GECF

Gas Exporting
Countries Forum

ANNUAL GAS MARKET REPORT

2025

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ABOUT THE GECF

The Gas Exporting Countries Forum (GECF) is an intergovernmental organisation established in May 2001. It became a fully-fledged organisation in 2008, with headquarters in Doha, the State of Qatar.

As of April 2025, the GECF gathers 20 countries, including 12 full members and 8 observer members (hereafter referred to as the GECF Member Countries) from four continents. Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela have the status of full members, while Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal have the status of observer members.

In accordance with the GECF Statute, the organisation aims to support the sovereign rights of its Member Countries over their natural gas resources and their abilities to develop, preserve and use such resources for the benefit of their peoples, through the exchange of experience, views, information and coordination in gas-related matters. Cooperation has been extended to technology with the establishment of the Gas Research Institute, headquartered in Algiers, the People's Democratic Republic of Algeria.

The vision of the GECF is "to make natural gas the pivotal resource for inclusive and sustainable development", and its mission is "to shape the energy future as a global advocate of natural gas and a platform for cooperation and dialogue, with the view to support the sovereign rights of Member Countries over their natural gas resources and to contribute to global sustainable development and energy security".

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The preparation of this Annual Gas Market Report (AGMR) was made possible through the dedicated efforts of the experts from the Gas Market Analysis Department (GMAD).

The GMAD team would like to extend its sincere appreciation to all those who contributed to the development of this report, particularly the Executive Board (EB) and Technical and Economic Council (TEC) members for their guidance, and HE Eng. Mohamed Hamel, Secretary General of the GECF, for his supervision.

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FOREWORD

"There are decades where nothing happens, and there are weeks where decades happen."

As I sat at my desk on the warm afternoon of 5 April to write this foreword, these words attributed to Vladimir Lenin came to mind. The acceleration of history in recent weeks — marked by deep geopolitical realignments, promising yet potentially disruptive digital technologies, the onset of new trade wars, among others — makes the year 2024 seem distant. It was a year of relative calm and stability in the energy landscape, especially when contrasted with the turbulent period shaped by the COVID-19 pandemic, the subsequent energy crisis, and the profound geopolitical, technological, and economic transformations now underway.

In this context, the GECF Annual Gas Market Report covering 2024 captures a moment of renewed strength and resilience for natural gas. In a year when global primary energy demand surged, natural gas reaffirmed its central role, with consumption reaching an all-time high and contributing 35% to the incremental growth in primary energy demand — the highest share among all fuels. All major sectors — power generation, industry, residential and commercial, and transport — registered growth in gas consumption, underscoring the strategic versatility of natural gas across economies and regions.

The Report also highlights the continued migration of the world's energy demand centre towards developing countries, particularly in Asia, led by China and India, alongside the expanding role of electrification and the increased penetration of natural gas into the heavy truck and maritime transportation sectors.

The flexibility provided by gas-based power generation was more critical than ever in 2024, ensuring stability for variable renewables, offering backup to hydropower during periods of drought — particularly in Asia and South America — supplying power to the rapidly growing data centre sector, and supporting cooling needs during intense heatwaves in regions such as China and India.

Global gas production rose by 2.5% in 2024, with GECF Member Countries playing a pivotal role in maintaining a stable and reliable supply to international markets. Meanwhile, gas trade flows adapted to evolving market dynamics, with pipeline gas trade rebounding and LNG demand remaining firm, particularly across Asia. Gas prices stabilised, restoring confidence across the value chain.

Looking ahead, the short- and medium-term outlook for natural gas remains robust, with global demand expected to grow by 2% annually in 2025 and 2026. Significant LNG liquefaction capacity is poised to come online between the end of this year and 2029, reinforcing natural gas's role in supporting clean cooking, facilitating coal-to-gas switching, enabling the integration of renewables, driving decarbonisation across key sectors, and enhancing food security through fertiliser production.

In this context, it is worth noting that many international energy companies revised their strategies in 2024 to place greater emphasis on natural gas and LNG within their portfolios, recognising the enduring role of gas in meeting future energy needs while ensuring long-term value creation for stakeholders.

As emphasised in the Algiers Declaration adopted at the 7th GECF Summit of Heads of State and Government, natural gas — a reliable, dispatchable, versatile, and lower-carbon energy source — will continue to serve as a critical enabler of economic growth, social progress, and environmental protection, while ensuring energy security, affordability, and sustainability.

In an increasingly complex and fast-evolving global environment, the GECF remains resolute in its mission to advocate for natural gas as a cornerstone of sustainable development and orderly, inclusive, affordable energy transitions that leave no one behind. The Forum will continue to champion dialogue, cooperation, and the sovereign rights of its Member Countries over their natural resources, while contributing to global energy security and prosperity.

I extend my sincere appreciation to all those who contributed to the preparation of this Report, and I commend its findings to policymakers, industry leaders, and all stakeholders committed to shaping a secure, sustainable, and equitable energy future.

In these turbulent times, allow me to conclude on a note of optimism: a careful reading of this Annual Gas Market Report, together with the recently released Global Gas Outlook, leads to a compelling conclusion — the golden age of natural gas lies ahead of us, not behind.

Eng. Mohamed Hamel
Secretary General
Gas Exporting Countries Forum

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

Global gas consumption reached an all-time high level in 2024

Natural gas solidified its crucial role in the global energy system in 2024, with global gas consumption increasing by 100 billion cubic meters (bcm), or 2.5%, reaching an all-time high of 4,170 bcm, and contributing 35% to the increase in primary energy supply. This growth, one of the fastest rates over the past decade, was fuelled by economic expansion, industrialisation, technological advancements, population growth, urbanisation, and changing weather patterns. Natural gas demonstrated its essential role in addressing the energy trilemma, particularly in ensuring energy security, affordability, and sustainability.

Asia Pacific was a key regional driver of global gas consumption growth

From a regional perspective, global gas consumption growth was driven primarily by Asia Pacific, which accounted for 60% of the global incremental demand. Notably, China's gas consumption increased by 33 bcm, reaching 430 bcm. Other key contributors included Russia and the US, each experiencing gains of up to 20 bcm. The Latin America and Caribbean region, as well as Africa, saw modest growth, while Europe's gas consumption stabilized after two years of decline.

Power generation and industrial sectors were sectoral drivers of gas consumption growth

From a sectoral perspective, the power generation and industrial sectors experienced notable growth in gas consumption. Gas-fired electricity output increased, driven by the electrification of transport and industry, as well as the expansion of data centres. Natural gas reinforced its role not only as a reliable baseload but also as a dispatchable electricity source supporting intermittent renewable energy generation. Similarly, gas consumption in the industrial sector rose, supported by lower gas prices. At the same time, the residential and commercial sectors saw higher demand for gas due to increased heating needs, driven by colder-than-usual weather in the Northern Hemisphere during the 2024/2025 winter season. The transport sector also experienced a surge, fuelled by the growth of LNG-fuelled trucks in China.

Short-term natural gas demand prospects may be impacted by the tariff war

Looking ahead, short-term projections for energy and gas demand were optimistic in recent months, supported by a positive economic outlook. However, the onset of a tariff war initiated by the new US administration, culminating in the imposition of high tariffs on imports from 185 countries on 2 April 2025, along with retaliatory measures already enacted by some affected nations, has introduced significant downside risks to global economic growth expectations. This, in turn, has created considerable uncertainty surrounding energy demand in general, and gas demand in particular. At the time of this report's publication, it is still too early to assess the full impacts of this unfolding trade war on the gas markets. In this context, the projections provided in this report reflect the economic and market conditions as of the end of March 2025.

Increased demand for gas was supported by steady global economic growth

The global economy continued its steady growth trajectory in 2024, supported by easing inflationary pressures, with global GDP growth estimated at 3.2% based on purchasing power parity. This drove an increase in demand for natural gas, particularly in the power generation and industrial sectors. Notably, China and India experienced the fastest economic growth among major economies, with growth rates at 5.0% and 6.7%, respectively. Meanwhile, the US witnessed GDP growth at 2.8%, and the EU experienced subdued economic activity, with GDP growth estimated at 0.9%.

Global gas production experienced strong growth to meet increasing gas demand

Global gas production grew by 2.5% in 2024, reflecting a robust response to rising global gas demand. The increase in supply was predominantly driven by Eurasia, the Middle East, and Asia Pacific. Specifically, Russia's production increased by 50 bcm, while China and Saudi Arabia added 15 bcm and 12 bcm, respectively. In contrast, the US, the world's largest gas producer, experienced a decline due to output cuts by domestic gas producers in response to low Henry Hub gas prices. GECF member countries continued to play a key role in the global gas supply, with their output rising by 3.2% to 1,598 bcm.

Stable upstream investment supported exploration and development activities

Global upstream oil and gas investment totalled $625 billion in 2024, the second-highest level since the COVID pandemic. This relatively high level of investment supported both exploration and development activities. In exploration, 420 bcm of gas was discovered, marking a rebound from the record-low discovery volume of 2023; however, gas discoveries still fell short of the pre-COVID historical average. In development, 130 gas projects commenced production, with an expected combined plateau production of 60 bcm per year.

Global gas trade rebounded, with Asia gaining market share from Europe

Global gas trade rose by 4% to reach 1.17 tcm in 2024, fuelled by growth in both pipeline gas and LNG segments. This marked a recovery to 2022 levels, although still below the record high seen in 2021. In Asia, total gas imports increased by 8% to 470 bcm, reinforcing its position as the leading gas-importing region. In Europe, total gas imports fell by 5% to 359 bcm, with a rebound in pipeline gas imports only partially mitigating the drop in LNG supply.

Pipeline gas trade rebounded, with growth observed in nearly all regions

After two years of decline, global pipeline gas trade — defined as gas flows via export pipelines to final destinations, excluding regasified LNG, transit pipeline flows, and pipeline gas re-exports — increased by 6%, reaching 606 bcm in 2024. Notably, the EU imported 158 bcm of pipeline gas, a 3% rise, driven by higher flows from Russia and Norway. Intra-North American flows continued to grow, with the US maintaining its position as a net exporter. Trade in Asia Pacific also rose, led by China, which increased imports by 13% to reach 75 bcm in 2024, primarily due to greater supply from Russia via the Power of Siberia pipeline.

Global LNG market remained relatively tight, driven by strong demand in Asia

The global LNG market remained relatively tight in 2024, with global LNG exports growing by just 0.9%, marking the slowest pace since 2020. Asia's LNG imports surged by 8%, reaching a record high, driven primarily by increased demand from China and India, fuelled by rising gas consumption across multiple sectors, lower spot LNG prices, and the commissioning of new LNG import terminals. In contrast, Europe’s LNG imports fell by 18%, largely due to increased pipeline gas imports and high gas storage levels.

Significant LNG liquefaction capacity is anticipated to come online in the short term

Global LNG liquefaction capacity additions rebounded to 10 Mtpa in 2024, following a record low in the previous year. Four projects were commissioned in the Republic of Congo, Mexico, Russia, and the US, with the first two countries emerging as new LNG exporters. Looking ahead, global liquefaction capacity is set to increase by 206 Mtpa between 2025 and 2028, representing a 42% rise from 2024 levels. This rapid expansion could lead to an oversupply, exerting downward pressure on spot LNG prices, while stimulating demand in price-sensitive markets, which could help balance the global LNG market.

Spot LNG shipping costs declined due to the excess availability of carriers in the market

Spot LNG shipping costs dropped significantly in 2024, despite longer voyages resulting from partial disruptions to traditional LNG shipping routes through the Suez and Panama Canals, caused by geopolitical tensions and drought conditions, respectively. The drop in shipping costs was driven by spot charter rates for LNG carriers plummeting to an unprecedented low, as the LNG shipping market saw a record-breaking 70 new carriers entering into service, with most of the newly commissioned carriers temporarily deployed into the spot charter market.

Gas storage levels in the EU dropped due to reduced gas supply and colder weather

EU gas storage levels remained high throughout the first three quarters of 2024, supported by low gas withdrawals during the mild 2023/2024 winter season. Storage levels exceeded expectations at every checkpoint set by the 2022 gas storage regulations, reaching 90% of regional capacity two months ahead of the November 1 target. However, this was followed by the largest drawdown in seven years during the last two months of the year, driven by declining LNG imports and colder temperatures during the 2024/2025 winter season.

Spot gas prices stabilised but stayed elevated compared to pre-COVID levels

Spot gas prices settled in 2024, marking a stark contrast to the extreme volatility of the previous four years, which saw both record lows and highs. This stabilisation was largely driven by a balanced supply-demand dynamic, supported by adequate gas production growth, the mitigation of supply disruption impacts, and high gas storage levels. TTF spot prices averaged $11/MMBtu in 2024, down from $13/MMBtu in 2023, $38/MMBtu in 2022, and $16/MMBtu in 2021. Similarly, the average NEA spot LNG price decreased to $12/MMBtu. Despite this stabilisation, spot gas prices remained elevated compared to pre-COVID levels in both Europe and Asia. Meanwhile, Henry Hub spot prices in the US dropped by 12%, averaging $2/MMBtu.

CHAPTER

01

GLOBAL PERSPECTIVES

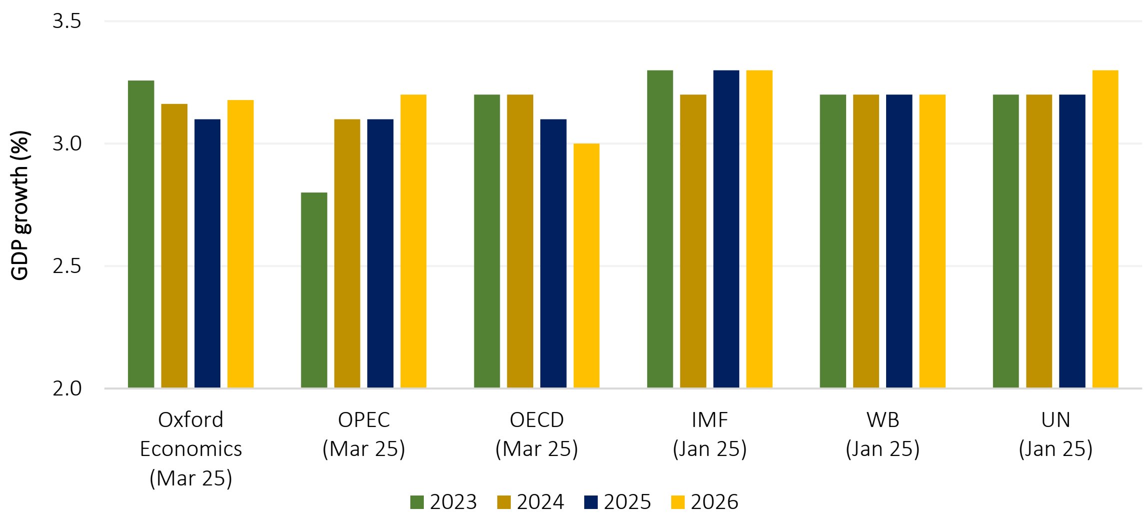
1.1 Global Economy

The global economy maintained steady growth momentum despite persistent challenges

The global economy demonstrated resilience over the past year, maintaining steady growth momentum, bolstered by easing inflationary pressures. In 2024, global GDP growth is estimated at 3.2%, based on purchasing power parity weights (PPP). This is lower than the pre-pandemic average growth rate of 3.6%, recorded between 2010 and 2019. Growth disparities persisted, with advanced economies expanding by 1.8%, while emerging and developing economies grew at a stronger pace of 4.2%. Similarly, global GDP growth was estimated at 2.8%, based on market exchange rates weights (MER).

Looking ahead, global GDP growth for 2025 was projected at 3.1% as of the end of March 2025 (Figure 1). However, the newly imposed US import tariffs, coupled with retaliatory measures from some affected nations, could severely disrupt global trade flows and supply chains, leading to significant negative consequences for the global economy. In particular, the escalating tariff war may slow global economic growth and trigger inflation.

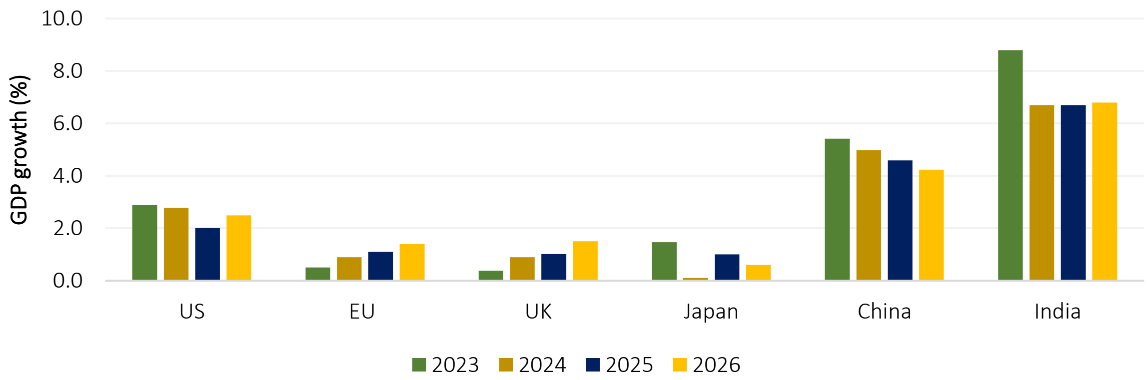
Figure 1: Global GDP growth



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. Preliminary estimate for 2024 and forecast for 2025-2026, as of March 2025. Forecasts do not consider US tariffs announced on 2 April 2025.

While the global economy remains stable, economic performance varies across countries and regions. In the US, GDP growth for 2024 is estimated at 2.8%, driven by strong consumer spending and a resilient labour market, but is expected to moderate to 2.4% in 2025 due to the impact of new tariffs and policy uncertainties. The EU experienced subdued economic activity, with GDP growth estimated at 0.9% for 2024 and projected to rise slightly to 1.1% in 2025. In China, GDP growth for 2024 is estimated at 5.0%, supported by steady industrial activity despite weaker consumer demand, but is expected to slow to 4.6% in 2025. India's GDP growth is estimated at 6.7% for 2024 and is expected to remain steady in 2025 (Figure 2). However, the imposition of US import tariffs on 2 April 2025, affecting 185 countries, may have significant implications for the growth of national economies.

Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics
Note: Preliminary estimate for 2024 and forecast for 2025-2026, as of March 2025. Forecasts do not consider US tariffs announced on 2 April 2025.

A more comprehensive comparison of specific countries' contributions to global GDP can be made by examining the magnitude of national GDPs. In this context, consideration of GDP based on purchasing power parity (PPP) is more appropriate, as it better reflects a country's actual production and consumption capacity (Table 1).

Table 1: GDP in top 20 largest economies in 2024

	Country	GDP (PPP) (Int$ billion)	GDP (MER) (US$ billion)		Country	GDP (PPP) (Int$ billion)	GDP (MER) (US$ billion)
1	China	37,072	18,273	*11*	Italy	3,598	2,377
2	US	29,168	29,168	*12*	Türkiye	3,457	1,344
3	India	16,020	3,889	*13*	Mexico	3,303	1,848
4	Russia	6,909	2,184	*14*	South Korea	3,258	1,870
5	Japan	6,572	4,070	*15*	Spain	2,665	1,731
6	Germany	6,017	4,710	*16*	Canada	2,582	2,215
7	Brazil	4,702	2,188	*17*	Egypt	2,232	380
8	Indonesia	4,658	1,403	*18*	Saudi Arabia	2,113	1,101
9	France	4,359	3,174	*19*	Australia	1,898	1,802
10	UK	4,282	3,588	*20*	Poland	1,891	863

Source: GECF Secretariat based on data from IMF
Note: Preliminary estimates for 2024, as of October 2024. GDP (PPP) is typically measured in International Dollars (Int$), a hypothetical currency that represents the purchasing power of US dollars in a given country.

Inflation continued to ease, prompting central banks to reduce interest rates

Global inflation was estimated at 4.5% in 2024, down from 6.1% in 2023 and 8.1% in 2022. This was driven by the lagged effects of tightening monetary policies, and softening energy and commodity prices. The pace of disinflation varied across countries, influenced by the timing of monetary policy adjustments and differing supply and demand dynamics. Looking ahead, global inflation is projected to continue its downward trajectory, reaching 3.7% in 2025 (Table 2). However, the escalation of the tariff war could lead to a resurgence of a high-inflation environment.

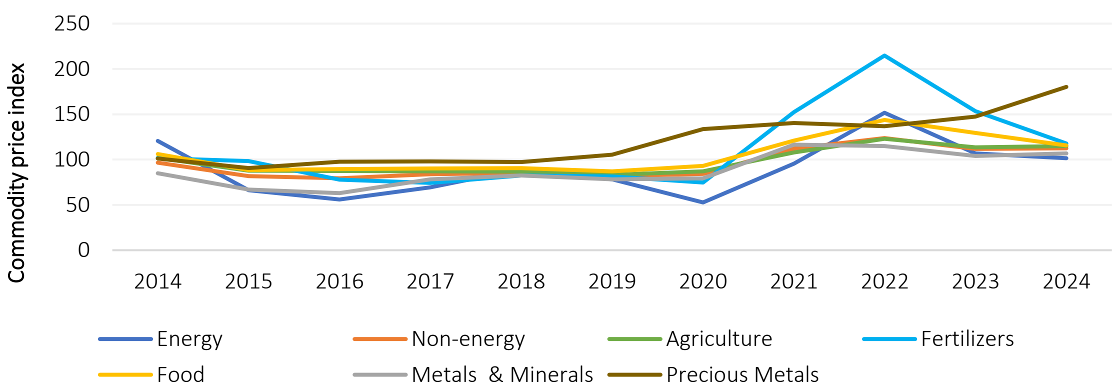
Table 2: Inflation rates

	2023	2024	2025	2026
Global	*6.1*	*4.5*	*3.7*	*3.1*
US	4.1	3.0	3.0	2.1
Euro area	5.4	2.4	2.1	1.8
UK	7.3	2.5	3.2	2.6
China	0.2	0.2	0.4	1.0
India	5.7	4.9	4.4	4.6

Source: GECF Secretariat based on data from Oxford Economics
Note: Preliminary estimates for 2024 and forecast for 2025-2026, as of March 2025

Commodity prices stabilised in 2024 after experiencing significant volatility in previous years due to market shocks and geopolitical tensions. However, prices remained above the 10-year average. The energy price index declined by 5% y-o-y, driven by lower oil, gas and coal prices, against the backdrop of steady global economic growth. In contrast, the non-energy price index remained relatively unchanged from the previous year. Notably, the precious metals price index surged by 22% y-o-y, while the fertiliser price index saw a sharp 23% decline y-o-y (Figure 3). Looking ahead to 2025, commodity prices are expected to moderately decline, with the energy price index forecast to decrease by 6% y-o-y, driven by lower oil prices amid slowing oil demand growth, particularly in China, despite a projected rise in gas prices.

Figure 3: Commodity price indices

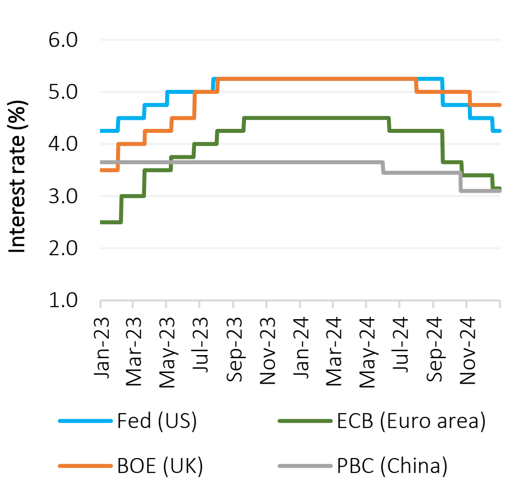


Source: GECF Secretariat based on data from World Bank Commodity Price Data
Note: Annual price indices based on nominal US dollars, 2010=100. The energy price index is calculated using a weighted average of global crude oil (84.6%), gas (10.8%) and coal (4.7%) prices. The non-energy price index is calculated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

Interest rates decreased globally in 2024 as central banks responded to signs of easing inflation and evolving economic conditions (Figure 4). After a period of aggressive rate hikes aimed at controlling inflation, many major central banks shifted their focus towards supporting economic growth, gradually implementing rate cuts following a cautious approach. In the first half of the year, central banks in the US, UK, Euro area, and China kept their rates unchanged, however, this trend reversed in the latter half of the year. The US Federal Reserve (Fed) implemented three interest rate cuts, lowering rates by 0.50 percentage points in September, followed by two consecutive cuts of 0.25 percentage points in November and December. By year-end, the Fed's benchmark interest rate ranged from 4.25% to 4.5%. In the Euro area, the European Central Bank (ECB) reduced its key interest rates by 0.25 percentage points on four occasions — in June, September, October and December — bringing its main refinancing operations rate to 3.15% by year-end. In the UK, the Bank of England (BOE) implemented two interest rate cuts of 0.25 percentage points in August and November, bringing the BOE's benchmark rate to 4.75% by the end of the year. The People's Bank of China (PBC) made two rate cuts in June and October, reducing its one-year Loan Prime Rate (LPR) to 3.1%. Looking ahead to 2025, central banks are expected to proceed cautiously with further limited rate cuts, closely monitoring economic activity and inflationary trends.

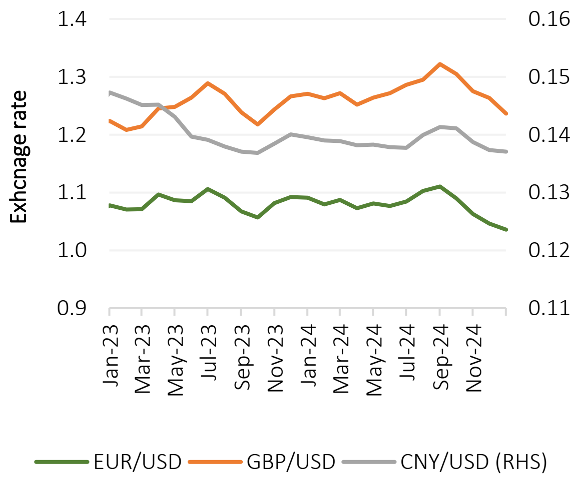
Exchange rates remained relatively stable in 2024, with minimal fluctuations observed across major currencies (Figure 5). The euro maintained its value against the US dollar, averaging $1.0820, virtually unchanged from the previous year. Meanwhile, the British pound appreciated by 3% against the US dollar, averaging $1.2783. In contrast, the Chinese yuan weakened against the US dollar, with an average exchange rate of $0.1390, reflecting a 2% decline. Looking ahead to 2025, the US dollar is expected to strengthen, supported by robust US economic performance, though the current trade war will influence its trajectory.

Figure 4: Interest rates in major central banks



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

Figure 5: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Energy Policies

1.2.1 Global Developments

Energy security and affordability moved to the top of the agenda for policy decision-makers

The global energy policy landscape in 2024 increasingly prioritised energy security and affordability over the climate agenda, a shift that began during the 2022 energy crisis, fuelled by rising concerns over energy security.

Natural gas remained a key component of energy policies worldwide. Many countries continued to rely on natural gas to meet growing energy demands while pursuing long-term carbon reduction targets. Viewed by several nations as a cleaner alternative to coal, since natural gas emits less carbon dioxide when burned, continued investment in gas infrastructure to support global energy needs has been evident. Furthermore, as many countries expanded wind and solar power generation, natural gas solidified its role not only as a baseload energy source but also as a dispatchable energy alternative. By serving as a backup for the intermittent output of wind and solar energy, natural gas played a critical role in ensuring grid stability, particularly as countries worked to phase out coal-fired power generation.

Looking ahead, uncertainty is growing around global and regional energy policies, driven by shifts in leadership across several major countries. The new US administration has already withdrawn from the Paris Agreement and implemented a new policy agenda focused on economic growth, deregulation, and energy independence, which will be supported by increased oil and natural gas production. Meanwhile, the new EU Commission may adopt a more pragmatic approach to the climate agenda and energy policies, balancing sustainability with energy security concerns. In this shifting landscape, the prominent role of natural gas in energy security and the transition to lower emitting fuels are more widely acknowledged.

1.2.1.1 GECF

Two key milestones in 2024 highlight the ongoing importance of natural gas in global energy policies. The Algiers Declaration, adopted at the 7th GECF Summit held on 2 March 2024 in Algiers, Algeria, reflects the shared commitment of the Heads of State and Governments of GECF Member Countries to "promote natural gas as an abundant, affordable, flexible and reliable energy source, and harness and develop more environmentally-friendly, efficient and sustainable natural gas technologies". Additionally, the Ministerial Statement, adopted at the 26th Ministerial Meeting held on 8 December 2024 in Tehran, Iran, emphasised "the pivotal role of natural gas in advancing the United Nations Sustainable Development Goals, notably to end hunger and ensure universal access to energy, as well as in driving orderly, just, inclusive, cost-effective, and nationally determined energy transitions that leave no one behind" and called for "enhanced dialogue between key stakeholders to ensure security of demand and security of supply".

1.2.1.2 COP29

The 29th session of the Conference of the Parties (COP29) to the United Nations Framework Convention on Climate Change (UNFCCC) took place from November 11-22, 2024, in Baku, Azerbaijan. COP29 made progress on several key topics, particularly on climate finance commitments, advancements in carbon markets, and trade-related climate measures, which may have significant, albeit indirect, implications for the gas industry.

At the centre of discussions was climate finance, a cornerstone of Article 9 of the Paris Agreement. This article stipulates that "developed country Parties shall provide financial resources to assist developing country Parties with respect to both mitigation and adaptation, in continuation of their existing obligations under the Convention." In 2015, COP21 agreed to establish, prior to 2025, a new collective quantified goal (NCQG) for financial assistance to developing countries, replacing the annual target of $100 billion set at COP15 in 2009. Ultimately, COP29 decided to set the NCQG at a minimum of $300 billion per year by 2035.

Despite the increase in pledged amounts, many stakeholders view the agreements in this area as insufficient and inefficient. First, the financial commitment falls short of the estimated funding requirements, with concerns of developing countries reflected in a non-binding statement with a call for all actors to "work together to enable the scaling up of financing to developing country Parties for climate action from all public and private sources to at least $1.3 trillion per year by 2035." Second, the statement that funding may come from a wide variety of sources does not impose binding commitments on developed countries to provide public funding, which is the most critical element of the financing. Third, while developing countries have long called for financial support to be provided exclusively in grant-equivalent forms, the final text acknowledges not only grant-based resources but also concessional finance. Overall, the inadequate commitments from developed countries highlight their reluctance to bear substantial financial burdens, posing a significant challenge to advancing the energy transition, especially given their strong emphasis on expanding renewable energy. In this context, there is a growing global consensus that there is no “one-sise-fits-all” model when it comes to regional energy transitions, as each region has its own unique challenges and resources. In many regions, energy transitions cannot rely solely on renewables; all energy sources must contribute, with natural gas holding significant potential.

COP29 also achieved progress on carbon markets under Article 6 of the Paris Agreement, which provides the framework for international collaboration in carbon markets to help meet nationally determined contributions. Parties reached an agreement on the final building blocks that define how carbon markets will function, opening the door for future integration of national and regional carbon markets, with emission allowances or credits generated under one system to be recognised in another. COP29 also reached a significant agreement to establish a four-year work plan (2026–2030) aimed at addressing the effects of carbon-cutting policies, with a specific focus on their cross-border impacts. However, the US withdrawal from the Paris Agreement is likely to have an adverse effect on future climate change negotiations, particularly on COP30, which is scheduled to be held in Brazil.

1.2.1.3 G20

The G20 Summit took place on 18-19 November 2024 in Rio de Janeiro, Brazil, under the theme of "Building a just world and a sustainable planet". In the adopted G20 Rio de Janeiro Leaders' Declaration, the leaders recognised "the need to catalyse and scale up investment from all financial sources and channels for bridging the funding gap for energy transitions globally, especially in developing countries." Reaffirming that developing countries need to be supported in their transitions to low carbon emissions, they committed to "work towards facilitating low-cost financing for them." The next G20 Summit will take place in 2025 in Johannesburg, South Africa, under the theme "Solidarity, Equality, Sustainability."

1.2.1.4 BRICS

The 16th BRICS Summit took place on 22-24 October 2024 in Kazan, Russia, under the theme of "Strengthening Multilateralism for Just Global Development and Security". In the Kazan Declaration, the leaders stated that "the efficient use of all energy sources is critical for just energy transitions towards more flexible, resilient and sustainable energy systems and in this regard we uphold the principle of technological neutrality, i.e. using all available fuels, energy sources and technologies to reduce greenhouse gas emissions which includes, but is not limited to fossil fuels with abatement and removal technologies, biofuels, natural gas and LPG, hydrogen and its derivatives, including ammonia, nuclear and renewable power, etc."

1.2.1.5 G7

The G7 Summit took place on 13-15 June 2024 in Apulia, Italy. On the topic of energy, climate and the environment, the G7 leaders reiterated their "determination to address the triple global crisis of climate change, pollution, and biodiversity loss. We remain steadfast in our commitment to the Paris Agreement and keeping a limit of 1.5°C global temperature rise within reach and note with deep concern the findings of the first Global Stocktake at the UN Climate Change Conference (COP28) that there is a significant gap between global current emissions trajectories and this commitment." Furthermore, the G7 leaders, alongside Côte d'Ivoire, Ethiopia, Kenya, Mozambique, Nigeria, the Republic of Congo and South Africa, launched the G7's "Energy for Growth in Africa" initiative, which aims to develop clean energy projects, attract private capital and overcome barriers to investments in clean energy across Africa.

1.2.1.6 APEC

The APEC Summit took place on 16 November 2024 in Lima, Peru, under the theme of "Empower. Include. Grow." In the 2024 APEC Leaders' Machu Picchu Declaration, the leaders of APEC recognised "the importance of ensuring energy security, resilience and access to support a sustainable economic growth and development." They recognised that "more intensive efforts are needed for economies to accelerate their clean, sustainable, just, affordable, and inclusive energy transitions through various pathways, consistent with global net-zero greenhouse gas emissions / carbon neutrality by or around mid-century, while taking into account the latest scientific developments and different domestic circumstances."

1.2.2 Regional Developments

1.2.2.1 Europe

Energy policies sought to balance sustainability and security

The EU's energy policies demonstrated its commitment to achieving a sustainable and secure energy future, balancing environmental objectives with economic priorities. Various energy policies implemented throughout 2024 have had a significant impact on the regional gas market.

Coordinated Gas Demand Reduction Measures: On 25 March 2024, the European Parliament and the Council of the EU adopted Regulation (EU) 2024/234, urging member states to continue their voluntary gas demand reduction efforts until 31 March 2025. This initiative, first introduced in 2022 in response to the ongoing energy crisis, aims to mitigate the risks of gas supply disruptions. Specifically, Regulation (EU) 2022/1369, adopted in August 2022, set a voluntary target for member states to reduce gas consumption by 15% from 1 August 2022 to 31 March 2023. Acknowledging the ongoing uncertainties in the energy landscape, the EU extended this target with Regulation (EU) 2023/706, covering the period from 1 April 2023 to 31 March 2024. The measures helped stabilise the European gas market, particularly during the peak of the 2022-2023 energy crisis. However, this policy, although essential for energy security, has led to disruptions in some industrial sectors that rely heavily on natural gas.

Methane Emission Reduction Regulation: On 13 June 2024, the EU authorities adopted Regulation (EU) 2024/1787, aimed at reducing methane emissions across the energy sector, with a focus on hydrocarbon production and imports. The regulation mandates that operators in the oil, gas and coal industries adhere to stringent monitoring, reporting and verification (MRV) practices to ensure accurate and up-to-date emissions data. In addition, operators must implement regular leak detection and repair (LDAR) programs to address methane leaks in infrastructure, utilising advanced technologies. The regulation also mandates the cessation of routine flaring and venting to curb methane emissions. Furthermore, it extends to imported fossil fuels, requiring importers to demonstrate the application of equivalent MRV practices by January 2027. Non-compliance will result in financial penalties for oil, gas and coal imports exceeding methane intensity limits by 2030.

Electricity Market Reform: On 13 June 2024, the EU authorities adopted Regulation (EU) 2024/1747 to enhance the EU’s electricity market design, boosting its resilience, stability and sustainability. The regulation introduces measures to protect consumers from price volatility and market fluctuations, supports the integration of renewable energy sources, and works to prevent market manipulation. It also focuses on ensuring greater energy cost predictability, strengthening security of supply through capacity mechanisms, and enhancing market flexibility.

