GECF

Gas Exporting
Countries Forum

MONTHLY GAS MARKET REPORT

July 2026

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Disclaimer

About the GECF

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

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

Acknowledgements

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

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CONTENTS

List of Figures

List of Tables

HIGHLIGHTS

Gas consumption: Global gas consumption remained under significant pressure as severe LNG supply disruptions and elevated spot prices reshaped regional demand patterns. In Asia, constrained LNG availability and high import prices reduced the competitiveness of natural gas relative to coal, accelerating gas-to-coal switching in the power and industrial sectors across major importing markets, including China, India, Japan, and South Korea. In contrast, gas consumption in Europe increased, supported by higher gas-fired power generation driven by elevated cooling demand during prolonged heatwaves and lower wind and hydropower output.

Gas production: Global gas production continued to be heavily impacted by the supply shock in the Middle East resulting from the closure of the Strait of Hormuz. Consequently, the region's gas supply declined by nearly one-third year-on-year, primarily reflecting sharp production cuts among the region's major gas and LNG producers, with Qatar recording the largest decline. However, the global supply shock was partially offset by continued production growth in North America, where the US posted the largest increase in output, rising by 3.3% y-o-y and helping to mitigate part of the global supply shortfall.

Gas trade: The pace of decline in global LNG imports continued to moderate in June 2026, with imports down just 2.9% y-o-y (1.0 Mt) to reach 33.4 Mt. The weaker import volumes reflected tighter global LNG supply resulting from continued restrictions on LNG transit through the Strait of Hormuz. Europe's LNG imports fell sharply by 21%, marking a fourth consecutive monthly y-o-y decline as Atlantic Basin cargoes were increasingly diverted to higher-priced Asian markets. In contrast, Asia recorded its first y-o-y increase in LNG imports since February 2026, supported by stronger demand in China, India, Indonesia, Thailand and Vietnam. On the infrastructure front, Mexico's Energia Costa Azul (ECA) LNG project exported its first LNG cargo.

Gas storage: Gas inventory levels exhibited contrasting regional trends throughout June 2026, reflecting differing market conditions. In the EU, the monthly average gas storage level stood at 46 bcm (45% of capacity), down significantly from 56 bcm (54% of capacity) a year earlier, primarily due to lower LNG imports. In the US, the monthly average inventory reached 79 bcm (59% of capacity), broadly unchanged from 80 bcm recorded a year earlier. In Asia, combined LNG inventories in Japan and South Korea edged up to 8.5 bcm but remained 25% below the level a year ago, as the tight spot LNG market constrained further stockbuilding.

Energy prices: Gas and LNG spot prices recorded modest declines as optimism surrounding the reopening of the Strait of Hormuz, following the signing of a MoU on 18 June 2026 to end the conflict, eased concerns over supply disruptions. Average TTF prices fell by 7% m-o-m to $15.1/MMBtu, while NEA spot LNG prices declined by 4% m-o-m to $17.2/MMBtu. In contrast, North American prices continued to strengthen, with HH rising by 7% m-o-m to $3.1/MMBtu. Looking ahead, spot gas prices are expected to remain supported by forecasts of above-normal summer temperatures, while any renewed escalation of geopolitical tensions in the Middle East could exert additional upward pressure on prices.

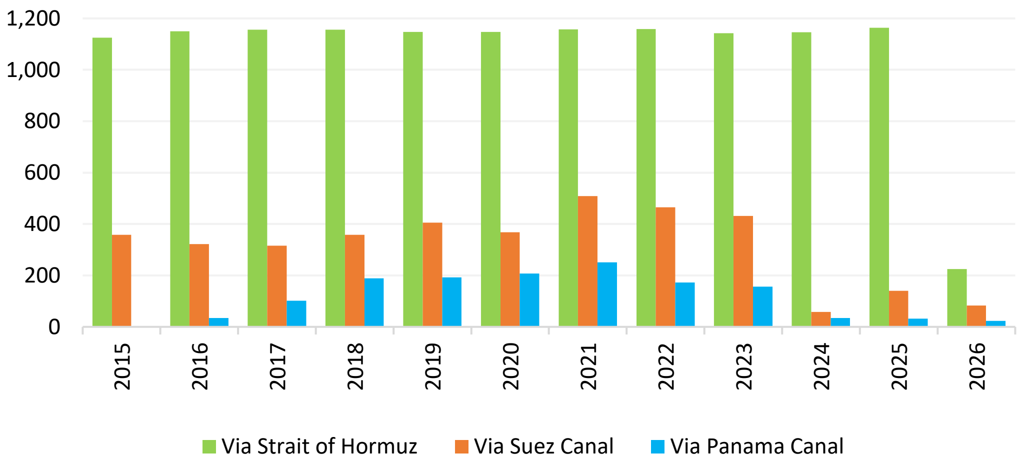
FEATURE ARTICLE:

LNG shipping as a critical pillar of energy security amid geopolitical uncertainty

Traditionally, gas supply security has been primarily associated with the availability of natural gas resources and the reliability of supply. However, the recent conflict in the Middle East has brought the security of LNG shipping routes into sharp focus, highlighting the importance of maritime transportation to the resilience of the global gas market. The global LNG trade is inherently shaped by a limited number of strategic maritime chokepoints that are critical to global energy security. As LNG transportation relies on specialised carriers operating between fixed liquefaction and regasification terminals along established shipping routes, disruptions at these waterways can significantly constrain LNG trade. Although alternative routes may exist in some cases, they are typically longer, more costly, and less efficient, making these chokepoints strategic pressure points exposed to geopolitical, security, operational and environmental risks.

The most critical maritime chokepoints for LNG trade are the Strait of Hormuz, Suez Canal, and Panama Canal, owing to their strategic locations and limited navigational capacity. The number of LNG carrier transits through each of these chokepoints has varied considerably over the recent years (Figure i). The Strait of Hormuz serves as the sole maritime outlet for LNG exports from Qatar and the UAE, accounting for one-fifth of global LNG supply. The Suez Canal, together with the Bab el-Mandeb, forms a critical bidirectional corridor. While it is widely recognised for enabling westbound LNG shipments from the Middle East to Europe, it is equally important for eastbound trade, allowing Atlantic Basin LNG suppliers to serve markets across the Asia-Pacific region. Similarly, the Panama Canal provides the principal maritime shortcut linking LNG exports from the US Gulf Coast and Trinidad and Tobago with Asia-Pacific markets.

Figure i: LNG carrier transits through major global chokepoints



Source: GECF Secretariat based on data from ICIS LNG Edge. Note: 2026 data cover H1 2026.

In addition, the Strait of Malacca and the Cape of Good Hope, while important for global LNG shipping, are generally considered less critical to the resilience of global LNG trade. The Strait of Malacca, through which 17% of global LNG carrier sailings pass, is complemented by alternative routes through the Indonesian archipelago, in contrast to the Strait of Hormuz. The Cape of Good Hope, by comparison, is an open-ocean route rather than a narrow maritime chokepoint and therefore does not rely on a single constrained navigational corridor susceptible to blockage. Consequently, disruptions along these routes are less likely to severely impede global LNG trade or undermine the resilience of global LNG supply chains.

Each of these five maritime routes is exposed to a distinct combination of geopolitical, security, operational and environmental risks that can disrupt global LNG trade. The Strait of Hormuz is mainly exposed to geopolitical tensions and military conflict, reflecting its role as the sole maritime outlet for LNG exports from the Gulf. The Suez Canal faces predominantly regional security risks, particularly instability in the Red Sea region that can disrupt vessel transits. By contrast, the Panama Canal is chiefly affected by environmental risks, especially drought-induced water shortages that reduce canal capacity. The Strait of Malacca is primarily exposed to navigational congestion, maritime accidents, and localized security incidents. Likewise, the Cape of Good Hope is mainly exposed to adverse weather conditions and the operational challenges associated with significantly longer voyage distances. In addition to these route-specific risks, piracy remains an intermittent security threat along certain LNG shipping routes.

These risks have moved beyond theoretical concerns and have had tangible consequences for global LNG shipping. In particular, the unprecedented simultaneous disruption of the Suez Canal and Panama Canal routes in 2024, driven by security concerns and environmental constraints, respectively, has fundamentally reshaped global LNG shipping patterns. Prior to these disruptions, LNG carrier transits through both canals had increased steadily, reaching record levels in 2021, as they served as critical maritime shortcuts linking LNG supplies from the US and the Middle East with markets in Europe and Asia. However, the convergence of geopolitical instability in the Middle East and severe drought affecting Gatun Lake triggered a sharp decline in traffic through both corridors. LNG carrier transits through the Suez Canal fell from a peak of 509 in 2021 to 140 in 2025, while transits through the Panama Canal declined from 251 to 32 over the same period. During these years, global LNG exports increased by approximately 500 cargoes to more than 6,500 cargoes annually, underscoring an even more pronounced decline in the relative importance of both canals within the global LNG transportation network.

Consequently, LNG carriers have increasingly been rerouted via the Cape of Good Hope, transforming it from an occasional diversionary route into a major shipping corridor despite significantly longer voyage distances, reduced shipping efficiency, and higher transportation costs. The shift in global LNG shipping patterns has fundamentally altered the commercial economics of LNG transportation by widening the time and cost differentials between direct canal transits and longer diversionary routes. For example, a voyage from the US Gulf Coast to Japan takes 20 days via the Panama Canal but 34 days when rerouted via the Cape of Good Hope. Similarly, a shipment from the US Gulf Coast to India takes 23 days via the Suez Canal, compared with 30 days via the Cape of Good Hope. Middle Eastern LNG exports to Southwest Europe exhibit a similar pattern, with shipments from Qatar requiring 17 days via the Suez Canal and 27 days when rerouted via the Cape of Good Hope.

An even greater shock to the global LNG market occurred following the blockade of the Strait of Hormuz amid the escalation of the Middle East conflict beginning on 28 February 2026. As the Strait of Hormuz is the sole maritime export route for LNG shipments from Qatar and the UAE, any disruption to vessel movements through the Strait poses an immediate risk to global gas supply security. The blockade has effectively brought LNG exports from both countries to a standstill, triggering an unprecedented disruption to global LNG trade. Between March and June 2026, the global LNG market lost more than 300 Qatari LNG cargoes and around 20 from the UAE. The sudden removal of one-fifth of global LNG supply from international markets exacerbated market tightness, forcing importing countries to secure alternative LNG supplies and diversify their energy mix, thereby significantly reshaping global LNG trade flows.

An estimated 160 LNG carriers were stranded inside the Gulf or forced to remain at anchor in the Gulf of Oman following the blockade, creating an acute shortage of available vessels. As a result, the LNG shipping market experienced an unprecedented shock, with spot charter rates rising to levels not seen since the peak of the 2022 energy crisis. Daily spot charter rates for Tri-Fuel Diesel Electric (TFDE) carriers surged to $235,000/day in early March, compared with just $5,000/day in early February. At the monthly level, average TFDE spot rates increased from $18,000/day in February to $108,000/day in March (Figure ii). The market tightening extended across the entire LNG fleet. Even legacy steam turbine carriers, the least fuel-efficient vessels and a segment undergoing gradual phase-out, experienced a sharp recovery in demand, with average monthly spot charter rates rising from $3,000/day to $50,000/day.

Another key driver of elevated freight rates was the contraction in effective fleet capacity resulting from the sharp expansion in ton-mile demand. With the Red Sea designated a high-risk area and the Suez Canal route effectively bypassed, LNG carriers were increasingly rerouted around the Cape of Good Hope. This diversion extended a typical ballast or laden voyage between the Atlantic Basin and Asia-Pacific markets by 15–20 days, substantially increasing the time each vessel remained employed per voyage. As a result, a larger fleet was required to transport the same volume of LNG, reducing the availability of vessels in the spot market and placing sustained upward pressure on charter rates. These capacity constraints began to ease in April 2026, as a significant number of vessels previously committed to long-term Qatari contracts became available for spot employment following the sharp decline in Qatari LNG exports.

Figure ii: Average spot charter rates for TFDE carriers

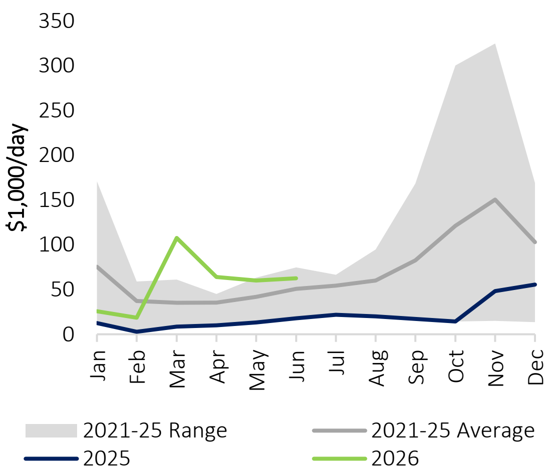
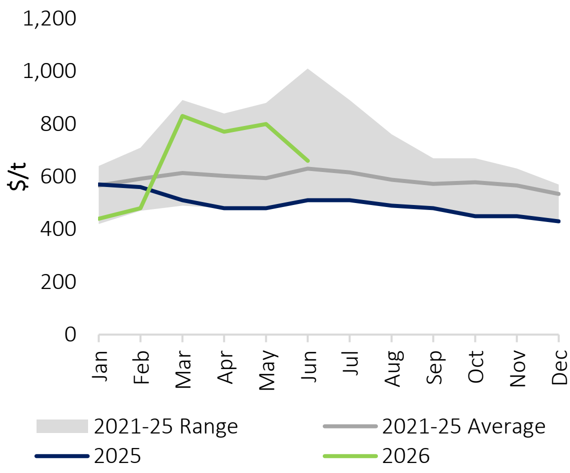


Figure iii: Average price of shipping fuels



Source: GECF Secretariat based on data from Argus and Platts

Marine bunker fuel prices, another key component of LNG shipping costs, are closely linked to global crude oil benchmarks. Consequently, the surge in crude oil prices following the blockade of the Strait of Hormuz translated into a sharp increase in marine fuel costs. In March 2026, the average bunker fuel price for the LNG carrier fleet rose by 73% m-o-m to more than $800/t, reaching its highest level since the peak of the 2022 energy crisis (Figure iii). Although bunker fuel prices subsequently eased from these highs, they became increasingly decoupled from crude oil benchmarks. This divergence reflected persistent supply-demand imbalances at major bunkering hubs, compounded by refining bottlenecks. The widespread rerouting of LNG carriers via the Cape of Good Hope increased fuel consumption and concentrated bunkering demand at a limited number of strategic ports. As demand outpaced local fuel inventories and refinery output, bunker fuel premiums remained elevated despite fluctuations in crude oil prices.

Insurance costs also increased sharply, adding another major source of cost escalation for LNG shipping. The maritime insurance sector experienced severe disruption as leading global underwriters issued blanket cancellations of war-risk cover for the Gulf and adjacent waters. For the few LNG carriers still attempting to navigate the region at the onset of the conflict, Additional War Risk Premiums escalated dramatically. Standard transit premiums, which averaged around 0.25% of a vessel's hull and machinery value before the conflict, surged to between 5% and 10% for voyages through the Strait of Hormuz. For an LNG carrier valued at $250 million, this translated into a single-transit insurance cost of up to $25 million, representing a forty-fold increase that often exceeded the commercial margin of the cargo. The tightening of insurance markets also extended to cargo cover, with premiums for LNG cargoes rising to between 10% and 20% of cargo value during the peak of hostilities.

The combined impact of longer voyage distances, soaring charter rates, higher shipping fuel prices, and escalating insurance premiums resulted in a surge in overall LNG shipping costs. For example, the cost of transporting LNG on a TFDE carrier from the US Gulf Coast to Southwest Europe averaged $1.1/MMBtu in Q2 2026, compared with $0.6/MMBtu a year earlier. The increase was even more pronounced on voyages to Northeast Asia, where shipments routed via the Cape of Good Hope averaged $3.6/MMBtu in Q2 2026, compared with $1.8/MMBtu in Q2 2025. By comparison, shipments transiting the Panama Canal averaged $2.8/MMBtu in Q2 2026, highlighting the substantial cost premium associated with the longer Cape route.

Consequently, the share of spot shipping costs in the total delivered price of spot LNG cargoes increased sharply. In July 2025, spot shipping costs from the US Gulf Coast to Europe averaged $0.7/MMBtu, while European spot gas prices were $12/MMBtu, meaning freight accounted for 6% of the delivered price. By March 2026, however, spot shipping costs had risen to $2/MMBtu, increasing freight's share to more than 10% of the delivered value. A similar trend was observed on the US Gulf Coast–Northeast Asia route via the Panama Canal, where spot shipping costs increased from $1.6/MMBtu, representing 13% of the delivered price in July 2025, to nearly $5/MMBtu by March 2026, accounting for one-quarter of the total delivered LNG price.

Looking ahead, the commissioning of around 250 Mtpa of new global liquefaction capacity by 2030 is expected to reshape LNG shipping patterns and alter the relative importance of key maritime routes and traditional chokepoints. Nearly half of this new capacity is concentrated along the US Gulf Coast, increasing pressure on the Panama Canal as growing volumes of US LNG exports compete for transit to Asian markets. Although long-term slot reservation systems will continue to facilitate canal access, the projected scale of future LNG trade is expected to increase the use of longer alternative routes, particularly via the Cape of Good Hope elevating their role from occasional diversionary routes to an integral component of global LNG shipping.

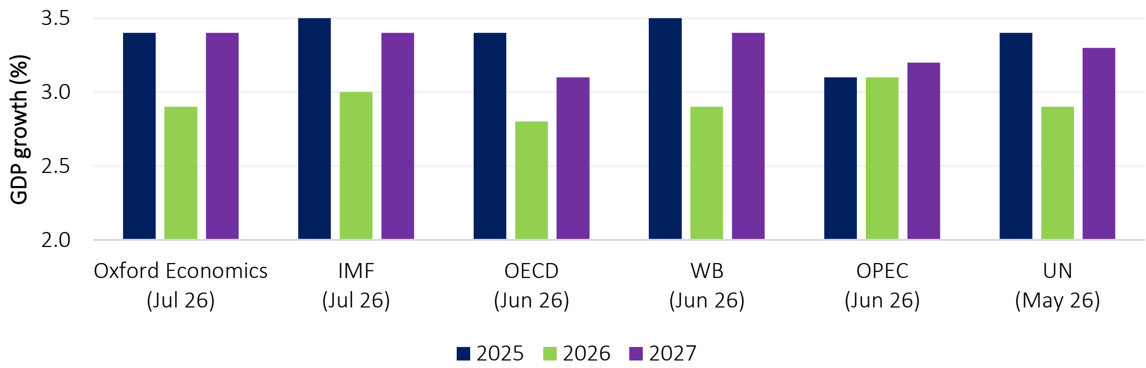
At the same time, the emergence of new LNG export hubs beyond the US Gulf Coast is expected to diversify global trade flows and reduce dependence on traditional maritime chokepoints. Export terminals under development on the Canadian and Mexican Pacific coasts will enable North American LNG to reach Asian markets directly across the Pacific Ocean, bypassing the Panama Canal altogether. Likewise, under-development and planned LNG projects in Africa will be strategically positioned to supply both European and Asian markets through diversified shipping routes. Although global LNG trade is projected to expand substantially, these evolving supply patterns are expected to reduce the concentration of LNG flows through a limited number of strategic chokepoints, thereby enhancing the flexibility and resilience of the global LNG transportation network and strengthening global energy security.

1 GLOBAL PERSPECTIVES

1.1 Global economy

Global GDP growth for 2026 based on purchasing power parity was forecast at 2.9% by Oxford Economics in July 2026 (Figure 1). The global economy has maintained steady momentum despite geopolitical developments in the Middle East, underpinned by strong investment in artificial intelligence and supportive fiscal policies that have helped offset the impact of higher energy costs. Looking ahead, global economic activity is expected to strengthen, with GDP growth accelerating to 3.4% in 2027.

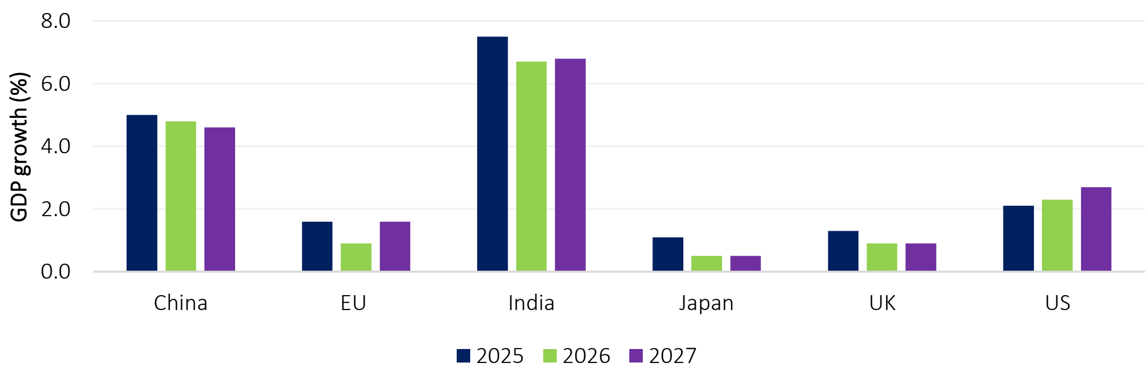
Figure 1: Global GDP growth



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

Several revisions were made to GDP growth forecasts for the major economies compared with the previous month (Figure 2). In the US, the 2026 GDP growth was revised upward by 0.2 percentage points to 2.3%, supported by strong AI-related investment and easing inflation. Growth is expected to accelerate further to 2.7% in 2027. In the EU, the 2026 GDP growth estimate was raised by 0.1 percentage points to 0.9%, reflecting easing inflation, with growth projected to strengthen to 1.6% in 2027. China's 2026 GDP growth forecast remained unchanged at 4.8%, underpinned by resilient exports and continued fiscal support, although growth is expected to moderate to 4.6% in 2027. India's GDP growth for both 2026 and 2027 were revised upward to 6.7% and 6.8%, respectively.

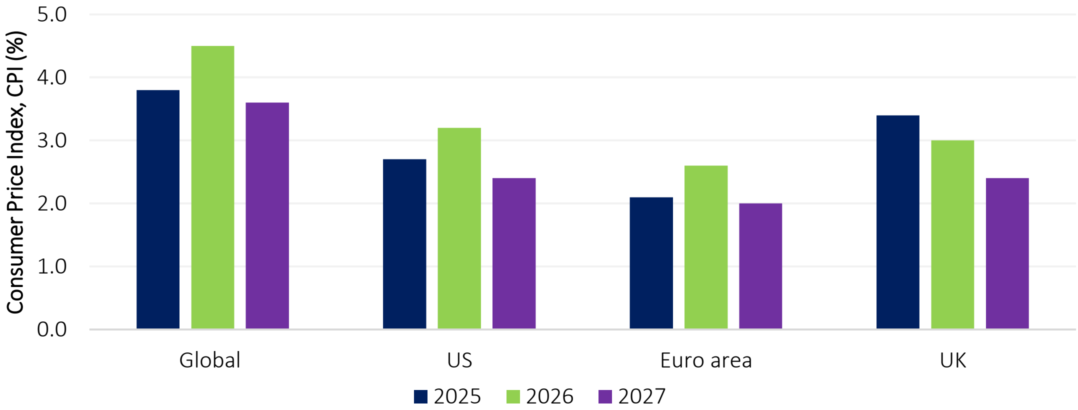
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

In July 2026, Oxford Economics revised its global inflation forecast for 2026 downward by 0.3 percentage points to 4.5%, while the forecast for 2027 remained unchanged at 3.6% (Figure 3). In the Euro area, inflation projections were also revised lower, to 2.6% in 2026 and 2.0% in 2027. The UK's inflation rate was forecast at 3.0% in 2026 and 2.4% in 2027. In the US, the 2026 inflation forecast was lowered by 0.4 percentage points to 3.2%, while the 2027 forecast was revised upward by 0.3 percentage points to 2.4%.

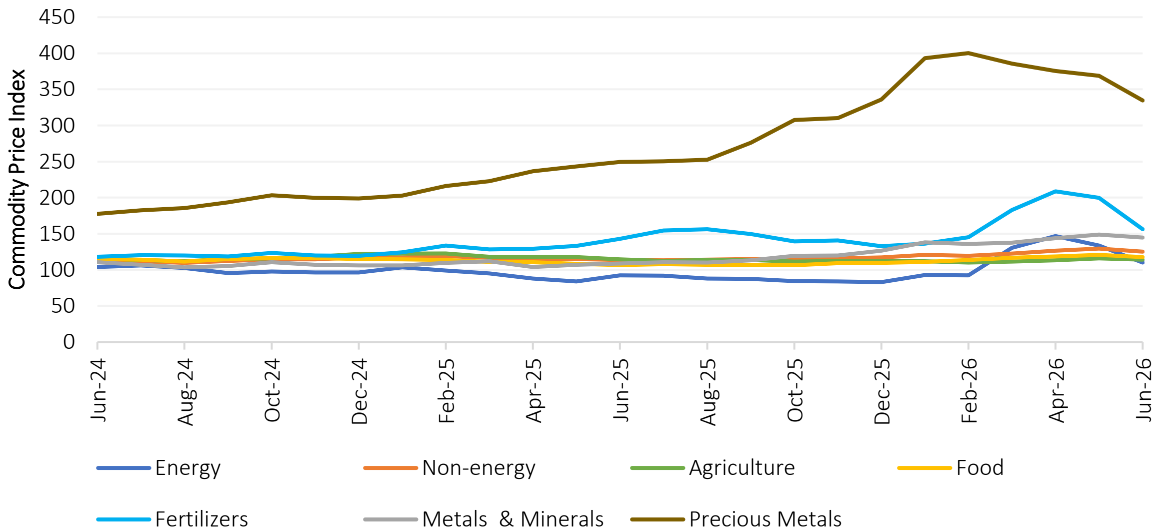
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In June 2026, commodity prices across all major sectors moved lower (Figure 4). The energy price index recorded the sharpest decline, falling 18% m-o-m, driven by a steep decline in oil prices, although it remained 19% higher than a year earlier. The non-energy price index declined more modestly, down 3% m-o-m, while remaining 10% higher y-o-y. Fertilizer prices also weakened significantly, with the index falling 22% m-o-m, but staying 9% higher y-o-y. The precious metals price index extended its decline, decreasing 9% m-o-m, yet remained 34% above its level a year earlier.

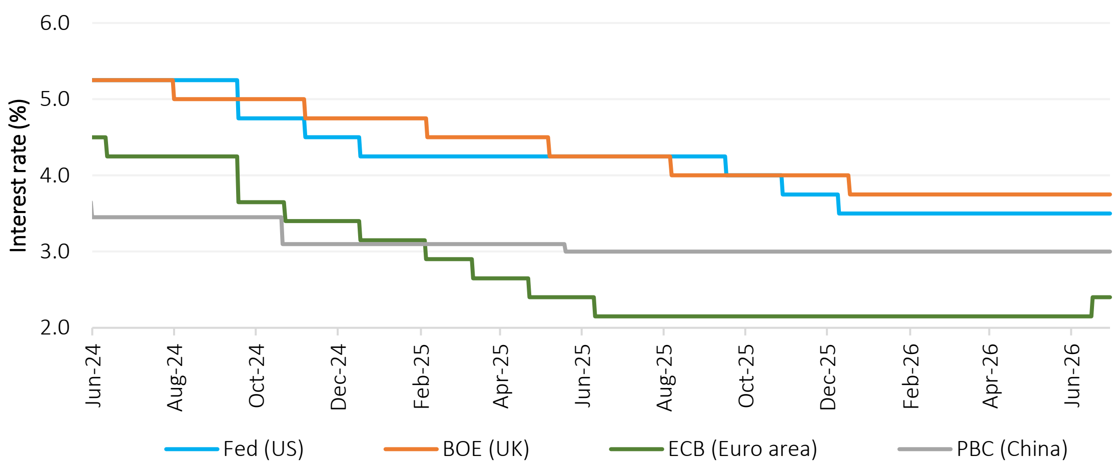
Figure 4: Monthly commodity price indices



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%).

