 14%.

Across the past five years, this is the highest January monthly gas production and gives a strong start for the US gas output for the full year (2.3% projected growth) (Figure 59).

Figure 58: Trend in gas production in the US

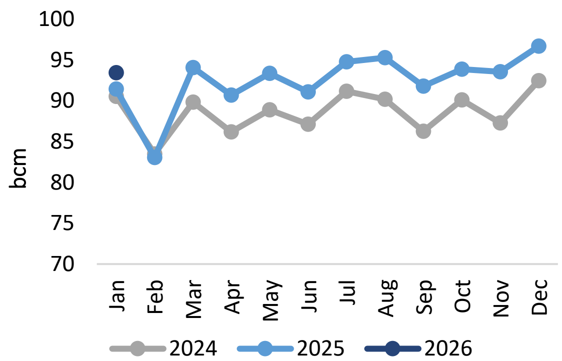
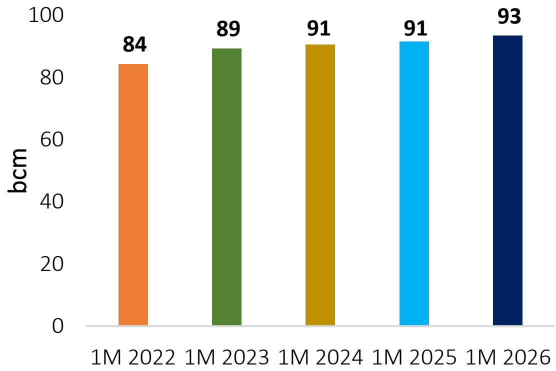


Figure 59: YTD gas production in the US



Source: GECF Secretariat based on data from the US EIA

As of January 2026, the number of gas drilling rigs operating in the US stood at 124, marking a 4-rig decrease, compared to December 2025, but 24-rig rise, compared to January 2025 (Figure 60). Additionally, in January 2025, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 5,015, marking an 18-well m-o-m rise and 786 wells lower than January 2025 (Figure 61). This m-o-m increase in DUCs reflected the slowdown in the completion activity during January, driven by the extreme weather condition that hindered the operation and the pipeline infrastructure constrains in the Permian region.

Figure 60: Gas rig count in the US

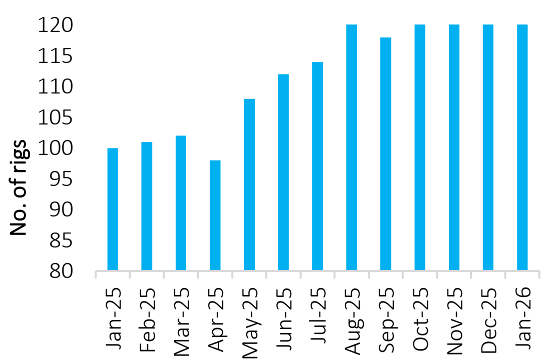
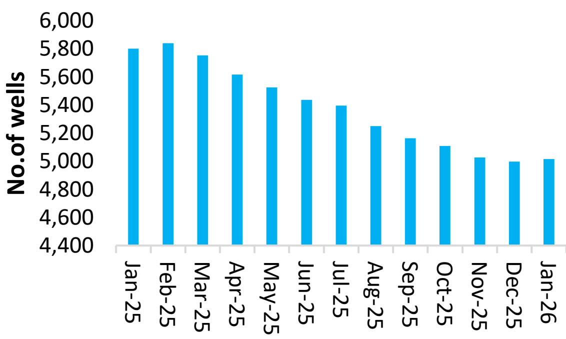


Figure 61: DUC wells count in the US



Source: GECF Secretariat based on data from Baker Hughes *Source: GECF Secretariat based on data from the US EIA*

3.4 Latin America and the Caribbean (LAC)

In December 2025, gas production in LAC was estimated at 13 bcm (0.7% y-o-y rise), mainly driven by increased Argentinian and Brazilian gas outputs.

3.4.1 Argentina

In December 2025, Argentina's gas production stood at 4.1 bcm, representing a 5.4% y-o-y growth (Figure 62). Most of the gas output originated from the Vaca Muerta shale gas basin, however there was a decline from the conventional gas fields. Notably, shale gas production witnessed a 17% y-o-y rise to stand at 2.25 bcm, accounting for 55% of total gas production (Figure 63). Moreover, tight gas production reached 0.4 bcm, to represent a 10% share of the total production, whilst the remaining output was produced from conventional fields.

Figure 62: Trend in gas production in Argentina

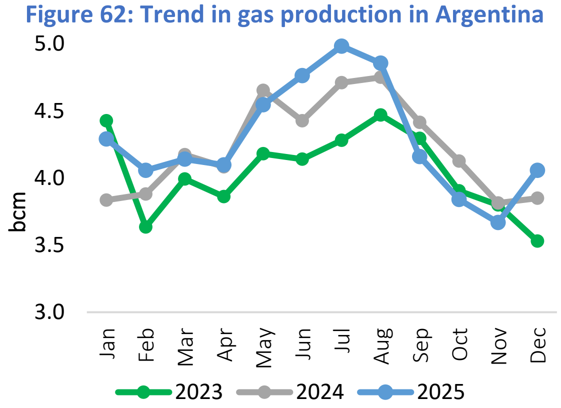
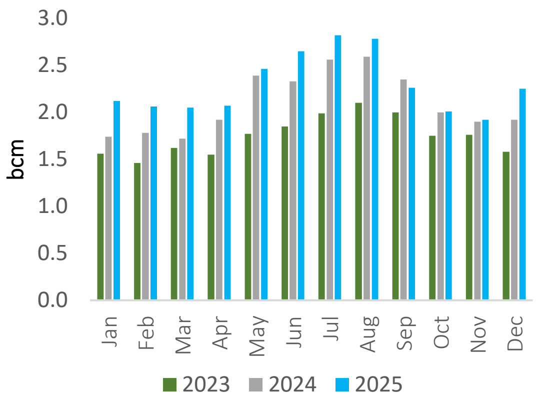


Figure 63: Shale gas output in Argentina



Source: GECF Secretariat based on data from Argentinian Ministry of Economy

3.4.2 Brazil

In December 2025, Brazil's marketed gas production continued its strong growth for the tenth consecutive month, to achieve a record high output of 2 bcm (26% y-o-y) (Figure 64), driven by record monthly gross gas production that stood at 6 bcm (20 % y-o-y rise), with the pre-salt fields representing 80% of the total production. Notably, 86.5% of production originated from offshore fields. In terms of distribution, 54% of gross gas production was reinjected into reservoirs, while there was a 14.8% reduction in flaring compared to the previous month, and a 14% reduction compared to December 2024 (Figure 65).

Figure 64: Marketed gas production in Brazil

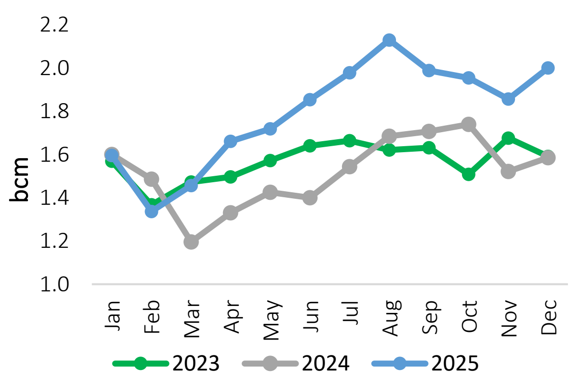
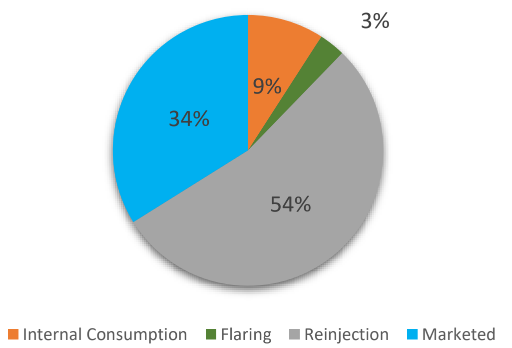


Figure 65: Distribution of gross gas production



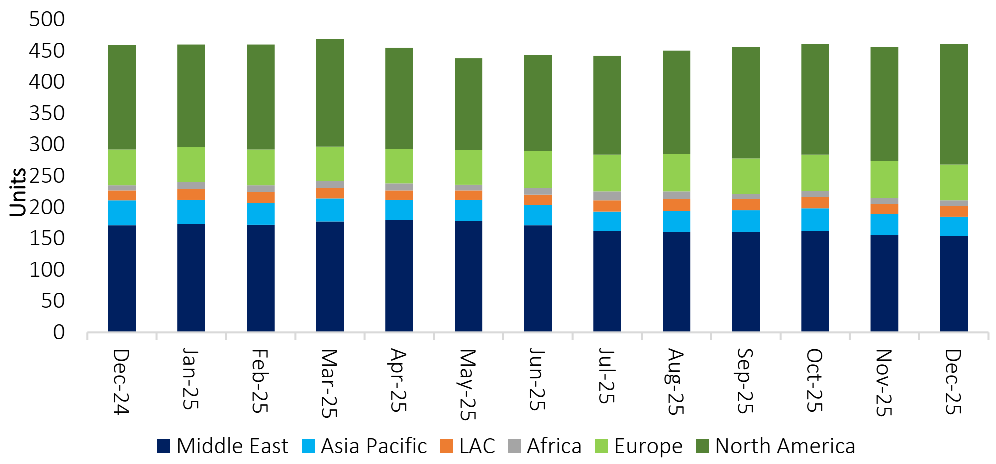
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In December 2025, the number of gas drilling rigs globally ramped-up by 4 additional units, reaching 464 rigs (Figure 66). This was driven mainly by the accelerated drilling activity in the Middle East, specifically in Saudi Arabia, along with LAC, specifically in Argentina. Onshore drilling accounted for the majority, with 433 units, while offshore accounted for 31 rigs.

Figure 66: Trend in monthly global gas rig count



Source: GECF Secretariat based on data from Baker Hughes
Note: Figure excludes Eurasia and Iran

In December 2025, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 375 million barrels of oil equivalent (boe), the highest result since August 2025 (Figure 67). New discoveries were equally split by natural gas, which totalled 32 bcm, and liquid oil, which accounted for 190 million bbl. 13 new discoveries were announced, eight of which were offshore. In terms of regional distribution, Asia Pacific dominated the new discovered volumes with 41% (primarily in Indonesia and China), followed by Europe (Norway) with 21% (Figure 68). The Kavango West discovery, onshore northeastern Namibia, within the Kavango Basin, was the most significant discovery announced in December. The discovery opens a new onshore province in a country historically dominated by offshore exploration.

Figure 67: Monthly discovered oil and gas volumes

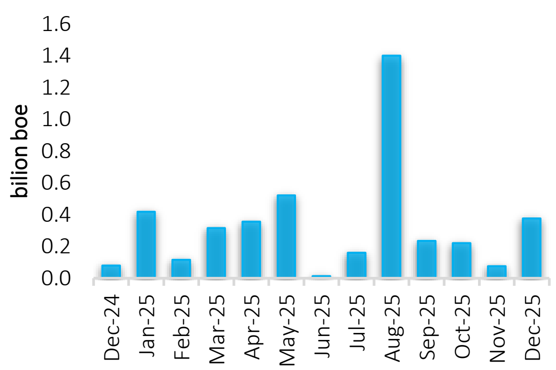
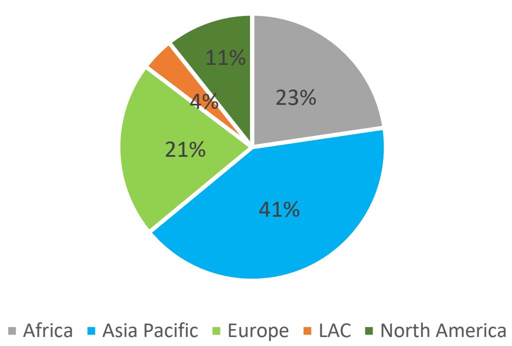


Figure 68: Discovered oil and gas volumes in December 2025 by region



Source: GECF Secretariat based on data from Rystad

3.5.2 Regional developments

Libya to award oil and gas upstream licences: Libya announced the results of its first upstream licensing round since 2007, as the country accelerates efforts to increase gas output for domestic power needs and restore exports to Europe. The licensing round - offering onshore and offshore acreage under revised fiscal terms - drew bids from more than 30 international companies. Libya's plans to raise crude production in phases to 1.6 million b/d and ultimately to 2 million b/d, while targeting gas output of up to 40 bcma. Libya is also seeking to unlock incremental gas supply by reducing reinjection and curbing flaring.

Eni announced a significant gas discovery in the Kutei Basin in Indonesia: Eni announced a significant gas discovery in the Konta-1 exploration well, drilled in the Muara Bakau PSC, in the Kutei Basin, about 50 km off the coast of East Kalimantan in Indonesia. Estimates indicate 17 bcm of gas initially in place with a potential upside beyond 30 bcm. Konta-1 was drilled to a depth of 4,575 m in 570 m water depth, encountering gas in four separate sandstone reservoirs of Miocene age with good petrophysical properties that have been subject to an extensive data acquisition campaign. The discovery confirms the effectiveness of Eni's near-field exploration strategy in the Kutei Basin, aimed at creating value through its deep knowledge of geological plays and the application of advanced geophysical technologies, while exploiting the synergies with existing projects and facilities. The Konta discovery is sitting nearby existing facilities and adjacent to existing discoveries, providing significant synergies for the development; options for a fast-track development are already under study.

Egypt announced oil and gas discoveries in Western desert: Egypt has announced discoveries at 4 exploration wells in the Western Desert as the country looks to boost oil and gas production. The four exploration wells are expected to have a combined daily production capacity of nearly 4,500 barrels of crude oil and 2.6 million cubic feet of natural gas, according to the Egyptian Ministry of Petroleum and Mineral Resources. Notably, a total of 101 exploration wells are scheduled for drilling in 2026, spread across Egypt's main producing regions.

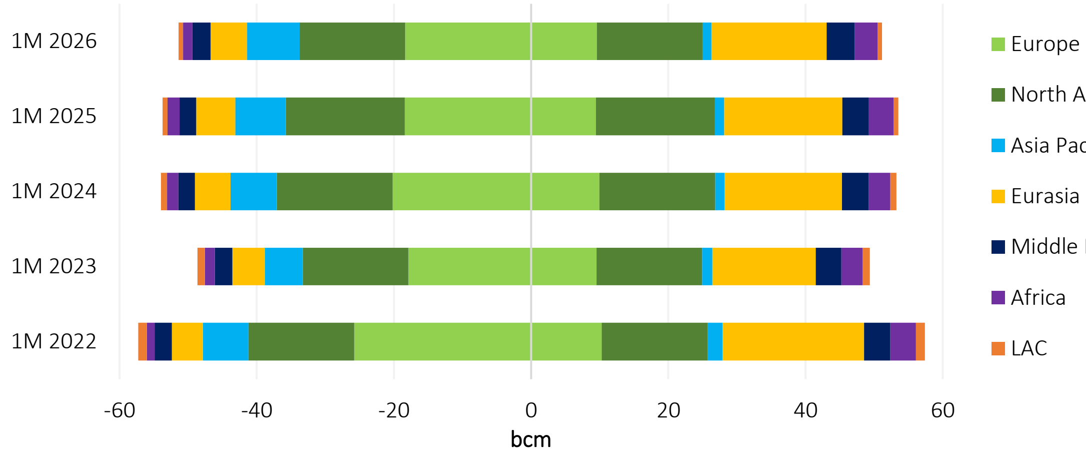
Malaysia announced new licensing round: PETRONAS has launched the Malaysia Bid Round 2026 (MBR 2026), offering 15 opportunities comprising nine exploration blocks and six Discovered Resource Opportunity (DRO) clusters across the Malay, Sarawak and Sabah basins. Under the MBR 2025, new PSC awards including the Permata Cluster, comprising the South East Collins, Lokan, Axinit, Realgar and Manikam fields, were awarded to Bridge Petroleum, marking its entry into Malaysia. Separately, the Cendramas PSC was awarded to a consortium led by PT Medco Energi Internasional Tbk , with Dialog Group Berhad and EnQuest as partners. MBR 2026 reflects PETRONAS' strategy to attract diverse upstream investments by combining exploration upside with commercially ready DRO opportunities across Malaysia's core basins as it aims to sustain 2 MMboe/d of production to 2035.