FuelEU Maritime Regulation: The regulation, adopted in July 2023 and effective from 1 January 2025, is part of the EU's "Fit for 55" package. It applies to ships over 5,000 gross tonnes calling at EU ports, covering energy used during voyages and port calls within the EU/EEA, as well as some energy used on voyages to/from non-EU/EEA ports. It mandates a 2% reduction in GHG intensity by 2025 (compared to 2020 levels), aiming for an 80% reduction by 2050.

Corporate Sustainability Due Diligence Directive: On 13 June 2024, the EU authorities adopted Directive (EU) 2024/1760 on corporate sustainability due diligence *(CSDDD)*. The directive mandates large companies to implement robust human rights and environmental due diligence across their supply chains. Additionally, companies must adopt a climate change mitigation transition plan to ensure their business models and strategies align with the EU's climate neutrality targets. Member states are required to adopt the necessary regulations by 26 July 2026. However, the directive has been met with substantial global criticism, especially for its inclusion of non-EU companies with a €450 million net turnover in the EU, which will be subject to fines up to 5% of their worldwide turnover for non-compliance.

Gas Price Cap: The EU gas price cap, officially known as the Market Correction Mechanism (MCM), was in effect throughout 2024 and expired on 31 January 2025, with no extension, signalling a recovery of the gas market and reduced need for emergency interventions. Introduced on 15 February 2023 in response to the extreme volatility and record-high gas prices during the 2022 energy crisis, the MCM aimed to prevent excessive price spikes in the European gas market. The mechanism set a ceiling of €180/MWh for natural gas prices, triggering automatic activation if prices remained at or above this threshold for three consecutive days. However, the cap was never triggered, as the market conditions improved over time, with gas prices stabilising and volatility decreasing.

Emissions Trading System (ETS): The EU ETS has seen significant developments in recent years to strengthen its role in reducing greenhouse gas emissions. One of the key changes in 2024 was the inclusion of the maritime sector, effective from 1 January. The expansion now covers CO_2 emissions from large ships (5,000 gross tonnage and above) entering EU ports. This system operates on a flag-neutral and route-based approach, capturing emissions from the following voyages: 50% of emissions from voyages starting or ending outside the EU, and 100% of emissions from voyages between two EU ports and while ships are within EU ports.

Carbon Border Adjustment Mechanism (CBAM): The EU's CBAM entered its transitional phase on 1 October 2023, which will continue until 31 December 2025. During this period, importers of carbon-intensive goods are required to report the embedded emissions of their imports, with no financial obligations imposed at this stage. Once fully implemented in 2026, the CBAM will require importers to pay for the carbon emissions associated with their goods entering the EU, placing a price on carbon for goods coming from countries with less stringent climate policies, while protecting EU industries from carbon leakage.

Joint Gas Purchasing: The EU Energy Platform, established in December 2022 under EU Council Regulation (2022/2576), facilitates joint gas, LNG and hydrogen purchases to ensure affordable energy and diversify supply sources. The platform aggregates gas demand from EU member states, with countries required to meet 15% (13.5 bcm) of their storage needs via the platform. Since its launch, five short-term rounds have aggregated 55 bcm of gas demand, surpassing the requirement with 43 bcm of matched supply. In February 2024, the EU extended the platform to the medium-term, securing 34 bcm of gas demand for April 2024–October 2029. The mechanism is now permanent, with the next round set for March 2025.

1.2.2.2 Asia Pacific

Energy security was the central focus of energy policies

China focused on accelerating its energy transition, promoting sustainability and bolstering energy security. Key initiatives included the introduction of the "Guiding Opinions on Vigorously Implementing the Renewable Energy Substitution Initiative", aimed at reducing reliance on fossil fuels by increasing the use of wind, solar, hydro and biomass energy in power generation, heating and industrial processes. China also made significant progress in advancing its national Emissions Trading System (ETS), relaunching the Chinese Certified Emissions Reduction (CCER) scheme to allow companies to offset up to 5% of their emissions. The government issued regulations to establish the ETS framework and announced plans to expand it to the cement, steel and aluminium sectors in two phases, with the initial phase from 2024–2026 focusing on data quality and the second phase, starting in 2027, tightening the system. Additionally, China unveiled an updated National Gas Utilisation Policy aimed at improving natural gas efficiency and optimising energy consumption. This policy includes linking upstream and downstream gas prices, implementing differential pricing for regions with seasonal demand fluctuations, and prioritising users such as households and industrial consumers, while restricting gas-based methanol and petrochemical production.

India made efforts to advance its transition to a gas-based economy through the expansion of gas pipeline infrastructure and the increase of domestic gas production. This strategy will be reinforced by the Oilfields Amendment Bill, which was approved by the legislative branch in December 2024. The bill aims to strengthen India's energy security by broadening the definition of "mineral oils" to encompass both petroleum and natural gas. It also modernises governance for oil and gas exploration, separates petroleum operations from mining activities, and streamlines the regulatory framework to attract investment and enhance exploration efficiency.

Japan advanced its energy policies with a focus on decarbonisation, renewable energy and nuclear power and increasing the role of LNG. The 7th Strategic Energy Plan, released in December 2024, outlines ambitious targets, including carbon neutrality by 2050 and a 70% emissions reduction by 2040. The plan emphasises expanding renewable energy to contribute 50% of electricity generation by 2040, while maintaining nuclear energy at 20%. Additionally, Japan is preparing to launch a mandatory Emissions Trading System (GX-ETS) in the fiscal year 2026-2027, building on a voluntary system introduced in 2023.

South Korea also advanced its energy policies by focusing on energy security, nuclear power and renewable energy. The government introduced the National Natural Resources Security Special Act, requiring LNG importers to stockpile LNG. Additionally, it boosted support for the nuclear industry with a KRW150 billion financial package. On the renewable energy front, South Korea continued its transition to cleaner sources, though it reduced subsidies for biomass energy due to environmental concerns about deforestation. These measures reflect South Korea's efforts to ensure energy security, support nuclear power, and promote renewable energy while addressing environmental issues.

1.2.2.3 North America

Key priorities were decarbonisation and the promotion of clean energy

Canada's energy policies concentrated on clean energy and decarbonisation through policies like the Carbon Pollution Pricing Act, which increases carbon prices to incentivise emission reductions. The government advanced the Clean Fuel Standard (CFS), aiming to cut 30 million tonnes of carbon emissions annually by 2030, with a particular focus on natural gas. Additionally, the Oil and Gas Emissions Reduction Plan, updated in 2024, introduced stricter methane emission reduction targets and promoted carbon capture technologies within the natural gas sector to enhance energy efficiency and further cut emissions.

Mexico concentrated on reinforcing state planning, ensuring fair electricity access, and establishing transparent regulations to encourage private investment. Notable initiatives included the launch of the National Strategy for the Electricity Sector (2024–2030) in November 2024, designed to foster energy justice while boosting private sector participation. In addition, a constitutional reform, published in October 2024, aimed to clarify the roles of public utilities and private companies, with legislative changes anticipated to further streamline and align the sector.

United States energy policies focused on advancing clean energy, reducing greenhouse gas emissions, and accelerating the transition to renewable sources. The Biden administration continued to prioritise the Inflation Reduction Act (IRA), driving investments in clean energy technologies, electric vehicles, and energy efficiency. Several initiatives specifically targeted the natural gas sector. In January 2024, the administration paused new LNG export authorisations to non-Free Trade Agreement (non-FTA) countries, allowing the Department of Energy time to reassess the economic and environmental impacts of LNG exports, including considerations of domestic energy costs, emissions and supply security. Additionally, in May 2024, the US Environmental Protection Agency (EPA) implemented Methane Emission Abatement Rules under the Clean Air Act, imposing stricter regulations on methane emissions from the oil and gas sector. These regulations included enhanced monitoring, reporting, leak detection and repair programs, as well as more stringent restrictions on flaring and venting.

With the arrival of the new US administration in January 2025, a notable shift in energy policies is underway, which could significantly impact global energy markets. President Trump signed several executive orders, including "Declaring a National Emergency," "Unleashing American Energy," and "Putting America First in International Environmental Agreements," aimed at boosting domestic energy production, with a particular focus on fossil fuels. The new administration is removing regulatory barriers to fast-track energy project approvals, lifting the LNG export pause. Trump's policies also include rolling back environmental regulations to stimulate fossil fuel investments and support economic growth. Furthermore, his administration is emphasising the strengthening of energy infrastructure while signalling a shift away from international climate agreements, such as the Paris Climate Agreement, reinforcing a focus on energy independence.

1.2.2.4 Latin America and the Caribbean

Both renewable energy and fossil fuel initiatives were at the centre of energy policies

Argentina's energy policies focused on advancing renewable energy initiatives and enhancing fossil fuel production. In December 2024, Argentina amended the National Hydrocarbons Law, to include hydrocarbon processing and storage, replace the concession system with authorisation, and introduce uniform environmental regulations. The amendments remove state intervention in the domestic market to foster a market-driven environment and attract private investment.

Brazil implemented several key energy policies to further its energy transition and sustainability objectives. In August, President Luiz Inácio Lula da Silva launched the National Energy Transition Policy, which aims to align energy transition efforts across the country. In October, the "Fuel of the Future" law was enacted, focusing on increasing the use of sustainable and low-carbon fuels, decarbonising the transportation sector, and improving vehicle energy efficiency. Additionally, Brazil's National Energy Policy Council (CNPE) approved two resolutions in August 2024. The first established additional guidelines for the federal oil and natural gas marketing policy, optimising the government's share from production-sharing contracts, and enhancing national energy security. The second resolution provided guidelines for decarbonising oil and natural gas exploration and production activities, emphasising technological development, reducing natural gas flaring, and maintaining zero routine flaring.

Bolivia promoted efforts to reform the hydrocarbon sector, promote renewable energy, and develop green hydrogen. In November 2024, Bolivia launched a strategy for developing green hydrogen, offering financial incentives, promoting public-private partnerships, and establishing a legislative framework to foster the growth of the sector, with plans to build two green hydrogen plants leveraging the country's renewable resources.

Peru's energy policies emphasised advancing low-carbon energy solutions and developing renewable resources, while simultaneously prioritising the enhancement of gas infrastructure and positioning natural gas as a central element of the country's energy transition. In March 2024, Peru adopted the Green Hydrogen Promotion Act, recognising activities related to green hydrogen, including research, production, export and usage, as a national priority.

Trinidad and Tobago focused on enhancing the oil and gas sector, promoting renewable energy, and ensuring energy security. The government implemented measures to attract investment, including tax incentives and policy reforms, aiming to boost production and revenue.

Venezuela's energy policies concentrated on revitalising its oil and gas industry while simultaneously initiating renewable energy projects. The country's oil production saw a resurgence, driven by internal improvements within the state oil company PDVSA, greater participation of national capital, and the easing of unilateral economic sanctions. In June 2024, the Venezuelan government unveiled a plan to generate solar energy in the Andes region, aimed at diversifying the nation's energy mix and addressing local energy challenges.

1.2.2.5 Africa

Energy policies were focused on boosting production and attracting investment

Algeria focused on boosting its energy output by launching the country’s first oil and gas licensing round since 2014. This move is part of a broader strategy to ramp up production and attract foreign investments. The government outlined plans to hold annual licensing rounds until 2028, ensuring an increased exploration of the country’s oil and gas reserves.

Angola enacted the Incremental Production Act, designed to incentivise investment in the upstream oil and gas industry. This new policy focuses on rewarding reinvestment in existing assets, while offering specialised fiscal and legal frameworks for investors.

Egypt introduced a new set of financial incentives aimed at increasing both oil and gas production, including mechanisms designed to promote exploration and development activities, especially drilling and new exploratory projects. The government also made strides towards energy diversification by unveiling its National Low-Carbon Hydrogen Strategy.

Equatorial Guinea introduced strategic initiatives aimed at modernising its energy sector. These reforms focus on improving tax policies, optimising the use of hydrocarbon resources, and promoting regional cooperation. The government is working to diversify the economy beyond oil and gas, with an emphasis on attracting international investments.

Libya made significant efforts to boost oil and gas output. The country is preparing to launch its first international licensing round in over 15 years, signalling its intention to attract global investors back into its energy sector. In addition to this, Libya focused on its power sector by restoring aging power plants, upgrading its grid infrastructure, and constructing new facilities.

Mauritania approved its Hydrogen Law, aimed to attract foreign investments in hydrogen production. This policy could enable the country to become a key player in the global hydrogen market, while promoting sustainable development.

Mozambique launched its Just Energy Transformation Strategy, which outlines transitioning to modern energy systems based on renewable sources, fostering green industrialisation, developing clean energy transport systems, and ensuring universal access to modern energy.

Nigeria continued its “Decade of Gas” initiative, which aims to increase gas production as part of its broader goal to diversify its energy sector. In addition, Nigeria introduced a Compressed Natural Gas (CNG) initiative to provide a cleaner and more affordable alternative for transportation, reducing reliance on imported fuel and addressing environmental concerns.

Senegal was working on the plan to phase out energy subsidies by 2025, redirecting the savings towards social development initiatives. This move is part of the country’s broader strategy to create a more sustainable and equitable energy system.

South Africa amended its Electricity Regulation Law to boost market competitiveness, reduce costs, increase generation, and improve transmission. Additionally, the amendments seek to liberalise the electricity market, allowing for more private sector participation.

CHAPTER

02

GAS CONSUMPTION

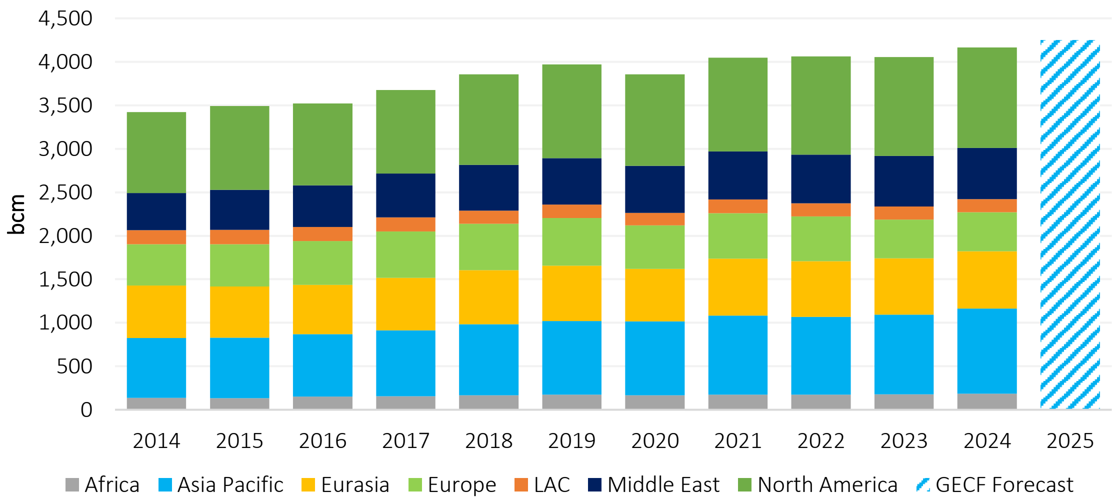
Global gas consumption saw its fastest growth in the past three years, with Asia leading regionally and the expanding power and industrial sectors driving the sectoral demand

Global gas consumption is estimated to have risen by 2.5% (100 bcm) to reach 4,170 bcm in 2024, driven by a combination of economic growth, energy policies, and weather-related factors (Figure 6). This steady growth rate compares to 0.2% in 2023, 0.4% in 2022, and 4.9% in 2021. Strong economic performance in key regions such as Asia Pacific, North America and Eurasia spurred increased electricity demand and an industrial rebound. The stabilisation of gas prices at lower levels, compared to the record highs of 2022, further bolstered demand across various sectors. Additionally, energy policies promoting a shift from coal and oil to gas in multiple industries played a key role. Unusual weather patterns, such as a colder-than-usual 2024/2025 winter and record-high summer temperatures, also influenced seasonal gas demand in the residential/commercial and electricity sectors.

Natural gas consumption emerged a s the leading driver of global primary energy supply growth, contributing 35%, surpassing all other energy sources.

As of the end of March 2025, global gas consumption was projected to continue robust growth at an annual rate of 2% in both 2025 and 2026, driven primarily by Asia Pacific.

Figure 6: Trend in global gas consumption



Note: GECF's estimate for 2024 and forecast for 2025
Source: GECF Secretariat based on data from Cedigaz

2.1 Gas Consumption by Region

North America maintained its leadership in the global gas market, with overall consumption rising by 1.7% to reach 1,158 bcm in 2024. The US was the primary driver of this growth, adding an extra 15 bcm due to increased demand across all major sectors (Figure 7).

Asia Pacific was the primary driver of global gas demand growth, with its consumption rising by 7% to 980 bcm. This growth was fuelled by robust economic expansion in the region. Notably, China and India together accounted for 40 bcm of the incremental global gas demand.

Eurasia's gas consumption increased to 660 bcm, driven by Russia's economic growth. This expansion is reflected in the rising gas demand across the industrial and electricity sectors, which have been key contributors to the region's growth.

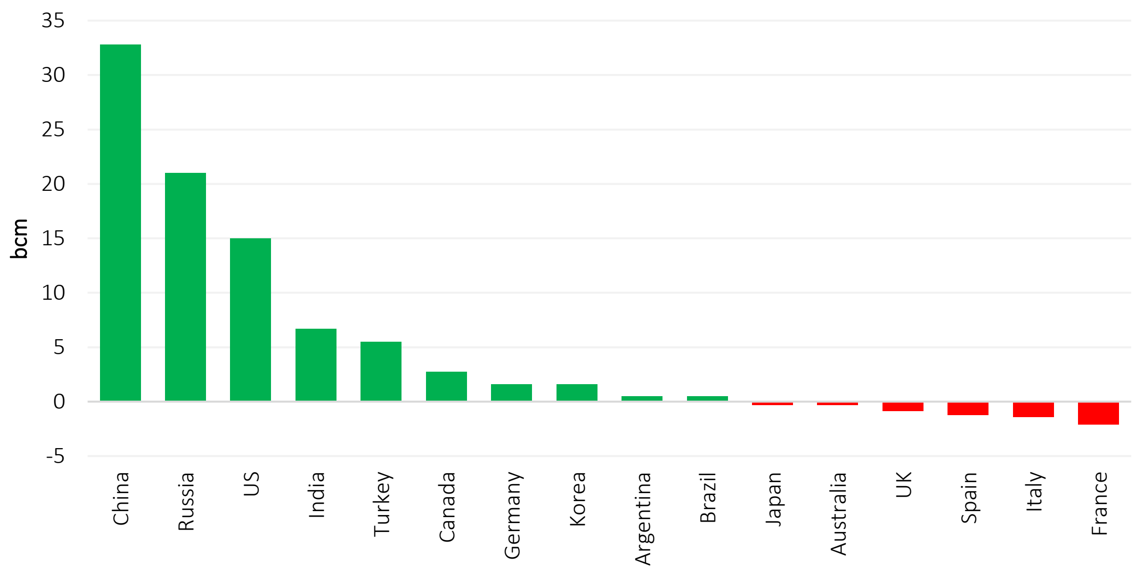
The Middle East's gas consumption rose to 588 bcm, driven by increased demand in the industrial and electricity sectors. Key to this growth is Saudi Arabia and the UAE, which have accelerated their transition from oil to natural gas in the power generation sector.

Europe's gas consumption stabilised at 451 bcm after two years of decline, supported by a recovery in industrial demand. However, overall gas consumption remained limited due to the ongoing growth of renewable energy and the implementation of energy efficiency measures.

Africa's gas consumption increased to 183 bcm, driven by the expansion of gas-to-power initiatives in Algeria, Egypt and Nigeria. These countries are prioritising gas-fired generation to meet growing electricity demand and support industrial development.

LAC’s gas consumption saw a slight recovery, reaching 150 bcm, primarily due to reduced hydroelectric output. In countries like Brazil and Colombia, prolonged droughts resulted in lower hydroelectric generation, leading to a greater reliance on gas-fired power plants.

Figure 7: Y-o-y variation in gas consumption in major consuming countries in 2024



Source: GECF Secretariat based on data from national governmental organisations

2.1.1 Europe

Gas consumption increased driven by Türkiye, despite a slight decrease in the EU

2.1.1.1 EU

The EU gas market continued its downward trend, with total gas consumption falling by 0.5% to 313 bcm in 2024 (Figure 8). This marks the third consecutive year of reduced demand, driven by policy measures to cut gas use, increased energy efficiency, a mild 2023/2024 winter season, and the ongoing growth of renewable energy sources. The decline was primarily due to reduced gas demand in the power sector, which was not offset by a recovery in industrial activity.

The power generation sector saw a decline in gas consumption, with gas-fired electricity generation dropping by 6% to 430 TWh, while coal-fired generation fell even more sharply, decreasing by 16% to 268 TWh (Figure 9). This shift was driven by the continued expansion of renewable energy, increased nuclear output, and a rebound in hydropower generation due to higher precipitation levels. Wind and solar power have rapidly become the backbone of the region's electricity production, with their combined share in the EU's electricity mix reaching 28.5% in 2024, with wind contributing 17.5% and solar 11%. This figure is nearly equal to the 29% share of fossil fuels in the mix. In particular, the share of gas in the power generation mix declined to 16%, which is lower compared to 20% in 2020 but still higher than 14% a decade ago. Likewise, the share of coal decreased to 10% from 25% a decade ago.

The 2024 figures clearly show that the EU electricity markets, heavily reliant on wind and solar power, require dispatchable energy to manage both regular intermittency and the irregular fluctuations associated with Dunkelflaute events, which were particularly evident in November. In this context, natural gas proved to be an essential backup power source for renewables, ensuring grid flexibility, reliability and security. As a result, natural gas continues to play a crucial role not only as a baseload energy source but also as a key dispatchable resource, increasingly vital for maintaining a stable and secure energy system.

Figure 8: Trend in EU gas consumption

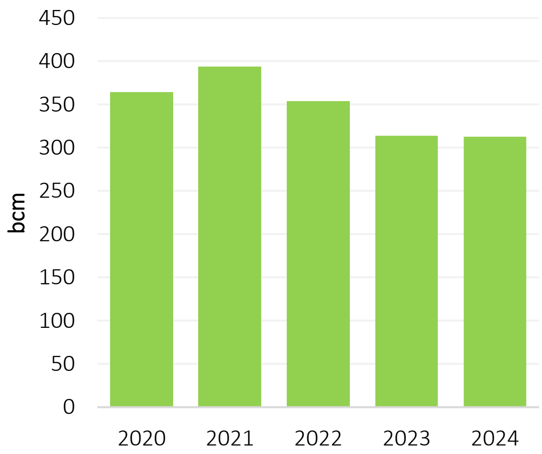
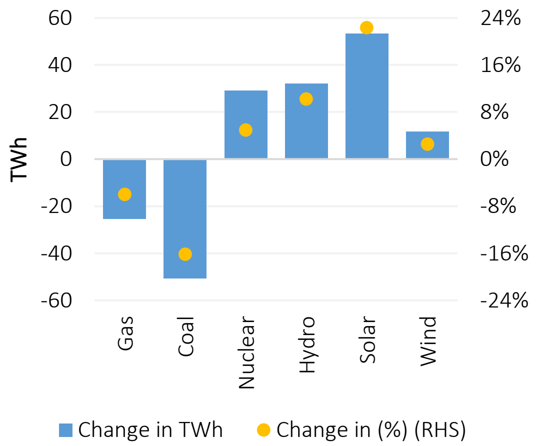


Figure 9: Y-o-y variation in EU's electricity generation



Source: GECF Secretariat based on data from LSEG and Ember

2.1.1.2 Germany

Germany's gas consumption rose by 1.5% to 76 bcm in 2024, reversing some of the decline seen in previous years (Figure 10). Gas consumption in the residential and commercial sectors fell by 1.3% to 30 bcm, driven by milder-than-usual temperatures in the first half of the year. However, this was offset by a 6% increase in gas demand from the industrial sector (Figure 11), fuelled by lower gas prices, as well as a rebound in the electricity sector.

Figure 10: Trend in Germany's gas consumption

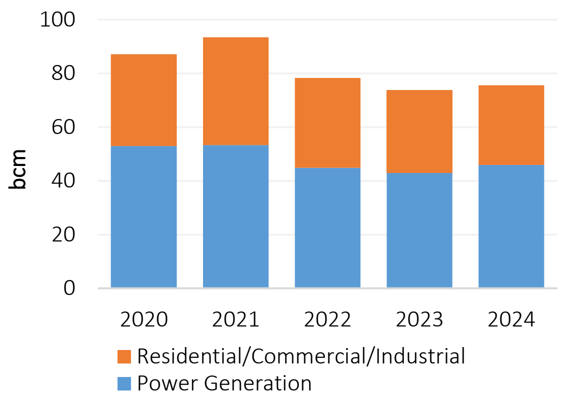
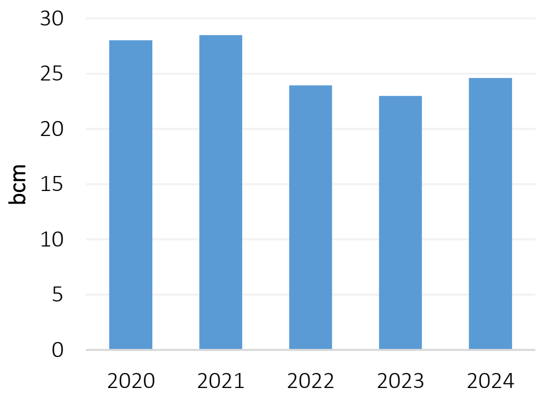


Figure 11: Germany's industrial gas consumption



Source: GECF Secretariat based on data from LSEG and Bundesnetzagentur

Gas-fired generation in Germany increased by 2% to 79 TWh, driven by several factors (Figure 12). First, coal-fired generation fell by 21 TWh to 104 TWh due to environmentally-driven energy policies. Second, the complete phase-out of nuclear power, driven by safety concerns, resulted in a 7 TWh loss in output. Third, wind output dropped by 4 TWh to 133 TWh due to reduced wind availability, especially during the Dunkelflaute events, leading to greater reliance on gas-fired power generation as a backup energy source. These losses — totalling 32 TWh — were mainly offset by growth in solar and hydro output, with natural gas also making a significant contribution. In this context, Germany's total electricity demand of 502 TWh was met by an energy mix primarily driven by non-hydro renewables, which made up 55% (wind 30%, solar 16%, and bioenergy 9%), followed by coal at 23% and natural gas at 17% (Figure 13).

Figure 12: Y-o-y variation in Germany's power output

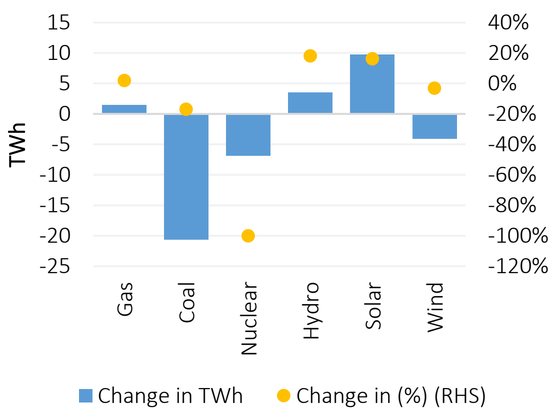
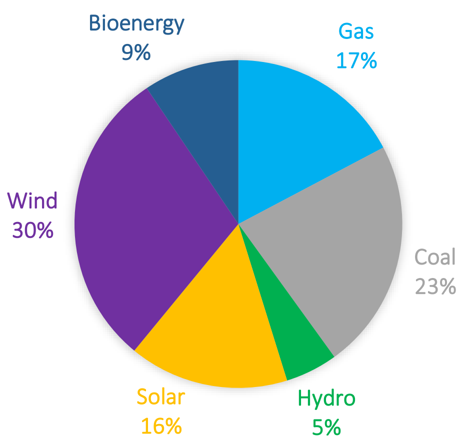


Figure 13: Germany's electricity mix in 2024



Source: GECF Secretariat based on data from Ember

2.1.1.3 Italy

Italy's gas consumption fell by 1.5% to 62 bcm, marking the third consecutive year of decline (Figure 14). Sectoral trends, however, varied. Gas demand in the industrial sector grew slightly by 0.2 bcm to 12 bcm, driven by lower gas prices and the recovery of energy-intensive industries (Figure 15). Similarly, the residential and commercial sectors saw a small increase to 27 bcm due to colder-than-expected temperatures in the final quarter of the year. In contrast, gas consumption in the power generation sector decreased slightly to 21 bcm.

Figure 14: Trend in Italy's gas consumption

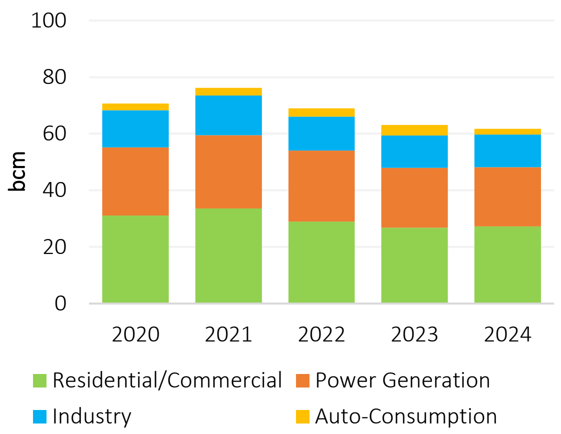
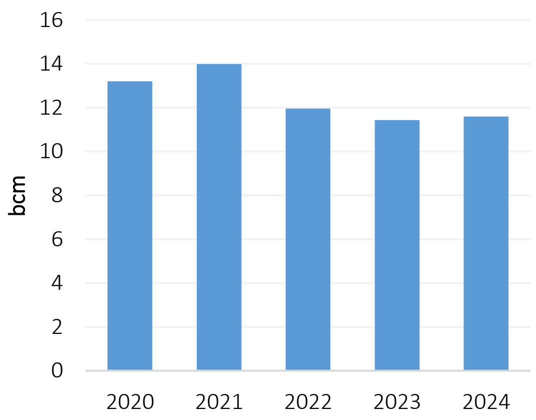


Figure 15: Italy's industrial gas consumption



Source: GECF Secretariat based on data from Snam

Gas-fired generation in Italy fell by 2% to 117 TWh (Figure 16), with a slight reduction in natural gas's role in power generation. This was due to a strong recovery in hydro output, which increased by 10 TWh, reflecting improved hydrological conditions, and continuous growth in solar power, which added 5 TWh thanks to expanded photovoltaic capacity. Meanwhile, coal-fired generation sharply dropped to 5 TWh, down from 13 TWh in 2023 and 43 TWh in 2014, highlighting Italy's ongoing coal phase-out. In this context, Italy's total electricity demand of 315 TWh was met by an energy mix dominated by natural gas, which accounted for 47%, followed by hydro (20%), solar (15%) and wind (10%) (Figure 17).

Figure 16: Y-o-y variation in Italy's power output

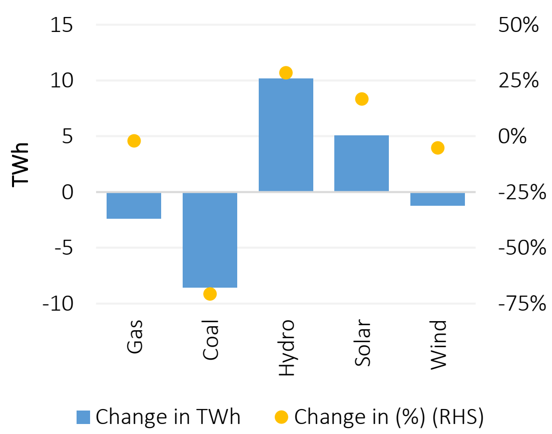
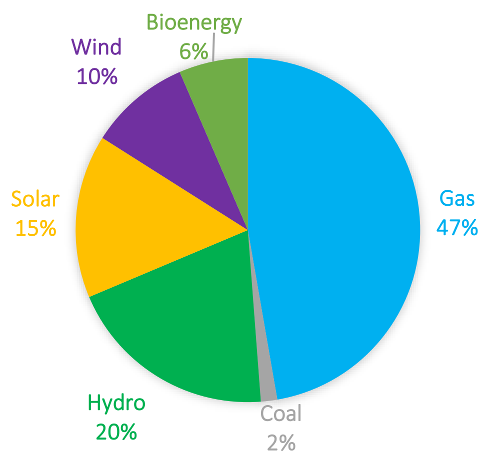


Figure 17: Italy's electricity mix in 2024



Source: GECF Secretariat based on data from Ember and Terna

2.1.1.4 France

France's gas consumption dropped by 6% to 31 bcm in 2024, maintaining the declining trend of recent years (Figure 18). This decline was primarily driven by a significant reduction in gas use for power generation. While residential and commercial demand also decreased slightly to 19 bcm, driven by efficiency improvements and moderate winter temperatures, gas consumption in the industrial sector saw a small increase, rising to 9 bcm (Figure 19).

Figure 18: Trend in France's gas consumption

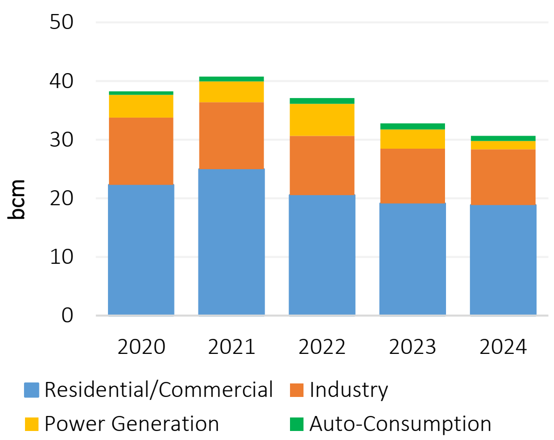
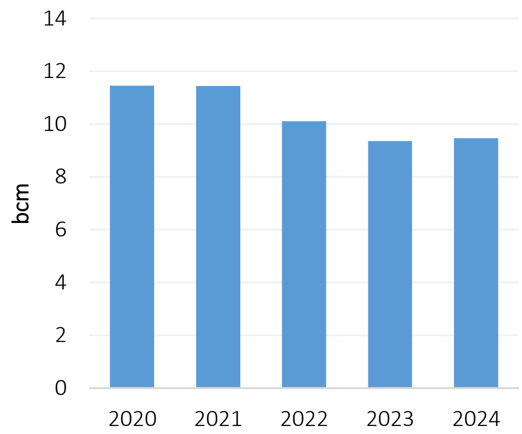


Figure 19: France's industrial gas consumption



Source: GECF Secretariat based on data from Grtgaz

Gas-fired generation in France dropped sharply by 11 TWh to 19 TWh (Figure 20). The decline was driven by a strong rebound in nuclear output, which rose by 42 TWh to 380 TWh as several reactors returned to full capacity after long maintenance outages. Hydropower also played an important role, increasing by 25% thanks to strong precipitation levels. In contrast, wind power decreased by 5% due to variable wind conditions, while coal-fired generation continued its decline, dropping to just 1.7 TWh as France neared the complete phase-out of coal. In this context, France's total electricity demand of 467 TWh was met by an energy mix dominated by nuclear energy, which accounted for 70%, with natural gas contributing just 3% (Figure 21).

Figure 20: Y-o-y variation in France's power output

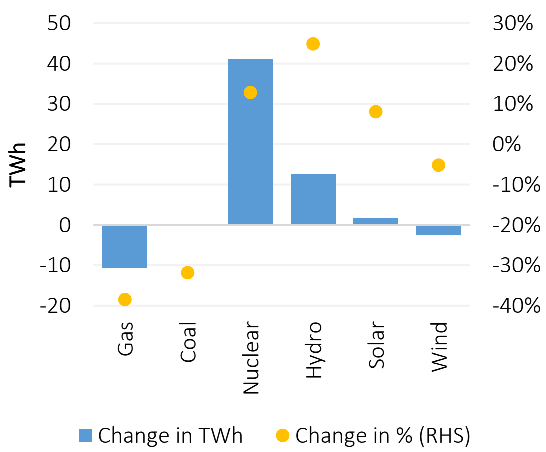
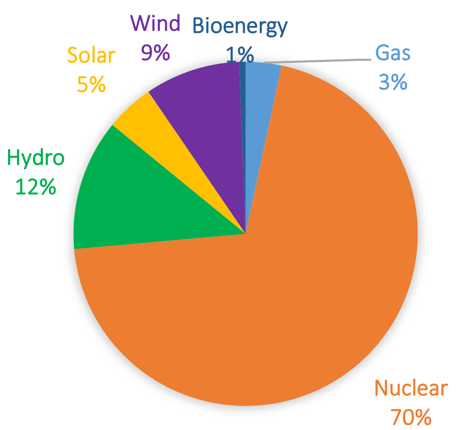


Figure 21: France's electricity mix in 2024



Source: GECF Secretariat based on data from Ember

2.1.1.5 Spain

Spain's gas consumption decreased by 4% to 28 bcm in 2024 (Figure 22). The decline happened primarily due to a reduction in gas demand from the electricity sector, which accounts for about a quarter of total gas consumption. While gas use in the residential and commercial sectors remained stable, industrial sector consumption rebounded by 4% to 16 bcm, though it still fell short of pre-energy crisis levels (Figure 23).