Additionally, in June 2026, global monetary policy remained steady as major central banks chose to maintain their existing benchmark interest rates, with the exception of the European Central Bank (ECB) (Figure 5). The US Federal Reserve (Fed) maintained its benchmark interest rate within the range of 3.5% to 3.75%, which has been unchanged since December 2025. The Bank of England (BOE) has kept its benchmark interest rate at 3.75% since December 2025. The European Central Bank (ECB) increased its main refinancing operations rate by 0.25 percentage points to 2.40%, effective 17 June 2026. Meanwhile, the People's Bank of China held its one-year Loan Prime Rate (LPR) at 3.0%.

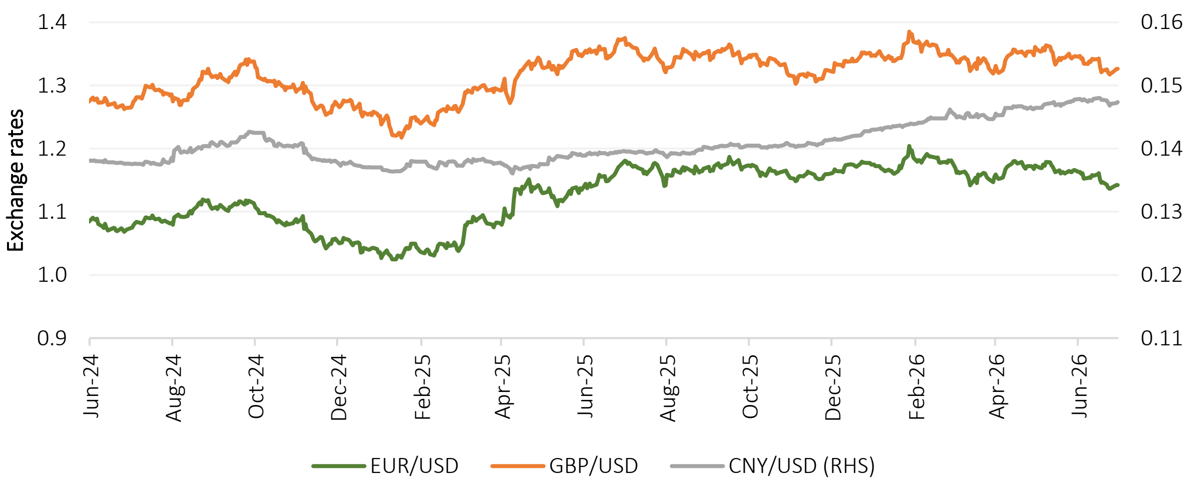
Figure 5: Interest rates in major central banks



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

In June 2026, major global currencies depreciated slightly against the US dollar (Figure 6). The euro averaged $1.1508 against the US dollar, reflecting a decline of 1% m-o-m, but remained at the same level compared to the previous year. Similarly, the British pound averaged $1.3326 against the US dollar, representing decreases of 1% m-o-m and 2% y-o-y. Meanwhile, the Chinese yuan was broadly stable against the US dollar, averaging $0.1476, gaining 6% y-o-y.

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

G7 Summit: The G7 Summit, held on 15-17 June 2026 in Évian, France, produced a series of declarations and joint statements reaffirming the group's commitment to collective action on global security, economic resilience, and sustainable development. Leaders endorsed efforts to preserve stability in the Middle East, agreed to strengthen critical mineral supply chains, and committed to addressing global economic imbalances. Recognizing the heightened risks to global economic growth, the G7 noted that rising pressures on energy and agricultural inputs continue to strain industries and households, especially in the most vulnerable countries. In the Leaders' Statement for More Balanced, Durable and Resilient Growth, they emphasized "the importance of affordable access to energy and reaffirm our commitment to well-functioning, stable and transparent markets for energy and other commodities. We call on all countries to avoid arbitrary export restrictions, and emphasize the importance of secure trade flows."

Bonn Climate Change Conference: The 2026 Bonn Climate Change Conference (SB 64), held on 8-18 June 2026 in Bonn, Germany, served as a critical preparatory meeting for COP31 in Antalya, Türkiye, but concluded with limited substantive progress amid deep divisions over climate finance, emissions reductions, and adaptation. Negotiators advanced technical work on operationalizing the new global Just Transition Mechanism, agreed on draft texts to support further negotiations at COP31, and reaffirmed the importance of accelerating electrification. However, discussions on scaling up climate finance, strengthening adaptation efforts, and advancing the Global Stocktake remained largely deadlocked, reflecting persistent tensions between developed and developing countries.

UN: The "Tracking SDG 7: The Energy Progress Report", published on 24 June 2026 and jointly prepared by the UN, IEA, IRENA, World Bank, and WHO, concludes that the world is not on track to achieve Sustainable Development Goal 7 (SDG 7) by 2030. According to the report, 655 million people still lack access to electricity, while 2 billion people do not have access to clean cooking solutions. Addressing these significant energy access gaps will require a diverse portfolio of clean energy technologies tailored to national circumstances. The report recognizes natural gas as one of the clean fuels for household cooking, alongside electricity, biogas, solar-based cooking technologies, alcohol fuels, and LPG, highlighting the role that multiple clean cooking solutions can play in expanding access to modern energy services.

China: China's National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) jointly released the 15^{th} Five-Year Plan for Building a New-Type Energy System on 25 June 2026, reaffirming natural gas as a key transition fuel and a strategic source of system flexibility to support the continued expansion of wind and solar power. The plan targets the expansion of the national gas transmission network to 500 bcm per year, an increase in domestic gas production to 300 bcm annually, and average annual growth in apparent gas consumption of 2.8%, reaching 489 bcm by 2030. While maintaining natural gas at 8% to 9% of the country's primary energy mix, the plan also establishes regional production targets, including 70 bcm per year for Sichuan Province, and promotes the development of gas infrastructure capable of supporting future applications such as hydrogen blending.

2 GAS CONSUMPTION

In the first five months of 2026, aggregated gas consumption in some of the major gas consuming countries, which account for 75% of global gas demand, decreased by 1.2% y-o-y to reach 1,440 bcm. Decline was recorded in North America and Southern Asia, while EU and Middle East showed growth.

2.1 Europe

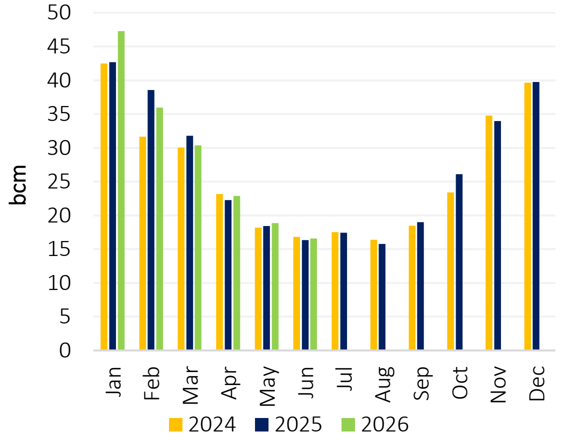
2.2.1 European Union

In June 2026, EU natural gas consumption increased by 1.4% y-o-y, reaching 16.6 bcm (Figure 7). The increase was primarily driven by the power sector, as an intense heatwave across much of Europe boosted electricity demand for cooling while lower wind and hydropower generation increased reliance on gas-fired power plants. Industrial gas consumption continued to provide steady support to overall demand, whereas residential consumption remained subdued owing to seasonal factors.

EU electricity generation increased by 2.3% y-o-y to 203 TWh. Gas-fired generation rose by 9% y-o-y (2.6 TWh), while coal-fired generation recorded the strongest increase among conventional sources, rising by 25% y-o-y. In contrast, wind generation declined by 11% y-o-y, while hydropower output decreased by 9% y-o-y. Solar generation continued its strong expansion, increasing by 10% y-o-y, supported by favourable seasonal conditions, whereas nuclear generation remained broadly stable, declining marginally by 0.7% y-o-y (Figure 8).

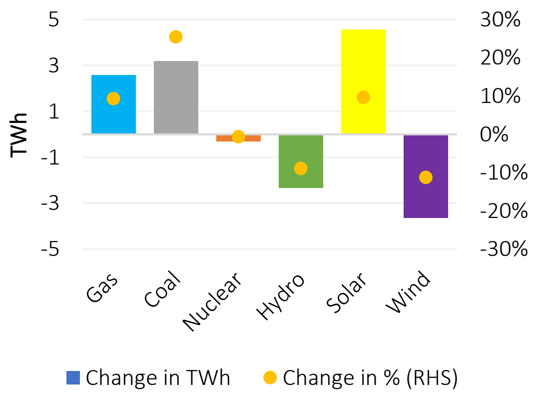
Within the power mix, non-hydro renewables remained the largest source, accounting for 44% of output, followed by nuclear (22%), natural gas (15%), hydropower (12%), and coal (8%). These developments highlight the continued expansion of solar power in Europe, while underscoring the important role of natural gas in maintaining system flexibility and balancing intermittent renewable generation during periods of weaker wind and hydro availability.

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 June 2026 (y-o-y change)



Source: GECF Secretariat based on data from Ember

In the first half of 2026, the EU's gas consumption rose by 1.1% y-o-y to 172 bcm.

2.1.1.1 Germany

In June 2026, Germany's natural gas consumption increased to 3.6 bcm, up by 6.6% y-o-y (0.2 bcm) (Figure 9). The increase was primarily driven by the power sector, as an intense heatwave raised the average temperature to 20.0°C from 19.1°C in June 2025, increasing cooling demand and boosting gas-fired electricity generation amid lower wind power output. Industrial gas consumption also remained resilient, rising by 2% y-o-y (Figure 10). Meanwhile, residential gas consumption remained subdued owing to seasonal factors.

Figure 9: Gas consumption in Germany

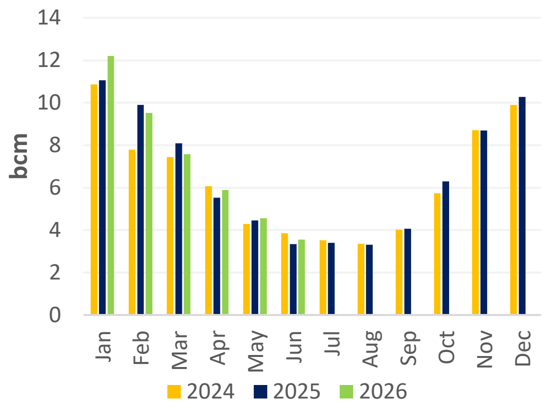
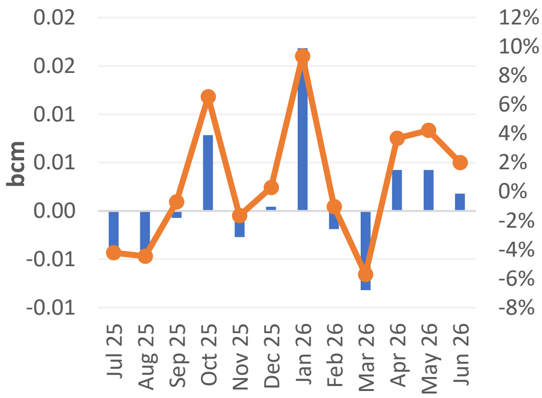


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Germany's electricity generation increased by 1.5% y-o-y to 34 TWh. The increase was supported by higher generation from natural gas, coal, and solar, while wind and hydropower output declined. Gas-fired generation increased by 22% y-o-y, while coal-fired generation rose by 21% y-o-y, compensating for the sharp decline in wind generation, which fell by 25% y-o-y. Hydropower generation also edged down by 5% y-o-y, whereas solar generation continued its strong seasonal performance, increasing by 15% y-o-y (Figure 11). Non-hydro renewables dominated Germany's power mix, representing 66% of total output, while coal and natural gas accounted for 16% and 13%, respectively (Figure 12).

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

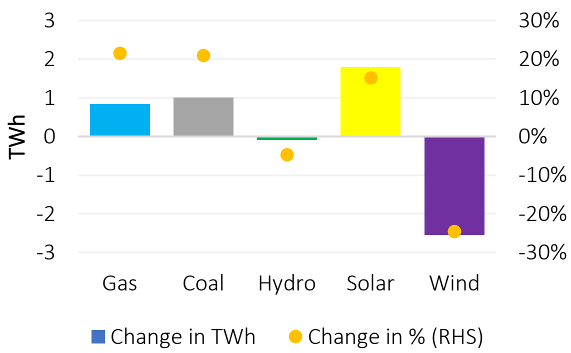
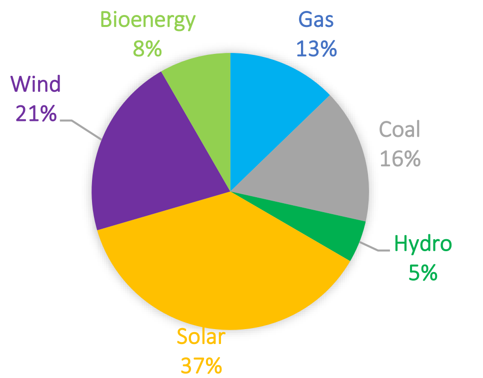


Figure 12: German electricity mix in June 2026



Source: GECF Secretariat based on data from LSEG and Ember

In the first half of 2026, Germany's gas consumption rose by 2.2% y-o-y to 43.3 bcm.

2.1.1.2 Italy

In June 2026, Italy's natural gas consumption declined by 0.7% y-o-y to 3.7 bcm (Figure 13). The slight decline was primarily driven by lower industrial and residential/commercial gas demand. Industrial gas consumption fell by 2.5% y-o-y, marking the third consecutive monthly contraction following the temporary recovery observed in February and March (Figure 14). Gas demand in the power generation sector remained robust, supported by an early summer heatwave that increased cooling needs and electricity demand.

Figure 13: Gas consumption in Italy

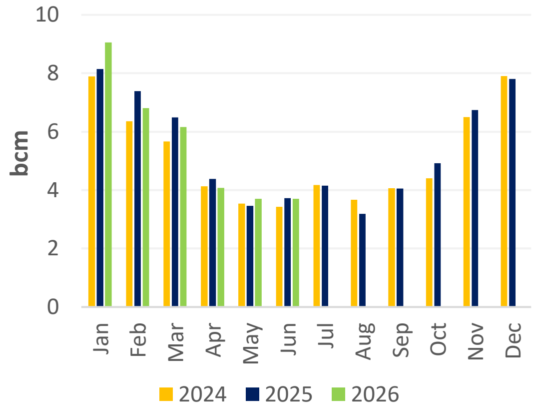
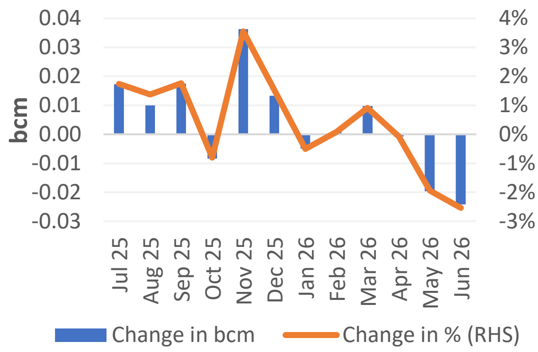


Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change)



Source: GECF Secretariat based on data from Snam

Italy's total electricity generation increased by 5.6% y-o-y to 21.9 TWh. Gas-fired power generation rose by 13% y-o-y, driven by stronger electricity demand for cooling and lower wind generation. Solar power increased by 16% y-o-y, and hydropower output rose by 24% y-o-y. In contrast, wind generation declined by 2% y-o-y (Figure 15). Natural gas remained a cornerstone of Italy's electricity system, accounting for 40% of total generation, while non-hydro renewables represented 39% of the power mix, highlighting the continued expansion of renewable energy alongside the essential role of natural gas in ensuring system flexibility and reliability during periods of weaker renewable output (Figure 16).

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

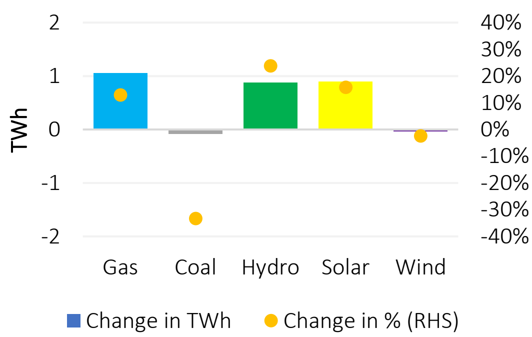
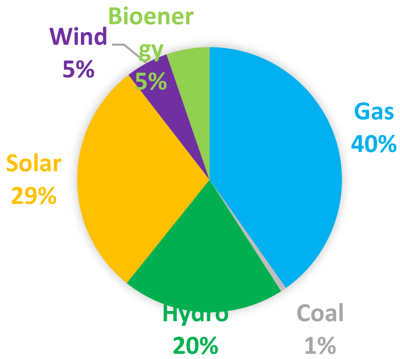


Figure 16: Italian electricity mix in June 2026



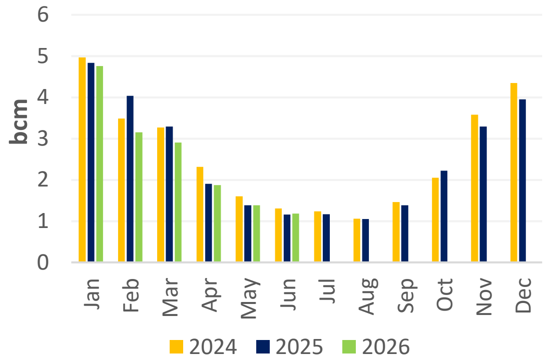
Source: GECF Secretariat based on data from Terna, LSEG and Ember

For the first half of 2026, Italy's gas consumption declined by 0.3% y-o-y to 33.5 bcm.

2.1.1.3 France

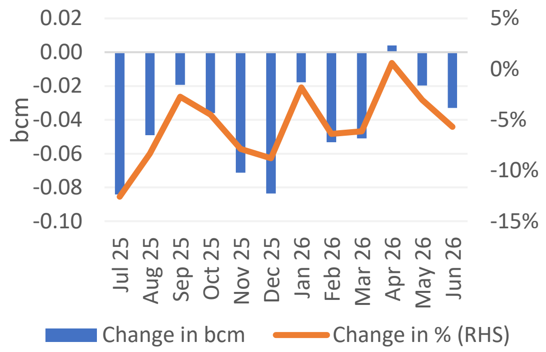
In June 2026, France's natural gas consumption increased by 2.1% y-o-y to 1.2 bcm (Figure 17). The increase was primarily driven by higher demand from the power generation sector, supported by stronger cooling needs during periods of elevated temperatures. Meanwhile, industrial gas consumption continued to contract, declining by 6% y-o-y (Figure 18), reflecting persistent weakness in energy-intensive industries. Residential gas consumption remained subdued owing to the summer season, which significantly reduced heating requirements

Figure 17: Gas consumption in France



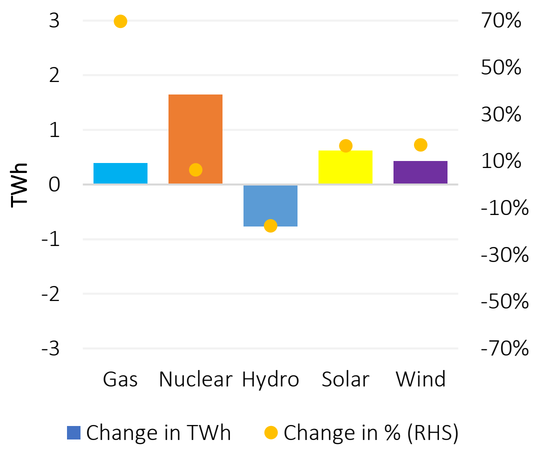
Source: GECF Secretariat based on data from GRTgaz

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



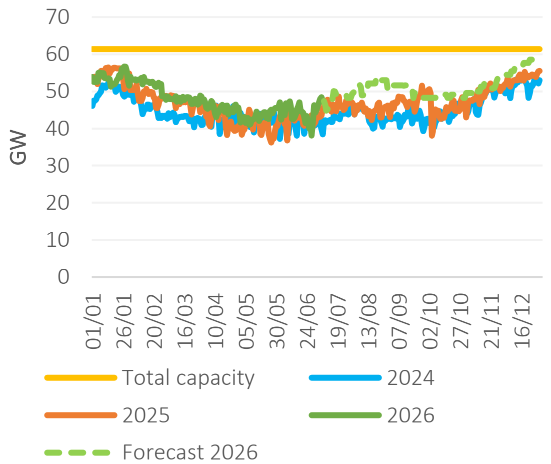
Total electricity generation in France increased by 6.2% y-o-y to 39.8 TWh. Gas-fired output recorded the strongest growth among all generation sources, surging by 70% y-o-y, supported by higher electricity demand for cooling during periods of elevated temperatures. Solar generation also expanded significantly, increasing by 16% y-o-y, while hydropower output declined by 18% y-o-y (Figure 19). Nuclear generation grew by 6.3% y-o-y, in line with the rise of nuclear capacity availability by 3.6% y-o-y and 1% m-o-m (Figure 20). Nuclear energy remained the dominant source in France's electricity mix, accounting for 70% of total generation, followed by non-hydro renewables (19%), hydropower (9%), and natural gas (2%).

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



Source: GECF Secretariat based on data from Ember

Figure 20: French nuclear capacity availability



Source: GECF Secretariat based on LSEG and RTE

For the first half of 2026, France's gas consumption declined by 8.1% y-o-y to 15.3 bcm.

2.1.1.4 Spain

In June 2026, Spain's gas consumption declined by 6.7% y-o-y to 2.1 bcm (Figure 21). The decline was mainly driven by weaker demand from both the power generation and industrial sectors. Gas consumption in the power sector fell by 19% y-o-y as stronger wind, solar and nuclear generation reduced the need for gas-fired electricity production. Industrial gas demand also declined by 3% y-o-y, extending the downward trend observed in recent months and reflecting continued weakness in industrial activity (Figure 22).

Figure 21: Gas consumption in Spain

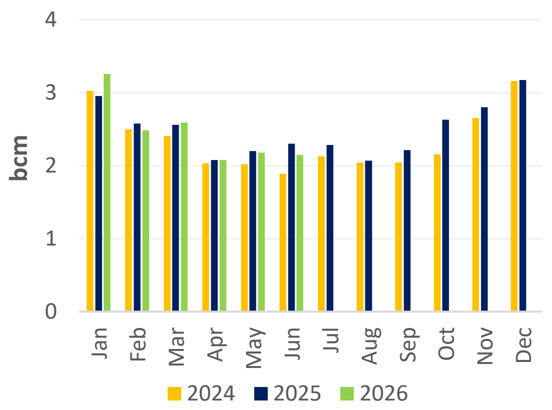
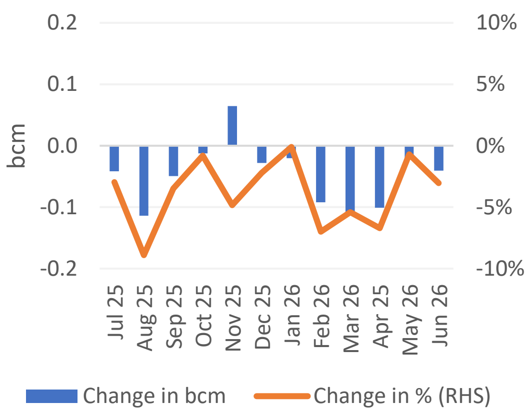


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Spain's electricity generation declined by 1.2% y-o-y to 22 TWh. Gas-fired generation recorded the largest decline among the major generation sources, falling by 19% y-o-y (Figure 23). In contrast, wind generation increased by 17% y-o-y, supported by favourable wind conditions, while nuclear and solar generation rose by 8% and 4% y-o-y, respectively. Hydropower generation, however, declined by 15% y-o-y. Within the electricity mix, non-hydro renewables remained the largest source of generation, accounting for 53% of total output, followed by nuclear (20%), natural gas (19%) and hydropower (8%) (Figure 24).

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

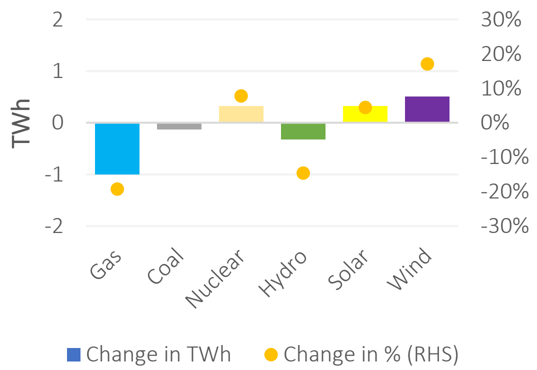
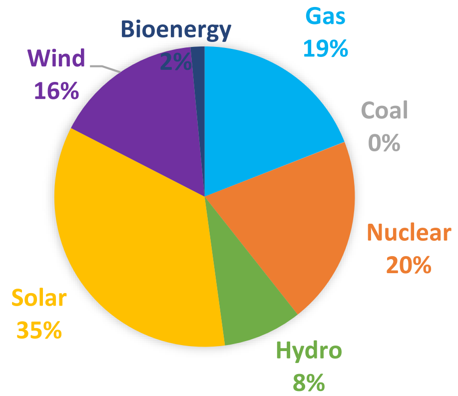


Figure 24: Spanish electricity mix in June 2026



Source: GECF Secretariat based on data from Ember and Ree

For the first half of 2026, Spain's gas consumption rose by 0.4% y-o-y to 14.7 bcm.

2.1.2 United Kingdom

In June 2026, gas consumption in the UK increased by 15% y-o-y to 2.7 bcm (Figure 25), primarily driven by significantly stronger demand from the power generation sector. Gas consumption for power generation surged by 48% y-o-y to 1.0 bcm, reflecting higher electricity demand during periods of elevated temperatures and increased cooling needs, as well as greater reliance on gas-fired generation. Residential gas consumption increased modestly by 2% y-o-y to 1.7 bcm, while industrial gas demand remained broadly stable, declining by only 0.8% y-o-y (Figure 26).

Figure 25: Gas consumption in the UK

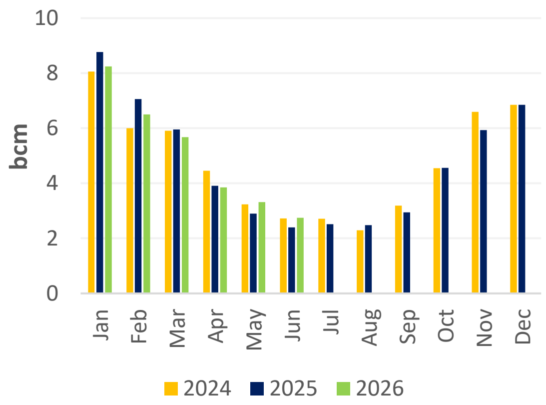
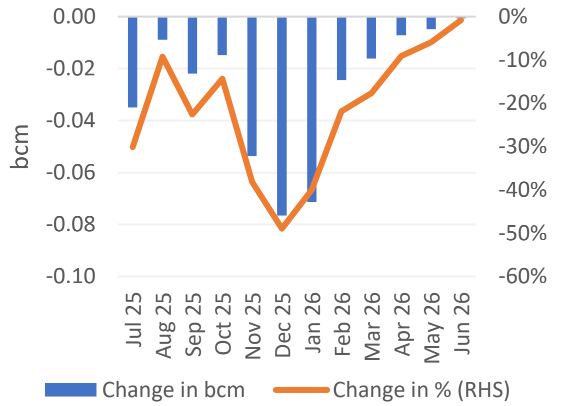


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

For the first half of 2026, aggregated gas consumption in the EU and UK increased by 0.6% y-o-y (1.1 bcm) to reach 202 bcm (Figure 27). The EU was the main contributor to this growth, with a y-o-y increase of 1.8 bcm (Figure 28).