4 GAS TRADE

4.1 PNG trade

In January 2026, global PNG imports were estimated at 51 bcm, which represented a decrease of 4% compared to one year prior (Figure 69). Europe is the leading region for PNG imports, accounting for 36% of the global total. PNG imports in Middle Eastern countries increased by 9% y-o-y. Similarly, Eurasian countries together accounted for one third of global PNG exports in 2026, while intra-North American flows represented a further 30%.

Figure 69: Global PNG imports (-) and exports (+) by region

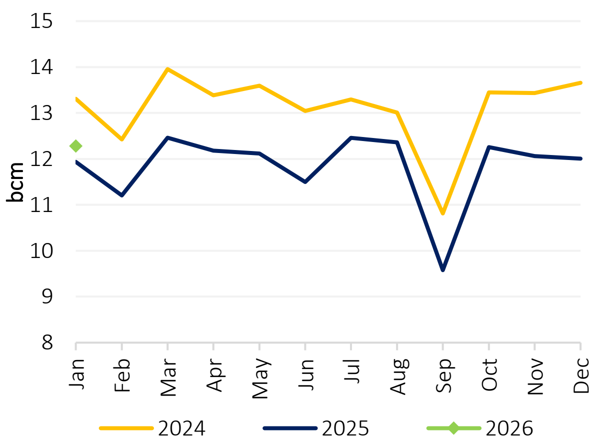


Source: GECF Secretariat based on data from Cedigaz, ENARGAS, Eurostat, GACC, JODI, LSEG and US EIA

4.1.1 Europe

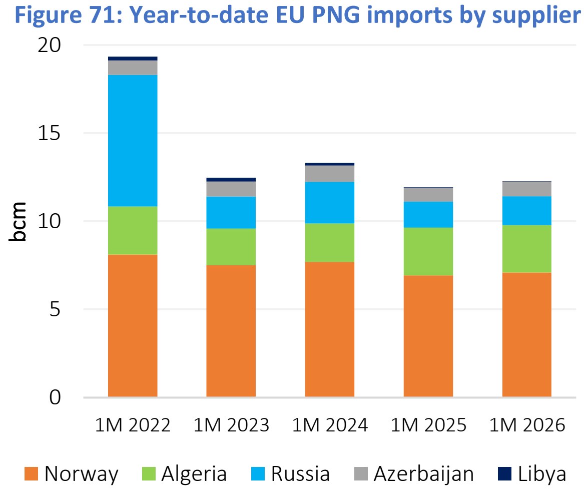
In January 2026, EU countries imported 12.3 bcm of PNG, which was 2% higher m-o-m (Figure 70). Of all five producers, only Algeria recorded a m-o-m increase in PNG supply, of 22%. While this month's PNG import was also 3% greater than one year ago, both Algeria and Libya recorded small y-o-y decreases during January (Figure 71). Overall, Norway continues to account for 58% of the regional PNG supply, while Algeria contributes 22%.

Figure 70: Monthly PNG imports to the EU



Source: GECF Secretariat based on data from LSEG

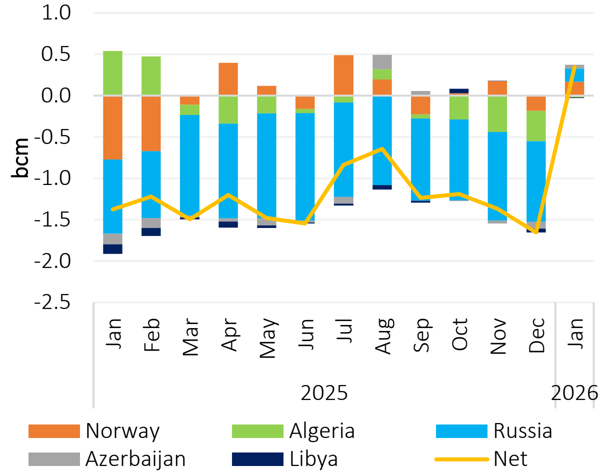
Figure 71: Year-to-date EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

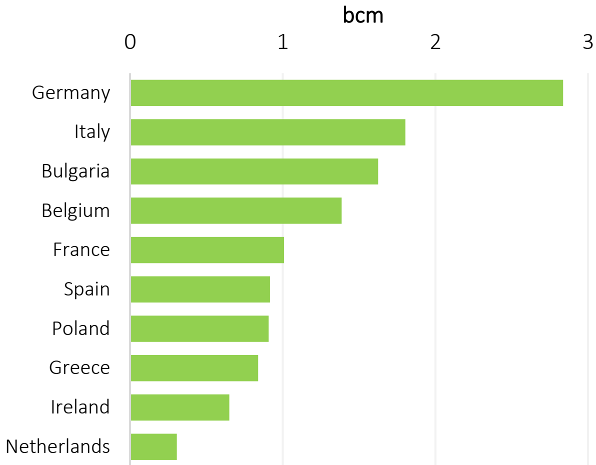
In January 2026, there was a net 0.3 bcm increase in PNG supply to the region compared to the previous year, driven particularly by Russia and Norway (Figure 72). Moreover, there were 2.8 bcm of PNG flows entering the region via Germany, with both Greece and the Netherlands moving downwards on the ranking of entry points for EU PNG imports (Figure 73).

Figure 72: Y-o-y variation in EU PNG supply



Source: GECF Secretariat based on data from LSEG

Figure 73: EU PNG imports by entry, after 1M 2026

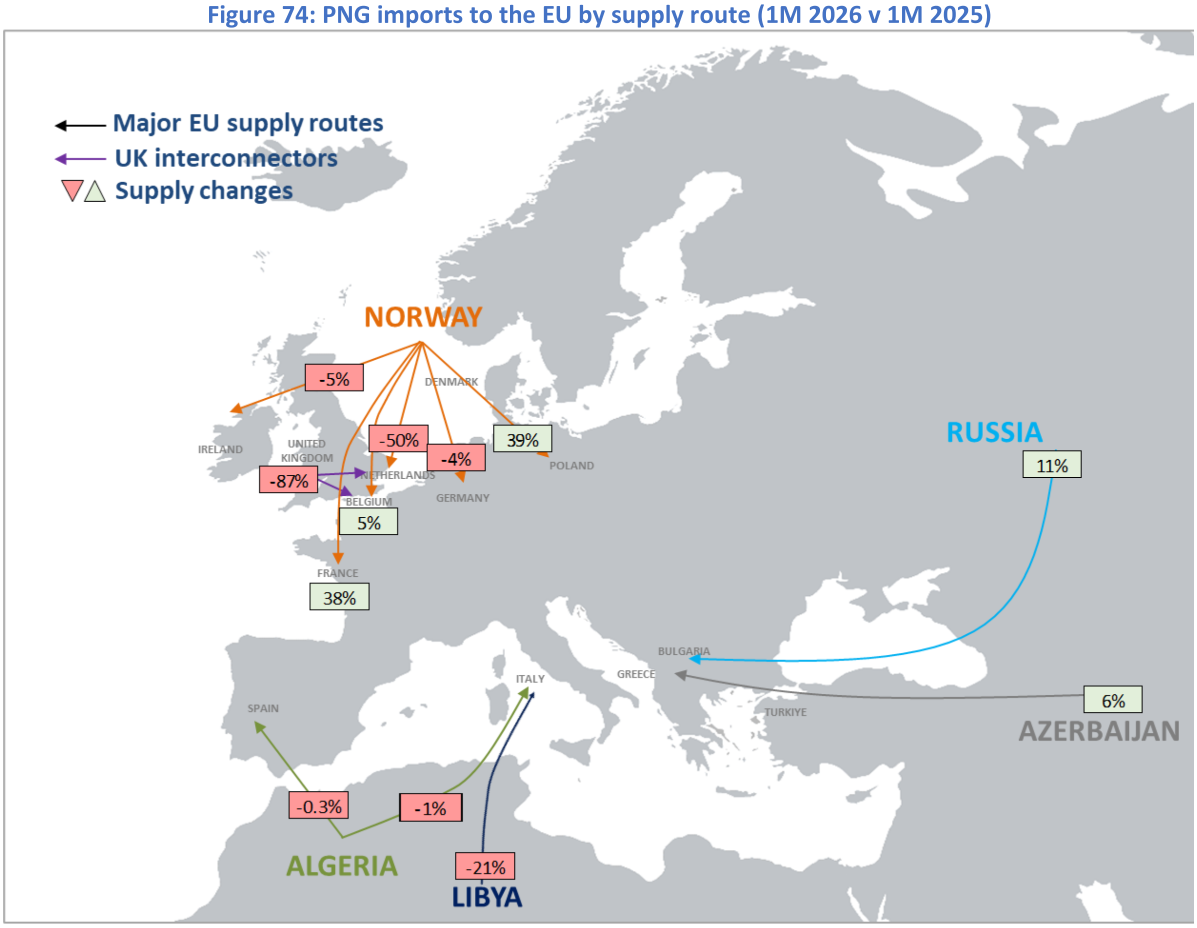


Source: GECF Secretariat based on data from LSEG

Figure 74 shows the PNG imports to the EU via the major supply routes during 1M 2026, compared with 1M 2025. There were significant increases in flows from Norway to both Poland (39%) and France (38%), while Russian supply via the Turkstream pipeline also increased by a notable 11%, and Azeri PNG exports to the EU increased by 6%.

Meanwhile, almost zero net gas flows were recorded along the interconnectors between the UK to mainland Europe in 2026 thus far, compared to one year ago when there were 0.4 bcm of supply in the direction from the EU towards the UK.

Figure 74: PNG imports to the EU by supply route (1M 2026 v 1M 2025)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

In the final month of 2025, China imported 6.8 bcm of PNG, which was 1% lower than was imported in November 2025 (Figure 75). Nevertheless, this volume represented an increase of 13% compared to the previous year, which marked the twentieth consecutive month of y-o-y increases in Chinese PNG imports, highlighting the growing role of PNG in the country's energy mix. Accordingly, the share of PNG in China's gas import mix rose from 42% in 2024 to 46% in 2025. After all of 2025, cumulative Chinese PNG imports totalled 81 bcm, which is an increase of 8% y-o-y, following on from the 13% growth rate in the previous year (Figure 76).

Figure 75: Monthly PNG imports in China

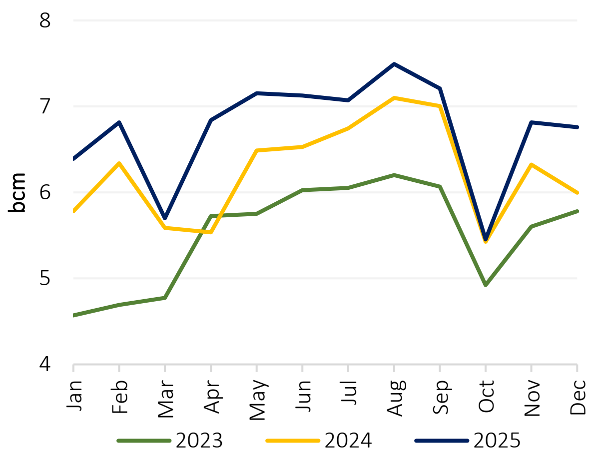
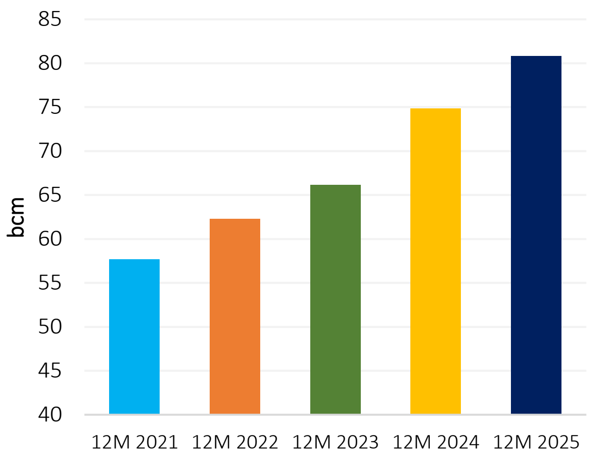


Figure 76: Year-to-date PNG imports in China



Source: GECF Secretariat based on data from LSEG and General Administration of Customs China

In November 2025, Singapore imported 0.56 bcm of PNG from Indonesia and Malaysia (Figure 77). This volume was 2% higher y-o-y, as well as 4% greater m-o-m. From January to November 2025, PNG imports totalled 6.0 bcm, which was an increase of 8% y-o-y. In the same month, Thailand imported 0.30 bcm of PNG from Myanmar (Figure 78). This volume represented decreases of 25% y-o-y, as well as of 23% compared to the previous month. PNG imports after eleven months of 2025 decreased by 15% y-o-y, to reach 4.1 bcm.

Figure 77: Monthly PNG imports in Singapore

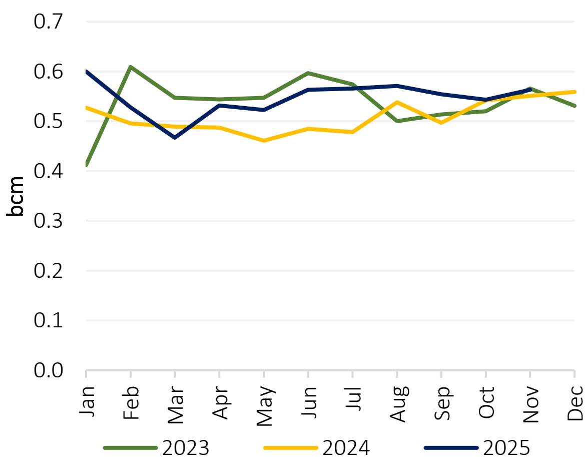
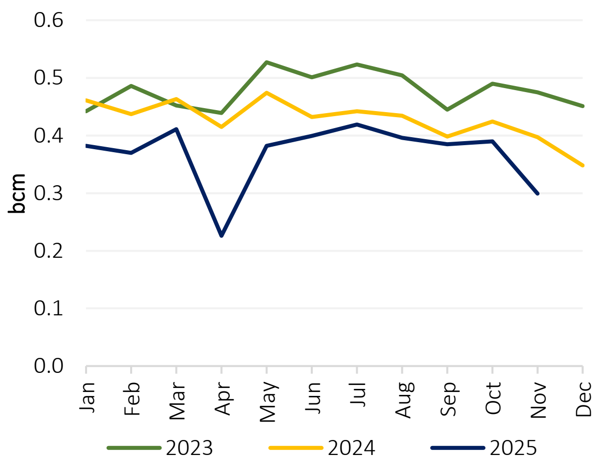


Figure 78: Monthly PNG imports in Thailand

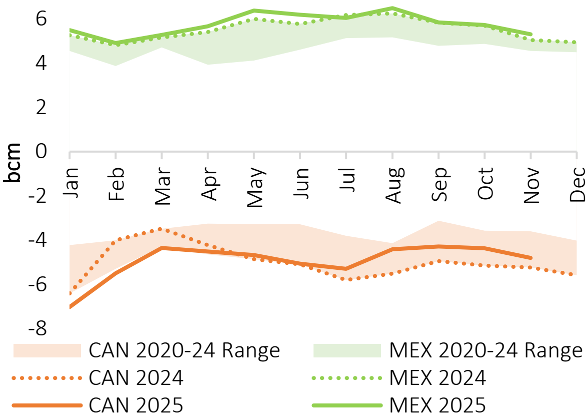


Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

In November 2025, Mexico imported 5.3 bcm of PNG from the US. This volume was 5% greater y-o-y, but was 7% lower m-o-m (Figure 79). After eleven months of 2025, Mexico's total PNG imports increased by 3% to reach 63 bcm. In the same month, there were 4.8 bcm of net PNG flows from Canada to the US, a decrease of 8% y-o-y, but 10% higher than the previous month. Flows from Canada to the US rose m-o-m to 7.5 bcm, and flows from the US to Canada increased m-o-m to 2.7 bcm. After eleven months of 2025, net flows from Canada to the US fell by 1% y-o-y to 54 bcm.