Figure 22: Trend in Spain's gas consumption

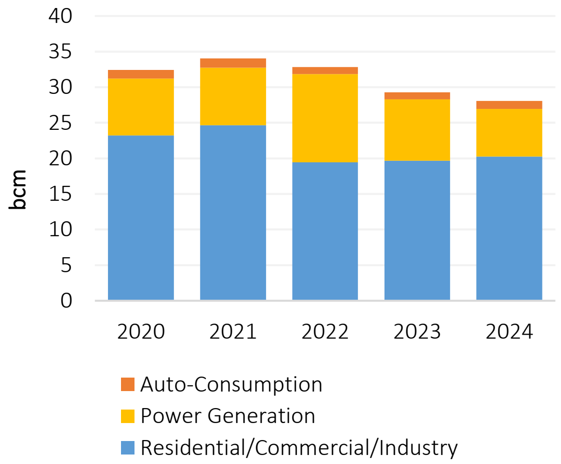
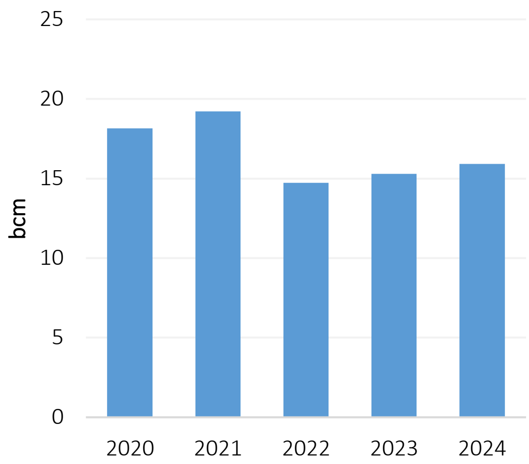


Figure 23: Spain's industrial gas consumption



Source: GECF Secretariat based on data from Enagas and LSEG

Gas-fired power generation in Spain fell by 19% to 52 TWh (Figure 24), with declines also seen in nuclear, coal and wind output. However, these decreases were offset by an increase in hydropower generation, which added 8 TWh, and solar power, which contributed an additional 10 TWh, driven by favourable weather conditions. In this context, Spain's overall electricity demand of 270 TWh was met by a diversified energy mix, with wind contributing 24%, solar 22%, nuclear 21% and natural gas 17% (Figure 25).

Figure 24: Y-o-y variation in Spain's power output

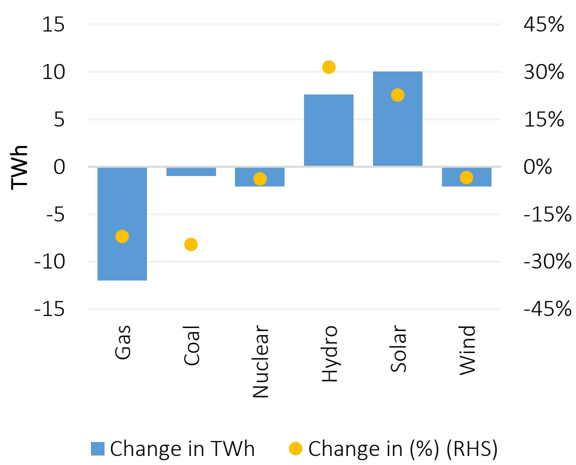
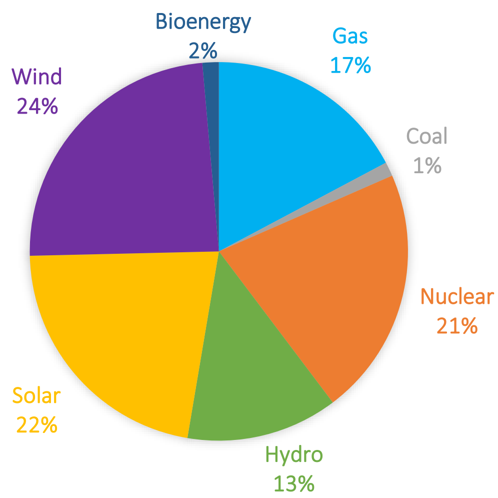


Figure 25: Spain's electricity mix in 2024



Source: GECF Secretariat based on data from Ember and Ree

2.1.1.6 United Kingdom

The UK's natural gas consumption remained stable at 57 bcm (Figure 26). The trends in gas demand varied across sectors. Gas demand from power generation, which accounts for 23% of total consumption, dropped significantly, while industrial consumption decreased marginally to 2 bcm (Figure 27). In contrast, the residential and commercial sectors, which make up 74% of domestic gas demand, saw a 4% increase, reaching 42 bcm, primarily due to higher heating demand driven by colder-than-usual winter weather.

Figure 26: Trend in the UK gas consumption

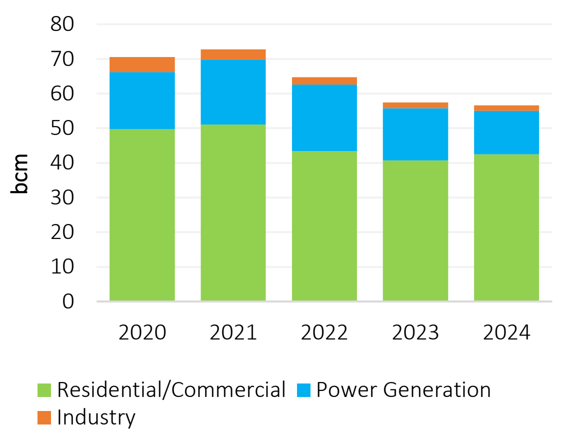
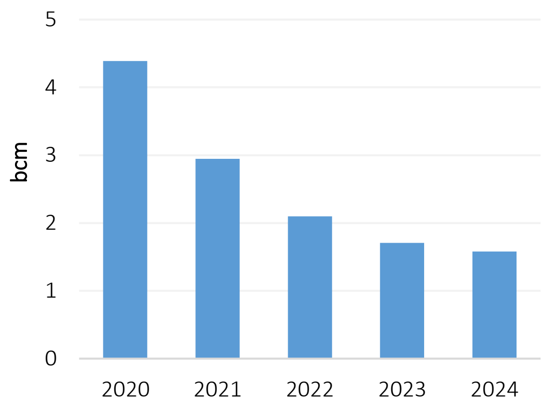


Figure 27: The UK industrial gas consumption



Source: GECF Secretariat based on data from LSEG and National Grid

Gas-fired power generation in the UK dropped significantly by 14 TWh to 84 TWh (Figure 28). Similarly, coal-fired generation saw a decline to 2.3 TWh in 2024, down from 3.5 TWh in 2023. Notably, the UK became the first G7 country to phase out coal from its energy mix by closing its last coal-fired power plant on 30 September 2024. The share of coal in the UK's power mix has steadily decreased from 80% in the 1980s to 40% in 2012, and to zero as of 2025. These declines in fossil fuels were offset by a growing reliance on renewables in the electricity sector. In this context, the UK's total electricity demand of 317 TWh was met by a diverse energy mix, with natural gas contributing 37%, followed by wind at 34% and nuclear at 16% (Figure 29).

Figure 28: Y-o-y variation in the UK power output

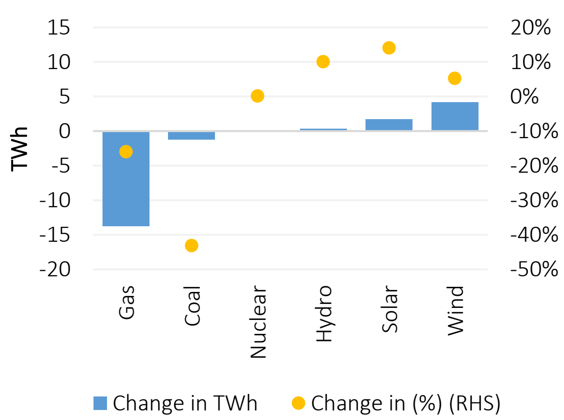
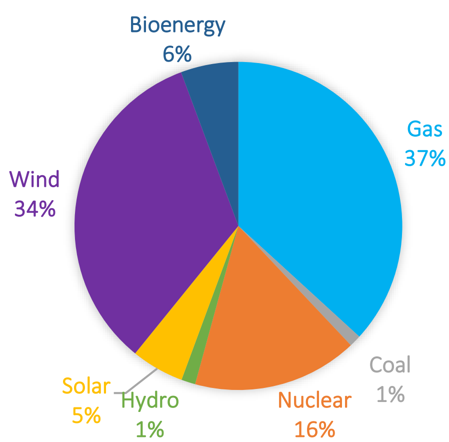


Figure 29: The UK electricity mix in 2024



Source: GECF Secretariat based on data from Ember

2.1.2 Asia Pacific

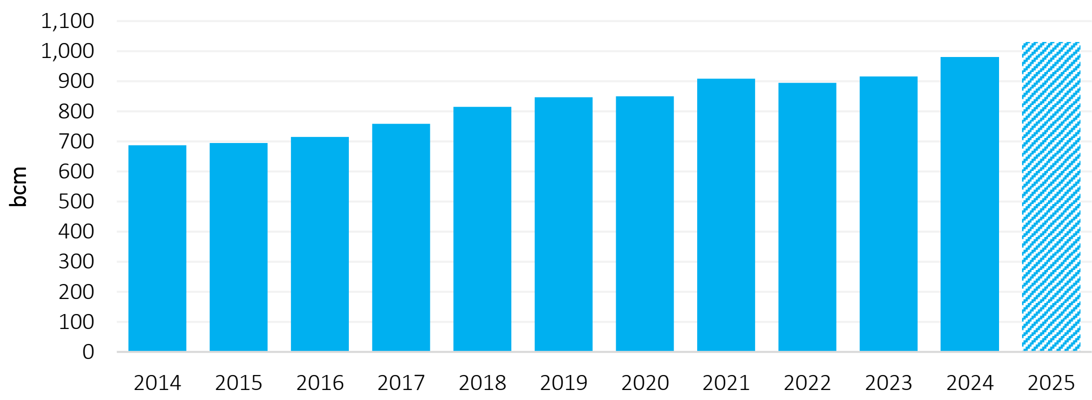
China and India drove the regional gas demand surge, powered by industrial growth

Gas consumption in the Asia Pacific region is estimated to have grown by 7% in 2024, reaching 980 bcm, following a modest 2.5% increase in 2023 (Figure 30). This growth was primarily driven by China, which added 33 bcm to its demand, and India, which contributed an additional 7 bcm. In both countries, natural gas consumption rebounded in the industrial sector and gained momentum in the power sector, driven largely by favourable gas prices and increased cooling demand due to heatwaves. China led the regional growth, benefiting from policy-driven coal-to-gas switching and the expansion of its LNG import capacity through new regasification terminals and the Power of Siberia gas pipeline from Russia. In India, rising gas demand was supported by the growth of city gas distribution networks and increased consumption in the fertiliser and power sectors.

In addition, Japan experienced stagnant gas consumption, while South Korea saw a 2 bcm increase in demand. The fluctuations in gas consumption in both countries were primarily influenced by their electricity markets' reliance on nuclear power and the increasing integration of renewable energy sources. In particular, Japan reactivated several nuclear plants and emphasised energy efficiency measures to better balance its energy mix.

Looking ahead to 2025, regional gas demand is projected to maintain its upward trajectory, with a 5% increase driven by robust industrial activity and the ongoing expansion of LNG terminals. The Asia-Pacific region will reach a historic milestone by surpassing the 1,000 bcm threshold for the first time—a level previously attained only by North America. This achievement underscores the region's growing significance in the global natural gas market and highlights its dynamic energy landscape. This growth will be particularly notable in countries working to diversify their energy mix away from coal. China and India are expected to lead the way, with continued industrial sector developments fuelling demand. Southeast Asia will emerge as a key growth region, as countries like Indonesia, Thailand, the Philippines and Bangladesh ramp up LNG imports to offset declines in domestic gas production.

Figure 30: Trend in Asia Pacific gas consumption



Source: GECF Secretariat based on data from Cedigaz
Note: GECF's estimate for 2024 and forecast for 2025

2.1.2.1 China

China's gas consumption rose by 8% to 430 bcm in 2024, marking the second consecutive year of growth (Figure 31). After a decline in 2022, driven by record-high spot LNG prices and weaker economic activity, demand increased by 28 bcm in 2023 and 33 bcm in 2024. This growth was primarily driven by a rebound in the industrial sector, higher demand for gas-fired power generation, and government initiatives promoting LNG as a cleaner transportation alternative.

The industrial sector, representing 40% of China's gas consumption, experienced a notable rise in gas usage as economic recovery drove increased demand in manufacturing and production. Natural gas played a crucial role in key industrial processes, including petrochemical, steel and cement production, where it serves both as a heat source and feedstock. This surge in demand was driven by the recovery of industrial activity, bolstered by government policies that promoted cleaner energy alternatives and efforts to reduce reliance on coal.

The electricity generation sector, accounting for 20% of China's gas consumption, saw a 2% increase in gas-fired electricity output, reaching 283 TWh. Despite this increase, the share of natural gas in China's energy mix remained steady at 3%, as coal continued to dominate with a 59% share. Meanwhile, the drive for decarbonisation resulted in a record expansion of renewable energy, with solar power increasing by 46% and wind energy rising by 12%, gradually reshaping China's electricity landscape. Hydro generation also surged by 11%, reducing gas consumption during months of high precipitation availability (Figure 32).

The residential and commercial sectors experienced stable gas consumption, primarily influenced by seasonal weather conditions. Milder temperatures during the 2023/2024 winter season led to lower heating demand, but this was counterbalanced by increased demand for heating in the colder-than-usual 2024/2025 winter season.

The transport sector saw significant growth in gas consumption, driven by LNG-fuelled heavy-duty trucks. Annual sales of these trucks reached 200,000 vehicles, supported by government subsidy programs, while the existing fleet grew to 750,000 vehicles.

Figure 31: Trend in China's gas consumption

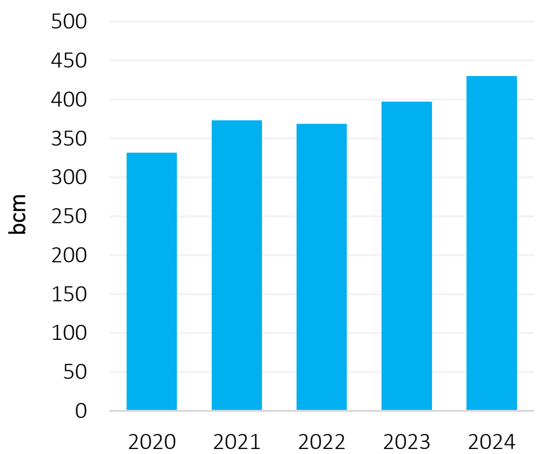
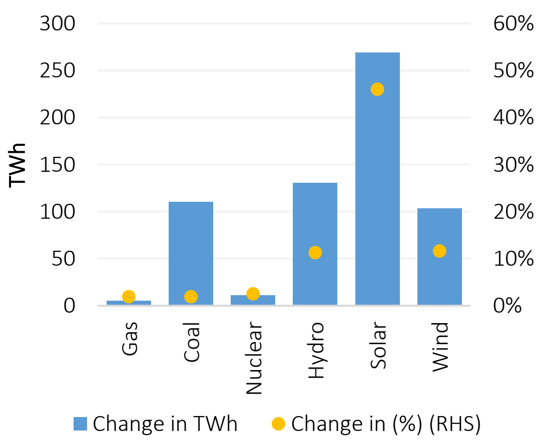


Figure 32: Y-o-y variation in China's power output



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

2.1.2.2 India

India's gas consumption rose by 10% to reach 72 bcm in 2024 (Figure 33). This growth was primarily driven by higher demand in the industrial sector, increased use in power generation, and the ongoing expansion of the city gas distribution network. Additionally, supportive government policies, favourable energy pricing, and infrastructure developments played a significant role in driving this rise in consumption.

The industrial sector, accounting for 40% of total gas consumption, played a key role in driving gas demand growth due to a rebound in industrial activity. Key industries such as fertilisers, petrochemicals, refineries and steel rely on natural gas both as an energy source and feedstock. Fertiliser production remained the largest consumer of gas within the industrial sector. The increase in gas demand was further supported by government initiatives promoting the use of cleaner fuels, reducing dependence on coal and other polluting energy sources.

The electricity sector saw a significant 15% increase in gas-fired generation, driven by the growing demand for electricity (Figure 34). Gas-fired plants became crucial in meeting peak demand, especially during high-demand periods, as government policies mandated these plants to operate at full capacity. This trend was particularly noticeable during the summer months when disruptions in coal supply, caused by monsoon-related transport challenges, forced a greater reliance on gas-based power generation. Despite the increased role of gas, coal remained dominant, making up 75% of total electricity output, while gas-fired generation, contributing 60 TWh, accounted for only 3% of the overall power mix.

The residential and commercial sectors drove gas consumption growth, supported by the expansion of city gas networks and government clean energy initiatives. Natural gas increasingly replaced traditional fuels for cooking and heating, especially in urban areas.

The transport sector saw a rise in the adoption of CNG vehicles, with the number of CNG stations surpassing 7,000, as well as an increase in the use of LNG for trucks, with the government planning to have one-third of the truck fleet running on LNG within the next five to seven years.

Figure 33: Trend in India's gas consumption

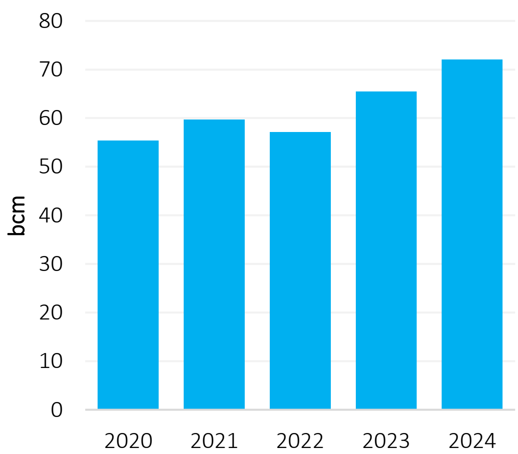
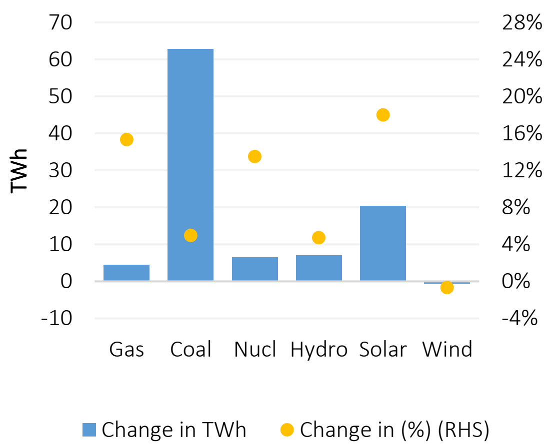


Figure 34: Y-o-y variation in India's power output



Source: GECF Secretariat based on data from PPAC and Ember

2.1.2.3 Japan

Japan's gas consumption remained stable at 92 bcm in 2024, maintaining the same level as the previous year after several years of decline (Figure 35). This stability was due to a combination of steady power sector demand and a slight dip in city gas use. The country's natural gas landscape was influenced by temperature variations, efforts to diversify energy sources, and fluctuations in nuclear power availability.

The power generation sector in Japan saw gas consumption stabilising at 51 bcm, following a 10% decline in 2023. Gas-fired electricity generation continued to play a key role, accounting for 35% of the country's total power generation, producing 350 TWh. However, the restarting of idle nuclear reactors, which resulted in an average operational nuclear capacity of over 10 GW, helped limit the need for gas in the power mix (Figure 36). The restart of these plants, such as Onagawa 2 and Shimane 2, along with stronger renewable energy output, reduced reliance on gas-fired generation. Still, during periods of peak electricity demand, particularly in the summer months, gas-fired power was ramped up to maintain grid stability.

The city gas sector, encompassing the production, distribution and consumption of natural gas in urban areas, remained stable at 40 bcm. This sector plays a critical role in meeting the energy needs for heating, cooking and hot water in residential and commercial sectors. The Japanese government supports this sector through policies promoting energy efficiency, clean energy adoption, and the expansion of gas infrastructure, aiming to reduce reliance on coal and oil. The warmer-than-usual weather in early 2024, particularly in April, led to reduced heating demand. However, this was offset by colder-than-average temperatures in December, which triggered a sharp rise in gas demand for heating.

Figure 35: Trend in Japan's gas consumption

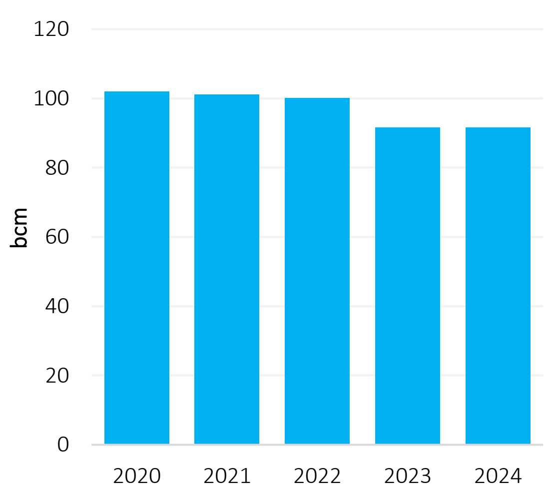
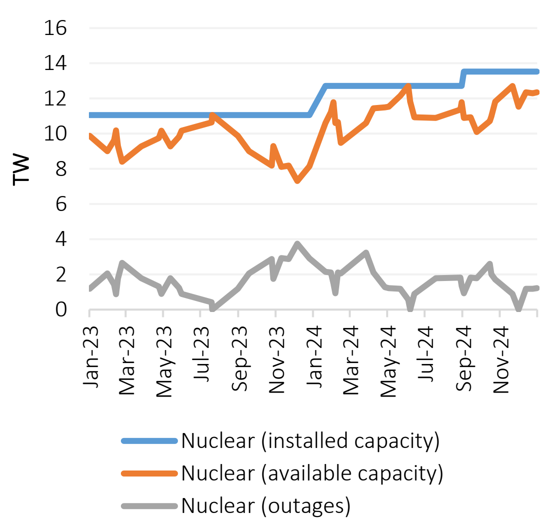


Figure 36: Japan's nuclear availability



Source: GECF Secretariat based on data from LSEG

2.1.2.4 South Korea

South Korea's gas consumption grew by 3% to reach 56 bcm in 2024, reversing the decline seen the previous year (Figure 37). This increase was largely driven by higher demand in the power generation sector. Several factors contributed to the growth in gas consumption, including grid constraints, challenges in nuclear power availability, and extreme weather conditions.

The power sector was the primary driver of gas demand growth, with gas-fired generation increasing by 5% to 170 TWh (Figure 38). A key challenge for South Korea's electricity system was grid congestion, as coal and nuclear plants are mainly located on the east coast, while demand is concentrated in the Seoul metropolitan area. This resulted in transmission bottlenecks, compounded by scheduled coal plant maintenance, causing an 8% decline in coal-fired generation. Additionally, delays in bringing new nuclear reactors online limited nuclear output growth. As a result, the constrained transmission capacity increased reliance on gas-fired plants, which are more flexible and better suited to respond to fluctuating demand. Additionally, the 2024 summer became the hottest in South Korea's history, driving up electricity demand for cooling, especially in July and August, and consequently spiking gas demand. Despite this increase, natural gas continued to represent 27% of the power generation mix, maintaining its position as the third-largest energy source behind coal and nuclear, each accounting for around 30%.

The city gas sector experienced a slight 1% decline in consumption, influenced by seasonal fluctuations in demand. Warmer-than-usual weather in Q1 2024 reduced heating demand, while colder-than-usual conditions in Q4, especially in December, led to a notable increase in gas usage for heating. These seasonal variations reflect the sector's sensitivity to temperature changes, with demand for heating driving consumption during colder months.

Figure 37: Trend in South Korea's gas consumption

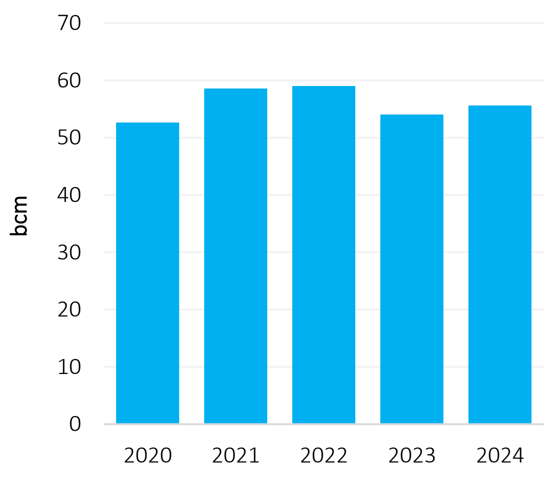
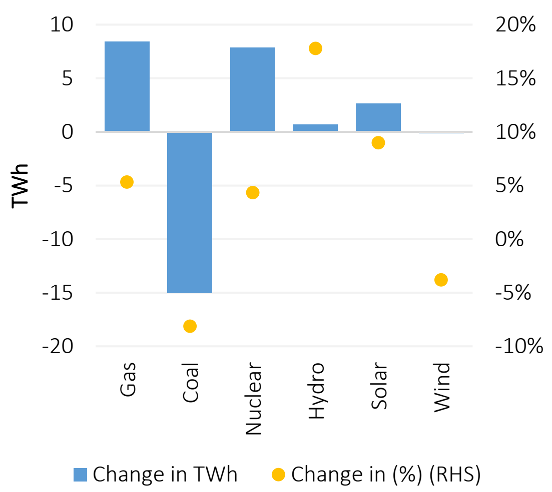


Figure 38: Y-o-y variation in S. Korea's power output



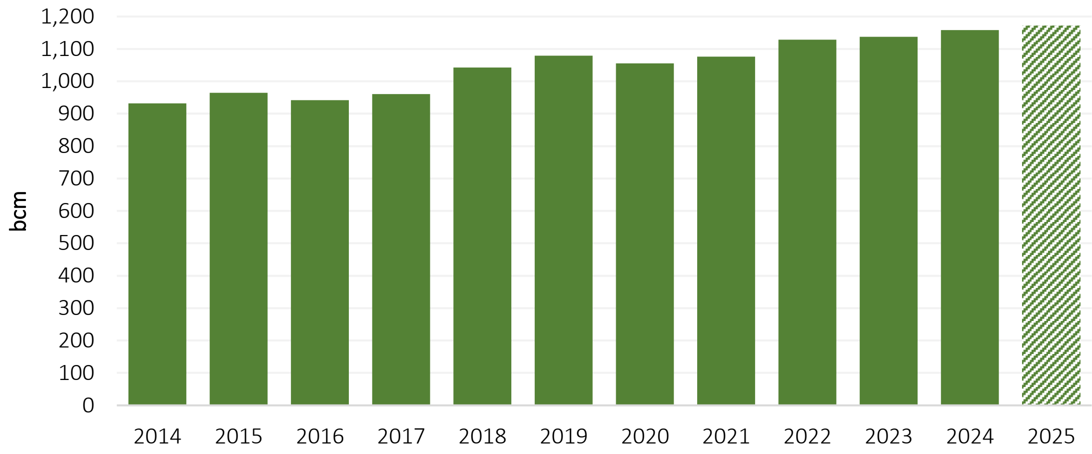
Source: GECF Secretariat based on data from LSEG and Ember

2.1.3 North America

Gas consumption remained strong, supported by the power sector

North America's gas consumption is estimated to have reached 1,158 bcm in 2024, reflecting a 1.7% increase, with the primary driver being rising demand in the power generation sector (Figure 39). The US continued to lead this growth, fuelled by stable industrial demand and robust power sector usage. This growth was especially driven by the ongoing shift away from coal and the increasing integration of intermittent renewable energy sources, which has intensified the reliance on natural gas for grid stability and backup power.

Figure 39: Trend in North America's gas consumption



Source: GECF Secretariat based on data from Cedigaz
Note: GECF's estimate for 2024 and forecast for 2025

2.1.3.1 Canada

Canada's natural gas consumption rose by 2% to 124 bcm, rebounding from a sharp decline in 2023 (Figure 40). Growth was driven by the industrial and power generation sectors. In the power sector, gas-fired electricity generation grew by 8% to 81 TWh due to decreased nuclear and coal output (Figure 41).

Figure 40: Trend in Canada's gas consumption

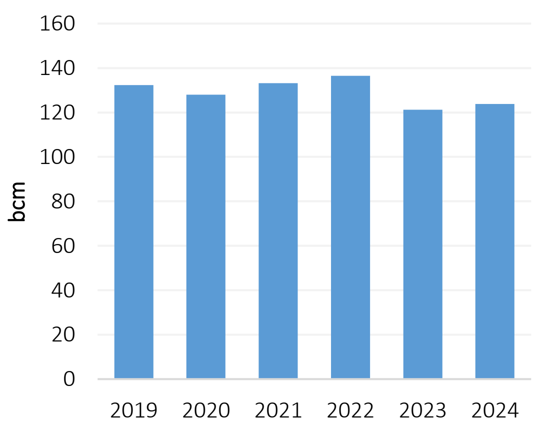
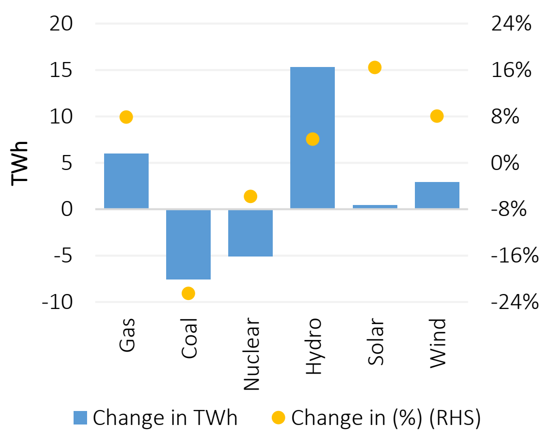


Figure 41: Y-o-y variation in Canada's power output



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

2.1.3.2 United States

US gas consumption continued its upward trajectory, increasing by 1.6% to reach 925 bcm (Figure 42). This growth was largely driven by the power generation sector, consuming 378 bcm of natural gas.

The power sector's reliance on natural gas continued to strengthen, with gas-fired electricity generation rising by 3.7% to reach 1,868 TWh. This growth was driven by increased electricity demand, fuelled by the rapid expansion of energy-intensive data centres and higher demand for cooling during extreme heat events in June and July. As the dominant fuel for electricity generation with a 43% share in total output, natural gas effectively met the increasing electricity demand. The growth in gas-fired power generation was further supported by the ongoing retirement of coal plants, with coal-fired generation declining by 3% to 652 TWh (Figure 43). Additionally, low gas prices throughout the year made natural gas more competitive than other thermal sources. While renewables experienced significant growth — solar generation rising by 26% and wind by 7% — issues like intermittency and grid constraints underscored the continued need for natural gas to balance electricity demand and ensure grid reliability.

The industrial sector’s natural gas consumption showed only marginal growth, driven by steady demand in manufacturing processes such as heating, steam generation and chemical production. The sector benefited from low natural gas prices, making it an attractive fuel option.

The residential and commercial sectors experienced a decline in gas consumption, primarily due to milder temperatures during the 2023/2024 winter season. While a cold snap in January 2024 led to a temporary surge in gas demand, this was offset by significantly lower consumption during the warmer-than-usual weather in February and March 2024. The overall impact was a decrease in gas usage for heating and other seasonal needs, reflecting the weather’s influence on demand patterns.

Figure 42: Trend in the US gas consumption

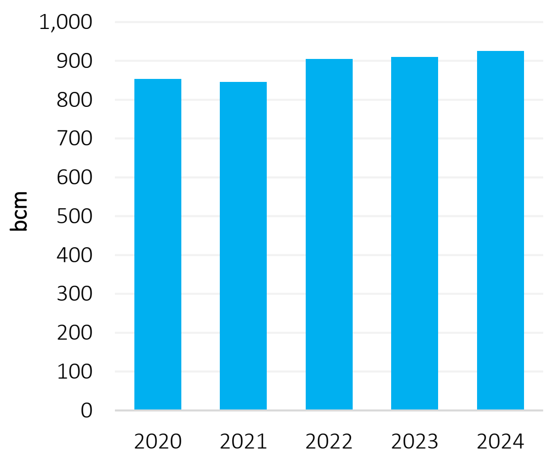
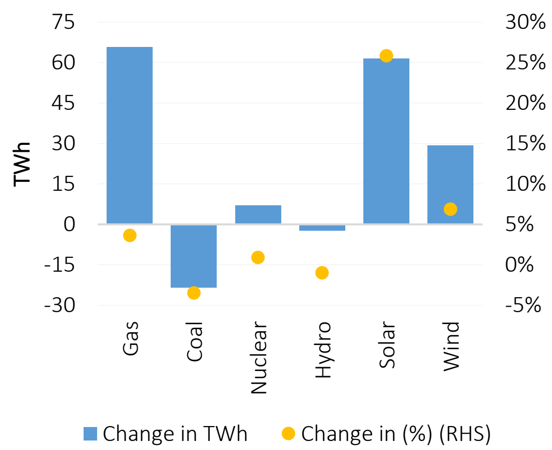


Figure 43: Y-o-y variation in the US power output



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

2.1.4 Latin America & the Caribbean (LAC)

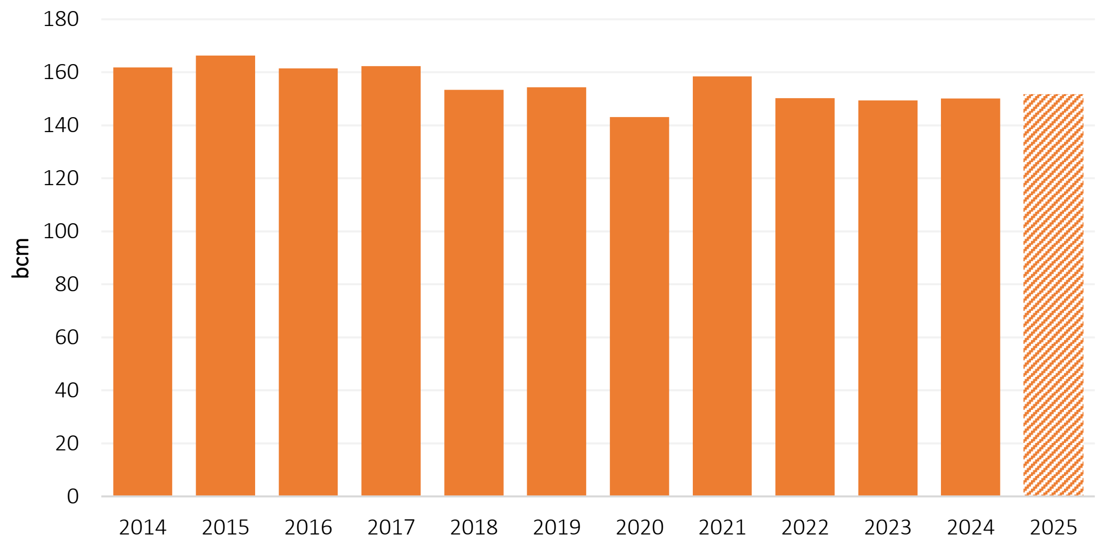
Gas consumption stabilised, with hydro fluctuations driving gas-fired generation

Gas consumption in Latin America and the Caribbean (LAC) is estimated to have reached 150 bcm in 2024, reflecting a 1% increase compared to 2023 (Figure 44). This modest recovery was largely driven by reduced hydroelectric output, which prompted greater reliance on gas-fired electricity generation, particularly in Brazil and Colombia. Drought conditions in these countries diminished hydropower availability, leading to an increased use of gas-fired plants to ensure grid stability and meet rising electricity demand. Argentina, Brazil and Venezuela remained the dominant players in the region, collectively accounting for 65% of Latin America's gas consumption.

Looking ahead to 2025, regional gas demand in LAC is projected to grow by 1%. This growth will be driven by increased industrial and power sector demand across several countries, along with the development of new gas pipeline infrastructure, particularly in Argentina, aimed at improving energy access and reliability.

