GECF

Gas Exporting Countries Forum

MONTHLY GAS MARKET REPORT

January 2026

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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.

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HIGHLIGHTS

Gas consumption: Major gas consuming regions recorded an increase in gas demand in late 2025. In December 2025, EU gas consumption rose by 0.3% y-o-y to 40 bcm, driven primarily by higher residential heating demand and increased gas-fired power generation amid lower average temperatures compared with a year earlier. Similarly, US gas consumption increased by 6.8% y-o-y to 99.5 bcm, supported by growth in the residential and commercial sectors as cooler-than-average temperatures intensified space heating needs, particularly in northern regions. In November 2025, China's apparent gas demand grew by 7.8% y-o-y to 38.4 bcm.

Gas production: Global gas production trends varied across regions in late 2025. In December 2025, US gas production rose 3.7% y-o-y to a record high of 95.9 bcm, supported by favourable Henry Hub prices and rising LNG exports. The Asia-Pacific region recorded marginal growth of 0.3% y-o-y, led by higher output in China. In November 2025, European gas production declined by 1.3% y-o-y to 16 bcm, reflecting reduced output in the UK and the Netherlands. On the upstream front, Nigeria, a GECF member, launched a new licensing round for oil and gas exploration.

Gas trade: In December 2025, global LNG trade reached new highs, with imports hitting a record 41.9 Mt, rising 10% y-o-y and surpassing the 40 Mt threshold for the first time. Europe led the growth as LNG compensated for declining pipeline gas imports, while Asia Pacific also strengthened amid softer prices. Europe remained the preferred destination for US LNG exports, supported by the narrow spot price spread with Asia.

Gas storage: In December 2025, the net gas withdrawal season continued in northern hemisphere countries. In the EU, the monthly average aggregated gas stocks declined to 72 bcm, or 69% of capacity, compared with 82 bcm a year earlier. In the US, the monthly average storage level fell to 100 bcm, or 75% of capacity, compared with 101 bcm last year. In Asia, milder temperatures and increased imports contributed to a 14% y-o-y increase in combined LNG storage levels in Japan and South Korea, reaching 15 bcm.

Energy prices: In December 2025, European TTF spot prices averaged $9.48/MMBtu, declining by 8% m-o-m and 31% y-o-y, with daily prices touching a 19-month low of $9.14/MMBtu. In Asia, NEA spot LNG prices averaged $9.89/MMBtu, down 11% m-o-m and 30% y-o-y. In contrast, US gas prices continued their upward trajectory, with Henry Hub averaging $4.18/MMBtu, reflecting increases of 8% m-o-m and 39% y-o-y. Looking ahead, spot prices could receive support and firm modestly if colder weather materializes and seasonal heating demand strengthens across key consuming regions.

FEATURE ARTICLE:

COP30 signals climate policy shifts reinforcing the global role of natural gas

The year 2025 represented a pivotal moment for the global energy industry, marked by a shift away from the traditional climate agenda and a reassessment of previously dominant climate-driven energy policies. In particular, after several years of a negative narrative, natural gas regained credibility as a reliable and sustainable energy source, increasingly recognized as one of the most effective means of meeting rapidly growing global energy demand.

This policy shift culminated in the outcomes of the 30th session of the Conference of the Parties (COP30) to the United Nations Framework Convention on Climate Change (UNFCCC), held from 10 to 21 November 2025 in Belém, Brazil, bringing together representatives from nearly 200 countries. Notably, the event also marked the 10-year anniversary of the Paris Agreement, serving as an important benchmark for assessing global climate mitigation efforts largely focused on accelerating the transition toward lower carbon energy sources.

Major COP30 outcomes with potential implications for the gas industry include agreements on climate adaptation, climate finance, and climate-related trade measures.

COP30 elevated climate adaptation to an equal political footing with climate change mitigation, marking a historic shift in the trajectory of international climate summits. While the appropriate balance between these two pillars has long been a subject of rigorous debate, the conference signalled a strategic pivot toward the adaptation through the formal adoption of 59 voluntary Belém Adaptation Indicators. Established under the mandate of Article 7 of the Paris Agreement, these metrics provide a standardized, system-wide framework to monitor global progress toward the Global Goal on Adaptation (GGA). In this context, the heightened focus on climate adaptation recognizes that immediate energy security is a prerequisite for systemic resilience, reducing the pressure previously placed on natural gas and other hydrocarbon fuels, as reflected in COP28 outcomes. This approach enables natural gas to expand its role in the global energy mix, providing the reliable, sustainable energy needed for communities to withstand climate-driven disruptions.

COP30 largely preserved the status quo on climate finance, merely reaffirming the targets set at the previous COP without securing new binding commitments from developed countries. The final documents emphasized the urgent need to remain on a pathway toward mobilizing at least USD 300 billion in public finance and scaling total financing for developing countries to at least USD 1.3 trillion per year by 2035. However, they provided no clear mandatory roadmap for how developed nations would fulfil these commitments. Moreover, the final documents highlighted that Parties have divergent views on whether the previous goal of developed countries to jointly mobilize USD 100 billion per year in climate finance for developing countries, set at COP15 in 2009, was achieved. A lack of an agreed definition of climate finance and standardized accounting methodologies continues to frustrate developing countries. The reluctance of developed nations to assume significant financial burdens in supporting developing countries' adaptation and mitigation efforts poses a major challenge to advancing renewables-oriented energy transitions. In this context, many developing countries are inclined to prioritize energy transitions that rely more on traditional low-carbon sources, particularly natural gas, which provides a balanced solution to the energy trilemma and serves as a reliable backup for intermittent wind and solar power.

COP30 marked the first time trade policies became a central component of the official negotiated outcome, formally integrating trade into the international climate agenda through a structured dialogue process aimed at ensuring that trade policies and climate objectives are mutually reinforcing. The final documents reaffirmed that climate-related trade measures, including unilateral ones, must not constitute "arbitrary or unjustifiable discrimination or a disguised restriction on international trade." To implement this, the decision mandates a three-year series of dialogues (2026–2028) involving major international organizations, including the WTO, UNCTAD, and ITC, to examine opportunities and barriers for international cooperation at the intersection of climate and trade. These dialogues are intended to specifically address tensions over unilateral trade measures like the EU's Methane Emissions Regulation (MER) and Carbon Border Adjustment Mechanism (CBAM). These new EU regulations are poised to not only affect the EU but also reshape the global gas market by imposing strict requirements on international suppliers, potentially resulting in the fragmentation of global gas trade and altering supply routes, price signals, and competition patterns. The establishment of the dialogues provides a formal venue for exporting nations to contest border restrictions and taxes.

In addition, 2025 represented the third major cycle for Nationally Determined Contributions (NDCs 3.0) mandated by the Paris Agreement, with COP30 formally commending the 122 Parties whose updated 2035 targets account for 80% of global greenhouse gas (GHG) emissions. These updates are critical for the gas industry because they establish clear regulatory benchmarks through explicit methane reduction targets. For instance, China's NDC includes non-CO_2 gases for the first time, Nigeria targets a 60% reduction in fugitive methane alongside zero routine flaring by 2030, and Canada aims to cut oil and gas methane emissions by at least 75%. Furthermore, the gas industry is poised to benefit from a strategic reliance on natural gas by major emitters seeking to fulfil coal reduction commitments without compromising energy security. This trend is evident in China's updated climate strategy, which positions gas as a critical stabilizer for its 2035 absolute emission reduction goals. Similarly, India and Vietnam are accelerating plans to phase down unabated coal in favour of expanded gas capacity and LNG imports, utilizing them as flexible baseload power.

The legacy of COP30 is also defined by the decision to refrain from including a formal hydrocarbon phase-out roadmap in the final documents, despite such requests from a coalition of countries seeking to build on the COP28 decision, which urged "transitioning away from fossil fuels in energy systems." The absence of such a roadmap recognizes the practical complexities of the energy transition and reflects a balanced approach that prioritizes national sovereignty over energy policies, leaving the development of voluntary roadmaps to individual nations.

This decision highlights that global climate cooperation has increasingly fractured, with disagreements among major players widening, as short-term national interests take precedence over long-term international environmental objectives. Following his return to office in January 2025, President Trump rapidly reversed U.S. energy and climate policies, withdrawing from the Paris Agreement and subsequently from the UN Framework Convention on Climate Change and the Intergovernmental Panel on Climate Change, while boycotting COP30 entirely. In contrast, the EU has maintained its commitment to advance the climate agenda, though it recalibrated its energy transition after the new European Commission took office in December 2024, loosening certain regulatory pressures to ensure industrial competitiveness and affordable energy.

More broadly, global pressure on the climate agenda has diminished as many countries prioritize immediate economic and social development. This shift generally aligns with the Paris Agreement's recognition that balancing climate action with sustainable development and the eradication of energy poverty is essential for long-term success. Today, energy poverty remains a staggering challenge, with 750 million people still lacking basic electricity, primarily in Sub-Saharan Africa. Simultaneously, 2.3 billion people still rely on polluting fuels for cooking, leading to millions of premature deaths from indoor air pollution each year. Looking ahead, global energy demand is expected to rise sharply, driven by economic growth, industrial expansion, population increases, climate-related heating and cooling needs, and the rapid growth of AI data centers. This underscores the need for a broad mix of sustainable energy sources, as renewables alone are not able to meet this demand at the required scale and reliability.

Despite some advancements in global climate policy, COP30 acknowledged for the first time the high likelihood of overshooting the 1.5°C temperature rise target relative to pre-industrial levels. The rise in global temperatures is closely linked to the growth in GHG emissions, with the energy sector contributing roughly 75% of the total. Energy-related GHG emissions reached 41.2 GtCO2eq in 2024, up from 38.2 $GtCO_2eq$ in 2015, with CO_2 emissions driving this growth, while methane emissions have remained almost flat (Figure i). This divergence highlights significant progress in the upstream sector, especially within the gas industry, in deploying methane abatement technologies, while underscoring the persistent challenge faced by the downstream sector in reducing CO_2 emissions during fuel combustion. Four major economies are responsible for 60% of global energy-related GHG emissions (Figure ii). Notably, the combined emissions of China and India in 2024 were 3.1 $GtCO_2eq$ higher than in 2015, even exceeding the net global emissions growth of 3.0 $GtCO_2eq$ over the same period. This places these economies at the forefront of global mitigation efforts.

Figure i: Global energy-related GHG emissions

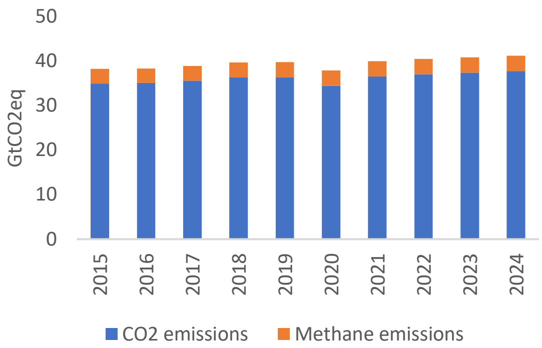
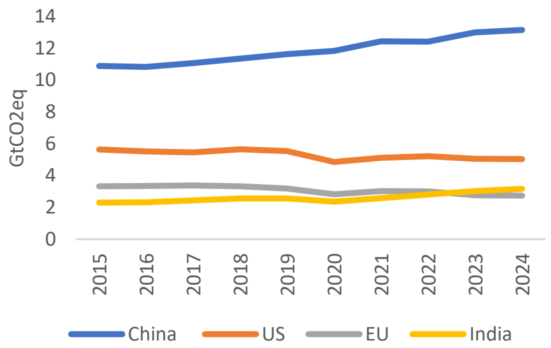


Figure ii: Energy-related GHG emissions by economy



Source: GECF Secretariat based on data from IEA, S&P Global and EDGAR

Global CO_2 emissions growth over the last decade has been mainly driven by coal combustion. Between 2015 and 2024, total emissions rose from 31.4 Gt to 35.0 Gt, with coal contributing 2.1 Gt of that increase, compared to only 1.3 Gt from natural gas (Figure iii). This occurred even though global natural gas consumption grew faster than coal, increasing by 30 EJ compared with coal's 28 EJ over the same period. In contrast, growth in primary consumption of other fuels, such as oil (12 EJ), wind and solar electricity (13 EJ), and biomass (8 EJ), was much lower, making natural gas the largest contributor to primary energy consumption growth over the last decade.

Coal-fired generation, which accounts for 55% of CO_2 emissions from coal combustion, 65% of CO_2 emissions from the power sector, and 27% of global CO_2 emissions, should be at the center of global mitigation efforts. In recent UN climate summits, the international community has shifted from broad environmental aspirations toward more explicit policy mandates aimed at reducing coal use. This shift began with the COP26 Glasgow Climate Pact in 2021, which marked the first UN agreement to call for a phase down of unabated coal power, a commitment subsequently reaffirmed at later COPs. Despite this strengthened rhetoric, coal-fired generation has continued to expand globally, rising from 9,300 TWh in 2015 to 10,500 TWh in 2024, with associated CO_2 emissions increasing from 8.6 Gt to 9.5 Gt over the same period.

Against this background, substantial untapped potential remains to reduce CO_2 emissions through coal-to-gas switching, which is already underway but not at a pace sufficient to deliver large-scale progress. As a significantly cleaner alternative to other hydrocarbon fuels, natural gas has a lower carbon intensity and a cleaner combustion profile, emitting roughly 50% less CO_2 than coal and 30% less than oil per unit of energy (Figure iv). This allows natural gas to meet growing energy demand while generating substantially fewer emissions per unit of energy consumed. In addition, natural gas combustion produces far lower levels of particulate matter, sulphur dioxide, and nitrogen oxides, thereby reducing air pollution and associated health impacts. Furthermore, advances in methane abatement technologies in the upstream gas sector have helped limit fugitive emissions, strengthening the overall climate performance of natural gas and reinforcing its role as a key lower carbon energy source.

Figure iii: Growth in CO_2 emissions from 2015 to 2024

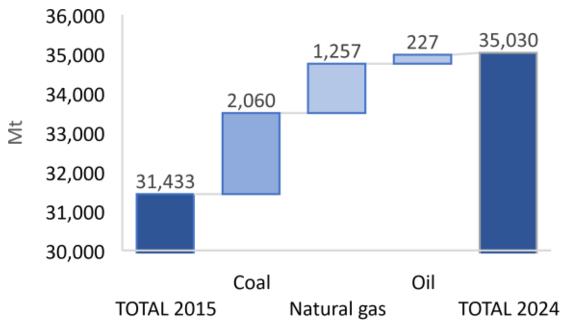
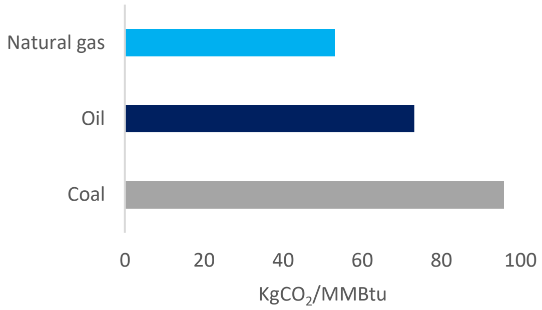


Figure iv: CO_2 emission intensity of hydrocarbon fuels



Source: GECF Secretariat based on data from Enerdata and US EIA

As 2026 begins, the international climate agenda remains marked by a widening gap between ambition and implementation, underscoring the need to shift from potentially unattainable aspirational targets toward pragmatic and achievable pathways grounded in technological readiness, economic feasibility, and social realities. In an increasingly complex energy and climate environment, effective climate action must reconcile emissions mitigation with the imperative to sustain economic development and social progress.

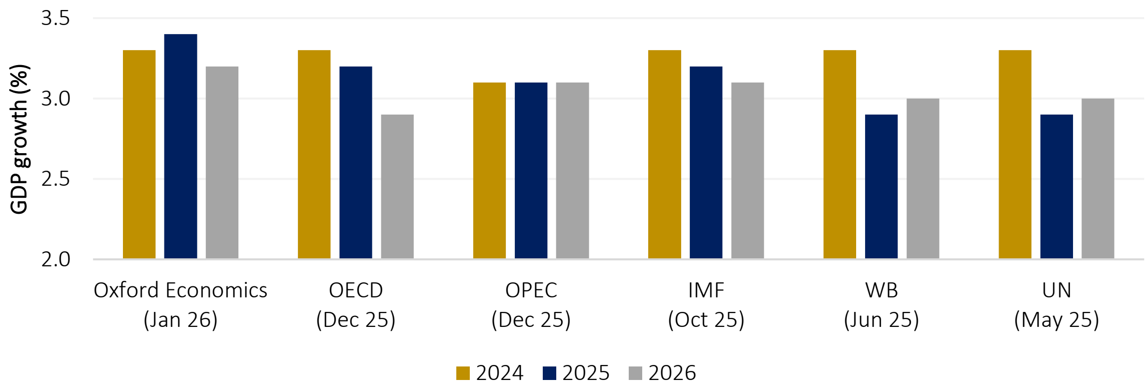
Against this backdrop, global energy demand is projected to continue rising, while hydrocarbon fuels are expected to retain a dominant share in the global energy mix through mid-century, according to all major energy outlooks. In this context, natural gas, owing to its lower carbon intensity compared to other hydrocarbon fuels, occupies a unique position. It is increasingly recognized both as a transition and a destination fuel within realistic decarbonization pathways. As global GHG emissions continue to increase and energy security concerns intensify, natural gas plays a critical role in addressing the energy trilemma by supporting emissions reduction efforts, enhancing energy security, and maintaining affordability.

1 GLOBAL PERSPECTIVES

1.1 Global economy

As of January 2026, global GDP growth for 2025 was estimated at 3.4% by Oxford Economics, based on purchasing power parity (Figure 1). This outlook underscores the continued resilience of the global economy, which has maintained steady growth despite ongoing geopolitical tensions and trade-related uncertainties. Looking ahead to 2026, global economic activity is expected to slow, with GDP growth forecast at 3.2%.

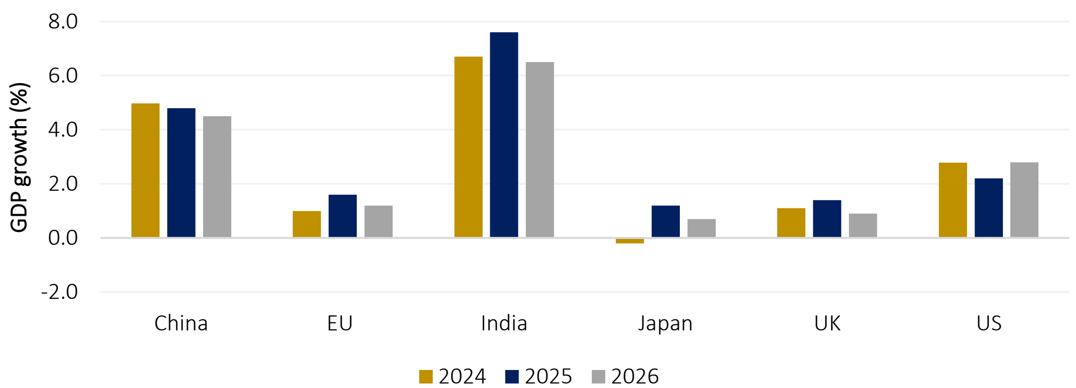
Figure 1: Global GDP growth



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 a country level, US GDP growth for 2025 was estimated at 2.2%. Growth is expected to strengthen in 2026, with the forecast revised up to 2.8% (0.3 percentage point increase), supported by robust consumer spending and rising business investment particularly in AI-related sectors. In the EU, GDP growth for 2025 was estimated at 1.6%. Growth is expected to moderate in 2026 to 1.2%, reflecting softer investment conditions. China's GDP growth for 2025 was estimated at 4.8%. Growth is expected to be ease slightly in 2026, with GDP projected to expand by 4.5%, supported by continued government stimulus and external demand. Meanwhile, India's GDP growth for 2025 was estimated at 7.6%, with the outlook for 2026 maintained at 6.5% (Figure 2).

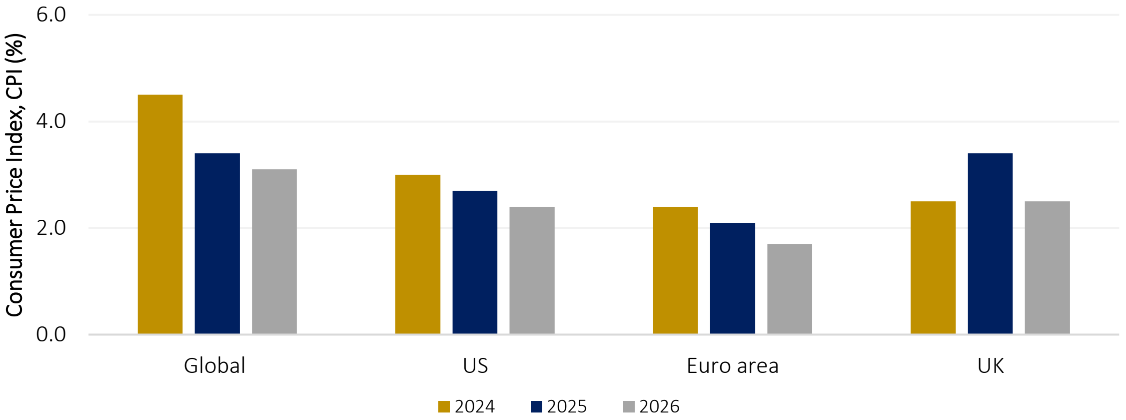
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

Global inflation was estimated at 3.4% in 2025, and is expected to moderate to 3.1% in 2026, according to Oxford Economics. In the Euro area, inflation was estimated at 2.1% in 2025 and is forecast to ease to 1.7% in 2026. In the UK, inflation was estimated at 3.4% in 2025 and is expected to decline to 2.5% in 2026. Similarly, in the US, inflation was estimated at 2.7% in 2025 and is expected to ease to 2.4% in 2026 (Figure 3).

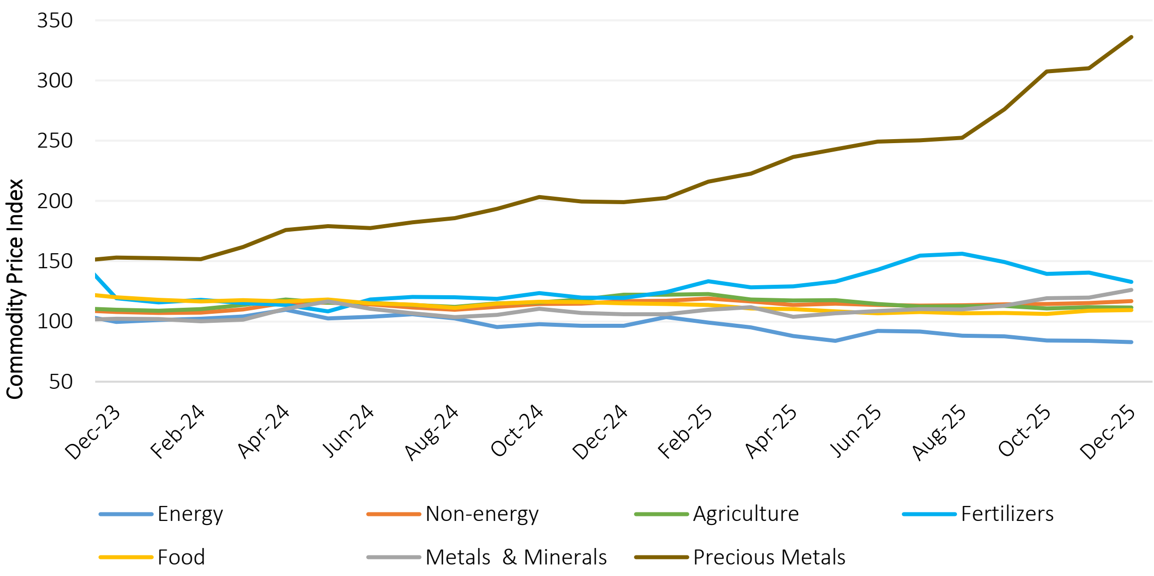
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In December 2025, commodity prices in the energy sector decline slightly. The energy price index decreased by 1% m-o-m and 14% y-o-y, reflecting softening oil, gas and coal prices. Meanwhile, the non-energy price index increased by 1% m-o-m and was relatively stable compared to the previous year. Additionally, the fertilizer price index decreased by 5% m-o-m, but was 11% higher y-o-y. Notably, the precious metals price index continued to climb, increasing by 8% m-o-m (Figure 4).

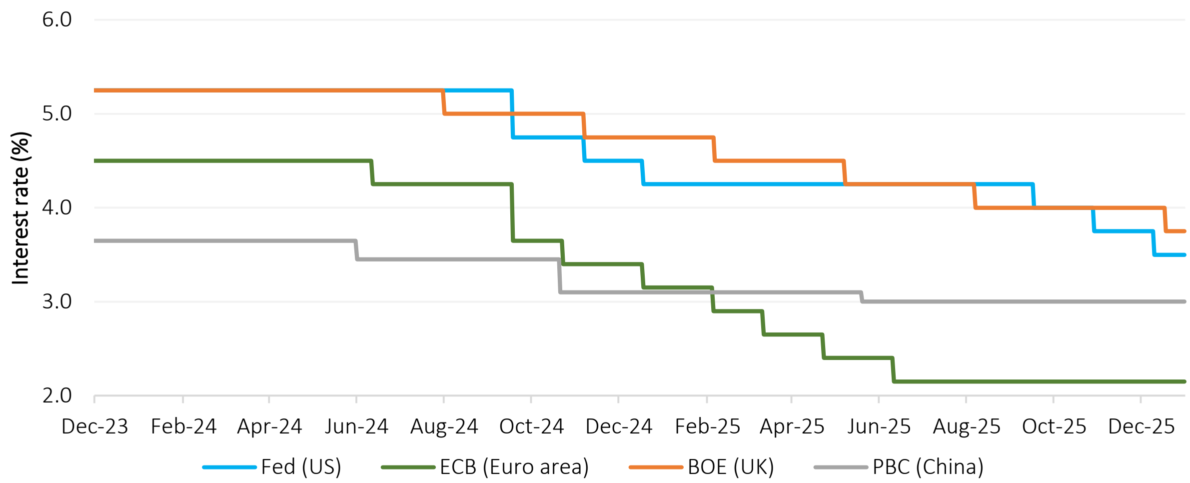
Figure 4: Monthly commodity price indices



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 December 2025, the US Federal Reserve (Fed) lowered its benchmark interest rate by 0.25 percentage points to bring it within the range of 3.5% to 3.75%. The Bank of England (BOE) also reduced its benchmark interest rate by 0.25 percentage points to 3.75%. Meanwhile, other major central banks maintained their benchmark interest rates. The European Central Bank (ECB) also held its main refinancing operations rate at 2.15%. Similarly, the People's Bank of China (PBC) maintained its one-year Loan Prime Rate (LPR) at 3.0% (Figure 5).