Figure 27: YTD EU and UK gas consumption

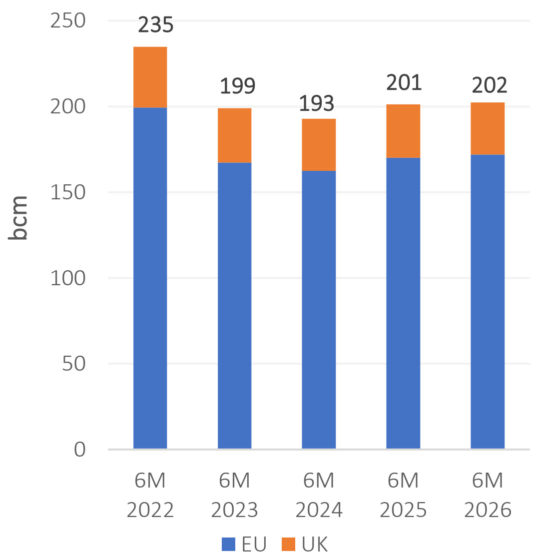
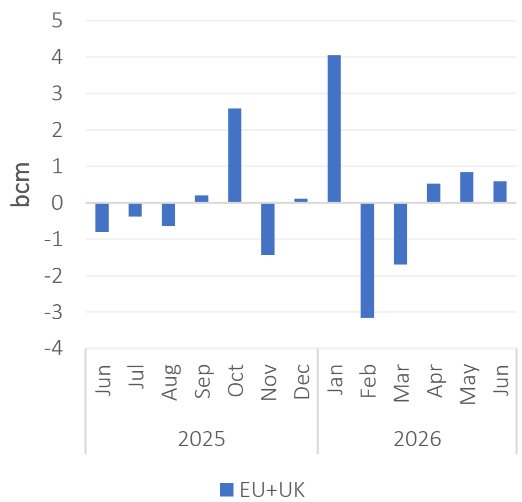


Figure 28: Y-o-y variation in EU and UK gas consumption



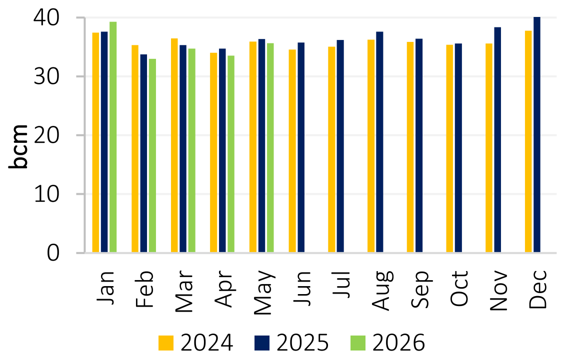
Source: GECF Secretariat based on data from LSEG

2.2 Asia

2.2.1 China

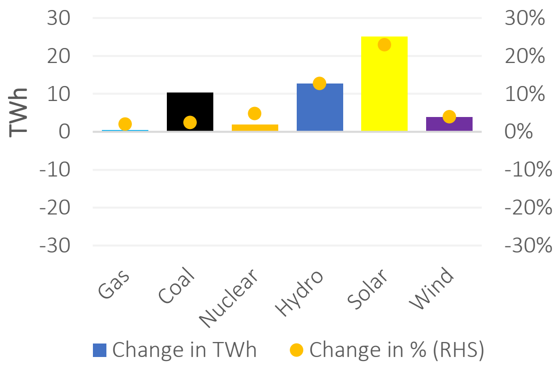
In May 2026, China's apparent gas demand (production + LNG and pipeline gas imports) declined by 2.1% y-o-y to 35.6 bcm (Figure 29), marking the fourth consecutive monthly contraction. Elevated LNG prices and reduced LNG availability following supply disruptions in the Middle East curtailed gas demand, particularly in Guangdong, where power sector gas consumption was constrained by lower gas supply and increased reliance on coal. Despite these headwinds, China's electricity generation increased by 6.7% y-o-y to 863.2 TWh in May, supported by robust economic activity and rising seasonal electricity demand (Figure 30). For the period January–May 2026, Chinese gas consumption declined by 0.9% y-o-y to 176.2 bcm.

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

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

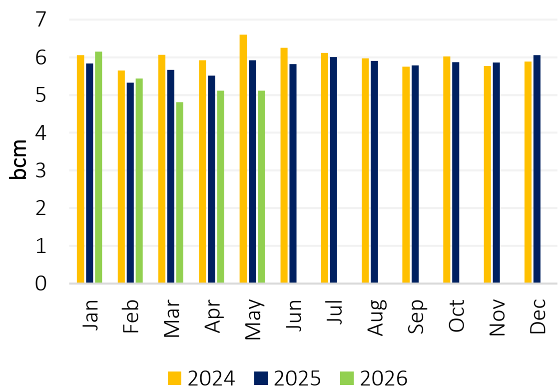


Source: GECF Secretariat based on data from Ember

2.2.2 India

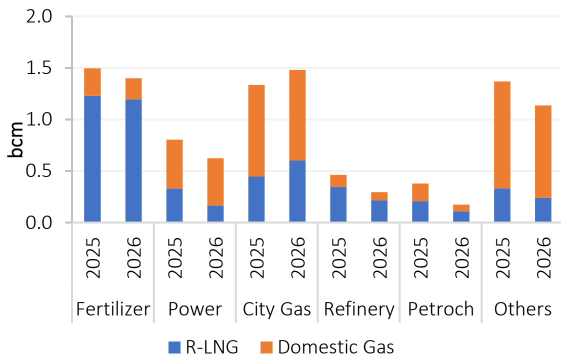
In May 2026, India's gas consumption declined by 13% y-o-y to 5.1 bcm, reflecting weaker demand across several key consuming sectors (Figure 31). The decline was primarily driven by lower gas consumption in the petrochemical, refinery, power generation, fertilizer and other industrial sectors. Consumption in the petrochemical, refinery, power generation and fertilizer sectors fell by 54% (0.2 bcm), 36% (0.17 bcm), 23% (0.18 bcm) and 6.5% (0.1 bcm) y-o-y, respectively. In contrast, gas demand in the city gas distribution sector increased by 11% (0.15 bcm), making it the largest source of gas consumption with a 29% share of total demand, followed by the fertilizer sector with a 27% share (Figure 32).

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

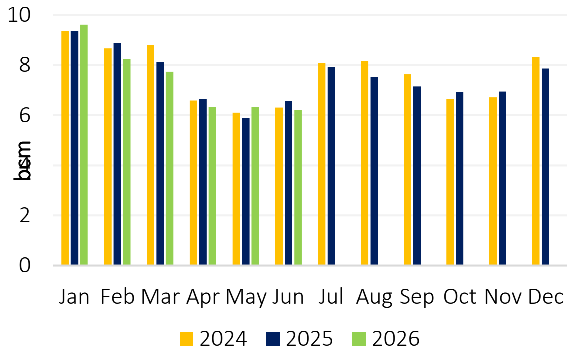
Figure 32: India's gas consumption by sector in May 2026



2.2.3 Japan

In June 2026, Japan's gas consumption declined by 5.4% y-o-y to 6.2 bcm (Figure 33). Power demand fell by 7% y-o-y, while gas-fired electricity generation declined by 16% y-o-y as coal-fired generation increased and became more competitive than natural gas. Utilities actively managed LNG inventories. Stable LNG inventories and adequate generation capacity are expected to support electricity supply reliability during the summer season despite forecasts of above-normal temperatures.

Figure 33: Gas consumption in Japan

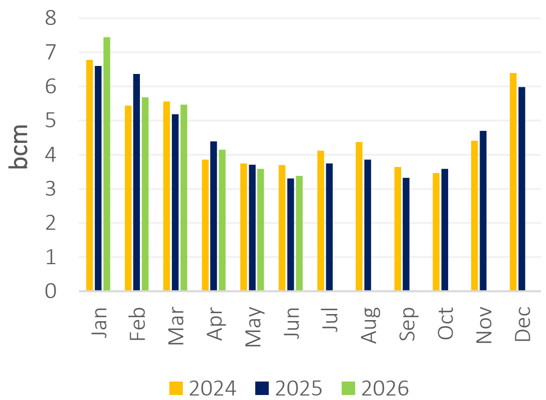


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In June 2026, South Korea's gas consumption increased by 2.4% y-o-y to 3.4 bcm (Figure 34). Despite higher temperatures and a 1.9% y-o-y increase in power demand, gas-fired generation declined by 6% y-o-y as coal-fired generation rose by 9%, marking the first month since March that coal output exceeded gas-fired generation. The continued shift from gas to coal, supported by coal's improved competitiveness and operational flexibility, moderated LNG demand despite stronger cooling needs during the month.

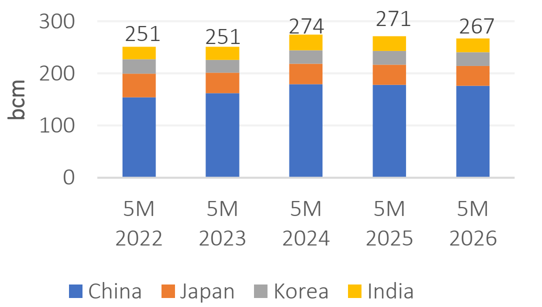
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

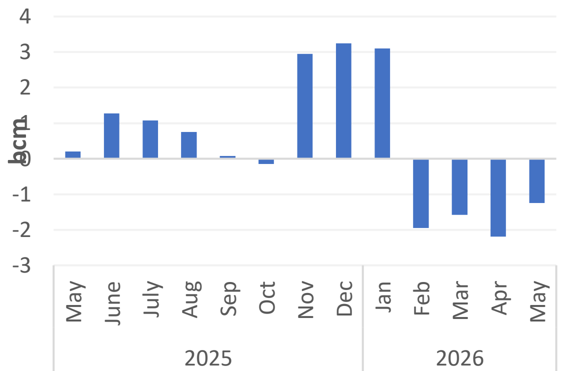
The regional aggregated gas consumption data for the period January-May 2026 in major Asian gas consuming countries, namely China, India, Japan and South Korea, declined by 4 bcm y-o-y to reach 267 bcm (Figure 35), driven largely by a decrease of a total of 1.6 bcm each for both China and India (Figure 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

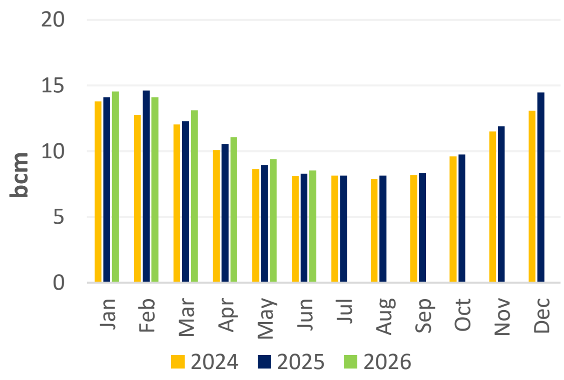


2.3 North America

2.3.1 Canada

In June 2026, Canada's gas consumption rose by 2.8% y-o-y to 8.5 bcm (Figure 37), supported primarily by continued growth in the industrial and power generation sectors. Gas demand from these sectors increased by 3% y-o-y to 7.5 bcm, reflecting sustained industrial activity and steady electricity demand. Residential and commercial gas consumption also recorded modest increases of 1.5% and 0.4% y-o-y, respectively. For the period January–June 2026, Canada's gas consumption increased to 70.7 bcm, up 2.8% y-o-y.

Figure 37: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.3.2 US

In June 2026, US natural gas consumption declined by 5.8% y-o-y to 63.7 bcm (Figure 38), reflecting lower demand across all major consuming sectors. Residential and commercial gas consumption fell by 15% y-o-y, as milder weather reduced space-cooling and heating requirements in several regions. Industrial gas demand remained relatively stable, declining by just 0.8% y-o-y, while gas consumption in the electric power sector decreased by 1.6% y-o-y, reflecting increased competition from renewable energy sources and nuclear generation.

Total electricity generation in the US increased by 3% y-o-y to 410 TWh. Despite remaining the largest source of electricity generation, natural gas-fired output declined by 1.6% y-o-y (Figure 39). Natural gas continued to dominate the electricity mix with a 40% share, followed by nuclear (17%), coal (14%), solar (12%), wind (10%), hydropower (6%), and bioenergy (1%).

Figure 38: Gas consumption in the US

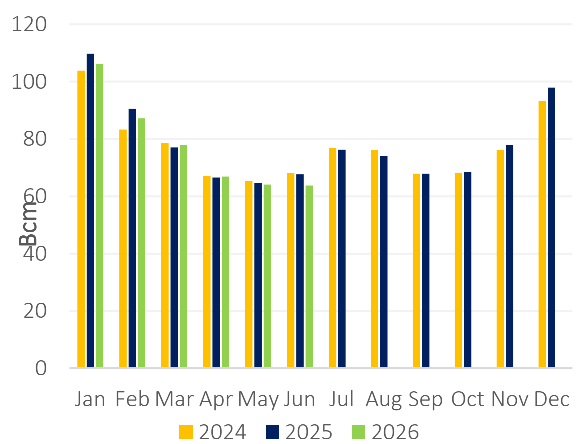
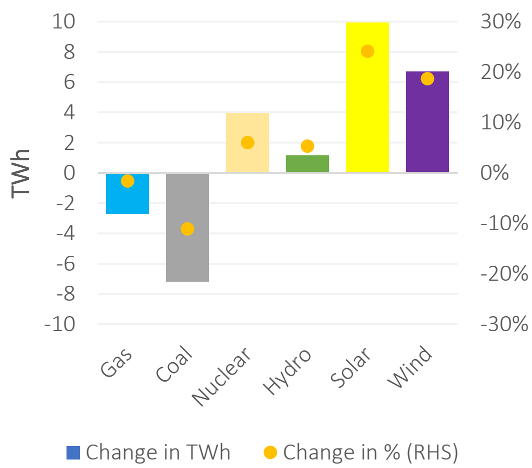


Figure 39: Electricity production in US in June 2026



Source: GECF Secretariat based on data from EIA and LSEG

For the first half of 2026, US gas consumption declined by 2.2% y-o-y to 466 bcm.

2.4 Other developments

2.4.1 Sectoral developments

Taiwan expands gas-fired power capacity to support coal phase-out: Taiwan's Ministry of Economic Affairs unveiled an ambitious power development plan to add 26 GW of gas-fired generation capacity between 2026 and 2035, representing a significant increase from the previous target of 15.6 GW. The expanded strategy aims to accelerate the phase-out of coal-fired power generation while strengthening the island's energy security, as LNG and gas-fired generation already account for more than half of Taiwan's electricity mix. Operating the expanded fleet is expected to increase power-sector LNG demand to around 34 Mtpa, far exceeding the combined nameplate capacity of Taiwan's three existing LNG import terminals. Given delays in the construction of permanent onshore terminals, state-owned utility Taipower is accelerating the deployment of FSRUs to meet the anticipated increase in LNG imports.

Mexico invests $8.1 billion in gas pipeline expansion to support gas-fired power growth: Mexico plans to invest 140 billion pesos ($8.1 billion) over the next four years to construct 12 new gas pipelines, expanding critical infrastructure to strengthen the country's power sector. With natural gas already accounting for 60% of Mexico's electricity generation, the pipeline expansion aims to enhance supply reliability, reduce the risk of seasonal power shortages, and meet an expected increase in electricity demand of 65 GW by 2030. To support this growth, the state-owned utility Comisión Federal de Electricidad (CFE) is constructing seven gas-fired power plants, planning to begin construction on four additional facilities, and preparing to launch tenders for two more plants in the coming months.

Australia raises 2050 gas-fired power capacity forecast to strengthen grid reliability: The Australian Energy Market Operator (AEMO) has increased its 2050 gas-fired power capacity forecast to 17 GW in its 2026 Integrated System Plan, up from 14 GW in the December 2025 draft. The upward revision reflects the growing need for flexible, dispatchable generation to complement renewable energy and maintain reliability in the National Electricity Market, particularly during periods of peak winter demand. With around 8 GW of the current 12 GW of gas-fired capacity expected to retire by 2050, Australia will need to develop 13 GW of new gas-fired capacity, alongside additional gas transport, storage, and LNG import infrastructure.

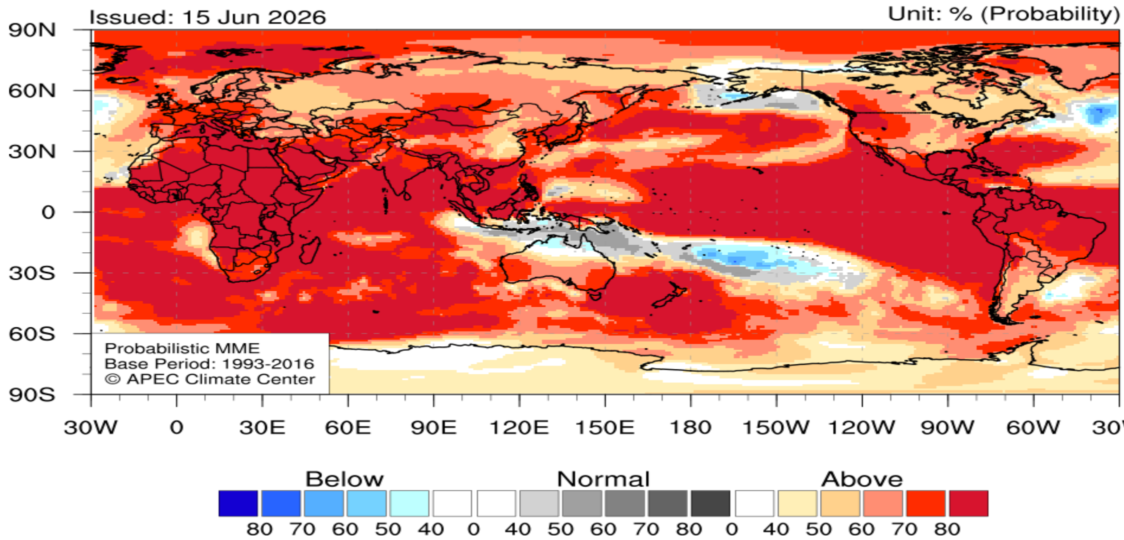
US data centre boom drives global gas turbine orders to a 25-year high: Global orders for new gas-fired power plants reached 130 GW in 2025, the highest level in 25 years, driven by the rapid expansion of US data centres. According to the IEA, if US data centres were treated as a separate country, they would rank as the world's second-largest source of gas turbine demand over the past five quarters. This surge has nearly tripled US investment in gas-fired power generation to $32 billion, straining global gas turbine manufacturing capacity and creating supply bottlenecks that could delay power projects in emerging LNG-importing countries.

Japan targets up to 55 GW of gas-fired power capacity by 2040 to meet rising electricity demand: Japan's Ministry of Economy, Trade and Industry (METI) has proposed developing between 39 GW and 55 GW of new and replacement gas-fired power capacity by 2040 to strengthen energy security and address a projected 16 GW power supply gap driven by growing electricity demand, including from the expansion of AI and data centres. To accelerate deployment amid tight global gas turbine manufacturing capacity, the government plans to auction between 5.5 GW and 8 GW of generation capacity annually over seven years beginning in fiscal year 2026. The new gas-fired plants will be required to incorporate lower-carbon technologies, such as hydrogen co-firing or CCS, within 10 years of entering operation.

2.4.2 Weather forecast

According to the APEC Climate Centre, El Niño alert is now issued for the second time, after three months of El Niño Watch in the last previsions. Between July - September 2026, above-normal temperatures are expected across most regions worldwide, except in some parts of the North Atlantic (Figure 40).

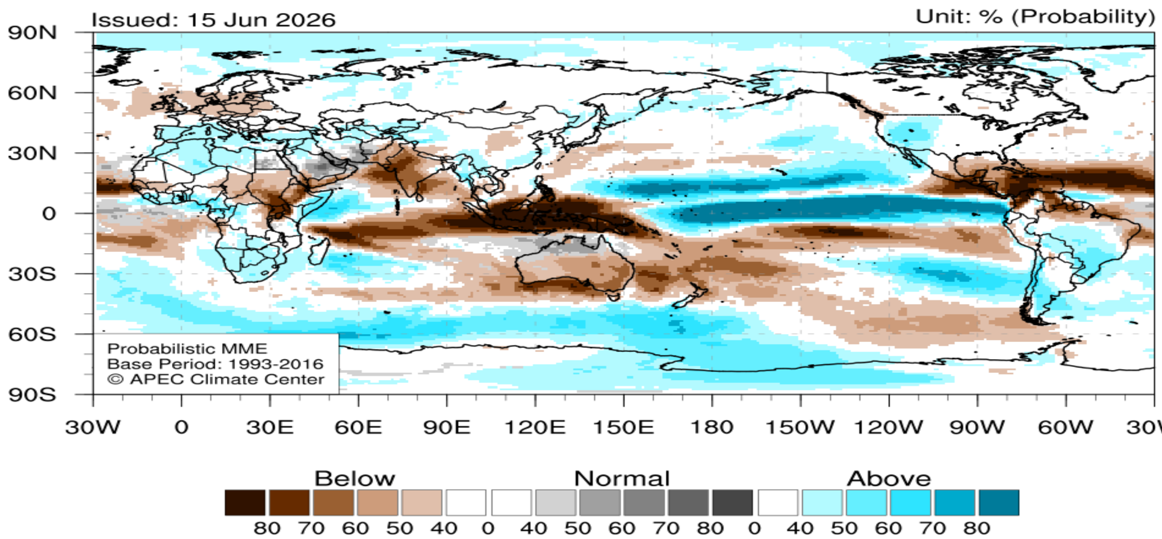
Figure 40: Temperature forecast for July - September 2026



Source: APEC Climate Center

Precipitation is expected to be above average in the Equatorial Pacific, Sub-equatorial North Pacific regions, Southeastern Pacific, the eastern tip of East Africa, the western Equatorial Indian Ocean, the western United States, and southern southeastern South America, the Mediterranean, North and South Africa, parts of Central Asia, southern China, and central South America. Below-average precipitation is forecast for the central equatorial South Pacific, parts of Indonesia, the western tropical southern Indian Ocean, East Africa, India, the tropical North Atlantic, Central America, the northern tip of South America, the tropical southwestern Pacific, Australia, central China and parts of Europe (Figure 41).

Figure 41: Precipitation forecast July - September 2026

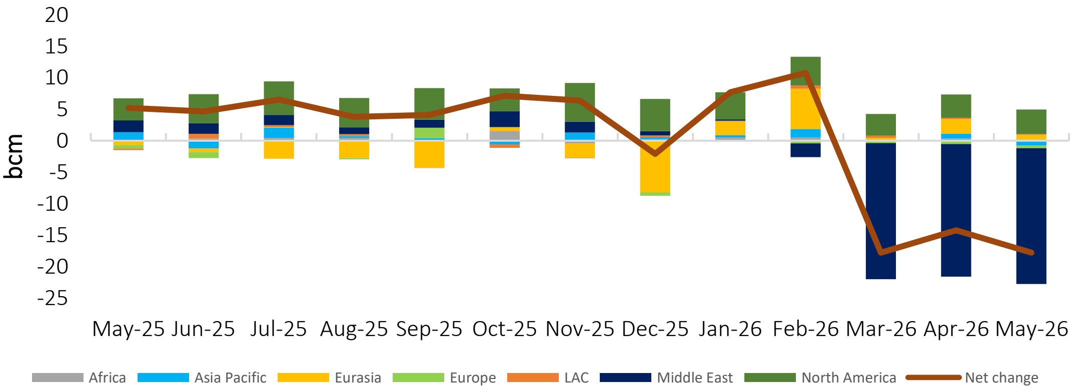


Source: APEC Climate Centre

3 GAS PRODUCTION

In May 2026, global gas production was estimated to have declined by 5% y-o-y to stand at 333 bcm. The contraction was primarily driven by the supply shock in the Middle East resulting from the ongoing geopolitical conflict and the closure of the Strait of Hormuz, which reduced the region's gas production by nearly one-third compared with a year earlier, largely owing to lower LNG output. By contrast, continued growth in North American gas production partially mitigated the global supply decline, with increased output in the US and Canada providing a significant offset to the disruption in the Middle East (Figure 42).

Figure 42: Y-o-y variation in global gas production



Source: GECF Secretariat estimation

From a regional perspective, there was a structural shift in the regional distribution of the global gas supply, driven by the conflict in the Middle East, with North America keeping its extending position as the frontrunner producing region (dominated by US production), accounting for 34% of global gas production (rising from 31% in May 2025), followed by Eurasia and the Middle East with 20%, and Asia Pacific with 18%, whilst the Middle East share declined to 13% down from 18% in May 2025. Africa, Europe, Latin America and the Caribbean (LAC) held shares ranging from 4% to 6% (Figure 43).

For the period January - May 2026, global gas production was estimated to have declined by 1.8% y-o-y to stand at 1,718 bcm (Figure 44). This decline was mainly driven by the reduction in the Middle East supply; however, it was partially counterbalanced by the strong production growth in North America and Eurasia.

Figure 43: Regional gas production in April 2026

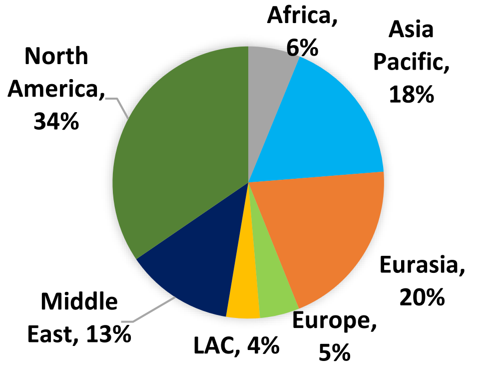
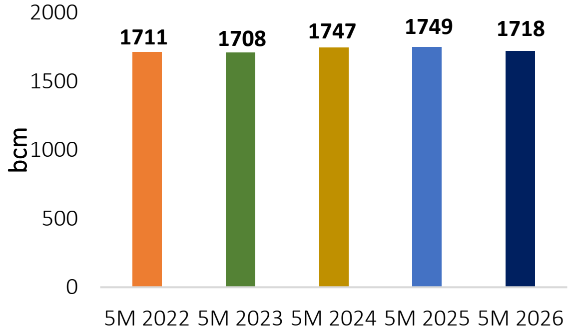


Figure 44: YTD global gas production



Source: GECF Secretariat estimation

3.1 Europe

In May 2026, gas production in Europe witnessed a 2.7% y-o-y reduction, with a total output of 14.2 bcm (Figure 45). This is the fifth month in 2026 to record a y-o-y decrease in the European output, mainly driven by lower gas production in UK and the Netherlands. However, the magnitude of overall European production decline in May was limited by a rise in Denmark's gas output, mainly from Tyra phase II gas field in the North Sea, along with the slight increase in Türkiye's gas production (Figure 46). Notably, monthly gas production in the EU stood at 2.3 bcm (2.5% decline compared to 2025 level), with the Netherlands and Romania maintaining their positions as top producers.