The dominance of hydropower in Latin America's energy mix plays a key role in shaping the regional gas demand. Hydroelectricity accounts for more than half of the region's total power generation, making it highly vulnerable to climatic variations, particularly the El Niño and La Niña phenomena. El Niño, which is marked by warmer-than-usual Pacific Ocean temperatures, often leads to drier conditions and reduced rainfall in hydropower-dependent countries like Brazil, Colombia and Peru. This drives a greater reliance on gas-fired power generation to compensate for the hydropower shortfall. In contrast, La Niña typically brings above-average rainfall, boosting hydroelectric output and potentially reducing the need for natural gas in the power mix. Consequently, the growth of gas demand in the region is closely tied to hydropower fluctuations, alongside the continued expansion of solar and wind energy.

Figure 44: Trend in LAC's gas consumption



Source: GECF Secretariat based on data from Cedigaz
Note: GECF's estimate for 2024 and forecast for 2025

2.1.4.1 Argentina

Argentina's gas consumption showed modest growth, with total demand reaching 41 bcm in 2024, marking a slight increase of 1.5% (Figure 45).

The power generation sector was the primary driver of growth, as Argentina worked to stabilise its electricity mix amid fluctuating hydroelectric output. Gas-fired power generation rose by 5% compared to the previous year, offsetting a 14% decline in hydroelectric generation caused by lower precipitation levels. Additionally, nuclear power generation increased by 17%, while wind and solar energy saw growth of 12% and 21%, respectively (Figure 46). Despite Argentina's broader energy transition efforts, natural gas remained Argentina's dominant energy source, accounting for 52% of total electricity production.

In addition, the industrial sector maintained steady natural gas consumption at 12 bcm, reflecting consistent demand in this area. The industrial sector is a significant consumer of natural gas, primarily for processes in manufacturing, petrochemicals and other heavy industries. Gas is used for a variety of purposes, including heating, steam generation and as a feedstock in the production of chemicals and fertilisers.

Residential and commercial sectors saw only marginal gains, indicating stable gas usage patterns. These sectors are major consumers of natural gas, using it primarily for heating, cooking, and water heating. Despite challenges such as economic instability, natural gas remains the preferred and reliable energy source in these sectors.

The road transport sector remained unchanged, mainly due to the ongoing shift toward other cleaner transportation alternatives and the challenges of transitioning from conventional gasoline and diesel-powered vehicles to natural gas-powered ones.

Figure 45: Trend in Argentina's gas consumption

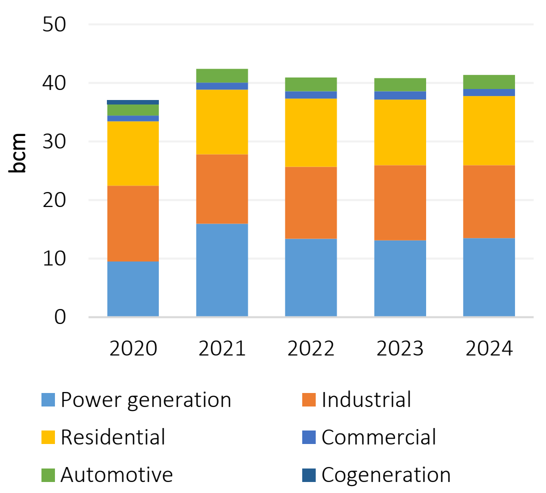
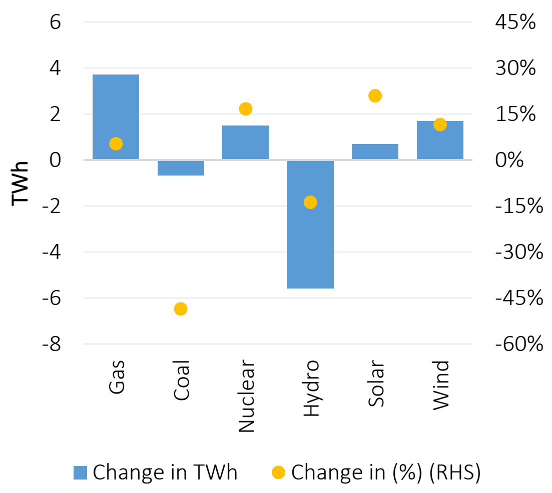


Figure 46: Y-o-y variation in Argentina's power output



Source: GECF Secretariat based on data from Brazil's Ministry of Mines and Energy, and Ember

2.1.4.2 Brazil

Brazil's gas consumption reached 24 bcm, marking a 5% increase, driven by increased demand in the power generation sector (Figure 47).

Gas consumption in Brazil's power generation sector saw a significant surge, reversing previous declines. This sharp increase was largely driven by the country's severe drought conditions, which severely impacted hydroelectric generation—responsible for over 60% of Brazil's power supply. The drought, one of the worst in recent years, depleted hydroelectric reservoirs, compelling the government to ramp up natural gas-fired power generation to maintain grid stability. To address the energy shortfall, several thermal plants, including natural gas facilities, were brought online. This response underscores the growing reliance on natural gas to balance the grid when hydropower output is lower due to droughts or seasonal variations. This reliance on natural gas rises during dry periods, like those associated with the El Niño phenomenon, which reduces hydropower generation.

In this context, Brazil's overall power generation mix experienced notable shifts, driven by the impact of the drought and the growing role of renewables (Figure 48). Gas-fired generation saw a notable increase of 29%, compensating for the decline in hydro generation, which fell by 3%. At the same time, renewable energy sources continued to grow, with solar generation jumping by an impressive 45%. Wind energy also contributed to the mix, helping to further diversify Brazil's power generation and improve the stability of its energy system.

However, natural gas consumption in other sectors remained subdued. Industrial gas demand experienced a slight decline, reflecting broader economic challenges and slower industrial growth. Similarly, consumption in the residential and commercial sectors remained largely stagnant, as energy efficiency measures and alternative energy sources took hold. The road transport sector also saw a decrease in natural gas consumption, primarily due to increased competition from biofuels and the growing adoption of electric vehicles.

Figure 47: Trend in Brazil's gas consumption

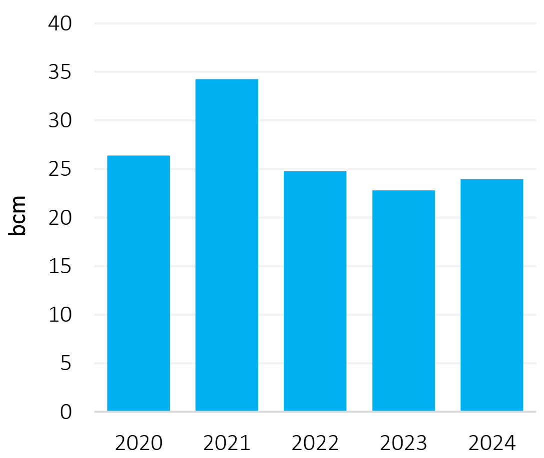
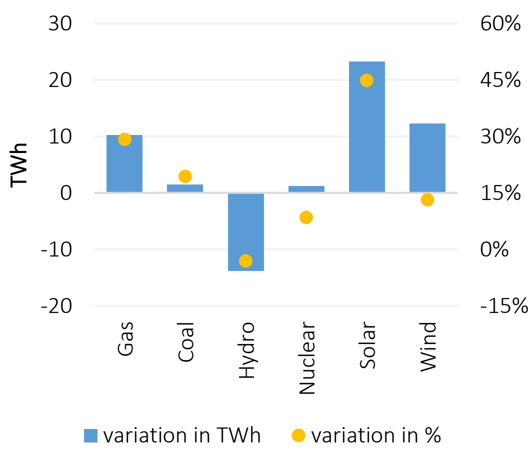


Figure 48: Y-o-y variation in Brazil's power output



Source: GECF Secretariat based on data from Brazil's Ministry of Mines and Energy, and Ember

2.1.5 Africa

Gas consumption rose driven by power sector expansion

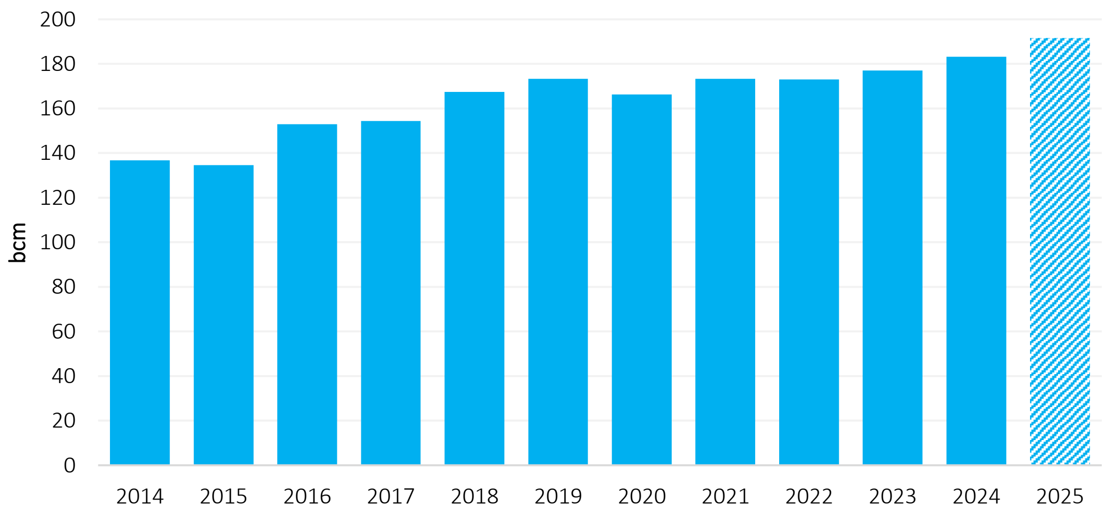
Africa's natural gas consumption continued to rise, reaching 183 bcm, marking a 3% y-o-y increase (Figure 49). Algeria and Egypt, representing together over 60% of the regional market, were the primary drivers of this growth, with demand fuelled by the industrial and electricity sectors. Nigeria also contributed significantly, particularly through its expanding gas-to-power projects. The power sector remained the dominant force behind gas consumption across the continent, as governments focused on improving electricity access and reliability.

Looking ahead to 2025, Africa's gas consumption is expected to grow by 4%, fuelled by ongoing industrialisation, increased demand in the power sector, and the expansion of LNG regasification terminals in key markets such as South Africa.

As the region works to strengthen energy security and reduce reliance on coal and oil, natural gas will continue to play a crucial role in Africa's evolving energy mix. Several developments in the region are poised to boost gas consumption. Various countries, including South Africa and Ghana, are investing in LNG import infrastructure and pipeline projects to meet the growing demand for gas in industrial and power generation sectors. At the same time, as many countries expand their renewable energy capacity, they are also prioritising the development of natural gas supply to ensure grid stability during periods of low renewable output.

Despite ongoing efforts, several challenges continue to hinder the ability to meet growing gas consumption needs, particularly in Sub-Saharan Africa. Key obstacles include inadequate gas infrastructure, a conflict between prioritising domestic gas use and fulfilling export commitments, limited energy access, especially in remote areas, and difficulty in securing financing for gas development projects. Overcoming these challenges requires coordinated efforts in policy-making, investment and infrastructure development.

Figure 49: Trend in Africa's gas consumption



Source: GECF Secretariat based on data from Cedigaz
Note: GECF's estimate for 2024 and forecast for 2025

2.2 Gas Consumption by Sector

Electricity generation dominated global gas consumption

Natural gas continued to be a cornerstone of the global energy system in 2024, playing a pivotal role across various sectors, including electricity generation, industry, residential/commercial and transport sectors (Figure 50).

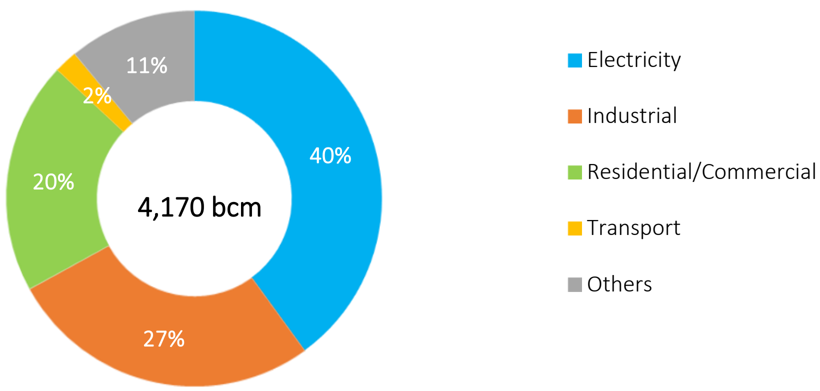
The power generation sector accounted for the largest share of global gas consumption, at 40%. Natural gas is a crucial component in this sector due to its high efficiency and comparatively lower emissions than other fossil fuels, such as coal and oil. Gas-fired power plants also provide reliable baseload and dispatchable electricity, ensuring grid stability. This is particularly crucial as renewable energy sources like wind and solar, which are intermittent, make up an increasing portion of the energy mix.

The industrial sector represented 27% of global gas consumption. Natural gas is widely used in manufacturing processes, including heating, power generation, and as a feedstock, in industries like petrochemicals, fertilisers, steel, cement and food processing. Natural gas, as a feedstock in ammonia production for fertilisers, is vital to global food security by supporting agricultural productivity and sustainable food supply growth.

The residential and commercial sectors represented 20% of global gas consumption. Natural gas serves as a vital energy source for heating, cooking and water heating in homes and businesses. Demand in these sectors tends to be seasonal, peaking during colder months, and is driven by ongoing urbanisation, population growth, and expanding gas distribution networks, making it a crucial market for natural gas consumption.

The transport sector accounted for 2% of global gas consumption. Natural gas is increasingly being adopted in the transport sector as a cleaner alternative to gasoline, diesel and other oil-based fuels. CNG and LNG are used in road transport, particularly in buses, trucks and passenger vehicles, reducing emissions and fuel costs. LNG is also becoming a dominant fuel in the maritime industry due to increasingly stringent environmental regulations.

Figure 50: Global gas consumption by sector in 2024



Source: GECF Secretariat's estimates

2.2.1 Electricity Sector

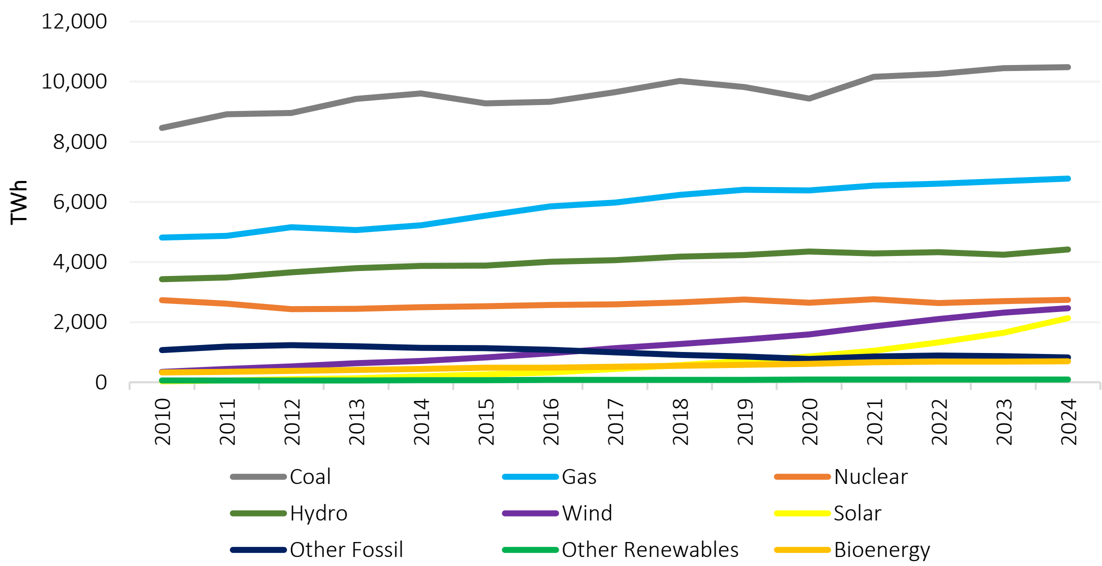
Gas-fired electricity generation increased driven by overall electricity demand growth

Global gas consumption in the electricity sector grew by 1.8% in 2024, driven by a 4.2% increase in overall electricity demand, which reached 30,600 TWh. This growth was fuelled by factors such as economic expansion, rising industrial activity, urbanisation, and the rapid growth of AI data centres, which consume substantial amounts of electricity. In this context, gas-fired power generation reached circa 6,800 TWh (Figure 51), solidifying its role as a crucial component of the global energy mix. The growth in gas use was further supported by coal-to-gas switching, particularly in North America and Asia, where lower gas prices and efficiency improvements enhanced the competitiveness of natural gas.

In parallel to an increase in gas demand for power, renewable energy sources experienced significant growth, with solar and wind leading the way. Solar power generation surged by 30%, adding 486 TWh, driven by rapid deployment of solar photovoltaic systems in countries like China, India and the US. Wind power saw a 7% increase, contributing an additional 151 TWh. Hydropower also rebounded from prior declines, registering a 4% increase due to improved precipitation levels in key regions. Nuclear power generation rose by 1.5%, as countries such as France and Japan reactivated nuclear plants following years of maintenance and favourable policy shifts toward nuclear energy. Meanwhile, coal-fired power generation remained relatively stagnant.

However, in the global power generation mix, coal remained the dominant source of electricity, though its share dropped to 34% due to increasingly stringent environmental policies worldwide. Natural gas followed with a 22% share, while the combined contribution of wind and solar power grew to 15%, highlighting the continued shift towards cleaner energy solutions.

Figure 51: Trend in global electricity generation by energy source



Source: GECF Secretariat based on data from Ember and The Energy Institute Statistical Review of World Energy

2.2.2 Industrial Sector

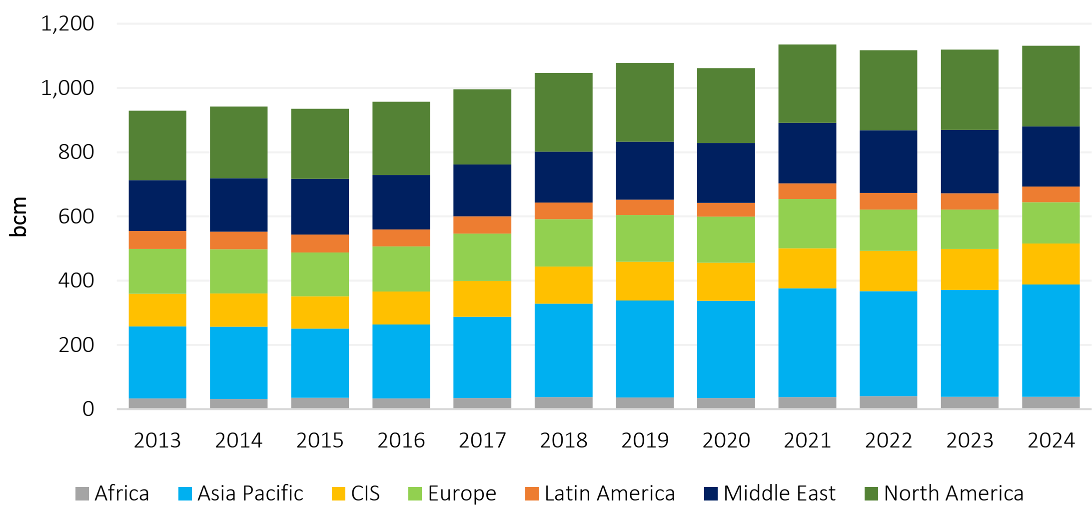
Industrial gas demand grew slightly, driven by lower prices and economic recovery

Global gas consumption in the industrial sector increased to 1,130 bcm in 2024, reflecting a 1.1% growth (Figure 52). The growth was largely supported by the decline in gas prices in some regions, making natural gas a more attractive and cost-effective feedstock for industries.

This growth was also driven by the recovery of demand from the industrial sector in major global economies, especially in Europe, the US, China, and India. A key factor behind the increase in industrial gas consumption was the fertiliser sector, where natural gas plays a crucial role as a feedstock, particularly for ammonia production. With a surge in agricultural demand, especially in emerging markets, fertiliser production saw a significant uptick, thereby driving higher gas consumption. Furthermore, the resurgence of energy-intensive industries contributed to the overall growth, with sectors such as petrochemicals, glass and cement experiencing a rebound in demand as global economic activity accelerated. Additionally, the growing trend of shifting to cleaner fuels, such as natural gas, due to stricter environmental regulations and policies, further bolstered the demand for gas across various industrial sectors.

At the regional level, Asia Pacific led global gas consumption in the industrial sector, driven by expanding industrial activities in China and India. Unlike other major gas markets, where power generation is the dominant driver of gas demand, these two countries stand out due to the industrial sector's significant gas usage, accounting for approximately 40% of their total gas consumption. Notably, China's industrial sector consumes over 160 bcm of natural gas, with a significant potential for substantial growth, particularly through coal-to-gas switching and as a feedstock for specific industries. Meanwhile, Europe's industrial gas demand saw a modest recovery, supported by lower gas prices that helped sustain industrial output. However, gas demand in the region remained well below pre-energy crisis levels, owing to ongoing energy efficiency improvements and structural shifts in energy consumption patterns.

Figure 52: Trend in gas consumption in the industrial sector by region



Source: GECF Secretariat based on data from Enerdata, Cedigaz and IEA Monthly Gas Statistics

2.2.3 Residential and Commercial Sector

Colder winter weather sustained residential and commercial gas consumption

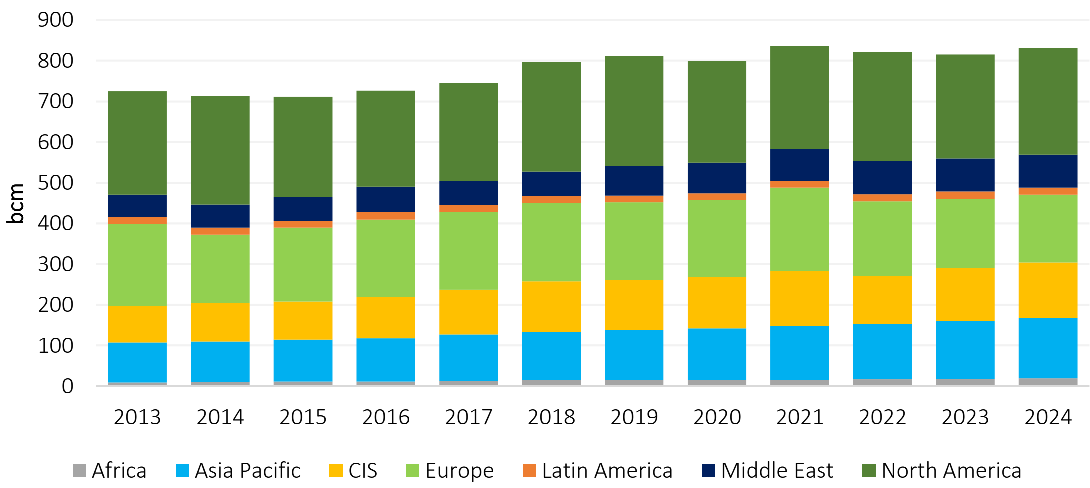
Global gas consumption in the residential and commercial sector rose to 832 bcm in 2024, surpassing pre-pandemic levels (Figure 53). This growth was driven by increased heating demand in the fourth quarter of the year, as well as urbanisation, improving living standards and infrastructure expansion in emerging economies. The rise occurred despite ongoing energy efficiency improvements in the building sector, along with the continued shift toward electrification in residential heating, including the expansion of heat pumps.

Regionally, North America and Europe together account for over half of global gas consumption in this sector, largely due to their high reliance on natural gas for heating during winter. North America experienced a 2% increase in gas consumption in 2024, supported by colder-than-expected weather and population growth in states with high gas heating dependence. Conversely, Europe saw a continued decline, resulting in 2% this year, driven by energy efficiency improvements, policy-driven demand reduction measures, and an ongoing shift toward electrified heating solutions.

Meanwhile, Asia Pacific saw a 4% growth, driven by expanding natural gas use in key markets like China and India. In China, the residential sector, which consumes over 80 bcm of natural gas, remains a priority in the government's Natural Gas Utilisation Policy. The most recent edition continues to prioritise gas use for cooking, domestic hot water and centralised heating for urban residents. The number of new residential clients served by city gas companies has grown steadily, with an additional 10 million in 2022 and 8 million in 2023. Since many households still rely on high-carbon energy sources, particularly coal, gas consumption in this sector is expected to increase, especially through coal-to-gas switching.

Additionally, Africa experienced steady growth, driven by expanding gas infrastructure, increasing urban gas connections, and the growing adoption of natural gas for cooking.

Figure 53: Trend in gas consumption in the residential/commercial sector by region



Source: GECF Secretariat based on data from Enerdata, Cedigaz and IEA Monthly Gas Statistics

2.2.4 Transport Sector

LNG-fuelled trucks, particularly in China, emerged as a new driver of gas demand growth

The transport sector remains an emerging area for gas utilisation compared to the more established power generation, industrial and residential/commercial sectors, which have maintained significant shares of global gas consumption over the past two decades. However, the share of the transport sector in global gas consumption has steadily increased, particularly in the automotive and maritime industries, driven by two key factors: the cost competitiveness of natural gas and supportive environmentally focused energy policies.

The cost competitiveness of natural gas is the crucial factor driving its adoption in the transport sector. With natural gas prices remaining relatively stable — aside from the 2022 energy crisis — it provides significant cost savings for vehicle operators, particularly in commercial and heavy-duty segments. This cost advantage makes natural gas a viable alternative to conventional fuels, not only for short-range vehicles but also for long-haul operations, enhancing its appeal in both freight and public transport applications.

Environmentally focused energy policies have also had an undeniable influence on the shifting fuel choices in the transport sector, which is responsible for one quarter of global greenhouse gas emissions, with road transport standing out with a significant share of emissions. Amidst the climate change agenda, decarbonisation of the transport sector will become an imperative. One of the most efficient ways to promote carbon reduction of road transport is switching from conventional oil-based fuels to natural gas. Compared with conventional fuels, switching to natural gas can reduce GHG emissions by around 20%, while carbon dioxide emissions in particular, may decrease by up to 25%. In addition to these reductions, the combustion of natural gas-based fuels produces lower levels of nitrogen oxides, sulphur oxides and particulate matter, further contributing to improving air and water quality.

2.2.4.1 Automotive industry

Natural gas vehicles (NGVs) in the automotive industry typically run on compressed natural gas (CNG) or liquefied natural gas (LNG). Currently, over 30 million vehicles worldwide are powered by either CNG or LNG fuel systems. CNG is commonly used in cars, rickshaws and motorcycles. It has gained popularity due to its ease of adaptation to petrol-fuelled internal combustion engines with only minor modifications to the fuel storage and intake systems. In contrast, LNG offers a higher energy density, making it ideal for heavy hauling and long-range transportation. As a result, LNG is increasingly used in buses, trucks, municipal utility vehicles, agricultural machinery, ships (including LNG carriers), and even rail transport.

China is the undisputed global leader in the NGV market, holding a dominant position in both the LNG and CNG segments. This shift is part of China's broader strategy to reduce emissions and tackle air pollution, as well as to decrease its dependency on imported oil. Notably, the adoption of LNG as a fuel for heavy-duty trucks, especially those with a load capacity exceeding 15 tonnes, has gained considerable momentum in 2024.

China, home to the world's largest and most developed LNG-powered heavy-duty truck market, accounting for an estimated 80% share of the global market, introduced its first LNG-powered trucks in 2003. Since then, it has implemented supportive energy policies through various government mechanisms, including subsidies for fuel, truck scrapping and refuelling infrastructure. With both favourable policies and economics, China has seen an unprecedented surge in LNG-powered truck sales. In 2024, approximately 200,000 LNG-powered trucks were sold, representing one-third of the annual heavy-duty truck sales, a sharp increase from just 4% in 2022. As a result, the number of LNG-powered trucks in operation in China is now estimated at around 750,000, with their share in the country's total heavy-duty truck fleet almost doubling from 5% in 2022 to 9% in 2024. If the current sales trajectory continues, China's LNG-powered truck fleet is expected to exceed one million vehicles by the end of 2025. With LNG rapidly gaining market share, it is set to become a dominant fuel alongside diesel in China's heavy-duty truck market.

Other countries are looking to replicate China's successful promotion of CNG and LNG in the automotive sector as part of their broader transition to a gas-based economy. Key to this effort will be addressing challenges such as limited refuelling infrastructure. The upcoming expansion of global LNG export capacity is expected to stabilise prices and support the continued growth of the LNG-powered truck market, particularly in countries reliant on gas and LNG imports.

India stands out among other countries in its approach to adopting LNG for the transport sector. Although the country currently has fewer than 1,000 LNG-powered trucks, the government aims to have one-third of the truck fleet running on LNG within the next five to seven years. India's high dependence on oil imports, which surpasses that of China, adds further impetus to this transition. To support this goal, the government is focused on expanding LNG refuelling infrastructure, which remains limited, and is allocating domestic gas — cheaper than imported LNG — for LNG-powered trucks.

The EU and the US are also making strides in utilising natural gas in the automotive sector. The EU currently boasts 1.5 million CNG-powered vehicles and 30,000 LNG-powered trucks, serviced by 800 LNG refuelling stations and 4,200 CNG refuelling stations. Germany, Italy, Spain and France lead the way, accounting for three-quarters of the region's LNG-fuelled truck market. In the US, LNG-powered trucks are supported by 50 LNG refuelling stations, with significant growth potential, especially as LNG production projects continue to develop.

GECF member countries play a pivotal role in the adoption of NGVs, with Iran ranked second globally — behind China — in gas consumption for road transport. Iran operates 2,600 CNG refuelling stations and has 5 million vehicles powered by CNG engines, representing about a quarter of the country's automotive fleet. Egypt, with 800 natural gas refuelling stations, has advanced its "One Million Vehicles Running on Compressed Natural Gas (CNG)" initiative, converting over 500,000 vehicles and aiming to convert an additional 250,000 to CNG. Russia is also expanding its natural gas use in the automotive sector, with an annual consumption of 2.3 bcm and a growing fleet of around 300,000 NGVs, supported by an expanding infrastructure for refuelling stations.

2.2.4.2 Maritime industry

Traditional oil-based marine fuels still dominate the maritime industry, with 98% of the global vessel fleet relying on them. However, alternative fuel options are progressively gaining market share, with natural gas, particularly in the form of LNG, emerging as the most popular alternative marine fuel among currently operating vessels (Figure 55). LNG offers notable environmental advantages, such as significant reductions in greenhouse gas emissions and the near-elimination of sulphur oxides, nitrogen oxides and particulate matter. Additionally, methanol and ammonia are gaining attention as promising alternative fuels, with their production largely reliant on natural gas as a key feedstock. While alternatively fuelled vessels make up less than 2% of the active fleet, they account for nearly half of the ships on the global orderbook. This growing adoption of natural gas positions it as a vital enabler of cleaner, more sustainable maritime fuel alternatives, aligning with global efforts to decarbonise the shipping industry and reduce its carbon footprint.

The adoption of natural gas as a fuel option in the maritime industry is primarily driven by global and regional decarbonisation policies, with economic competitiveness playing a crucial supportive role. A significant policy milestone came with the International Maritime Organisation (IMO) 2023 regulations, which introduced measures aimed at enhancing operational efficiency. These regulations are backed by ambitious greenhouse gas (GHG) reduction targets for the sector: a minimum 20% reduction from 2008 levels by 2030 (with an aspirational target of 30%), progressing to a 70% reduction by 2040 (aiming for 80%), and ultimately targeting net-zero GHG emissions by 2050 or sooner. These regulatory frameworks are expected to expedite the shift toward cleaner fuel alternatives, including LNG, accelerating the maritime industry's transition to a more sustainable and low-carbon future.

A key regional regulation shaping maritime decarbonisation is the EU’s FuelEU Maritime, which governs the well-to-wake lifecycle of marine fuels within the European Economic Area. The regulation establishes stringent annual CO_2 reduction targets, starting with a 2% decrease in 2025 and increasing progressively to 80% by 2050. In addition, the shipping sector was integrated into the EU Emissions Trading Scheme beginning in January 2024, further reinforcing efforts to reduce emissions. These measures aim to accelerate the transition to cleaner fuels, substantially lowering the carbon footprint of maritime transport within the EU and driving the industry's shift toward more sustainable practices.

The global LNG-fuelled fleet has experienced significant growth over the past decade (Figure 54). By 2024, the fleet had expanded to 435 vessels, excluding LNG carriers, with approximately 130 more ships on order. The tanker and passenger segments have been key contributors to this expansion, with the cruise ship and ferry sectors seeing substantial uptake. Additionally, LNG propulsion is becoming increasingly popular in the cargo ship segment, which has more than doubled in size over the past five years, reflecting a growing commitment to cleaner, more efficient maritime transport solutions.

Figure 54: Trend in the global LNG fuelled fleet

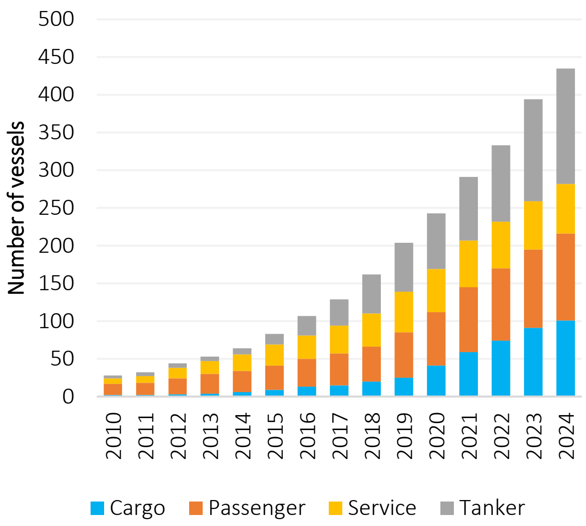
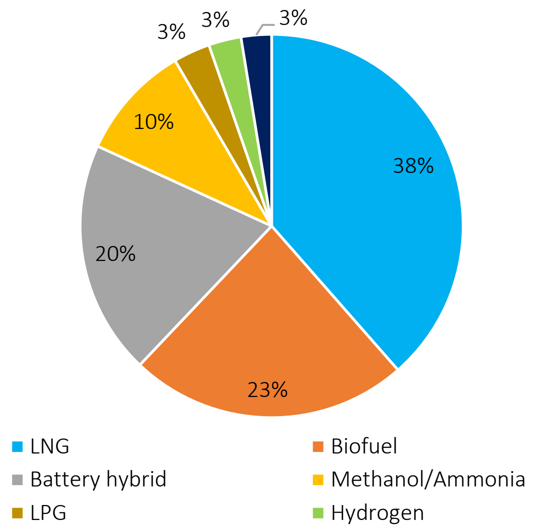


Figure 55: Alternative fuel options in the existing fleet

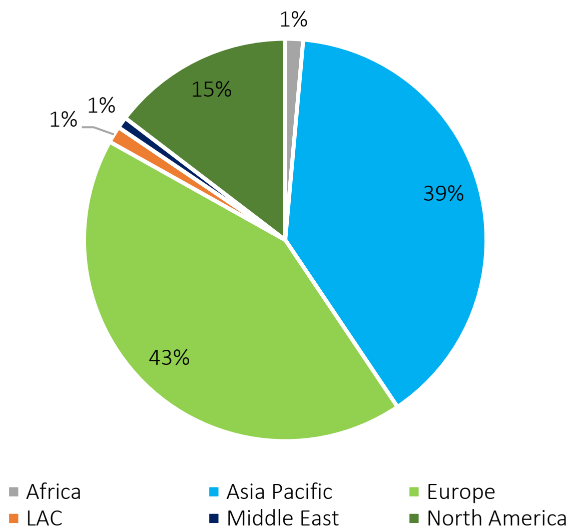


Source: GECF Secretariat based on data from Argus

The growth of the LNG-fuelled fleet has been accompanied by a significant expansion in ship-to-ship LNG bunkering. In 2024, global LNG bunkering capacity reached 560,000 cubic metres, more than four times the amount in 2020 (Figure 56). Europe leads the world in LNG bunkering, with bunker vessels primarily concentrated in hubs across northwest Europe and the Nordic countries (Figure 57). The Asia Pacific region accounts for around 40% of the global capacity, with major hubs in Singapore and China. Singapore, the largest global marine bunker hub, saw a significant increase in LNG bunker fuel sales, reaching 465,000 tonnes in 2024 — more than four times the volume sold in 2023. Rotterdam also experienced a surge in LNG bunker fuel sales, with 410,000 tonnes sold in 2024, approximately 1.5 times the amount sold the previous year. This growth highlights the increasing adoption of LNG as a marine fuel and the global infrastructure development to support its use.