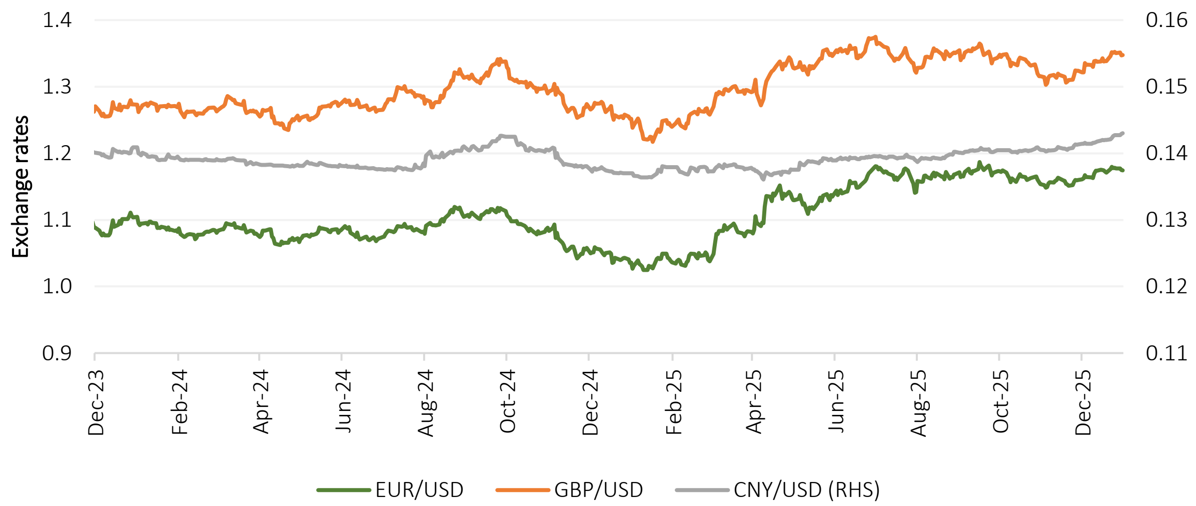
Figure 5: Interest rates in major central banks



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

In December 2025, the euro appreciated against the US dollar, resulting in an average exchange rate of $1.1716, representing an increase of 1% m-o-m and 12% y-o-y. The British pound also strengthened against the US dollar, with an average exchange rate of $1.3398, reflecting increases of 2% m-o-m and 6% y-o-y. Additionally, the Chinese yuan also strengthened against the US dollar, averaging $0.1420, representing increases of 1% m-o-m and 3% y-o-y (Figure 6).

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

European Union: The European Parliament formally adopted the Omnibus I Package, which includes significant amendments to the Corporate Sustainability Reporting Directive (CSRD) and the Corporate Sustainability Due Diligence Directive (CSDDD), on 16 December 2025. Under the revised CSRD, sustainability reporting now applies to EU companies with over 1,000 employees and €450 million in annual turnover, as well as non-EU firms generating over €450 million within the EU. Notably, the amendment substantially raises the CSDDD thresholds, increasing the requirements for EU companies to 5,000 employees and €1.5 billion in net turnover. For non-EU groups, the final text removes the employee threshold entirely, applying due diligence obligations solely where EU-generated net turnover exceeds €1.5 billion. These amended rules are scheduled to take effect on 26 July 2029, following a designated transition period in 2028.

United States: President Trump signed a Presidential Memorandum on 7 January 2026, directing the United States to withdraw from 66 international organizations, conventions, and treaties deemed "contrary to the interests of the United States." This retreat targets the foundational pillars of global climate governance, including the United Nations Framework Convention on Climate Change (UNFCCC), the Intergovernmental Panel on Climate Change (IPCC), and the International Renewable Energy Agency (IRENA). As the US prepares for its second formal exit from the Paris Agreement on 27 January 2026, the administration is simultaneously dismantling domestic protections by terminating all federal environmental justice offices and finalizing the removal of implementing regulations for the National Environmental Policy Act (NEPA) to streamline industrial and energy infrastructure projects.

China and India: Reports by the Centre for Research on Energy and Clean Air (CREA) and Carbon Brief confirmed a historic energy milestone: for the first time in over half a century, China and India recorded a simultaneous decline in coal-fired power generation in 2025. Driven by massive clean energy expansion, coal output fell by 1.6% (58 TWh) in China and 3.0% (57 TWh) in India, marking the first joint drop for the two nations since 1973. This decline was fuelled by China's record-shattering addition of 400 GW of wind and solar and India's nearly 45 GW of new renewable capacity, which together proved sufficient to cover the total rise in electricity demand. This breakthrough indicates a definitive decoupling of economic growth from coal consumption in the world's two largest coal-burning economies.

European Union and South America: After 25 years of negotiations, the European Union and the Mercosur bloc signed a landmark free trade agreement on 17 January 2026, establishing one of the world's largest free trade zones covering 700 million consumers and 25% of global GDP. The pact aims to eliminate tariffs on over 90% of bilateral trade, facilitating South American market access for European industrial goods while easing entry for Mercosur's agricultural exports. To overcome long-standing opposition, the final agreement incorporates a "two-part" legal structure for accelerated implementation, a €6.3 billion support fund for European farmers, and binding climate clauses linked to the Paris Agreement. This signing serves as a strategic geopolitical hedge against global protectionism, though the deal must still clear a final European Parliament ratification vote before taking effect later in 2026.

2 GAS CONSUMPTION

In the first 11 months of 2025, aggregated gas consumption of some major gas consuming countries, which account for 75% of global gas demand, increased by 1.4% y-o-y to reach 3,210 bcm. Growth was recorded in all regions, including the EU, UK, North America, and Asia.

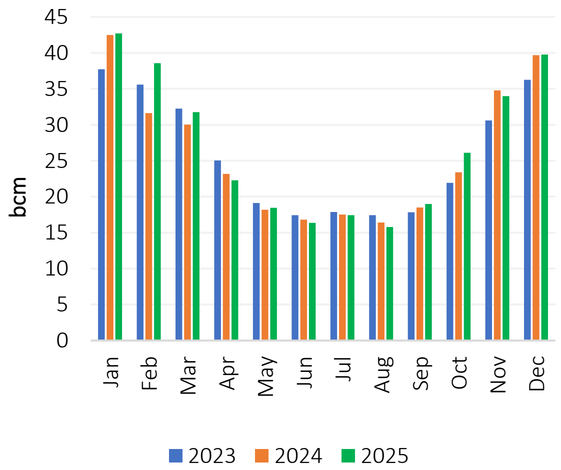
2.1 Europe

2.2.1 European Union

EU natural gas consumption increased by 0.3% y-o-y in December 2025, reaching 40 bcm (Figure 7). The rise was driven primarily by higher residential heating needs and increased gas-fired power generation. Average temperatures across Europe were 0.6°C lower than a year earlier, with particularly cold conditions in southeastern Europe, the western Balkans and southern Poland. Several areas experienced early-season snowfall, further boosting heating demand. Although wind and solar output also increased, renewable generation was not sufficient to meet the additional load during colder conditions. As a result, natural gas played a crucial role in covering the seasonal uptick in heating and power needs, ensuring system reliability during periods of high energy demand.

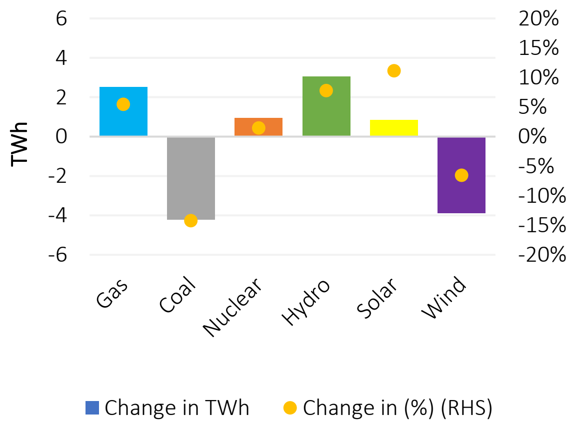
EU electricity generation saw a slight y-o-y increase to reach 227 TWh. Notably, gas-fired power surged by 5% y-o-y, reflecting gas's continued importance in balancing the grid, particularly during the recent cold spell. Solar and hydro generation also expanded, by 11% and 8% y-o-y, respectively (Figure 8). In the overall power mix, non-hydro renewables remained the largest source at 27%, followed by nuclear (24%), gas (19%), hydro (16%), and coal (10%). 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 December 2025 (y-o-y change)



Source: GECF Secretariat based on data from Ember

2.1.1.1 Germany

In December 2025, Germany's natural gas consumption posted a second consecutive monthly decrease after two months of growth, reaching 9.8 bcm — down by 0.7% y-o-y (Figure 9). The decline was mainly driven by lower demand in the residential and industrial sectors. Industrial consumption recorded its second month of decline following two consecutive months of y-o-y growth, decreasing by 1% y-o-y (Figure 10). Residential gas demand declined by 2.4% y-o-y, although December recorded the same average temperature as in 2024, at 3.2 °C, being 0.6°C colder than in 2023.

Figure 9: Gas consumption in Germany

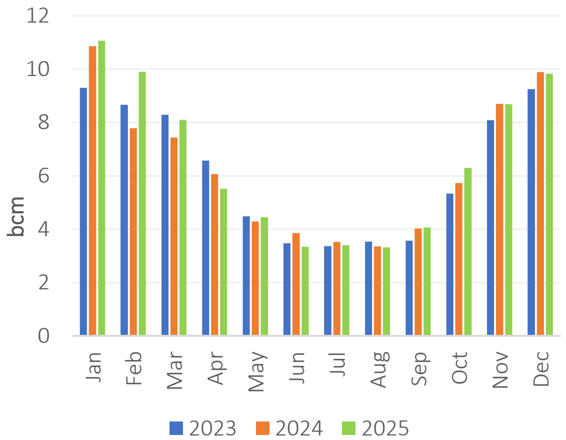
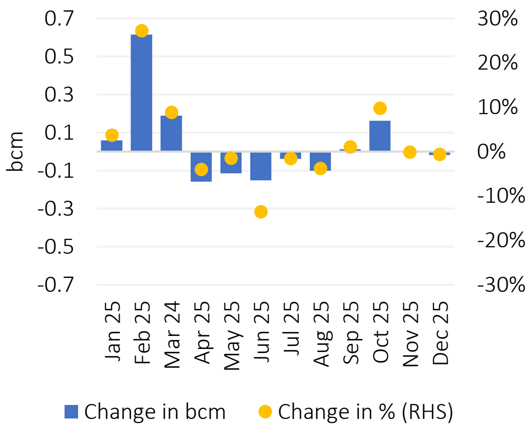


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Total electricity generation increased by 0.2% y-o-y, reaching 38.6 TWh. Gas-fired power output surged by 21% y-o-y, offsetting the decline in both hydro and coal generation, which fell by 20% and 21%, respectively (Figure 11). In contrast, solar output expanded significantly, rising by 50% y-o-y during the month. In Germany's power mix, non-hydro renewables continued to lead, representing 54% of total electricity generation, followed by gas (23%) and coal (20%) (Figure 12).

Figure 11: Trend in electricity production in Germany in December 2025 (y-o-y change)

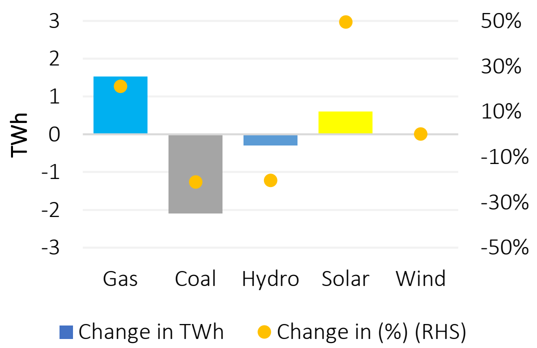
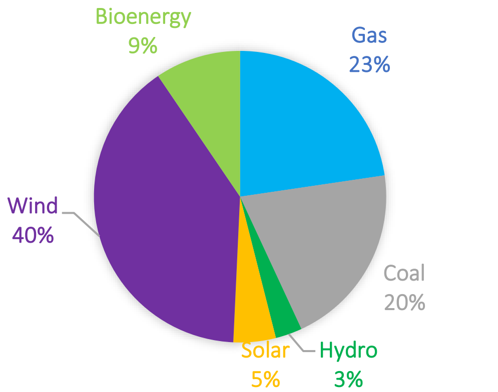


Figure 12: German electricity mix in December 2025

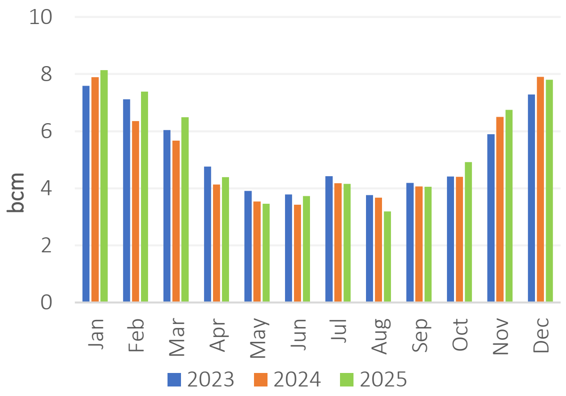


Source: GECF Secretariat based on data from LSEG and Ember

2.1.1.2 Italy

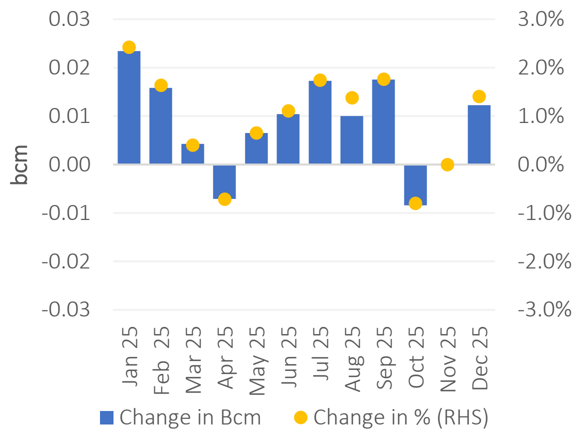
In December 2025, Italy's natural gas consumption declined by 1.3% y-o-y to 7.8 bcm (Figure 13), largely driven by milder-than-average temperatures across the country. Residential consumption dropped by 12% y-o-y to 4.1 bcm, supported by higher temperatures (6.9°C, which is 1.4°C above the previous year), which reduced heating needs in households and commercial buildings. In contrast, industrial demand rose by 1.4% y-o-y to 0.9 bcm, marking the first increase in manufacturing activity after two months of decline (Figure 14). Meanwhile, the rebound in gas use for power generation underscored its vital role during cold spells.

Figure 13: Gas consumption in Italy



Source: GECF Secretariat based on data from Snam

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



Total electricity generation in Italy rose by 4.6% y-o-y to 20.3 TWh. Gas-fired power generation also increased 20% y-o-y to 2.5 bcm, supported by a reduction in hydro, wind and coal output, which declined by 18%, 46% and 33%, respectively (Figure 15). Even as the electricity mix evolved, natural gas continued to play a central role in Italy's power sector, supplying 67% of total electricity output. Meanwhile, non-hydro renewable sources contributed 23%, highlighting Italy's ongoing reliance on gas as a key pillar for maintaining power system stability (Figure 16).

Figure 15: Trend in electricity production in Italy in December 2025 (y-o-y change)

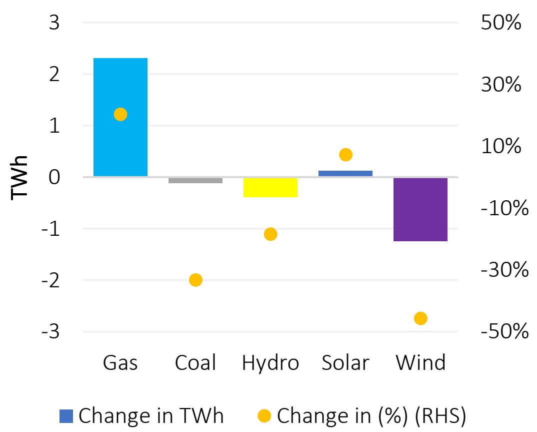
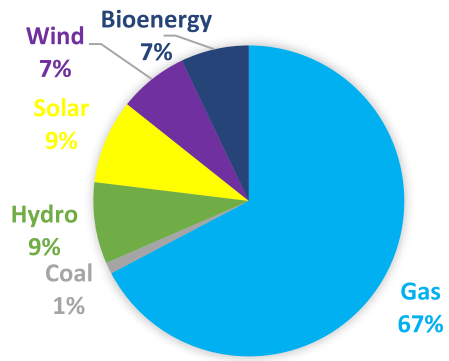


Figure 16: Italian electricity mix in December 2025

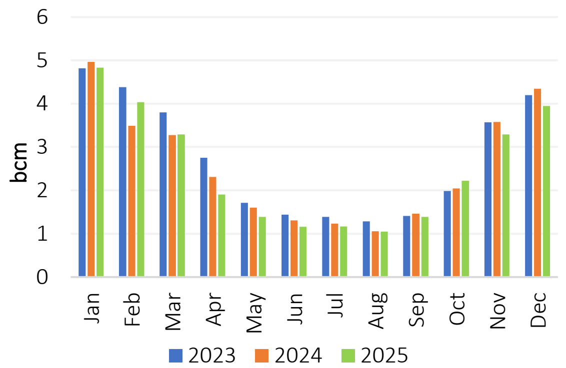


Source: GECF Secretariat based on data from Terna, LSEG and Ember

2.1.1.3 France

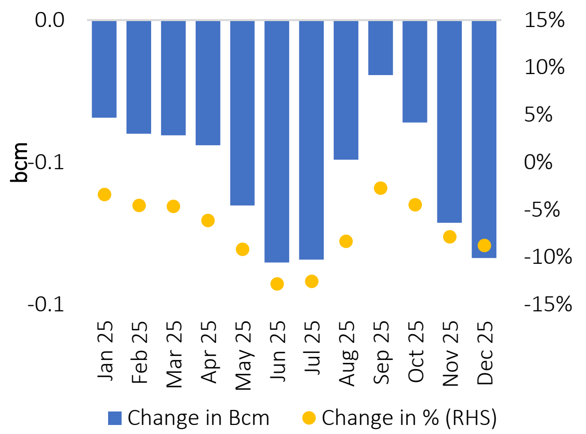
In December 2025, France's natural gas consumption declined by 9.1% y-o-y to 4 bcm (Figure 17), driven by lower demand in the industrial, power generation and residential sectors. Residential consumption declined by 10% y-o-y to 2.7 bcm, supported by warmer weather, with average temperatures at 7.6°C — 0.8°C higher than the same month last year. The industrial sector recorded a decline of 8.8% to reach 0.9 bcm (Figure 18).

Figure 17: Gas consumption in France



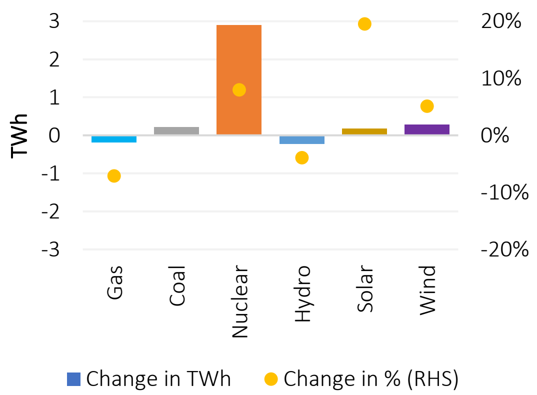
Source: GECF Secretariat based on data from GRTgaz

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



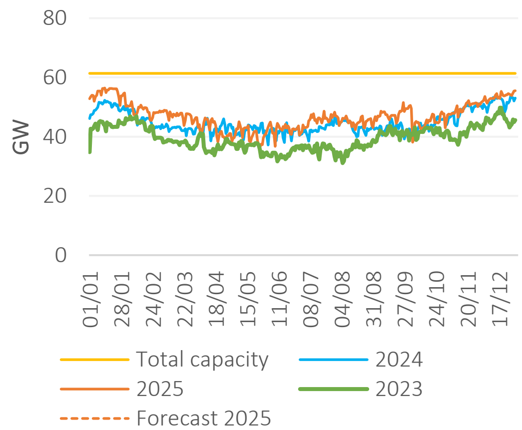
Total electricity generation in France edged up by 6.2% y-o-y to 54.5 TWh. Notably, nuclear generation, soaring by 8% y-o-y, as hydropower and gas output fell by 4% and 7% y-o-y respectively. In contrast, wind and solar generation continued to grow over the period (Figure 19). French nuclear capacity availability grew by 12% m-o-m and 4% y-o-y (Figure 20). France's electricity market was shaped by strong nuclear availability, supported by the ramp-up of the Flamanville 3 reactor, while improved inspections allowed several units to be removed from the corrosion risk list. Temporary maintenance shutdowns at other EDF reactors slightly reduced availability during the last two weeks of the month. In the overall power mix, nuclear energy continued to dominate, representing 72% of total electricity supply, followed by non-hydro renewables (13%), hydro (10%) and natural gas (4%). Meanwhile, RTE revised down its renewable generation outlook to 17% by 2035, citing weaker-than-expected electricity demand growth.

Figure 19: Trend in electricity production in France in December 2025 (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 December 2025, Spain's gas consumption rose by 0.4% y-o-y to 3.2 bcm, recording its eleventh consecutive y-o-y growth in a row (Figure 21). This increase was primarily supported by higher gas demand in the power generation sector, which helped compensate for lower coal, wind, and solar output. Meanwhile, industrial gas consumption recorded a decline of 2.2% y-o-y. The downtick was largely driven by lower consumption in the metallurgy sector (-14%), agro-food sector (-3.4%), and the paper industry (-3%) (Figure 22).

Figure 21: Gas consumption in Spain

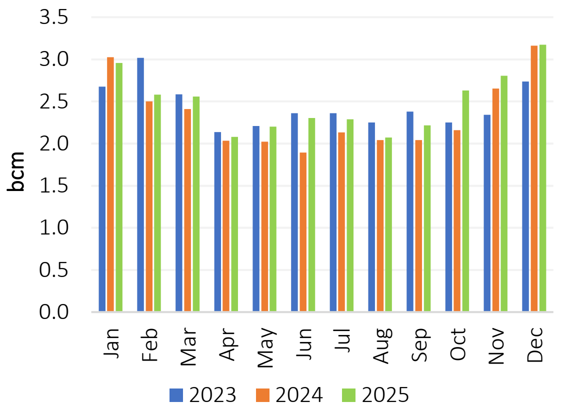
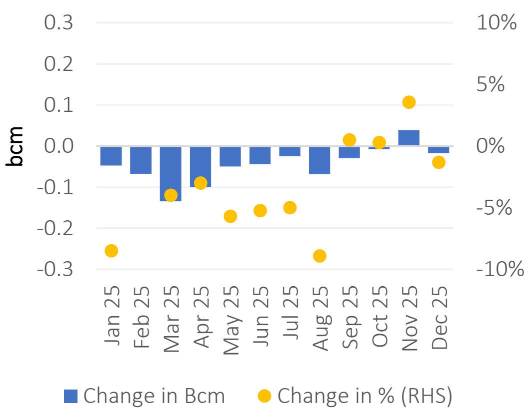


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Total electricity generation in Spain increased by 0.4% y-o-y to 21 TWh. However, natural gas-fired power generation surged by 11% y-o-y, primarily to balance low wind and solar output caused by unfavourable weather conditions (Figure 23). Likewise, coal power-generation output decreased significantly compared to last year. Non-hydro renewables remained the largest contributor to the power mix, accounting for 37%, while natural gas made up 27%, highlighting its role in balancing the electricity grid amid fluctuating renewable output (Figure 24).

Figure 23: Trend in electricity production in Spain in December 2025 (y-o-y change)

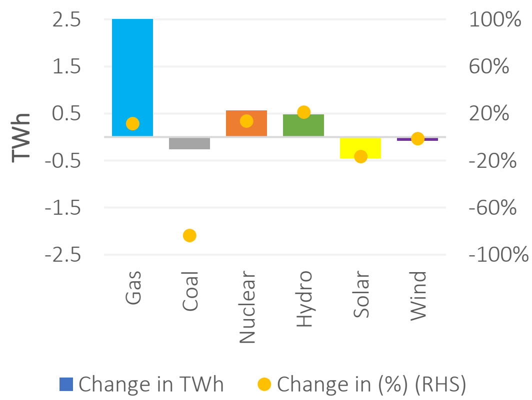
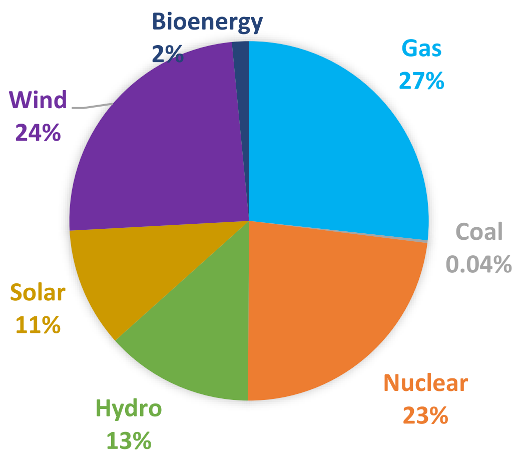


Figure 24: Spanish electricity mix in December 2025



Source: GECF Secretariat based on data from Ember and Ree

2.1.2 United Kingdom

In December 2025, the UK recorded a slight growth in gas consumption. It rose by 0.1% y-o-y to 6.8 bcm (Figure 25). The residential sector recorded a growth of 3% y-o-y to reach 5.6 bcm, mainly driven by colder than normal temperatures during the month. The average temperature in UK reached 7.1°C — 0.2°C lower than the same month last year. By contrast, the industrial sector recorded a 49% y-o-y decline in gas consumption, reflecting weaker demand across energy-intensive industries (Figure 26).

Figure 25: Gas consumption in the UK

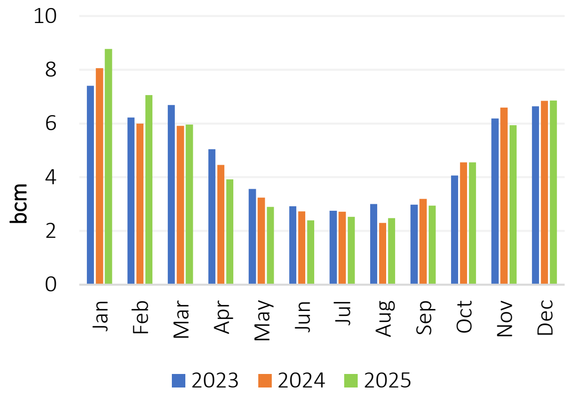
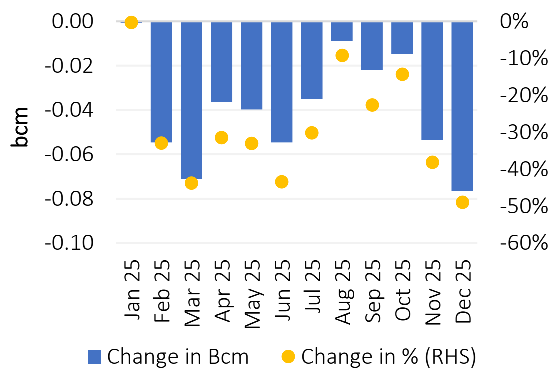


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Total electricity generation in the UK increased by 4% y-o-y to 22.3 TWh. However, natural gas-fired power generation declined by 9% y-o-y, largely offset by strong wind and solar output driven by favourable weather conditions. Wind and solar generation rose by 15% and 67% 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 55%, while natural gas made up 31%, highlighting its role in balancing the electricity grid amid fluctuating renewable output (Figure 28).