Figure 79: Net US PNG exports (+) and imports (-)



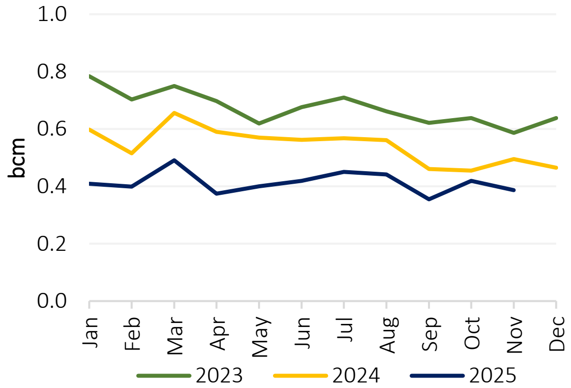
Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

In November 2025, Bolivia exported 0.39 bcm of PNG to Brazil, representing decreases of 22% compared to one year prior, as well as of 8% compared to the previous month (Figure 80). After eleven months of 2025, total Bolivian PNG exports decreased by 25% y-o-y, to reach 4.5 bcm.

During the same month, Chile imported 0.24 bcm from Argentina. This volume represented an increase of 69% y-o-y, as well as an increase of 6% compared to the previous month.

Figure 80: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

Azerbaijan continues gas push into Europe: Azerbaijan's SOCAR and Hungary's MVM ONEnergy have signed a new gas supply agreement, which takes effect from January 1, 2026, and is expected to deliver approximately 100 million cubic metres of gas to Hungary during the winter period, mirroring the volume of a previous deal signed in June 2023. This contract reinforces Azerbaijan's position as a growing supplier to Europe (already serving 15 countries).

South American countries advance regional integration: Representatives from six South American nations, namely Argentina, Bolivia, Brazil, Chile, Paraguay and Uruguay, met to advance plans for a new inter-oceanic gas pipeline. This proposed 32-inch pipeline would connect the Pacific and Atlantic coasts, running from Chile through Argentina and Paraguay to Brazil, with the capacity to transport 30 mcm/d. The meeting focused on the harmonization of energy regulations, financing and business models. This pipeline is one of several projects being considered to leverage Argentina's vast Vaca Muerta unconventional gas reserves, with other proposals including potential pipelines linking Argentina to Paraguay and extending an existing connection to Brazil.

4.2 LNG trade

4.2.1 LNG imports

In January 2026, global LNG imports reached a new record of 43.03 Mt, rising by 11% y-o-y (4.77 Mt) and marking the largest m-o-m increase since January 2022 (Figure 81). All regions except LAC recorded higher imports, with Asia Pacific and Europe driving most of the growth (Figure 82). Notably, this was the first time since August 2025 that Asia Pacific's incremental LNG imports exceeded those of Europe, despite the TTF maintaining a premium over Asia's spot LNG prices during the month.

Figure 81: Trend in global monthly LNG imports

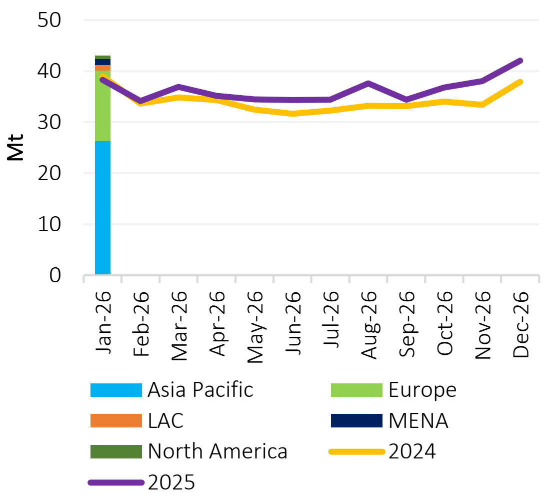
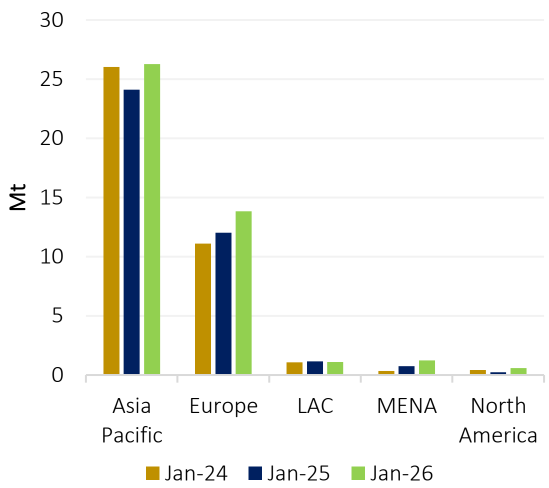


Figure 82: Trend in regional LNG imports in Jan



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In January 2026, Europe's LNG continued to rise, growing by 15% (1.81 Mt) y-o-y to reach a new monthly record of 13.82 Mt (Figure 83). This marks only the second month in which Europe's LNG imports have exceeded 13 Mt, following the first occurrence in December 2022. The increase was driven primarily by stronger gas consumption, due to colder-than-usual weather and lower gas production. The region continued to be the preferred destination for US cargoes, which provided a higher netback price compared to delivery into Asia Pacific. At the country level, Belgium, Germany, Italy, Türkiye and the UK, drove the increase, which offset weaker imports in France, Portugal and Spain (Figure 84).

LNG imports increased in Belgium, Germany, and Italy, supported by stronger gas demand amid colder weather compared with a year earlier and higher flows of regasified LNG to Central Europe. In Germany, imports were further boosted by the ramp-up of newly commissioned LNG terminals. In the UK, LNG inflows rose despite weaker gas consumption, compensating for lower pipeline gas imports and declining domestic production. In Türkiye, stronger gas demand and the start of several short-term LNG contracts lifted imports, which reached a monthly record in January. By contrast, France's LNG imports declined due to weaker demand and higher pipeline gas supplies. Meanwhile, firmer gas prices in North-West Europe, combined with a surge in LNG imports by Egypt and Türkiye, limited LNG inflows into Spain and Portugal despite stronger gas demand, with higher pipeline gas exports from France helping to offset the reduced LNG imports.

Figure 83: Trend in Europe's monthly LNG imports

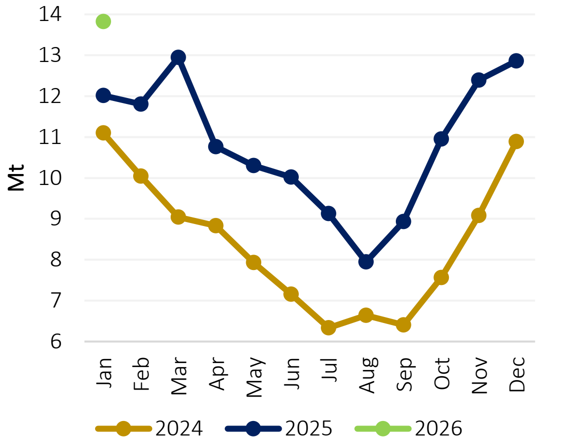
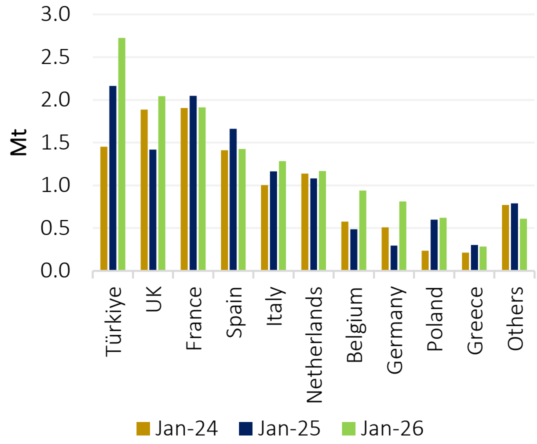


Figure 84: Top LNG importers in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia Pacific

In January 2026, Asia Pacific's LNG imports increased sharply by 9.0% (2.16 Mt) y-o-y to 26.28 Mt, representing the strongest incremental increase since October 2024 (Figure 85). China reclaimed its position as the main driver of the region's LNG import growth while India, South Korea, Taiwan and Thailand contributed to a lesser extent, together offsetting declines in Singapore (Figure 86).

China posted a second consecutive y-o-y increase in LNG imports after 13 months of decline, driven by stronger heating demand amid colder weather compared to January 2025 and a recovery in industrial gas consumption. Similarly, colder-than-normal temperatures in South Korea lifted heating demand and LNG imports. In India, LNG imports rose following the start of some new LNG contracts and to compensate for declining domestic gas production. Higher gas-fired generation in Taiwan, linked to the phase-out of nuclear, also supported LNG imports. In Thailand, lower pipeline gas imports contributed to increased LNG imports. In contrast, Singapore's LNG imports declined, mainly reflecting reduced imports from the US.

Figure 85: Trend in Asia's monthly LNG imports

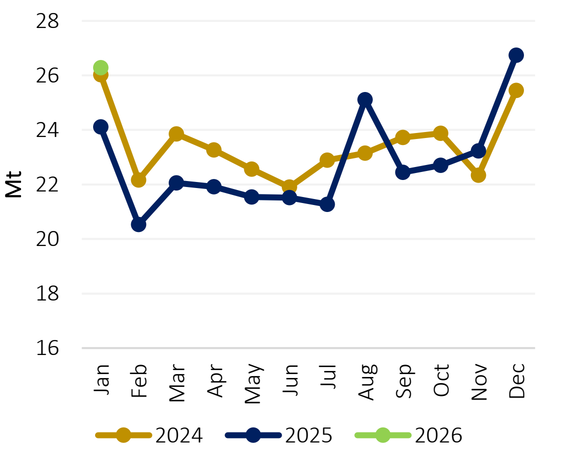
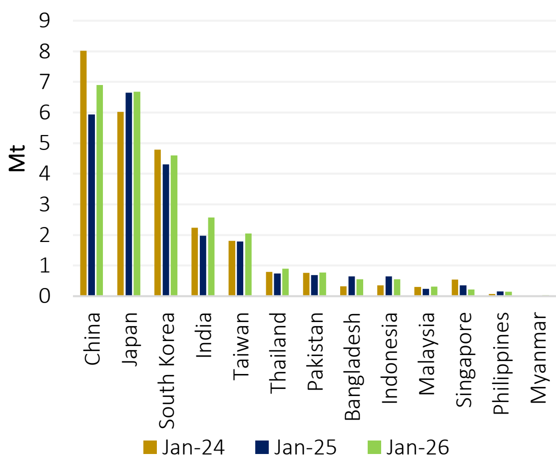


Figure 86: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In January 2026, LNG imports in the LAC region moved slightly lower by % (0.06 Mt) y-o-y to reach 1.09 Mt (Figure 87). Jamaica and the US Virgin Islands (USVI) drove the decline in the region's LNG imports, while Colombia and Panama recorded large increases (Figure 88).

The drop in Jamaica's LNG imports reflects weaker power-sector gas demand amid ongoing repair to its energy infrastructure caused by Hurricane Melissa. At the same time, direct LNG trade between the US and Puerto Rico has reduced imports into the USVI, previously a regional redistribution hub, while declining gas production in Colombia has driven higher LNG imports.

Figure 87: Trend in LAC's monthly LNG imports

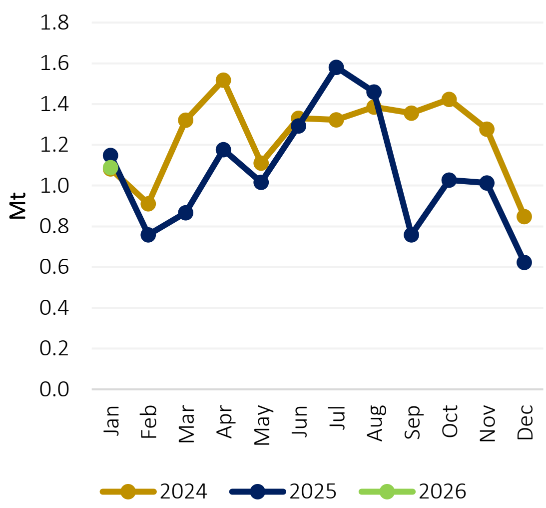
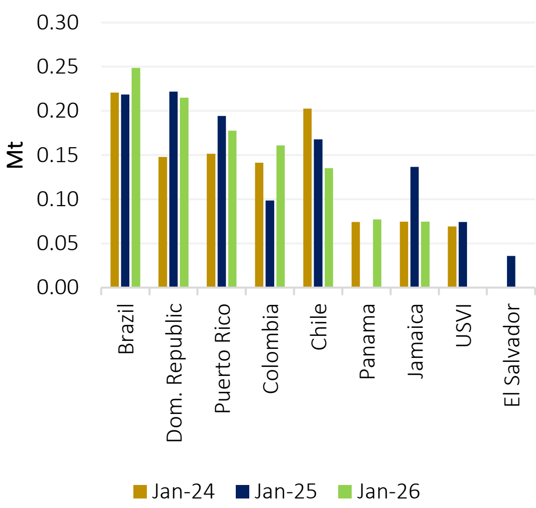


Figure 88: Top LNG importers in LAC



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 MENA

In January 2026, LNG imports in the MENA region rose by 68% (0.50 Mt) y-o-y to a monthly record of 1.25 Mt (Figure 89). Egypt accounted for most of the increase, with LNG imports playing a key role in meeting domestic gas demand (Figure 90).

Figure 89: Trend in MENA's monthly LNG imports

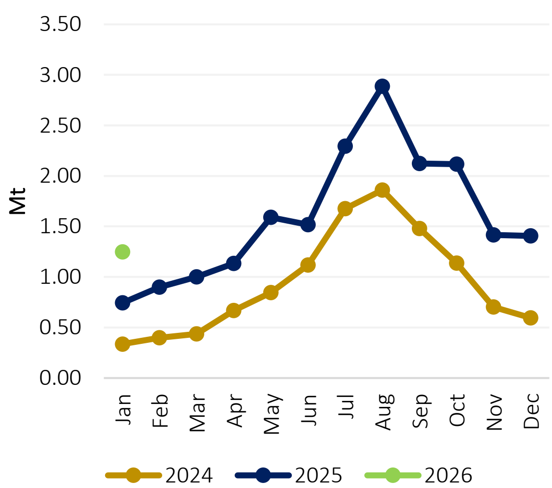
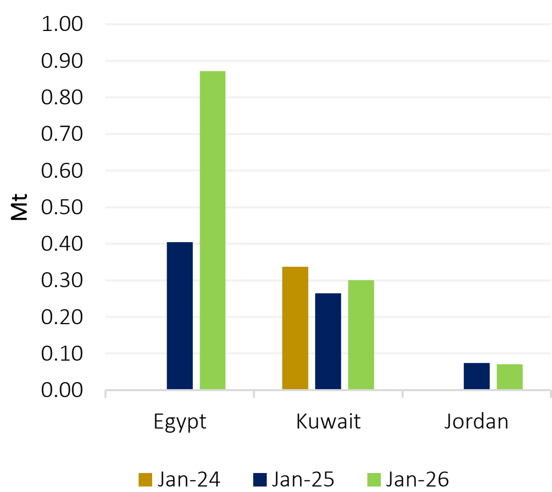


Figure 90: Top LNG importers in MENA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In January 2026, global LNG exports climbed by 15% (5.56 Mt) y-o-y year to a record high of 42.39 Mt, marking the strongest monthly growth ever (Figure 91). Higher exports from both GECF and non-GECF countries more than offset a slight decline in LNG re-exports (Figure 92).