Figure 56: Global LNG bunker vessels capacity

Figure 57: LNG bunker vessel capacity distribution



Source: GECF Secretariat based on data from Argus

CHAPTER

03

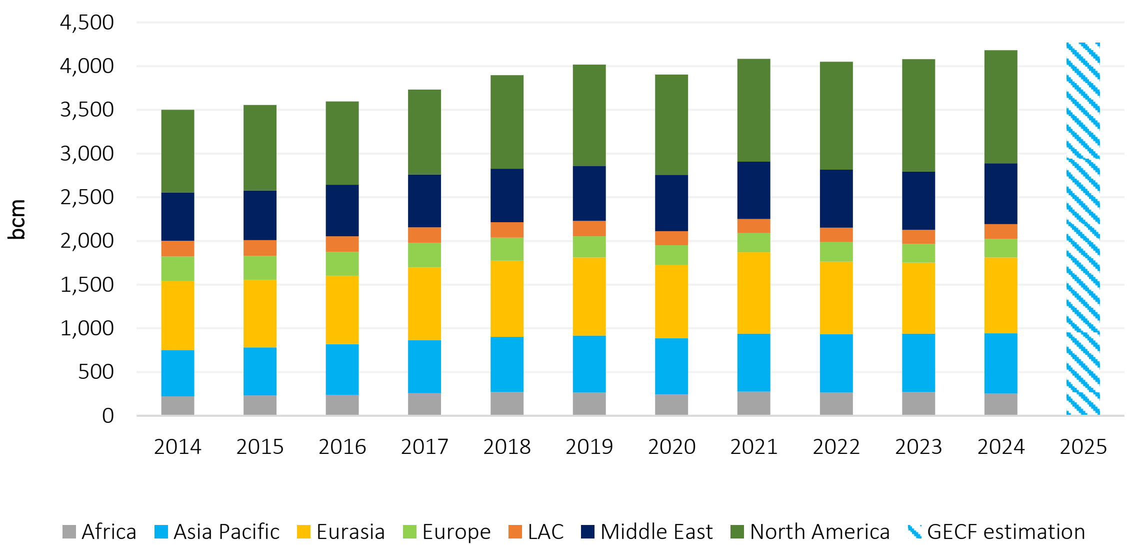
GAS PRODUCTION

Global gas production witnessed strong growth in response to rising gas demand, with Eurasia at the forefront of these developments

Global gas production is estimated to have risen by 2.5% year-on-year, reaching 4.18 tcm in 2024 (Figure 58), following a modest increase of 0.7% in 2023. This growth reflects a robust response from the global gas supply to the rising global demand, with key producing countries demonstrating resilience amid evolving market conditions. GECF member countries, in particular, continued to play a key role in the global gas supply, with their output rising by 3.2% year-on-year to 1,598 bcm. Over the past decade, global gas supply has recorded a compound annual growth rate (CAGR) of 1.8%.

As of the end of March 2025, global gas production was projected to maintain robust growth at an annual rate of 2% in both 2025 and 2026, driven primarily by developments in the Middle East, North America and Asia Pacific. This upward trend will be supported by the ramp-up of newly commissioned gas projects in Saudi Arabia and China, along with a rebound in output in the US, fuelled by higher gas prices. Additionally, Africa is expected to boost its production, with emerging gas players such as Mauritania and Senegal entering the global gas market.

Figure 58: Trend in global gas production



Note: GECF's estimate for 2024 and forecast for 2025

Source: GECF Secretariat based on data from Rystad Energy and Cedigaz

3.1 Gas Production by Region

Although most of the main producing regions witnessed a positive production variation trend, the supply growth was primarily led by Eurasia, the Middle East and Asia Pacific.

Eurasia was the primary driver of global gas supply growth, with more than a 6.8% rise. Specifically, Russia witnessed a 50 bcm increase in its total production, driven by the increased domestic consumption, increasing pipeline exports to China, and recovering pipeline exports to the EU (Figure 59).

The Middle East recorded a 4.8% growth, driven by the development of multiple gas projects in the region. Saudi Arabia led the uptick (12 bcm rise), with Iran and UAE showing positive increase as well.

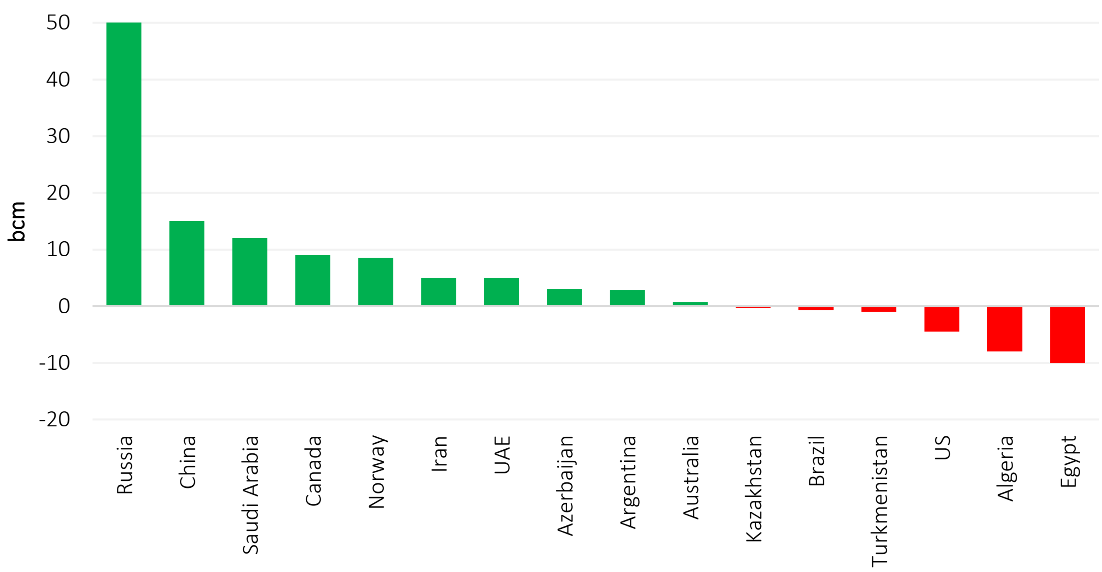
Asia Pacific saw a growth rate of 2.5%, with China continuing its significant production growth (15 bcm increase), and its unconventional gas output recording a sustained increase.

LAC followed with a 2.2% annual rise and represented a 16% share of global gas production. The upstream development in Argentina drove this rise and counterbalanced the decline in other producing countries.

North America's total gas production remained relatively stable compared to 2023, with growth in Canada's unconventional output offsetting the decline in US dry gas supply, as a result of the production cuts amid low Henry Hub gas prices.

On the other hand, African production in 2024 witnessed the largest decrease among the main producing regions, with a decline rate of 5.6% y-o-y. This mainly stemmed from the decrease in gas output of some key African producers. However, a positive outlook is anticipated for Africa in 2025, with new players stepping into the market.

Figure 59: Y-o-y variation in gas production in major producing countries in 2024



Source: GECF Secretariat based on data from Rystad Energy, Cedigaz and GECF estimation

3.1.1 Europe

Norway and Türkiye spearheaded the recovery in regional gas production

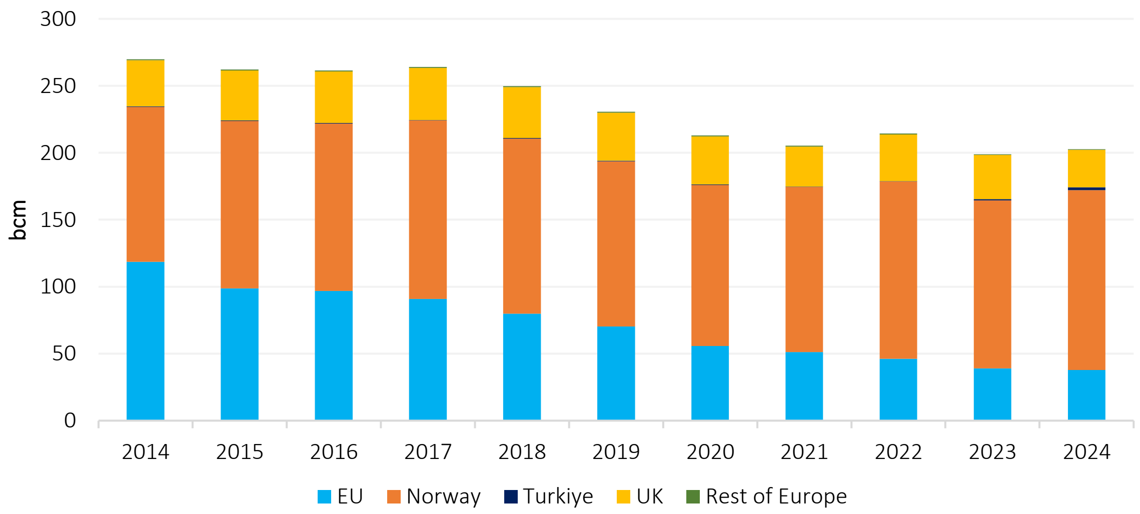
European gas production rose by 1.5% to reach 202 bcm in 2024, accounting for 5% of the global gas output (Figure 60). This growth was primarily driven by increased production in Norway and Türkiye. In particular, the ramp-up of the Sakarya gas field in the Black Sea contributed to a threefold increase in Türkiye's production, reaching 2.2 bcm. However, the overall rise in the regional production was tempered by declines in output from the UK and several EU countries.

The EU's total gas production decreased by 1 bcm to 38 bcm, largely due to declines in the Netherlands and Germany. The Netherlands experienced a drop of 1.8 bcm, reaching 9.4 bcm, while Germany's output fell by 0.5 bcm to 4.2 bcm. Similarly, Poland and Italy saw small decreases in production. These declines were partially offset by increases in gas output from Romania and Denmark.

Romania's gas production slightly increased to 9.2 bcm, positioning itself to surpass the Netherlands as the EU's largest gas producer by 2025, a title the Netherlands has historically held. Romania's production outlook remains positive in the short to medium-term, especially with the development of the Neptun Deep gas field in the Black Sea. This field, estimated to hold 100 bcm of recoverable gas resources, is expected to begin production in 2027, reaching an output of 8 bcm annually. With this boost, Romania is poised to become an important gas exporter to neighbouring Eastern European countries, strengthening their collective energy security.

Denmark experienced significant growth in gas production, rising from 1.0 bcm in 2023 to 2.8 bcm in 2024. This surge was driven by the Tyra II redevelopment project in the Danish North Sea, Europe's largest gas project to start production in 2024 and one of the continent's top ten developments this decade in terms of gas resources. The Tyra field is expected to produce 2.8 bcm annually, positioning Denmark to transition from a gas importer to an exporter.

Figure 60: Trend in Europe's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation for 2024

3.1.1.1 Norway

Norway's gas production surged by 7% to a record 134 bcm in 2024, surpassing its previous high of 132 bcm set in 2022 (Figure 61). This significant increase reinforced Norway's position as the leading gas producer in Europe, accounting for two-thirds of the continent's gas output. The growth was largely driven by higher production from key fields on the Norwegian Continental Shelf (NCS), particularly the Troll field, which saw a 12% rise to 45 bcm, thanks to reduced maintenance downtime at both the field and the Kollsnes gas processing plant.

Norway's gas production is entirely conventional and offshore. Associated gas accounted for 25% of Norway's marketed gas production, a significant increase from 13% a decade ago (Figure 62). This growth is attributed to higher Norwegian oil production, particularly from high gas-oil ratio (GOR) wells, and the enhanced infrastructure that allows for the recovery of associated gas rather than flaring it. Notably, Norway is recognised for having some of the lowest upstream emissions globally, thanks to reduced gas flaring volumes and the electrification of upstream operations, with power supplied from the onshore grid.

Three relatively small new fields — Hanz, Kristin South, and Tyrving — came on stream, collectively contributing an initial production of 0.7 bcm. Gas output from these fields is expected to average 1 bcm per year in the medium-term. Exploration activity remained robust, with 42 exploration wells drilled and 16 new discoveries made on the Norwegian Continental Shelf (NCS). These discoveries are estimated to hold 250 million boe of recoverable resources. Notably, almost half of these resources, are gas (circa 20 bcm), with many of the smaller discoveries being considered for development through tiebacks into existing fields, thereby minimising development costs.

In the short to medium-term, gas production is projected to stay steady at elevated levels, with a gradual decline anticipated towards the late 2020s, as forecasted by the Norwegian Offshore Directorate.

Figure 61: Trend in Norway's gas production

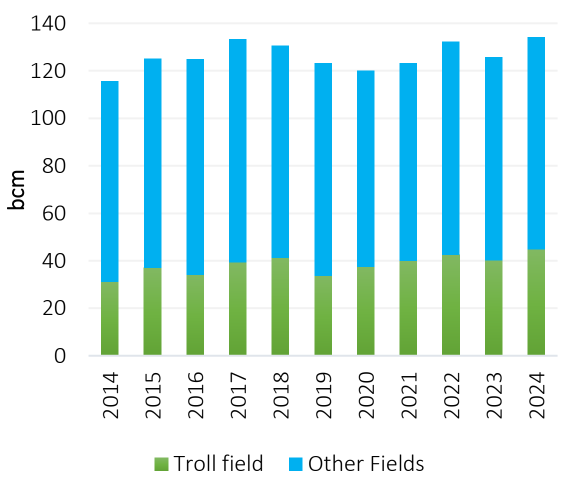
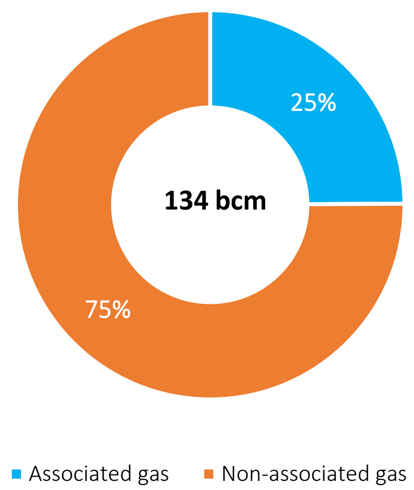


Figure 62: Norway's gas production by type in 2024



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

3.1.1.2 Netherlands

Gas production in the Netherlands continued its downward trajectory in 2024, reaching a total output of 9.4 bcm, reflecting a decrease of 1.8 bcm (Figure 63). This decline was primarily driven by the rapid depletion of aging Dutch gas fields, which had entered the maturity phase, coupled with a lack of investment in new gas development projects. Additionally, production from the Groningen field ceased entirely following its closure at the end of 2023. The country's reported proven gas reserves were estimated at 72 bcm, and at the current rate of production, along with the absence of new volumes, these reserves could be depleted within approximately 10 years, raising concerns about the country's energy security.

The A15 gas development project, in the Dutch North Sea, was the only new development project to come online in 2024, contributing 0.25 bcm annually. Notably, two-thirds of the Netherlands' gas production came from offshore fields, all of which was non-associated gas.

3.1.1.3 United Kingdom

The UK's gas production declined by 15% to 27.9 bcm in 2024 (Figure 64). This continuous reduction reflected the lack of investments in new gas field developments, due to long-standing energy policies aimed at achieving net-zero emissions. However, amidst a recent shift in policies driven by heightened concerns over energy security, the UK's North Sea Transition Authority (NSTA) awarded 31 new oil and gas licences for exploration and production in the third tranche of the 33rd licensing round in 2024. These licences are mainly directed at gas production from the Southern North Sea, with new fields expected to come online within a five-year period.

In terms of distribution, the entire British gas production originated from offshore fields on the UK Continental Shelf (UKCS), while associated gas production constituted 12% of the total production, nearly the same level as in previous years.

Figure 63: Trend in the Netherlands' gas production

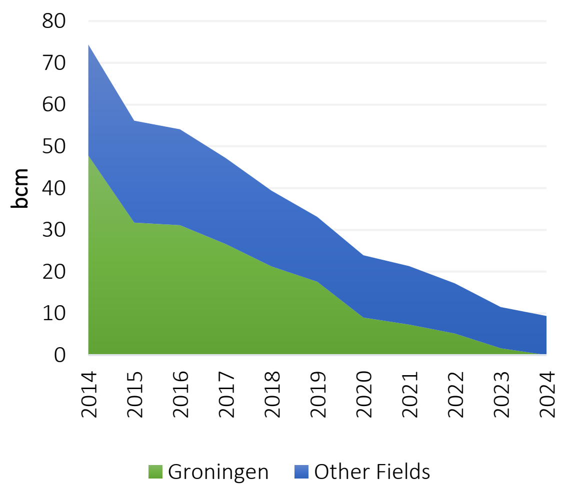
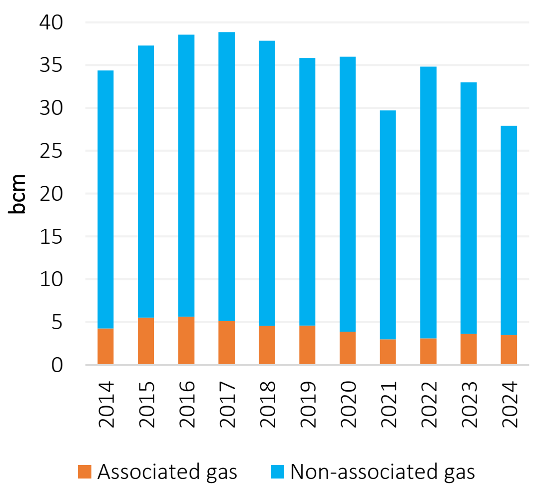


Figure 64: Trend in the UK gas production



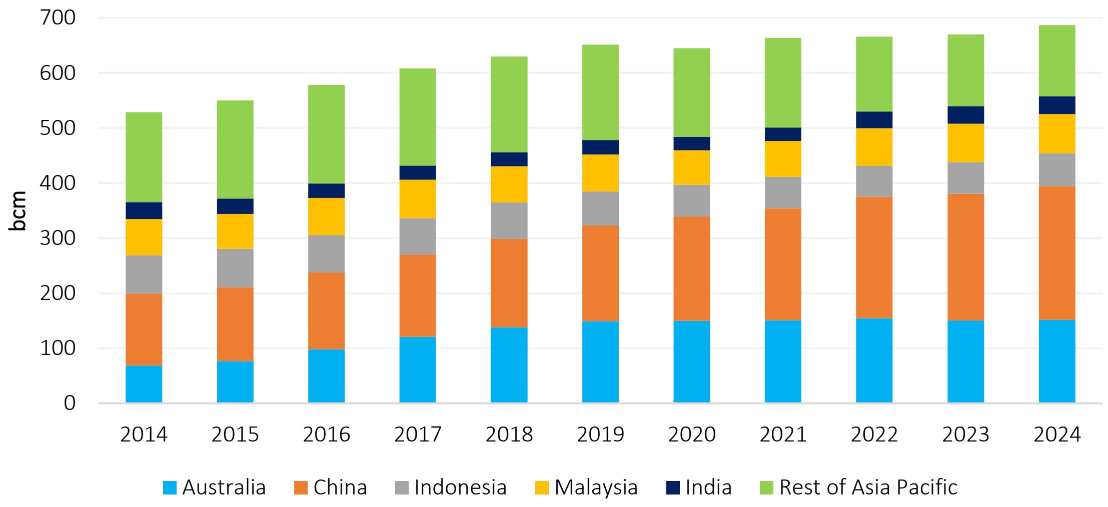
Source: GECF Secretariat based on data from Rystad Energy and LSEG

3.1.2 Asia Pacific

The region witnessed a sustained production growth, led by the surge in China's output

Gas production in the Asia Pacific region is estimated to have increased by 2.5% (21 bcm), reaching 681 bcm in 2024 (Figure 65). This growth was driven by a steady rise in China's production (13 bcm), followed by increased output in Thailand (3.6 bcm) and Indonesia (2 bcm).

Figure 65: Trend in Asia Pacific's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.1.2.1 Australia

Australia's gas production saw a slight increase, reaching 151.2 bcm in 2024 (Figure 66). Unconventional gas production, primarily coalbed methane (CBM), accounted for 28% of total output, with CBM production significantly rising over the past decade, driven by new liquefaction projects fed by CBM. Australia has become the global leader in CBM production, supplying 55% of the world's CBM in 2024. Offshore production constituted over two-thirds of the country's gas supply (Figure 67), although its share has declined from 81% in 2014 due to the growth of onshore CBM production.

Figure 66: Trend in Australia's gas production

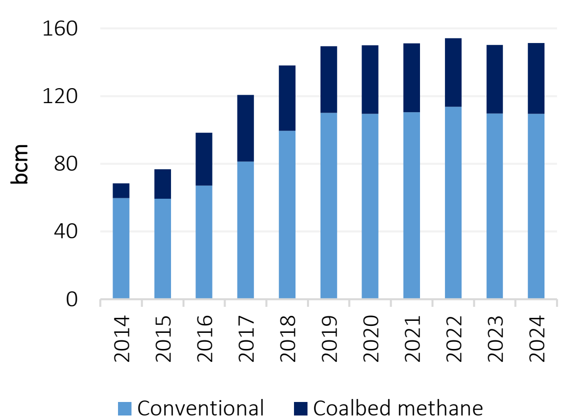
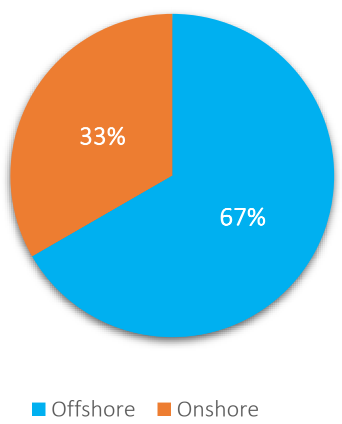


Figure 67: Australia's gas production by segment in 2024



5Source: GECF Secretariat based on data from Rystad Energy and the Australian Department of Energy

3.1.2.2 China

China's gas production maintained steady growth, increasing by 6.2% (13 bcm) to reach 243.5 bcm in 2024 (Figure 68), emerging as one of the key contributors to global gas supply growth.

Notably, China's total unconventional gas production rose to 99 bcm in 2024, up from 35 bcm in 2014, accounting for 40% of the country's total gas output (Figure 69). Within this, shale and tight gas contributed 33%, while coal bed methane (CBM) made up 7% of domestic production. CBM achieved a record output of 16.5 bcm, reflecting a 19% y-o-y growth, driven by the launch of several new projects. Furthermore, the majority of China's gas production, 90%, came from onshore fields, despite the country's efforts to focus on developing its offshore gas resources.

Nine new gas fields came online in 2024, with an initial combined production of 2 bcm and an expected average output of 9 bcma in the medium-term. Among them, five new conventional gas fields were developed, including the Shenhai-1 Phase II deepwater project in the northern South China Sea, the largest, with a plateau production target of 1.7 bcma. Additionally, three CBM fields, including Shenfu and Linxing Deep in the Sichuan basin, began production, with an anticipated combined plateau production of 1.3 bcma. The Longmazi gas field in the southern Sichuan basin marked the only shale gas development to be commissioned.

With a CAGR of 6.5% over the past decade, Chinese gas output has continuously increased. In 2024, 21 new gas development projects reached the Final Investment Decision (FID) stage, with a combined anticipated annual plateau production of 15 bcma.

In the short-term, China is well positioned to become the third largest gas producer globally, after the US and Russia.

Figure 68: Trend in China's gas production

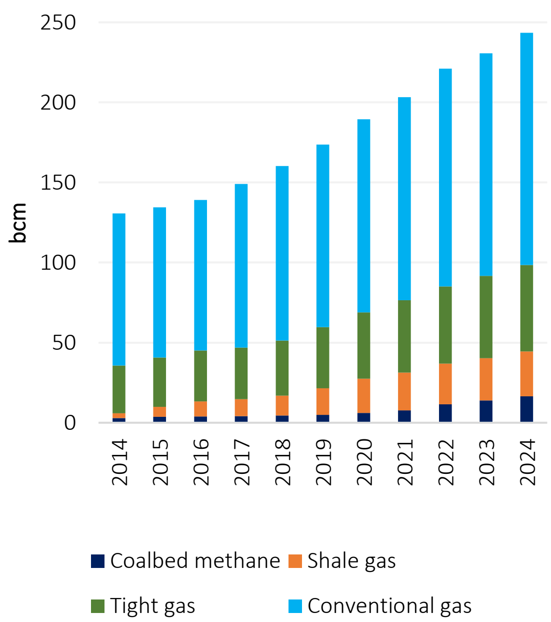
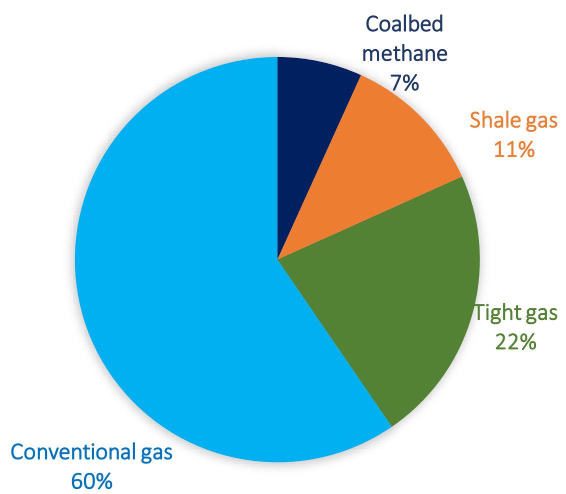


Figure 69: China's gas production by source in 2024



Source: GECF Secretariat based on data from the National Bureau of Statistics of China and Rystad Energy

3.1.2.3 India

India annual gas production experienced a 3.5% increase, reaching 33.8 bcm in 2024 (Figure 70). This growth was primarily driven by a government initiative to rejuvenate production from mature gas fields, leading to a noticeable increase in output, alongside the commissioning of new gas field development projects, particularly offshore.

In terms of production distribution, the majority of India's gas output came from conventional gas fields, accounting for 93% of the total, while 4% came from CBM development, primarily in the West Bengal field, and 3% from tight gas fields. Offshore production made up 71% (Figure 71) of the total gas output; however, its share has decreased over the past decade, down from 77% in 2014. Additionally, associated gas production represented nearly 30% of the overall output, a percentage that has remained stable over the last decade.

A total of 13 relatively small new gas fields came on stream in 2024, with initial combined production reaching 1.8 bcm and expected plateau production of 3 bcm annually. All of the newly commissioned fields are conventional gas fields. In addition, 21 new gas development projects in India reached the FID stage, with an anticipated combined plateau production of 3.5 bcm per year over the medium-term.

India's reported proven gas reserves witnessed a decline over the last five years, to stand at 1.14 tcm, with the majority being conventional proven gas reserves. This was mainly driven by a reduced number of new gas discoveries in India. Additionally, India is in possession of a considerable volume of technically recoverable shale gas resources, estimated at 2.15 tcm. These volumes are still untapped and need extensive development studies for their exploitation.

In the short-term, India is anticipated to increase production, driven by the offshore sector.

Figure 70: Trend in India's gas production

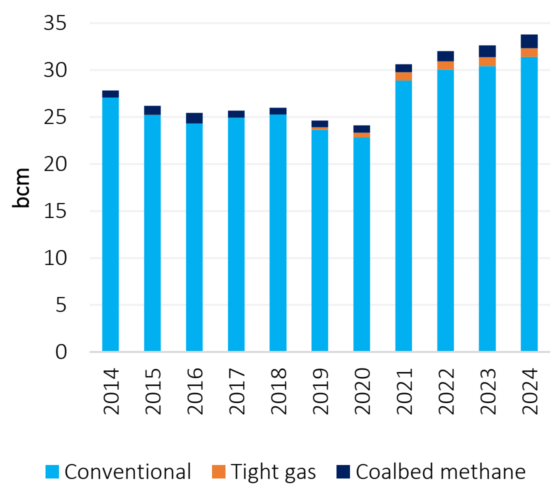
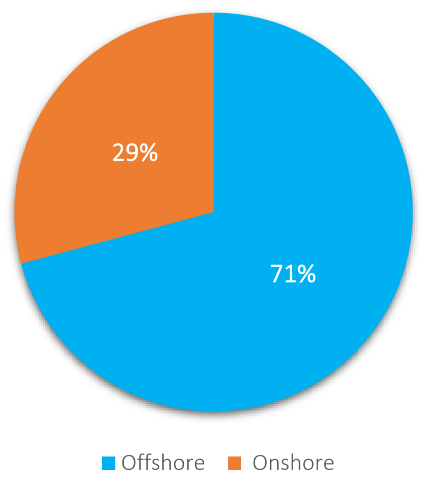


Figure 71: India's gas production by segment in 2024



Source: GECF Secretariat based on data from Rystad Energy and PPAC

3.1.2.4 Indonesia

Gas production in Indonesia increased by 4% to reach 59.5 bcm in 2024 (Figure 72). That marked a continuation of the recovery trend following a decade-long decline, when gas output fell from 70 bcm in 2014 to a low of 55.6 bcm in 2022. However, this trend reversed recently with the commissioning of new gas projects and the rejuvenation of aging fields. In 2024, three new gas fields came online. Notably, Indonesia saw a significant increase in development activity, with the number of wells drilled rising to 889 in 2024, up from just 240 in 2020 (Figure 73). In terms of production distribution, all of Indonesia's gas output came from conventional fields, with offshore production accounting for 60% of the total.

Figure 72: Trend in Indonesia's gas production

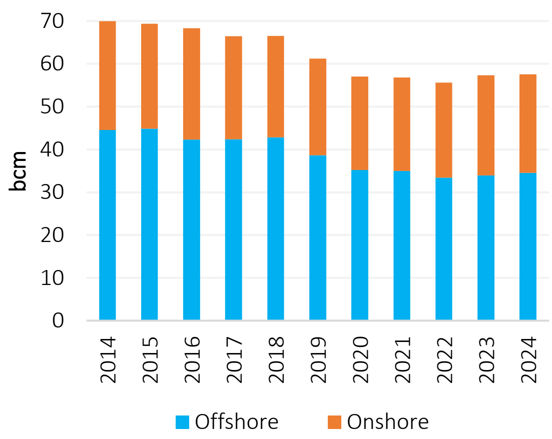
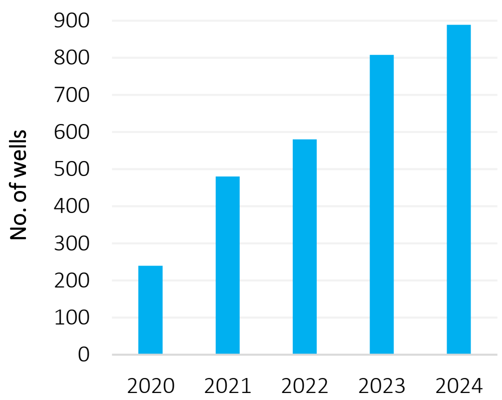


Figure 73: Indonesia's new development wells



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

3.1.2.5 Malaysia

Malaysia's gas production grew by 2% to 71 bcm in 2024, driven by the ramp-up of newly commissioned gas development projects (Figure 74). The country's production is entirely offshore, with the majority stemming from its continental shelf (87%) (Figure 75). Notably, three new fields were brought online in 2024, with Kasawari Phase 1 and Jerun fields being the most significant, together expected to contribute an anticipated production of 10 bcma.

Figure 74: Trend in Malaysia's gas production

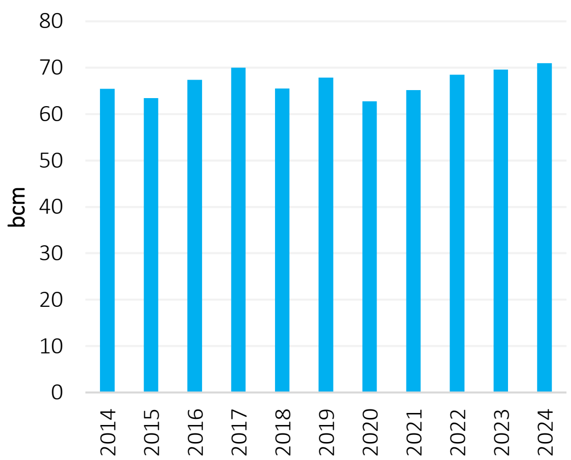
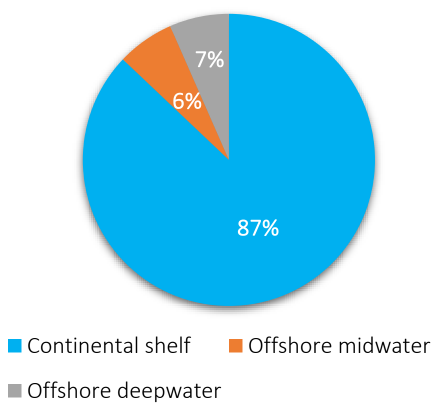


Figure 75: Malaysia's gas output by segment in 2024



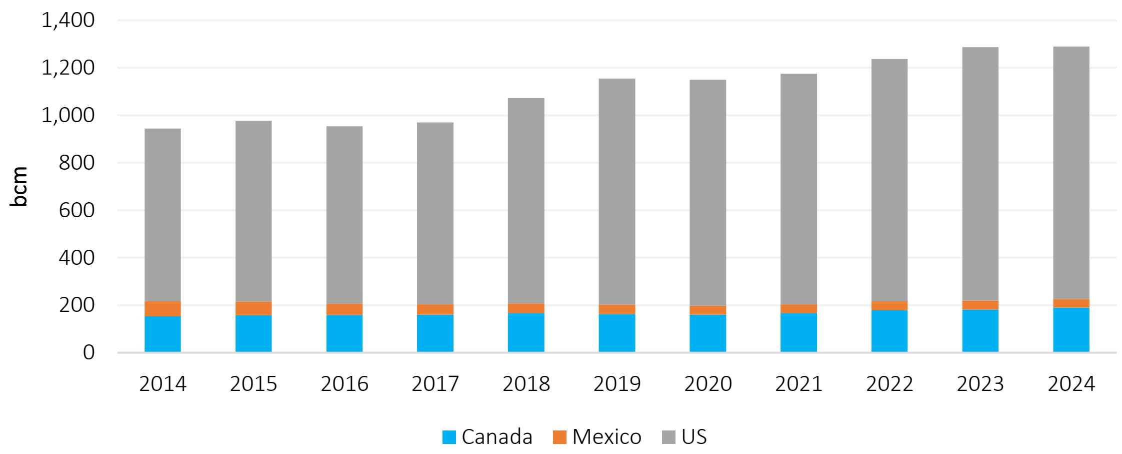
Source: GECF Secretariat based on data from Rystad Energy and JODI gas

3.1.3 North America

Canada's gas production growth offset the decline in US output

Gas production in North America remained stable in 2024, totalling 1,290 bcm and contributing 31% of global gas output (Figure 76). This was primarily driven by an increase in Canada's unconventional gas production, which helped offset reductions in gas output from both the US and Mexico. Looking forward, the region is expected to experience a positive production outlook in 2025, with an anticipated rebound in the US gas production levels.

Figure 76: Trend in North American gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF's estimations

3.1.3.1 Canada

Canada's gas output increased by 5% to reach 190.2 bcm in 2024 (Figure 77). Notably, shale and tight gas production accounted for more than two-thirds of the total output. Associated gas production contributed 11% of Canada's total gas production, and all production originated from onshore fields. Regionally, the province of Alberta produced 118 bcm, representing 62% of the country's total gas production. Drilling activity remained relatively stable throughout the year, with a 4-rig year-on-year decline in December 2024 (Figure 78).