Figure 27: Trend in electricity production in UK in December 2025 (y-o-y change)

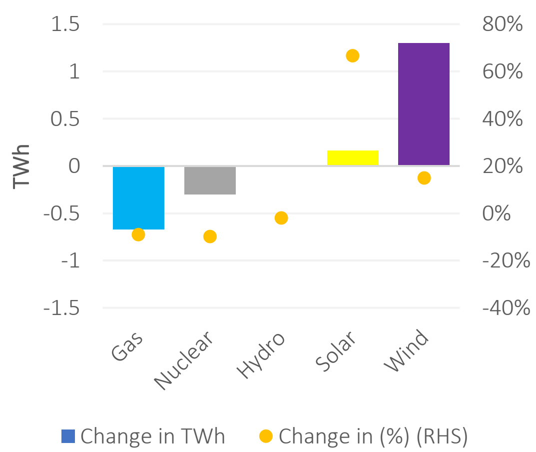
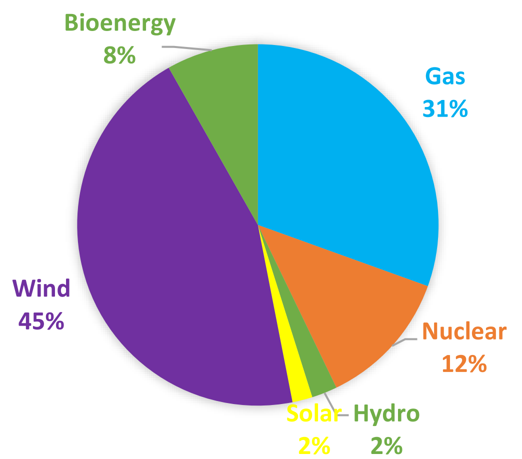


Figure 28: UK electricity mix in December 2025



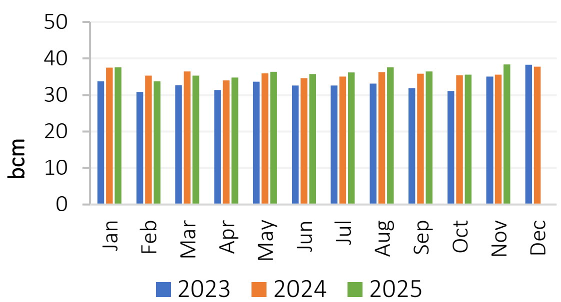
Source: GECF Secretariat based on data from Ember

2.2 Asia

2.2.1 China

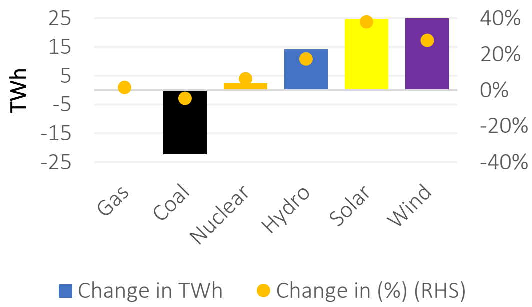
In November 2025, China's apparent gas demand (production + LNG and pipeline gas imports) recorded a growth of 7.8% y-o-y to reach 38.4 bcm (Figure 29). In the first eleven months of 2025, China's gas demand rose by 1.5% y-o-y. China's electricity generation reached 840 TWh in November a rise of 6% y-o-y (Figure 30). According to a newly published forecast by Kpler, China's electricity demand growth will reaccelerate to 5.1% in 2026, driven by a recovering manufacturing sector. While solar and wind are expected to contribute a record 55% of new generation, thermal power will remain indispensable, with coal generation forecast to rise by 1.6% and gas-fired output by 3.5% to ensure grid stability during peak demand periods.

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

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

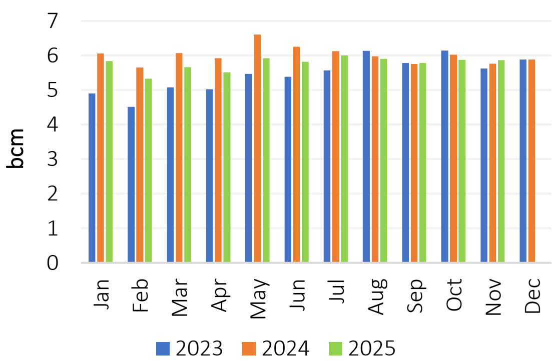


Source: GECF Secretariat based on data from Ember

2.2.2 India

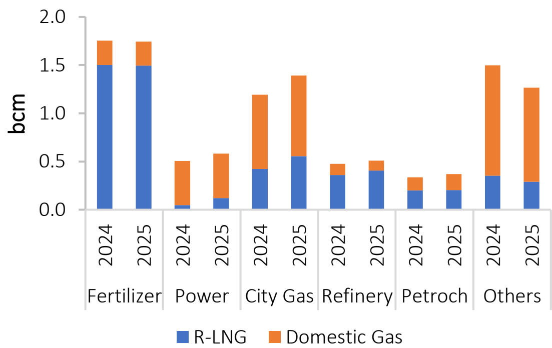
In November 2025, India's natural gas consumption grew by 1.6% y-o-y to 5.9 bcm, marking its third consecutive growth after seven months of y-o-y decline (Figure 31). This upturn was primarily driven by higher demand in the city gas, power generation, refinery and petrochemicals sectors, which recorded y-o-y increases of 17% (0.2 bcm), 15% (0.1 bcm), 6.5% (0.03 bcm) and 9.7% (0.02 bcm), respectively. Fertilizer production remained the largest consumer of natural gas, accounting for 30% of total demand, followed by city gas distribution at 24% (Figure 32).

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

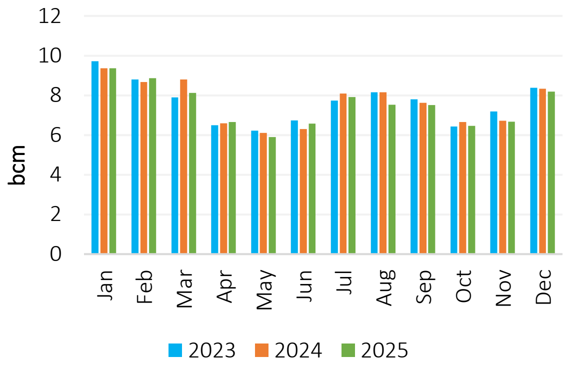
Figure 32: India's gas consumption by sector in November 2025



2.2.3 Japan

In December 2025, Japan's gas consumption decreased by 1.7% y-o-y to 8.2 bcm (Figure 33). Japan's electricity demand declined by 1.9% y-o-y in December, averaging 102.7 GW, as warmer-than-normal temperatures (+1.2 °C) limited heating needs and reduced reliance on natural gas-fired generation. Demand, however, rose 18% m-o-m due to a sharp temperature drop from November, while nuclear availability remained relatively high, further constraining gas use in the power mix.

Figure 33: Gas consumption in Japan

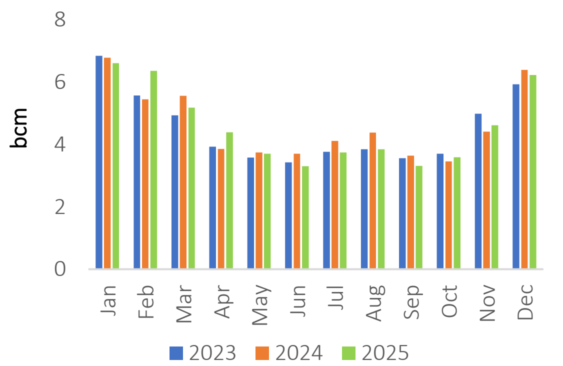


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In December 2025, South Korea's natural gas consumption decreased by 2.6% y-o-y to reach 6.2 bcm (Figure 34). South Korea's power-sector gas demand remained weak y-o-y, with gas-fired output down about 2 GW to 18.2 GW, despite slightly higher electricity demand. Lower nuclear availability supported a 3.5 GW rise in coal generation. In the meantime, ongoing nuclear maintenance delays may support gas demand in the short term, but lower overall power demand and strong coal output continue to cap gas use.

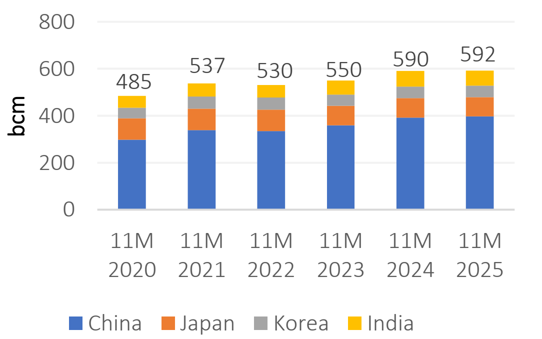
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

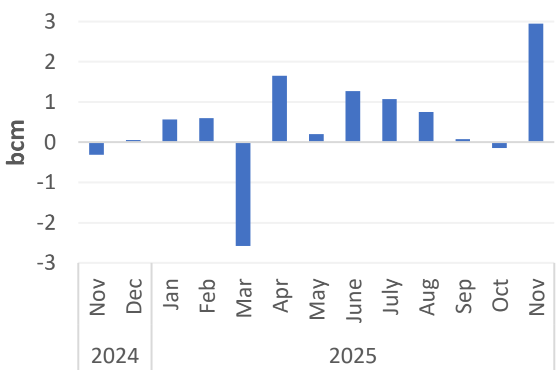
From January to November 2025, aggregated gas consumption in major Asian gas consuming countries, namely China, India, Japan and South Korea, rose by 0.3% y-o-y (1.6 bcm) to reach 592 bcm (Figure 35), driven mainly by a rise of 5.8 bcm in China (Figure 36).

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

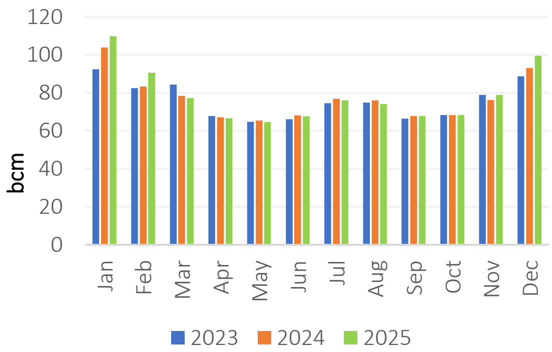


2.3 North America

2.3.1 US

In December 2025, US natural gas demand rose by 7% y-o-y, reaching 99.5 bcm (Figure 37), driven by a sharp increase in heating-related consumption. Residential and commercial gas use expanded significantly, up 15.6% (3.3 bcm) and 13% (1.6 bcm) y-o-y, respectively, as cooler-than-average temperatures intensified space heating needs, particularly in northern regions. Industrial demand edged higher by 0.7% (0.2 bcm), supported by modest growth in manufacturing activity and continued industrial operations during the winter months.

Figure 37: Gas consumption in the US



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

Total electricity generation in the US increased by 6% y-o-y to 382 TWh. Natural gas-fired power generation grew by 1.5% 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 19%, 17.7% and 18.5% respectively (Figure 39).

Figure 38: Electricity production in US in Dec 2025

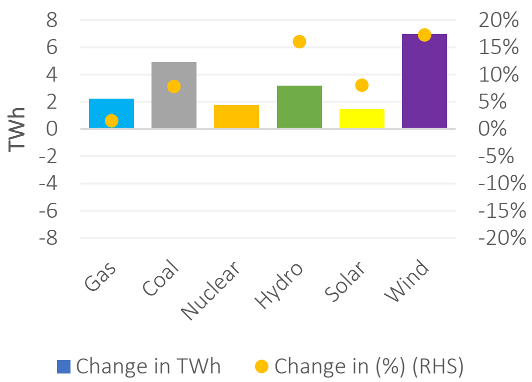
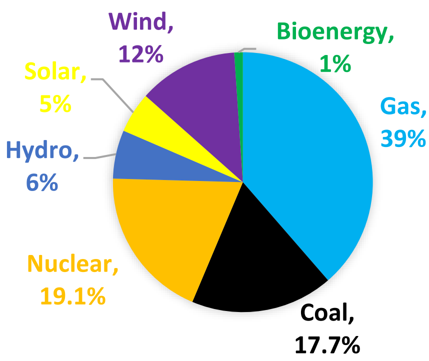


Figure 39: US electricity mix in Dec 2025

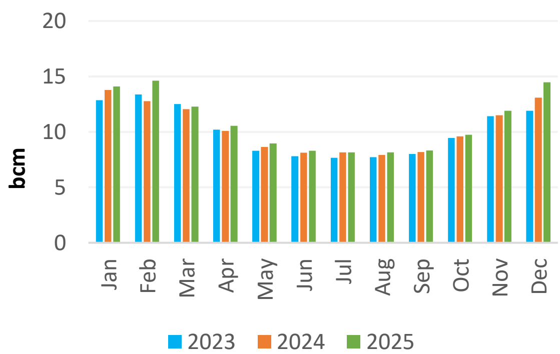


Source: GECF Secretariat based on data from EIA and LSEG

2.3.2 Canada

In December 2025, Canada's gas consumption increased by 11% y-o-y, reaching 14.5 bcm (Figure 40), driven largely by stronger demand in the residential and commercial sectors, where consumption rose by 19% and 18% y-o-y respectively. Similarly, the industrial/power generation sector saw an increase of 6% y-o-y. This steady growth across the industrial and power generation sectors highlights the resilience of Canadian gas demand despite broader market uncertainties.

Figure 40: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.4 Other developments

2.4.1 Sectoral developments

China’s CNOOC sets new LNG bunkering record in the Greater Bay Area: State-owned CNOOC Gas and Power Group reached a new peak in the Guangdong-Hong Kong-Macao Greater Bay Area (GBA), where its bonded LNG bunkering volume for international vessels hit 80,000 tons during the January-November 2025 period. This record highlights the company's aggressive expansion in the region, which contributed to its total national bunkering volume exceeding 200,000 tons for the full year of 2025—a 3.6-fold increase over 2024. By completing landmark operations such as Hong Kong's largest single ship-to-ship refuelling in mid-2025 and Shenzhen's first anchorage bunkering in January 2026, CNOOC has firmly established the GBA as a leading international green maritime gateway.

Taiwan’s power mix hits historic milestone as LNG exceeds 50% share: Taiwan’s power generation mix saw LNG account for 53% of output in October 2025, marking the first time the fuel has surpassed the 50% threshold. This surge, driven by the final phase-out of nuclear power and lower-than-expected renewable generation, allowed the island to meet its year-end goal ahead of schedule, following a previous monthly high of 48.8% in August. As LNG’s share climbed from an average of 41.8% in 2024 to 47.8% during the first ten months of 2025, coal-fired generation plummeted to a record low of 32.2% in October – its lowest level since the 1990s – solidifying gas as the island's primary energy source.

Vietnam’s Nhon Trach LNG Power Complex enters full commercial operation: Vietnam achieved a landmark energy milestone as the Nhon Trach 3 and 4 power complex, the nation's first LNG-to-power project, officially entered full commercial operation on 5 January 2026. The $1.4 billion facility near Ho Chi Minh City provides a combined capacity of 1,624 MW and is projected to supply over 9 billion kWh annually to the national grid. Utilizing high-efficiency gas turbines fueled via the Thi Vai LNG Terminal, the complex significantly reduces carbon emissions compared to traditional coal-fired plants. This successful integration serves as the primary blueprint for Vietnam’s strategic goal to reach 22 GW of gas-fired capacity by 2030 under the National Power Development Plan VIII.

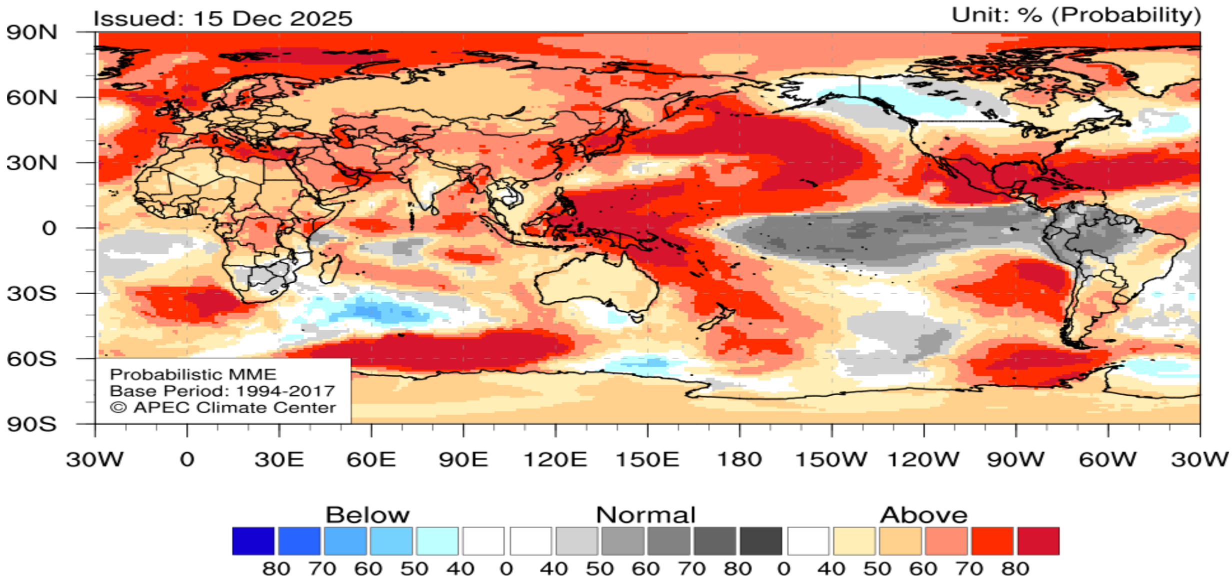
Myanmar restarts LNG power generation to stabilize national grid: In a major move to address chronic energy shortages, Myanmar has resumed LNG imports and power generation following a more than four-year hiatus. By mid-December 2025, the 200 MW Thanlyin and 300 MW Thaketa power plants successfully began test runs, initially injecting 150 MW into the national grid with plans to ramp up to their full 500 MW combined capacity throughout 2026. This restart, managed by a consortium including CNTIC VPower and local partner Everest Energy Solution, is a critical step in mitigating a generation deficit that currently meets only about 50% of the nation's 3,400 MW peak demand.

Uruguay’s Punta del Tigre Plant secures cost-saving gas deal with Argentina: Uruguay's state-owned utility UTE achieved a major operational breakthrough by successfully fuelling its 840 MW Punta del Tigre thermal plant with natural gas from Argentina’s Vaca Muerta formation. This transition allows the facility to replace expensive fuel oil and diesel with more cost-effective natural gas. Within just the first week of operation, the switch resulted in approximately US$3 million in savings, with UTE officials projecting an overall 50% reduction in energy production costs for the plant. This deal not only stabilizes Uruguay's energy costs amid volatile global fuel prices but also marks the first time in two decades that the cross-border pipeline infrastructure has been utilized at this scale for national power generation.

2.4.2 Weather forecast

According to the APEC Climate Center, from January to March 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 Indian Ocean, western Canada and the western North Atlantic (Figure 41).

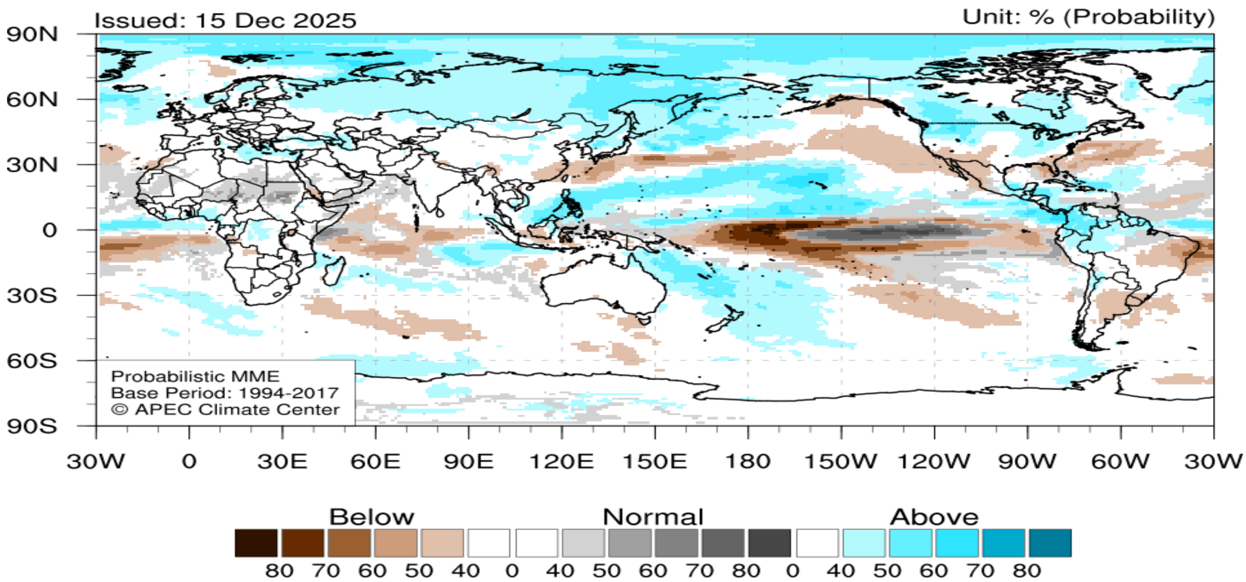
Figure 41: Temperature forecast for January to March 2026



Source: APEC Climate Center

According to the same source, precipitation is expected to be above average in parts of the Arctic, eastern North America, western Russia, Central America, in addition to the tropical Indian and Atlantic Oceans. Rainfall is likely near normal in North Africa and West Africa's coast, while below-average precipitation is forecast for the Central and South Pacific, western Indian Ocean, the southwestern United States, Mexico and southern South America, with drier conditions also affecting parts of the North Atlantic and East Asia (Figure 42).

Figure 42: Precipitation forecast for January to March 2026



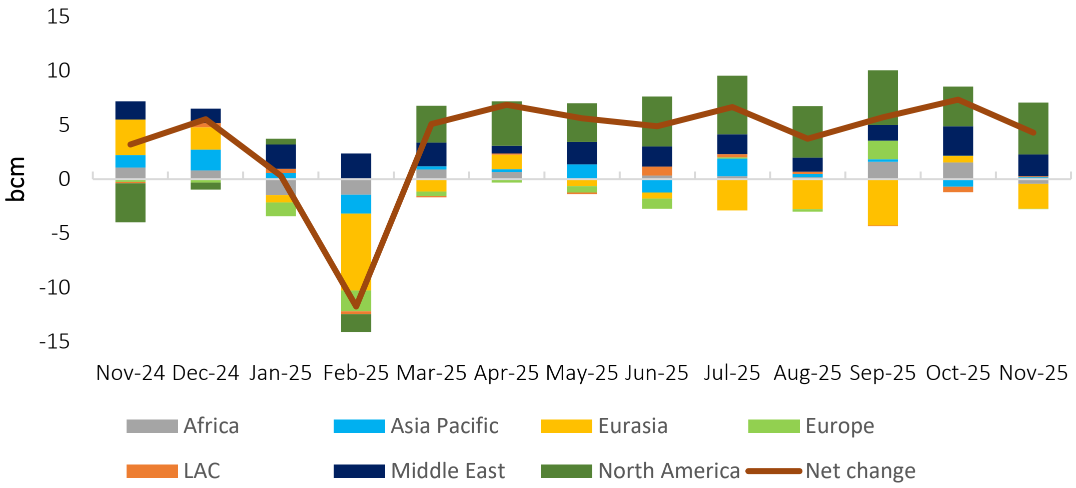
Source: APEC Climate Center

3 GAS PRODUCTION

In November 2025, global gas production growth was estimated at 1.1% y-o-y, to stand at 360 bcm (Figure 43). All gas producing regions, except Eurasia and Europe, witnessed positive production variation, with North America, specifically the US, leading the growth. Conversely, Eurasia recorded the largest output reduction in November, with about 3% y-o-y decline.

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 21% (dominated by Russia), the Middle East with 18%, and Asia Pacific with 16%, whilst Africa, Europe, Latin America and the Caribbean (LAC) held shares ranging from 3% to 6% (Figure 44).

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



Source: GECF Secretariat estimation

For the period Jan-Nov 2025, global gas production was estimated to have risen by 1.6% y-o-y to 3,858 bcm (Figure 45). This rise was mainly driven by the strong production growth in North America and the Middle East, offsetting the decrease in the output levels of Eurasia and Europe.

Figure 44: Global gas production by region in November 2025

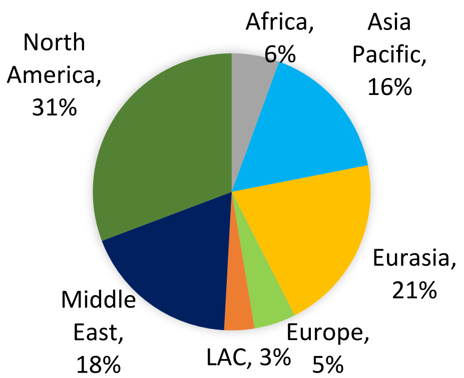
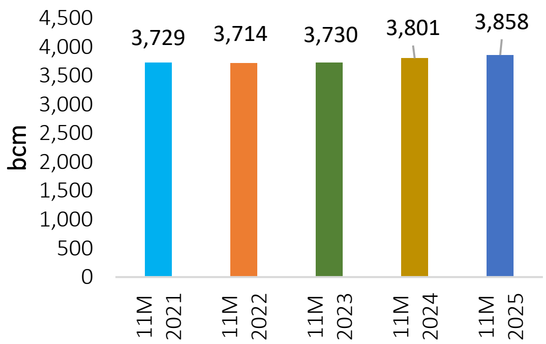


Figure 45: YTD global gas production



Source: GECF Secretariat estimation

3.1 Europe

In November 2025, gas production in Europe recorded a 1.3% y-o-y reduction, with a total output of 16 bcm (Figure 46). Out of the last 11 months, European output has decreased year-on-year in 10 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 a marginal rise in the Norway's gas production (Figure 47). Notably, monthly gas production in the EU reached 2.3 bcm, with the Netherlands and Romania maintaining their positions as top producers.