Although LNG exports from both GECF and non-GECF countries increased year on year, stronger growth from non-GECF countries lifted their share of global LNG exports. The share of non-GECF countries rose from 51.3% in January 2025 to 54.8% in January 2026. Over the same period, the shares of GECF Member Countries and LNG re-exports edged down from 47.1% to 44.4% and from 1.6% to 0.8%, respectively.

The US, Australia, and Qatar remained the three largest LNG exporters during the month.

Figure 91: Trend in global monthly LNG exports

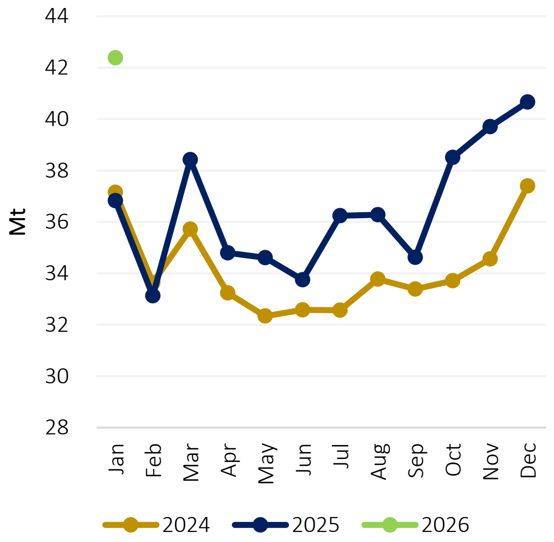
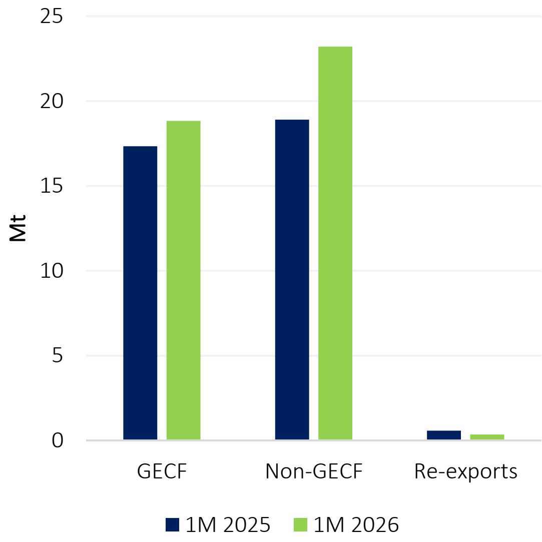


Figure 92: Trend in LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In January 2026, LNG exports from GECF Member and Observer Countries rose by 8.7% (1.50 Mt) y-o-y to a record monthly high of 18.83 Mt (Figure 93). The increase was mainly driven by higher exports from Egypt, Malaysia, Mauritania, Nigeria, Qatar, Russia and Senegal (Figure 94). In addition, GECF's LNG exports increased by 9.2% (1.58 Mt) m-o-m.

Stronger exports from Egypt, Malaysia, Nigeria, and Qatar reflected higher feedgas availability for LNG production. In Egypt, exports increased from the Idku LNG facility, while in Malaysia the gains were driven by the Bintulu LNG plant. Despite becoming a net LNG importer, Egypt continued to ship occasional cargoes from Idku. Qatar's Ras Laffan LNG facility continued to operate well above its nameplate capacity, pushing the country's LNG exports to a record high of 7.72 Mt.

In Russia, higher exports from Arctic LNG 2, Portovaya LNG, and Sakhalin 2 supported overall growth. The recently commissioned Arc7 LNG carriers assigned to Arctic LNG 2 have enabled operations during the winter season. Meanwhile, the continued ramp-up of the GTA FLNG 1 project sustained higher LNG exports from both Mauritania and Senegal.

Figure 93: Trend in GECF monthly LNG exports

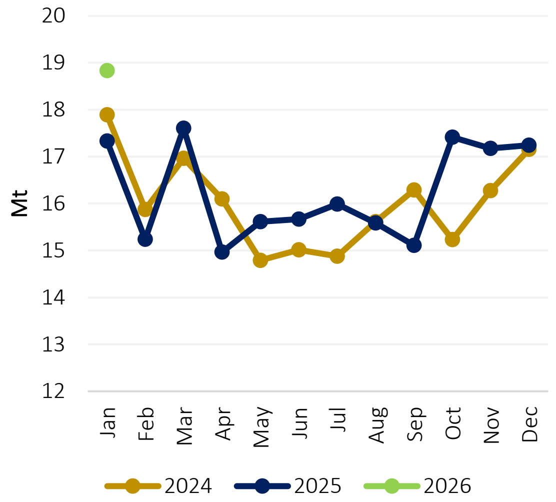
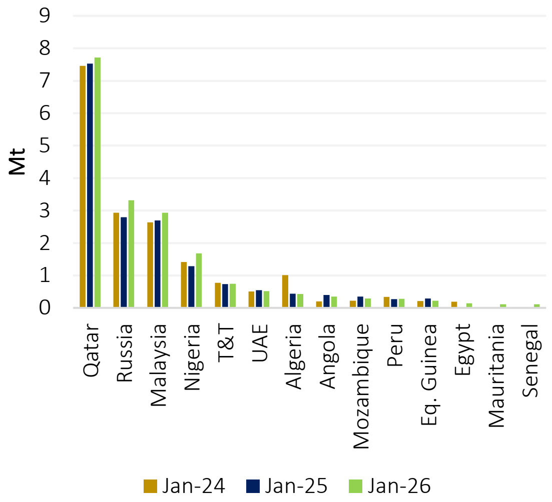


Figure 94: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In January 2026, LNG exports from non-GECF countries jumped by 23% (4.30 Mt) y-o-y to 23.21 Mt, remaining broadly flat compared with December (Figure 95). The increase was led by the US, with Australia, Canada and Norway also making notable contributions (Figure 96).

Despite a sharp y-o-y increase, US LNG exports edged down slightly from December due to the impact of a severe winter storm that disrupted feedgas supplies to LNG facilities. Compared with January 2025, higher exports from the Corpus Christi and Plaquemines LNG facilities, supported by newly commissioned trains boosted overall US LNG exports, while reduced outages at the Calcasieu Pass and Freeport LNG plants also contributed.

Meanwhile, stronger exports from the APLNG, Darwin, Gorgon and Wheatstone facilities lifted Australia's LNG shipments. The Darwin LNG plant loaded its first cargo since November 2023, supported by feedgas from the newly commissioned Barossa gas project. In addition, the ramp-up of LNG Canada and lower maintenance at Norway's Hammerfest facility further supported higher non-GECF LNG exports.

Figure 95: Trend in non-GECF monthly LNG exports

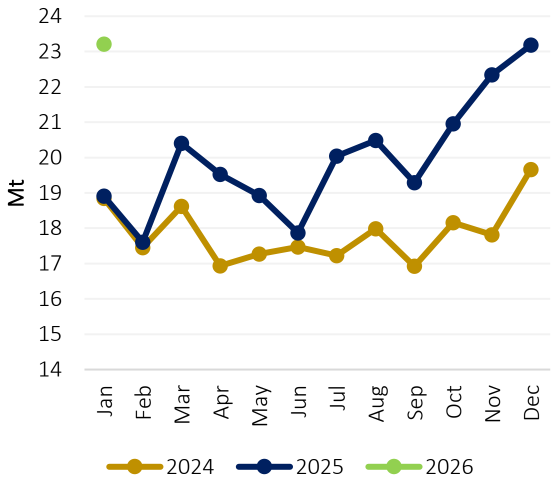
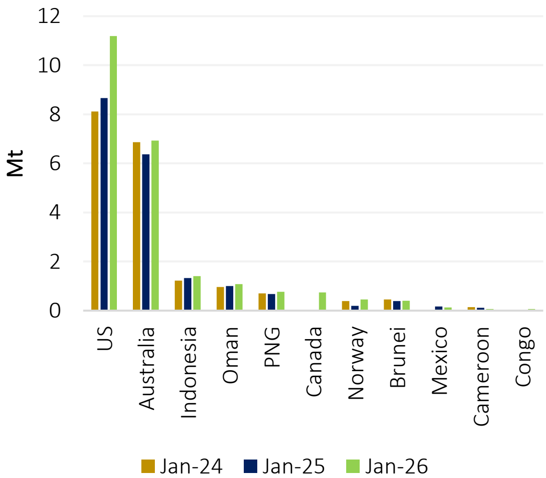


Figure 96: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG re-exports

In January 2026, global LNG re-exports totalled 0.35 Mt, down 41% (0.24 Mt) year on year, marking the lowest January level since 2021 (Figure 97). The decline was mainly driven by weaker re-exports from Brazil, Malaysia, and the US Virgin Islands (USVI), partly offset by higher re-exports from Spain (Figure 98).

In January 2025, Brazil re-exported two LNG cargoes—one each to Türkiye and the UK—supported by a spike in European gas prices; however, no re-exports were recorded in January 2026. Malaysia's re-exports in January 2025 reflected a rare intra-country transfer between LNG import terminals. Meanwhile, re-exports from the USVI, which had previously functioned as a break-bulking hub in the Caribbean, declined due to regular LNG shipments from the US to Puerto Rico. In contrast, Spain re-exported a conventional-sized LNG cargo to Türkiye, supported by favourable price arbitrage.

Figure 97: Trend in global monthly LNG re-exports

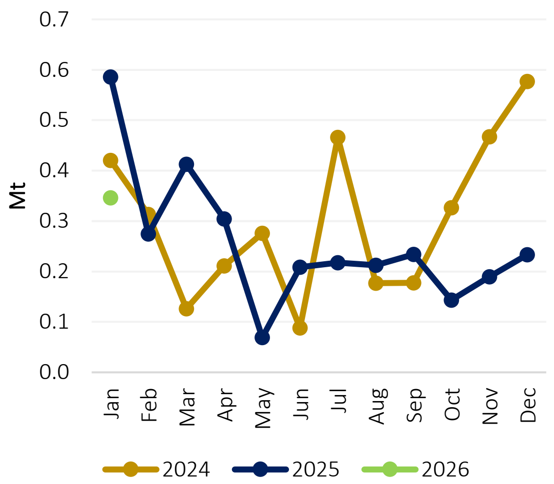
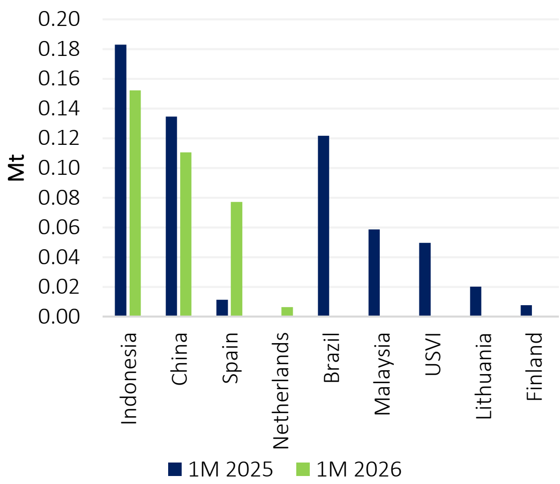


Figure 98: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

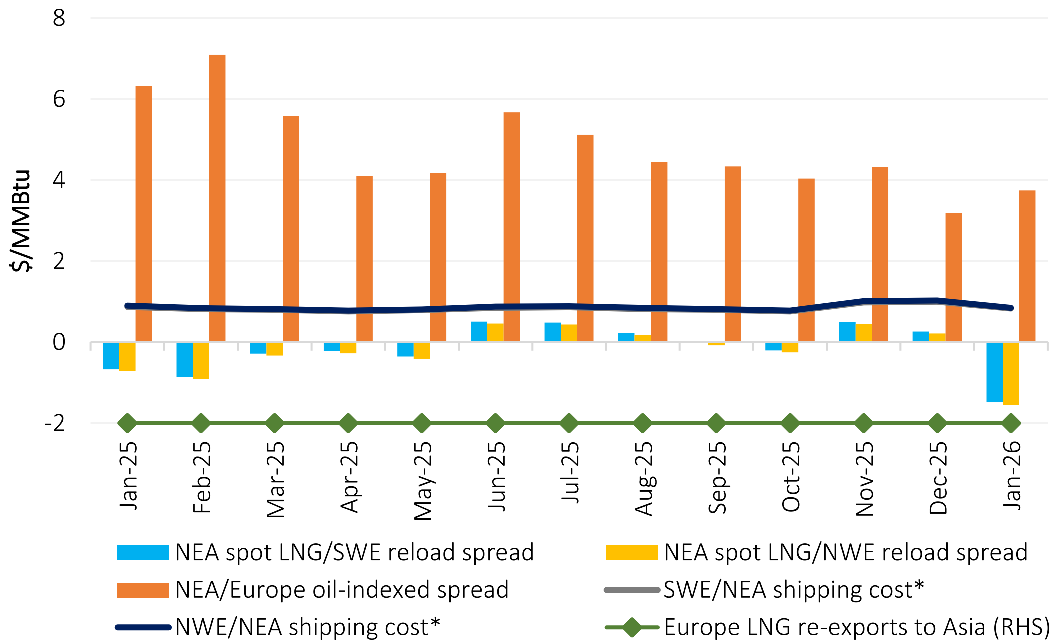
4.2.4 Arbitrage opportunity

In January 2026, LNG re-export arbitrage from Europe to Asia was absent, as European LNG reload prices moved to a premium over North East Asia (NEA) spot LNG prices (Figure 99). Conversely, Asian spot LNG prices continued to trade at a wide premium to European oil-indexed LNG, exceeding one-way shipping costs.

The NEA/Southwestern Europe (SWE) and NEA/Northwestern Europe (NWE) spreads reversed from $0.27/MMBtu and $0.22/MMBtu in December to -$1.49/MMBtu and -$1.56/MMBtu in January, respectively, driven by a sharp rise in European reload prices alongside only a modest increase in the NEA spot LNG price. At the same time, the NEA premium over European oil-indexed LNG widened from $3.19/MMBtu to $3.74/MMBtu, while average shipping costs from SWE and NWE to NEA declined by $0.17/MMBtu.

As a result, no LNG cargoes were re-exported from Europe to Asia in January 2026. Compared with January 2025, the NEA/SWE and NEA/NWE spreads moved deep into negative territory from -$0.67/MMBtu and -$0.72/MMBtu, respectively, underscoring weaker arbitrage incentives. At the same time, the NEA premium over oil-indexed LNG narrowed sharply from $6.32/MMBtu, while lower shipping costs on these routes, down by $0.04/MMBtu, were insufficient to restore re-export economics.