Figure 77: Trend in Canada's gas production

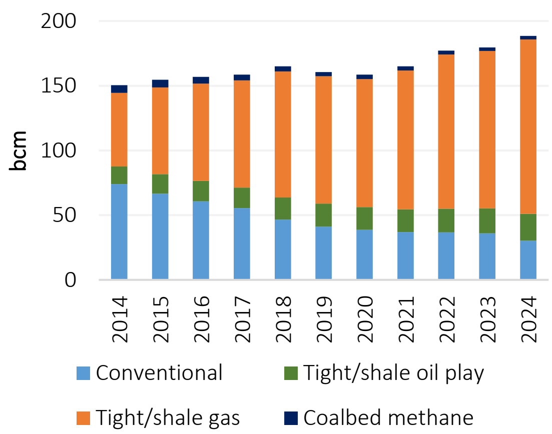
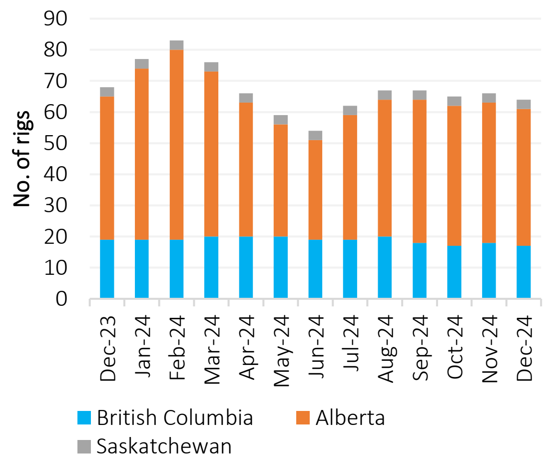


Figure 78: Gas rig count in Canada in 2024



Source: GECF Secretariat based on data from Rystad Energy and LSEG

3.1.3.2 United States

US gas production declined by 0.5%, reaching 1,063 bcm in 2024 (Figure 79). This 5 bcm reduction was primarily driven by output cuts from major domestic producers, especially in the shale gas sector, in response to low Henry Hub gas prices. These cuts were announced in February 2024, when Henry Hub prices fell below the breakeven cost for price-sensitive shale gas production. However, the overall decline in gas output was partially offset by a rise in associated gas production, which has a breakeven cost close to zero.

In terms of production distribution, shale gas production, including associated gas production from shale/tight oil plays, accounted for 90% of total US gas production, while the remainder originated from the dry gas production in Alaska and the Gulf of Mexico (GoM). It is noteworthy that the production of unconventional gas in the US witnessed a CAGR of 6.5% over the last decade to reach 961 bcm. This constituted 72% of the global unconventional gas output and solidified the US position as the global frontrunner in shale gas production.

Haynesville shale gas production region recorded the largest decline in the main producing regions with more than 20 bcm. This was followed by the GoM and Alaska, which witnessed 5 bcm decline. However, the Permian basin recorded a 24 bcm rise, driven by the increase in associated gas production from shale oil plays. Notably, the associated gas production accounted for about 24% of the US gas production, with the past decade witnessing a consistent rise in its share, culminating a CAGR of 7.9%, driven by the rise in US oil production and the improved utilisation of US pipeline infrastructure to recover flared gas.

Notably, the effect of the announced production cuts was reflected in the number of drilled but uncompleted (DUC) wells, which amounted to 5,238 in December 2024 and marked a 587-well decrease compared to December 2023. This can be attributed to the increased reliance on the producers' inventory of DUCs, to reduce production costs and maintain their market shares (Figure 80). In 2025, the US gas production is expected to rebound from its reduced output in 2024, with an increase of 10 bcm, driven by the presence of favourable Henry Hub prices. Associated gas production is expected also to be a main driver for this growth.

Figure 79: Trend in the US gas production

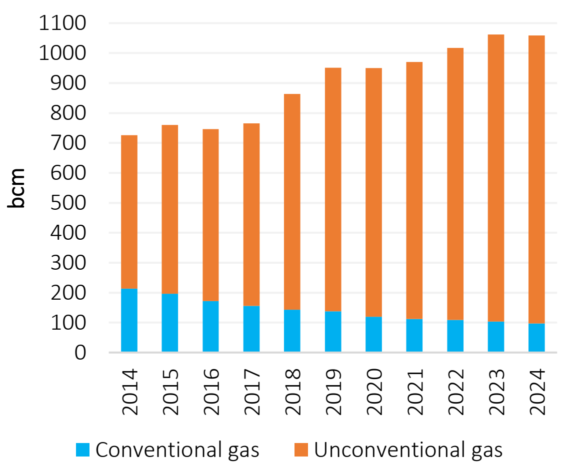
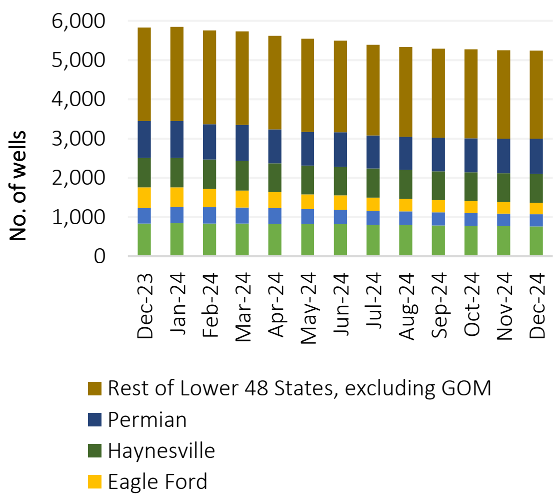


Figure 80: DUC wells count in the US



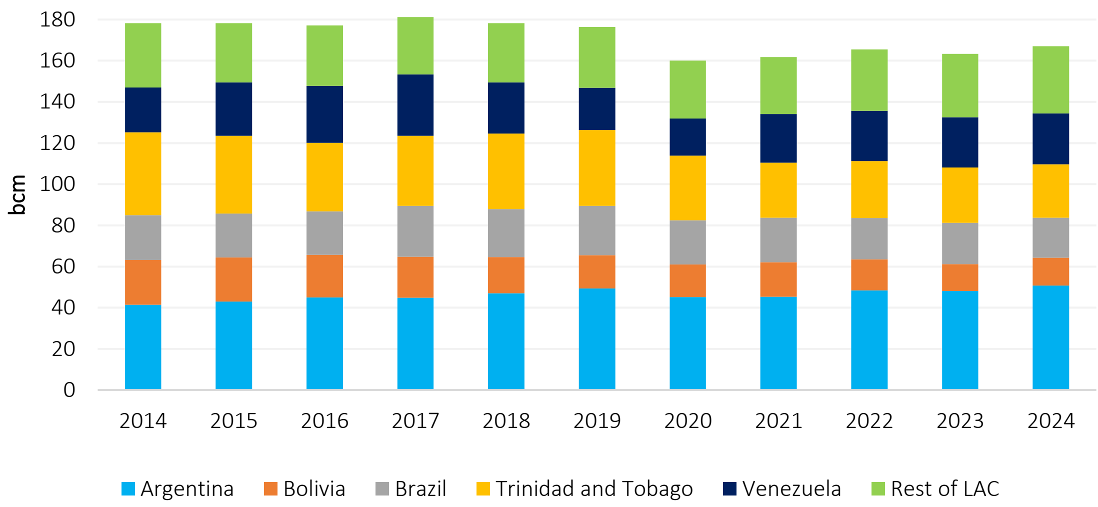
Source: GECF Secretariat based on data from Rystad Energy and the US EIA

3.1.4 Latin America and the Caribbean (LAC)

Gas production was on the rise, driven by shale gas development in Argentina

LAC's gas production grew by 2.2%, reaching 167 bcm in 2024 (Figure 81). This growth was largely fuelled by the continued increase in shale gas production in Argentina, as well as key developments in other countries such as Bolivia, Trinidad and Tobago, and Venezuela.

Figure 81: Trend in LAC's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.1.4.1 Brazil

Brazil's marketed gas production declined by 3%, reaching 19.6 bcm in 2024 (Figure 82). Despite a 2% increase in gross gas output, which reached a record 55.8 bcm. The decrease in marketed production was largely due to higher volumes of gas being reinjected, which accounted for 54% of gross production (Figure 83). Notably, 79% of marketed gas output came from associated gas, while offshore production represented 83% of total output, with pre-salt fields contributing 78% of total gas production.

Figure 82: Trend in Brazil's marketed gas production

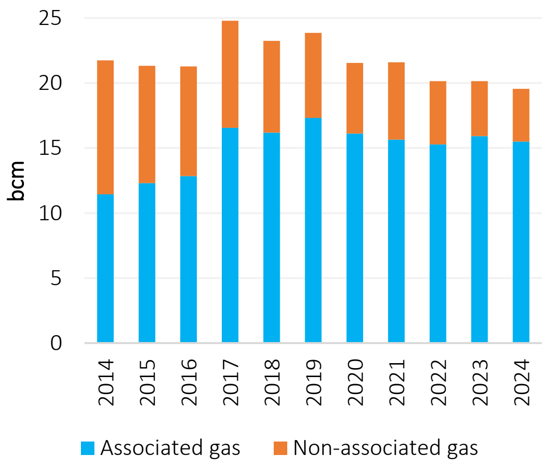
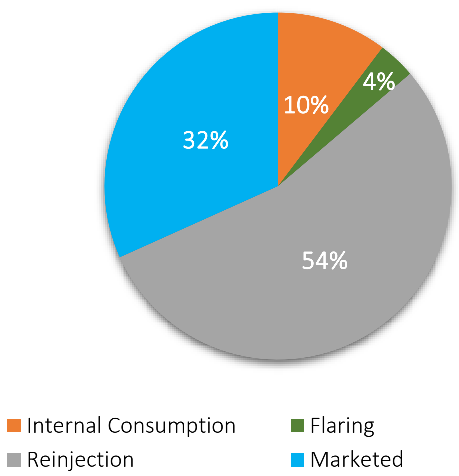


Figure 83: Brazil's gross output distribution in 2024



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

3.1.4.2 Argentina

Argentina's gas production rose by 5% to reach 50.8 bcm in 2024 (Figure 84). This growth was primarily driven by the ongoing development of the Vaca Muerta shale basin, coupled with the debottlenecking and expansion of the gas pipeline infrastructure linked to it.

Unconventional gas production, including shale and tight gas, was the dominant source of Argentina's gas output, accounting for 63% of the total production, while the remainder came from conventional gas fields. Notably, shale gas production continued its impressive growth, increasing by 21% annually to reach 25.4 bcm, with the Vaca Muerta shale gas basin being the main contributor to shale gas output (Figure 85). Tight gas production stood at 6.5 bcm, representing 13% of total production. Meanwhile, conventional gas field output declined by 6%, totalling 19 bcm.

Historically, the development of the Vaca Muerta shale basin began a decade ago, with a significant surge in activity taking place in 2021. This was driven by increased drilling, technological advancements in hydraulic fracturing and horizontal drilling, favourable gas prices, infrastructure improvements (including the commissioning of new gas pipelines for debottlenecking), and supportive policy measures. Notably, Argentina is investing in infrastructure to expand the transportation of natural gas from the Vaca Muerta shale basin to northern Argentina, including reversing pipelines originally designed for imports from Bolivia to facilitate gas exports to Brazil.

In the short-term, Argentina's gas production is expected to maintain consistent growth, particularly with the ramp-up of production at the recently commissioned Fenix offshore gas field. With this rapid pace of growth, Argentina is well-positioned to become a significant exporter of LNG and pipeline gas in the short to medium-term.

Figure 84: Trend in Argentina's gas production

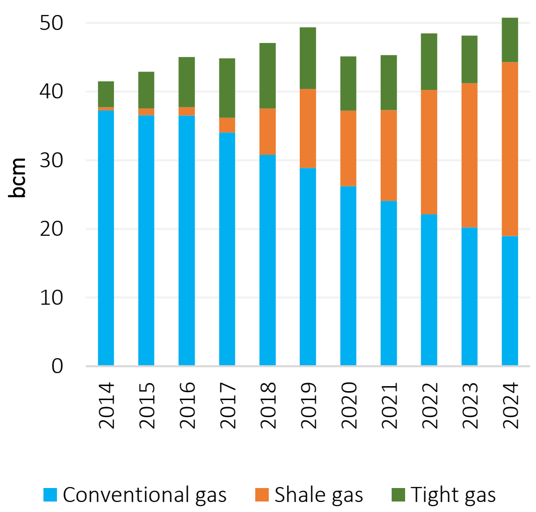
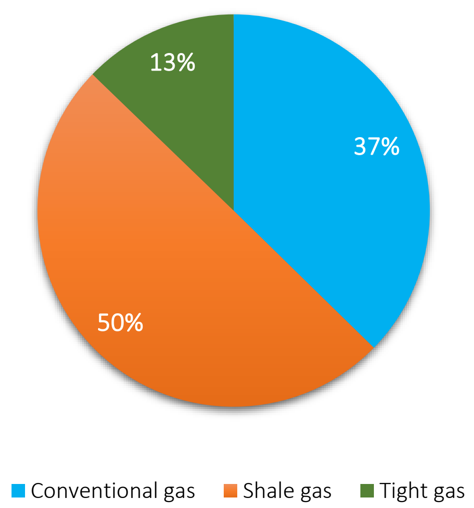


Figure 85: Argentina's gas output by source in 2024



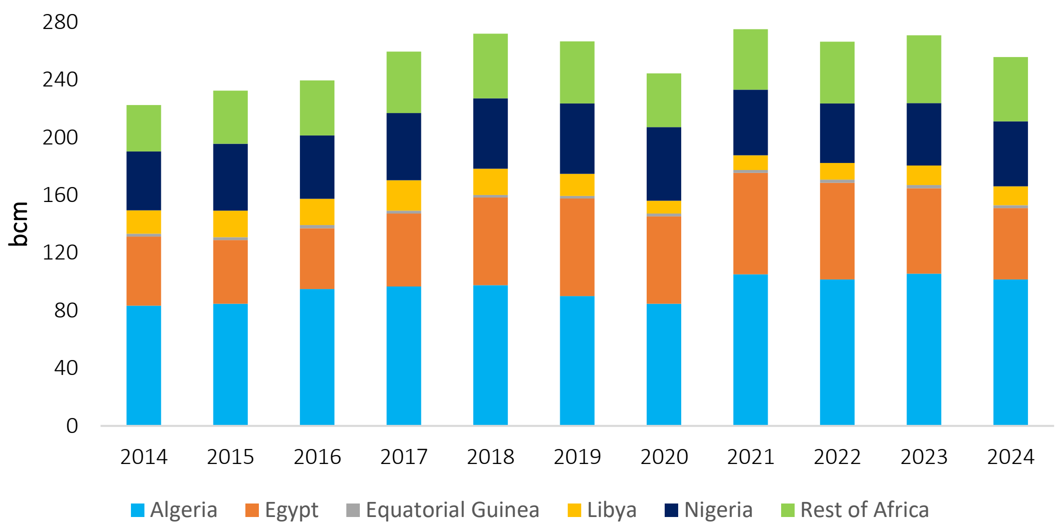
Source: GECF Secretariat based on data from Argentinian Ministry of Economy

3.1.5 Africa

Gas production is expected to experience a strong recovery in 2025

Africa's gas production experienced the largest decline among the major producing regions, falling by 5.6% to reach 255 bcm in 2024, or 6% of global gas output. This decline was primarily driven by reductions in the output of key gas producers in North Africa. However, the overall impact was somewhat mitigated by gas supply growth in some Sub-Saharan countries, including Nigeria and Mozambique (Figure 86).

Figure 86: Trend in Africa's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

Algeria, the largest gas producer in the continent, saw a decline in its marketed gas production, despite gross gas production remaining almost on par with the previous year. This reduction was primarily due to an increase in gas volumes allocated for reinjection. However, a strong recovery in Algerian gas production is expected in 2025, driven by the ramp-up in production from the Hassi Ba Hamou and Hassi Mounia fields, alongside the startup of the Ain Tsila gas field.

Angola's gas production experienced a decline after years of consistent growth, primarily driven by a reduction in associated gas from lower oil production. Despite this, the country remains a successful case study in associated gas recovery and monetisation, primarily through its LNG plant in Soyo. With a liquefaction capacity of 5.2 Mtpa, the facility is recognised as one of the world's first to be supplied only with associated gas.

Egypt witnessed a decrease in its annual gas production, primarily due to a reduction in output from the Zohr field, which accounts for 40% of the country's domestic gas production. However, the government is actively pursuing a plan to boost domestic gas supply by offering financial incentives to encourage further upstream investments. Notably, two new development wells are set to be drilled in the Zohr field in 2025, which are expected to significantly enhance its gas production and contribute to reversing the decline.

Equatorial Guinea kept its production level stable. In addition, the country introduced a series of strategic initiatives aimed at modernising its energy sector and providing a boost for its oil and gas output, through enhancing regional and cross-border gas development projects.

Libya’s gas production remained stable, with output levels closely matching those of the previous year. Looking ahead, the outlook for Libyan gas production is positive in the short-term. Development is underway for two offshore gas fields, Structures A and E, with production expected to commence in 2026 and reach a combined plateau of 8 bcma. The project also includes the construction of a Carbon Capture and Storage (CCS) facility to reduce its carbon footprint. Once operational, the project will not only boost domestic gas supply but also create opportunities for increased exports to Europe.

Nigeria, the regional leader in proven gas reserves, played a pivotal role in counterbalancing lower gas production elsewhere in Africa, with increased gas production in 2024. The increase was primarily attributed to a rise in associated gas production, which now accounts for 42% of total gas output. Notably, the government is executing an ambitious program for associated gas recovery and monetisation, through utilising this gas as feedstock for LNG export terminals. This initiative has significantly reduced Nigeria’s flaring intensity. Looking ahead, a positive outlook for Nigeria's gas production is expected in the short and medium-term, largely fuelled by substantial upstream and midstream investments from major international companies, as part of Nigeria’s "Decade of Gas" initiative.

Mauritania and Senegal reached a significant milestone in December 2024 with the commencement of gas production from the offshore Greater Tortue Ahmeyim (GTA) project. Gas from the first phase of the GTA started flowing from wells to the floating production storage and offloading (FPSO) vessel, ahead of its delivery to the 2.7 Mtpa FLNG vessel for liquefaction. LNG production is set to begin in 2025, marking the transformation of both countries into new players in the global gas market.

Mozambique’s gas production rose by 14% to reach 10.3 bcm, driven by the ongoing ramp-up in production following the country’s commencement of LNG exports in November 2022. This growth reflects the continued development of Mozambique’s LNG sector, solidifying its emerging role as an important player in the global gas market.

GECF member countries dominate Africa’s gas production, representing 92% of the continent's output. This share is expected to rise further in the short-term, driven by the production ramp-up in Mauritania and Senegal.

Looking ahead to 2025, a strong rebound in Africa's gas production is anticipated, supported by a recovery in North African output and increased gas production in Sub-Saharan Africa. Strategic investments in new projects will play a key role in unlocking the continent's vast gas resources, positioning Africa to enhance its influence in the global gas market in the years to come.

3.1.6 Middle East

Startup of new gas projects made the region a key driver of global production growth

The Middle East played a major role in global gas supply growth, with regional production rising by 5% to reach 697 bcm, expanding its global share to 17% (Figure 87). This growth was driven by gas development projects in Iran, Oman, the UAE and Saudi Arabia, which collectively added 30 bcm of new production. Looking ahead, the region is expected to remain a significant contributor to global production growth in the short to medium-term.

Iran, the region's largest gas producer, saw significant output growth, driven by the startup of several new gas projects. Notably, the Kish offshore gas field began production, with seven development wells brought online to date.

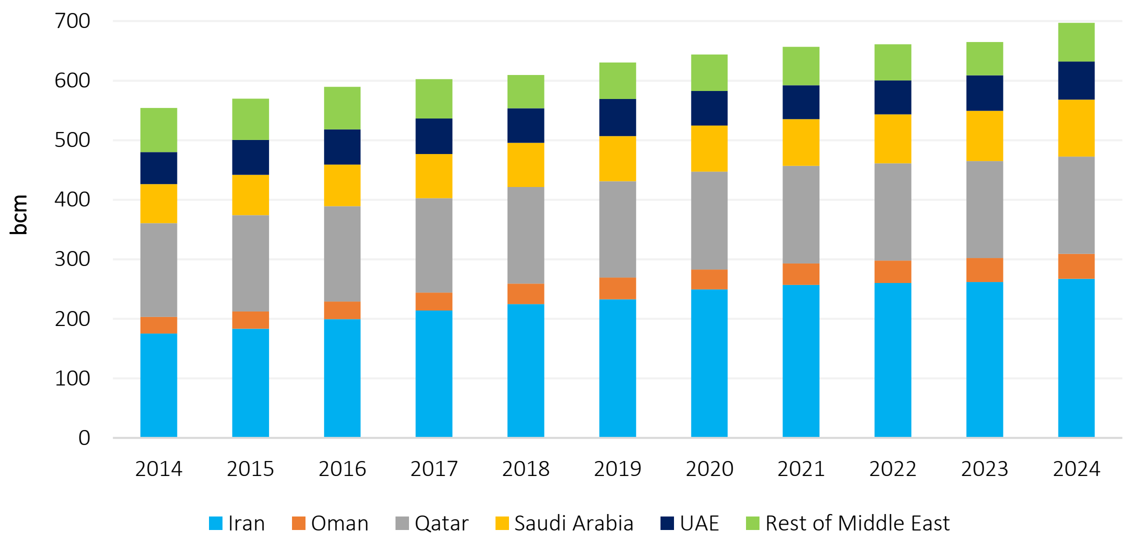
Oman witnessed a 5% increase in domestic gas production, reaching 42 bcm, with associated gas accounting for 20% of the total. The country also launched its first licensing round in nearly two years, offering three new blocks for exploration.

Qatar's gas production remained steady at 163 bcm, maintaining the same level as the previous year. The country focused on advancing the North Field expansion project, which is set to significantly boost LNG exports once operational in 2027.

Saudi Arabia's gas production grew by 11% to 96 bcm. The country is projected to increase output by 60% by 2030, driven by both conventional and unconventional resources, particularly through the development of the Jafurah and South Ghawar gas projects.

The UAE boosted its gas production by 6% to reach 64 bcm, in line with plans to expand LNG export capacities. Notably, the Shah gas expansion project, which saw a 7% growth, played a key role in driving the overall production increase.

Figure 87: Trend in the Middle East's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF's estimation

3.1.7 Eurasia

The region emerged as a key contributor to global gas production growth, led by Russia

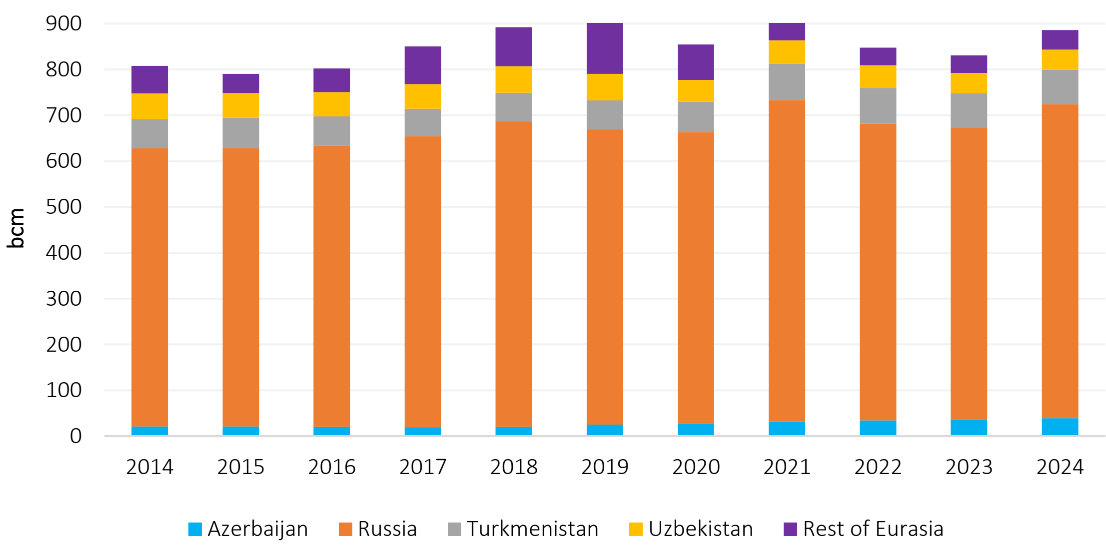
Eurasia's gas production grew by an estimated 7% to reach 887 bcm in 2024 (Figure 88). With an incremental output of 58 bcm, Eurasia became a main driver of global gas production, raising its share to 21%. Russia dominated the region, accounting for 79% of the total, followed by Turkmenistan, Uzbekistan, Azerbaijan and Kazakhstan.

Russia's gas production is estimated to have risen by 7.5% to 685 bcm, marking the highest annual growth globally. The near 50 bcm increase was primarily driven by rising domestic gas consumption, fuelled by higher demand from the electricity generation and industrial sectors, as well as expanded pipeline exports to China and the EU.

Azerbaijan's gas output grew by 8% to reach 36 bcm, driven by the ramp-up of the Absheron gas field, which contributed 1.5 bcma from its initial phase and is expected to reach 5.5 bcma upon the completion of its multi-phase development. Additionally, Azerbaijan is poised to further increase output with the development of the 112 bcm Azeri-Chirag-Deepwater Gunashli (ACG) non-associated gas field, set to begin production in 2025.

Turkmenistan's gas production fell by 1%, reaching 75.4 bcm in 2024, mainly due to challenges in the country's gas output from its mature fields. Meanwhile, Uzbekistan's gas production remained largely stable compared to 2023, as the country maintained steady output levels from its existing fields, though it faced challenges in ramping up production from new projects. Despite these fluctuations, both countries are continuing efforts to boost their gas production capacity, including development plans and enhanced infrastructure.

Figure 88: Trend in Eurasia's gas production



Source: GECF Secretariat based on data from Rystad Energy and its own estimations

3.2 Gas Production by Category

3.2.1 Associated gas production

In 2024, the landscape of global natural gas production continued to evolve. Most of the gas production remained rooted in non-associated sources, accounting for 86.7% of the total output. This dominance underscored the critical role of gas fields, specifically dedicated to gas production, in meeting global energy demands. Associated gas, which is produced in conjunction with oil, contributed 13.3% to global gas output, nearly mirroring the previous year's level (Figure 89). The associated gas uptick to 556 bcm in 2024 from 446 bcm in 2014 (a CAGR of 2.2%) suggests the growing importance of associated gas production.

Another important aspect of associated gas production stems from the environmental perspective. In the process of oil production, associated gas (gas in solution in the oil) is produced at the surface facilities, mostly as a by-product. In the event where associated gas is not recovered for use, it will be otherwise flared. Gas flaring is a serious environmental hazard that has its impact on the total carbon footprint of the upstream oil and gas industry. Notably, several countries have successfully reduced gas flaring across the value chain, while others still face challenges. These challenges include infrastructure limitations, economic barriers, technological gaps, insufficient financial incentives for gas recovery, and inadequate regulatory frameworks.

From a regional perspective, nearly half of the associated gas production in 2024 originated in North America, specifically from the US Permian basin and the Canadian Bakken shale. This is followed by the Middle East (12%), with Saudi Arabia leading in this regard, with 38 bcm of associated gas production, with the Ghawar oil field (the largest oil field in the world) being the most significant contributor. Eurasia represented 11%, primarily from Russia (Figure 90).

Figure 89: Global gas production by type

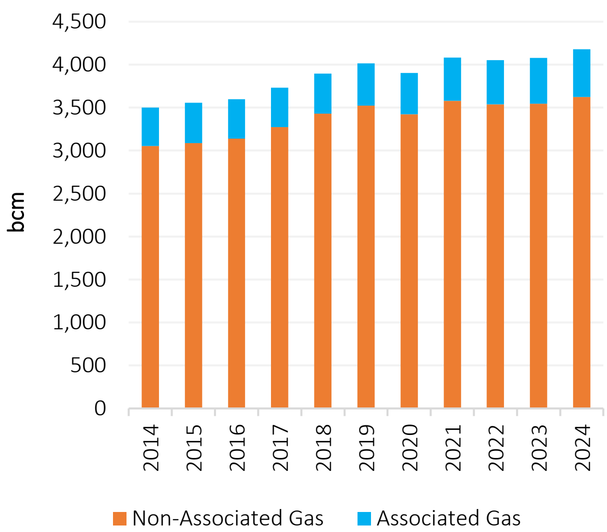
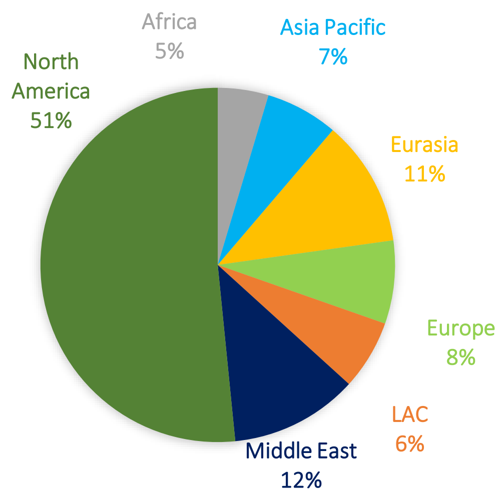


Figure 90: Associated gas output by region in 2024



Source: GECF Secretariat based on data from Rystad Energy

3.2.2 Unconventional gas production

Unconventional gas production grew by 30 bcm to reach 1,336 bcm in 2024 (Figure 91). However, its growth rate slowed to just 2% annually, a significant drop from the previous decade's average CAGR of 7.3%, when unconventional gas was a key driver of global gas production. Over the past decade, its share increased from around 19% in 2014 to around 32% in 2024, driven by technological advancements in multistage hydraulic fracturing and horizontal drilling, favourable market conditions, and rising investments in unconventional gas development.

North America dominated global unconventional gas production in 2024, holding an 84% share, driven primarily by the US shale gas revolution, with Canada contributing as well. Asia Pacific followed with 10%, largely due to China's significant growth in shale gas and CBM production, which made up 40% of its total gas output. Latin America (LAC) accounted for 3%, with Argentina's Vaca Muerta shale basin driving a significant increase in production.

Shale gas basins made up 57% of the total unconventional gas supply, with the US Lower 48 states accounting for the majority. Furthermore, associated gas from shale oil plays followed, contributing 20%, primarily driven by the US Permian basin's increased output. Additionally, tight gas production represented 11%, mainly from the Montney basin in Canada and China. Finally, coalbed methane (CBM) production contributed 6%, with Australia and China leading its growth (Figure 92).

In the short-term, unconventional gas production, particularly shale gas, is set to play a pivotal role in driving global gas supply growth. This will be fuelled by the US's recovery in shale gas output as Henry Hub prices rise, alongside Saudi Arabia launching new large-scale projects.

Figure 91: Trend in global gas production by source

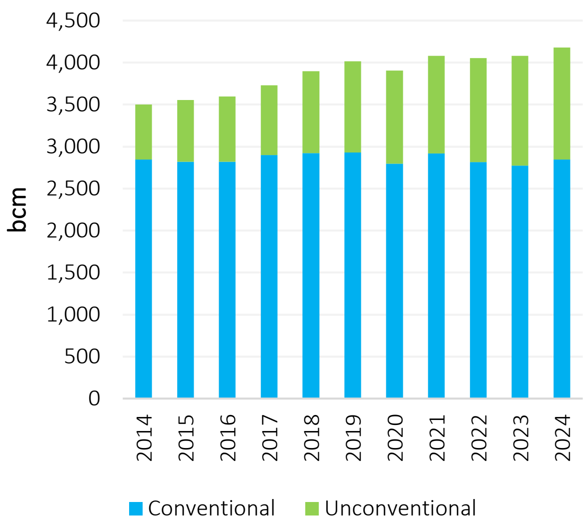
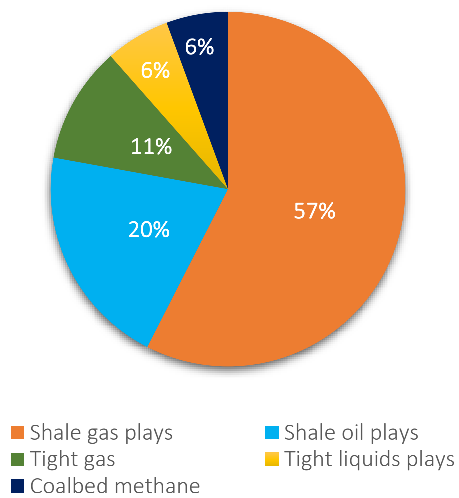


Figure 92: Unconventional gas output by type in 2024



Source: GECF Secretariat based on data from Rystad Energy

3.2.3 Offshore gas production

Offshore gas production, including continental shelf, deepwater, and ultra-deepwater, rose by 1% to reach 1,187 bcm in 2024 (Figure 93). This accounted for around 29% of global gas output, a share that has remained stable over the past decade, with increased investments in offshore gas development offsetting declines from major offshore producing regions, such as the North Sea. Meanwhile, onshore gas production, the traditional backbone of the industry, continued to play a dominant role, contributing approximately 71% of global gas production.

Regionally, the Middle East accounted for the largest share of offshore gas production, at 39%, driven mainly by Iran and Qatar (Figure 94). This represents a significant increase from a decade ago, due to the ongoing phased development of the massive South Pars gas field in Iran. Asia Pacific followed with a 26% share, fuelled by growing offshore production in Australia and China, along with contributions from historical producers like Malaysia and Indonesia. In contrast, the European share of global offshore gas supply declined to 15% in 2024, down from 25% in 2014. This drop reflects a reduction in output from key producers such as the Netherlands and the UK in the North Sea, though the decline was partially offset by increased gas production in Norway.

In the short to medium-term, offshore gas production is set to play a crucial role in driving global gas supply growth, with numerous new gas development projects expected to begin production in the coming years. Notable projects include the North Field Expansion in Qatar, the GTA project in Mauritania/Senegal, and various gas fields in Cyprus, such as Aphrodite and Cronos. According to a recent study by Energy Maritime Associates, 54 floating production, storage, and offloading (FPSO) units, with an estimated investment of 88 billion USD, are planned through 2030, with Brazil remaining the largest FPSO market.

Figure 93: Trend in global gas production by segment

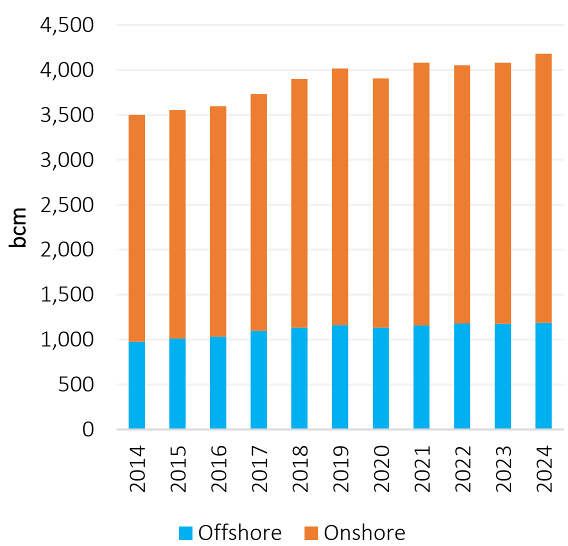
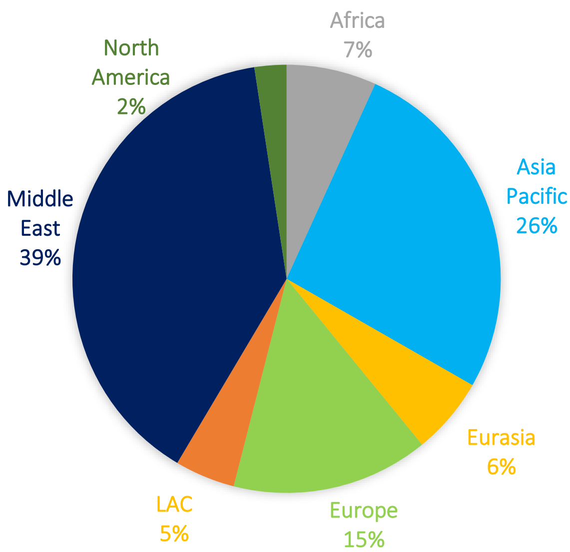


Figure 94: Offshore gas output by region in 2024



Source: GECF Secretariat based on data from Rystad Energy

3.3 Upstream Developments

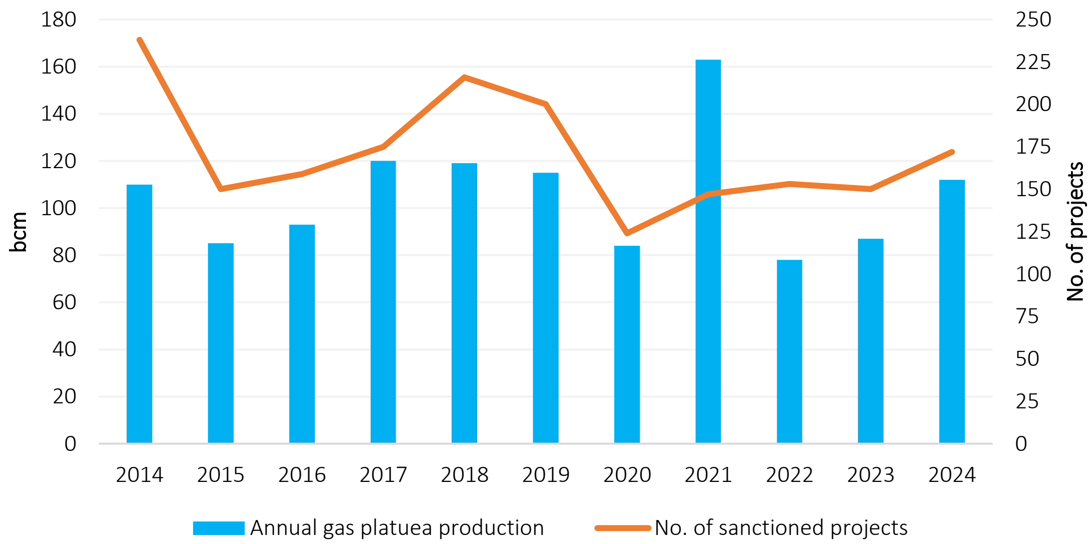
3.3.1 Development Activity

The number of commissioned and sanctioned upstream gas projects increased

A total of 130 newly commissioned gas projects began production in 2024, with an anticipated combined plateau production of 60 bcm per year, unlocking a total of 1.2 tcm of technically recoverable gas resources over their lifetimes. Regionally, Asia Pacific contributed one-third of this plateau production, driven mainly by new gas project startups in China and Malaysia. In the Middle East, Iran's South Pars Phase 16 expansion project and Iraq's associated gas recovery projects are key contributors. In Africa, notable projects include Algeria's initiatives, the Mauritania/Senegal GTA project, and Côte d'Ivoire's Baleine oil and gas field. Of the total anticipated plateau production, 15% will come from associated gas projects, while offshore gas production will account for 55%.