Figure 45: Europe's monthly gas production

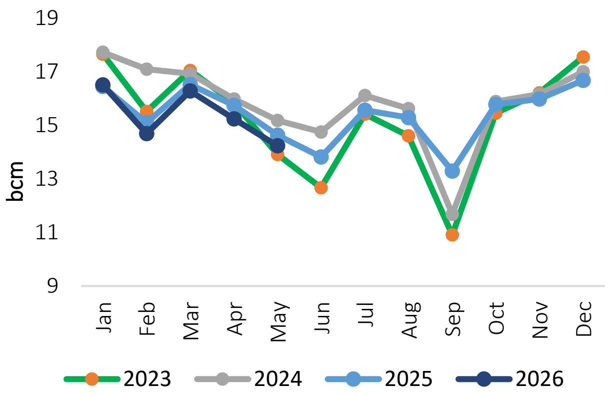
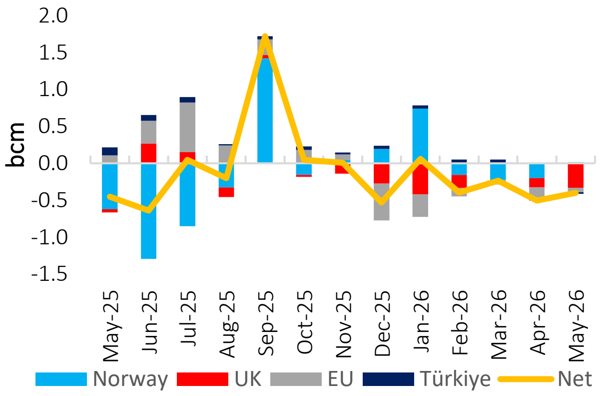


Figure 46: Y-o-y variation in Europe's gas production



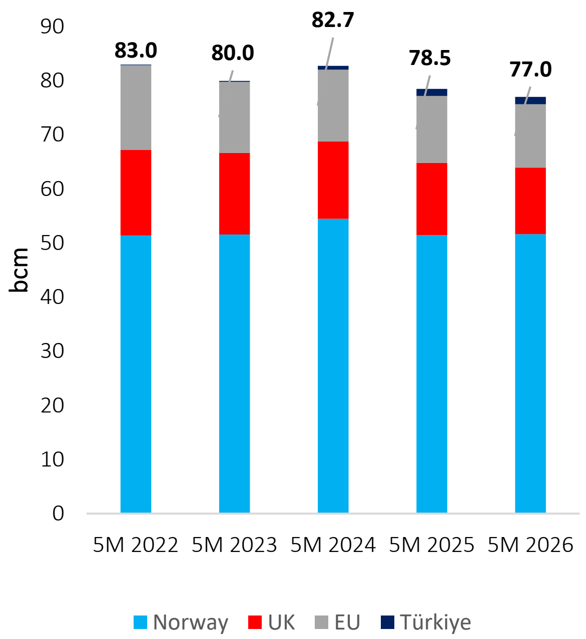
Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

In Jan-May 2026, the aggregated gas output in Europe amounted to 77 bcm (Figure 47), representing a 1.9% y-o-y decline, compared with the production level during the same period in 2025, and recording the lowest output in the last 5-year period.

This result indicates a negative production projection in Europe for the full year of 2026. Norway - the largest European gas producer with nearly 67% 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 notable declines.

Denmark is on a positive trajectory trend for the full year of 2026, driven by the rise of Tyra gas field, with both Romania and Türkiye also showing positive projections.

Figure 47: YTD Europe's gas production



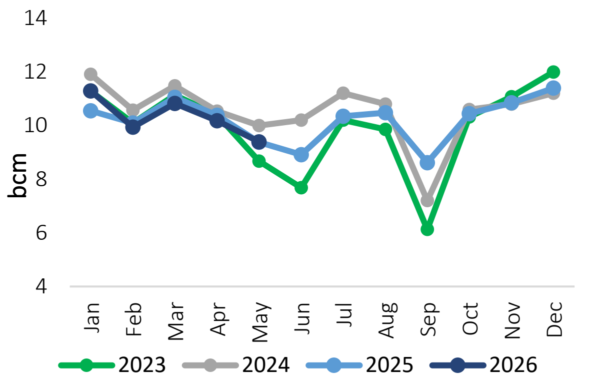
Source: GECF Secretariat based on data from Refinitiv, the Norwegian Offshore Directorate and JODI Gas

3.1.1 Norway

Norway's gas output recorded a marginal rise of 0.2% y-o-y, to stand at the level of 9.4 bcm (Figure 48). Notably, the 130 mcm/d Troll gas field witnessed reduced production for 2 days, as a result of planned activity. In addition, the 31.9 mcm/d Oseberg gas platform underwent planned maintenance, which ceased its output for the entire month.

For the period Jan–May 2026, cumulative output amounted to 51.5 bcm, representing a 0.3% y-o-y growth, driven by lower planned and unplanned maintenance durations.

Figure 48: Trend in gas production in Norway



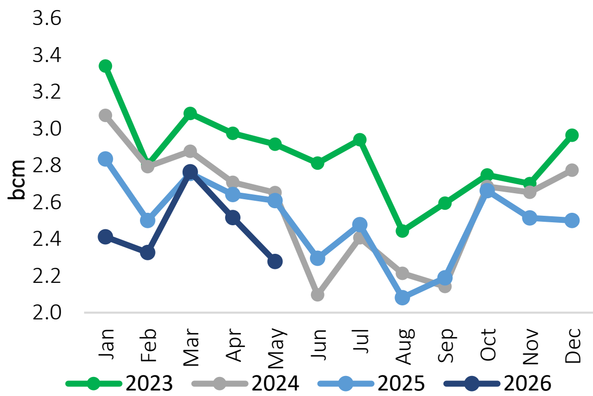
Source: GECF Secretariat based on data from the Norwegian Offshore Directorate

3.1.2 UK

UK gas production declined by 12% y-o-y to stand at 2.3 bcm (Figure 49). This is a continuation of the declining trend over the past period, with this being the lowest May monthly production over the last decade, as a result of reduced output from the UK's mature fields, lack of new gas projects and longer than expected maintenance periods. The 8.2 mcm/d Bacton Perenco terminal underwent planned maintenance activities that stopped its production for 3 days.

In Jan–May 2026, cumulative production declined by 7.8% y-o-y to 12.3 bcm.

Figure 49: Trend in gas production in the UK



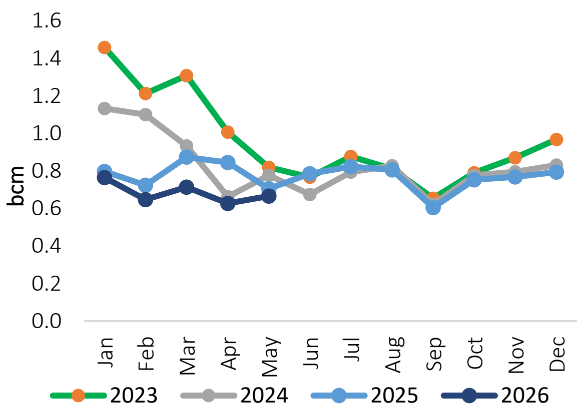
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' annual gas production kept its downwards trend, with a 5.7% y-o-y decrease, to stand at 0.67 bcm (Figure 50).

For the period Jan-May 2026, cumulative production in the Netherlands reached 3.4 bcm, representing a 13.4% y-o-y reduction. With the absence of new field development or rejuvenation, this production drop from the ageing Dutch fields is likely to continue in the coming years, with the remaining reserves reaching depletion in 8 years.

Figure 50: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In May 2026, gas output in Asia Pacific was estimated to stand at 58.3 bcm, representing a 1.3% y-o-y decline. This decrease was driven by the declining output in some regional Asia Pacific producers, including China. For the period Jan–May 2026, the cumulative production reached 296.3 bcm, representing a 0.5% rise.

3.2.1 China

In May 2026, China's gas production witnessed its first monthly decline in years to stand at 21.7 bcm, representing a 2% y-o-y reduction (Figure 51). This decline was mainly driven by the shut-down of some main offshore production platforms for maintenance activities. Coal bed methane production continued its annual growth as well, with 10% y-o-y rise, to stand at 1.3 bcm. For the period Jan-May 2026, cumulative production in China reached 111.6 bcm, representing a 1.8% y-o-y growth (Figure 52).

Figure 51: Trend in gas production in China

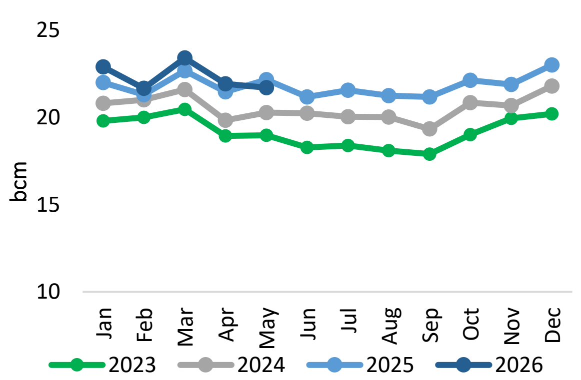
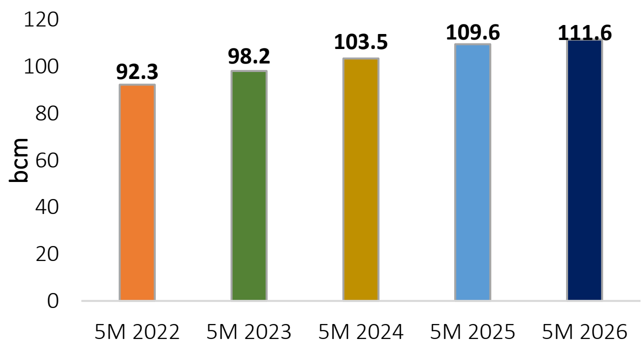


Figure 52: YTD China's gas production



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

3.2.2 India

In May 2026, India's gas production continued its negative trend, declining by 4.9% y-o-y to stand at 2.8 bcm (Figure 53). The decrease was driven by a reduction in offshore gas output, which represented 74% of Indian production, along with reduced production from the onshore Rajasthan field. Meanwhile, the CBM gas fields recorded a 1.4% y-o-y growth, mainly from the West Bengal fields. For the period January - May 2026, the cumulative production in India amounted to 13.8 bcm, representing a 4.6% y-o-y reduction (Figure 54).

Figure 53: Trend in gas production in India

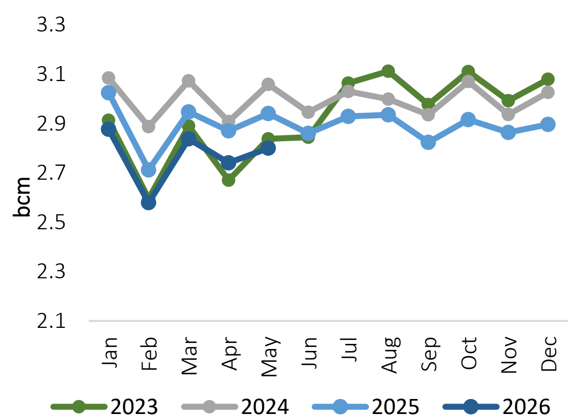
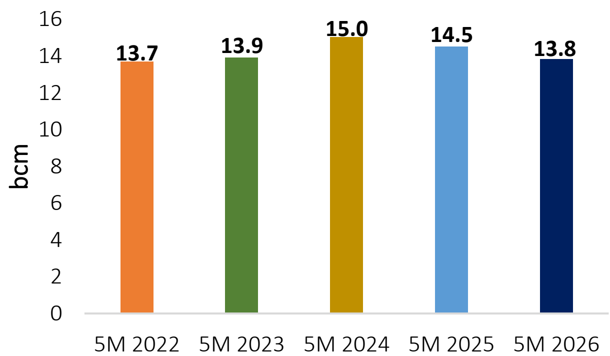


Figure 54: YTD India's gas production

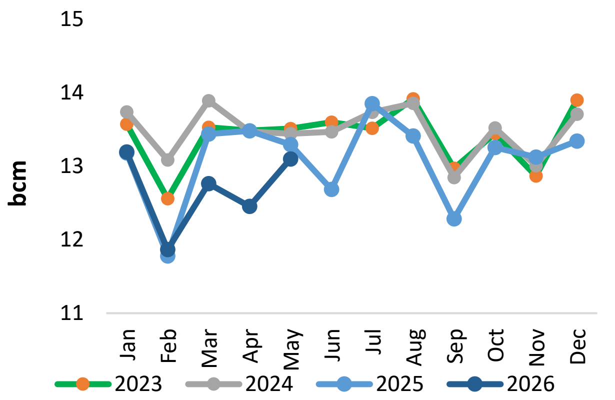


Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In May 2026, Australia's gas production declined by 1.4% y-o-y, to stand at 13.1 bcm (Figure 55). Gas production from CBM fields amounted to 3.4 bcm, representing a 2.3 % y-o-y rise and accounted for 26% of the domestic production. Notably, Australia kept its position as the global leader in terms of CBM production, with sustained growth in the past years and CBM being used as feedstock for LNG export terminals. For the period January - May 2026, the cumulative production in Australia amounted to 63.4 bcm, representing a 2.8% y-o-y reduction.

Figure 55: Trend in gas production in Australia

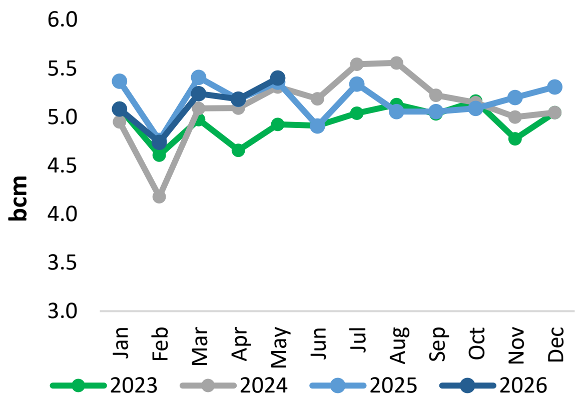


Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In May 2026, Indonesia's gas output rose by 0.8% y-o-y to 5.4 bcm (Figure 56). This was driven by an extensive development drilling campaign, with 35 new development wells drilled during the month. Their incremental production was able to exceed the natural decline in the producing fields. In addition, 7 new exploration wells were drilled, which represented an acceleration for the drilling activity. For the period January - May 2026, the cumulative production reached 25.6 bcm, representing a 1.7% y-o-y decline

Figure 56: Trend in gas production in Indonesia

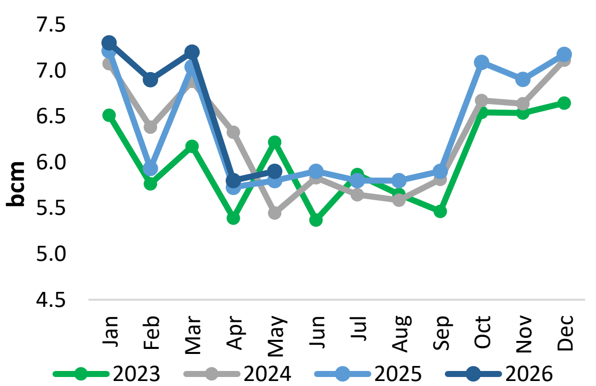


Source: GECF Secretariat based on data from SKK Migas and JODI Gas

3.2.5 Malaysia

In May 2026, Malaysia's gas output was estimated at 5.9 bcm, representing a 1.7% y-o-y production growth (Figure 57). For the period January - May 2026, the cumulative production in Malaysia reached 33.1 bcm, representing a 4.4% y-o-y growth.

Figure 57: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

In May 2026, gas production in North America (including Mexico) rose by 3.6% y-o-y to reach 114.8 bcm, driven by strong gas supply growth in the US and Canada. In January - May 2026, cumulative production in North America reached 566 bcm, representing a 3.6% y-o-y growth.

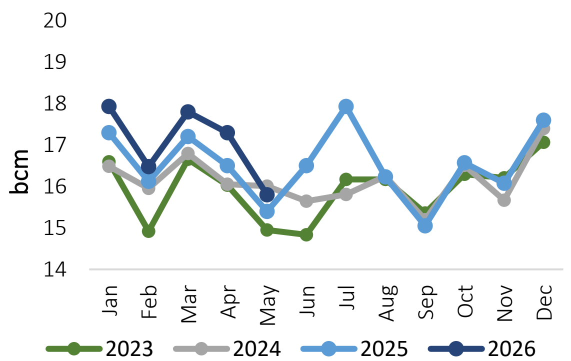
3.3.1 Canada

In May 2026, Canada's gas production grew by 2.6% y-o-y to 15.8 bcm (Figure 58), supported by an LNG export rise. From a regional perspective, Alberta was responsible for 9.2 bcm of the production, mainly originating from the Bakken shale production, whilst British Columbia accounted for 6.4 bcm, stemming from tight gas production from the Montney Basin.

For the period January - May 2026, the cumulative production amounted to 85.3 bcm, representing a 3.4% y-o-y uptick. In this context, Canada is well poised to continue strong production growth, driven by the rising LNG exports and favourable market conditions.

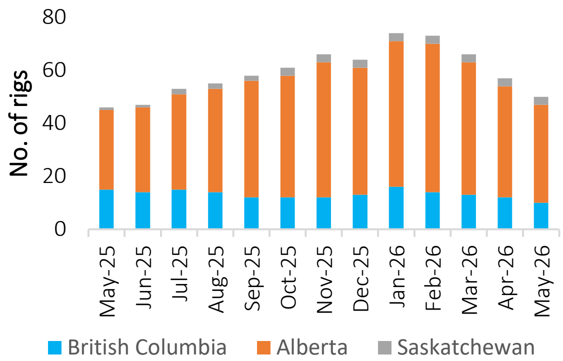
In terms of gas drilling activity, there was an overall 7-rig-decrease in May 2026, with Alberta and British Columbia releasing 5 and 2 drilling rigs, respectively, while Saskatchewan kept the same level. Moreover, this still represented a 4-rig-increase in the number of drilling rigs, as compared to May 2025 (Figure 59).

Figure 58: Trend in gas production in Canada



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

Figure 59: Gas rig count in Canada



Source: GECF Secretariat based on data from LSEG

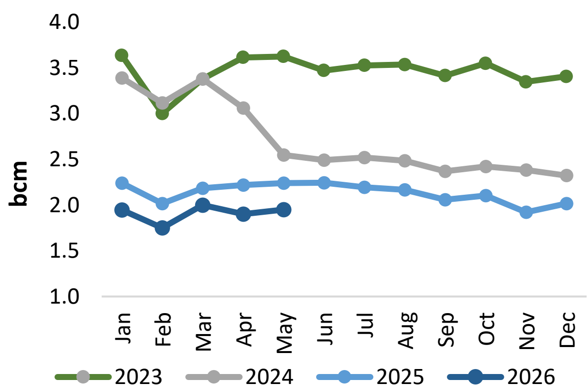
3.3.2 Mexico

In May 2026, Mexico's gas output was estimated at 1.95 bcm, representing a production decrease of 13% y-o-y (Figure 60). This reduction was driven by the natural decline in the Mexican legacy fields and lack of new gas fields' commission.

Associated gas production from oil fields represented 39% of the total Mexican production, at 0.76 bcm.

For the period Jan-May 2026, the cumulative production in Mexico amounted to 9.5 bcm, representing a 12.4% y-o-y decline.

Figure 60:Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In June 2026, US total gas production kept its consistent growth trend, with monthly output rising by 3.3% y-o-y to 94.1 bcm (Figure 61). This growth reflected the favourable market dynamics, driven by the increased Henry Hub gas prices, rising gas demand, along with the increased feed gas directed to LNG exports terminals.

In terms of supply distribution, shale dry gas production sustained its frontrunner position in the US dry gas output, accounting for 83% and represented the main driver for the growth, with a 3.5% uptick, while conventional gas and associated gas production from shale oil represented the remaining 17%. In terms of field type, associated gas production represented one quarter of total gas output. From a regional perspective, the Appalachian region accounted for 32% of total production, followed by the Permian region output with 23% and Haynesville with 14%.

For the period Jan-Jun 2026, cumulative gas production in the US reached 565 bcm (Figure 62), representing 4% y-o-y growth and therefore provided evidence on the positive trajectory of the US gas supply for the full year.

Figure 61: Trend in gas production in the US

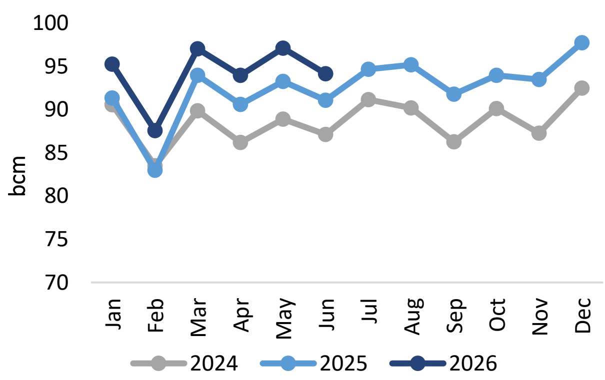
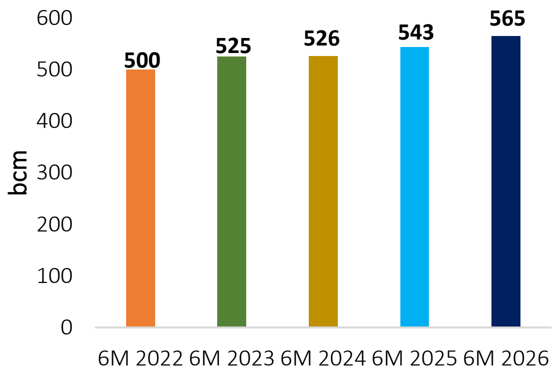


Figure 62: YTD gas production in the US



Source: GECF Secretariat based on data from the US EIA

As of June 2026, the number of gas drilling rigs operating in the US stood at 123, marking a 4-rig decrease compared to May 2026, and an 11-rig rise, compared to June 2025 (Figure 63), giving evidence of accelerated upstream activity in the US. Additionally in June 2026, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 4,959, marking a 25-well m-o-m decrease and 588 wells lower than June 2025 (Figure 64). This reduction in DUCs reflected the reliance of the operators on their inventory of drilled wells, targeting the benefits of bringing the gas to market, during favourable conditions.

Figure 63: Gas rig count in the US

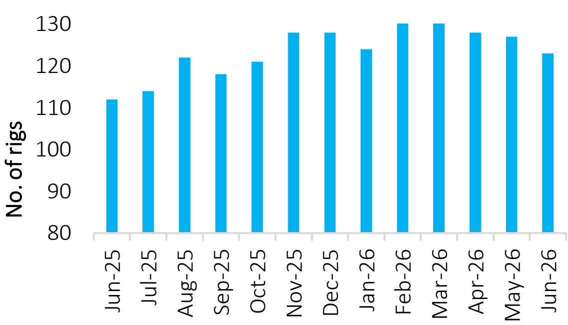
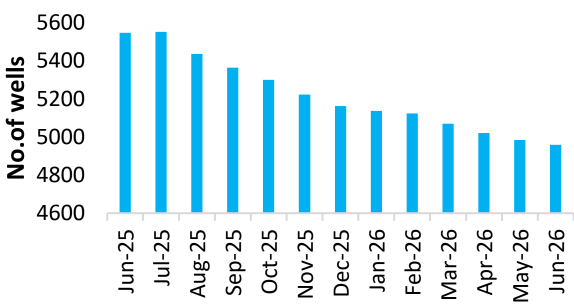


Figure 64: DUC wells count in the US



Source: GECF Secretariat based on data from Baker Hughes

Source: GECF Secretariat based on data from the US EIA

3.4 Latin America and the Caribbean (LAC)

In May 2026, gas production in LAC was estimated at 13.2 bcm (0.6% y-o-y rise), mainly driven by higher output in Argentina. For the period January - May 2026, cumulative production reached 63.8 bcm, representing a 2% y-o-y growth.

3.4.1 Argentina

In May 2026, Argentina's gas production stood at 4.8 bcm, representing a 5.2% y-o-y growth (Figure 65). Most of the gas output originated from the Vaca Muerta (shale gas) Basin, however the conventional gas fields witnessed a 9.4% the decline. Notably, shale gas production witnessed a 20% y-o-y rise to stand at 2.95 bcm, accounting for 61% of total gas production (Figure 66). Moreover, tight gas production reached 0.395 bcm representing an 8.2% share of the total production, whilst the remaining output was produced from conventional fields. For the period January – May 2026, cumulative production in Argentina reached 21.1 bcm, a 1.2% y-o-y rise.

Figure 65: Trend in gas production in Argentina

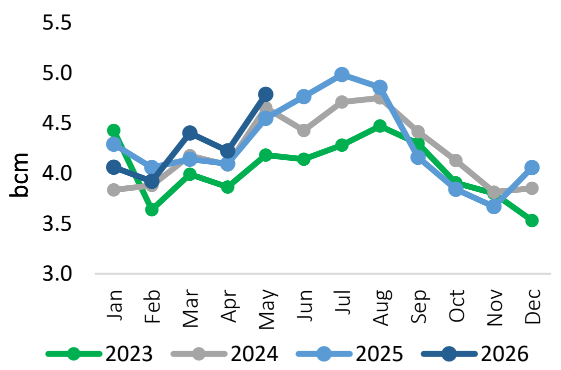
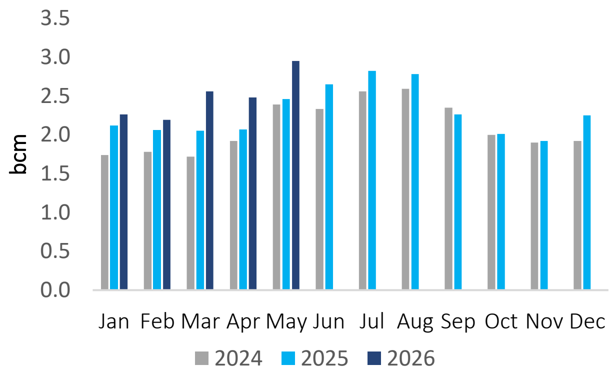


Figure 66: Shale gas output in Argentina



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

3.4.2 Brazil

In May 2026, Brazil's marketed gas production witnessed a marginal decline of 0.8%, to achieve an output level of 1.7 bcm, driven by high gross gas production that stood at 6.4 bcm (20 % y-o-y rise) and large reinjection volumes (Figure 67), with the pre-salt fields representing 79% of the total production. Notably, 88% of production originated from offshore fields. In terms of distribution, 58% of gross gas production was reinjected into reservoirs, while there was a 30% increase in flaring compared to the previous month – due to the commissioning of the FPSO P-79 in the Búzios Field – and a 37% reduction compared to May 2025. (Figure 68). For the period January - May 2026, cumulative production reached 9.1 bcm, a 17.4% y-o-y growth.