Figure 46: Europe's monthly gas production

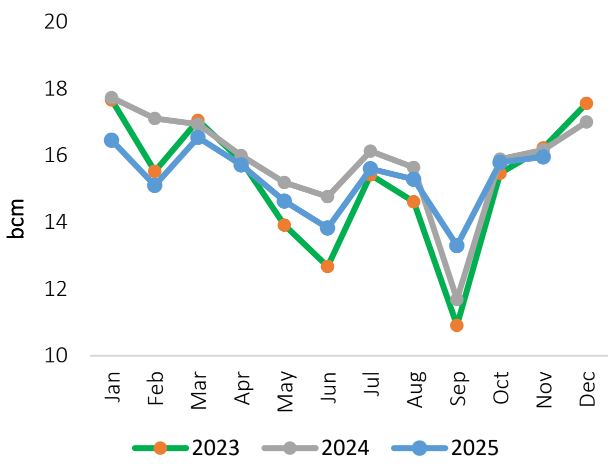
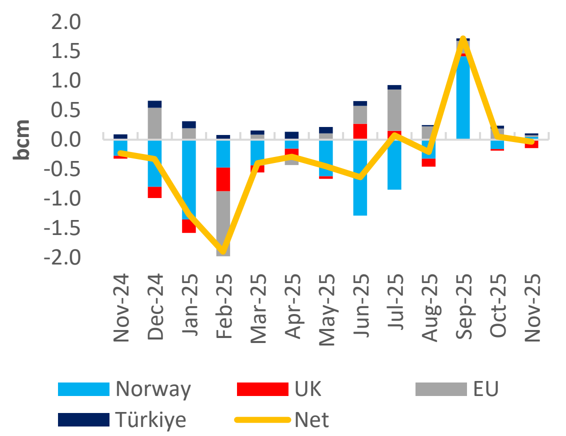


Figure 47: Y-o-y variation in Europe's gas production



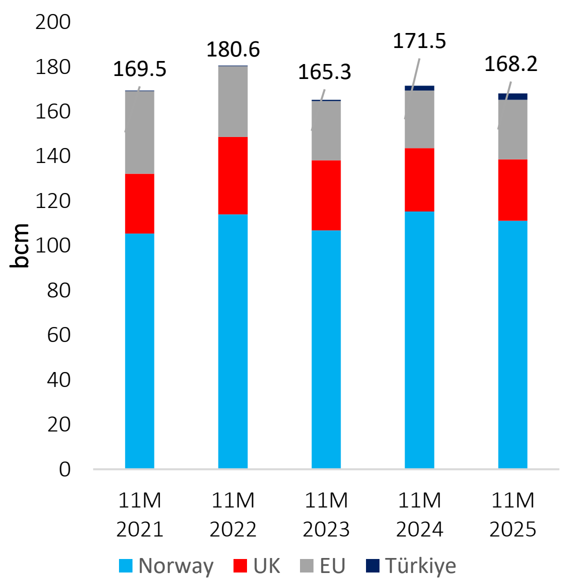
Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

For the period Jan-Nov 2025, the aggregated gas output in Europe amounted to 168.2 bcm (Figure 48), representing a 2% decline compared with the production level during the same period in 2024, and 2.9 bcm higher than the lowest output in the last 5-year period which was recorded in 2023.

This result indicates a negative production projection in Europe for the full year of 2025. Norway - the largest European gas producer with nearly 68% of cumulative European production - was the main driver for the European gas production reduction over this period, with the UK and the Netherlands also showing considerable declines.

Denmark is anticipated to have a positive production trend in 2025, driven by the ramp-up of Tyra gas field, with Romania and Türkiye recording positive projections as well.

Figure 48: YTD Europe's gas production



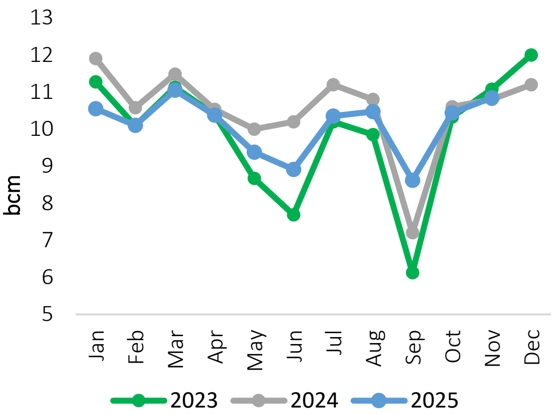
Source: GECF Secretariat based on data from Refinitiv, the Norwegian Offshore Directorate and JODI Gas

3.1.1 Norway

Norway's gas output witnessed a marginal rise of 0.4% y-o-y, to stand at the level of 10.8 bcm (Figure 49) in November. This was mainly driven by lower-than-expected maintenance duration. Notably, the 124 mcm/d Troll field witnessed reduced production for 2 days. In addition, the 28.3 mcm/d Oseberg gas field underwent planned outage, which nearly ceased its production for a period of 3 days.

For the period Jan-Nov 2025, cumulative production in Norway amounted to 111.1 bcm, representing a 3.6% y-o-y decline.

Figure 49: Trend in gas production in Norway



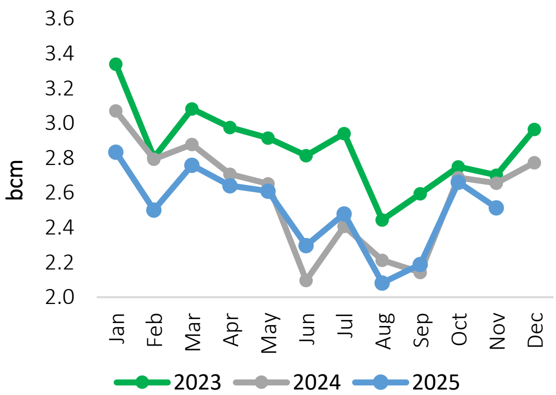
Source: GECF Secretariat based on data from the Norwegian Offshore Directorate

3.1.2 UK

UK gas production maintained its declining trend to stand at 2.5 bcm in November, representing a 5.3% y-o-y decrease (Figure 50). This was driven by reduced output from mature fields, lack of new gas projects and longer-than-expected maintenance periods.

For the period Jan–Nov 2025, cumulative production reached 27.6 bcm, representing a 2.6% y-o-y decline. Multiple planned maintenance activities took place at the 24 mcm/d Vesterled terminal that reduced its output by 19 mcm/d for a period of 3 days.

Figure 50: Trend in gas production in the UK



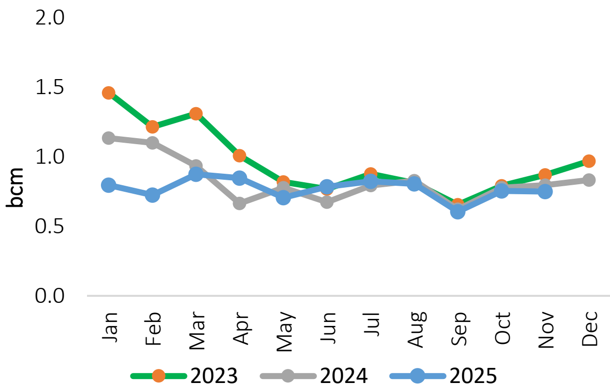
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' gas production maintained a decreasing trend, with a 2.9% y-o-y decline, to stand at 0.75 bcm (Figure 51). This represented a continuation in output declines observed for Dutch production, reflecting a continued negative outlook.

For the period Jan-Nov 2025, cumulative production reached 9.1 bcm, representing a 7% y-o-y decline. This production drop from the ageing Dutch fields is likely to continue in the coming years.

Figure 51: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In November 2025, gas output in Asia Pacific was estimated to stand at 58.6 bcm representing a 0.3% y-o-y growth. This increase was driven by growth in Chinese gas production, which counterbalanced the declining output in some main Asian producers. For the period Jan-Nov 2025, the cumulative production reached 642.8 bcm, representing a 0.2% growth.

3.2.1 China

In November 2025, China's gas production maintained its growth trend to stand at 21.9 bcm, representing a 5.9% y-o-y uptick (Figure 52). Coal bed methane production sustained its annual growth, with 15% y-o-y rise, to stand at 1.5 bcm. For the period Jan-Nov 2025, cumulative production in China reached 238.7 bcm, representing a 6% y-o-y rise (Figure 53). 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 field to reach this milestone, despite the complex geological conditions.

Figure 52: Trend in gas production in China

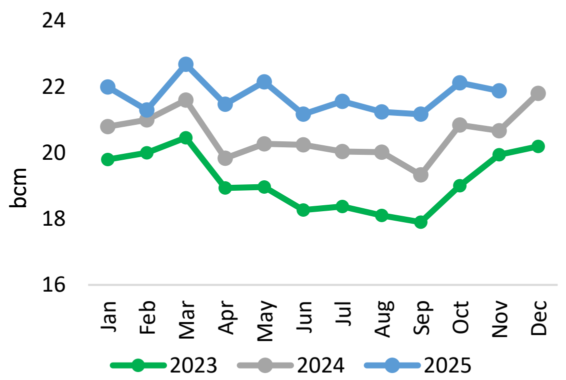
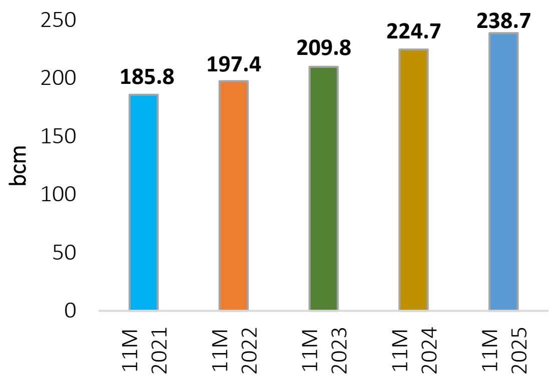


Figure 53: YTD China's gas production



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

3.2.2 India

In November 2025, India's gas production continued its negative trend, decreasing by 2.5% y-o-y to stand at 2.86 bcm (Figure 54). The decline was driven by a reduction in offshore gas output, which represented 72% of Indian production, along with the decreased output from the onshore Gujarat field. Meanwhile, the CBM gas fields witnessed a 10% y-o-y rise, mainly from the West Bengal fields. For the period Jan-Nov 2025, the cumulative production in India reached 31.8 bcm, representing 3.4% y-o-y decline (Figure 55).

Figure 54: Trend in gas production in India

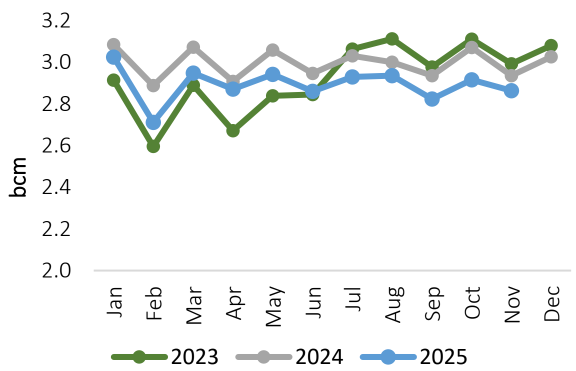
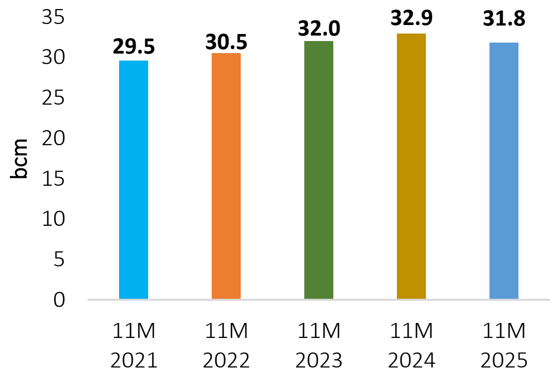


Figure 55: YTD India's gas production



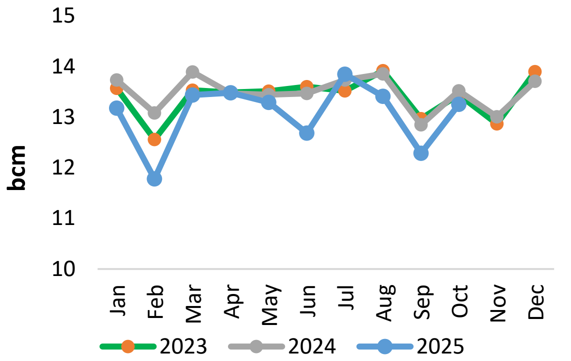
Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In October 2025, Australia's gas production decreased by 2% y-o-y to stand at 13.3 bcm (Figure 56). Gas production from CBM fields amounted to 3.5 bcm, representing a 0.2% y-o-y reduction and accounting for 27% of the total domestic production. Notably, Australia maintained the position of the leading CBM producer globally, with consistent growth in the past years, and CBM being used as feedstock for LNG export terminals.

For the period Jan-Oct 2025, the cumulative production in Australia reached 130.7 bcm, representing a 3.3% reduction.

Figure 56: Trend in gas production in Australia



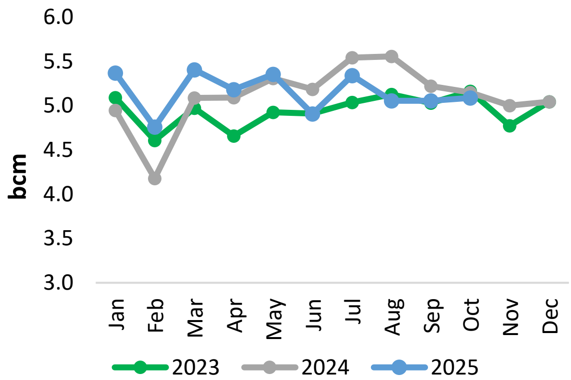
Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In October 2025, Indonesia's gas output recorded a 1.2% y-o-y decline to stand at 5.1 bcm (Figure 57). Although 101 new development wells have been drilled during the month, their incremental production was not able to counterbalance the natural decline in the producing fields.

For the period Jan-Oct 2025, cumulative production reached 51.5 bcm, representing a 0.5% y-o-y rise. This was driven by the startup of multiple gas projects, with 787 new development wells drilled in 2025 thus far, in addition to 25 new exploration wells.

Figure 57: Trend in gas production in Indonesia



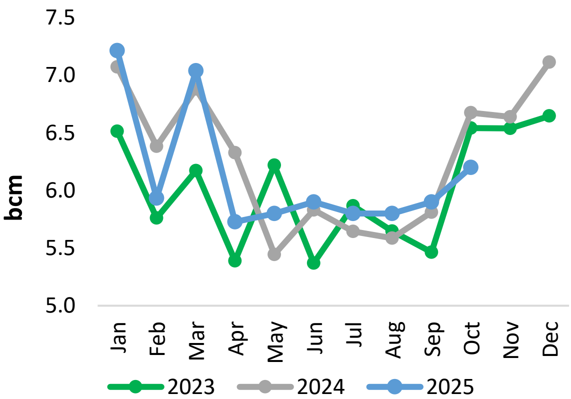
Source: GECF Secretariat based on data from Indonesia's upstream regulator (SKK Migas) and JODI Gas

3.2.5 Malaysia

In October 2025, Malaysia's gas output was estimated at 6.2 bcm, representing a production decline of 7% y-o-y (Figure 58). 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-Oct 2025, cumulative production in Malaysia reached 61.3 bcm, representing a 0.6% reduction y-o-y.

Figure 58: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

In November 2025, gas production in North America (including Mexico) rose by 6% y-o-y to reach 111.6 bcm, driven by strong gas supply growth in the US and Canada. For the period Jan-Nov 2025, cumulative production in the region reached 1,219 bcm, representing a 3.5% y-o-y growth.

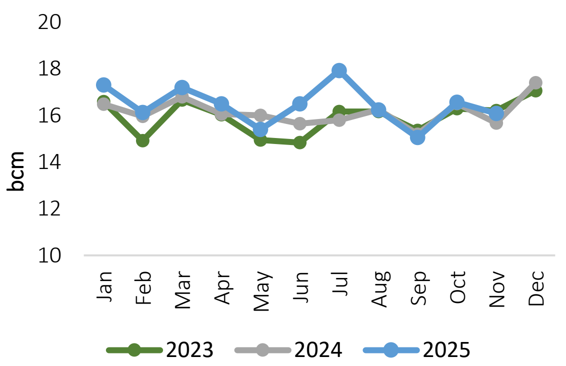
3.3.1 Canada

In November 2025, Canada's gas production witnessed a growth of 2.6% y-o-y, to stand at 16.1 bcm (Figure 59), mainly driven by the increase in the output of shale gas in Alberta and tight gas in British Columbia (BC), with a push from LNG export startup. From a regional perspective, Alberta was responsible for 10.2 bcm of the production, mainly originating from the Bakken shale production, while BC accounted for 5.5 bcm, with tight gas production from the Montney basin being the main contributor.

For the period Jan-Nov 2025, the cumulative production in Canada amounted to 180.9 bcm, representing a 2.6% y-o-y growth. In this context, Canada is well poised to continue the strong production growth, driven by the start of LNG exports.

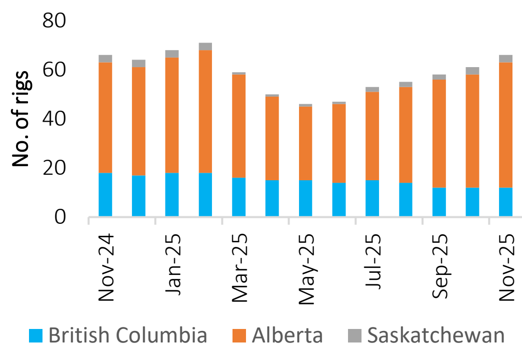
In terms of gas drilling activity, there was a 5-rig-increase in November 2025, specifically in Alberta, which added 5 more drilling rigs, while BC and Saskatchewan kept the same levels. Overall, this mirrored the same level of drilling rigs, as compared to November 2024 (Figure 60).

Figure 59: Trend in gas production in Canada



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

Figure 60: Gas rig count in Canada



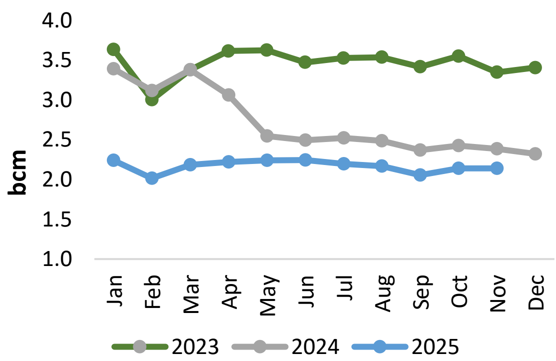
Source: GECF Secretariat based on data from LSEG

3.3.2 Mexico

In November 2025, Mexico's gas output was estimated at 2.15 bcm, representing a production decline of 12% y-o-y (Figure 61).

For the period Jan-Nov 2025, cumulative production reached 23.9 bcm, representing a considerable decline rate of 21% y-o-y. This was driven by the absence of new major gas field startups in 2025.

Figure 61:Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In December 2025, US total gas production maintained its growth trend for the year 2025, with a record monthly output of 95.9 bcm (3.7 % y-o-y surge) and a record daily average production of 109.5 bcf/d (Figure 62). This sustained growth reflected the combined effects of the favourable market dynamics, driven by the increased Henry Hub gas prices, rising gas demand, along with growing LNG exports.

In terms of supply distribution, shale dry gas production maintained its position as the frontrunner, with 82% share, and it was the main driver for the growth, with 4.3% rise, while conventional gas and associated gas production from shale oil, represented the remaining 18%. In terms of field type, associated gas production represented 25% of the aggregated gas output. From a regional perspective, the Appalachian region accounted for 30% of total gas production, followed by the Permian region output with 24%, and Haynesville with 13%.

In 2025, US cumulative gas production rose by 4.1% y-o-y to 1,107 bcm, being 43 bcm higher than its 2024 level and achieving a record high output (Figure 63).

Figure 62: Trend in gas production in the US

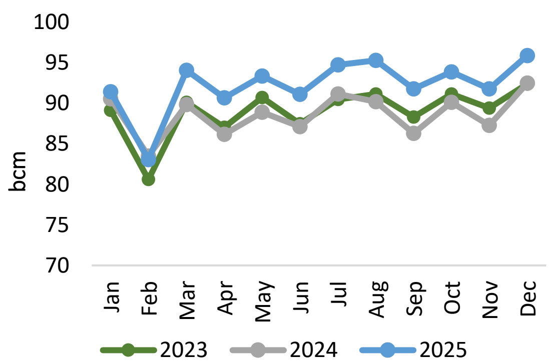
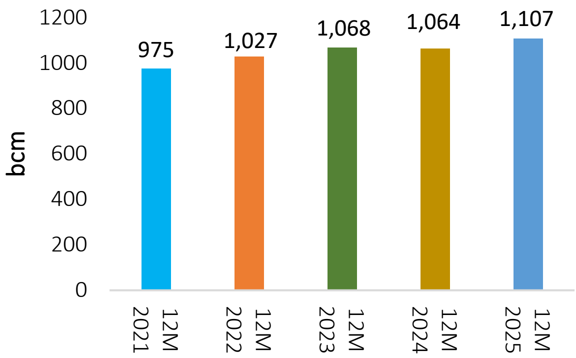


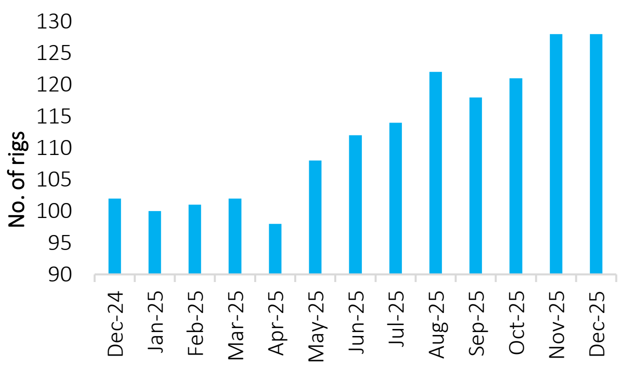
Figure 63: YTD gas production in the US



Source: GECF Secretariat based on data from the US EIA

As of December 2025, the number of gas drilling rigs operating in the US stood at 128, mirroring the same level of November 2025 (Figure 64). Additionally, in December 2025, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 5,020, marking a 29-well m-o-m decline and 778 wells lower than December 2024 (Figure 65). This m-o-m decrease in DUCs reflected the favourable gas markets dynamics in terms of gas prices, which encouraged producers to increase their wells being brought into production.

Figure 64: Gas rig count in the US



Source: GECF Secretariat based on data from Baker Hughes

Figure 65: DUC wells count in the US

Source: GECF Secretariat based on data from the US EIA

3.4 Latin America and the Caribbean (LAC)

In November 2025, gas production in LAC was estimated at 12.6 bcm (0.7% y-o-y rise), mainly driven by increased Brazilian gas output. For the period Jan-Nov 2025, cumulative production reached 143.3 bcm, representing 0.6% y-o-y growth.

3.4.1 Argentina

In November 2025, Argentina's gas production stood at 3.67 bcm, representing a 3.8% y-o-y reduction, the lowest in 2025 thus far (Figure 66). 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 1% y-o-y rise to stand at 1.9 bcm, accounting for 51% of the total gas production (Figure 67). Moreover, tight gas production reached 0.35 bcm, to represent a 9.5% share of the total production, whilst the remaining output was produced from conventional fields. For the period Jan–Nov 2025, cumulative production in Argentina reached 47.4 bcm, a 1.1% y-o-y growth.

Figure 66: Trend in gas production in Argentina

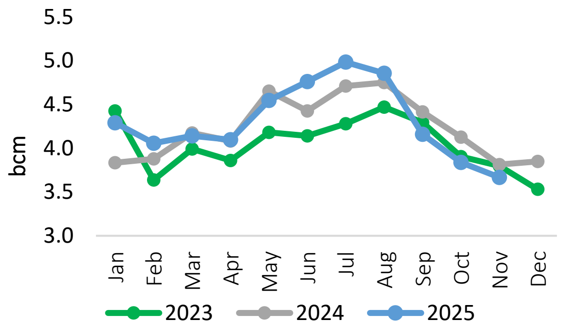
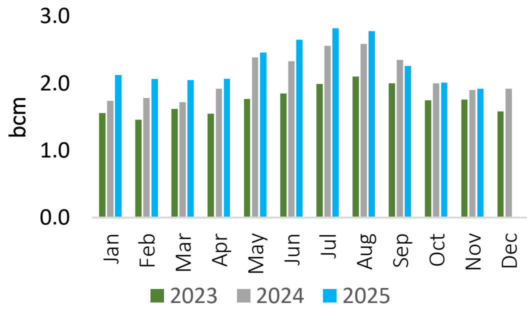


Figure 67: Shale gas output in Argentina



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

3.4.2 Brazil

In November 2025, Brazil's marketed gas production continued its strong growth for the ninth consecutive month, to stand at 1.86 bcm (22% y-o-y) (Figure 68), driven by high monthly gross gas production that stood at 5.5 bcm (16 % y-o-y rise), with the pre-salt fields representing 79% of the total production. Notably, 86% of production originated from offshore fields. In terms of distribution, 54% of gross gas production was reinjected into reservoirs, while gas flaring increased by 5% m-o-m, however, it decreased by 8% y-o-y (Figure 69). For the period Jan-Nov 2025, cumulative output in Brazil reached 19.5 bcm, a 17.4% y-o-y growth.

Figure 68: Marketed gas production in Brazil

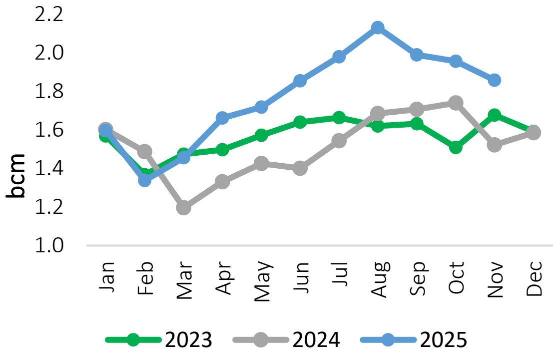
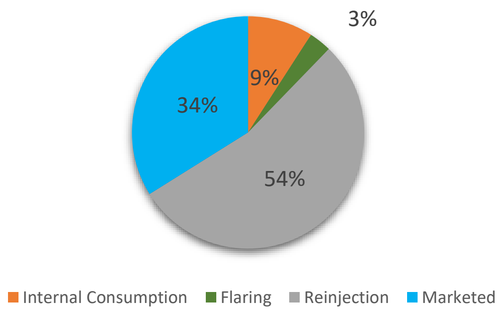


Figure 69: Distribution of gross gas production



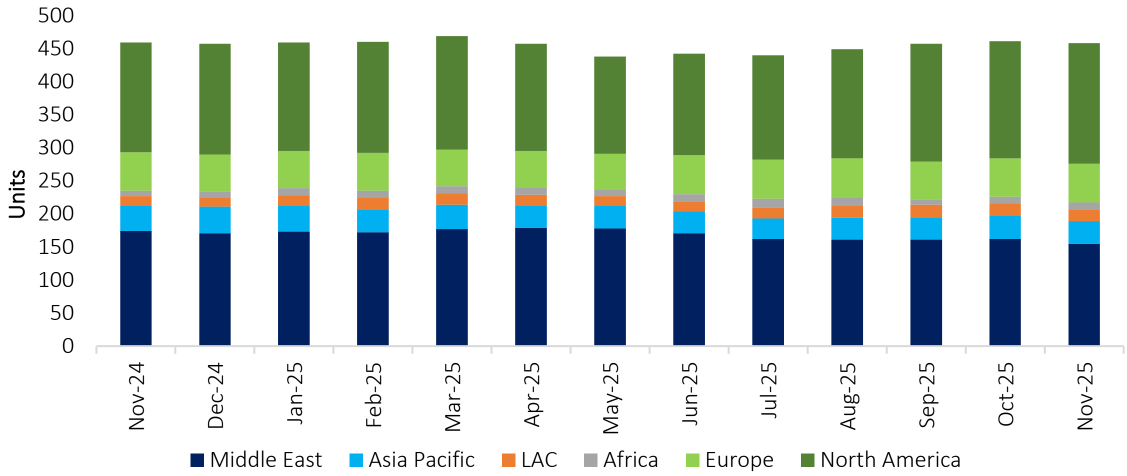
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In November 2025, the number of gas drilling rigs globally ramped-up by 2 additional units, reaching 460 rigs (Figure 70). This was driven mainly by the accelerated drilling activity in North America (Canada and the US), along with Asia Pacific, specifically in China. Onshore drilling accounted for the majority, with 429 units, while offshore accounted for 31 rigs.