Figure 99: Price spreads & shipping costs between Asia & Europe spot LNG markets

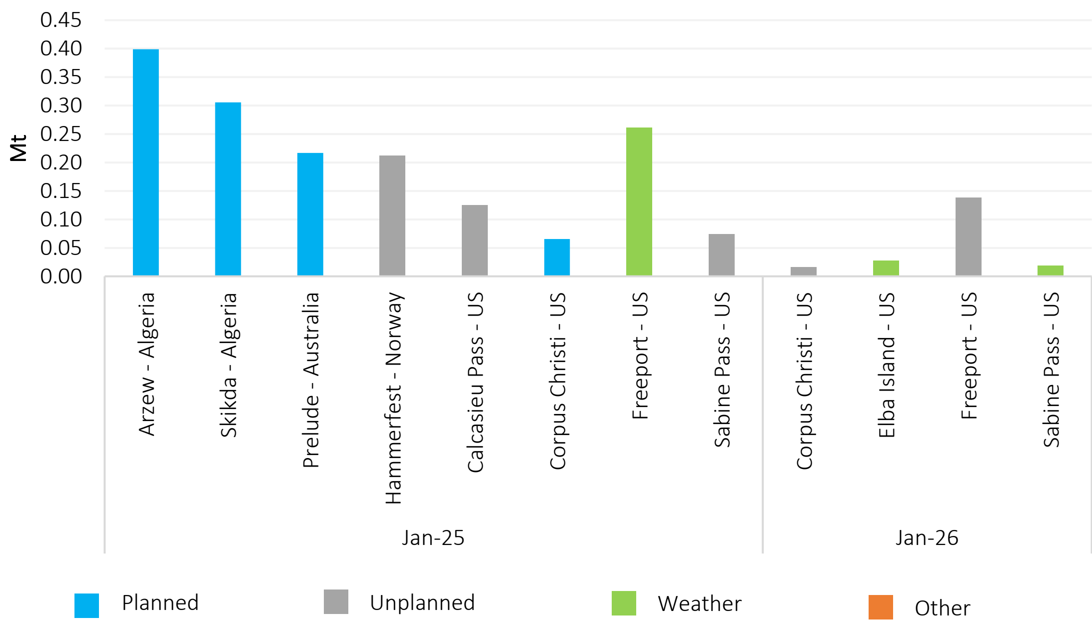


Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge
(*): One-way spot shipping costs

4.2.5 Maintenance activity at LNG liquefaction facilities

In January 2026, total disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages, and other operational issues, fell sharply from 1.66 Mt a year earlier to 0.20 Mt (Figure 100). All liquefaction outages occurred in the US, with unplanned disruptions affecting the Corpus Christi and Freeport facilities, while cold weather–related outages impacted the Elba Island and Sabine Pass facilities.

Figure 100: Maintenance activity at LNG liquefaction facilities during January (2025 and 2026)

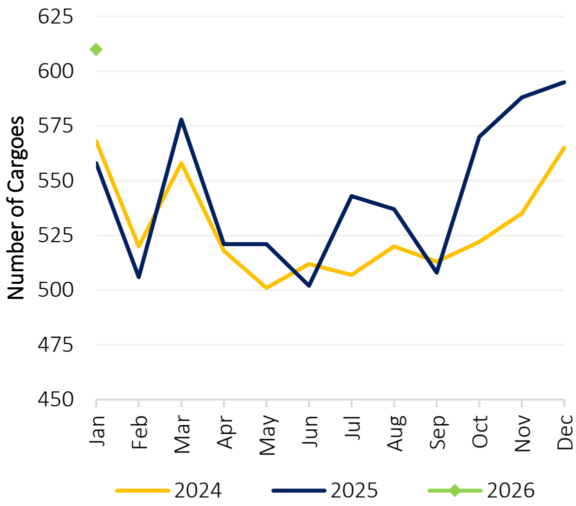


Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

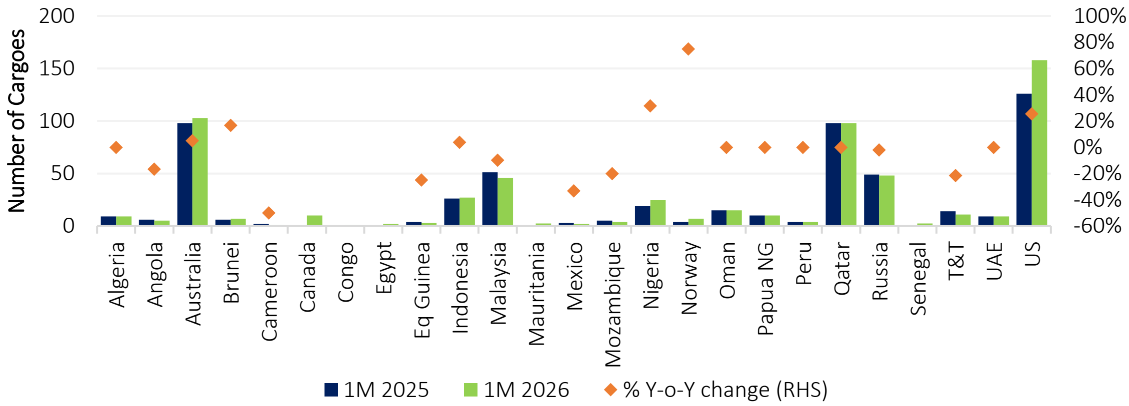
With the typical elevated gas demand for heating in Northern Hemisphere countries amidst the ongoing winter season, there was a record number of LNG cargo deliveries in January 2026. Specifically, 610 cargoes were exported globally, marking fifteen more shipments than in the previous month and 52 more than one year ago (Figure 101). This also translated to a 9% y-o-y increase in deliveries during the year thus far. GECF countries loaded 44% of the shipments in 2026, led by Qatar, Russia and Malaysia. The US (32) and Nigeria (6) lead in terms of y-o-y increases in export cargoes this year, while the largest percentage increases were attributed to Norway (75%) and Nigeria (32%) (Figure 102).

Figure 101: Number of LNG export cargoes



Source: GECF Secretariat based on data from ICIS LNG Edge

Figure 102: Changes in LNG cargo exports



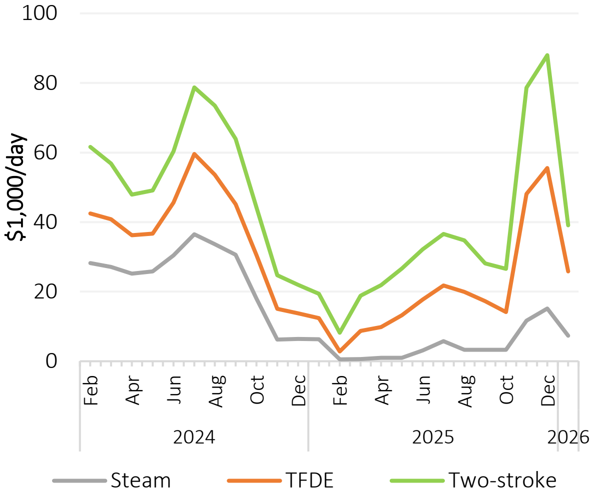
Source: GECF Secretariat based on data from ICIS LNG Edge

In January 2026, there were decreases in the spot charter rate for all segments of the global LNG carrier fleet (Figure 103). For TFDE carriers, which have become the dominant vessel option for spot LNG trade, the monthly average rate fell by 54% m-o-m to reach $25,800 per day. This average charter rate was 108% higher than one year ago, but $49,600 per day lower than the five-year average price for the month. Similarly, the average spot charter rate for two-stroke vessels reached $39,000 per day, which was 56% lower m-o-m but 101% higher y-o-y. The average rate for steam turbine vessels was $7,300 per day, falling by 52% m-o-m, but still 16% higher than one year ago.

The LNG shipping market faced persistent downward pressure throughout January 2026, overshadowing traditional seasonal tightness, as spot charter rates continued the decline initiated during the previous month. This bearish trend was primarily fuelled by the significant expansion in vessel availability, exacerbated by the ongoing arrival of newbuild carriers and continued repositioning into the Atlantic basin. Market sentiment remained weak as the inter-basin arbitrage remained firmly closed. Europe maintained its position as the preferred destination for Atlantic supply, effectively shortening voyage durations and increasing fleet efficiency. While a late-month cold snap in the US and production gains at Atlantic terminals provided some support, the overall market remains structurally oversupplied.

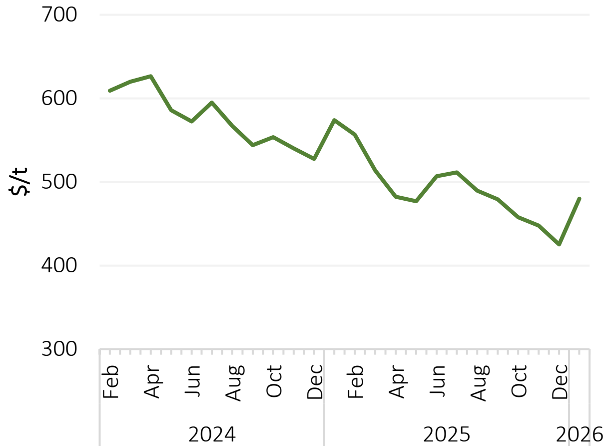
In January 2026, the average price of shipping fuels was estimated to increase by 12% m-o-m, reaching $480 per tonne (Figure 104). This average price was however 16% lower than one year ago, as well as 15% lower than the five-year average price for this month.

Figure 103: Average LNG spot charter rate



Source: GECF Secretariat based on data from Argus

Figure 104: Average price of shipping fuels

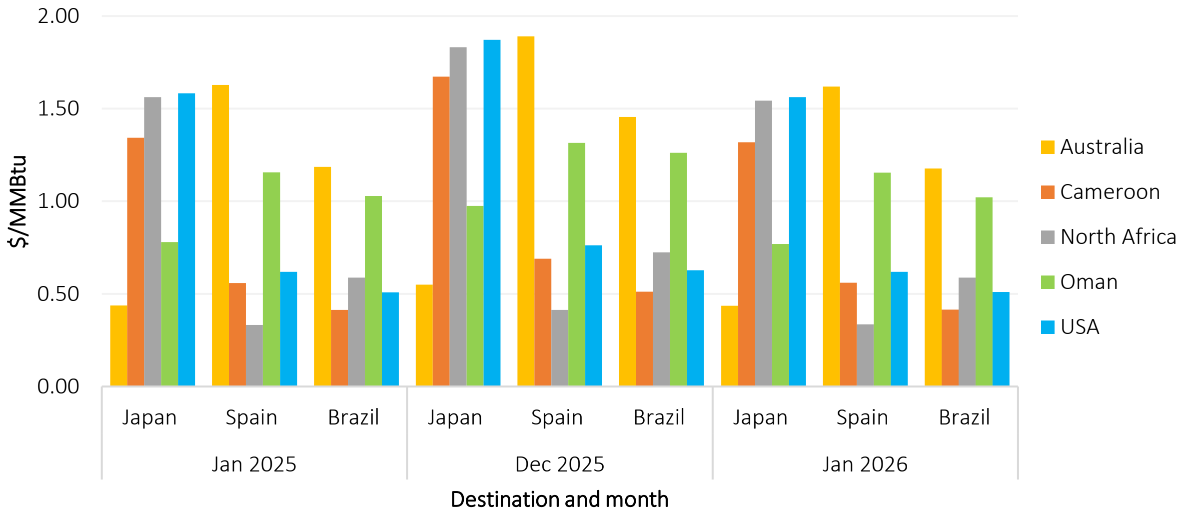


Source: GECF Secretariat based on data from Argus and Platts

There was a decrease in the spot shipping costs for TFDE LNG carriers in January 2026 compared with the previous month, by up to $0.35/MMBtu on certain routes (Figure 105). This was driven by the large decline in the monthly average LNG carrier spot charter rate, despite the smaller increases in the cost of shipping fuels and delivered spot LNG prices.

Compared to one year ago, in January 2026 the monthly average spot charter rate was higher, but the cost of shipping fuels and delivered spot LNG prices were all lower. The net effect of these fundamentals cancelled each other out, resulting in LNG shipping costs that were at a similar level to January 2025.

Figure 105: Spot shipping costs for TFDE LNG carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

New Zealand to develop an LNG import terminal: New Zealand's Government has confirmed plans to develop an LNG import facility to strengthen energy security and support economic growth. LNG will serve as a reliable back-up fuel to manage dry-year risks and intermittent renewables stabilise electricity prices, and offset declining domestic gas supply. Access to LNG is expected to generate annual savings of more than $265 million by reducing price volatility and risk premiums in power bills. Following extensive analysis and a procurement process launched in late 2025, shortlisted proposals are moving toward commercial contracting, with a final agreement targeted by mid-2026 and potential operation from 2027. The facility is likely to be located in Taranaki.

Eni starts exports from Congo FLNG 2 project: Eni has advanced its LNG footprint in the Republic of the Congo with the first cargo from the 2.4 Mtpa Nguya FLNG unit, marking the start of gas exports from Phase 2 of the Congo LNG project. With this phase, total LNG export reaches 3 Mtpa, underpinned by gas from the Nené and Litchendjili fields within the offshore Marine XII licence. Phase 2 was delivered just 35 months after construction began, setting a new international benchmark for execution speed and project efficiency, according to Eni.

Innovative engine solution for LNG shipping: The increasing demand for LNG fuel to reduce carbon emissions is driving the unprecedented growth in the market for LNG carriers. While these vessels must adhere to strict safety and environmental standards, they must also balance this requirement with operational efficiency to remain profitable. In this context, MAN Energy Solutions has introduced the Everllence portfolio, a series of four-stroke LNG cargo engines. This new technology offers a Dual-Fuel, Electric+ (DFE+) propulsion concept which reduces fuel costs, and has a smaller size than traditional engines. In addition, the engines are designed to significantly reduce methane slip and CO_2 emissions, with one model cutting methane slippage by up to 85% compared to current industry standards.

In January 2026, eight (8) LNG agreements were signed (Table 1).

Table 1: New LNG sale agreements signed in January 2026

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
MoU	Qatar	Ras Laffan	QatarEnergy	Egypt	Ministry of Petroleum and Mineral Resources	1.5	1
SPA	Portfolio	Portfolio	Shell	Vietnam	Petrovietnam Gas	0.4	5
SPA	Portfolio	Portfolio	Shell and TotalEnergies	Egypt		4-4.5	1
SPA	Portfolio	Portfolio	Engie	Thailand	Gulf Development Co.	0.8	15
SPA	Portfolio	Portfolio	Woodside Energy	Japan	JERA	0.2	5
SPA	US	Commonwealth LNG	Commonwealth LNG	Portfolio	Saudi Aramco	1	20
SPA	US	Texas LNG	Glenfarne	Portfolio	RWE Supply & Trading	1	20
SPA	UAE	Das Island	ADNOC Gas	India	HPCL	0.5	10

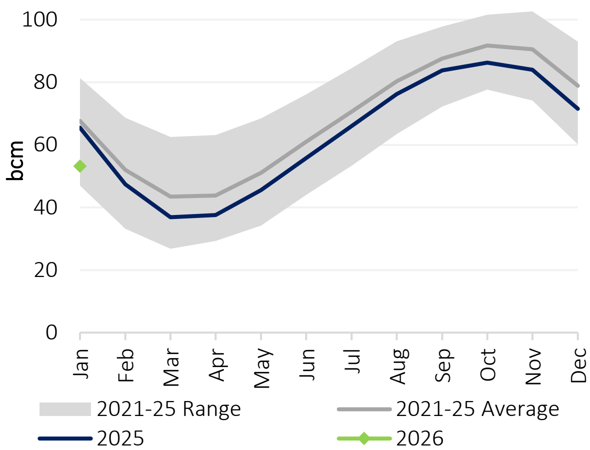
Source: GECF Secretariat based on Project Updates and News

5 GAS STORAGE

5.1 Europe

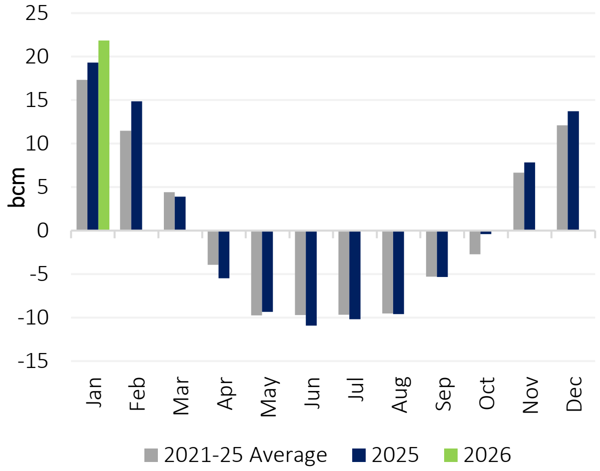
With surging gas demand for heating amidst a particularly cold January 2026, the average daily volume of gas in underground storage in the EU decreased to 53.2 bcm, down from 71.5 bcm in the previous month (Figure 106). This monthly average storage level was 12 bcm lower y-o-y, as well as 15 bcm lower than the five-year average. The EU's aggregated gas stocks decreased from 64.6 bcm on 31 December 2025 to 42.9 bcm on 31 January 2026. The average capacity utilisation across the region by the end of the month stood fell to 41%.