Figure 67: Marketed gas production in Brazil

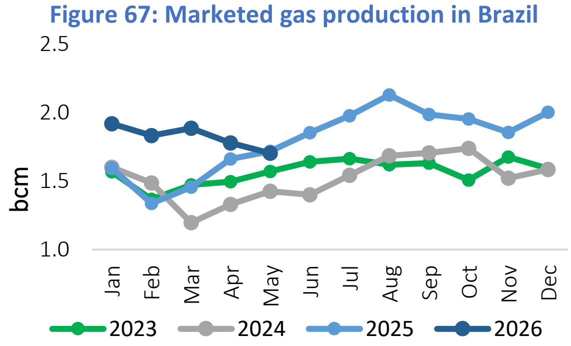
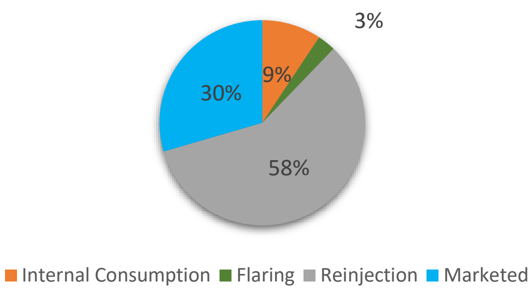


Figure 68: Distribution of gross gas production



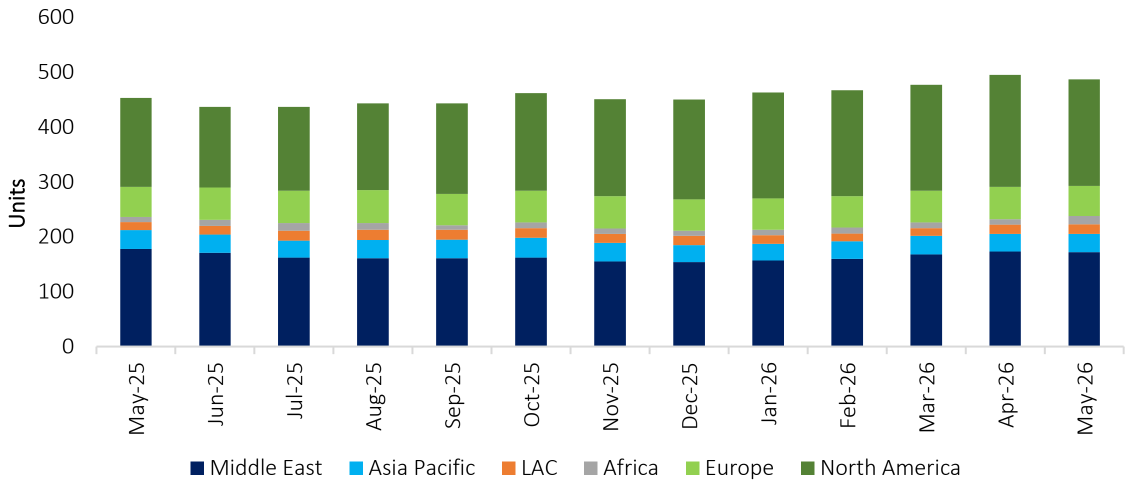
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In May 2026, the number of gas drilling rigs globally slowed down by 6 additional units m-o-m, reaching 467 rigs (Figure 69). This was driven mainly by the reduced drilling activity in North America, specifically in Canada. Onshore drilling accounted for the majority with 434 units, while offshore accounted for 33 rigs.

Figure 69: Trend in monthly global gas rig count



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

In May 2026, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 310 million barrels of oil equivalent (boe) (Figure 70). Oil dominated the discoveries with 79% of the volumes (245 million bbl), while natural gas constituted 11 bcm.

In terms of regional distribution, the Middle East (Iraq) dominated the new discovered volumes with 75%, Africa (mainly Egypt) followed by 23% (Figure 71). The Nidoco N-2 discovery, which is located lies the West Abu Madi concession area in Kafr El-Sheikh offshore Egypt, was the most significant gas discovery during the month. For the period January - May 2026, cumulative discovered volumes reached 2.2 billion boe.

Figure 70: Monthly discovered oil and gas volumes

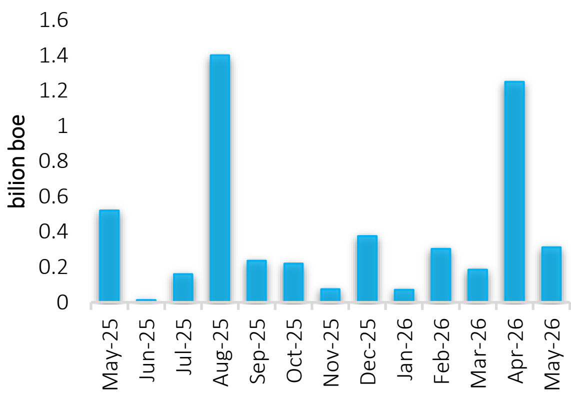
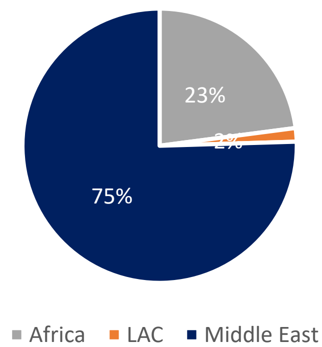


Figure 71: Discovered oil and gas volumes in May 2026 by region



Source: GECF Secretariat based on data from Rystad

3.5.2 Regional developments

Eni enters the upstream of the Argentina LNG integrated project: Eni announces the Sale and Purchase Agreement (SPA) for the acquisition of a 32% interest in three upstream blocks (Meseta Buena Esperanza, Aguada Villanueva, and Las Tacanas), which are part of the unconventional Vaca Muerta basin, in Argentina. Following the completion of the transaction, which remains subject to approval by the relevant authorities, participation in the three upstream blocks will be held by YPF with 36%, Eni with 32%, and XRG with 32. The three blocks will be part of the Argentina LNG integrated development, an upstream-midstream project aimed at leveraging the Vaca Muerta gas resources, helping to strengthen the country's position as a global LNG supplier in the long term. These assets' resources will feed the 12 Mtpa of LNG capacity (via two floating LNG units of 6 Mtpa each).

UAE awarded new concession agreement for Bab Gas Cap: On 24 June 2026, the UAE's Supreme Council for Financial Economic Affairs (SCFEA) announced the award of a concession agreement to develop the large gas cap resources of the Bab onshore oil field. The Bab Gas Cap Concession will be operated by ADNOC Group (60%) alongside partners TotalEnergies (10%), bp (10%), CNPC (8%), INPEX Corporation (5%), ZhenHua (4%) and GS Energy Corporation (3%). Production capacity is expected to be about 1.5 Bcf/d, approximately 15% of ADNOC Gas' operational gas processing capacity. The UAE is also pursuing its capacity expansion aims with other partners including ExxonMobil at Upper Zakum, and at the Umm Shaif and Nasr Oil fields where TotalEnergies is also a partner. This new concession will contribute to the UAE's parallel goal of gas self-sufficiency and building out its LNG export capacity at Ruwais.

BP started commercial gas production at Azerbaijan's ACG field: According to BP, the commercial production of non-associated gas has begun at the Azeri-Chirag-Gunashli (ACG) field off the coast of Azerbaijan. ACG, which has been producing oil for nearly three decades, holds estimated non-associated gas resources of 115 bcm (4 tcf) of recoverable reserves, with potential upside to 6 tcf. The first well was drilled from the existing West Chirag platform in the Azerbaijani sector of the Caspian Sea, establishing it as a critical integrated oil and gas asset.

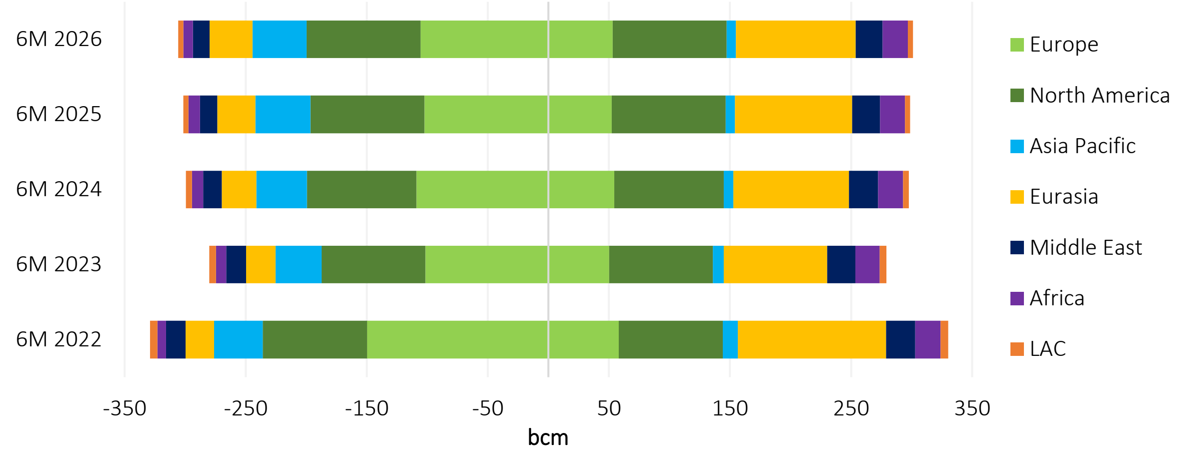
QatarEnergy signs commercial discovery declaration for Block 10 offshore Cyprus: QatarEnergy has signed a commercial discovery declaration for the Glaucus and Pegasus fields in Block 10, offshore Cyprus, as well as a collaboration statement, together with the Government of Cyprus and ExxonMobil. Signed in Nicosia, the declaration represents an important milestone in advancing the development of Cyprus' offshore resources. It also reflects the strong and constructive relationship between the parties and their shared commitment to continued collaboration and long-term strategic engagement, encompassing both the development of Block 10 and broader future opportunities. Under the declaration, the parties will work together to advance regulatory engagement and approvals, as well as development and production planning, in support of the next phase of Block 10 activities.

4 GAS TRADE

4.1 PNG trade

Cumulative global PNG imports between January and June 2026 grew by 1% y-o-y, reaching an estimated 306 bcm (Figure 72). This growth was driven by rising import volumes in Kazakhstan, Canada, and the EU, which offset reduced inflows to the US, Mexico, and China. Eurasia maintained its status as the leading PNG exporting region, commanding a 33% share of global trade flows in 2026, while intra-Asian flows saw a 3% y-o-y increase.

Figure 72: Global PNG imports (-) and exports (+) by region

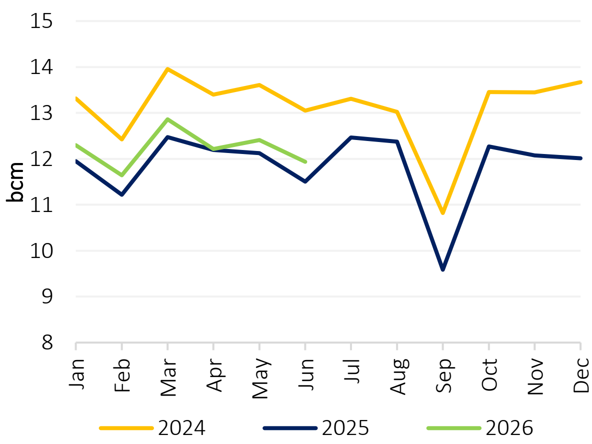


Source: GECF Secretariat based on data from Cedigaz, ENARGAS, Eurostat, GACC, JODI, LSEG and US EIA

4.1.1 Europe

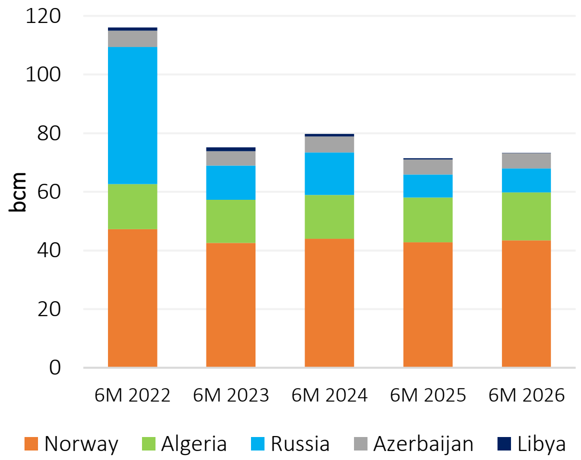
In June 2026, EU PNG imports rose 4% y-o-y to 11.9 bcm (Figure 73), though the daily rate of 398 mmcmd reflected a 1% decline m-o-m. This brought the EU's cumulative PNG imports for the first half of the year to 73 bcm, up by 3% y-o-y. This expansion was characterised by increased flows from all major suppliers with the exception of Libya (Figure 74).

Figure 73: Monthly PNG imports to the EU



Source: GECF Secretariat based on data from LSEG

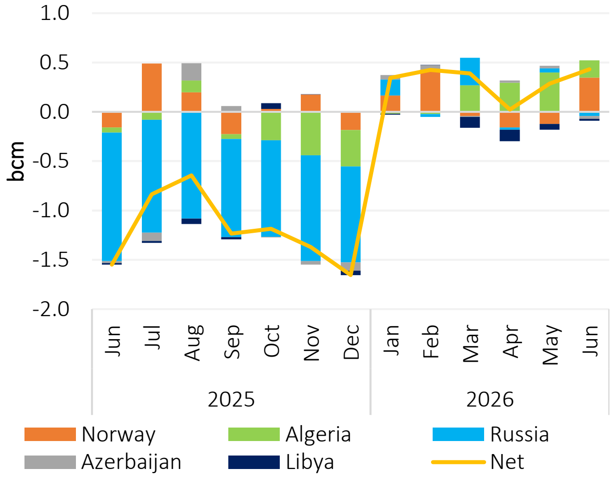
Figure 74: Year-to-date EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

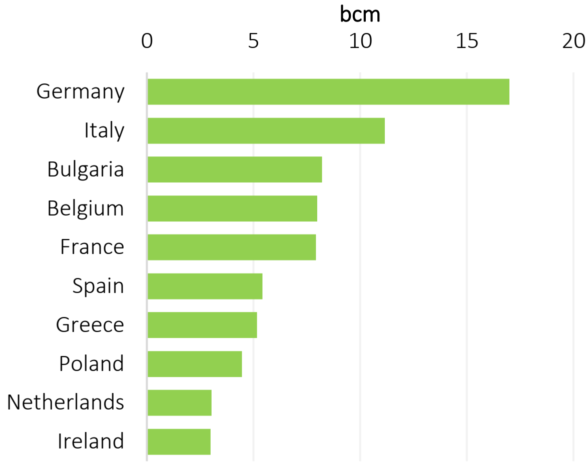
A surge in Algerian supply underpinned a consistent y-o-y expansion in the EU's PNG imports during each month of 2026 (Figure 75). From January to June, imports increased across almost all regional entry points, barring the Netherlands. France, Spain, and Poland recorded the largest increases in PNG imports during the first half of the year (Figure 76).

Figure 75: Y-o-y variation in EU PNG supply



Source: GECF Secretariat based on data from LSEG

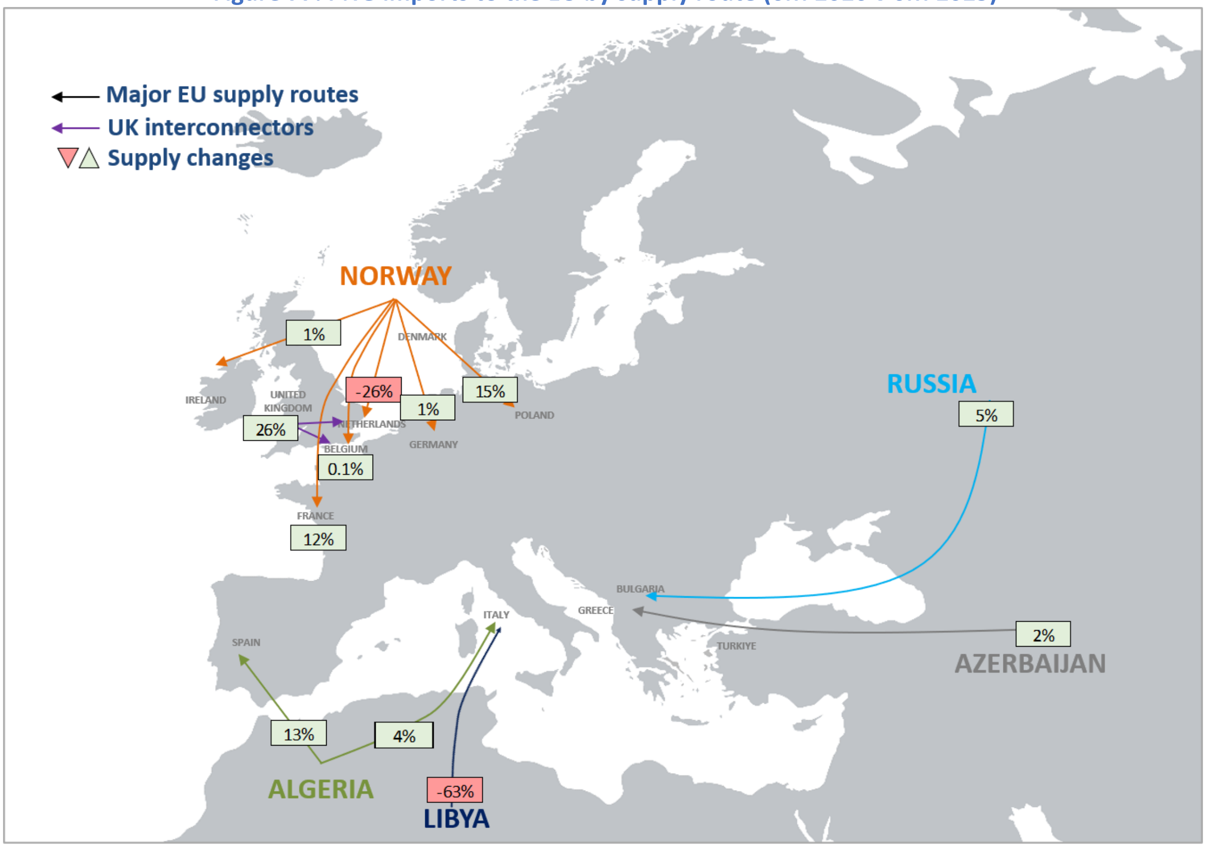
Figure 76: EU PNG imports by entry, after 6M 2026



Source: GECF Secretariat based on data from LSEG

Figure 77 shows the PNG imports to the EU via the major supply routes during the 6M 2026 period, compared with 6M 2025. Norwegian supply to Poland and France expanded by 15% and 12% y-o-y respectively, whilst Algerian deliveries to Spain grew by 13%. Similarly, Russian pipeline gas via TurkStream increased by 5% y-o-y. Meanwhile, the interconnectors with the UK delivered net 3.2 bcm of regasified LNG to mainland Europe in 2026 thus far, representing a 26% y-o-y surge.

Figure 77: PNG imports to the EU by supply route (6M 2026 v 6M 2025)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

In May 2026, China imported 7.1 bcm of PNG, which was virtually unchanged y-o-y (Figure 78). However, at 230 mmcmd, this volume represented a 4% increase m-o-m. PNG accounted for 52% of China's total gas imports during May, sustaining the dominance over LNG observed for four consecutive months. Furthermore, PNG comprised 51% of China's total gas imports for 2026 to date, with cumulative PNG imports reaching 32 bcm, representing a minor 1% decrease y-o-y (Figure 79).

Figure 78: Monthly PNG imports in China

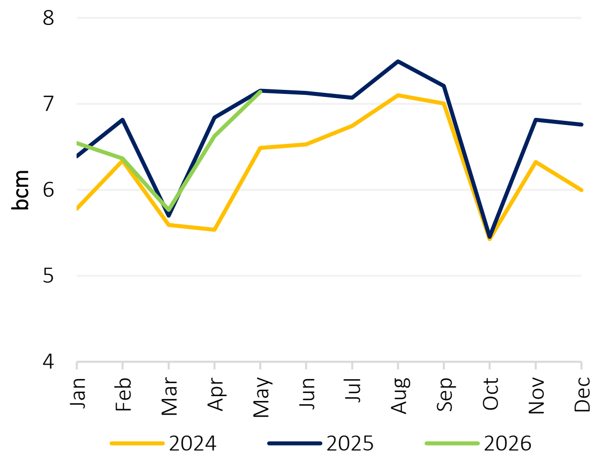
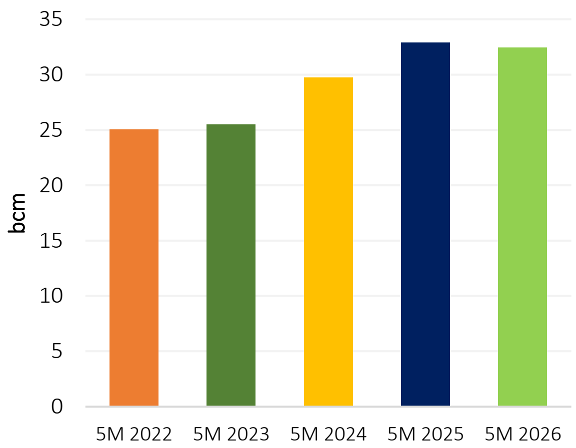


Figure 79: Year-to-date PNG imports in China



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

Singapore's PNG imports from Indonesia and Malaysia reached 0.64 bcm in April 2026, marking increases of 21% y-o-y as well as 18% m-o-m (Figure 80). Over the first four months of 2026, cumulative PNG imports rose by 18% to reach 2.4 bcm.

During the same month, Thailand imported 0.36 bcm of PNG from Myanmar, a 58% increase y-o-y but a 1% decline m-o-m (Figure 81). This brought Thailand's cumulative 2026 PNG imports to 1.4 bcm, representing a 22% decrease y-o-y.

Figure 80: Monthly PNG imports in Singapore

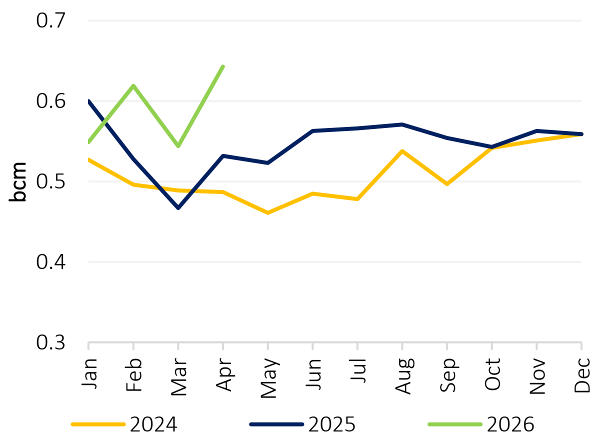
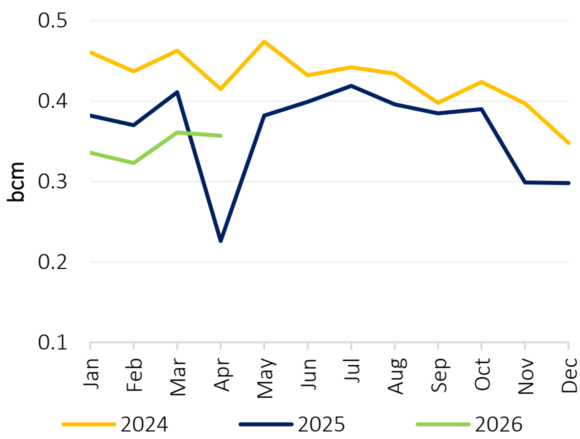


Figure 81: Monthly PNG imports in Thailand

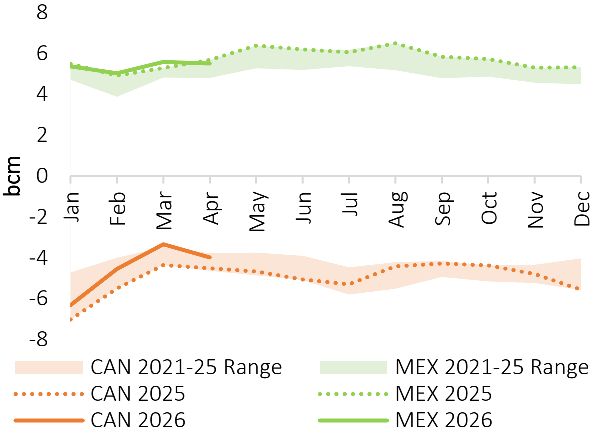


Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

In April 2026, Mexico imported 5.5 bcm of PNG from the US, representing a 3% decline y-o-y and a 1% decrease m-o-m (Figure 82). Following the first four months of 2026, total Mexican imports reached 21 bcm, remaining unchanged y-o-y. During the same month, net PNG flows from Canada to the US totalled 4.0 bcm, representing a 12% decrease y-o-y but a 19% increase m-o-m. Gross flows from Canada to the US fell m-o-m to 6.1 bcm, whilst flows in the opposite direction from the US to Canada also declined m-o-m to 2.1 bcm. For 2026 to date, cumulative net flows from Canada to the US dropped by 15% y-o-y to reach 18 bcm.

Figure 82: Net US PNG exports (+) and imports (-)

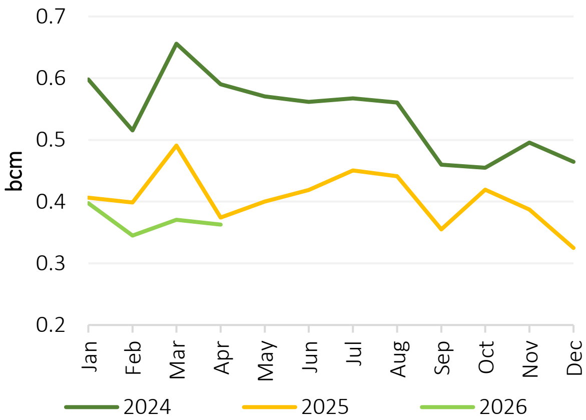


Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

In April 2026, Bolivia exported 0.36 bcm of PNG, representing a 3% decline y-o-y (Figure 83). However, at 12 mmcmd, the daily export rate rose by 1% m-o-m. For the first four months of 2026, cumulative Bolivian exports contracted by 12% y-o-y to reach 1.5 bcm. During the same month, Argentina exported 0.34 bcm of PNG to Brazil, Chile, and Uruguay, representing a 16% increase y-o-y. However, at 11 mmcmd, the daily export rate fell by 6% m-o-m. Over the first four months of 2026, cumulative Argentinian PNG exports rose by 19% y-o-y to reach 1.4 bcm.

Figure 83: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

Nigeria accelerates $20B export route through Chad and Libya: Nigeria's Federal Government and the Netoil consortium are advancing a landmark $20 billion "Renewed Hope" gas pipeline project spanning Nigeria, Chad and Libya. The initiative aims to transport 30 bcm of natural gas annually from Nigeria's southern reserves to Europe via a subsea link to Sicily. By leveraging the Petroleum Industry Act to attract global investment, Nigeria seeks to monetise its resources while providing Europe with an alternative to diversify its energy supply.

Capacity doubling on TAP pipeline in Greece: Greece is set to significantly boost Europe's energy security by doubling the capacity of the Trans Adriatic Pipeline (TAP) to 20 bcma of gas from Azerbaijan, following successful system upgrades by the Greek gas grid operator, DESFA. This capacity increase is a key strategic move which cements Greece's growing role as a vital regional hub, a position already established by its LNG terminals at Revithoussa and Alexandroupoli.

4.2 LNG trade

4.2.1 LNG imports

In June 2026, global LNG imports declined by 2.9% y-o-y (0.99 Mt) to 33.36 Mt, with the pace of contraction continuing to moderate compared with the previous two months (Figure 84). The decline was driven primarily by lower LNG imports in Europe, while stronger imports in Asia and the Middle East and Africa (MEA) partially offset the global decrease. The weaker import volumes reflected tighter global LNG supply resulting from the continued restrictions on LNG transit through the Strait of Hormuz amid the Middle East conflict.

For the period January to June 2026, global LNG imports grew by 1.1% y-o-y (2.39 Mt) to reach 215.64 Mt, supported mainly by stronger LNG imports in the MEA (Figure 85).