In addition, a total of 172 upstream gas projects reached FID in 2024. While still recovering from the low levels of 2020, this figure remains below the levels observed between 2017 and 2019. These projects are expected to achieve a combined plateau production of 112 bcm per year in the medium term (Figure 95), with the Middle East contributing nearly half of this total. Notably, Qatar's North Field Production Sustainability Offshore Compression Program (COMP 3) was the largest project to reach FID in 2024, with an allocated investment of $4 billion. The program aims to sustain and gradually increase gas production at the natural gas reservoir located off Qatar's northeast coast. Other significant regional expansion projects include in Saudi Arabia (Fadhili project) and in the UAE (Bab Gas Cap project).

Figure 95: Forecasted annual plateau gas production from projects that reached FID



Source: GECF Secretariat based on data from Rystad Energy
Note: Annual plateau production is calculated over a 10-year period from approval date

3.3.2 Exploration Activity

Discoveries rebounded from their record low in the previous year

The total volume of discovered gas and liquids reached 5.7 billion barrels of oil equivalent (boe) in 2024. Of this, natural gas represented 43% (420 bcm), while oil made up 57% (3.2 billion boe). This marked a recovery from the record low volume of 5 billion boe in 2023, when natural gas accounted for 340 bcm. However, the 2024 figures still fall short of the pre-COVID historical average (Figure 96) and reflect an absence of significant discoveries and underwhelming results from some high-impact exploration wells.

The low levels of discovered volumes also kept the cost of finding both oil and gas at elevated levels compared to historical averages. For natural gas, the marginal cost of finding gas was \$4.2/boe, or \$0.7/MMBtu (Figure 97).

Figure 96: Global oil and gas volumes discovered

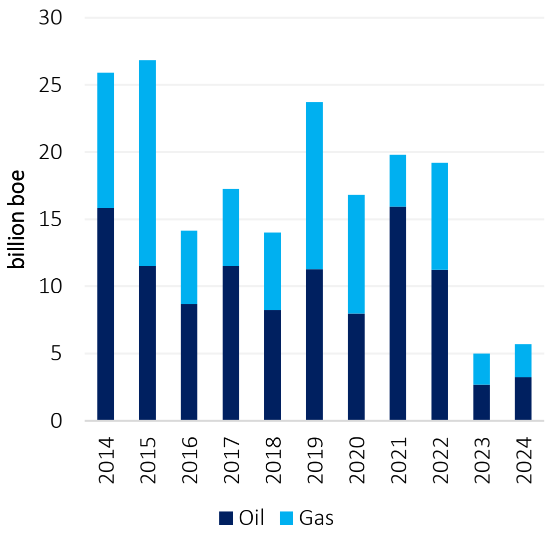
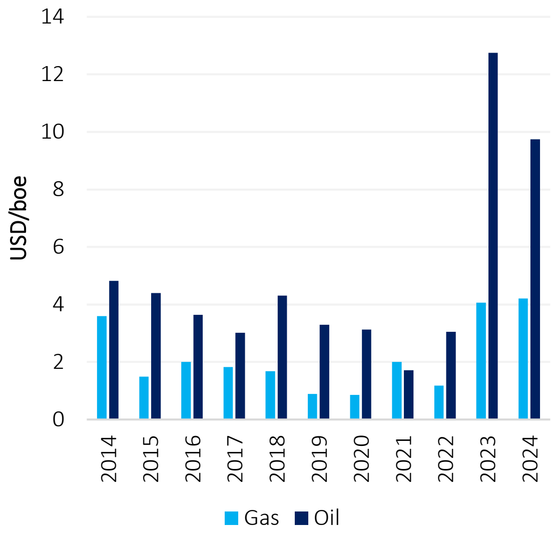


Figure 97: Gas and oil marginal cost of finding



Source: GECF Secretariat based on data from Rystad Energy

Offshore discoveries continued to dominate, accounting for 83% of total discovered volumes (4.7 billion boe). Ultra-deepwater prospects dominated offshore discoveries, accounting for half of the total, followed by deepwater prospects, which made up one-third. This reflects the growing challenges faced by global exploration activities, as high-value prospects are increasingly located in difficult offshore areas, resulting in higher exploration costs compared to onshore or continental shelf campaigns.

Africa held the largest share of discovered oil and gas volumes at 40%, driven by successful offshore exploration in Namibia and Côte d'Ivoire. Asia Pacific followed with 18%, fuelled by continued exploration success in Indonesia and China. Latin America, North America and the Middle East accounted for 14%, 13% and 7%, respectively. Notable gas discoveries included the offshore Calao field in Côte d'Ivoire, the Al-Nokhatha offshore field in Kuwait, and the Bohai Bay offshore discovery in China.

3.3.3 Gas Reserves and Resources

Low volumes of new discoveries require adequate exploration investments

Global reported proven gas reserves were estimated at 206 tcm in 2024, according to Enerdata. While conventional gas still dominates, unconventional gas has steadily increased its share to 30%, according to Rystad Energy. Shale gas and associated gas from shale oil plays represent three-quarters of unconventional reserves, followed by tight gas and associated gas from tight oil plays reserves at one-fifth, with the remainder coming from CBM. Additionally, offshore gas makes up 30% of global reserves, with two-thirds located on continental shelves and the remaining third in deep offshore areas. Moreover, associated gas reserves account for 14.5% of global gas reserves.

Regionally, the Middle East continued to lead in gas reserves, holding 39% of the global total, with Qatar, Iran and Saudi Arabia as the key contributors. Eurasia followed with 31%, driven largely by substantial reserves in Russia and Turkmenistan. North America held 9% of global reserves, primarily due to the large shale gas reserves in the US and Canada (Figure 98).

Global technically recoverable gas resources (TRR) were estimated at 658 tcm in 2024, according to Enerdata. Eurasia, North America and Asia Pacific held the largest shares, with 26%, 21% and 18%, respectively. Africa, Latin America & the Caribbean (LAC), the Middle East and Europe followed with shares of 13%, 10% and 9%, respectively. Conventional gas resources accounted for 446 tcm, while unconventional gas resources totalled 212 tcm, with shale gas being the dominant contributor. Additionally, 33% of global TRR are located in offshore geological settings, with deep-offshore prospects making up one-third of that total.

The gas reserve replacement ratio (RRR) increased to 10% in 2024, up from 8.5% in 2023. This low ratio was primarily driven by disappointing exploration results and the associated low volumes of discovered gas (Figure 99). In addition, this trend raises concerns about the ability to maintain medium to long-term supply security and underscored the need for ensuring adequate upstream investments in both exploration and development.

Figure 98: Proven gas reserves by region in 2024

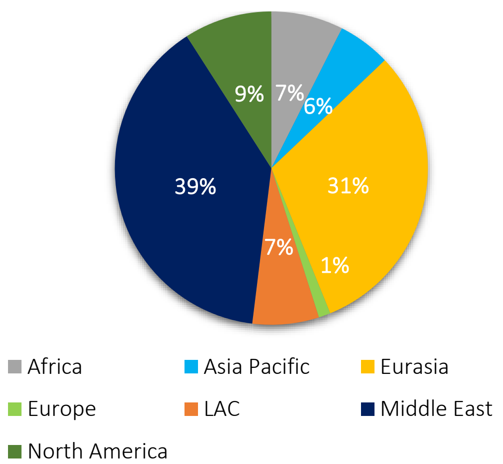
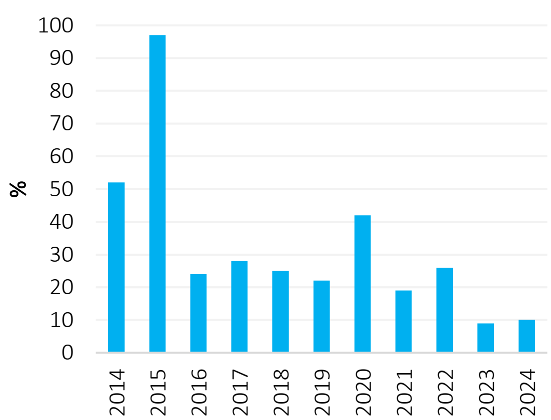


Figure 99: Gas reserve replacement ratio (RRR)



Note: RRR% is calculated as the ratio between added reserves of new discoveries over total production
Source: GECF Secretariat based on Rystad Energy, Cedigaz and Enerdata

3.3.4 Developments in Decarbonisation Projects

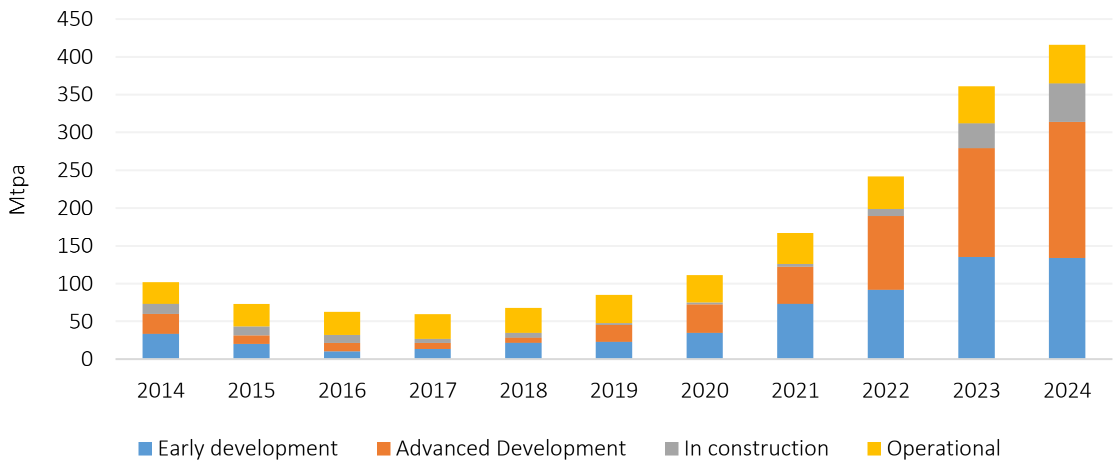
3.3.4.1 Carbon Capture, Utilisation and Storage (CCUS)

The deployment of Carbon Capture, Utilisation and Storage (CCUS) has gained significant momentum as a crucial pathway to meeting global decarbonisation targets. According to the Global Status of CCS 2024 report by the Global CCS Institute, the total number of operational, under-construction and planned CCUS facilities worldwide rose to 628 projects in 2024, with a combined capture capacity of 416 Mtpa of CO_2 (Figure 100). Notably, there were 50 operational facilities with capturing capacity of 51 Mtpa of CO_2, reflecting a 4% increase from the previous year. Additionally, 44 projects with FID already made, were under construction, which will contribute 51 Mtpa of capture capacity — a 57% increase compared to 2023. The project pipeline also included 247 in advanced development and 287 in early development, collectively accounting for 314 Mtpa in capacity.

North America continued to lead in CCUS deployment, with the US accounting for over one-third of global capacity in operational, under-construction and planned projects. This growth was driven by policy support, including the US Inflation Reduction Act (IRA) and the 45Q tax credit, which incentivised investment in CCUS infrastructure. Europe followed closely, contributing nearly a quarter of global capacity, with notable progress in the UK, Norway and the Netherlands. China also made significant strides, announcing a record number of CCUS projects supported by policy incentives. Additionally, transnational cooperation has expanded, with over 50 bilateral agreements and memorandums of understanding (MoUs) signed since 2020, fostering cross-border CCUS initiatives that involve capturing CO_2 in one country and transporting and storing it in another.

The growth in CCUS adoption highlights its increasingly vital role in global decarbonisation and climate mitigation efforts. As countries strengthen regulatory frameworks, offer financial incentives, and advance technologies, CCUS is poised to become a key enabler of decarbonisation across upstream, midstream, and downstream sectors.

Figure 100: Global capacity of operational, under construction and planned CCUS projects



Source: GECF Secretariat based on data from Global CCS Institute 2024 Status Report

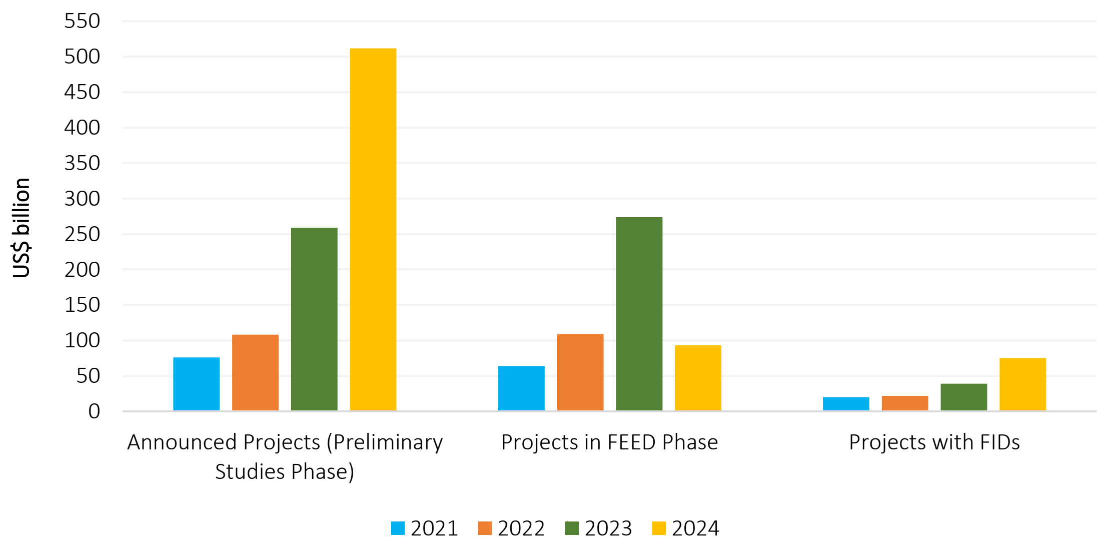
3.3.4.2 Hydrogen

The hydrogen sector has seen rapid growth over the past four years, driven by rising investment and project commitments worldwide. According to the Hydrogen Insights 2024 report by the Hydrogen Council, the number of clean hydrogen projects, including blue hydrogen, has surged to 1,572, marking a sevenfold increase since 2020. Investments in hydrogen projects have also surged to $680 billion, with $75 billion allocated to projects that have already reached FID. This represents a 90% increase compared to the previous report, reflecting growing confidence in hydrogen as a crucial energy carrier for the transition to a low-carbon economy (Figure 101).

Low-carbon hydrogen, including blue hydrogen, saw a notable expansion in production capacity. Announced production volumes have reached 48 Mtpa through 2030, with 75% coming from renewable sources and 25% from blue hydrogen. North America has emerged as the dominant force in blue hydrogen, accounting for 90% of committed capacity, while Europe, China and Latin America lead the way in renewable hydrogen investments. Giga-scale projects represent two-thirds of all announced capacity, signaling a shift toward large-scale hydrogen deployment.

Hydrogen refueling stations have surpassed 1,150 globally, with China, Japan, and South Korea leading deployment, while growth in Europe and North America has slowed. Investments in hydrogen end-use applications, particularly in steelmaking, chemicals, and mobility, have also risen. However, despite significant progress, achieving climate goals necessitates an eightfold increase in investment by 2030, especially in hydrogen transportation and storage infrastructure. Regulatory clarity, stronger policy support, and infrastructure development will be essential to scaling up hydrogen deployment and ensuring its pivotal role in global decarbonisation efforts.

Figure 101: Investment in hydrogen projects



Source: GECF Secretariat based on data from Hydrogen Council 2024 Report

3.3.4.3 GHG Emissions Reduction

Global advocacy for GHG emissions reduction continues to gain momentum, with CO_2 emissions being a primary driver of climate change, and as such, their reduction remains central to addressing this environmental challenge. Global energy-related greenhouse gas (GHG) emissions are estimated to have reached 41.5 Gt CO_2-equivalent in 2024, with CO_2 accounting for 90%, methane-related emissions representing 9%, and the remaining 1% attributed to other GHGs.

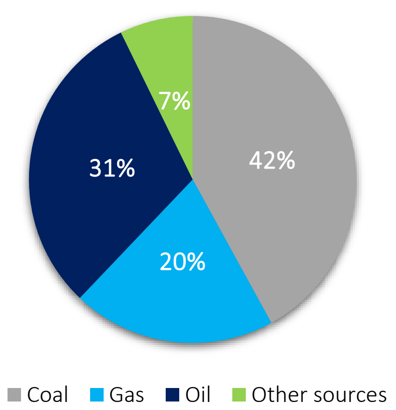
Energy-related CO_2 emissions are estimated to have reached a new record high of 37.4 Gt in 2024. Natural gas was the cleanest hydrocarbon fuel in terms of its contribution to total energy-related emissions, accounting for 20% (7.5 Gt). Meanwhile, coal remained the largest contributor, responsible for 42% (15.7 Gt) of energy-related CO_2 emissions, followed by oil, which accounted for 31% (11.5 Gt) (Figure 102).

Likewise, energy-related methane emissions are estimated to have reached 128 Mt in 2024. Oil was the largest source of methane emissions, accounting for 39% (50 Mt), followed by coal at 31% (40 Mt). Natural gas contributed the least, with 23% (29 Mt) of methane emissions (Figure 103). Venting, leaks and flaring were the primary causes of methane emissions in oil and gas operations. The US was the largest emitter of methane from oil and gas operations, while China was the highest emitter in the coal sector.

These emission levels highlight the significant role natural gas can play in the energy mix from an environmental perspective. As the cleanest hydrocarbon fuel compared to oil and coal, natural gas offers environmental advantages. In this context, there is significant potential to reduce emissions through the broader adoption of coal-to-gas and oil-to-gas switching policies.

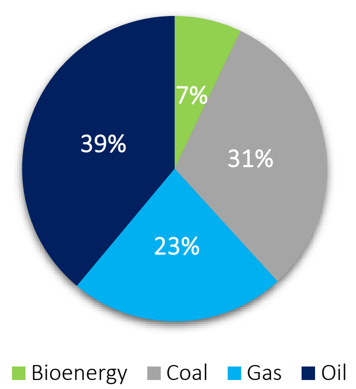
Meanwhile, the global gas industry is intensifying efforts to reduce its carbon footprint by increasingly adopting decarbonisation technologies, such as the electrification of upstream and midstream gas operations, flared gas recovery, fugitive emission detection and repair, as well as CCS/CCUS.

Figure 102: Energy-related CO_2 emissions in 2024



Source: GECF Secretariat based on data from Global Carbon Budget 2024 report

Figure 103: Energy-related methane emissions in 2024



Source: GECF Secretariat based on the IEA Global Methane Tracker 2024

3.3.5 Upstream Investment in the Oil and Gas Industry

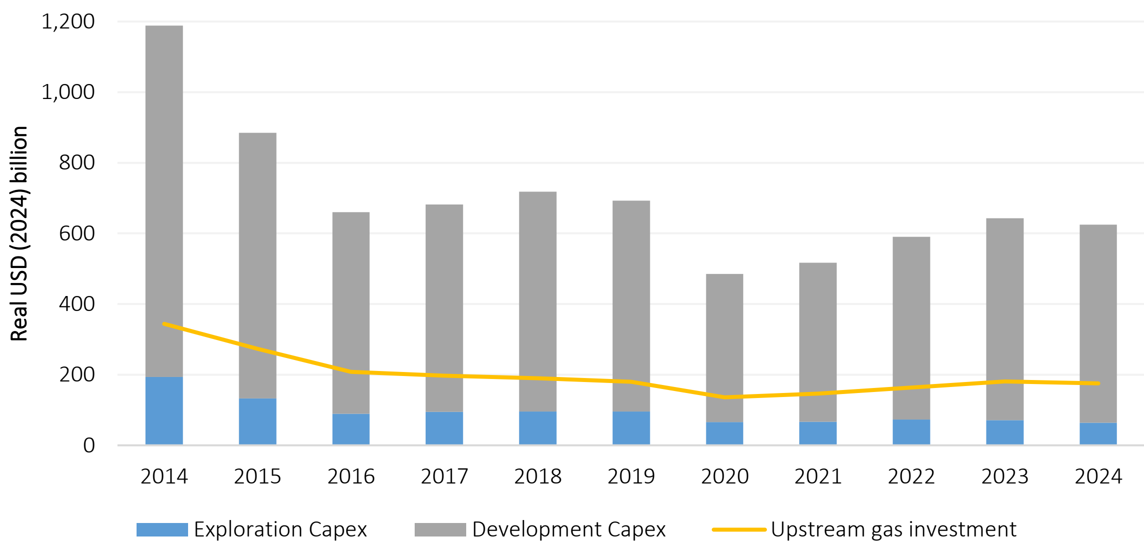
Upstream investment saw a slight decline amid energy policy uncertainties

Upstream oil and gas investment in 2024 was estimated at $625 billion (in real terms), marking a 2.5% decline (Figure 104). This decrease was driven by uncertainties surrounding energy policies, tight financial conditions and rising geopolitical tensions. However, despite these challenges, investment levels remained the second-highest since the COVID-19 pandemic, supported by easing inflation and a resilient energy price environment. In nominal terms, upstream investment remained relatively stable compared to the previous year, underscoring the impact of inflation on real spending. Of the total investment, 90% was allocated to development CAPEX, particularly for production and processing facilities, well drilling and completion, while exploration CAPEX accounted for the remaining 10%, totalling approximately $64 billion. Furthermore, upstream gas investment remained steady at $175 billion.

North America led global upstream oil and gas investment, accounting for 35% of total spending at $220 billion. This dominant position was driven by sustained activity in shale production. Asia Pacific followed in second place, capturing 18% of global investment with $114 billion in spending. The Middle East ranked third, securing 17% of total investment at $107 billion, while also recording the highest annual growth rate among all regions. The surge in spending was largely fuelled by national oil companies' expansion strategies, new field developments, and enhanced recovery projects aimed at boosting long-term production capacity. Meanwhile, other regions — including Africa, Europe, Eurasia and South America — each accounted for less than 10% of total upstream investment.

Looking ahead, gas investment is expected to recover in 2025, driven by major gas projects in Qatar and Saudi Arabia, favourable monetary policies, and strong gas prices.

Figure 104: Upstream oil and gas investment



Source: GECF Secretariat based on data from Rystad Energy

CHAPTER

04

GAS TRADE

Global gas trade rebounded, with Asia gaining market share from Europe

Global gas trade is estimated to have risen by 4% to reach 1.17 tcm in 2024, fuelled by growth in both pipeline gas and LNG segments. This marks a recovery to 2022 levels, although still below the record high seen in 2021 (Table 3). The global imports-to-consumption ratio stood at 28%, still 2% below the 2021 level, highlighting ongoing supply imbalances in certain regions and escalating competition for available imports. This situation keeps prices elevated, raising energy security concerns and threatening market stability.

Table 3: Global gas trade

Year	2019	2020	2021	2022	2023	2024
Pipeline gas trade (bcm)	686	644	697	624	572	606
LNG trade (bcm)	481	487	514	541	553	559
Total gas trade (bcm)	1,167	1,131	1,211	1,165	1,125	1,165
Gas consumption (bcm)	3,970	3,857	4,047	4,062	4,070	4,170
Imports-to-consumption ratio	29%	29%	30%	29%	28%	28%

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

In Europe, total gas imports fell by 5% to 359 bcm, with a rebound in pipeline gas imports only partially mitigating the drop in LNG supply (Figure 105). In Asia, total gas imports increased by 8% to 470 bcm, reinforcing its position as the leading gas-importing region (Figure 106).

Figure 105: Gas imports in Europe

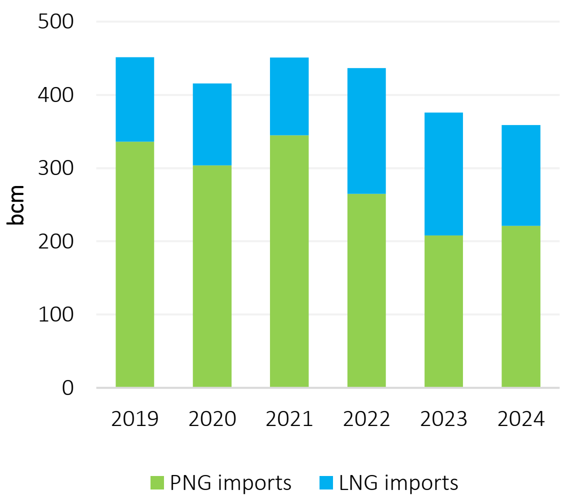
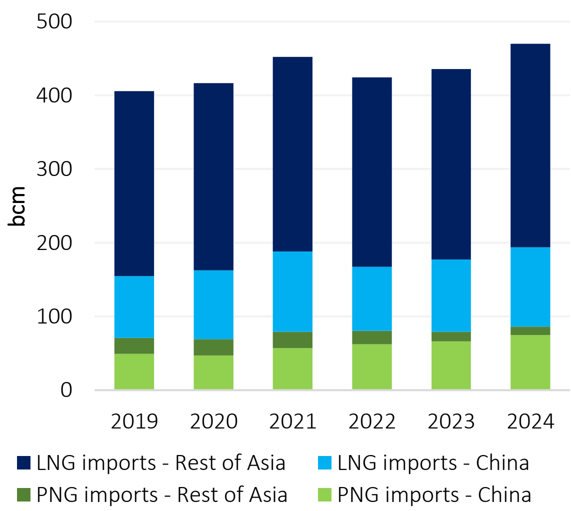


Figure 106: Gas imports in Asia



Source: GECF Secretariat based on data from GACC, ICIS, JODI Gas, and LSEG

4.1 Pipeline Gas Trade

Global pipeline gas trade returned to growth, after two consecutive years of decline

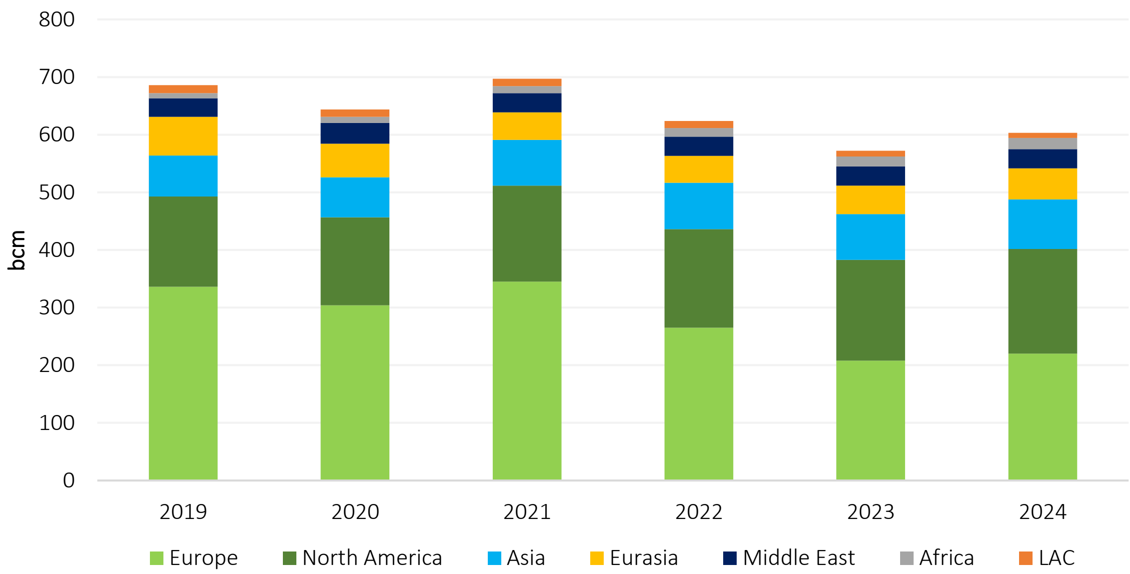
Global pipeline gas imports are estimated to have increased by 5% to reach 606 bcm in 2024 (Figure 107). The methodology considers flows of gas via export pipelines to final destinations, while disregarding flows of regasified LNG, transit pipeline flows and pipeline gas re-exports.

On the import side, despite recent shifts in pipeline gas trade, Europe remained the largest importing region, accounting for 36% of global imports, with a 13 bcm increase fuelled by higher flows from Russia and Norway. Imports by North American countries follow, representing 30% of global imports, driven by an 8 bcm rise primarily due to increased US-to-Mexico flows. Meanwhile, Asia accounted for 14% of global pipeline gas imports, with a 7 bcm increase, largely driven by expanded supply from Russia to China.

On the export side, countries in Eurasia and North America continued to dominate global pipeline gas exports, accounting for 33% and 30% of total flows, respectively, while Europe contributed 18%. These three regions were the only ones to show export growth compared to 2023 levels. The leading exporting countries in 2024 included Russia, Norway, the US, Canada and Turkmenistan.

The export trends highlight a high reliance on GECF countries to meet the rising global demand for natural gas, further solidifying their critical role as key players in the global energy market and reinforcing their influence in shaping energy trade dynamics.

Figure 107: Global pipeline gas imports by region



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

In 2025, global pipeline gas trade is likely to experience modest growth, driven by rising flows to China, primarily from Russia, and increased exports from Argentina to neighbouring countries.

4.1.1 Europe

Pipeline gas imports saw a slight rebound, supported by long-term contracts

Europe continued to be the world's largest pipeline gas importing region, accounting for 36% of global flows, with the EU, Türkiye and the UK serving as key market players. The EU, the dominant market in the region, imports gas from five main suppliers: Algeria, Azerbaijan, Libya, Norway and Russia. Additionally, the European mainland and the UK are linked by two bidirectional interconnector pipelines, allowing for the flexible flow of regasified LNG between the regions by pipeline and ensuring supply stability amidst fluctuating market conditions.

After two consecutive years of decline, the EU increased its pipeline gas imports by 3% to 157 bcm in 2024 (Figure 108), despite a decrease in overall gas import, which was reflected in a significant drop in LNG imports. The higher EU gas imports by pipeline were largely driven by long-term contractual obligations. These contracts, often spanning multiple years or decades, typically include fixed supply volumes, ensuring both buyers and suppliers benefit from greater security and predictability in the supply chain. This stability has helped maintain EU pipeline gas flows even amid fluctuations in broader market conditions and demand.

The positive drivers for the 5 bcm increase in pipeline gas imports were an additional 3 bcm supplied by Russia, with a further increase in flows of 2.5 bcm from Norway and 1 bcm from Azerbaijan (Figure 109). This growth stands in sharp contrast to the significant annual declines of 71 bcm and 49 bcm in 2022 and 2023, respectively, highlighting the recovery in pipeline gas imports following two consecutive years of reduced supply.

As in the previous year, Norway retained its position as the largest supplier, making up 53% of the region's pipeline gas imports, with Russia and Algeria each contributing around one-fifth.

Figure 108: EU pipeline gas imports by supplier

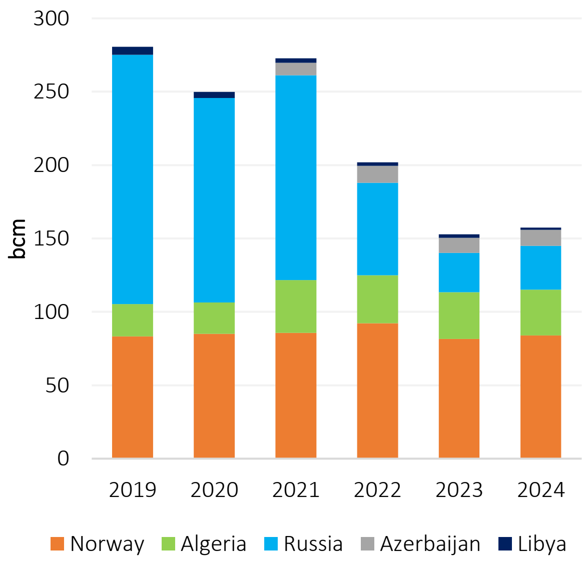
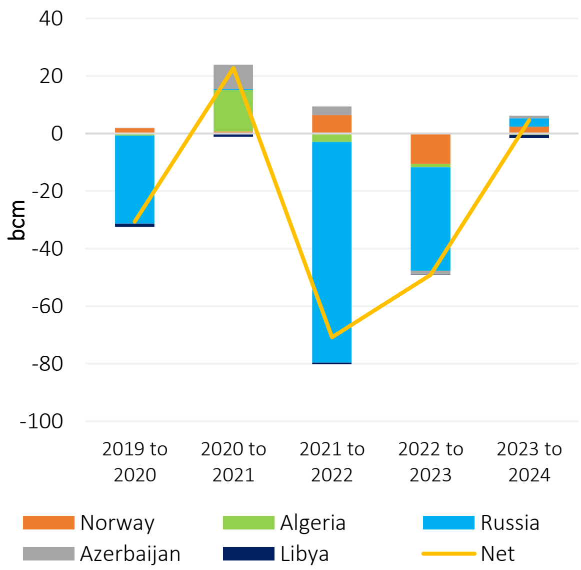


Figure 109: Variance in EU pipeline gas imports



Source: GECF Secretariat based on data from LSEG

Pipeline gas enters the region's transmission grid through multiple supply routes (Figure 110). In 2024, Norway increased its exports across five of its routes, except to Germany, where exports fell by 4% due to gas being redirected to Poland. Despite this shift, Germany still received 36% of Norway's exports to the EU, while France and Belgium boosted their pipeline gas imports by 15% and 7%, respectively, to compensate for a decline in LNG imports.

Russia increased pipeline gas exports to the region across both of its supply routes, with each route carrying a comparable volume of gas. Notably, there was a 24% rise in flows through the Turkstream pipeline, which enters southern Europe via Türkiye, while imports via the pipelines transiting gas through Ukraine to central Europe grew by 16%.

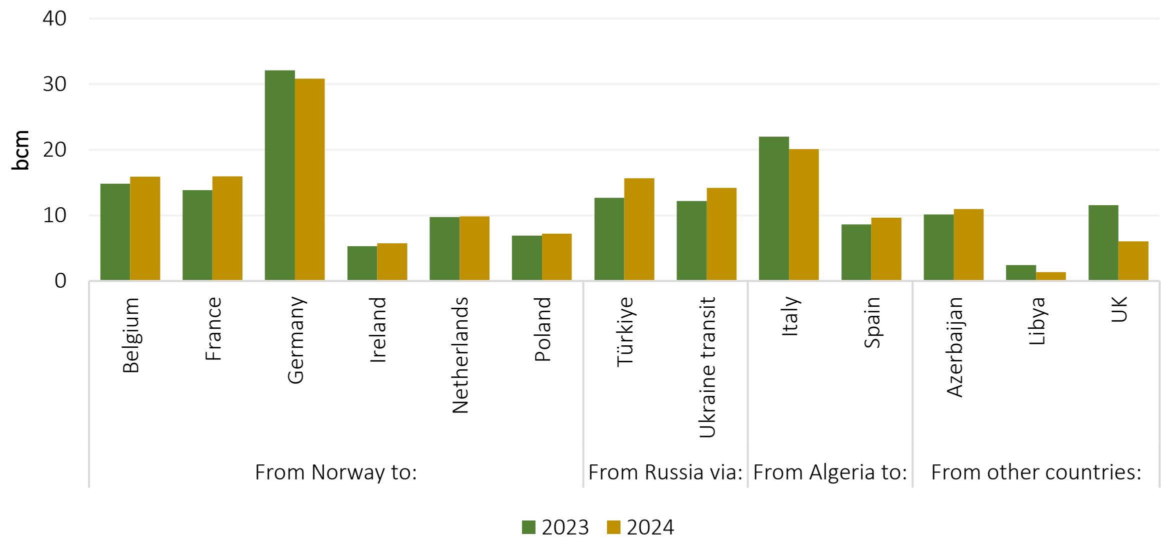
Algeria kept its exports stable, though there was a redistribution of supply. Exports to Italy decreased by 9%, while flows to Spain rose by 12%. Consequently, Spain accounted for 32% of Algeria pipeline gas exports to the EU, reflecting a shift in regional demand across Europe.