Figure 70: Trend in monthly global gas rig count



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

In November 2025, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 75 million barrels of oil equivalent (boe), the lowest output in 2025 thus far (Figure 71). New discoveries were equally split by natural gas, which culminated 7 bcm, and liquid oil, which accounted for 38 million bbl. Five new discoveries were announced, two of which were offshore. In terms of regional distribution, Africa dominated the new discovered volumes with 93% (primarily in Egypt and Libya), followed by Europe (Norway) with 7% (Figure 72). Jumana and BED15-31 natural gas and condensate discovery in the Western Desert in Egypt were the largest discoveries announced in November. Cumulative discovered volumes for the period Jan-Nov 2025 reached 4.5 billion boe, with gas accounting for 48% (370 bcm).

Figure 71: Monthly discovered oil and gas volumes

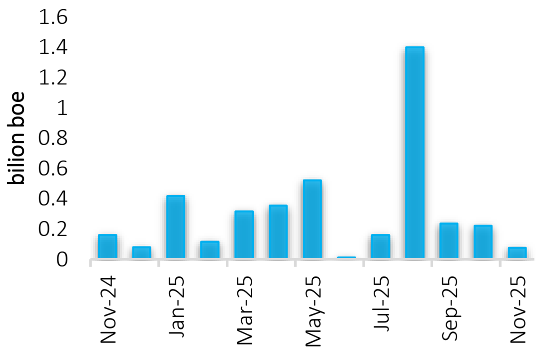
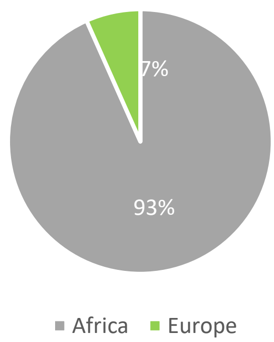


Figure 72: Discovered oil and gas volumes in November 2025 by region



Source: GECF Secretariat based on data from Rystad

3.5.2 Regional developments

ADNOC announced final investment decision for the SARB deep gas development: ADNOC announced the FID for the SARB Deep Gas Development, a strategic project within the Ghasha Concession located offshore of Abu Dhabi. The development will deliver 200 million standard cubic feet per day of gas before the end of the decade, enough energy to power more than 300,000 homes daily. This technically advanced project will embed advanced technologies and artificial intelligence (AI) and will be operated remotely from Arzanah Island, leveraging existing infrastructure to maximize efficiency and enhance safety. Located 120 km offshore from Abu Dhabi, the project comprises a new offshore platform with four gas production wells which connect to Das Island, where gas will be tied into ADNOC Gas facilities for upstream treatment, maximizing the integration with other ADNOC projects.

NewMed approved the FEED for the development of the Aphrodite gas field: NewMed Energy and its partners, Chevron and Shell, have approved the execution of Front-End Engineering Design (FEED) for the Aphrodite Gas Field. The FEED phase, with a total investment of approximately $106 million, represents a critical milestone on the path toward a Final Investment Decision (FID), expected in 2027. Under the approved development plan, the partners will construct a floating production facility above the reservoir, with natural gas exported via a subsea pipeline connected to Egypt's gas transmission system.

Indonesia launched new oil and gas block tenders: Indonesia has opened a new round of oil and gas block tenders, offering eight exploration areas to contractors as part of its strategy to reverse declining hydrocarbon production and strengthen long-term energy security. The move reflects the government's commitment to replenishing reserves after years of output decline caused by maturing fields. According to the Energy and Mineral Resources Ministry, bid submissions for the Tapah, Nawasena, and Mabelo blocks are open until 5 February 2026. The onshore Tapah block, located in South Sumatra and Jambi, holds an estimated 439 million barrels of oil and 23 bcf of gas. The Nawasena block, spanning both onshore and offshore areas of East Java, is estimated to contain 1.313 billion barrels of oil resources. In addition to these, the ministry is offering Arwana III, Tuah Tanah, Rangkas, Akimeugah I, and Akimeugah II blocks.

Nigeria announced new licensing round: The Nigerian Upstream Petroleum Regulatory Commission officially launched its largest traditional licensing round to date, activating a dedicated bid submission portal for the 50 blocks on offer. This massive round more than doubles the 24 blocks presented during the 2024 mini-auction and operates under the modernized fiscal incentives of the Petroleum Industry Act (PIA). The 2025 portfolio is strategically diversified: half of the onshore blocks are located in frontier or historically underexplored basins to encourage new discoveries, while the offshore selection focuses heavily on shallow-water assets, complemented by a single high-potential deepwater block.

4 GAS TRADE

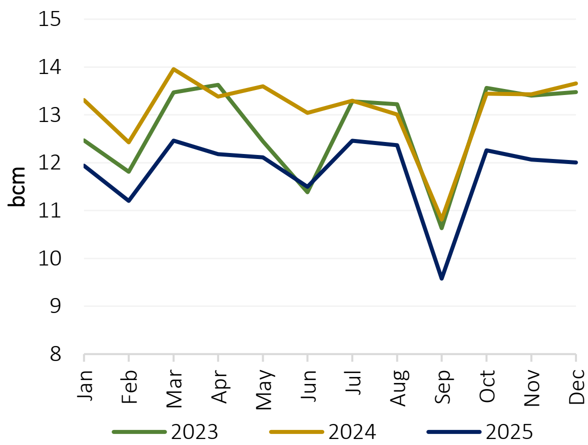
4.1 PNG trade

Global PNG imports (disregarding transit flows and re-exports) were estimated to decrease by 4% y-o-y in December 2025, with aggregated PNG imports over the entire 2025 estimated to increase by 1% y-o-y. In 2025, China, Kazakhstan and Mexico recorded the largest y-o-y increases out of all PNG importing countries. In addition, PNG exports originating from the Eurasian and African regions in 2025 were estimated to increase compared to one year prior.

4.1.1 Europe

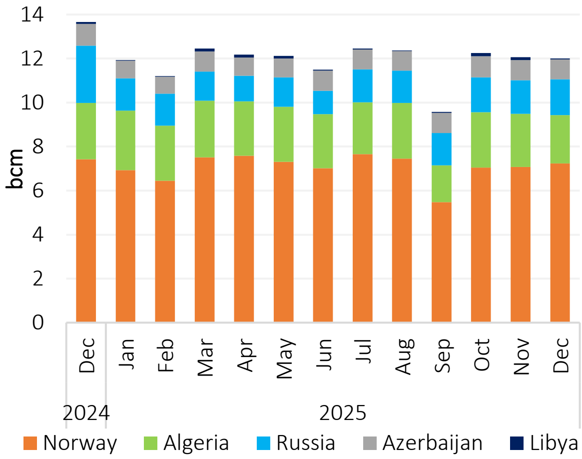
In December 2025, EU countries imported an aggregate of 12.0 bcm of PNG, which was largely reflective of the average monthly PNG import level over the year. This volume was just 0.5% lower m-o-m, but was still 12% less than the volume imported one year ago (Figure 73). There were m-o-m increases in imports from Norway (2%), and particularly from Russia (7%) as countries in South Central Europe ramped up gas demand for winter heating (Figure 74).

Figure 73: Monthly PNG imports to the EU



Source: GECF Secretariat based on data from LSEG

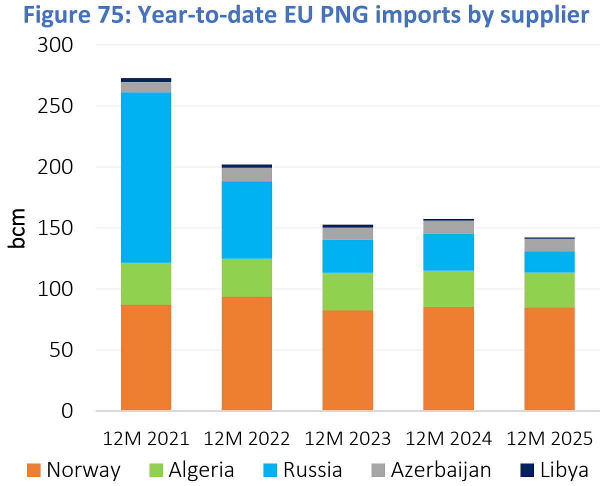
Figure 74: Monthly EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

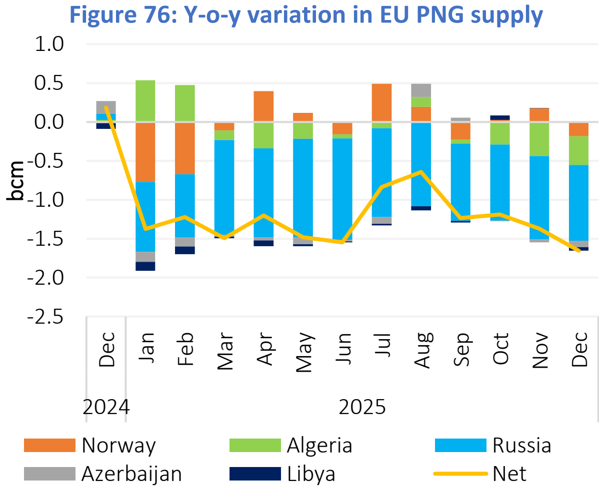
Moreover, the EU's cumulative PNG imports over the course of 2025 decreased by 10% compared to the total of the previous year (Figure 75). During this time, Norway accounted for three-fifths of the regional PNG supply, while Algeria contributed 20%. In December 2025, there were y-o-y decreases in PNG imports from all five EU suppliers (Figure 76).

Figure 75: Year-to-date EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

Figure 76: Y-o-y variation in EU PNG supply

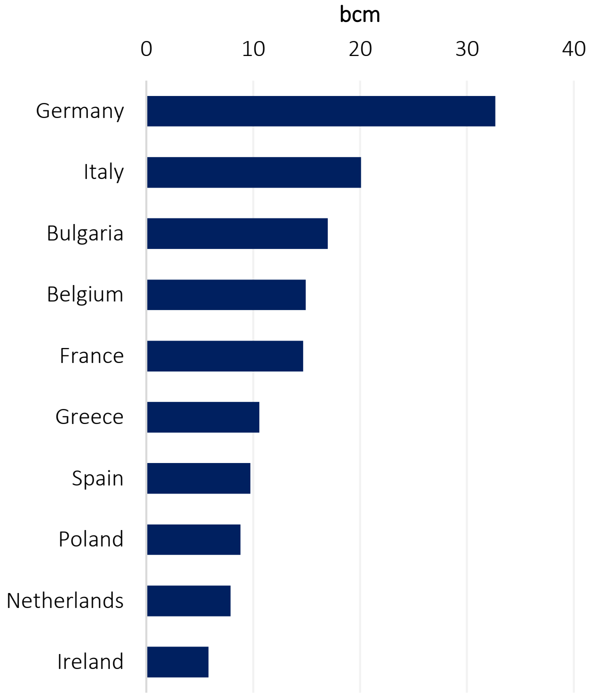


Source: GECF Secretariat based on data from LSEG

Figure 77 shows the EU's aggregated PNG imports by entry country, for the period January to December 2025. Germany is the largest PNG entry point into the EU, with 23% of the regional inflows in 2025 entering via this market. The Polish entry point registered the largest y-o-y increase at 23%, followed by Bulgaria at 8% y-o-y. Belgium has overtaken France as the fourth largest PNG entry point, with each accounting for 10% of the EU's PNG imports in 2025.

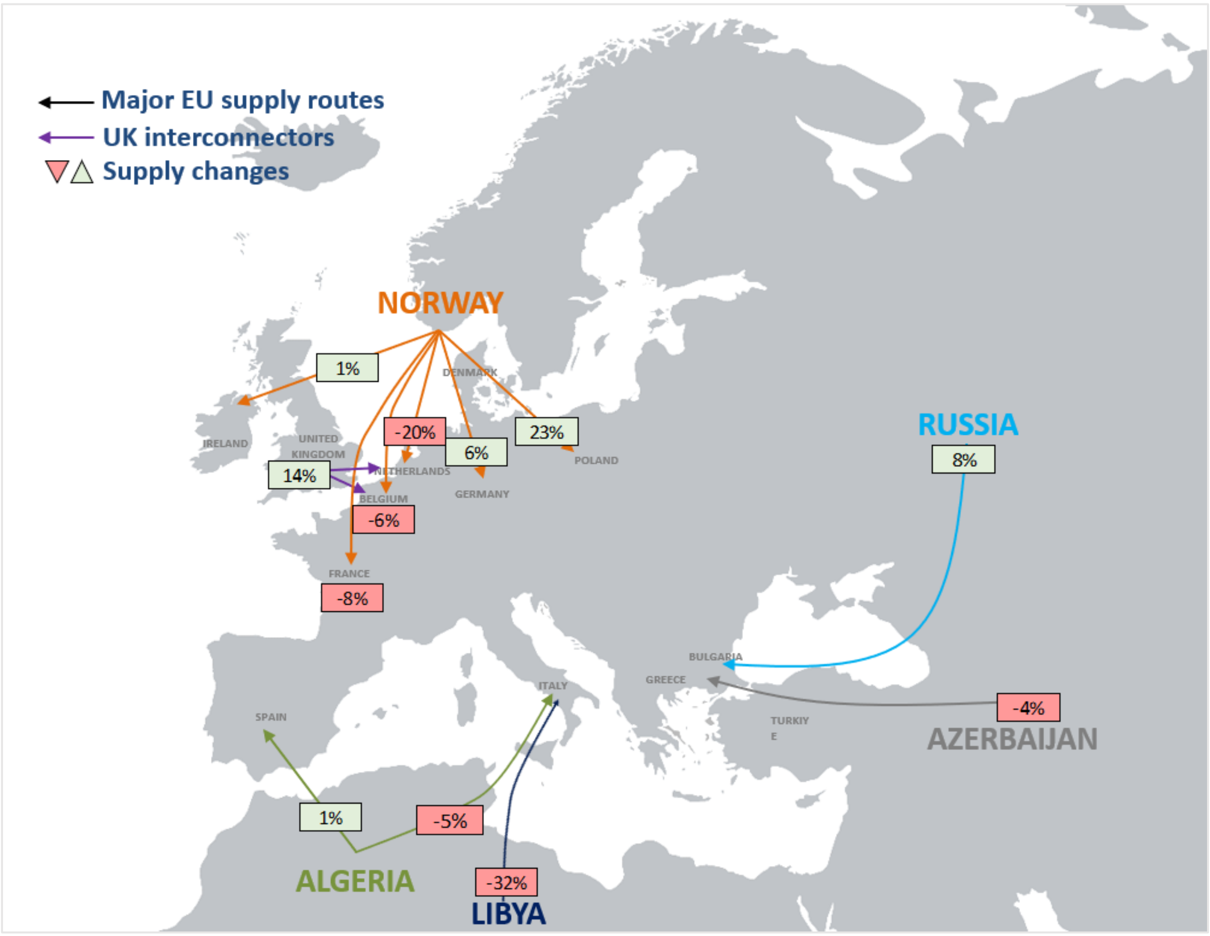
Figure 78 shows the PNG imports to the EU via the major supply routes during 12M 2025, compared with 12M 2024. Russian supply via the Turkstream pipeline increased by 8% y-o-y, while Algerian supply to Spain increased by 1% y-o-y. There were 6.9 bcm of net gas flows from the UK to mainland Europe in 2025, representing an increase of 14% compared to the same period one year ago.

Figure 77: EU PNG imports by entry country, after 12M 2025



Source: GECF Secretariat based on data from LSEG

Figure 78: PNG imports to the EU by supply route (12M 2025 v 12M 2024)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

In November 2025, China imported 6.8 bcm of PNG, which represented a rebound of 25% m-o-m following the reduced energy demand which coincides with lower industrial activity each year over Golden Week (Figure 79). Moreover, this volume represented an increase of 8% compared to the previous year, which marked the nineteenth consecutive month of y-o-y increases in Chinese PNG imports. With total gas imports increasing m-o-m, the share of PNG in the import mix rose to 42%. After eleven months of 2025, cumulative Chinese PNG imports reached 74 bcm, which is an increase of 8% y-o-y, and accounts for 47% of the country's total gas import mix (Figure 80).

Figure 79: Monthly PNG imports in China

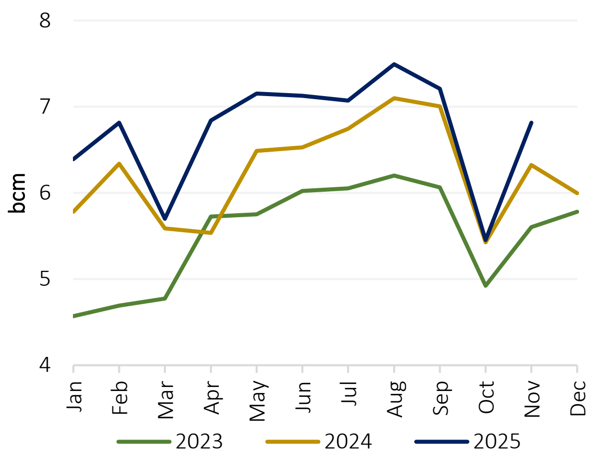
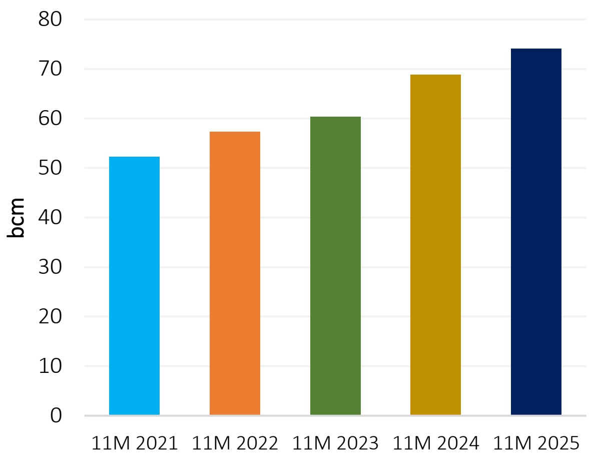


Figure 80: Year-to-date PNG imports in China



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

In October 2025, Singapore imported 0.54 bcm of PNG from Indonesia and Malaysia (Figure 81). This volume was unchanged y-o-y, but was 2% lower m-o-m. From January to October 2025, PNG imports reached 5.4 bcm, which was an increase of 9% y-o-y. In the same month, Thailand imported an estimated 0.37 bcm of PNG from Myanmar (Figure 82). This volume represented decreases of 12% y-o-y, as well as of 3% compared to the previous month. PNG imports after ten months of 2025 decreased by 15% y-o-y, to reach 3.7 bcm.

Figure 81: Monthly PNG imports in Singapore

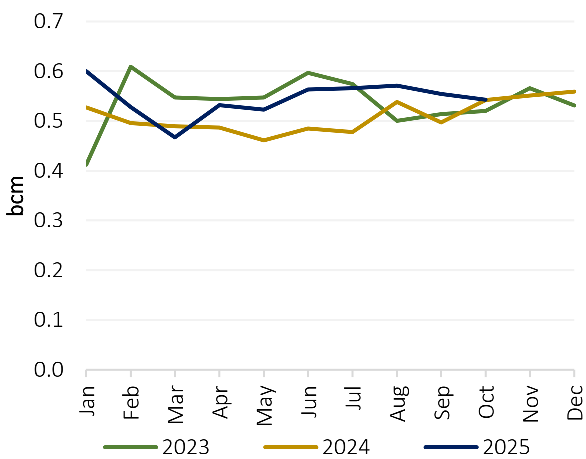
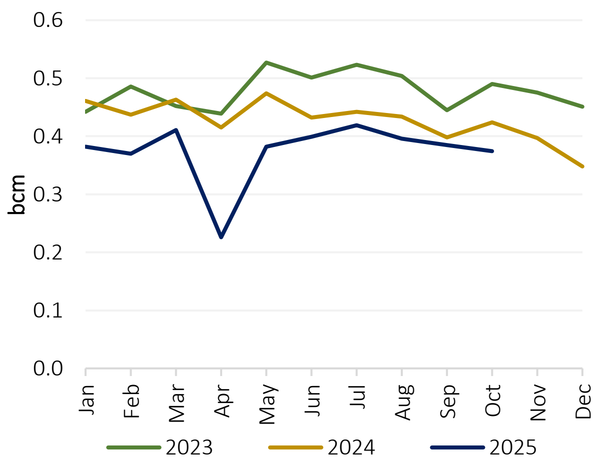


Figure 82: Monthly PNG imports in Thailand

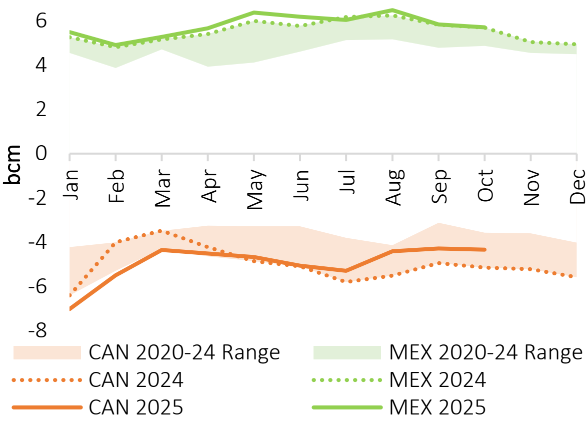


Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

In October 2025, Mexico imported 5.7 bcm of PNG from the US. This volume was the same as one year prior, but was 2% lower m-o-m (Figure 83). After ten months of 2025, Mexico's total PNG imports increased by 3% to reach 58 bcm. In the same month, there were 4.3 bcm of net PNG flows from Canada to the US, which was a decrease of 16% y-o-y, but which was the same level as the previous month. Flows from Canada to the US rose m-o-m to 6.6 bcm, and flows from the US to Canada increased m-o-m to 2.2 bcm. After ten months of 2025, net flows from Canada to the US were unchanged y-o-y.

Figure 83: Net US PNG exports (+) and imports (-)



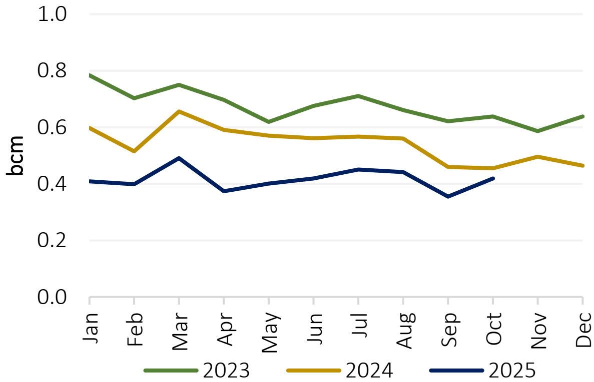
Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

In October 2025, Bolivia exported 0.42 bcm of PNG to Brazil, which represented an increase of 18% compared to the previous month (Figure 84). However, this volume was 8% lower compared to one year prior. After ten months of 2025, total Bolivian PNG exports decreased by 25% y-o-y, to reach 4.2 bcm.

During the same month, Chile imported an estimated 0.24 bcm from Argentina. This volume was an increase of 72% m-o-m, as well as an increase of 30% y-o-y.

Figure 84: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

Brazil secures new Argentine gas supply deal: Brazil's Petrobras has been authorised by the national hydrocarbon regulator ANP to import 180 mmcm/y of natural gas from Argentina for a period of two years. The gas will be delivered via the Gasbol pipeline to all Brazilian regions except the northern states. This authorisation formalises an earlier move by Petrobras, which began importing initial volumes in October under a one-year, 500,000 m³/d interruptible export contract approved by Argentina's energy secretary in September.

EU approves pipeline links for Mediterranean islands: The European Commission's 2026 Projects of Common Interest list has reaffirmed a strategic commitment to ending the energy isolation of the Mediterranean through the continued inclusion of two critical infrastructure projects: the Melita TransGas pipeline and the EastMed pipeline. These projects remain priority developments aimed at integrating Malta and Cyprus into the mainland European network, and both assets are classified as hydrogen-ready. The 159 km Melita pipeline will establish a high-pressure subsea connection between Malta and Sicily, while the 1,900 km EastMed project is expected to transport approximately 10 bcm of natural gas annually from the Levantine Basin to Greece and Italy.

4.2 LNG trade

4.2.1 LNG imports

In December 2025, global LNG imports reached a record 41.93 Mt, marking a 10% y-o-y increase (3.93 Mt) (Figure 85). This was the first time global imports surpassed the 40 Mt mark. Europe remained the primary driver of this growth, with Asia Pacific, the MENA region, and North America contributing to a lesser extent. In contrast, LNG imports in LAC declined (Figure 86). Europe also continued to serve as the most attractive market for US LNG exports, supported by higher netbacks compared to Asia.

Figure 85: Trend in global monthly LNG imports

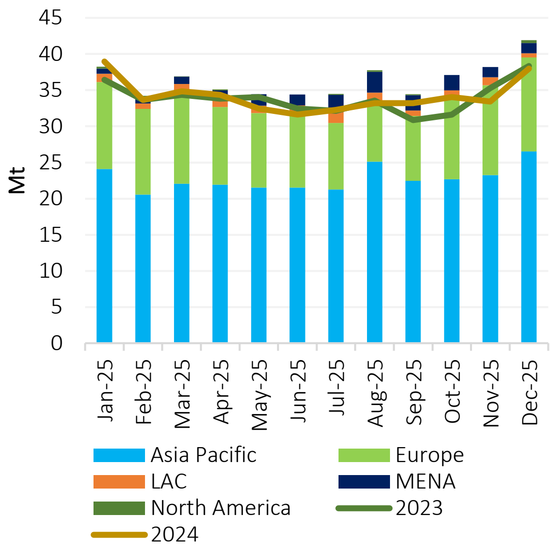
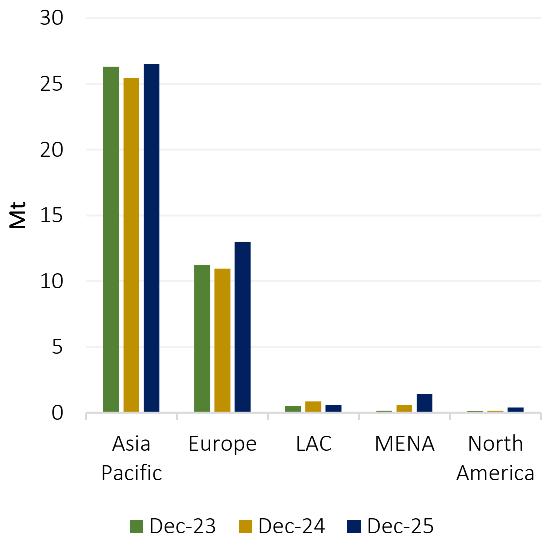


Figure 86: Trend in regional YTD LNG imports



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In December 2025, Europe's LNG imports rose sharply by 19% (2.04 Mt) y-o-y to 12.99 Mt, marking the second-highest monthly total ever, surpassed only by December 2022 (Figure 87). The increase was driven primarily by reduced pipeline gas inflows, while the narrow LNG price spread between Asia Pacific and Europe continued to make Europe the preferred destination for US cargoes. At the country level, Belgium, Germany, Greece, Italy, the Netherlands, Spain and Türkiye accounted for most of the growth, more than offsetting a decline in UK imports (Figure 88).