Figure 84: Trend in global monthly LNG imports

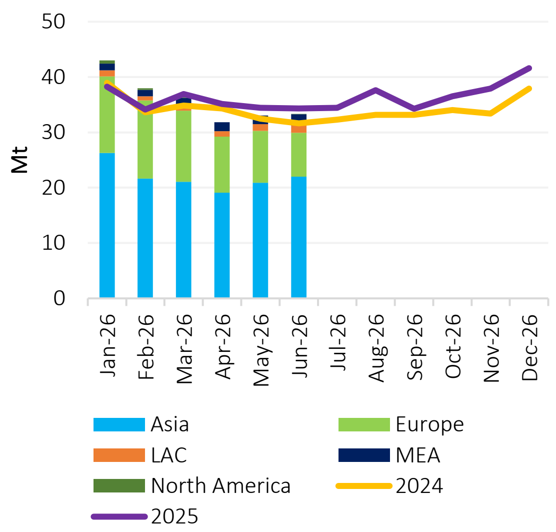
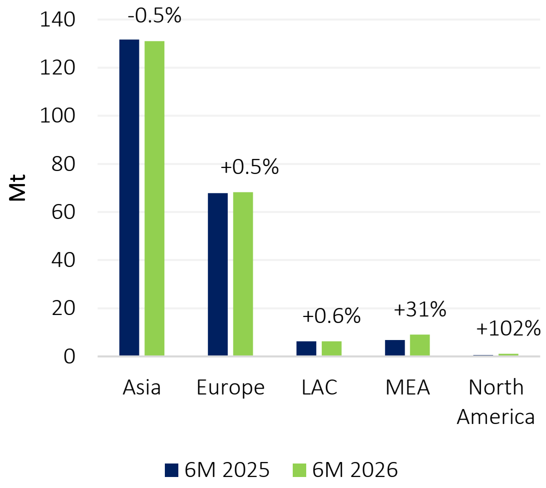


Figure 85: Trend in regional YTD LNG imports



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In June 2026, Europe's LNG imports declined for the fourth consecutive month on a y-o-y basis, falling sharply by 21% (2.13 Mt) to 7.89 Mt. The decline reflected tighter global LNG supply following continued disruptions to LNG transit through the Strait of Hormuz amid the Middle East conflict. As a result, the wide spot LNG price premium in Asia over Europe encouraged the diversion of Atlantic Basin LNG cargoes, particularly from the US and West Africa, away from Europe and towards higher-netback Asian markets. At the country level, Belgium, France, Germany, Italy, the Netherlands, Spain, and Türkiye accounted for most of the regional decline, while Lithuania and Portugal recorded significant increases (Figure 87).

The decline in Belgium's LNG imports was driven by lower volumes from Nigeria, Russia, and Senegal. Meanwhile, reduced imports from the US accounted for much of the decline in France, Germany, the Netherlands, Spain, and Türkiye. Lower imports from Algeria also weighed on LNG imports in Italy and Spain, while weaker deliveries from Angola and Nigeria contributed to the declines in Spain and France, respectively. In contrast, Lithuania increased its LNG imports from Norway, while Portugal recorded higher imports from Nigeria, Russia, and the US.

For the period January to June 2026, Europe's LNG imports rose by 0.5% y-o-y (0.33 Mt) to 68.21 Mt.

Figure 86: Trend in Europe's monthly LNG imports

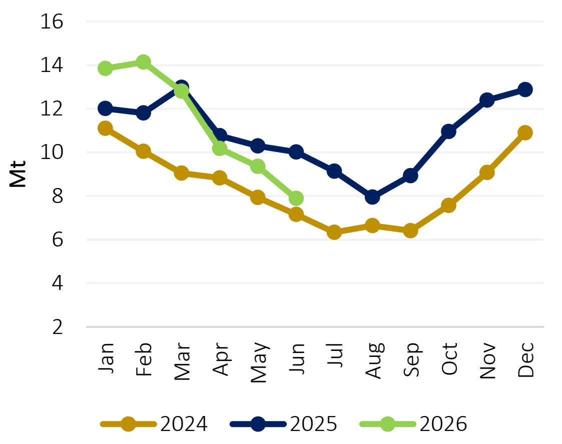
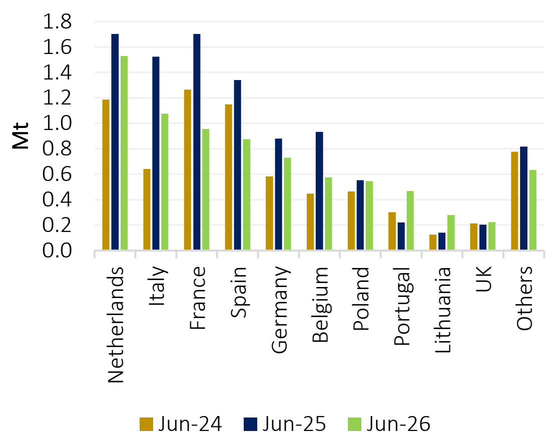


Figure 87: Top LNG importers in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia

In June 2026, Asia recorded its first y-o-y increase in LNG imports since February 2026, with imports rising by 2.3% (0.50 Mt) to 22.02 Mt (Figure 88). The increase came despite tighter global LNG supply resulting from lower exports from Qatar and the UAE amid continued restrictions on LNG transit through the Strait of Hormuz. Stronger LNG imports by China, India, Indonesia and Thailand more than offset weaker imports in Japan and Pakistan, driving the region's overall growth (Figure 89).

China recorded its first y-o-y increase in LNG imports since January, driven primarily by LNG restocking ahead of the peak summer season amid stable pipeline gas imports. In India, stronger gas demand from the power sector, coupled with lower domestic gas production, boosted LNG imports. Indonesia's LNG imports reached a record high, reflecting increased intra-country LNG trade to meet rising domestic gas demand. Thailand also increased its LNG imports, supported by robust gas demand and declining pipeline gas imports. In contrast, Japan's LNG imports declined due to partial gas to coal switching in the power sector, while Pakistan's imports remained constrained by the ongoing impact of the Middle East conflict.

For the period January to June 2026, Asia's LNG imports fell by 0.5% (0.67 Mt) y-o-y to 131.01 Mt.

Figure 88: Trend in Asia's monthly LNG imports

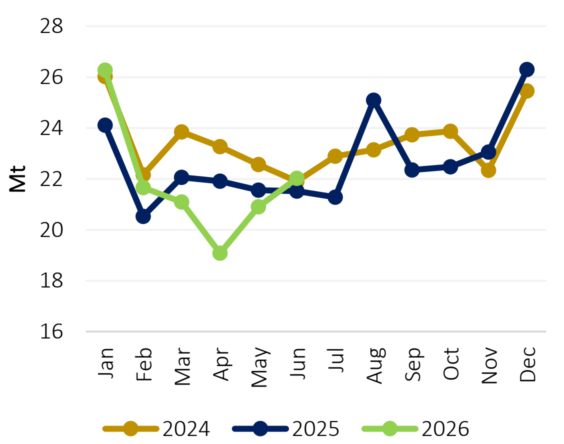
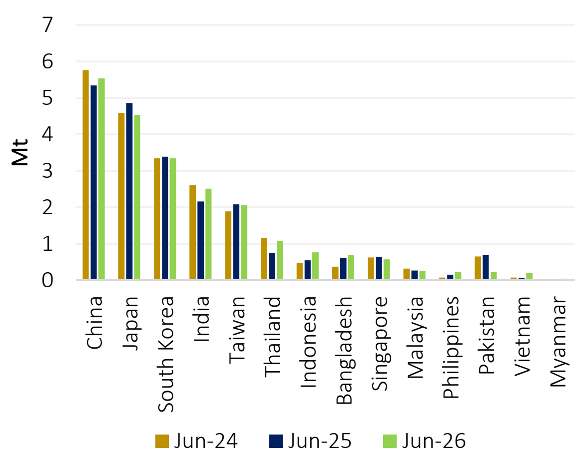


Figure 89: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In June 2026, LNG imports in Latin America and the Caribbean (LAC) rose marginally by 3.2% (0.04 Mt) y-o-y to 1.33 Mt (Figure 90). The increase was driven primarily by stronger LNG imports in Brazil, which more than offset lower imports in Chile and El Salvador (Figure 91).

Brazil's LNG imports were supported by higher gas demand from the power sector following the recent commissioning of the 1.7 GW GNA II gas-fired power plant. In contrast, Chile's LNG imports declined due to stronger renewable power generation and higher pipeline gas imports from Argentina. Meanwhile, lower LNG deliveries from Trinidad and Tobago contributed to the decline in El Salvador's LNG imports.

For the period January to June 2026, LAC’s LNG imports increased slightly by 0.6% (0.03 Mt) y-o-y to reach 6.29 Mt.

Figure 90: Trend in LAC’s monthly LNG imports

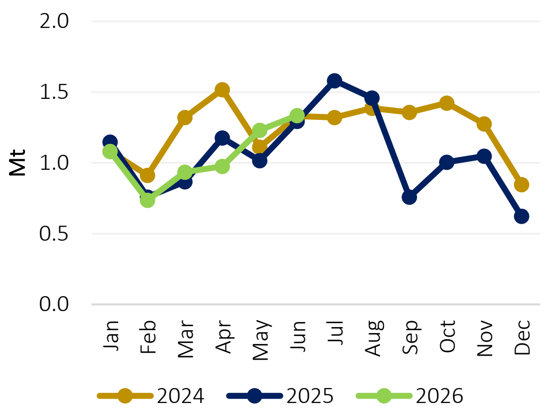
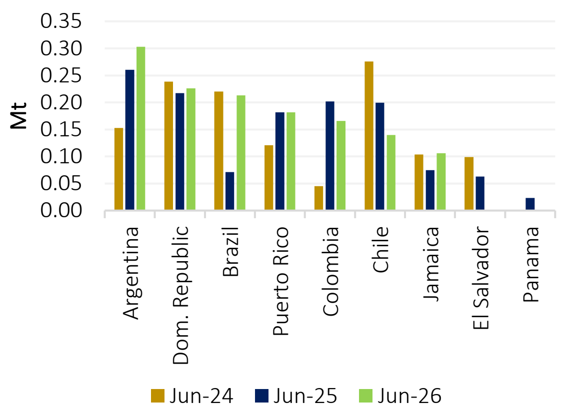


Figure 91: Top LNG importers in LAC



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 Middle East and Africa (MEA)

In June 2026, LNG imports in the MEA rebounded following a decline in May, increasing by 35% (0.52 Mt) y-o-y to 2.04 Mt (Figure 92). The recovery was driven primarily by stronger LNG imports into Egypt, which more than offset lower imports in Bahrain and Kuwait. Egypt's higher LNG imports reflected declining domestic gas availability, while Kuwait's imports remained constrained by the impact of the Middle East conflict (Figure 93).

For the period Jan-June 2026, MEA’s LNG imports rose by 31% (2.15 Mt) y-o-y to 9.03 Mt.

Figure 92: Trend in MEA’s monthly LNG imports

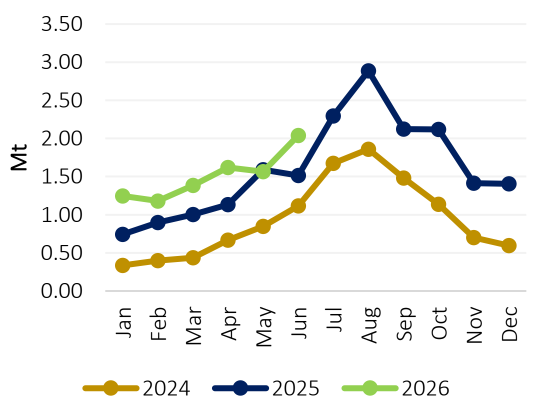
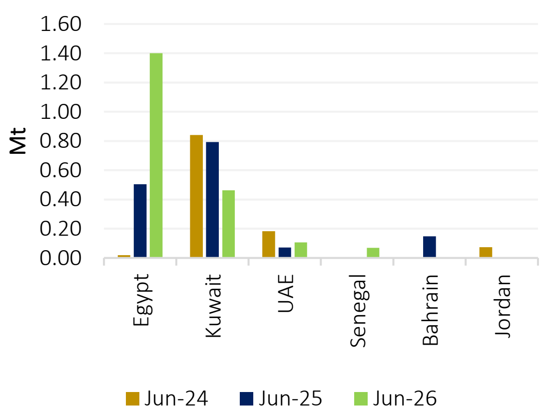


Figure 93: Top LNG importers in MEA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In June 2026, global LNG exports edged down by 0.5% (0.17 Mt) y-o-y to 33.58 Mt, marking a slower pace of decline compared with previous months (Figure 94). The decrease was mainly driven by continued restrictions on LNG transit through the Strait of Hormuz amid the Middle East conflict. Higher exports from non-GECF countries almost fully offset lower exports from GECF member countries and weaker LNG re-exports. The US, Australia and Russia were the world's largest LNG exporters during the month.

As a result, non-GECF countries' share of global LNG supply rose sharply from 52.9% in June 2025 to 67.8% in June 2026, while the shares of GECF member countries and LNG re-exports declined to 32.0% and 0.2%, respectively.

For the period January to June 2026, global LNG exports increased slightly by 1.3% (2.80 Mt) y-o-y to 214.37 Mt, supported by stronger exports from non-GECF countries (Figure 95).

Figure 94: Trend in global monthly LNG exports

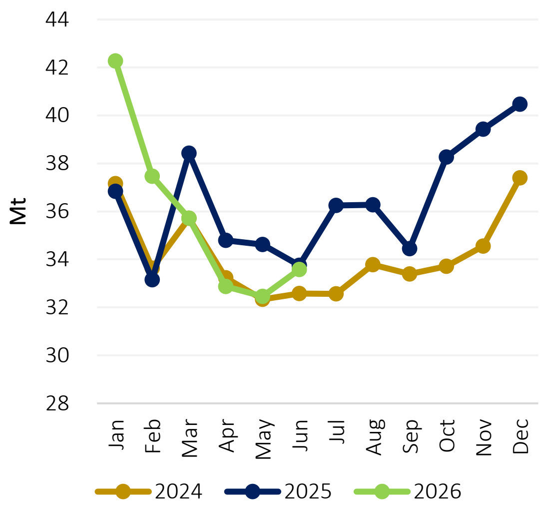
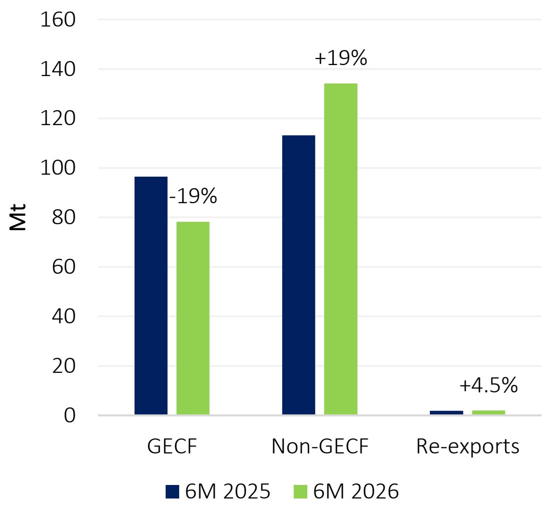


Figure 95: Trend in YTD LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In June 2026, LNG exports from GECF member countries continued to slide, falling by 32% (4.94 Mt) y-o-y to 10.74 Mt (Figure 96). The decrease was driven primarily by continued restrictions on LNG transit through the Strait of Hormuz, which constrained exports from the Middle East (Figure 97). Lower LNG exports from Qatar, Trinidad and Tobago and the United Arab Emirates (UAE) contributed to the decline, although this was partially offset by higher exports from Angola, Malaysia, Nigeria and Russia.

The weaker exports from Qatar and the UAE reflected the ongoing disruption to LNG transit through the Strait of Hormuz amid the Middle East conflict. In Trinidad and Tobago, planned maintenance at the Atlantic LNG facility reduced export volumes. By contrast, improved feedgas availability supported higher LNG exports from Angola, Malaysia and Nigeria. Meanwhile, increased production at the Arctic LNG 2 facility and lower maintenance activity at the Sakhalin 2 LNG facility boosted Russia's LNG exports.

For the period January to June 2026, cumulative LNG exports from GECF member countries reached 78.27 Mt, representing a 19% (18.19 Mt) y-o-y decrease.

Figure 96: Trend in GECF monthly LNG exports

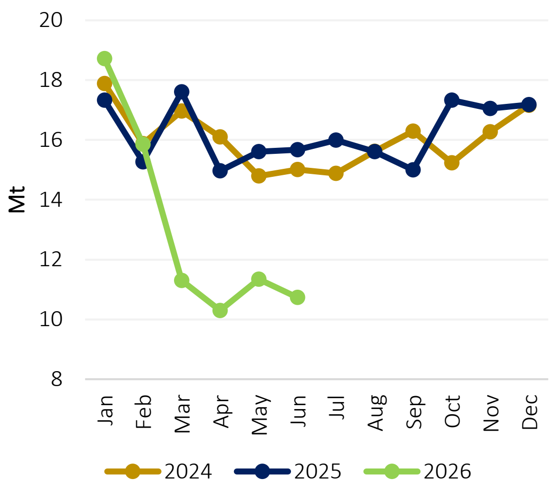
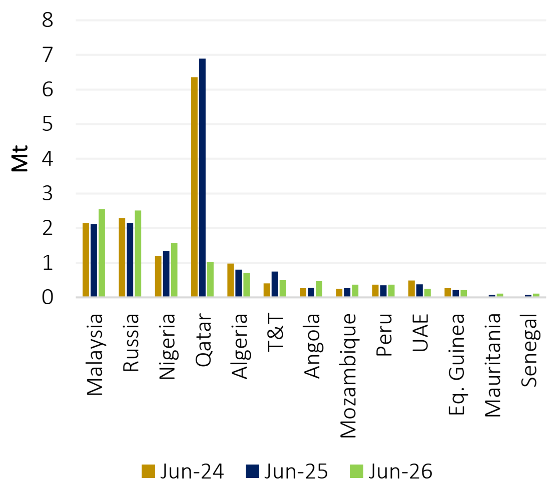


Figure 97: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In June 2026, LNG exports from non-GECF countries surged by 28% (4.91 Mt) y-o-y to 22.78 Mt (Figure 98), marking the largest monthly y-o-y increase ever. The growth was driven primarily by the US and Canada, with additional contributions from Australia, Congo, Norway and Oman (Figure 99).

In the US, higher LNG exports were supported by the continued ramp-up of the Corpus Christi Stage 3 and Plaquemines LNG projects, together with lower maintenance activity at the Cameron and Sabine Pass LNG facilities. Similarly, production ramp-ups at LNG Canada and Congo FLNG 2 boosted exports from Canada and Congo, respectively. Australia's LNG exports increased following the restart of the Darwin LNG facility and lower maintenance activity at the Gorgon LNG plant. In Norway and Oman, reduced maintenance activity also contributed to higher LNG exports.

For the period January to June 2026, non-GECF LNG exports rose sharply by 17% (16.20 Mt) y-o-y to 111.57 Mt.

Figure 98: Trend in non-GECF monthly LNG exports

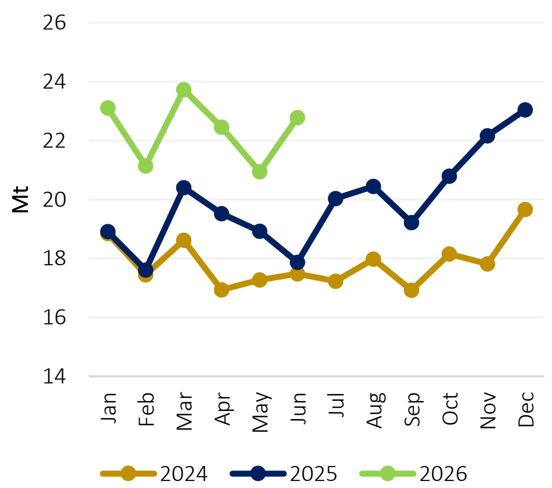
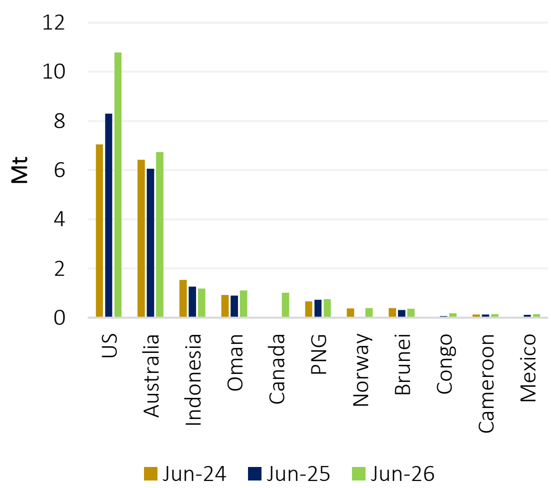


Figure 99: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG Re-exports

In June 2026, global LNG re-exports fell sharply by 68% (0.14 Mt) y-o-y to a multi-year low of 0.07 Mt, (Figure 100), driven mainly by lower re-export activity in Chile and Indonesia.

Chile re-exported an LNG cargo to Argentina in June 2025 to meet higher gas demand, however, rising domestic gas production in Argentina has reduced the need for the re-exports to the country. The Arun LNG facility in Indonesia is sometimes utilised as a storage and re-export hub to other Asian countries by some LNG portfolio players. However, the tight LNG market has discouraged this hub operations. In June 2025, an LNG was re-exported to South Korea but there were no re-exports outside of Indonesia in June 2026.

For the January to June 2026 period, global LNG re-exports increased marginally by 4.5% (0.08 Mt) y-o-y to 1.95 Mt. The increase was driven by stronger re-exports from China, which more than offset declines in Brazil, Singapore, and the US Virgin Islands (USVI) (Figure 101).

Figure 100: Trend in global monthly LNG re-exports

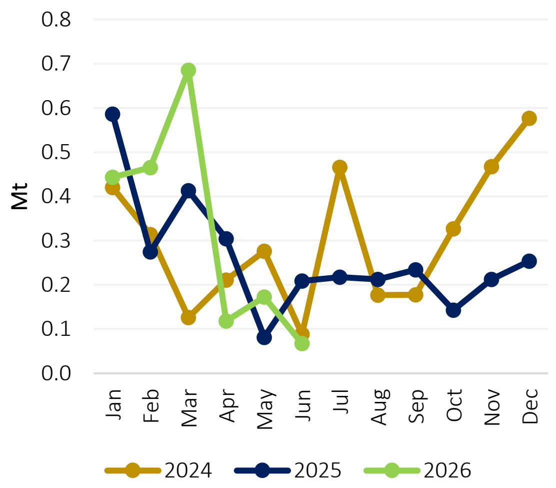
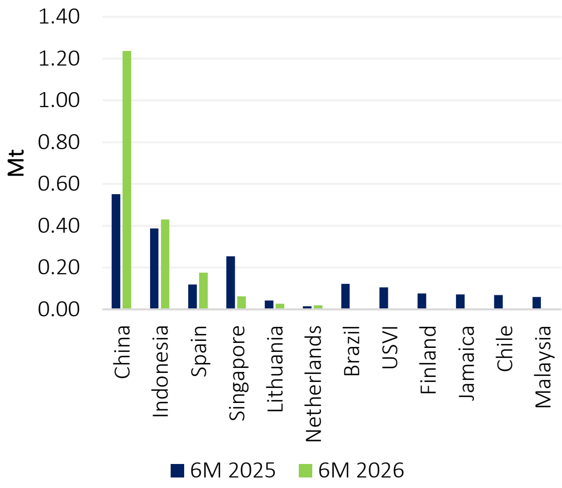


Figure 101: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

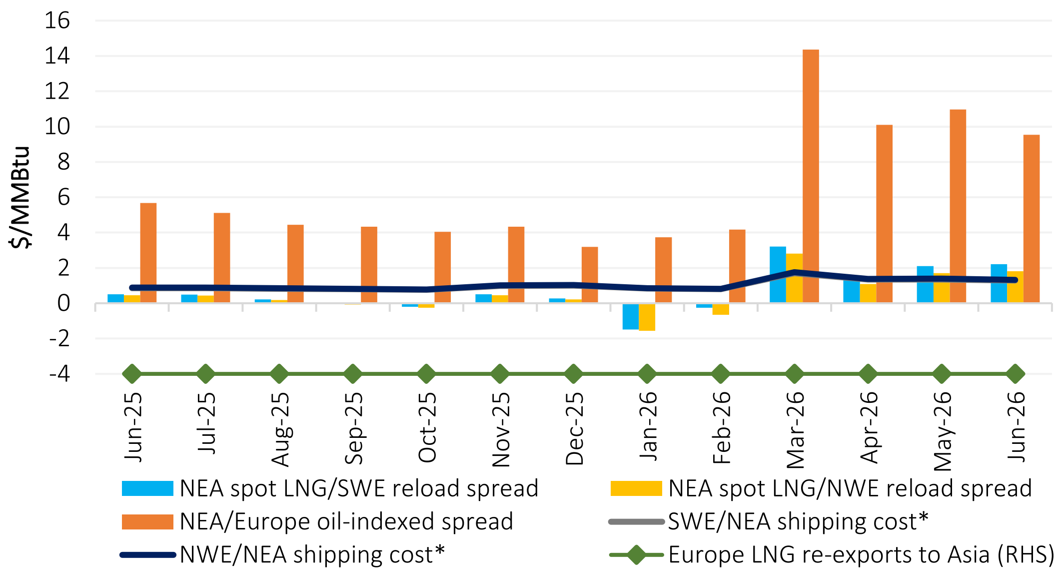
4.2.4 Arbitrage opportunity

In June 2026, arbitrage opportunities for LNG re-exports from Europe to Asia remained open, as the North East Asia (NEA) spot LNG price widened its premium over European LNG reload prices, while one-way spot shipping costs from Europe to Asia declined (Figure 102). Although the premium of the NEA spot LNG price over European oil-indexed LNG narrowed during the month, it remained well above spot shipping costs from Europe to Asia.

The NEA–Southwest Europe (SWE) and NEA–Northwest Europe (NWE) spreads widened from $2.10/MMBtu and $1.70/MMBtu in May to $2.22/MMBtu and $1.82/MMBtu, respectively, as European LNG reload prices declined more sharply than the NEA spot LNG price. By contrast, the premium of the NEA spot LNG price over European oil-indexed LNG narrowed from $10.98/MMBtu to $9.54/MMBtu, while one-way shipping costs from Europe to Asia fell from $1.38/MMBtu to $1.31/MMBtu.

Despite favourable arbitrage conditions, no LNG cargoes were re-exported from Europe to Asia during June. This reflected the continued tightness of the global LNG market, the diversion of some US LNG cargoes to higher-priced Asian markets, and Europe's ongoing need to replenish multi-year low gas inventory.

Figure 102: Price spreads & shipping costs between Asia & Europe spot LNG markets

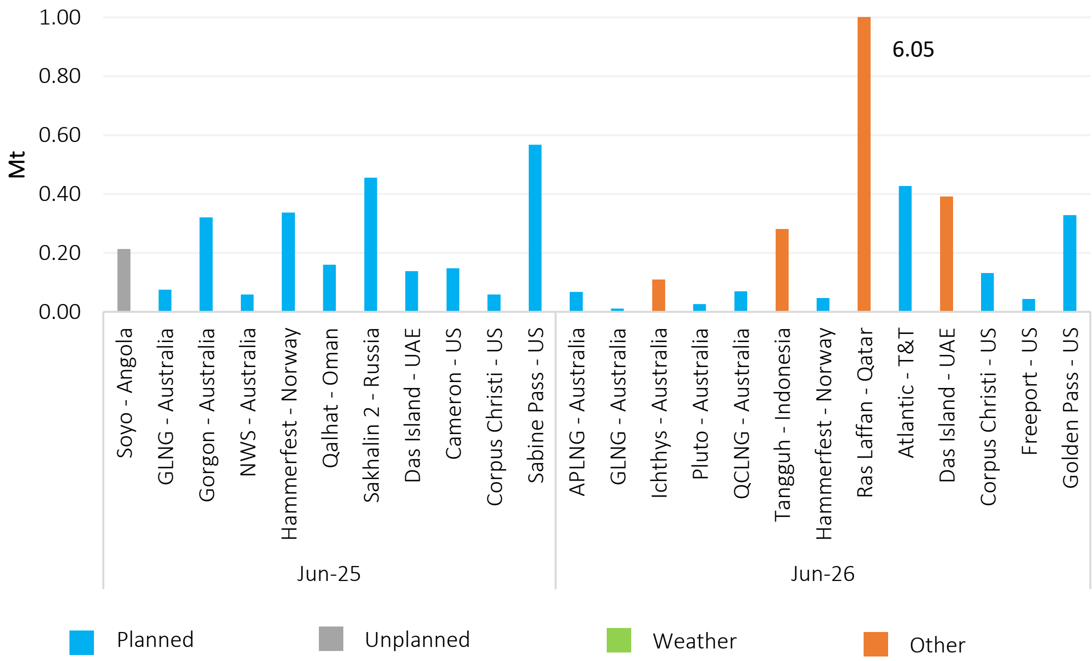


Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge
(*): One-way spot shipping costs

4.2.5 Maintenance activity at LNG liquefaction facilities

In June 2026, disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages and other operational issues, were significantly higher than a year earlier, rising from 2.53 Mt in June 2025 to 7.98 Mt (Figure 103). The rise was driven primarily by the impact of the Middle East conflict on operations at Qatar's Ras Laffan and the UAE's Das Island LNG facilities. Additional disruptions resulted from planned maintenance at several LNG plants in Australia, Norway and Trinidad and Tobago, industrial action at the Ichthys LNG facility, and unplanned outages at the Tangguh and Corpus Christi LNG plants.