Figure 106: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

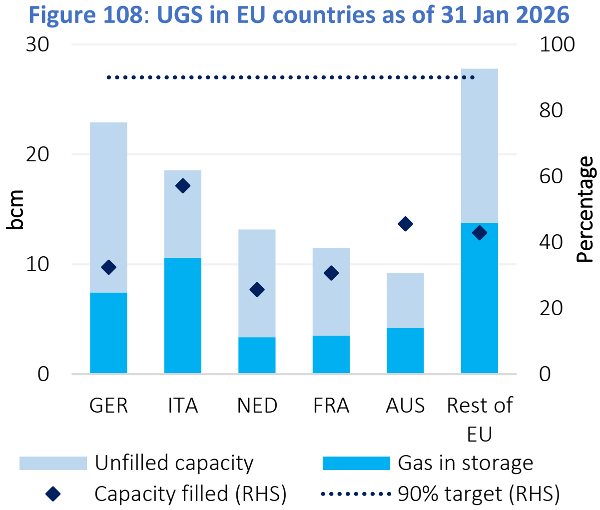
Figure 107: Net gas withdrawals in the EU



Source: GECF Secretariat based on data from AGSI+

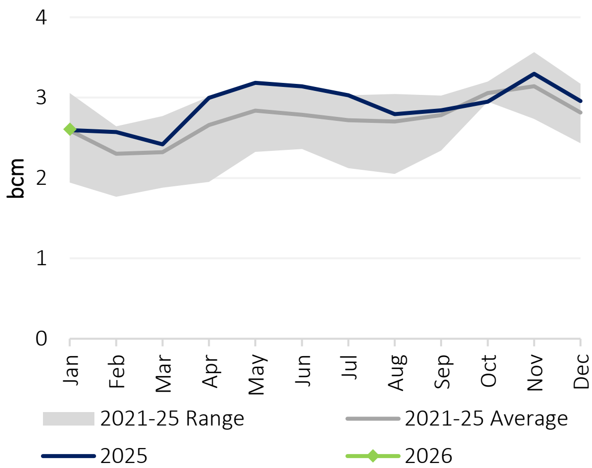
There were 22 bcm of net gas withdrawals in January 2026, as temperatures across the continent plunged colder than average. This was 13% more gas withdrawn than during January 2025, and was also 26% higher than the five-year average withdrawal for the month (Figure 107). EU countries have together withdrawn 44 bcm over the winter season thus far, similar to the total at the same time last year. The Netherlands (26% filled), France (31%) and Germany (32%) all recorded notably large withdrawals during the month (Figure 108). Moreover, the average LNG storage level in the EU was 2.6 bcm (Figure 109). At 46% of capacity, this storage level was unchanged y-o-y, but was 1% higher than the five-year average.

Figure 108: UGS in EU countries as of 31 Jan 2026



Source: GECF Secretariat based on data from AGSI+

Figure 109: Total LNG storage in the EU

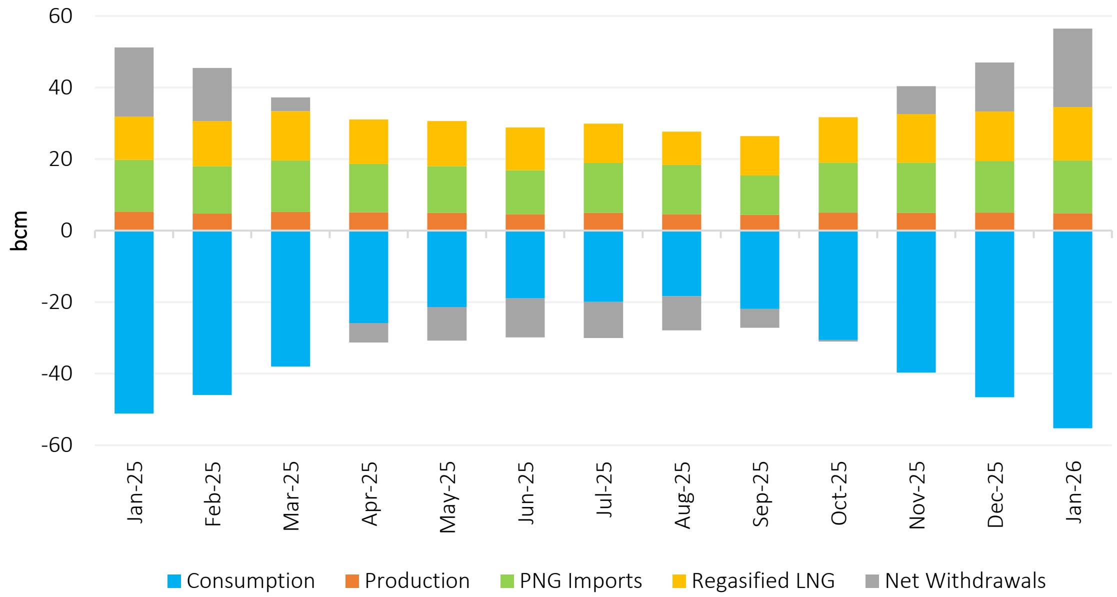


Source: GECF Secretariat based on data from ALSI

In Europe, gas storage is critical for balancing supply and demand. During the winter months, these reserves are essential to supplement production and imports, ensuring there is enough capacity to meet the seasonal surge in heating requirements.

In January 2026, the contribution of gas storage in the combined supply mix of the EU and UK surged to 39%, a level consistent with the previous year that underscores the critical role of inventories during the winter peak. Total gas imports accounted for 53% of the supply; notably, regasified LNG send-out reached 27%, surpassing PNG imports at 26% for the first time since June 2023. Domestic production remained a smaller component, representing 8% of the total supply mix (Figure 110).

Figure 110: EU + UK monthly gas balance



Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG

Table 2 below provides data on the gas supply and demand balance for the EU + UK for the month of January 2026.

Table 2: EU + UK gas supply/demand balance for January 2026 (bcm)

	2025	Jan-25	Jan-26	1M 2025	1M 2026	Change* y-o-y	Change** 2026/2025
(a) Gas Consumption	378.23	51.17	55.26	51.17	55.26	8%	8%
(b) Gas Production	58.90	5.32	4.81	5.32	4.81	-9%	-9%
Difference (a) - (b)	319.33	45.85	50.45	45.85	50.45	10%	10%
PNG Imports	162.00	14.44	14.78	14.44	14.78	2%	2%
Regasified LNG	147.08	12.11	15.00	12.11	15.00	24%	24%
Net Withdrawals	8.45	19.32	21.84	19.32	21.84	13%	13%
Variation	1.79	-0.02	-1.17	-0.02	-1.17		

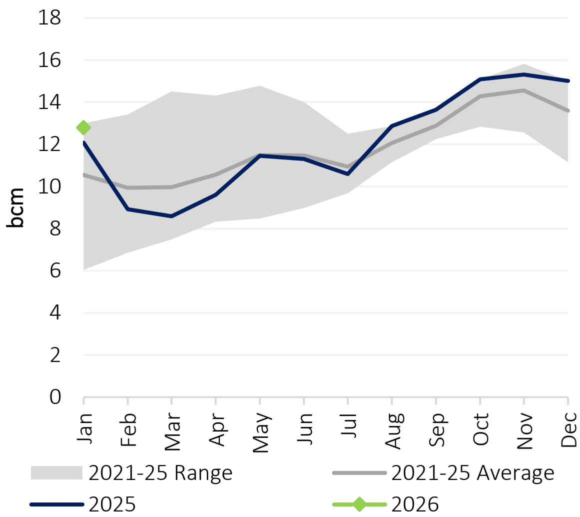
Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG
(*): y-o-y change for January 2026 compared to January 2025
(**): y-o-y change for 1M 2026 compared to 1M 2025

5.2 Asia

In January 2026, combined LNG stocks in Japan and South Korea were estimated at 12.8 bcm, which was 15% m-o-m lower (Figure 111). Despite the cold winter conditions, both countries entered the month with well-stocked LNG inventories. As a result, the combined stock level stood at 6% higher than one year ago, and was also 2.2 bcm greater than the five-year average for the month.

The estimated LNG storage level in Japan stood at 7.9 bcm, which was 17% higher compared to the previous year. Meanwhile in South Korea, the estimated storage level stood at 4.9 bcm, which was 8% lower than one year prior.

Figure 111: LNG in storage in Japan and South Korea



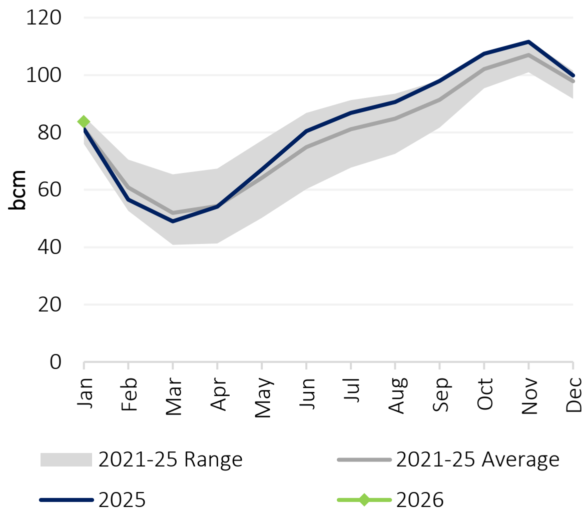
Source: GECF Secretariat based on data from LSEG

5.3 North America

Winter storms led to plummeting temperatures across the Midwest and Southern US in the second half of January 2026. Driven by the consequential surge in gas demand, the average volume of gas in storage fell to 83.8 bcm, down from 99.9 bcm in the previous month (Figure 112). However, US gas stocks remained 2.5 bcm higher than at the same point one year ago, and also 2.5 bcm greater than the five-year average for the month. The average UGS capacity utilisation stood at 63%.

During the month there were 25.8 bcm of net injections in the US, which was less than the 28.8 bcm of one year ago, but greater than the five-year average for the month at 21.4 bcm. Over the winter season thus far, the US has withdrawn 42 bcm.

Figure 112: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

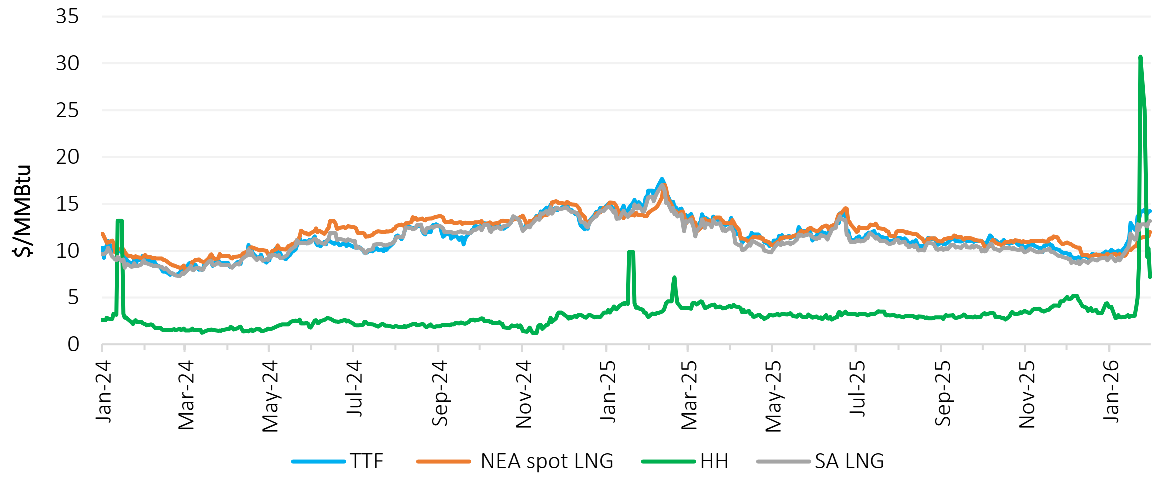
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

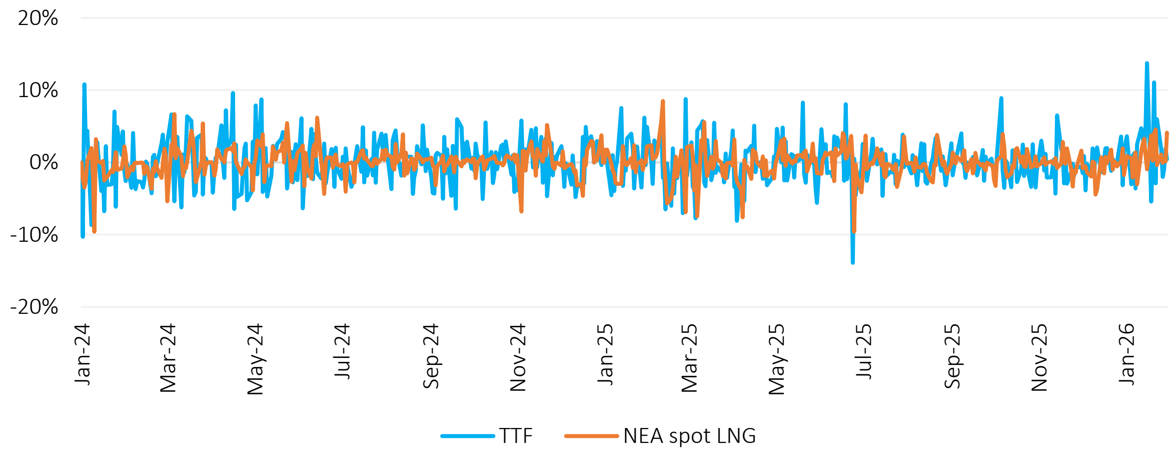
In January 2026, European spot gas prices rose sharply m-o-m, accompanied by heightened market volatility. Meanwhile, Asian spot LNG prices increased more moderately, tracking movements in European hub prices. During the month, European gas prices surpassed Asian spot LNG prices (Figure 113 and Figure 114). The upward momentum was driven by colder weather across the Northern Hemisphere relative to the previous year, geopolitical developments, and impact on US LNG production caused by cold-related feedgas supply issues, which resulted in a surge in the HH price. Looking ahead, spot prices are expected to ease in the coming months as seasonal gas demand declines and LNG supply continues to grow.

Figure 113: Daily gas & LNG spot prices



Source: GECF Secretariat based on data from Argus and LSEG
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment.