Belgium increased its LNG imports to re-export regasified volumes to neighbouring countries, which compensated for their reduced pipeline gas imports. Germany showed a similar pattern, with higher LNG imports driven by lower pipeline gas imports and additional re-export of regasified LNG to neighbouring countries. Greece's LNG imports reached a monthly record high, supported by expanded regasification capacity and the country's growing role as a gas hub in South-East Europe. In Italy and the Netherlands, a decline in pipeline gas imports, combined with falling domestic production, boosted LNG import requirements, while stronger gas consumption in the Netherlands provided further support. Poland's LNG imports also rose due to higher domestic gas consumption and increased regasified LNG exports to neighbouring markets. In Spain, LNG imports offset reduced pipeline gas imports and supported expanded gas exports to Morocco. Türkiye recorded a significant uptick in LNG imports, largely reflecting stronger domestic gas consumption. In contrast, the UK saw LNG imports fall, owing to higher pipeline gas imports and weaker gas demand.

Figure 87: Trend in Europe's monthly LNG imports

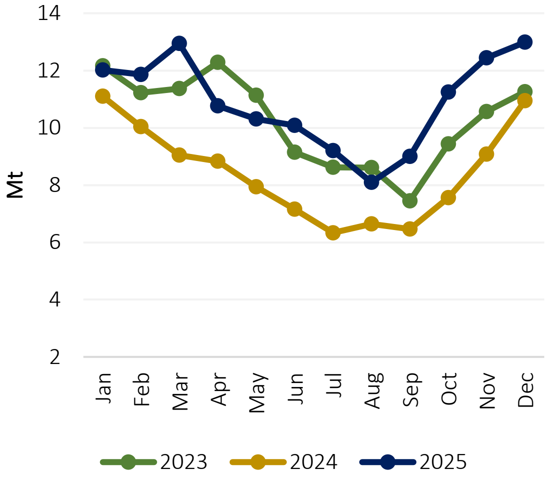
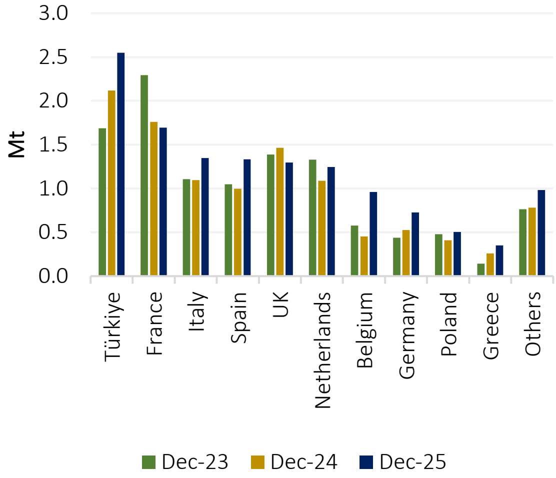


Figure 88: Top LNG importers in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia Pacific

In December 2025, Asia Pacific's LNG imports increased for the second consecutive month, rising by 4.3% (1.09 Mt) y-o-y to 26.54 Mt (Figure 89). The increase was driven by India, Indonesia, Malaysia and South Korea, which offset declines in Japan and Pakistan (Figure 90). China's LNG imports have stabilised and were relatively unchanged from December 2024.

India's LNG imports increased due to softer spot LNG prices, as the country's buyers remain highly price-sensitive. In Indonesia and Malaysia, stronger intra-country LNG movements supported higher imports, with Indonesia recently prioritising domestic gas demand. South Korea recorded a sharp rise in LNG imports, driven by several cargoes diverted away from China, a market currently well supplied, and expectations of a cold snap at the end of December. In contrast, Japan's LNG imports declined due to weaker gas demand in the power sector, driven by milder winter temperatures and higher nuclear availability. Pakistan also saw a steep drop in LNG imports, reflecting lower gas demand from both the electricity and industrial sectors.

Figure 89: Trend in Asia's monthly LNG imports

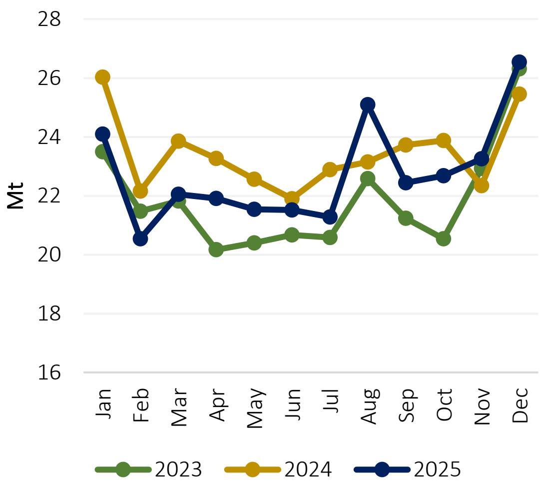
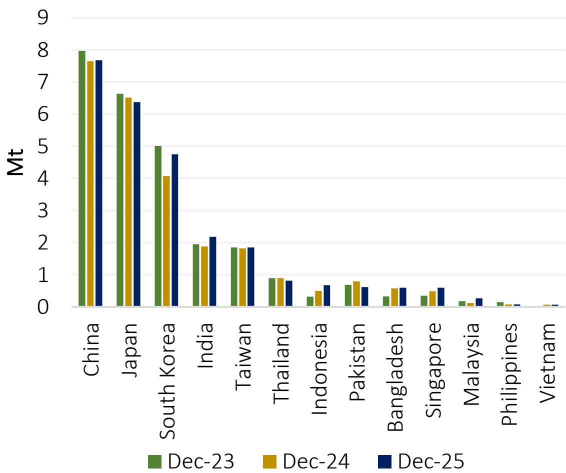


Figure 90: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In December 2025, LNG imports in the LAC region continued to slide, falling by 31% (0.26 Mt) y-o-y to 0.59 Mt, which is the lowest level since December 2023 (Figure 91). This decline was driven mainly by Jamaica as well as Colombia and the Dominican Republic (Figure 92).

The extensive damage caused by Hurricane Melissa to energy infrastructure in Jamaica and the Dominican Republic reduced gas demand for power generation, leading to lower LNG imports. In Colombia, the decline in LNG imports was likely driven by higher hydroelectric output, which reduced the need for gas-fired generation.

Figure 91: Trend in LAC's monthly LNG imports

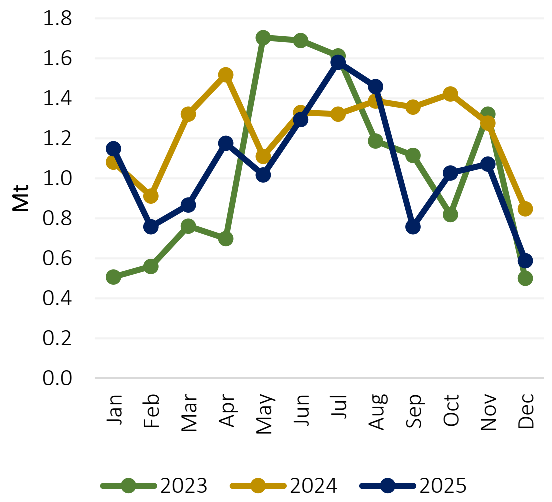
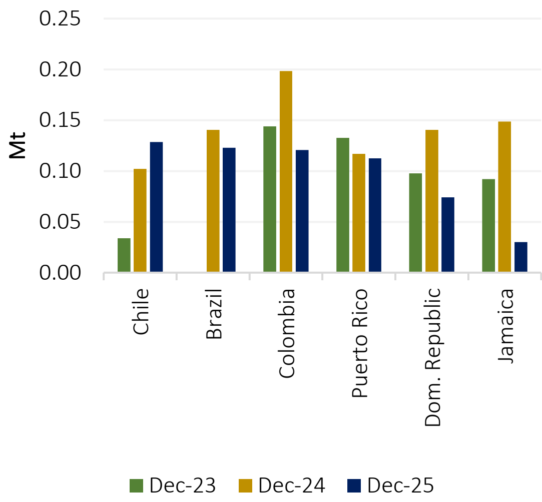


Figure 92: Top LNG importers in LAC



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 MENA

In December 2025, LNG imports in the MENA surged by 136% (0.81 Mt) y-o-y to 1.41 Mt, marking a record high for the month (Figure 93). The increase was driven primarily by Egypt, where LNG imports helped bridge the gap between domestic gas production and domestic gas demand (Figure 94).

Figure 93: Trend in MENA's monthly LNG imports

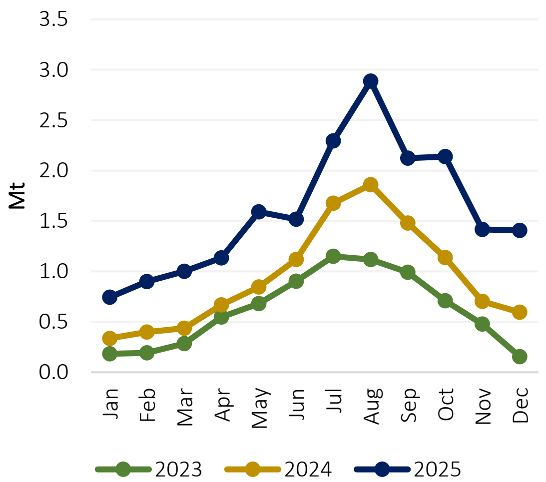
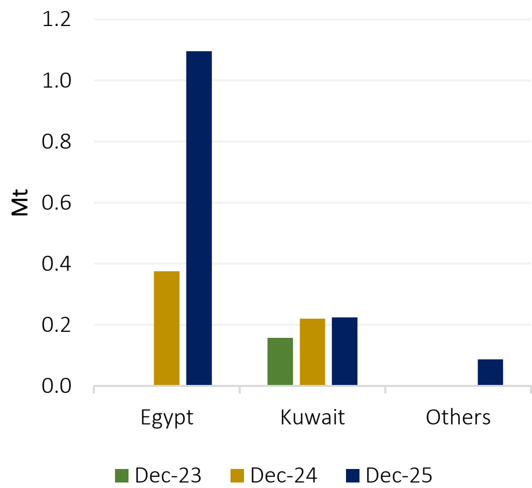


Figure 94: Top LNG importers in MENA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In December 2025, global LNG exports grew by 8.3% (3.11 Mt) y-o-y to reach a record 40.51 Mt—the first time monthly exports have exceeded the 40 Mt mark (Figure 95). Non-GECF countries led this expansion, offsetting a slight decline in exports from GECF Member Countries and a slowdown in LNG re-exports (Figure 96).

The share of LNG exports from non-GECF countries rose sharply from 52.6% in December 2024 to 57.4% in December 2025. Conversely, the shares of GECF Member Countries and LNG re-exports declined over the same period, falling from 45.9% to 42.2% and from 1.5% to 0.4%, respectively. The US, Australia and Qatar remained the top three LNG exporters.

Figure 95: Trend in global monthly LNG exports

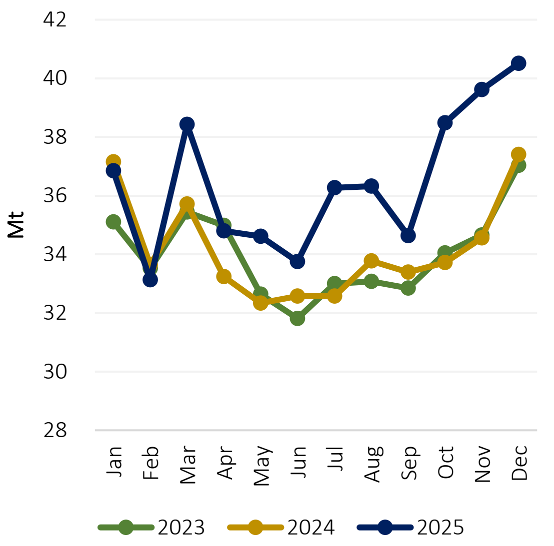
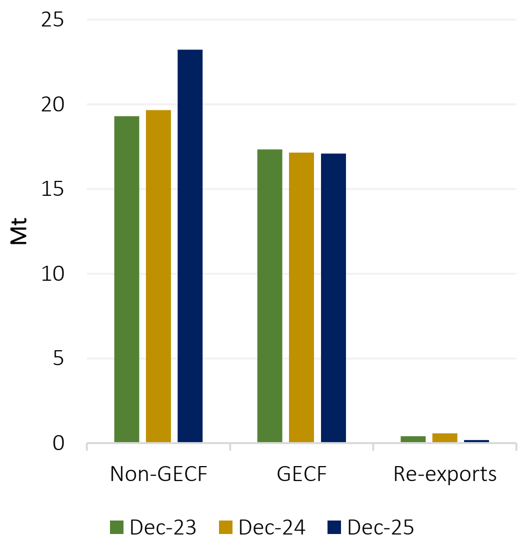


Figure 96: Trend in LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In December 2025, LNG exports from GECF Member and Observer Countries moved slightly lower by 0.3% (0.06 Mt) y-o-y to 17.1 Mt, which was the same level as the previous month (Figure 97). The slowdown in LNG exports came mainly from Algeria, Equatorial Guinea, Qatar, Russia and Trinidad and Tobago, which were partially offset by higher exports from Angola, Mauritania, Nigeria and Senegal (Figure 98).

The decline in LNG exports from Algeria, Equatorial Guinea and Trinidad and Tobago was driven by reduced feedgas availability. In Qatar, a slight drop in capacity utilisation at the Ras Laffan LNG facility—despite operating well above nameplate capacity for much of 2025—led to lower export volumes. Russia's slowdown stemmed from reduced output at the Portovaya, Sakhalin 2, Vysotsk and Yamal LNG plants.

In contrast, LNG exports from Angola and Nigeria increased due to improved feedgas availability, with Nigeria recording its highest monthly exports since January 2021. Additionally, the ongoing ramp-up of the GTA FLNG 1 project continued to support higher LNG exports from both Mauritania and Senegal. It is also worth mentioning that while Egypt has become a net LNG importer, it exported one LNG cargo in December.

Figure 97: Trend in GECF monthly LNG exports

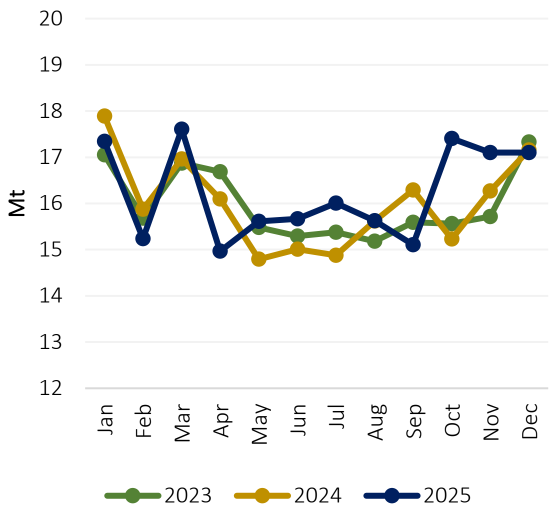
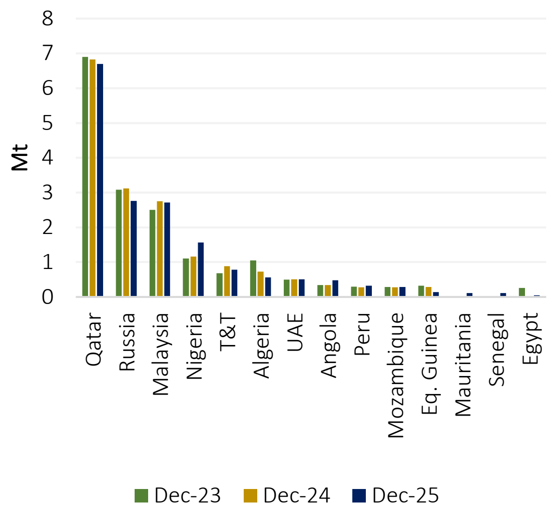


Figure 98: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In December 2025, LNG exports from non-GECF countries rose sharply by 18% (3.57 Mt) year-on-year, reaching a monthly high of 23.23 Mt (Figure 99). The US remained the primary driver of this increase, with Canada contributing to a lesser extent (Figure 100).

US LNG exports surpassed 11 Mt for the first time, setting a new monthly record. The ramp-up of production from Corpus Christi Stage 3 and Plaquemines LNG significantly boosted output, while reduced maintenance at Cameron LNG and higher exports from Calcasieu Pass further supported the increase. In Canada, ramp-up in production from the LNG Canada project lifted export volumes.

Australia's LNG exports were broadly stable, but stronger output from the Gorgon, Ichthys and Wheatstone facilities offset lower exports from the North West Shelf (NWS) LNG plant, where reduced feedgas availability and the shut-in of its second train constrained production.

Figure 99: Trend in non-GECF monthly LNG exports

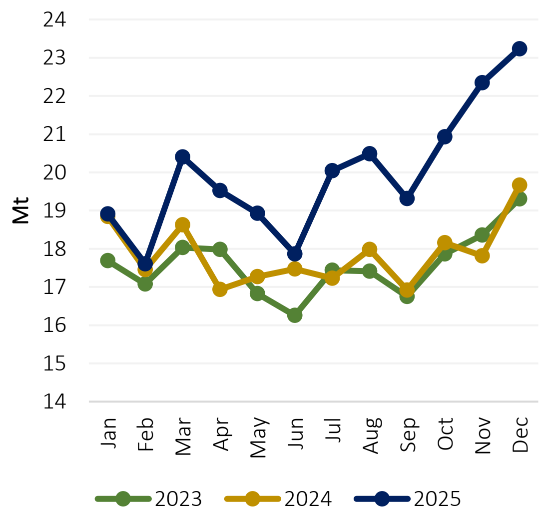
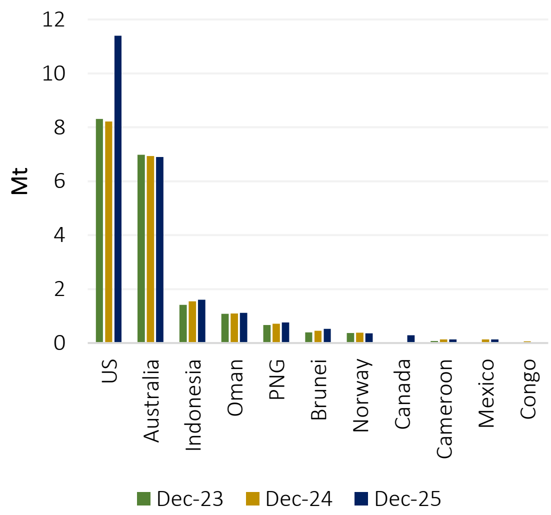


Figure 100: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG re-exports

In December 2025, global LNG re-exports fell sharply by 70% (0.40 Mt) y-o-y to 0.18 Mt (Figure 101), marking the lowest level for the month since 2019. The reduction in activity was driven primarily by Brazil, China, Indonesia and the United States Virgin Islands (USVI) (Figure 102).

Brazil had re-exported one cargo from the Sergipe import terminal to the Guanabara Bay terminal in December 2024, but no such activity occurred in December 2025. Meanwhile, a well-supplied LNG market in Asia reduced the need for re-exports from China and Indonesia. The decline in LNG re-exports from the USVI was linked to the recent start of regular LNG deliveries from the US to Puerto Rico, which had previously been the main destination for LNG re-exported from the USVI.

Figure 101: Trend in global monthly LNG re-exports

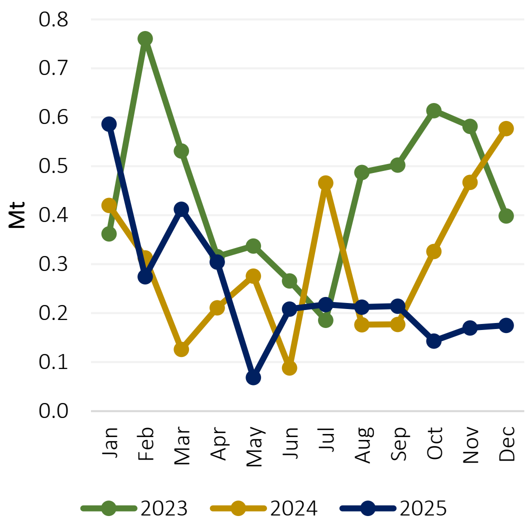
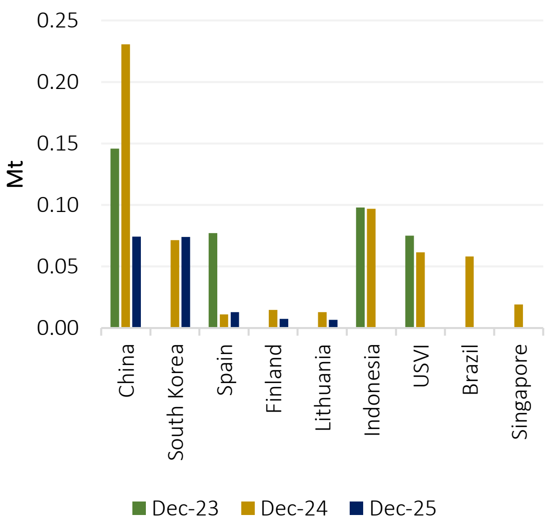


Figure 102: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

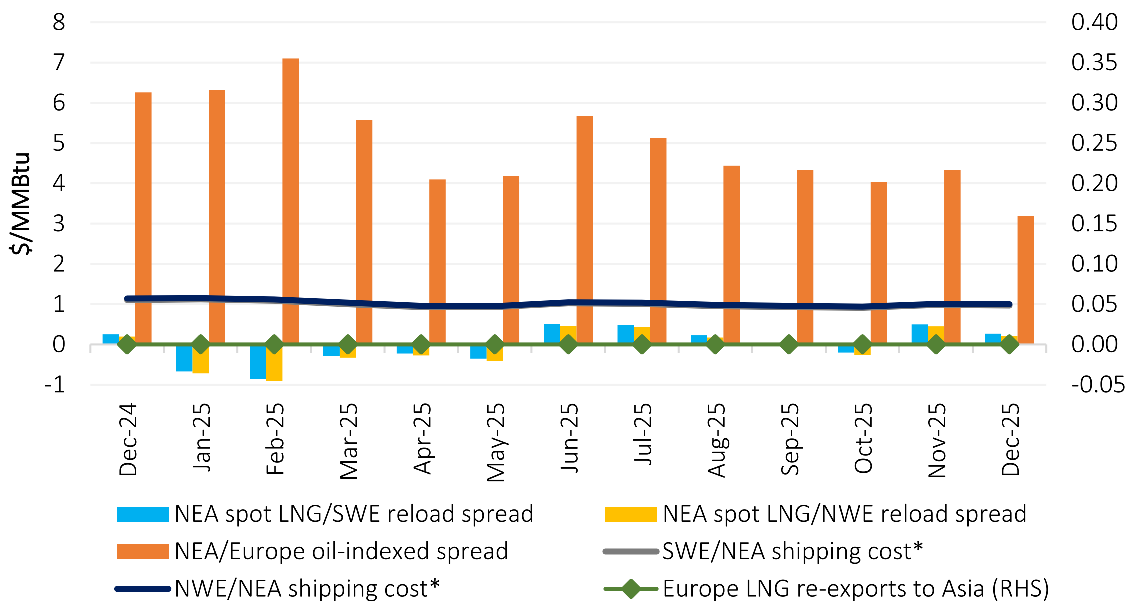
4.2.4 Arbitrage opportunity

In December 2025, arbitrage opportunities for LNG re-exports from Europe to Asia were absent, as the price spreads between Asian spot LNG and European LNG reload prices remained below the one-way spot shipping costs between the two markets (Figure 103). By contrast, Asian spot LNG continued to trade at a substantial premium over European oil-indexed LNG, staying well above one-way shipping costs.

The spread between North East Asia (NEA) spot LNG and Europe LNG reload prices narrowed m-o-m. The NEA/Southwestern Europe (SWE) spread fell from $0.50/MMBtu in November to $0.27/MMBtu in December, while the NEA/Northwestern Europe (NWE) spread declined from $0.45/MMBtu to $0.22/MMBtu. These reductions were driven by a steeper drop in Asian spot prices relative to European LNG reload prices. The NEA premium over European oil-indexed LNG also narrowed, sliding from $4.33/MMBtu to $3.19/MMBtu. Meanwhile, shipping costs from SWE and NWE to NEA remained relatively stable.

As a result, no LNG re-export cargoes moved from Europe to Asia in December 2025. Compared with December 2024, the NEA/SWE and NEA/NWE spreads edged slightly higher from $0.25/MMBtu and $0.20/MMBtu, respectively. However, the NEA premium over oil-indexed LNG fell sharply from $6.32/MMBtu, and shipping costs on these routes decreased by $0.14/MMBtu over the same period.

Figure 103: Price spreads & shipping costs between Asia & Europe spot LNG markets

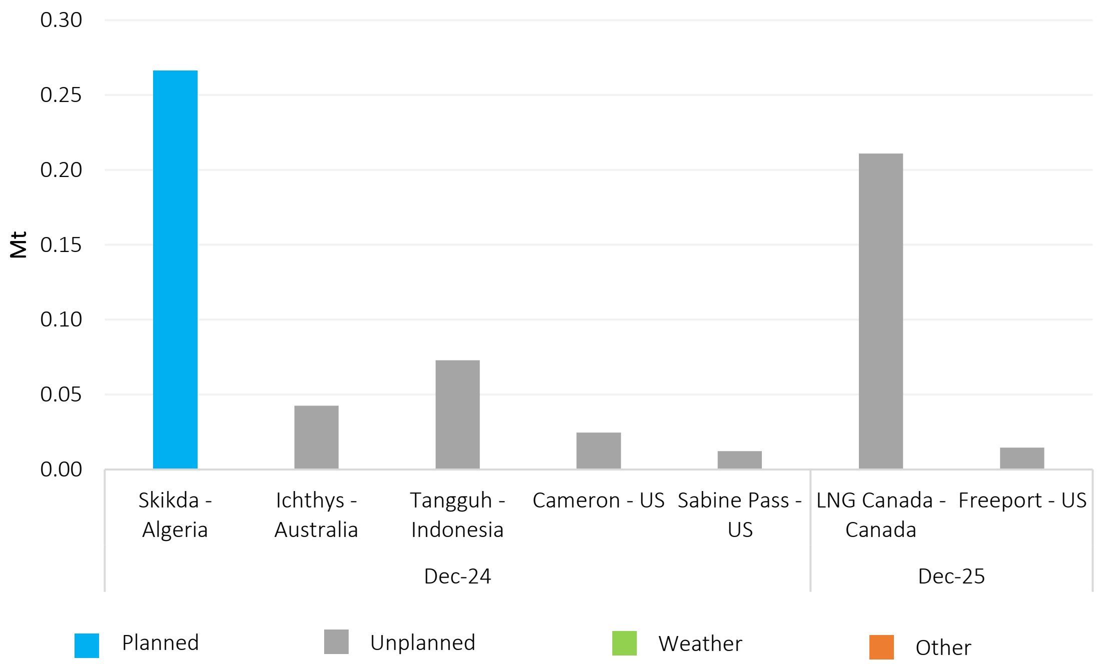


Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge
(*): One-way spot shipping cost

4.2.5 Maintenance activity at LNG liquefaction facilities

In December 2025, total disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages, and other operational issues, declined to 0.23 Mt, down from 0.42 Mt in December 2024 (Figure 104). Two unplanned outages occurred during the month: one at the LNG Canada facility and another at the Freeport LNG plant in the US.