Figure 103: Maintenance activity at LNG liquefaction facilities during June (2025 and 2026)

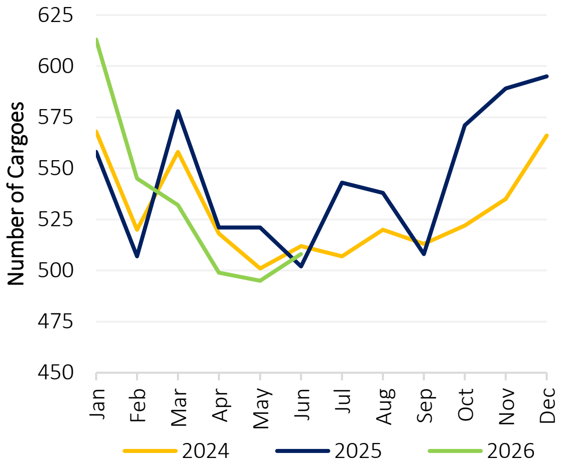


Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

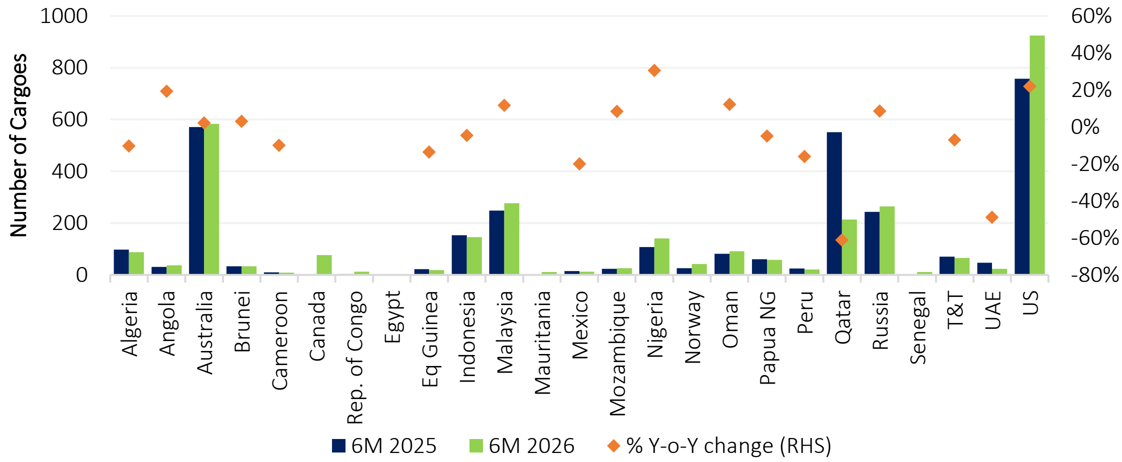
In June 2026, global LNG exports rose by 13 shipments m-o-m to reach 508 cargoes. Whilst this figure was 1% higher y-o-y, overall activity remained seasonally low, further constrained by reduced output from Qatar and the UAE (Figure 104). Between January and June, total shipments rose by a marginal five cargoes to reach 3,192 cargoes. GECF maintained a 38% market share, led by Malaysia, Russia, and Qatar. Year-to-date, the US (+166) and Nigeria (+33) recorded the largest expansions in cargo exports, whilst the Republic of the Congo and Egypt registered the highest percentage growth, with both countries increasing by 200% (Figure 105).

Figure 104: Number of LNG export cargoes



Source: GECF Secretariat based on data from ICIS LNG Edge

Figure 105: Changes in LNG cargo exports



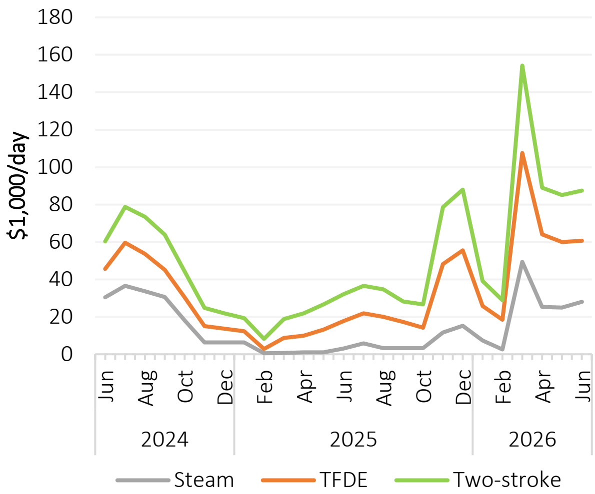
Source: GECF Secretariat based on data from ICIS LNG Edge

The spot charter market for LNG carriers maintained stability across all segments of the global fleet in June 2026 (Figure 106). For TFDE carriers, the monthly average rate rose by 1% m-o-m to reach $60,700 per day. This average rate remained 243% higher y-o-y and stood at $10,000 per day above the five-year average for the month. Meanwhile, the average spot charter rate for two-stroke vessels increased to $87,400 per day, up 3% m-o-m and 171% y-o-y. Steam turbine carriers experienced a 12% m-o-m lift to average $28,100 per day, whilst remaining a significant 806% higher y-o-y.

The market experienced a gradual positive sentiment in June 2026, supported by the framework peace agreement in the Middle East and the impending reopening of the Strait of Hormuz, signalling a return of Qatari and UAE supply to Asian markets. While spot rates initially held steady, they trended downward by late June as the anticipation of these shorter-haul Middle Eastern flows reduced the necessity for longer cross-basin voyages, effectively closing the inter-basin arbitrage window for uncommitted US Gulf Coast cargoes by month's end. Despite emerging fuel-switching to coal in regions like South Korea, peak summer cooling demand in Asia sustained robust baseline LNG consumption, ensuring that while spot charter rates corrected downward from their peaks, they maintained a resilient floor.

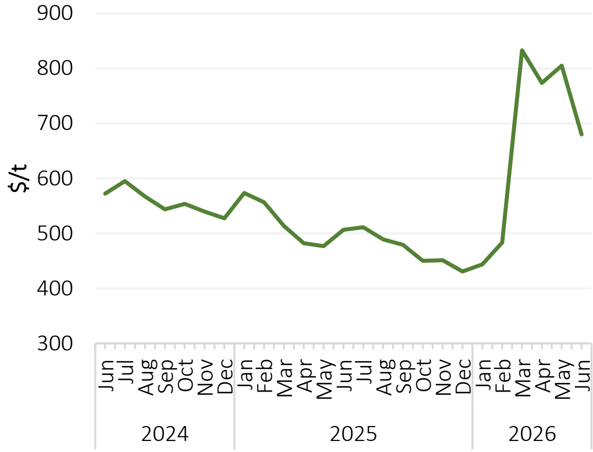
In June 2026, the average price of shipping fuels was estimated at $680 per tonne, representing a 15% decrease m-o-m (Figure 107). However, this average price remained 33% higher y-o-y and 8% above the five-year average for the month.

Figure 106: Average LNG spot charter rate



Source: GECF Secretariat based on data from Argus

Figure 107: Average price of shipping fuels

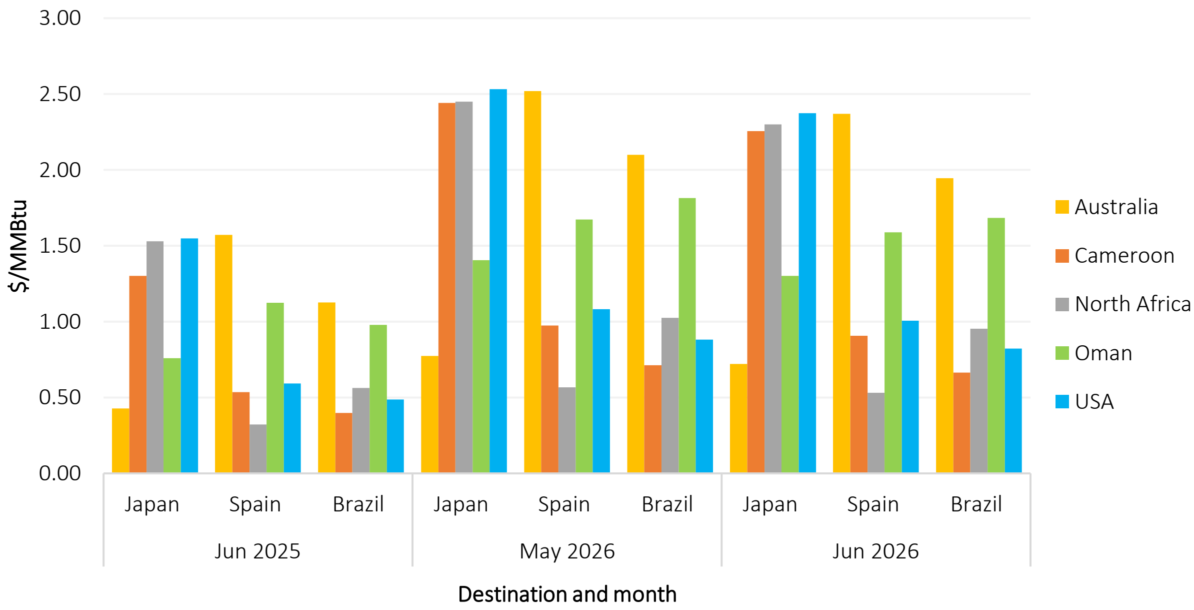


Source: GECF Secretariat based on data from Argus and Platts

Driven by the decreases in the cost of shipping fuels and in the delivered spot LNG prices, along with the stable monthly average spot charter rate, there was a decrease in spot shipping costs for TFDE LNG carriers in June 2026 compared to the previous month, by up to $0.18/MMBtu on certain routes (Figure 108).

Compared to one year ago, in June 2026 the monthly average LNG carrier spot charter rate, the cost of shipping fuels, and the delivered spot LNG prices were also all higher. As a result, spot LNG shipping costs were up to $0.95/MMBtu higher than in June 2025.

Figure 108: Spot shipping costs for TFDE LNG carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

Mexico's Energia Costa Azul exports first LNG cargo: On 8 July 2026, Mexico's Energia Costa Azul (ECA) LNG facility exported its first cargo, marking the country's entry into Pacific Basin LNG exports. The 3.25 Mtpa single-train facility, located on Mexico's Pacific coast, is jointly owned by Sempra Infrastructure (41.7%), IEnova (41.7%), and TotalEnergies (16.6%). The project reached final investment decision (FID) in 2020 and produced its first LNG on 4 June 2026. Supplied with feedgas from the Permian Basin in Texas and New Mexico, the facility is strategically positioned to serve Asian markets. TotalEnergies loaded the inaugural cargo aboard the Pacific Success LNG carrier and is expected to receive all commissioning cargoes.

US Delfin Midstream reaches FID on first FLNG facility: On 3 June 2026, US developer Delfin Midstream reached a final investment decision (FID) on the first floating liquefied natural gas (FLNG) export project in the United States. The 4.4 Mtpa facility has already secured long-term sales and purchase agreements covering more than 80% of its LNG production. Estimated to cost around US$5 billion, the project is expected to commence LNG production in 2030, with commercial operations starting in 2031. Prior to FID, Delfin placed an order with South Korea's Samsung Heavy Industries (SHI) for the project's first FLNG vessel.

New Zealand shortlists bidder for LNG import terminal: In June 2026, New Zealand shortlisted two bidders to develop a proposed LNG import terminal as part of its strategy to strengthen energy security amid declining domestic gas production and rising energy costs. The government plans to issue a request for proposals before selecting a preferred provider later this year, with operations expected to begin in 2028. The facility is intended to provide backup fuel for power generation during periods of low hydro output and weak renewable generation, helping to improve electricity supply reliability and reduce price volatility.

China's growing dominance in LNG carrier construction: In April 2026, China achieved a significant maritime milestone with the delivery of the Celsius Georgetown LNG carrier, which is its largest independently designed and built LNG carrier to date. Constructed by China Merchants Heavy Industry for the Danish firm Celsius Shipping, the vessel measures 298.8 meters in length and features a capacity of 180,000 cubic metres. This delivery marks the first of a six-ship order and signals China's growing competitiveness in the high-tech sector of shipbuilding, an area that has been traditionally dominated by South Korea.

In June 2026, LNG contracting was robust with seven (7) LNG agreements signed (Table 1).

Table 1: New LNG sale agreements signed in May 2026

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
SPA	Portfolio	Portfolio	INEOS Group	Asia-Pacific	Marubeni Corp.	N/A	N/A
SPA	US	Delfin FLNG 2	Delfin LNG	Portfolio	Centrica	0.25	20
SPA	Malaysia	Portfolio	Petronas	Japan	JERA	2	20
SPA	US	Portfolio	Venture Global	Greece	Atlantic-SEE LNG Trade	0.5	20
SPA	US	Portfolio	Venture Global	Germany	EnBW	0.82	2
SPA	Portfolio	Portfolio	BP	Malta	Enemalta	N/A	0.8
SPA	US	Delfin LNG	Vitol	Portfolio	IRH Global Trading	1	20

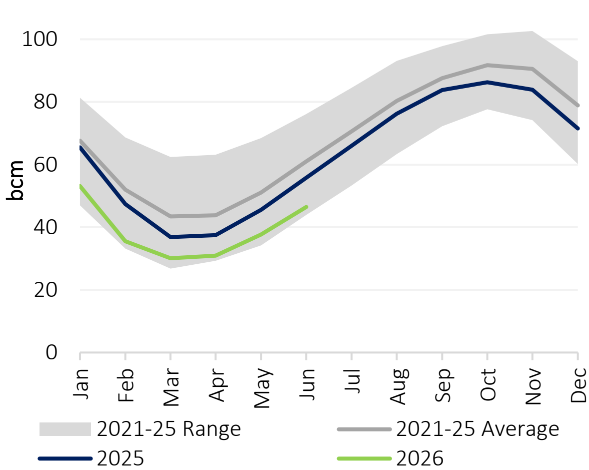
Source: GECF Secretariat based on Project Updates and News
N/A: Not Available

5 GAS STORAGE

5.1 Europe

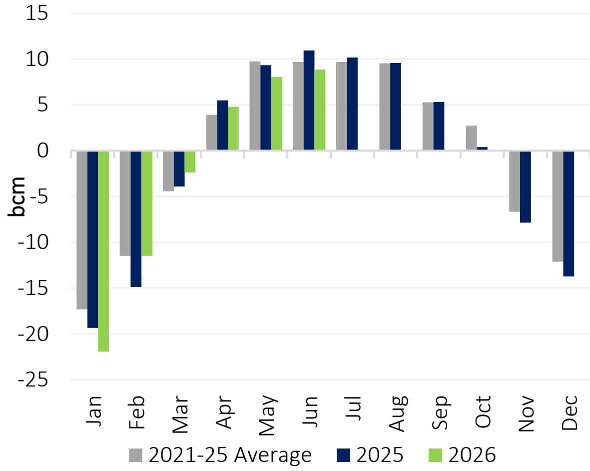
Europe is currently in the peak May-to-August phase of its net gas injection season, though the restocking pace has slowed this year because of tighter global LNG supply and unattractive storage economics. In June 2026, the average daily volume of gas in underground storage in the EU increased to 46.4 bcm, up from 37.7 bcm one month prior (Figure 109). This inventory level was 9.4 bcm lower y-o-y, 14.6 bcm below the five-year average, and marked the lowest average stock level for the month of June since 2021. Total EU stocks increased from 41.8 bcm on 31 May to 50.6 bcm on 30 June, equivalent to an average regional storage level of 49%.

Figure 109: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

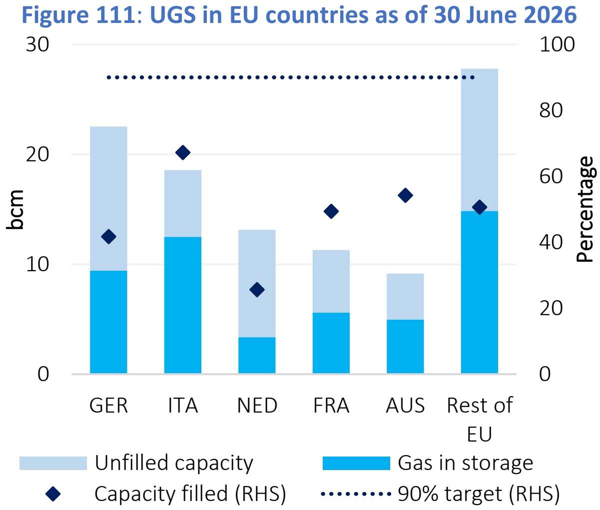
Figure 110: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

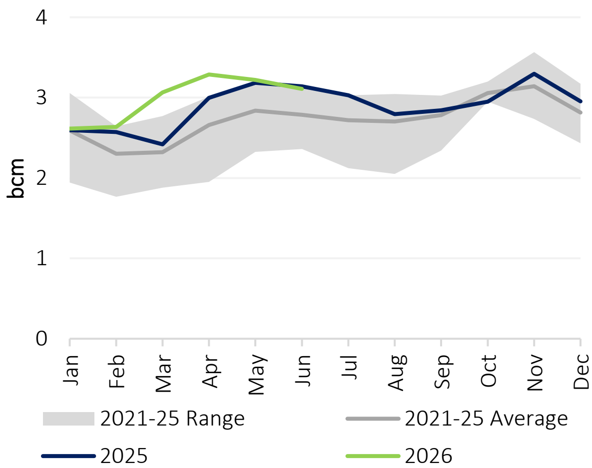
Net gas injections for the month stood at 8.9 bcm, falling below the 10.9 bcm recorded a year earlier and tracking 9% below the historical five-year average (Figure 110). The Netherlands recorded a significant increase in its stockbuild, though its total reserves reached only 26% by the end of the month (Figure 111). Other major regional markets showed higher inventory levels, with France and Austria at 50%, and Italy leading at 67%. Meanwhile, EU LNG storage averaged 3.1 bcm, equivalent to 55% of total capacity (Figure 112). This inventory level was 1% lower y-o-y, but remained 12% higher than the five-year average for the month.

Figure 111: UGS in EU countries as of 30 June 2026



Source: GECF Secretariat based on data from AGSI+

Figure 112: Total LNG storage in the EU

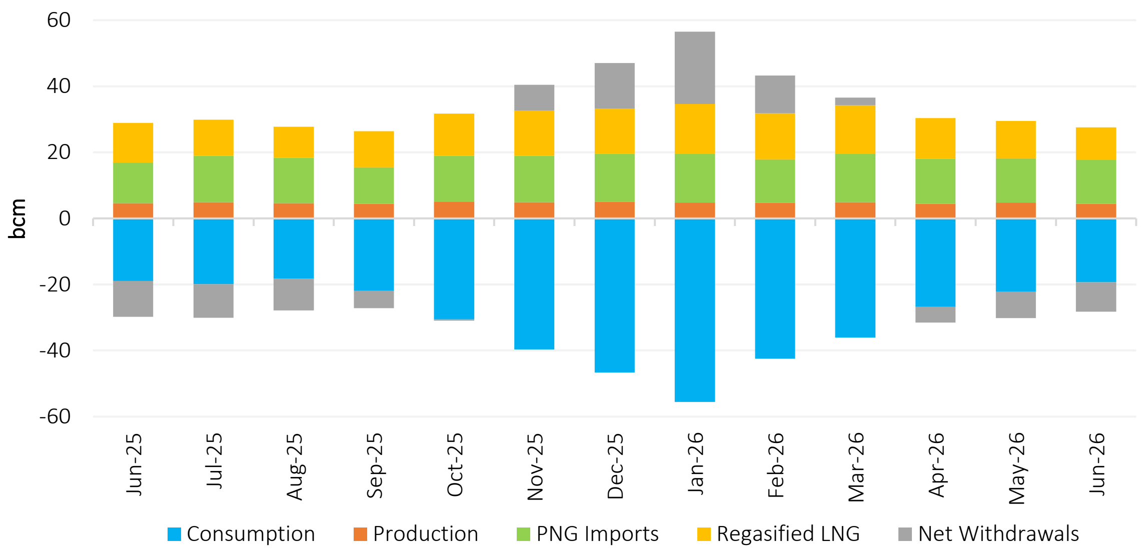


Source: GECF Secretariat based on data from ALSI

Throughout the month, prevailing market conditions continued to stall Europe's restocking efforts. The ongoing negative winter-summer spread left the market with little commercial motivation to inject gas, while a JKM-TTF price spread tilted toward Asia meant that spot LNG cargoes were routinely drawn to the Pacific Basin rather than European terminals. Consequently, the regional inventory build lagged behind historical trends, cementing a deep deficit against the five-year average. For the remainder of the refilling cycle, Europe will remain highly vulnerable to sudden market tightening, requiring a substantial acceleration in pipeline and LNG inflows over July and August to comfortably secure its winter supply buffer.

In June 2026, gas imports accounted for 84% of combined EU and UK gas demand, unchanged from a year earlier (Figure 113), while domestic production supplied the remaining 16%. Pipeline gas (PNG) remained the dominant source of imports, accounting for 48% of total gas imports, followed by LNG send-out at 36%. By comparison, in June 2025, PNG and LNG each represented 42% of imports. The increase in PNG's share reflected higher pipeline gas imports, while the decline in LNG's share was driven by lower LNG send-out.

Figure 113: EU + UK monthly gas balance



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

Table 2 outlines the EU and UK gas supply and demand balance for June 2026.

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

	2025	Jun-25	Jun-26	6M 2025	6M 2026	Change* y-o-y	Change** 2026/2025
(a) Gas Consumption	378.23	18.90	19.34	201.21	202.33	2%	1%
(b) Gas Production	58.90	4.62	4.40	30.02	28.03	-5%	-7%
Difference (a) - (b)	319.33	14.28	14.94	171.19	174.30	5%	2%
PNG Imports	162.14	12.27	13.28	80.93	82.95	8%	2%
Regasified LNG	147.08	11.98	9.86	75.56	77.02	-18%	2%
Net Withdrawals	8.46	-10.92	-8.85	12.36	14.08	-19%	14%
Variation	1.64	0.95	0.64	2.35	0.24		

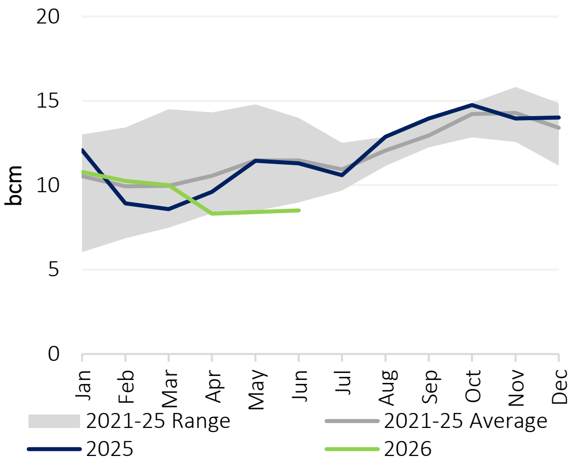
Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG
(*): y-o-y change for June 2026 compared to June 2025
(**): y-o-y change for 6M 2026 compared to 6M 2025

5.2 Asia

Combined LNG inventories for Japan and South Korea edged up 1% m-o-m to an estimated 8.5 bcm in June 2026 (Figure 114). However, due to tighter global LNG supply availability and higher gas-fired power demand for cooling in the region, this stock level sat 25% lower y-o-y and lagged 3.0 bcm behind the five-year average.

In Japan the estimated storage level fell 28% lower than the previous year to reach 5.0 bcm. Similarly, the estimated storage in South Korea level fell by 20% compared to the previous year to stand at 3.5 bcm.

Figure 114: LNG in storage in Japan and South Korea



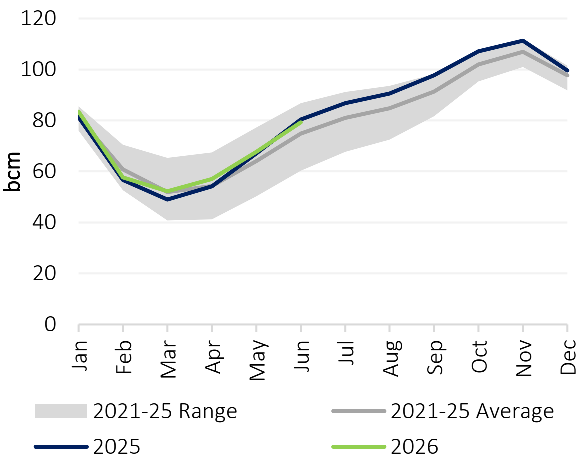
Source: GECF Secretariat based on data from LSEG

5.3 North America

In June 2026, the US also continued its net gas injection season, with the average volume of gas in storage increasing to 79.3 bcm, up from 67.7 bcm in the previous month (Figure 115). While this total was 1.1 bcm lower y-o-y, it remained 4.4 bcm above the historical five-year average for June, bringing average UGS capacity utilisation up to 59%.

Net gas restocking during the month reached 9.7 bcm, lagging behind the 10.1 bcm injected in June 2025, but exceeding the five-year average net injection of 9.2 bcm for the month. This brought total summer 2026 restocking to 31 bcm, down from the 36 bcm achieved by this point last year.

Figure 115: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

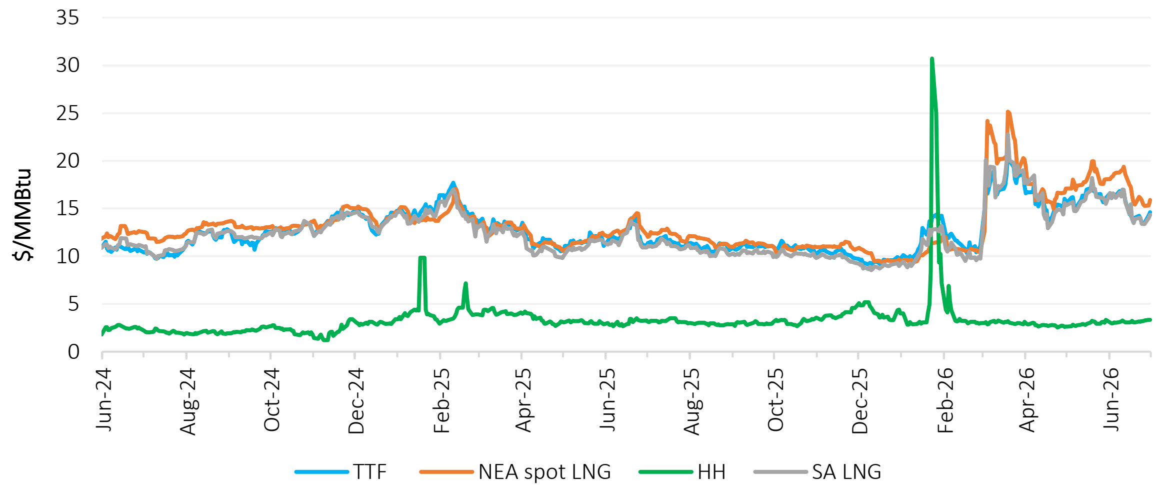
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

In June 2026, gas and LNG spot prices in Europe and Asia recorded modest declines, while market volatility remained moderate (Figure 116 and Figure 117). Optimism over the reopening of the Strait of Hormuz, following the signing of a MoU on 18 June 2026 to end the conflict, eased concerns over supply disruptions, exerting downward pressure on prices. However, rising temperatures across key consuming regions boosted gas demand for cooling, providing price support and limiting further declines. Looking ahead, spot prices are expected to remain supported by forecasts of above-normal summer temperatures. Additionally, any further escalation of the Middle East conflict is likely to put upward pressure on spot prices.