Figure 114: Daily variation of spot prices



Source: GECF Secretariat based on data from Argus and LSEG

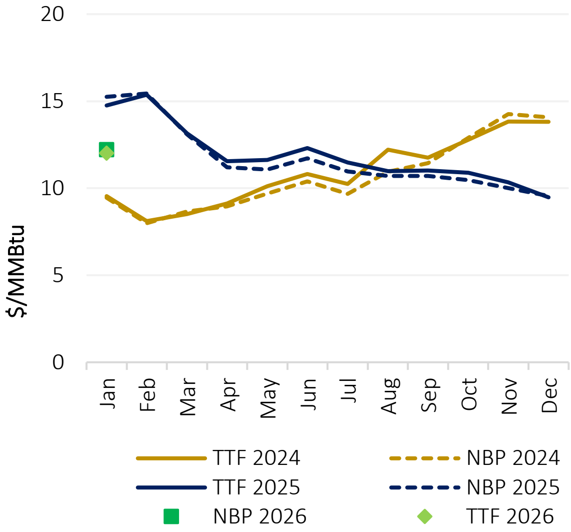
6.1.1.1 European spot gas and LNG prices

In January 2026, the TTF spot gas price averaged $12.00/MMBtu, up 27% m-o-m but down 19% y-o-y, reaching the highest level since June 2025 (Figure 115). Similarly, the NBP spot price averaged $12.22/MMBtu, rising by 28% m-o-m while declining by 20% y-o-y.

The m-o-m increase in European spot gas prices was driven primarily by colder-than-normal weather across Europe, heightened geopolitical risks, substantial UGS drawdowns, and weather-related disruptions to US LNG exports.

During the month, daily TTF prices peaked at $14.35/MMBtu, the highest level since February 2025, underscoring Europe's heightened exposure to gas price volatility driven by factors beyond the region.

Figure 115: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

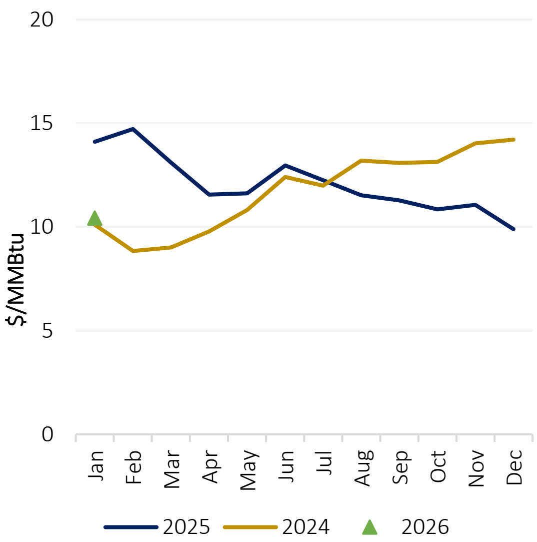
6.1.1.2 Asian spot LNG prices

In January 2026, the average Northeast Asia (NEA) spot LNG price stood at $10.43/MMBtu, up 5% m-o-m but down 26% y-o-y (Figure 116).

Asian LNG prices largely followed movements in European gas hub prices, while colder regional weather and weather-related disruptions to US LNG production provided some upward support. However, subdued downstream gas demand limited the extent of price increases in the spot LNG market.

Notably, daily NEA spot LNG prices rose to $12.00/MMBtu, the highest level since April 2025, reducing incentives for spot procurement among price-sensitive buyers.

Figure 116: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus

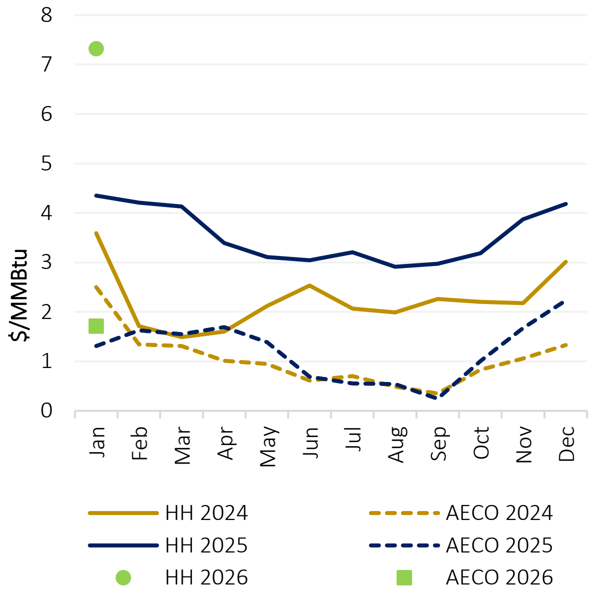
6.1.1.3 North American spot gas prices

In January 2026, the Henry Hub (HH) spot gas price surged by 75% m-o-m and was 68% higher y-o-y, reaching a multi-year high of $7.32/MMBtu. In contrast, Canada's AECO spot gas price averaged $1.71/MMBtu, down 23% m-o-m and 31% y-o-y (Figure 117).

The sharp increase in HH prices was largely weather-driven, as Winter Storm Fern caused wellhead freeze-offs that curtailed gas production. Notably, daily HH prices spiked to an all-time high of $30.72/MMBtu during the month.

Despite colder-than-normal temperatures in Canada, AECO prices weakened amid abundant domestic gas supply. Canada's gas market faced persistent oversupply during H2 2025.

Figure 117: Monthly North American spot gas prices



Source: GECF Secretariat based on data from LSEG

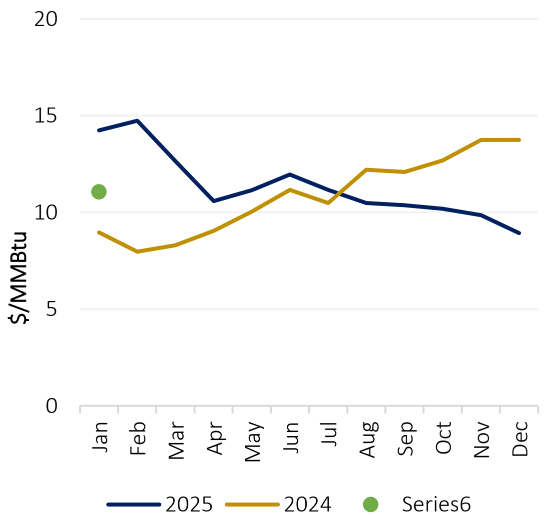
6.1.1.4 South American spot LNG prices

In January 2026, the South American (SA) spot LNG price averaged $11.06/MMBtu, up 24% m-o-m but down 22% y-o-y (Figure 118), marking the highest monthly average since July 2025.

Spot LNG prices in South America closely followed movements in European and Asian gas and LNG benchmarks, as the region competes directly with these major markets for spot LNG cargoes. Average delivered spot LNG prices stood at $11.11/MMBtu in Argentina, $10.94/MMBtu in Brazil and $11.12/MMBtu in Chile.

By the end of the month, the SA spot LNG price reached $13.17/MMBtu, exceeding the NEA spot LNG price but remaining below the TTF spot gas price.

Figure 118: Monthly South American spot LNG prices

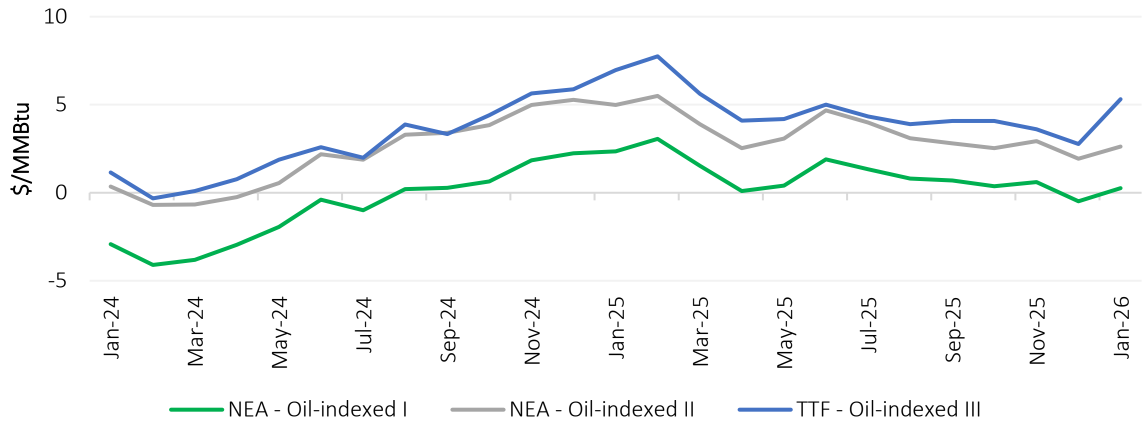


Source: GECF Secretariat based on data from Argus
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment

6.1.2 Spot and oil-indexed long-term LNG price spreads

In January 2026, the average Oil-indexed I LNG price stood at $10.18/MMBtu, down 2% m-o-m and 13% y-o-y. Similarly, the Oil-indexed II LNG price averaged $7.80/MMBtu, declining by 2% m-o-m and 14% y-o-y. In Europe, the Oil-indexed III LNG price averaged $6.69/MMBtu, easing marginally m-o-m while falling by 14% y-o-y. During the month, the NEA spot LNG price shifted to a premium of $0.25/MMBtu over the Oil-indexed I LNG price. The NEA spot LNG premium over the Oil-indexed II LNG price widened further to $2.63/MMBtu, while the TTF spot gas price significantly increased its premium over the Oil-indexed III LNG price to $5.31/MMBtu. (Figure 119).

Figure 119: Spot and oil-indexed LNG price spreads



Source: GECF Secretariat based on data from Argus and LSEG

Note: Oil-indexed I LNG prices are calculated using the traditional LTC slope (14.9%) and 6-month historical average of Brent. Oil-indexed II LNG prices are calculated using the 5-year historical average LTC slope (11.6% for 2025) and 3-month historical average of Brent. Oil-indexed III LNG prices are based on Argus' assessment for European oil-indexed long-term LNG prices.

6.1.3 Regional spot gas & LNG price spreads

In January 2026, the NEA–TTF spread reversed from a premium to a discount, as the TTF spot gas price rose above the NEA spot LNG price. As a result, TTF traded at a premium of $1.57/MMBtu over the NEA spot LNG price (Figure 120). Meanwhile, the TTF–HH spread narrowed sharply to $4.68/MMBtu, marking its lowest level since April 2021 (Figure 121).

Figure 120: NEA-TTF price spread

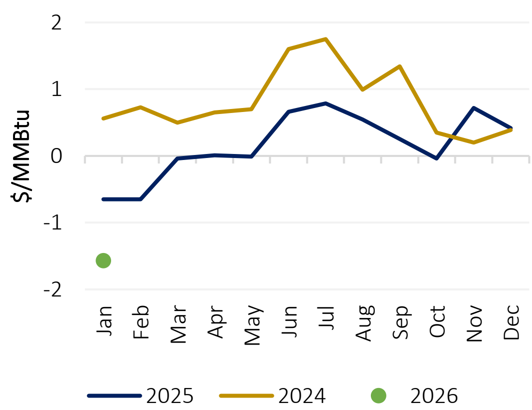
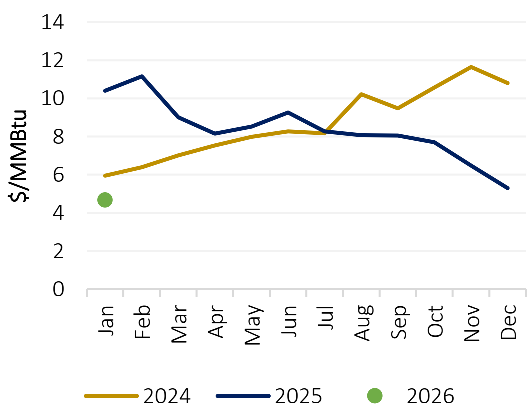


Figure 121: TTF-HH price spread



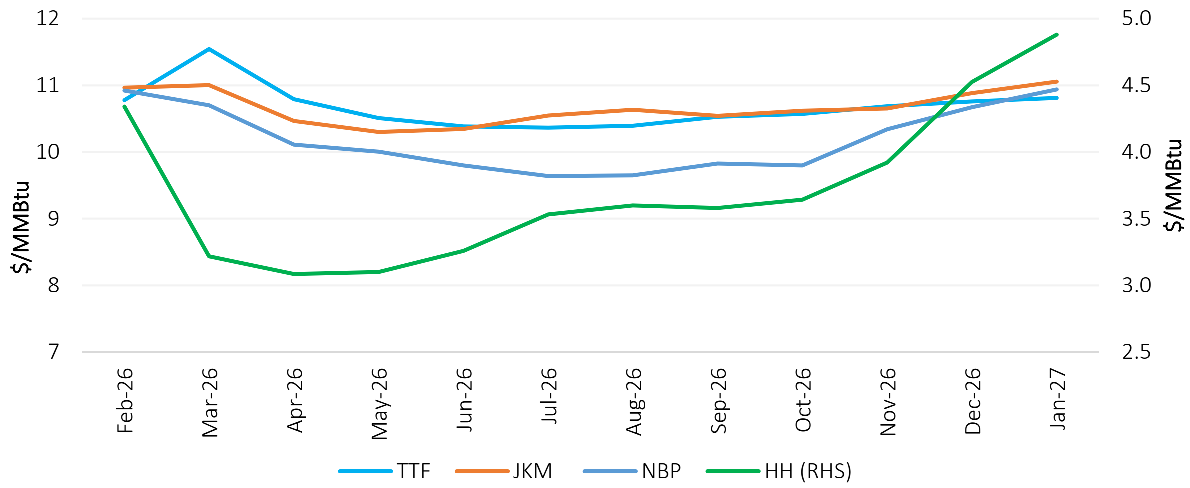
Source: GECF Secretariat based on data from Argus and LSEG

6.1.4 Gas & LNG futures prices

As of 13 February 2026, the average futures prices for TTF, NBP, and JKM over the 12-month period from March 2026 to February 2027 stood at $10.68/MMBtu, $10.20/MMBtu, and $10.67/MMBtu, respectively (Figure 122). Notably, these forward-curve averages were higher than the futures price expectations assessed on 9 January 2026, as reported in the GECF MGMR January 2026. Over the same period, the average Henry Hub futures price was $3.72/MMBtu, also exceeding previous expectations (Figure 123). Futures prices strengthened amid colder January weather, raising expectations of EU underground gas storage reaching multi-year lows by the end of winter.

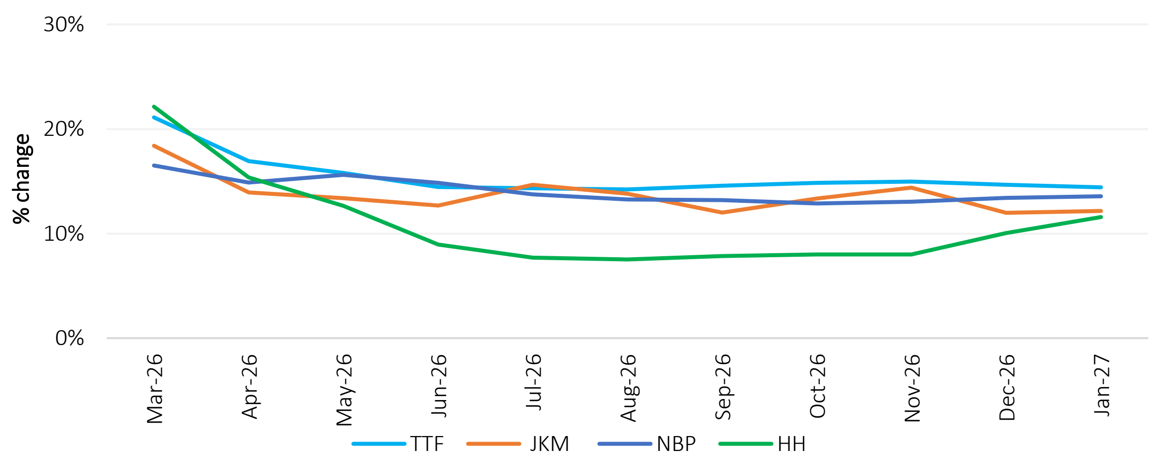
The TTF forward curve indicates a premium over JKM between March and May 2026, after which the two benchmarks converge, with JKM trading at a slight premium over TTF for the remainder of the period.