Figure 104: Maintenance activity at LNG liquefaction facilities during September (2024 and 2025)

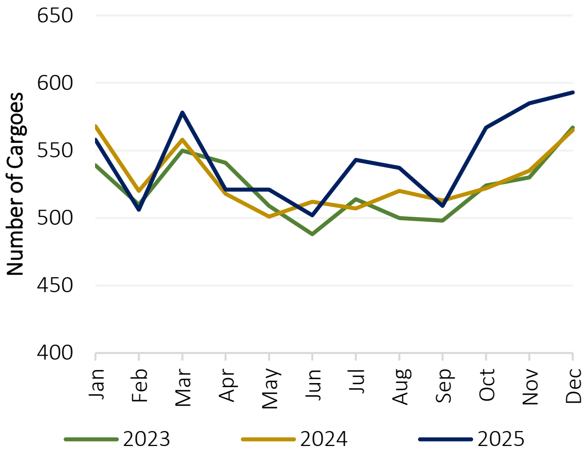


Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

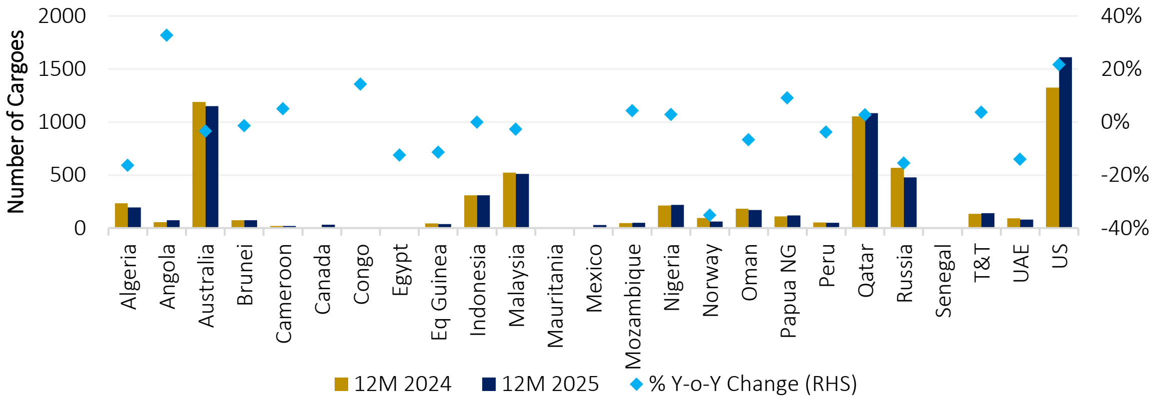
LNG cargo deliveries continued to surge in December 2025, driven by the increased demand for gas for heating amidst the winter conditions in northern hemisphere countries. During the month, 593 cargoes were exported globally, which was 8 more shipments than in the previous month and 28 more than one year ago (Figure 105). In 2025, total LNG cargoes increased by 3% y-o-y. GECF countries accounted for 45% of these, led by Qatar, Malaysia and Russia. The US shipped 287 more cargoes this year, while Qatar increased by 29 cargoes (Figure 106). The largest percentage increases were attributed to Angola (33%) and the US (22%).

Figure 105: Number of LNG export cargoes



Source: GECF Secretariat based on data from ICIS LNG Edge

Figure 106: Changes in LNG cargo exports



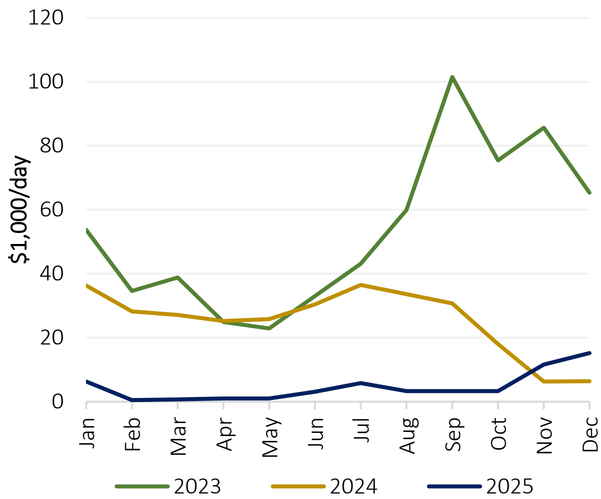
Source: GECF Secretariat based on data from ICIS LNG Edge

In December 2025, the monthly average spot charter rate for steam turbine LNG carriers increased by 31% m-o-m, to reach $15,200 per day (Figure 107). This average charter rate was 138% higher than one year ago, but was $58,500 per day lower than the five-year average price for the month. Similarly, monthly average charter rate for the other segments of the LNG carrier fleet also increased during the month. The average spot charter rate for TFDE vessels reached $55,500 per day, which was 15% higher m-o-m and 305% higher y-o-y. The average spot charter rate for two-stroke vessels was $88,000 per day, which was 12% greater m-o-m and 302% higher than one year ago.

Although the average monthly rate increased, in December 2025, the LNG shipping market actually underwent a reversal of the rally in the daily charter rates which occurred at the end of the previous month. This downturn was primarily driven by a rapid expansion in vessel availability, compounded by a record-high repositioning of empty carriers from the Pacific to the Atlantic basin. Furthermore, a closed inter-basin arbitrage, resulting from well-stocked Asian inventories and higher shipping costs, shortened voyage durations by channelling US LNG cargoes back to Europe, effectively increasing fleet efficiency and further loosening the market. While loading demand from the US Gulf Coast remained at historic highs, the steady arrival of newbuilds has reinforced a bearish sentiment for LNG carrier charter rates, marking a definitive end to the seasonal tightness.

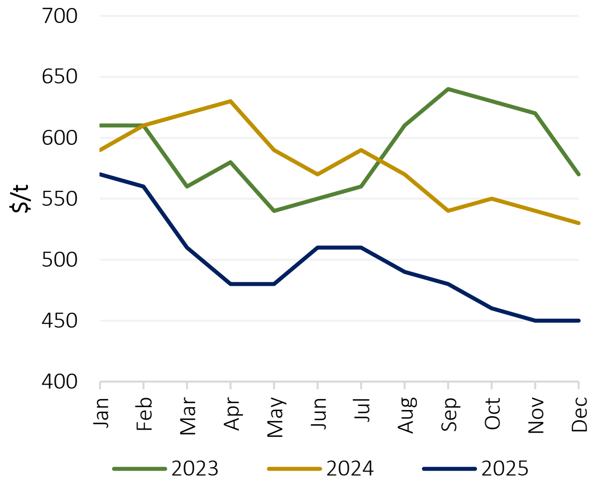
In December 2025, the average price of shipping fuels was estimated at the same level of $450 per tonne as in the previous month (Figure 108). This average price was 15% lower than one year ago, as well as 14% lower than the five-year average price for this month.

Figure 107: Average LNG spot charter (ST vessels)



Source: GECF Secretariat based on data from Argus

Figure 108: Average price of shipping fuels

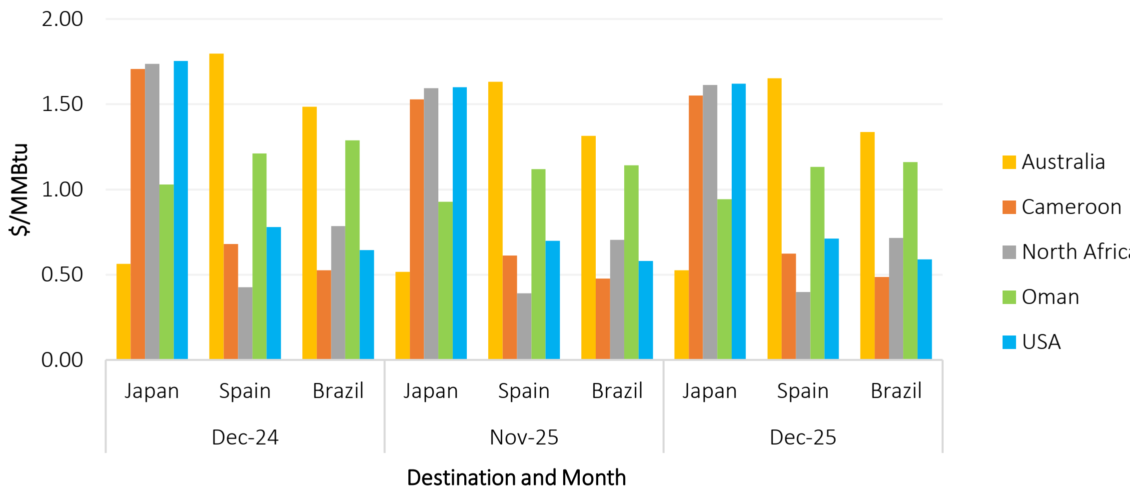


Source: GECF Secretariat based on data from Argus and Platts

There was an increase in the LNG spot shipping costs for steam turbine carriers in December 2025 compared with the previous month, by up to $0.03/MMBtu on certain routes (Figure 109). This was driven by the increase in the monthly average LNG carrier spot charter rate, despite the unchanged cost of shipping fuels and the decrease in delivered spot LNG prices.

Compared to one year ago, in December 2025 the monthly average spot charter rate was higher, but the cost of shipping fuels and delivered spot LNG prices were all lower. As a result, LNG shipping costs were up to $0.16/MMBtu lower than in December 2024.

Figure 109: LNG spot shipping costs for steam turbine carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

Bangladesh's gas tariff increase for the fertilizer industry to boost spot LNG purchases: Bangladesh's Petrobangla plans to import at least seven additional LNG cargoes annually—primarily from the spot market—using revenue from a recent gas tariff hike for fertilizer factories. The Bangladesh Energy Regulatory Commission raised the tariff by 82.8% to Tk 29.25/m³ from 1 December, generating an estimated Tk 20 billion ($162 million) per year. The higher tariff is intended to fund extra LNG imports to address chronic gas shortages that have repeatedly shut fertilizer plants.

MTEDD to develop LNG FSRU in Morocco: Morocco's Ministry of Energy Transition and Sustainable Development (MTEDD) has launched a tender to develop an LNG floating storage and regasification unit (FSRU), with a capacity of 5.1 bcm/year (3.75 Mtpa) at Nador West Med port. Bids are due by 30 January 2026. The tender covers construction and operation of gas pipelines linking the port to the Maghreb–Europe pipeline and key industrial zones. The project aims to diversify its energy mix and reduce reliance on coal-fired power generation.

Zvezda Shipyard delivers historic first LNG carrier to boost Arctic exports: Russia has reached a major maritime milestone with the construction of the Alexey Kosygin, the first domestically assembled Arc7 ice-class LNG carrier. Delivered to the state-owned shipping giant Sovcomflot in December 2025, the 172,600 m³ vessel is capable of navigating through two metres of Arctic ice year-round without icebreaker support.

NLNG subsidiary finalizes fleet renewal deal with China: The Nigerian NLNG's subsidiary, Bonny Gas Transport, is progressing its fleet renewal by finalising an order for three newbuild LNG carriers, with an option for three more, from a Chinese shipyard, most likely Hudong-Zhonghua, for delivery in 2029. The estimated cost per vessel is between $235 and 240 million. This order is notable as Chinese yards had received no other LNG carrier orders so far this year with shipyards currently operating at capacity, while South Korean yards secured 18.

In December 2025, 11 LNG agreements were signed (Table 1).

Table 1: New LNG sale agreements signed in December 2025

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
HOA	Argentina	Southern Energy LNG	Southern Energy	Germany	SEFE	2	8
SPA	Portfolio	Portfolio	Eni	Turkiye	Botas	0.4	10
SPA	Portfolio	Portfolio	SEFE	Turkiye	Botas	0.44	10
SPA	US	Texas LNG	Glenfarne	Portfolio	Macquarie	0.5	20
HOA	US	Alaska LNG	Glenfarne	Portfolio	POSCO	1	20
SPA	Portfolio	Portfolio	Eni	Thailand	Gulf Dev. Co.	0.8	10
SPA	Portfolio	Portfolio	JERA	India	Torrent Power	0.27	10
Tolling	Canada	Cedar LNG	Ovintiv	Portfolio	Portfolio	0.5	12
SPA	Portfolio	Portfolio	Chevron	Hungary	MVM	0.3	5
SPA	Portfolio	Portfolio	Petronas	China	CNOOC Gas and Power Singapore	1	10
SPA	Portfolio	Louisiana LNG	Woodside Energy	Turkiye	Botas	0.5	9

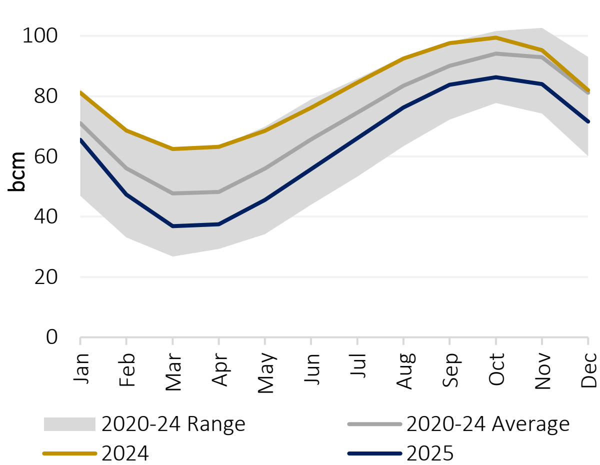
Source: GECF Secretariat based on Project Updates and News

5 GAS STORAGE

5.1 Europe

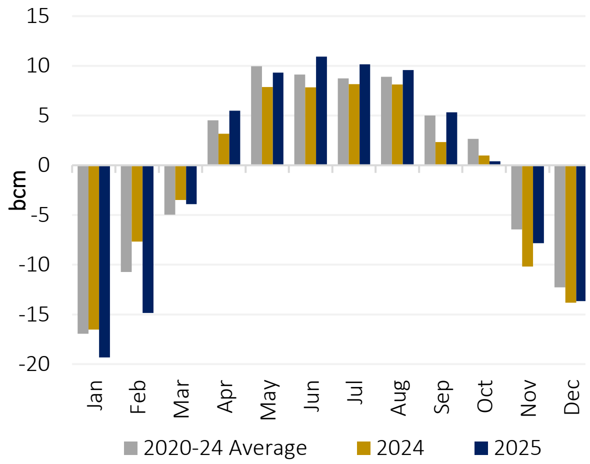
Net gas withdrawals are underway in Europe amidst the 2025/2026 winter season. In December 2025, the average daily volume of gas in underground storage in the EU decreased to 71.5 bcm, from 83.9 bcm one month prior (Figure 110). This monthly average storage level was 10 bcm lower y-o-y, as well as 9.6 bcm lower than the five-year average. The EU's aggregated gas stocks decreased from 78.4 bcm on 30 November to 64.6 bcm on 31 December. Accordingly, the average capacity utilisation across the region by the end of the month stood at 62%.

Figure 110: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

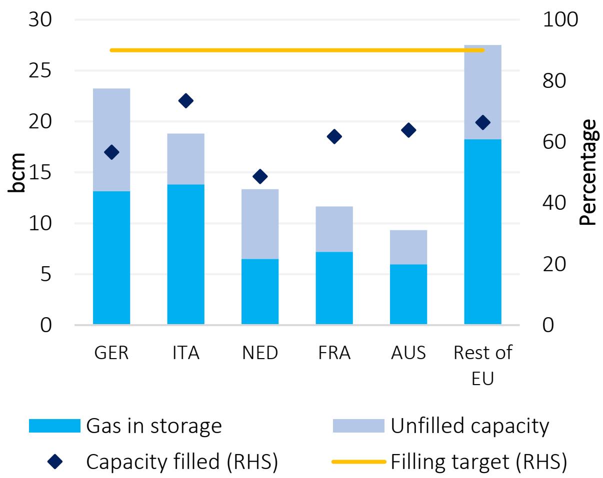
Figure 111: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

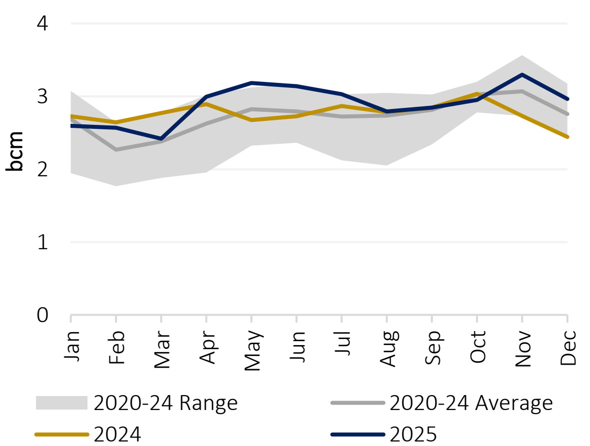
There was a notable 13.7 bcm of net gas withdrawals in December 2025, driven by colder than average temperatures during the second half of the month. In comparison, there were 13.8 bcm of net gas withdrawals one year ago, while the five-year average for the month stood at 12.3 bcm (Figure 111). Over the winter season thus far, the total amount of gas withdrawn in the EU countries reached 22 bcm. Germany (57% filled) and the Netherlands (49% filled) have already depleted considerable reserves, driven by the heating demand together with the lower maximum filled level compared to other top EU countries for UGS (Figure 112). In the same month, the average LNG storage level in the EU stood at 3.0 bcm or 54% of capacity (Figure 113). This average storage level was 21% higher y-o-y, but was 10% lower m-o-m.

Figure 112: UGS in EU countries as of 31 Dec 2025



Source: GECF Secretariat based on data from AGSI+

Figure 113: Total LNG storage in the EU



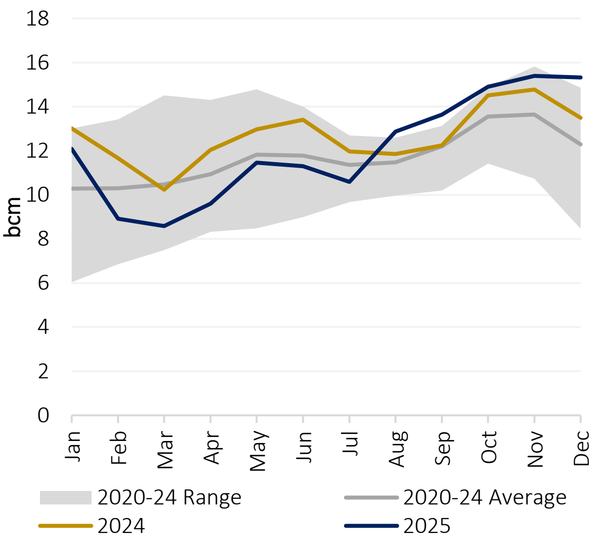
Source: GECF Secretariat based on data from ALSI

5.2 Asia

In December 2025, combined LNG stocks in Japan and South Korea were estimated to be 15.3 bcm, which was unchanged from the level of the previous month (Figure 114). Driven by warmer than average temperatures in the region, this combined stock level increased by 14% compared to one year ago and was also 3.0 bcm greater than the five-year average for the month.

In particular, the estimated LNG storage level in Japan stood at 8.2 bcm, which was 22% higher y-o-y. In South Korea, which greatly increased LNG imports, the estimated storage level stood at 7.1 bcm, which was 5% greater than one year prior.

Figure 114: LNG in storage in Japan and South Korea

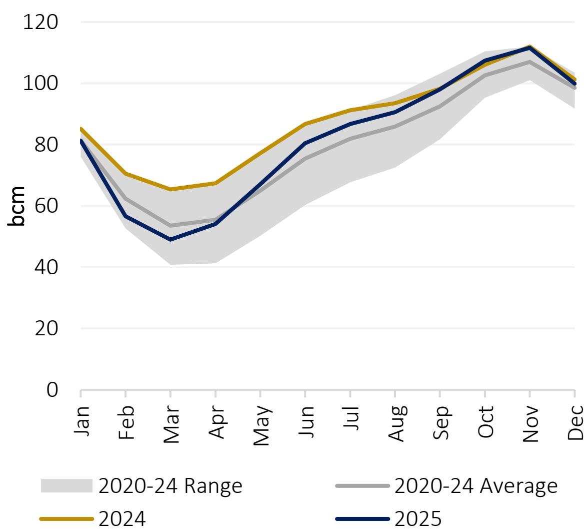


Source: GECF Secretariat based on data from LSEG

5.3 North America

The US is also undertaking net gas withdrawals to satisfy heating demand during the ongoing winter season. In December 2025, the average volume of gas in storage fell to 99.9 bcm, down from 111.6 bcm in the previous month (Figure 115). This average gas storage level was 1.4 bcm less than at the same point one year ago but was 1.4 bcm greater than the five-year average for the month. The average UGS capacity utilisation in the US stood at 75%. During the month there were 15.5 bcm of net injections in the US, which was greater than both the 14.8 bcm of one year ago, and the five-year average for the month at 13.2 bcm. Over the winter season thus far, the US has withdrawn 16 bcm.

Figure 115: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

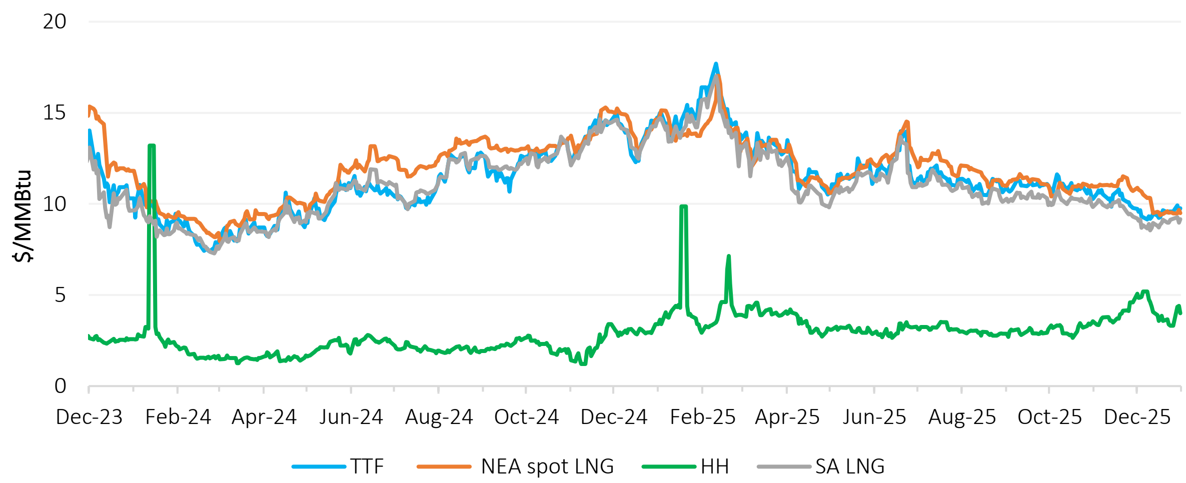
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

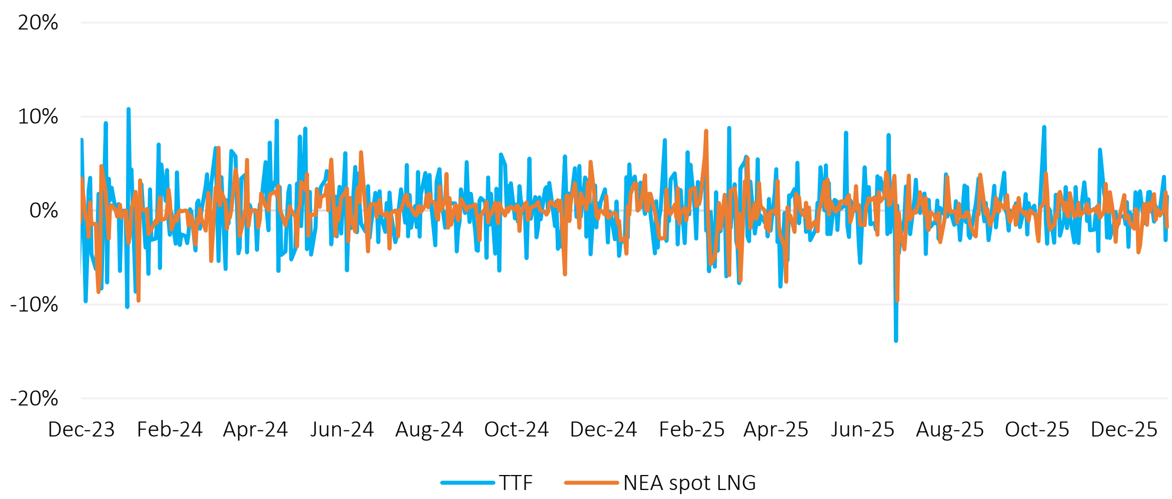
In December 2025, European and Asian gas and LNG spot prices declined, with overall market volatility remaining subdued (Figure 116 and Figure 117). Persistently strong global LNG supply, combined with mild weather conditions continued to weigh on spot prices. The resulting lower price environment may begin to stimulate incremental buying interest from price-sensitive importers, particularly in emerging Asian markets. Looking ahead, spot prices could find support and firm modestly if colder weather materializes and seasonal heating demand strengthens.

Figure 116: 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 117: Daily variation of spot prices



Source: GECF Secretariat based on data from Argus and LSEG

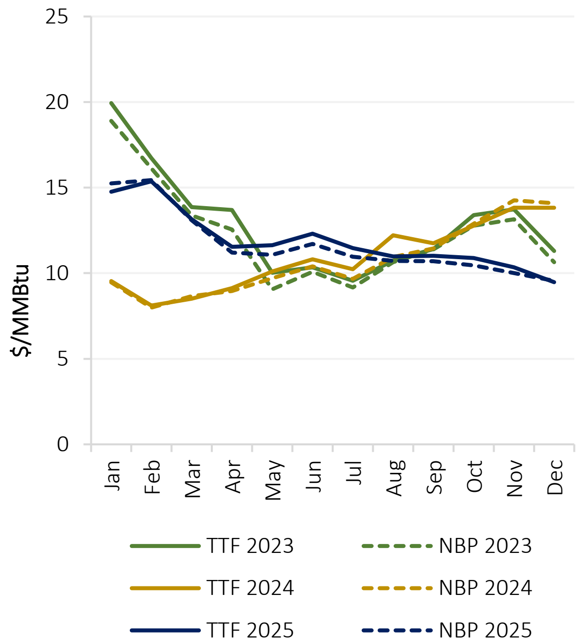
6.1.1.1 European spot gas and LNG prices

In December 2025, the TTF spot gas price averaged $9.48/MMBtu, reflecting decreases of 8% m-o-m and 31% y-o-y. Similarly, the NBP spot price averaged $9.55/MMBtu, declining by 5% m-o-m and 32% y-o-y (Figure 118).