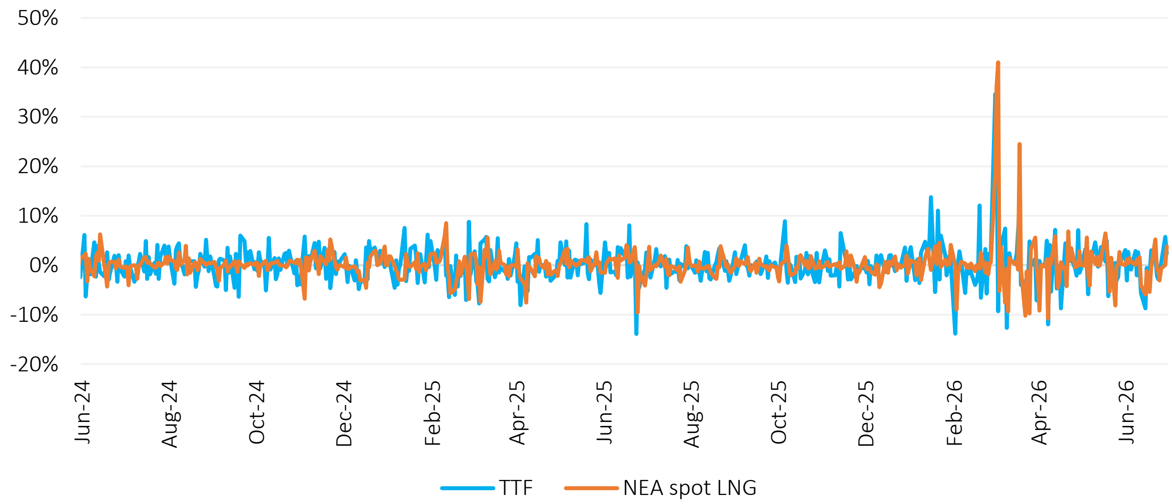
Figure 116: Daily gas & LNG spot prices



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

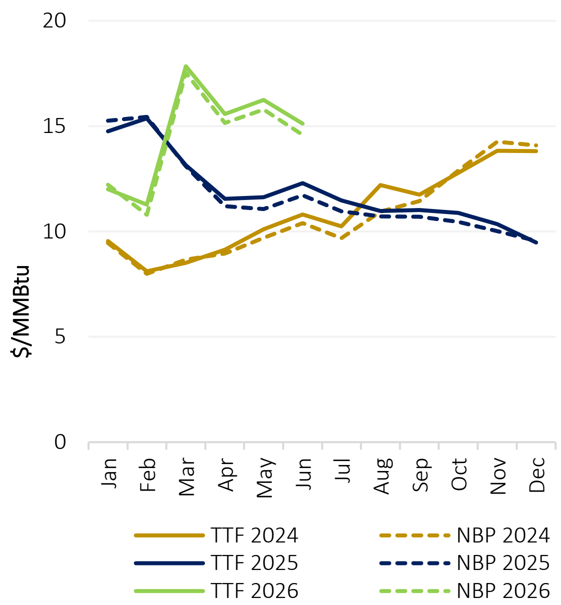
6.1.1.1 European spot gas and LNG prices

In June 2026, the TTF spot gas price averaged \$15.12/MMBtu, declining by 7% m-o-m, but was 23% higher y-o-y. Similarly, the NBP spot price averaged \$14.59/MMBtu, decreasing by 8% m-o-m, but was 24% higher y-o-y (Figure 118). During the month, daily TTF and NBP prices fell to lows of \$13.43/MMBtu and \$12.93/MMBtu, respectively.

European gas and LNG prices declined amid improved market sentiment and optimism over the reopening of the Strait of Hormuz, following the signing of an MoU to end the conflict. At the same time, heatwaves across Europe increased gas demand for cooling, limiting further downside.

For the period January to June 2026, TTF and NBP prices averaged \$14.68/MMBtu and \$14.35/MMBtu, increasing by 10% and 9% y-o-y, respectively.

Figure 118: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

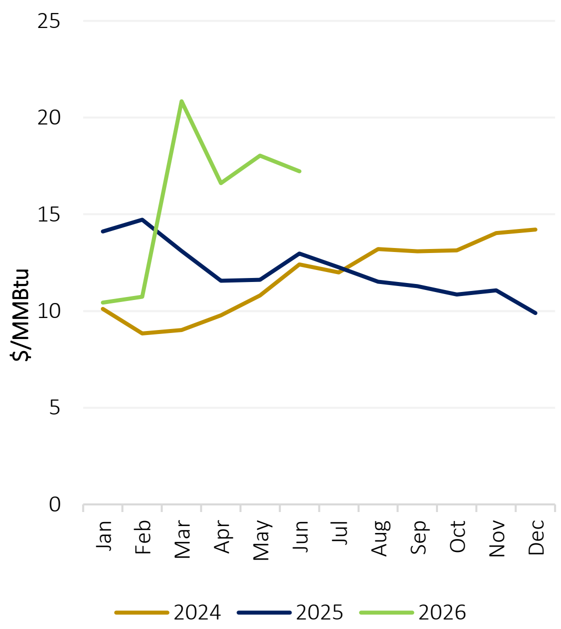
6.1.1.2 Asian spot LNG prices

In June 2026, the average North East Asia (NEA) spot LNG price averaged \$17.23/MMBtu, reflecting a decline of 4% m-o-m, but remained 33% higher y-o-y (Figure 119). Daily NEA spot LNG price fell to a low of \$15.30/MMBtu.

Asian LNG prices followed a similar downward trend, driven by easing concerns over potential supply disruptions through the Strait of Hormuz. Additionally, buying interest remained subdued amidst ample inventory levels, although higher temperature forecasts in the coming months have prompted some buyers to re-enter the spot market.

For the period January to June 2026, NEA spot LNG price averaged \$15.65/MMBtu, reflecting an increase of 20% y-o-y.

Figure 119: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus

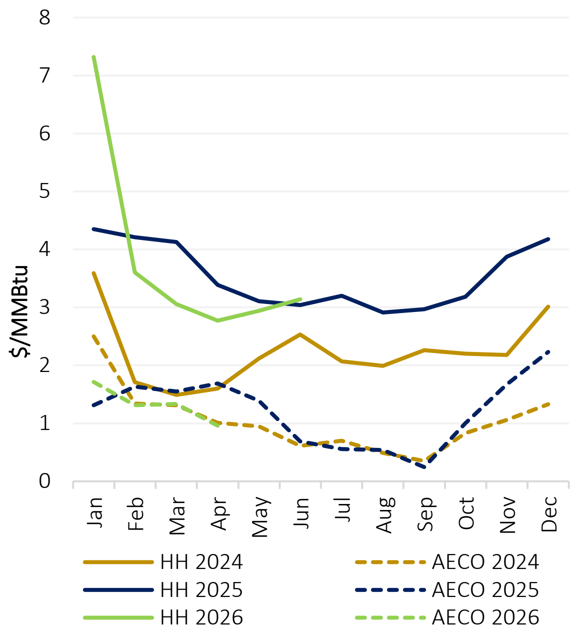
6.1.1.3 North American spot gas prices

In June 2026, the Henry Hub (HH) spot gas price averaged $3.14/MMBtu, increasing by 7% m-o-m and 3% y-o-y. Similarly, the AECO spot prices averaged $1.29/MMBtu increasing by 5% m-o-m and 87% y-o-y (Figure 120). Daily HH and AECO prices reached highs of $3.34/MMBtu and $1.50/MMBtu, respectively.

In the US, HH spot prices extended their gains, underpinned by elevated cooling demand as rising temperatures boosted gas-fired power generation. Prices were further supported by lower-than-expected storage injections, reflecting stronger domestic consumption and LNG exports.

For the period January to June 2026, HH and AECO spot prices averaged $3.80/MMBtu and $1.31/MMBtu, decreasing by 1% and 14%, respectively.

Figure 120: Monthly North American spot gas prices



Source: GECF Secretariat based on data from LSEG

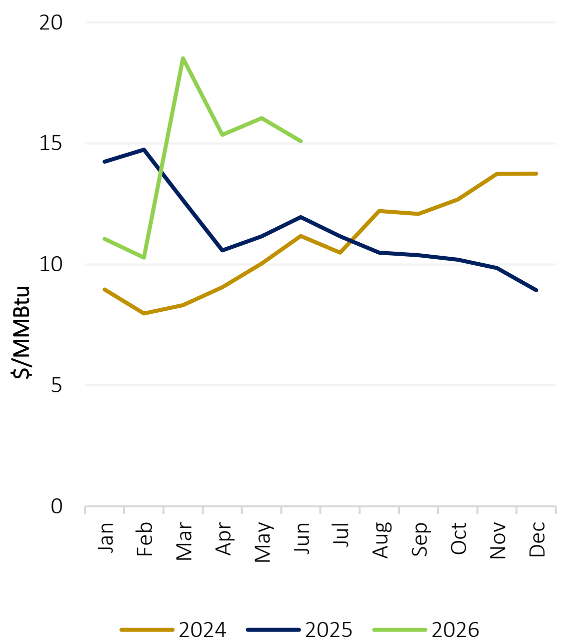
6.1.1.4 South American spot LNG prices

In June 2026, the South America (SA) spot LNG price averaged $15.10/MMBtu, decreasing by 6% m-o-m to, although it remained 26% higher y-o-y (Figure 121). During the month, daily SA spot LNG prices dropped to a low of $13.37/MMBtu.

The SA spot LNG prices continued to align with broader global LNG market trends, tracking losses in European and Asian prices. Delivered LNG prices in Argentina, Brazil and Chile averaged $15.17/MMBtu, $14.78/MMBtu and $15.35/MMBtu, respectively.

For the period January to June 2026, the SA spot LNG price averaged $14.39/MMBtu, up 14% y-o-y.

Figure 121: Monthly South American spot LNG prices

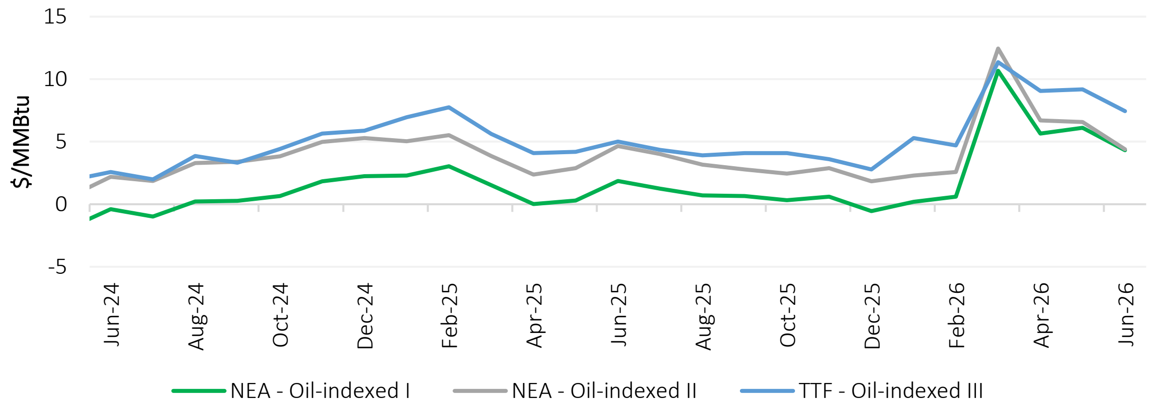


Source: GECF Secretariat based on data from Argus
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment

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

In June 2026, the Oil-Indexed I LNG price averaged $12.92/MMBtu, rising modestly by 8% m-o-m and 16% y-o-y. Meanwhile, the Oil-Indexed II LNG price averaged $12.85/MMBtu increasing by 12% m-o-m and 55% y-o-y. In Europe, the Oil-Indexed III LNG price averaged $7.69/MMBtu, reflecting increases of 9% m-o-m and 5% y-o-y. During the month, the premium of NEA spot LNG over Oil-Indexed I declined to $4.3/MMBtu, and the premium over Oil-Indexed II declined to $4.4/MMBtu. Similarly, the TTF spot gas premium over Oil-Indexed III narrowed to $7.4/MMBtu (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 (12.1% for 2026) 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 June 2026, the NEA–TTF price spread increased to $2.11/MMBtu, as the TTF spot price experienced a sharper decline than the NEA LNG spot price (Figure 123). Meanwhile, the TTF–HH price spread narrowed to $11.98/MMBtu (Figure 124).

Figure 123: NEA-TTF price spread

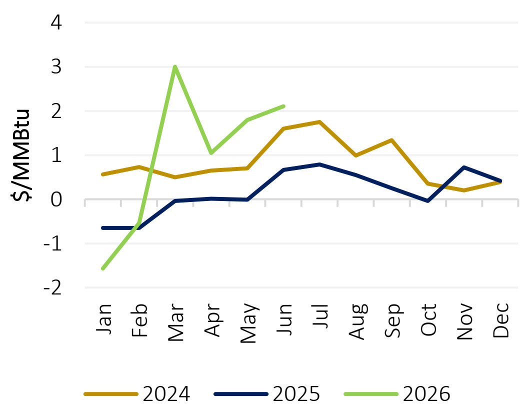
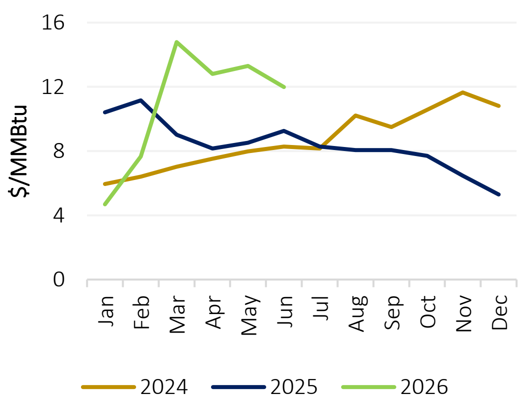


Figure 124: TTF-HH price spread



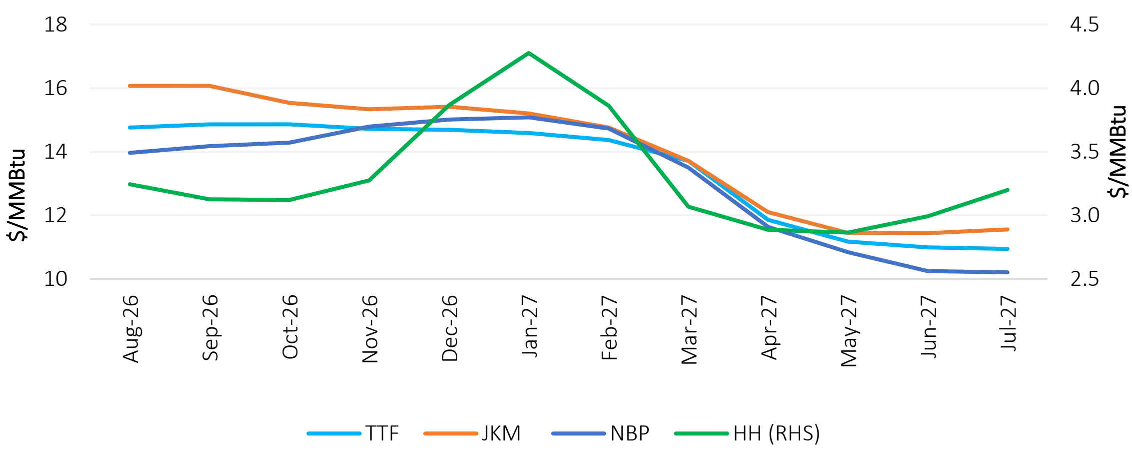
Source: GECF Secretariat based on data from Argus and LSE

6.1.4 Gas & LNG futures prices

As of 6 July 2026, the average futures prices for the 12-month period from August 2026 to July 2027 stood at $13.46/MMBtu for TTF, $13.21/MMBtu for NBP, and $14.05/MMBtu for JKM (Figure 125). Notably, all three benchmark prices were around 12% lower than the previous expectations presented in the GECF MGMR June 2026 assessment on 9 June 2026. Over the same period, Henry Hub futures averaged $3.32/MMBtu, also lower than previous expectations (Figure 126).

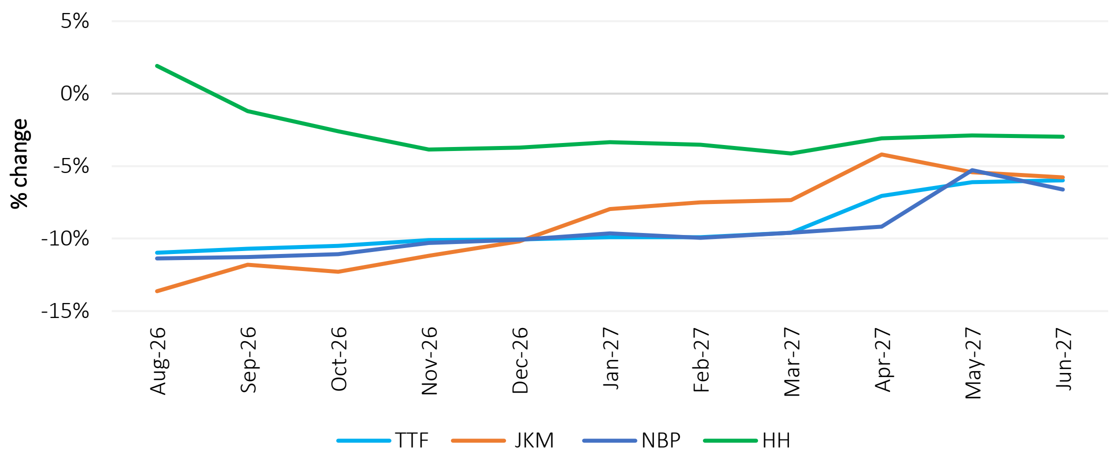
Looking ahead, the JKM–TTF spread is expected to narrow to around $1.3/MMBtu in August 2026, before tightening further to less than $1/MMBtu during the fourth quarter of the year.

Figure 125: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 6 July 2026

Figure 126: Variation in gas & LNG futures prices



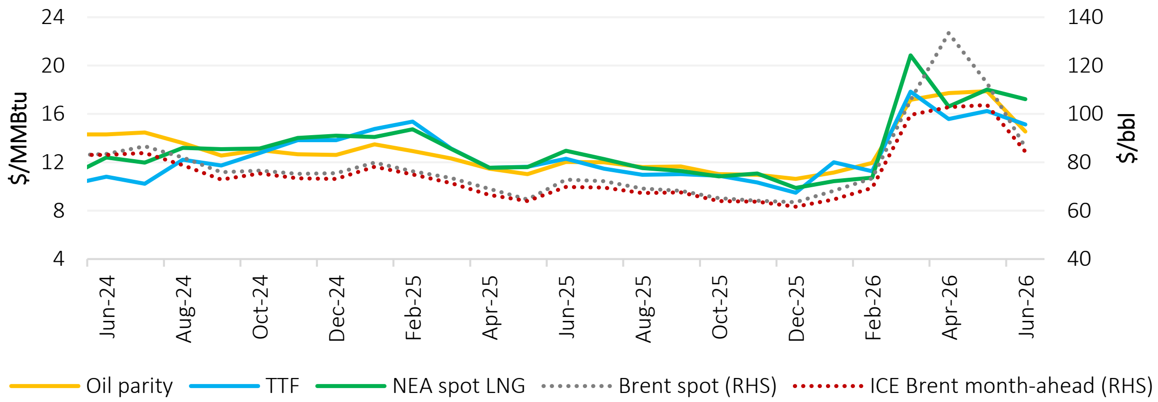
Source: GECF Secretariat based on data from LSEG
Note: Comparison with the futures prices as of 9 June 2026, as reported in GECF MGMR June 2026

6.2 Cross commodity prices

6.2.1 Oil prices

In June 2026, the average Brent crude spot price declined sharply by 24% m-o-m to $86.25/Bbl. However, it remained 18% higher y-o-y. Similarly, the month-ahead Brent price averaged $84.43/Bbl, decreasing substantially by 19% m-o-m, but was 21% higher y-o-y. Furthermore, TTF spot prices traded at a marginal premium of $0.6/MMBtu to the oil parity price, while NEA spot LNG prices traded at higher premium of $2.7/MMBtu (Figure 127).

Figure 127: Monthly crude oil prices

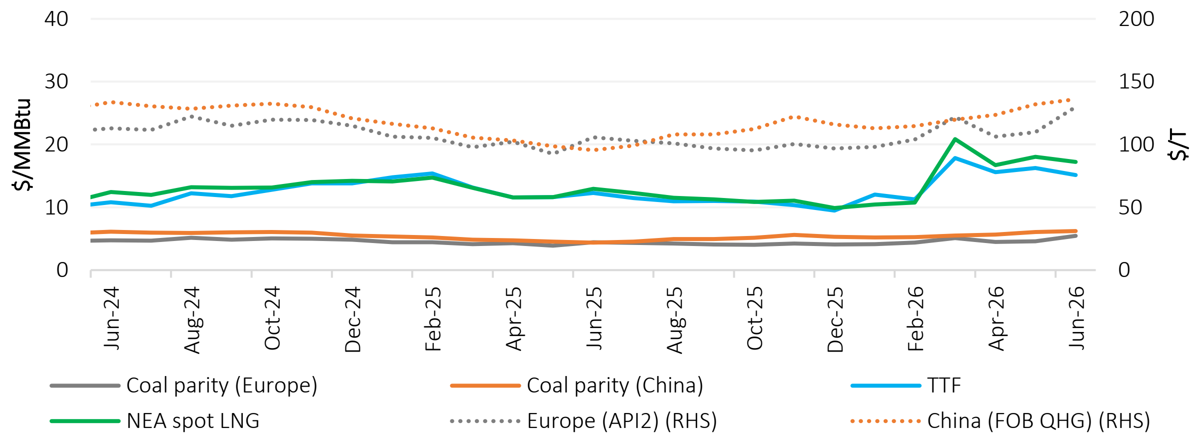


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factor of 5.8 was used to calculate the oil parity price in $/MMBtu based on the ICE Brent month-ahead price.

6.2.2 Coal prices

In June 2026, the European coal price (API2) averaged $129.85/t, increasing sharply by 18% m-o-m, and was 23% higher y-o-y. The premium of TTF spot gas over API2 parity narrowed compared to the previous month to $9.66/MMBtu. Meanwhile, in China, the Qinhuangdao (QHG) coal price averaged $136.06/t, increasing by 3% m-o-m and 42% y-o-y, whilst the premium of NEA spot LNG over QHG parity decreased to $10.99/MMBtu (Figure 128).

Figure 128: Monthly coal parity prices

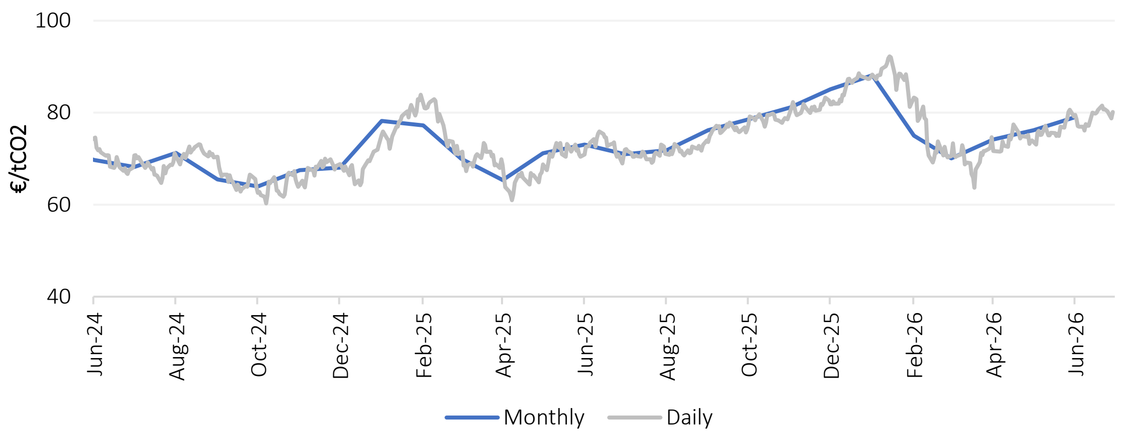


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in $/MMBtu for Europe (API2) and China (QHG) respectively.

6.2.3 Carbon prices

In June 2026, the EU carbon price averaged €79.06/tCO_2, reflecting increases of 4% m-o-m and 8% y-o-y (Figure 129). During the month, the daily EU carbon price climbed to a peak of €81.57/tCO_2.

Figure 129: EU carbon prices

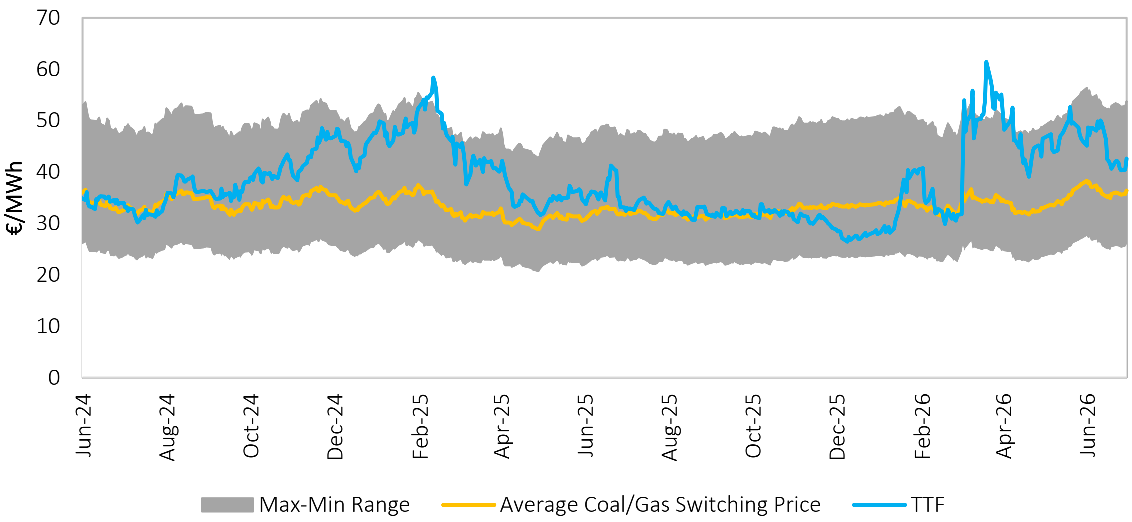


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In June 2026, TTF prices declined toward the average coal-to-gas switching price remaining above or near the upper bound of the switching range for several months (Figure 130). Despite this decline, the average TTF price remained above the average switching level. However, the price spread narrowed to €8.6/MWh, allowing coal to remain relatively more competitive over gas for power generation.

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

Abbreviations

Abbreviation	Explanation
AE	Advanced Economies
AECO	Alberta Energy Company
Bbl	Barrel
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
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
EMDE	Emerging Markets and Developing Economies
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
Fed	United States 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
mmcmd	Million cubic metres per day
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
OECD	Organization for Economic Co-operation and Development

PNG	Pipeline Natural Gas
PPAC	India’s 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
Tcm	Trillion cubic metres
tCO_2	Tonne of carbon dioxide
TFDE	Tri-Fuel Diesel Electric
TTF	Title Transfer Facility
TWh	Terawatt hour
UGS	Underground Gas Storage
UAE	United Arab Emirates
UK	United Kingdom
US	United States
y-o-y	year-on-year

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