Figure 122: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 13 February 2026.

Figure 123: Variation in gas & LNG futures prices



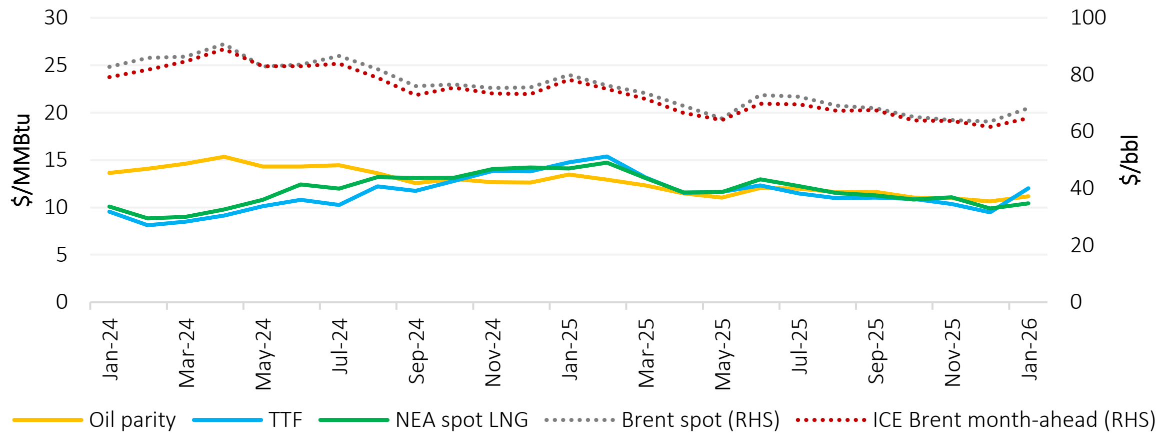
Source: GECF Secretariat based on data from LSEG
Note: Comparison with the futures prices as of 9 January 2026, as reported in GECF MGMR January 2026.

6.2 Cross commodity prices

6.2.1 Oil prices

In January 2026, the average Brent spot price stood at $68.19/bbl, up 7% m-o-m but down 15% y-o-y. Similarly, the Brent month-ahead price averaged $64.68/bbl, rising by 5% m-o-m while declining by 17% y-o-y. During the month, TTF spot gas prices shifted to a premium of $0.90/MMBtu over oil parity, whereas NEA spot LNG price continued to trade at a discount of $0.70/MMBtu to the oil parity (Figure 124).

Figure 124: Monthly crude oil prices

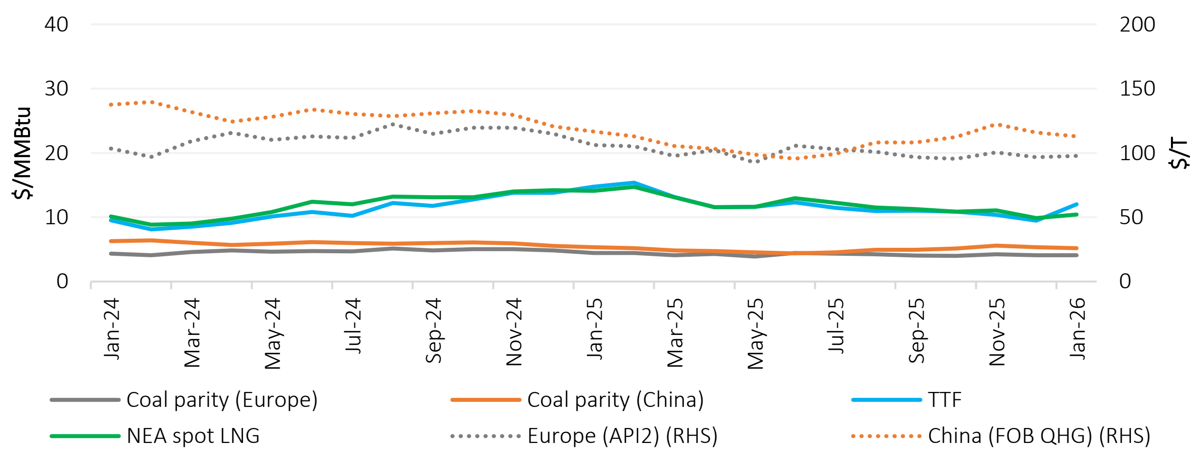


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factor of 5.8 was used to calculate the oil parity price in $/MMBtu based on the ICE Brent month-ahead price.

6.2.2 Coal prices

In January 2026, the European coal benchmark (API2) averaged $97.61/t, edging up by 1% m-o-m while declining by 8% y-o-y. Over the same period, the premium of the TTF spot gas price over the API2 parity price widened sharply, averaging $8/MMBtu. In China, the Qinhuangdao (QHG) coal price averaged $112.95/t, down 3% m-o-m and 3% y-o-y. The premium of the NEA spot LNG price over the QHG parity price remained unchanged at $5/MMBtu (Figure 125).

Figure 125: Monthly coal parity prices

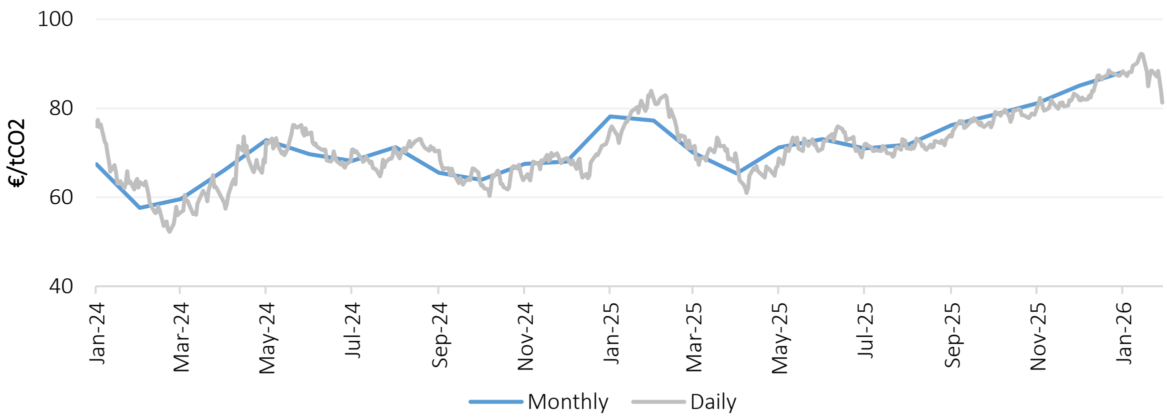


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in $/MMBtu for Europe (API2) and China (QHG) respectively.

6.2.3 Carbon prices

In January 2026, EU carbon prices averaged €88.13/tCO_2, which represents increases of 4% m-o-m and 13% y-o-y (Figure 126). During the month, daily prices reached a high of €92.24/tCO_2.

Figure 126: EU carbon prices

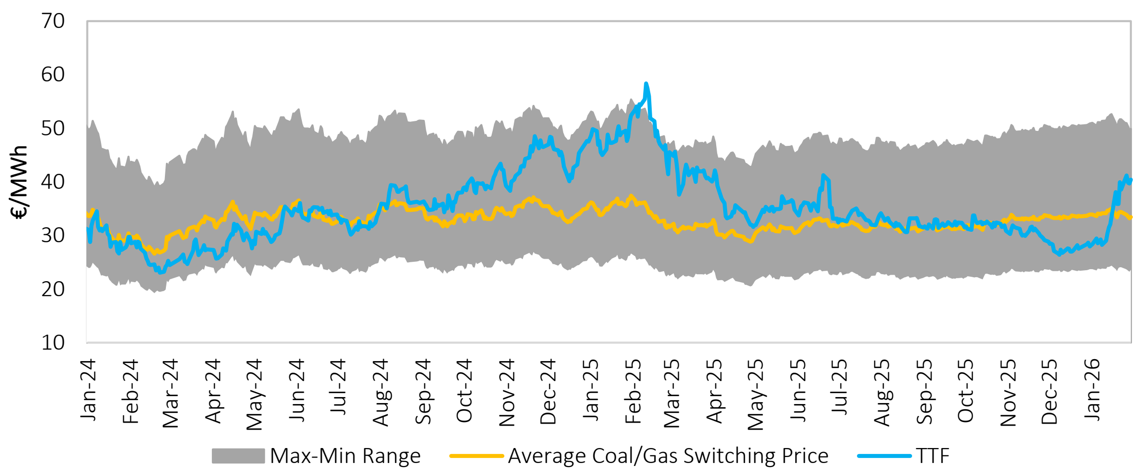


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In January 2026, despite an upward trend in daily TTF spot prices, levels remained broadly within the range conducive to coal-to-gas switching (Figure 127). The TTF price traded below the average coal-to-gas switching price during the first half of the month before shifting to a slight premium in the second half. On a monthly average basis, the spread between TTF prices and the coal-to-gas switching level was marginal, at just €0.20/MWh. Looking ahead to March 2026, TTF spot prices are expected to remain within the coal-to-gas switching range, potentially supporting continued fuel switching across the region.

Figure 127: Daily TTF vs coal-to-gas switching prices



Source: GECF Secretariat based on data from LSEG

Note: Coal-to-gas switching price is the price of gas at which generating electricity with coal or gas is equal. The estimate takes into consideration coal prices, CO_2 emissions prices, operation costs and power plant efficiencies. The efficiencies considered for gas plants are max: 56%, min: 46%, avg: 49.13%. The efficiencies considered for coal plants are max: 40%, min: 34%, avg: 36%.

ANNEXES

Abbreviations

Abbreviation	Explanation
AE	Advanced Economies
AECO	Alberta Energy Company
Bbl	Barrel
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
bcm/yr	Billion cubic metres per year
CBAM	Carbon Border Adjustment Mechanism
CBM	Coal bed methane
CCS	Carbon, Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CDD	Cooling Degree Days
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
CPI	Consumer Price Index
DOE	Department of Energy
EC	European Commission
ECB	European Central Bank
EEXI	Energy Efficiency Existing Ship Index
EMDE	Emerging Markets and Developing Economies
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
Fed	Federal Reserve
FID	Final Investment Decision
FSU	Floating Storage Unit

FSRU	Floating Storage Regasification Unit
G7	Group of Seven
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GHG	Greenhouse Gas
HDD	Heating Degree Days
HH	Henry Hub
IEA	International Energy Agency
IMF	International Monetary Fund
IMO	International Maritime Organization
JKM	Japan Korea Marker
LNG	Liquefied Natural Gas
LAC	Latin America and the Caribbean
LPR	Loan Prime Rate
LT	Long-term
MMBtu	Million British thermal units
mcm	Million cubic metres
mmscfd	Million standard cubic feet per day
MENA	Middle East and North Africa
METI	Ministry of Trade and Industry in Japan
m-o-m	month-on-month
Mt	Million tonnes
Mtpa	Million tonnes per annum
MWh	Megawatt hour
NEA	North East Asia
NBP	National Balancing Point
NDC	Nationally Determined Contribution
NGV	Natural Gas Vehicle

NZBA	Net-Zero Banking Alliance
OECD	Organization for Economic Co-operation and Development
PNG	Pipeline Natural Gas
PPAC	Petroleum Planning & Analysis Cell
PSV	Punto di Scambio Virtuale (Virtual Trading Point in Italy)
QHG	Qinhuangdao
R-LNG	Regasified LNG
SA	South America
SPA	Sales and Purchase Agreement
SWE	South West Europe
T&T	Trinidad and Tobago
TANAP	Trans-Anatolian Natural Gas Pipeline
TCFD	Task Force on Climate-Related Financial Disclosure
Tcm	Trillion cubic metres
tCO2	Tonne of carbon dioxide
TFDE	Tri-Fuel Diesel Electric
TEU	Twenty-foot equivalent unit
TTF	Title Transfer Facility
TWh	Terawatt hour
UGS	Underground Gas Storage
UAE	United Arab Emirates
UK	United Kingdom
UQT	Upward Quantity Tolerance
US	United States
y-o-y	year-on-year

References

Argus. (2025). *Argus LNG Daily and Global LNG.*

Baker Hughes. (2024). *Worldwide Rig Counts*. Retrieved from http://phx.corporateir.net/phoenix.zhtml?c=79687&p=irol-rigcountsintl

Bank of England. (2025). *Official bank rate*. Retrieved from https://www.bankofengland.co.uk/boeapps/database/Bank-Rate.asp

BloombergNEF. (n.d.). Retrieved from https://www.bnef.com/

China's Chongqing Petroleum & Gas Exchange. (n.d.). Retrieved from https://www.chinacqpgx.com/information/informationBulletinDetails.htm?type=14&id=4559&rownumber=3

Enagas Spanish Transport System Operator. (2024). Retrieved from https://www.enagas.es/

European Central Bank (ECB). (2025). *Official interest rates*. Retrieved from https://www.ecb.europa.eu/stats/policy_and_exchange_rates/key_ecb_interest_rates/html/index.en.html

GECF Secretariat. (2024). GECF Shipping Model.

General Administration of Customs. (2024). *Monthly Bulletin*. Retrieved from http://english.customs.gov.cn/statics/report/monthly.html

GIE AGSI+. (n.d.). *Gas Infrastructure Europe - Aggregated Gas Storage Inventory.*

GIE ALSI. (n.d.). European LNG Storage.

GRTgaz French Transport System Operator. (2024). Retrieved from https://www.smart.grtgaz.com/

ICIS. (n.d.). *ICIS LNG Daily and Global LNG Market.*

ICIS. (n.d.). ICIS LNG Edge.

India's Petroleum Planning & Analysis Cell (PPAC). (2024). Retrieved from https://www.ppac.gov.in/

International Monetary Fund (MF). (2025). *World Economic Outlook January 2025.*

Joint Organisations Data Initiative (JODI). (2024). *JODI Gas World database*.

LSEG. (n.d.). *LNG Infrastructure*. Retrieved from LSEG Online Database.

National Bureau of Statistics of China. (2024). Retrieved from http://data.stats.gov.cn/english/easyquery.htm?cn=A01

Organization for Economic Co-operation and Development (OECD). (2024). *OECD Economic Outlook December 2024.* Paris: OECD Publishing.

Organization of Petroleum Exporting Countries (OPEC). (2025). *Monthly Oil Market Reports.* Retrieved from https://www.opec.org/opec_web/en/publications/338.htm

Oxford Economics. (2025). *World Economic Prospects Monthly.*

People's Bank of China. (2025). *Monetary Policy Instruments*. Retrieved from http://www.pbc.gov.cn/en/3688006/index.html

Rystad Energy Ucube. (2024).

Snam, Italian Transport System Operator. (2024). Retrieved from https://www.snam.it/

U.S Energy Information Administration (EIA). (2024). Retrieved from https://www.eia.gov

United Nations. (2025). *World Economic Situation and Prospects 2025.*

US Federal Reserve. (2025). *Selected interest rates*. Retrieved from https://www.federalreserve.gov/releases/h15/

World Bank. (2025). *Global Economics Prospects January 2025.*

World Bank. (2025). World Bank Commodity Price Data.

GECF

Gas Exporting Countries Forum , GECF
GECF Headquarters
P.O.Box 23753, Tornado Tower
47th & 48th Floors, West Bay, Doha

www.gecf.org