European gas and LNG spot prices declined for a fourth consecutive month, falling to the lowest monthly average since April 2024. The downturn was driven by a combination of persistently strong global LNG supply and subdued winter demand, as unseasonably mild weather across much of Europe significantly reduced heating needs.

During the month, daily TTF spot prices dropped to a 19-month low of $9.14/ MMBtu, underscoring the extent of the downward price pressures in the region.

Figure 118: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

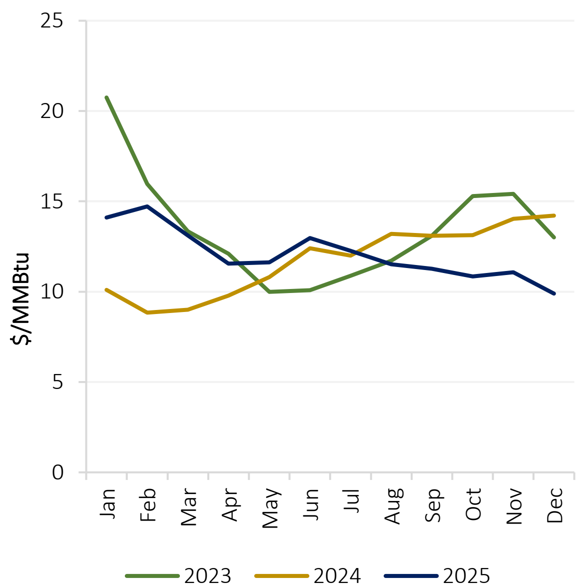
6.1.1.2 Asian spot LNG prices

In December 2025, the average Northeast Asia (NEA) spot LNG price averaged $9.89/MMBtu, reflecting declines of 11% m-o-m and 30% y-o-y (Figure 119).

Asian LNG prices declined, reversing the slight uptick in the previous month, as weak regional demand persisted, reinforced by robust global LNG supply and ample inventory levels.

Notably, daily NEA LNG spot prices dropped to a 20-month low of $9.38/MMBtu, a level that could begin to stimulate incremental buying interest from price-sensitive importers, particularly in emerging Asian markets.

Figure 119: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus

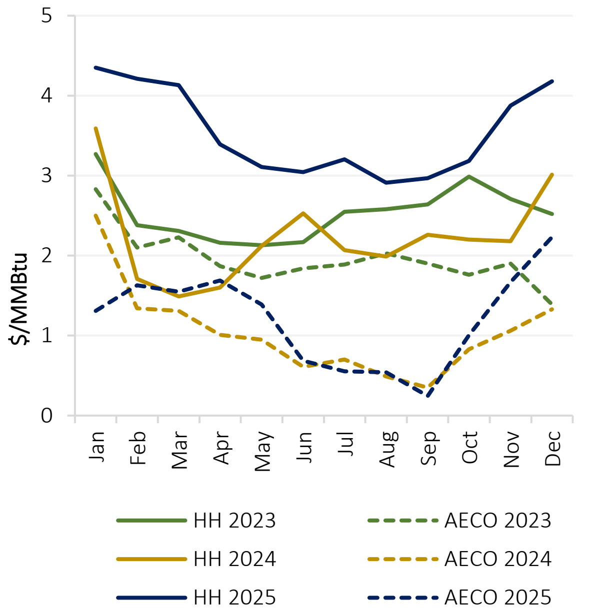
6.1.1.3 North American spot gas prices

In December 2025, the HH spot gas price averaged $4.18/MMBtu, reflecting increases of 8% m-o-m and 39% y-o-y. Meanwhile, in Canada, the AECO spot price averaged $2.23/MMBtu, reflecting sharp increases of 34% m-o-m and 68% y-o-y (Figure 120).

Henry Hub prices rose for a fourth consecutive month, reflecting firm market sentiment amid strong gas output and elevated storage levels. Notably, daily Henry Hub prices surged to a 10-month high of $5.19/MMBtu during the month.

In Canada, AECO prices also continued their upward trajectory, supported by improved demand fundamentals. Daily AECO spot prices climbed to a 10-month high of $2.68/MMBtu.

Figure 120: Monthly North American spot gas prices



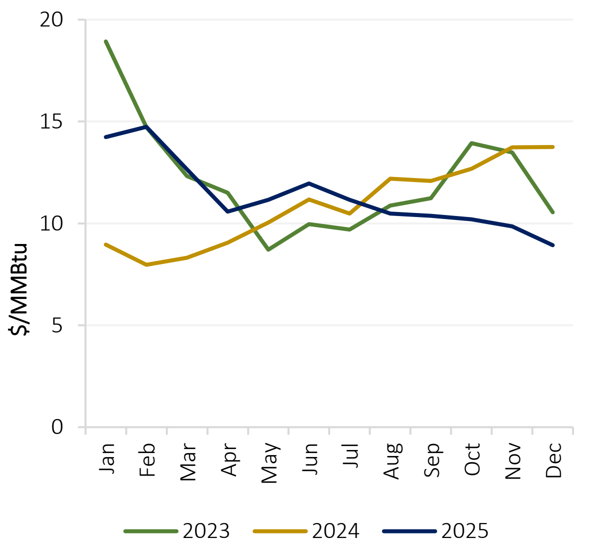
Source: GECF Secretariat based on data from LSEG

6.1.1.4 South American spot LNG prices

In December 2025, the South American (SA) LNG price averaged $8.93/MMBtu, reflecting a decrease of 9% m-o-m. Additionally, the SA LNG price was 35% lower compared to the average price of $13.75/MMBtu observed in December 2024 (Figure 121).

LNG spot prices in South America continued to align with the trends observed in European and Asian spot prices. The average LNG delivered prices in Argentina, Brazil and Chile were $9.08/MMBtu, $8.63/MMBtu and $9.09/MMBtu, respectively.

Figure 121: Monthly South American spot LNG prices

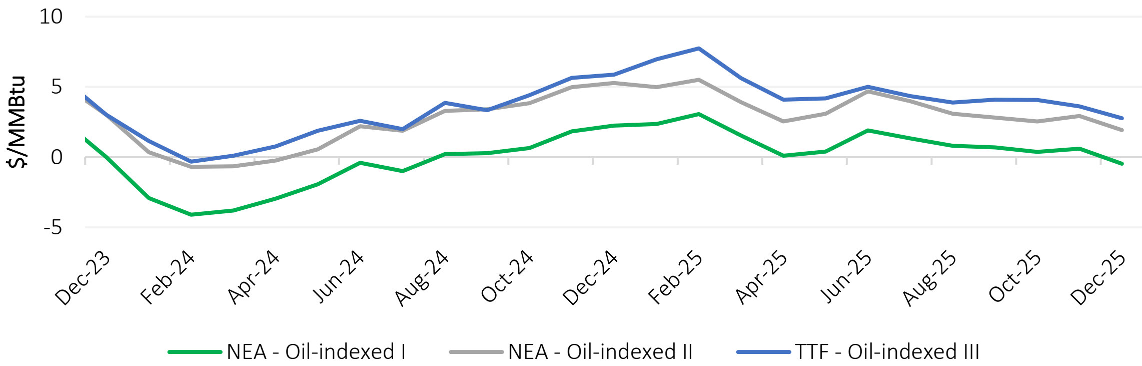


Source: GECF Secretariat based on data from Argus
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment

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

In December 2025, the average Oil-indexed I LNG price was $10.37/MMBtu, reflecting declines of 1% m-o-m and 13% y-o-y. Similarly, the Oil-indexed II LNG price averaged $7.96/MMBtu, reflecting decreases of 2% m-o-m and 11% lower y-o-y. Additionally, in Europe, the Oil-indexed III price averaged $6.70/MMBtu, reflecting declines of 1% m-o-m and 16% y-o-y. Furthermore, Oil-indexed I prices traded at a marginal premium of $0.5/MMBtu over NEA spot LNG prices. Meanwhile, Oil-indexed II prices showed a discount of $1.9/MMBtu over the NEA spot LNG prices, and the average Oil-indexed III price held a discount of $2.8/MMBtu over the average TTF spot price (Figure 122).

Figure 122: 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 December 2025, the NEA-TTF price spread remained slightly positive, with NEA spot LNG prices trading at a premium of $0.4/MMBtu over TTF spot LNG prices (Figure 123). Additionally, the TTF-HH spread declined averaging $5.3/MMBtu (Figure 124).

Figure 123: NEA-TTF price spread

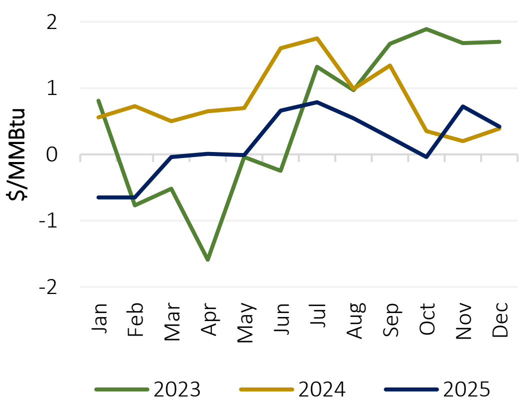
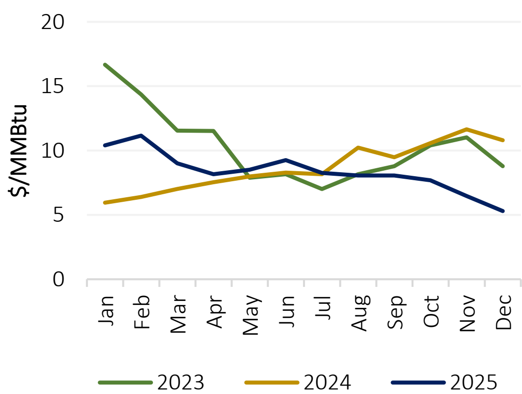


Figure 124: TTF-HH price spread



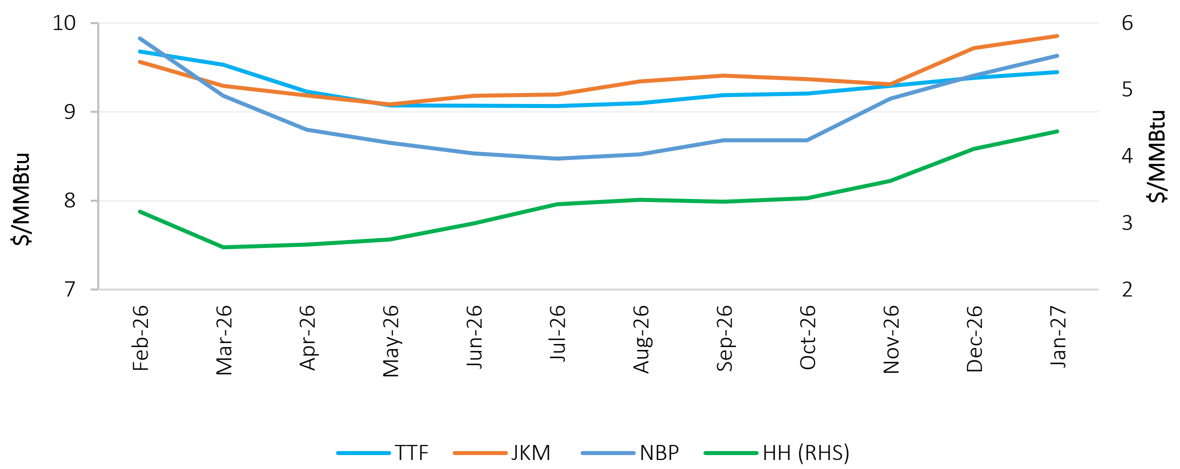
Source: GECF Secretariat based on data from Argus and LSEG

6.1.4 Gas & LNG futures prices

The average futures prices for TTF, NBP and JKM during the 12-month period from February 2026 to January 2027 were \$9.27/MMBtu, \$8.96/MMBtu and \$9.38/MMBtu, respectively, as of 9 January 2026 (Figure 125). Notably, these TTF, NBP and JKM futures prices for the forward 12-month period are lower than the futures prices expectations assessed on 2 December 2025 (as reported in the GECF MGMR December 2025). Additionally, the average Henry Hub futures price for the same period is \$3.30/MMBtu, which was also lower than previous expectations (Figure 126).

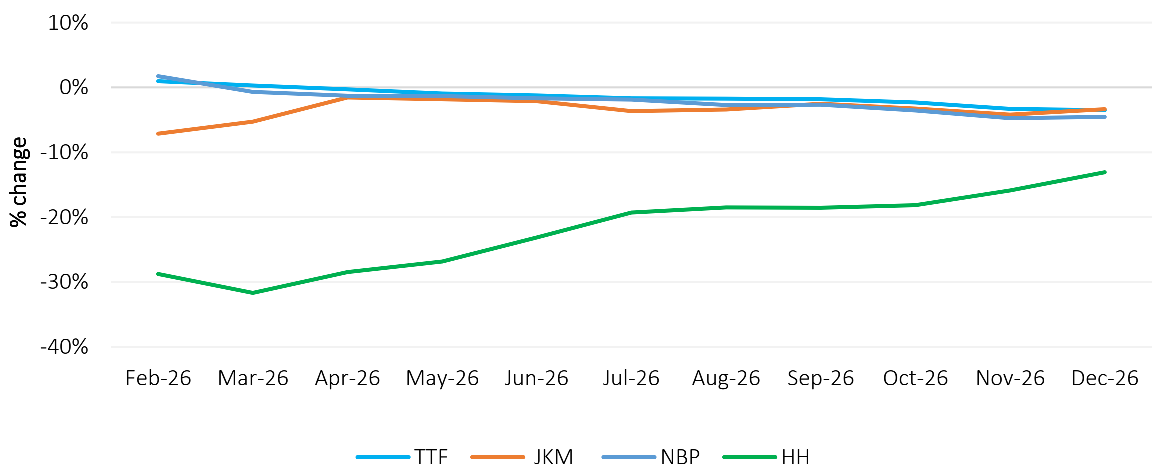
The JKM - TTF futures price spread is projected to be slightly negative, averaging -\$0.2/MMBtu from February to March 2026. Thereafter, the spread is expected to turn slightly positive from averaging \$0.2/MMBtu through January 2027.

Figure 125: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 9 January 2026.

Figure 126: Variation in gas & LNG futures prices



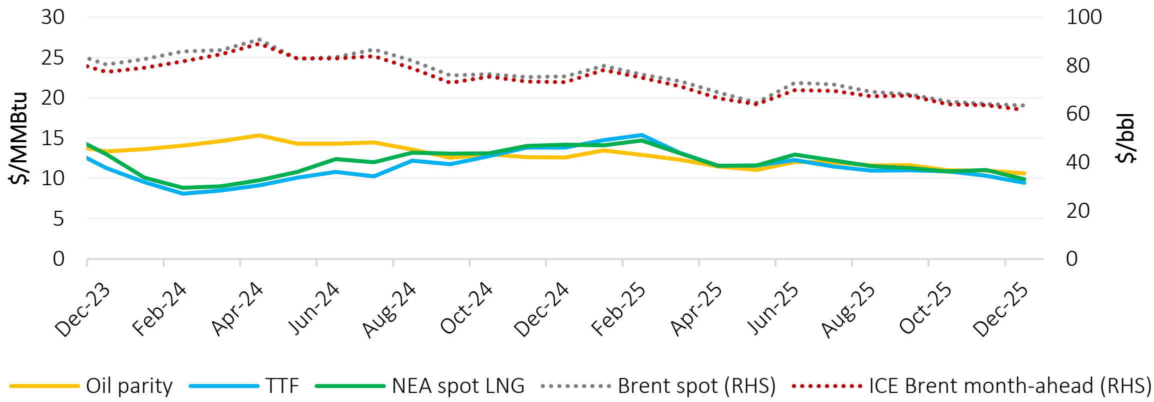
Source: GECF Secretariat based on data from LSEG
Note: Comparison with the futures prices as of 2 December 2025, as reported in GECF MGMR December 2025.

6.2 Cross commodity prices

6.2.1 Oil prices

In December 2025, the average Brent spot price was $63.51/bbl, reflecting decreases of 1% m-o-m and 3% y-o-y. The Brent month-ahead price averaged $61.66/bbl, reflecting decreases of 16% both m-o-m and y-o-y. Furthermore, in December 2025, TTF spot prices traded at a discount of $1.2/MMBtu to the oil parity price, while NEA spot LNG prices traded at discount of $0.7/MMBtu (Figure 127).

Figure 127: Monthly crude oil prices

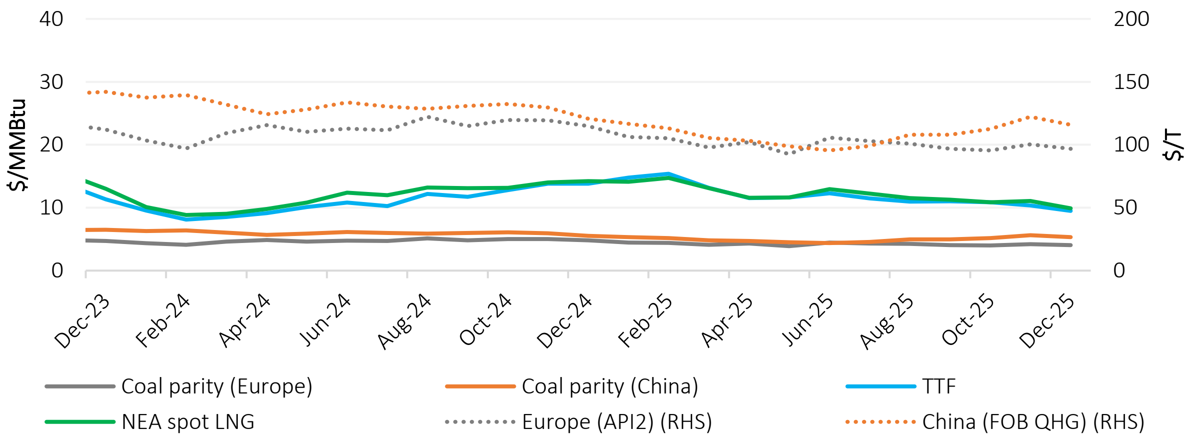


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factor of 5.8 was used to calculate the oil parity price in $/MMBtu based on the ICE Brent month-ahead price.

6.2.2 Coal prices

In December 2025, the European coal price (API2) averaged $96.78/T, reflecting decreases of 4% m-o-m and 16% y-o-y. The premium of TTF spot price over the API2 parity price declined slightly, averaging $5/MMBtu. Meanwhile, in China, the QHG coal price averaged $115.89/T, decreasing by 5% m-o-m and 6% y-o-y. The premium of NEA spot LNG price over the QHG parity price remained steady averaging $5/MMBtu (Figure 128).

Figure 128: Monthly coal parity prices

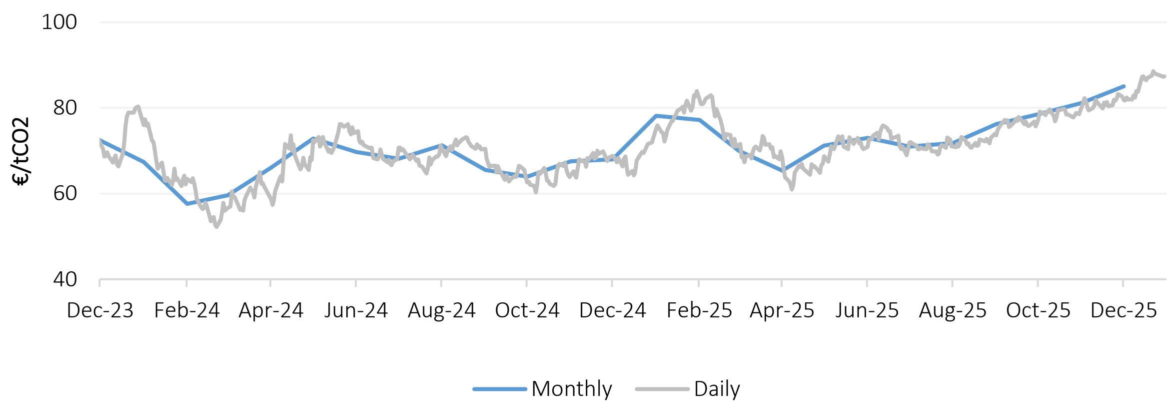


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in $/MMBtu for Europe (API2) and China (QHG) respectively.

6.2.3 Carbon prices

In December 2025, EU carbon prices averaged €85.08/tCO_2, reflecting increases of 5% m-o-m and 25% y-o-y (Figure 129). Notably, daily EU carbon prices reached a high of €88.54/tCO_2 during the month.

Figure 129: EU carbon prices

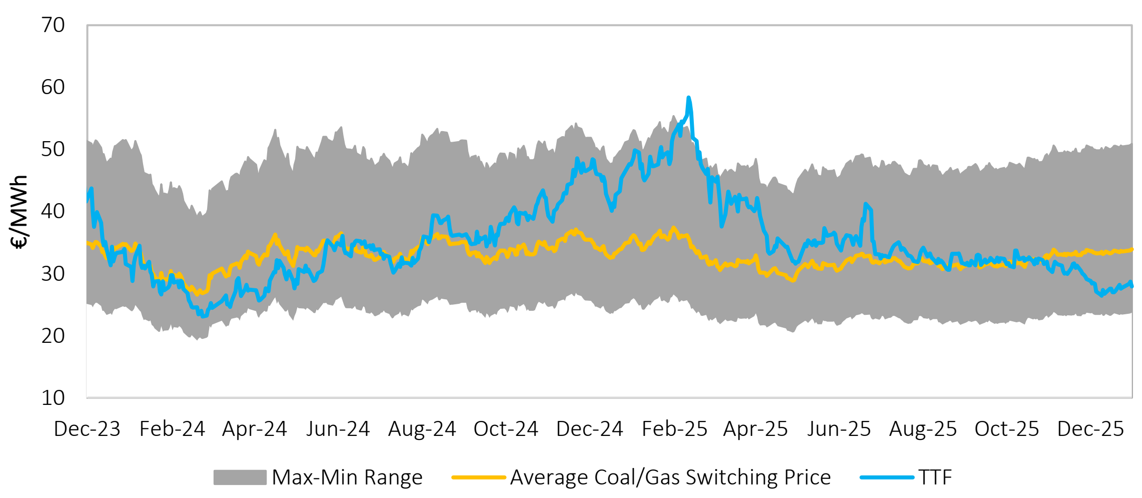


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In December 2025, daily TTF spot prices remained within the range that is favourable for coal-to-gas switching (Figure 130). Lower TTF prices during the month resulted in a significant drop below the average coal-to-gas switching price, with the monthly spread between the TTF spot price and the coal-to-gas switching price averaging -€6/MWh. Looking ahead to February 2026, the TTF spot price is expected to remain within the coal-to-gas switching range which may continue to encourage coal-to-gas switching in the region.

Figure 130: Daily TTF vs coal-to-gas switching prices



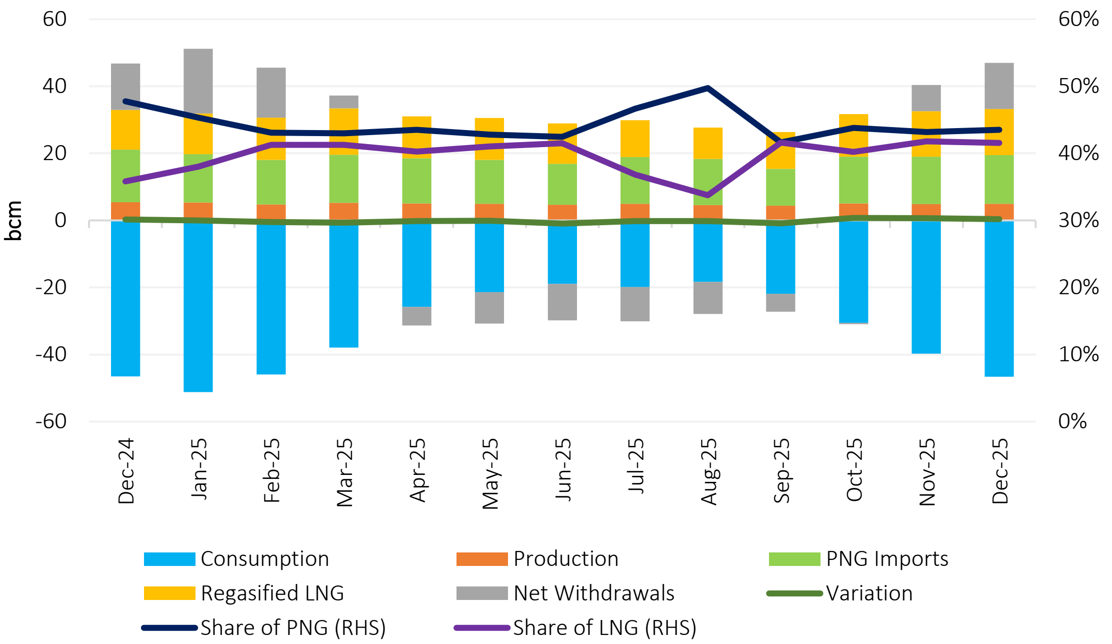
Source: GECF Secretariat based on data from LSEG
Note: Coal-to-gas switching price is the price of gas at which generating electricity with coal or gas is equal. The estimate takes into consideration coal prices, CO_2 emissions prices, operation costs and power plant efficiencies. The efficiencies considered 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

Gas balance in the EU + UK

In December 2025, the share of regasified LNG send-out in the EU and UK gas supply mix remained steady at 42%, while the share of pipeline natural gas (PNG) imports edged up from 43% to 44% (Figure 131). This slight shift reflected a stronger m-o-m increase in PNG imports relative to LNG send-out. However, compared with December 2024, LNG's share rose markedly from 36%, while PNG's share fell from 48%, highlighting both improved LNG availability and the continued decline in PNG imports.

Figure 131: EU + UK monthly gas balance



Note: Variation refers to losses and statistical differences
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 December 2025.

Table 2: EU + UK gas supply/demand balance for December 2025 (bcm)

	2024	Dec-24	Dec-25	12M 2024	12M 2025	Change* y-o-y	Change** 2025/2024
(a) Gas Consumption	369.26	46.51	46.62	369.26	378.23	0%	2%
(b) Gas Production	59.34	5.41	4.96	59.34	58.88	-8%	-1%
Difference (a) - (b)	309.92	41.10	41.66	309.92	319.35	1%	3%
PNG Imports	179.29	15.72	14.47	179.29	162.00	-8%	-10%
Regasified LNG	115.02	11.79	13.82	115.02	147.08	17%	28%
Net Withdrawals	13.29	13.90	13.72	13.29	8.45	-1%	-36%
Variation	2.32	-0.31	-0.35	2.32	1.82		

Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG
(*): y-o-y change for December 2025 compared to December 2024
(**): y-o-y change for 12M 2025 compared to 12M 2024

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

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