Azerbaijan boosted its pipeline gas exports by 8%, aligning with the country's strategic goal to increase its gas supply to the region, reflecting its growing role in the global energy market. Furthermore, exports from Libya decreased to 1.3 bcm.

In addition, the EU showed a significant decline in gas supply reliance on the interconnector pipelines between Europe and the UK. Flows of regasified LNG from the UK to the EU totalled 6 bcm, marking a 48% drop from the previous year. While these interconnectors were essential in supplying nearly 20 bcm to the EU in 2022, the current trend reflects a continued rebalancing in the region, as many EU countries are now sufficiently supplied by LNG imports.

In 2025, the EU is likely to see modest increases in imports, driven by fewer supply outages, as well as a slight boost in gas flows via the Turkstream pipeline and the Southern Gas Corridor.

Figure 110: EU pipeline gas imports by supply route



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

Increased supply from Russia boosted pipeline gas imports in China

The Asian region ranks as the third-largest importer of pipeline gas, accounting for 14% of global imports. The growth in imports is driven by the increasing energy needs of rapidly developing economies, particularly in China, which has seen significant increases in pipeline gas imports over the past few years.

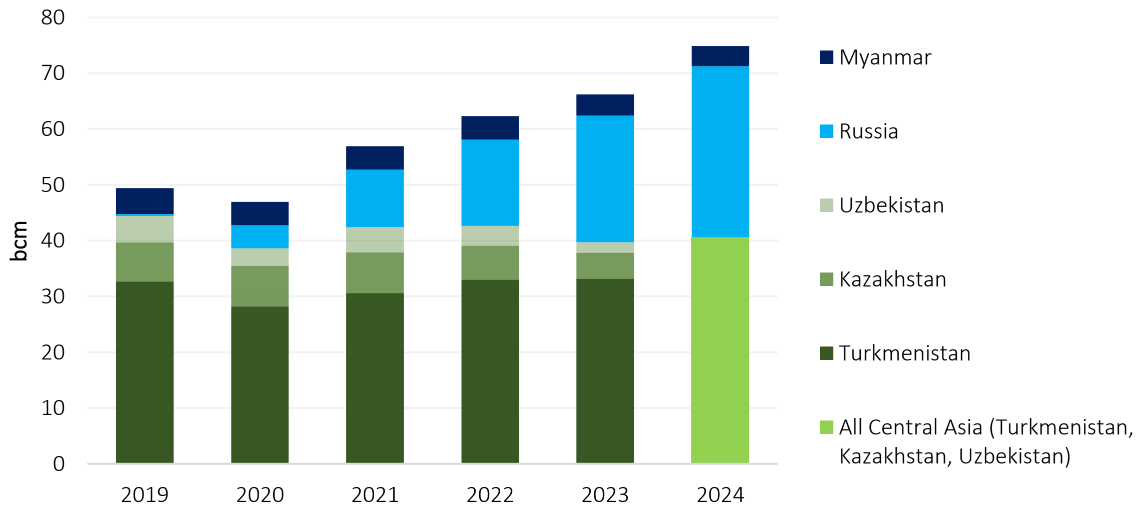
In 2024, China, the dominant player in the region, increased its imports by 13% to 75 bcm (Figure 111). This growth stands in contrast to previous years, when COVID-19 lockdowns and extended periods of reduced economic activity slowed import growth to just 9% in 2022 and 6% in 2023.

China imports pipeline gas from five key suppliers: Kazakhstan, Myanmar, Russia, Turkmenistan and Uzbekistan. The growth in China's pipeline gas imports has been largely driven by the launch of Russia's Power of Siberia (POS) pipeline, which began operations in December 2019, with a phased ramp-up planned for the subsequent years. Originally slated to reach full capacity by January 2025, POS achieved this milestone one month ahead of schedule, in December 2024. In 2024, Russia delivered 31 bcm to China, marking a 35% increase and accounting for two-fifths of the country's total pipeline gas supply.

More than half of China's pipeline gas imports are sourced from Central Asian countries, with Turkmenistan being the dominant supplier, providing over 30 bcm annually. However, in recent years, Kazakhstan and Uzbekistan have shifted their focus toward meeting domestic demand, particularly during the winter months, which has resulted in reduced gas exports to China.

Imports from Myanmar have remained stable, consistently at around 4 bcm per year. This stability reflects the ongoing reliable flow of gas, ensuring a steady supply particularly for regions in the south of China, despite fluctuations in other sources.

Figure 111: Pipeline gas imports to China by supplier



Source: GECF Secretariat based on data from Cedigaz and GACC

In the short-term, China is set to maintain its upward trajectory in pipeline gas imports, driven by its growing energy demands, particularly for natural gas. With the POS pipeline now operating at full capacity, Russia's supply to China is projected to increase by 24%, reaching 38 bcm. Furthermore, Russia plans to enhance its gas exports through the Far East Route, which involves extending the Sakhalin-Khabarovsk-Vladivostok pipeline to connect with the Chinese grid via the Hulin-Changchun pipeline in Jilin province. This expansion is scheduled to begin operations in 2027, with an expected capacity of 10 bcm per year.

Turkmenistan is also exploring the expansion of pipeline gas exports to China. Currently, the two countries are linked by the Central Asia - China Gas Pipeline (Lines A, B and C), with a combined capacity of 55 bcma. The proposed Line D could add 30 bcma of capacity, however, the project has faced several delays. Meanwhile, the reduced pipeline gas exports from Kazakhstan and Uzbekistan could impact China's ability to further increase its pipeline gas imports.

Elsewhere, Singapore decreased its pipeline gas imports by 6% to 6.1 bcm (Figure 112), with supply from Indonesia dropping, and imports from Malaysia remaining stable. The monthly import rate has levelled off at around 0.5 bcm per month since Q4 2023, as pipeline gas imports have increasingly been replaced by LNG imports during this period.

Thailand reduced its pipeline gas imports by 8% to 5.3 bcm, marking the second consecutive year of decline after three years of steady imports (Figure 113). This decrease was driven by falling gas production and consequently lower pipeline gas exports from Myanmar, its sole supplier, prompting Thailand to increase its LNG imports to compensate.

Due to the underlying drivers, both Singapore and Thailand may continue the downward trend for pipeline gas imports in 2025.

Figure 112: Pipeline gas imports to Singapore

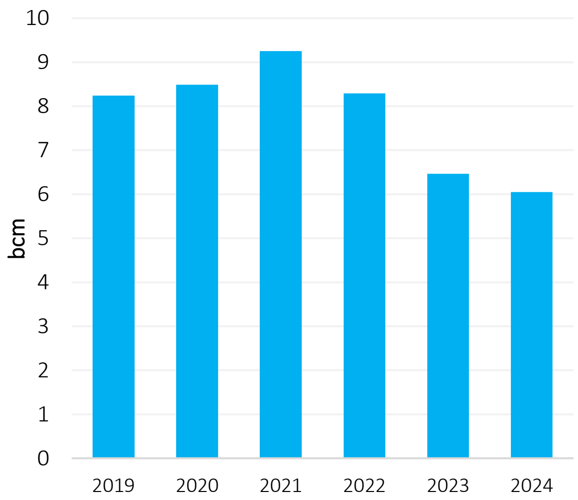
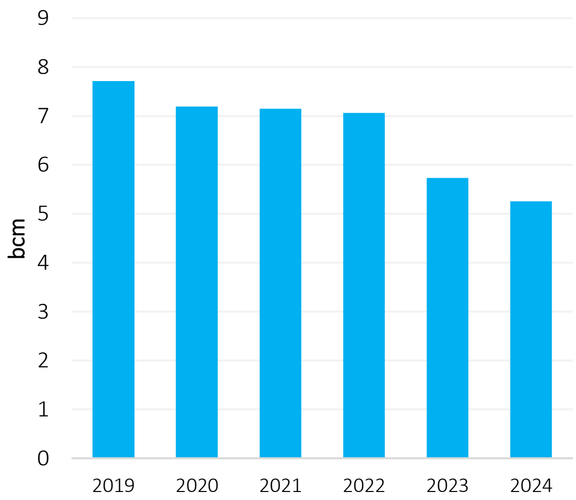


Figure 113: Pipeline gas imports to Thailand



Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

Pipeline gas trade growth was fuelled by US imports from Canada and its exports to Mexico

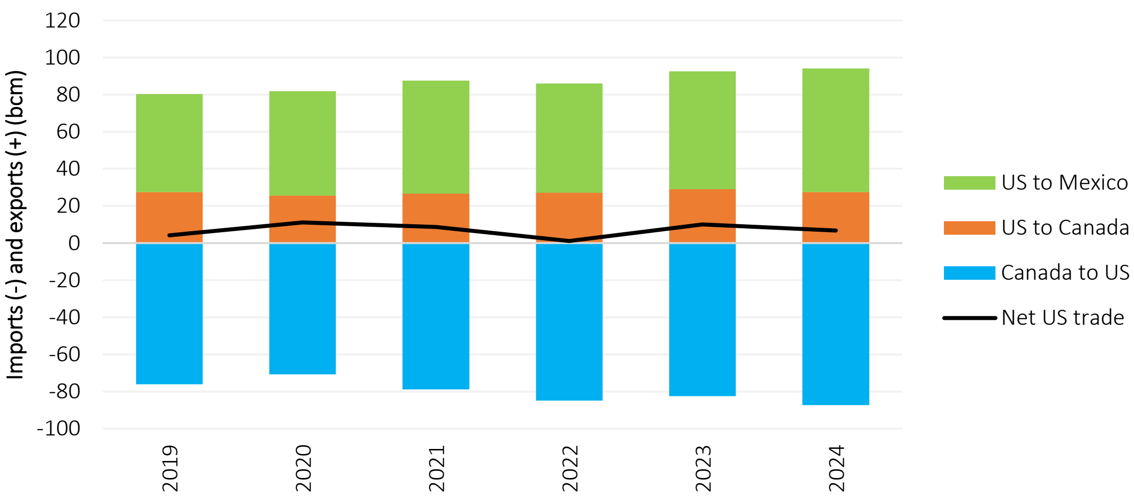
North America operates as a self-contained region for pipeline gas trade, with the three constituent countries — Canada, Mexico, and the US — engaged in mutual exports and imports. The US exports pipeline gas to both Mexico and Canada, while Canada also supplies gas to the US, particularly to regions within the northwestern and midwestern states. Over recent years, total pipeline gas flows within the region have been increasing, with the US consistently maintaining its position as a net exporter of pipeline gas (Figure 114).

In 2024, the US exported 94 bcm of pipeline gas, marking a 2% increase. Exports to Mexico grew by 5%, reaching 67 bcm, driven by increasing domestic demand and the expansion of LNG exports from Mexico's sole operational terminal. Conversely, after a strong trade year in 2023, US pipeline gas exports to Canada declined by 6%, totalling 27 bcm in 2024. Despite this decline, both nations continue to heavily depend on cross-border pipelines to ensure energy supply security and meet their respective energy demands.

Canada reinforced its position as one of the world's leading natural gas producers, with its pipeline gas exports to the US becoming the largest supply route at the country level globally. In 2024, Canada exported a total of 87 bcm, reflecting a 6% increase in gas supply to the US. This increase was largely driven by growing demand in the US, as well as Canada's strategic role in meeting the energy needs of its neighbour through both established and expanding pipeline infrastructure. With abundant natural gas reserves, Canada remains a key player in the global energy market, bolstering energy security for the North American region.

In 2025, the regional pipeline gas trade may be shaped by the potential impact of proposed tariffs on Canadian gas exports to the US. Additional factors influencing the trade include the volume of Mexican LNG exports, which may drive higher pipeline gas imports from the US, as well as the start of Canadian LNG exports, which could reduce its pipeline gas exports to the US.

Figure 114: Net pipeline gas trade in the US



Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

Pipeline gas trade declined, despite Argentina's efforts to expand its export capabilities

LAC (Latin America and the Caribbean) represents the smallest region for pipeline gas trade, making up only 1.5% of the global total in 2024. This market is primarily self-contained, with exports flowing from Bolivia to Argentina and Brazil, and from Argentina to Chile. Notably, LAC was the only region to experience a decline in pipeline gas trade in 2024, with total flows within the region dropping by 15% to reach 9 bcm. This decrease highlights challenges within the region, including shifts in demand and supply constraints.

Bolivia, the largest player in the region, exported 6.5 bcm of pipeline gas in 2024, a 19% decrease compared to the previous year (Figure 115). In particular, its exports to Brazil dropped by 13% to 4.9 bcm and exports to Argentina fell by 35% to 1.6 bcm, reflecting shifts in supply and demand dynamics within the region.

Argentina exported 2.3 bcm of pipeline gas to Chile, marking a 3% increase (Figure 116). Argentina is positioning itself to become a major exporter of both pipeline gas and LNG, driven by the abundant reserves of the Vaca Muerta formation. The country has reduced its gas imports from Bolivia in recent years and fully ended the contract in September 2024. Argentina also commissioned the Perito Francisco Pascacio Moreno Pipeline in 2023 to transport gas from Vaca Muerta to the Buenos Aires province, and completed the reversal of the Northern Gas Pipeline in 2024, both crucial for its export ambitions. Furthermore, Bolivia has updated its regulations to permit the transit of Argentine gas to Brazilian customers, with Argentina securing several contracts with Brazil in the second half of 2024.

In 2025, the outlook for pipeline gas trade in Latin America and the Caribbean (LAC) may depend on a redistribution of flows within the region. Additionally, there may be significant advancements in the project to export Venezuelan gas via pipeline to Trinidad and Tobago, potentially reshaping trade dynamics in the area.

Figure 115: Pipeline gas exports from Bolivia

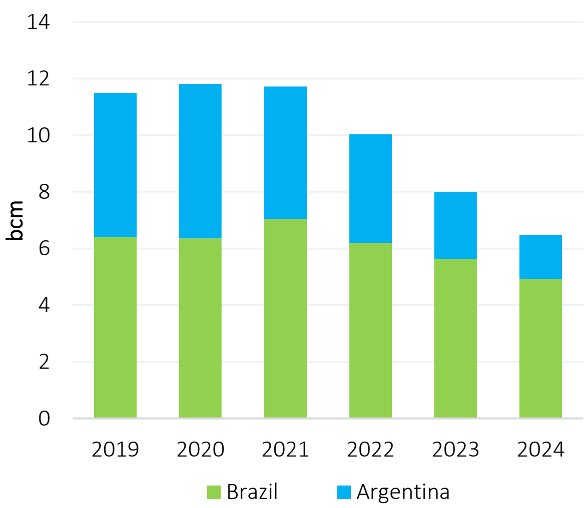
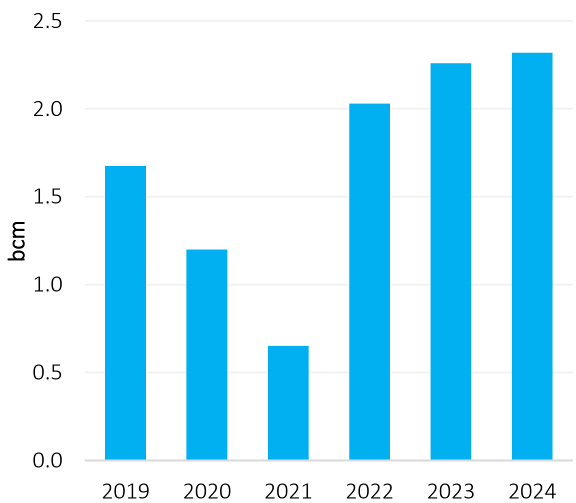


Figure 116: Pipeline gas exports from Argentina



Source: GECF Secretariat based on data from JODI Gas

4.2 Liquefied Natural Gas (LNG) Trade

4.2.1 LNG Supply

4.2.1.1 Global LNG Exports

Global LNG exports reached a record high, but the pace of growth slowed significantly

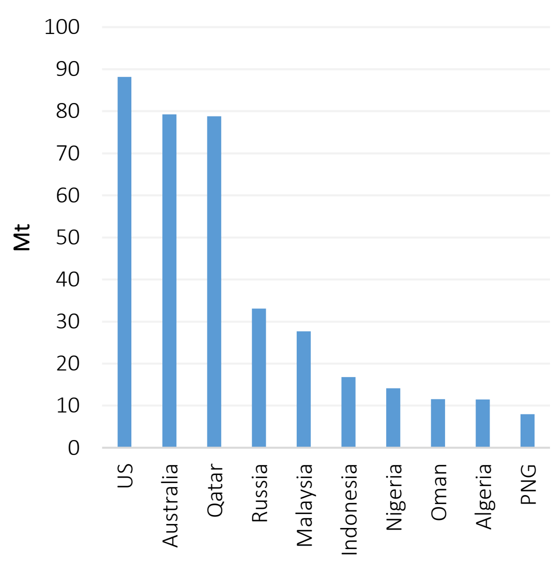
In this report, LNG exports refer to the volumes delivered to importing countries, excluding deliveries via ISO containers, trucks and rail. The export volumes also do not represent the exact volumes loaded at LNG export facilities as the reported LNG volumes exclude boil-off gas and losses incurred during unloading, shipping, and offloading. Global LNG exports encompass both exports from LNG-producing countries and LNG re-exports.

In 2024, global LNG exports increased by 0.9% (3.8 Mt), reaching a record high of 412 Mt (Figure 117). This growth was fuelled by the commissioning and ramp-up of new liquefaction projects, reduced maintenance activity at various facilities, and improved feedgas availability in certain countries. However, it marked the slowest annual growth rate since 2020, when the COVID-19 pandemic disrupted global LNG trade, leading to a modest 0.8% increase.

The increase in LNG exports was supported by higher shipments from both GECF and non-GECF countries, which offset a decline in LNG re-exports. Non-GECF countries remained the largest LNG exporters, accounting for 52% of global LNG exports, followed by GECF Member Countries with 47%, while LNG re-exports made up 1%. At a country level, the US remained the world's largest LNG exporter with 88 Mt, followed by Australia (79 Mt), Qatar (79 Mt), Russia (33 Mt) and Malaysia (28 Mt) (Figure 118).

Figure 117: Trend in global LNG exports by supplier

Figure 118: Top 10 LNG exporting countries in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1.1 GECF LNG Exports

In 2024, LNG exports from GECF Member Countries increased by a modest 0.6% (1.1 Mt) to reach 193 Mt, reversing the decline recorded in 2023. The leading exporters within the GECF were Qatar, Russia, Malaysia, Nigeria and Algeria (Figure 119).

The overall growth in exports was propelled by increased supply from Russia, Malaysia, Nigeria, Mozambique, and the UAE (Figure 120). Russia saw a boost in LNG shipments, aided by reduced maintenance at the Portovaya and Yamal LNG facilities. Improved feedgas availability contributed to higher LNG exports from Malaysia and Nigeria, with reduced maintenance activity at the NLNG facility further boosting Nigeria's growth. In Mozambique, the ongoing ramp-up of production at the Coral South FLNG facility drove a rise in exports. In the UAE, the increase was driven by higher production, supported by a reduction in unplanned outages.

Figure 119: GECF LNG exports by country in 2024

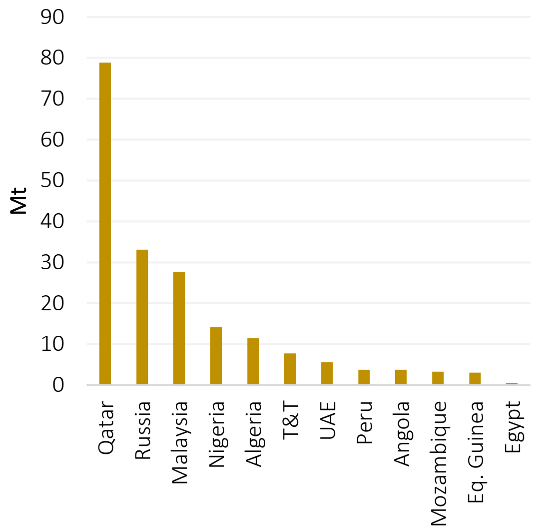
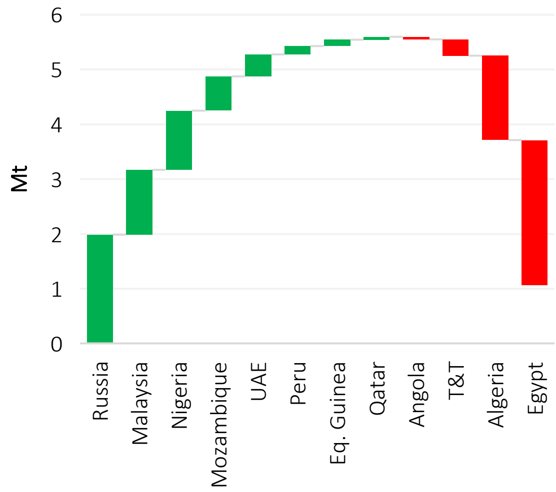


Figure 120: Variation in GECF LNG exports by country in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1.2 Non-GECF LNG Exports

In 2024, non-GECF LNG exports continued to grow, rising by 2.1% (4.5 Mt) to a record high of 216 Mt. However, this marked a slowdown from the 6.0% growth in 2023 and was the smallest annual increase since 2014. The US and Australia remained the largest LNG exporters among non-GECF countries (Figure 121).

The overall increase in exports was fuelled by Indonesia, the US, Australia, Mexico, Congo, Norway and Oman (Figure 122). Indonesia's Tangguh Train 3 ramp-up boosted exports, while Congo and Mexico joined the LNG exporters' club with the start-up of Congo FLNG 1 and Altamira FLNG 1. In the US, Freeport LNG's debottlenecking increased capacity from 15 Mtpa to 16.5 Mtpa, while lower maintenance at Sabine Pass supported export growth. Additionally, Plaquemines LNG shipped its first LNG cargo in December 2024. Australia's LNG export growth was driven by increased output from APLNG, Gorgon and Prelude, offsetting declines at Darwin, Ichthys, North West Shelf (NWS) and Wheatstone. Furthermore, Norway and Oman saw higher LNG exports due to reduced maintenance at Hammerfest and Qalhat LNG.

Figure 121: Non-GECF LNG exports by country in 2024

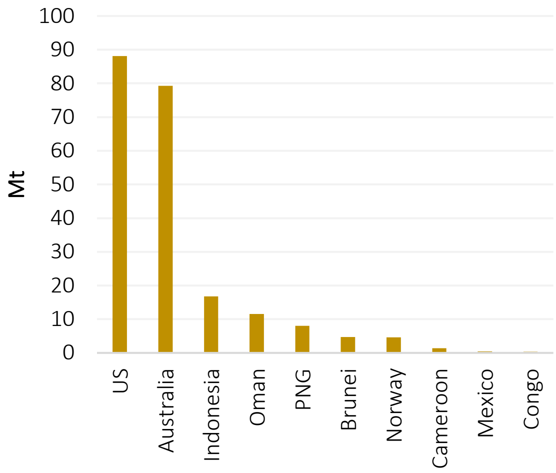
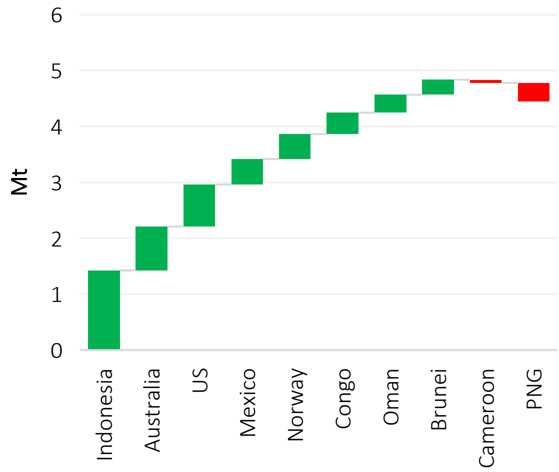


Figure 122: Variation in non-GECF LNG exports by country in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1.3 LNG Re-exports

In 2024, global LNG re-exports declined by 32% (1.7 Mt) to 3.6 Mt, the lowest level since 2021 and the first annual drop since 2019. Indonesia surpassed Spain to become the largest LNG re-exporter, with Spain slipping to the fourth position (Figure 123). The US Virgin Islands (USVI) and China were the second and third largest LNG re-exporters. The decline was driven by lower activity in Spain, China, Indonesia and Jamaica, which partially offset increased re-exports from the USVI (Figure 124).

Spain's drop in LNG re-exports was mainly due to weaker LNG demand in Italy. China's LNG re-exports fell due to lower shipments to Japan and South Korea, amid ample LNG supply and strong domestic demand. Indonesia's decline was linked to weaker intra-country LNG trade and reduced re-exports to Japan, South Korea and Taiwan. Meanwhile, increased USVI re-exports to Puerto Rico reduced Jamaica's LNG re-exports.

Figure 123: Global LNG re-exports by country in 2024

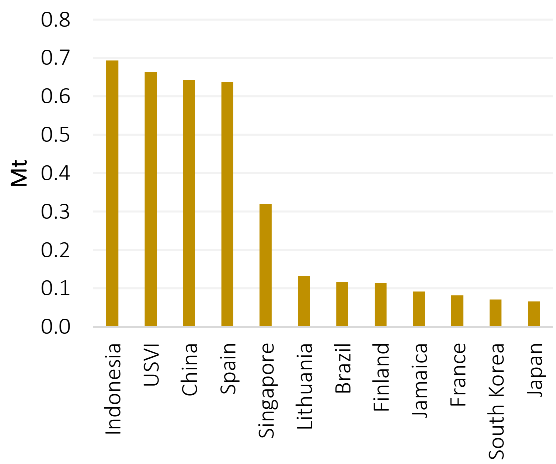
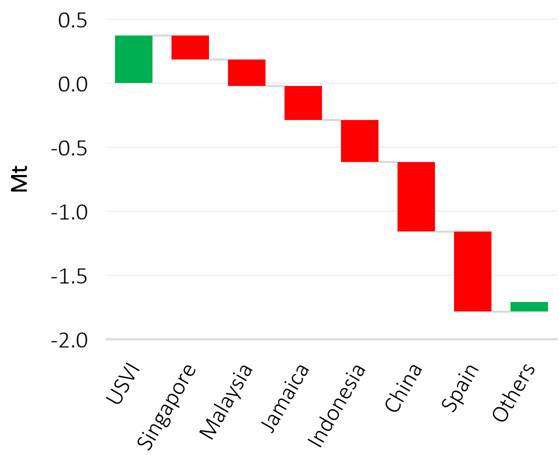


Figure 124: Variation in LNG re-exports by country in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 LNG Supply Short-Term Outlook

As of the end of March 2025, global LNG exports in 2025, including LNG re-exports, were projected to grow by 4% (16 Mt), assuming re-export volumes remain at 2024 levels (Figure 125). This marks a notable acceleration compared to 2024. Non-GECF countries are expected to drive the increase, adding 15 Mt, while GECF member countries are forecasted to see a marginal rise of 1 Mt.

Key assumptions for 2025 LNG export growth:

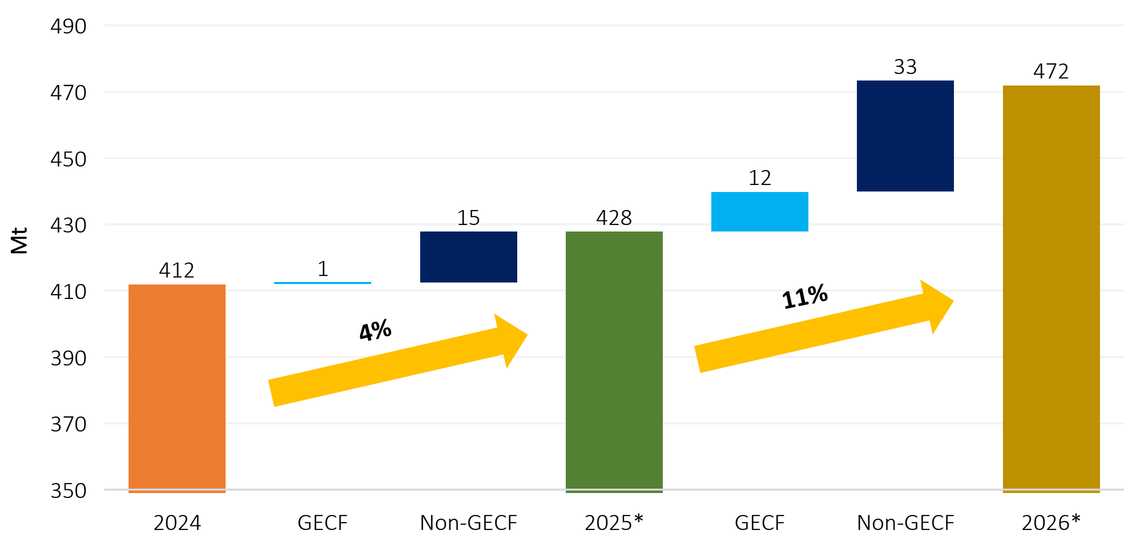
- New LNG export projects: 18-19 Mt increase in LNG exports from the start-up and ramp-up of new liquefaction facilities in Canada, Congo, Indonesia, Mauritania/Senegal, Mexico, Qatar and the US.
- Existing LNG export projects: 2-2.5 Mt decline in LNG exports due to higher planned maintenance and lower feedgas availability in some countries, which offset higher feedgas availability elsewhere.

As of the end of March 2025, global LNG exports in 2026 were forecasted to grow by 11% (45-46 Mt), assuming LNG re-exports remain unchanged from 2024 levels. Non-GECF countries will lead the expansion, contributing 33-34 Mt, while GECF Member Countries are expected to add 11-12 Mt.

Key assumptions for 2026 LNG export growth:

- New LNG export projects: 43-44 Mt increase in LNG exports from new liquefaction facilities starting and ramping up in Australia, Canada, Congo, Gabon, Mauritania/Senegal, Mexico, Nigeria, Qatar and the US.
- Existing LNG export projects: 1-2 Mt increase in LNG exports due to stable planned maintenance and higher feedgas availability in some countries.

Figure 125: Short-term outlook for global LNG exports



Source: GECF Secretariat based on data from ICIS LNG Edge for 2024
Note: GECF Secretariat's forecast for 2025 and 2026

4.2.1.3 Start-up of New LNG Liquefaction Capacity

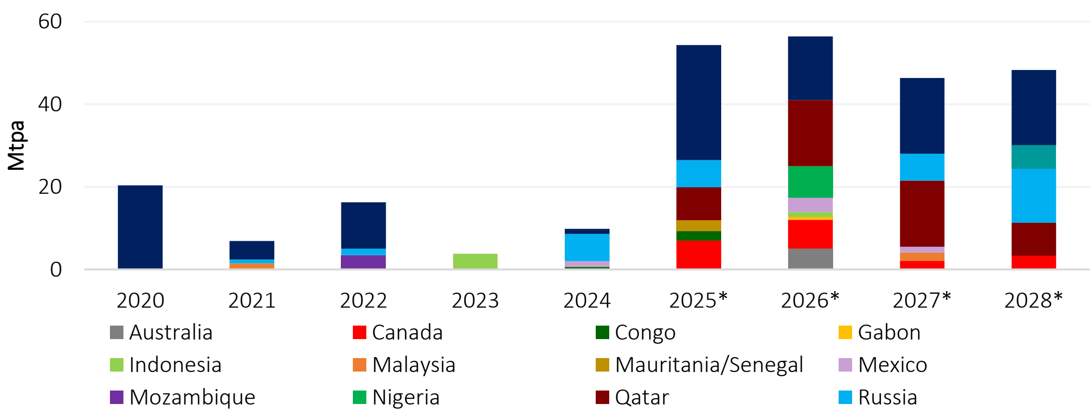
The commissioning of new liquefaction capacity rebounded from a record low and is expected to surge in the short to medium-term

In 2024, new LNG liquefaction capacity reached 10 Mtpa, up from a multi-year low of 3.8 Mtpa (Figure 126). Four new projects began operations: Congo FLNG1 (0.6 Mtpa) in Congo, Altamira FLNG1 (1.4 Mtpa) in Mexico, Arctic LNG Train 1 (6.6 Mtpa) in Russia, and the first two modular LNG trains (1.25 Mtpa) at the Plaquemines LNG Phase 1 facility in the US. Meanwhile, NWS Train 2 in Australia was permanently shut down in October 2024. By year-end, global liquefaction capacity stood at 497 Mtpa, with an average utilisation rate of 83%. The number of LNG-exporting countries reached 22, with Congo and Mexico entering the market in 2024. By 2028, Canada, Gabon, Mauritania and Senegal are also expected to enter the market as new LNG exporters.

In 2025, new liquefaction capacity is expected to surge to 54 Mtpa, with new projects launching in Canada, Congo, Mauritania/Senegal, Qatar, Russia and the US. These include LNG Canada Train 1 (7 Mtpa), Congo FLNG2 (2.4 Mtpa), Greater Tortue Ahmeyim FLNG1 (2.5 Mtpa), Qatar NFE Expansion Train 1 (8 Mtpa), Corpus Christi LNG Stage 3 Trains 1-3 (4.9 Mtpa), Golden Pass LNG Train 1 (6 Mtpa), Plaquemines LNG Phase 1 Blocks 2-11 (12.5 Mtpa) and Plaquemines LNG Phase 2 Blocks 12-15 (5.0 Mtpa). In 2026, an additional 57 Mtpa of liquefaction capacity is expected to come online across Australia, Canada, Gabon, Indonesia, Mexico, Nigeria, Qatar and the US Looking ahead to 2027 and 2028, new LNG liquefaction capacity is projected to grow by 50 Mtpa and 48 Mtpa, respectively.

As a result, between 2025 and 2028, global liquefaction capacity is expected to rise by 206 Mtpa, marking a 42% increase from end-2024 levels. This substantial growth in liquefaction capacity is projected to significantly boost global LNG supply, potentially leading to an oversupply in the market. Such an increase could exert downward pressure on spot LNG prices, which in turn may encourage additional gas demand in price-sensitive markets, helping to stabilise both the gas and LNG markets.

Figure 126: Start-up of new LNG liquefaction capacity by country



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG, Rystad Energy and Project Updates

4.2.1.4 FIDs on New LNG Export Projects

FIDs for new LNG export projects fell sharply, as the temporary pause on US LNG export authorisations to non-FTA countries delayed their project development

In 2024, the total LNG liquefaction capacity from export projects reaching final investment decisions (FIDs) dropped to 16 Mtpa, compared to 57 Mtpa in 2023, despite strong LNG contracting (Figure 127). This marked the lowest FID level since 2020, mainly due to a sharp decline in new LNG export project approvals in the US, which dominated FIDs in 2022 and 2023.

No US LNG export projects reached FID in 2024 due to the temporary pause on new LNG export authorisations to non-free trade agreement (non-FTA) countries, imposed by the previous US administration in January 2024. The pause was intended to allow the US Department of Energy to conduct a comprehensive review of the LNG export approval process, ensuring projects align with public interest. The review aimed to assess potential energy cost increases for American consumers and manufacturers, the environmental impact of greenhouse gas emissions, and the security of US natural gas supply.

The 16 Mtpa of liquefaction capacity that reached FID in 2024 included Canada's Cedar FLNG (3.3 Mtpa), Indonesia's Kasuri FLNG (1.2 Mtpa), Mexico's Altamira FLNG 2 (1.4 Mtpa) and the UAE's Ruwais LNG (9.6 Mtpa). Between 2025 and 2026, projects amounting to approximately 240 Mtpa of new export liquefaction capacity are targeting FID. The US leads with 130 Mtpa, followed by Mexico (19 Mtpa), Mozambique (19 Mtpa), Qatar (16 Mtpa), Russia (14 Mtpa) and Canada (12 Mtpa) (Figure 128). With the new US administration lifting the pause on LNG export authorisations to non-FTA countries in January 2025 and committed to expanding oil and gas exports, FIDs on new US LNG export projects are expected to rebound in the short term.

Figure 127: FIDs on LNG liquefaction capacity from export projects by country

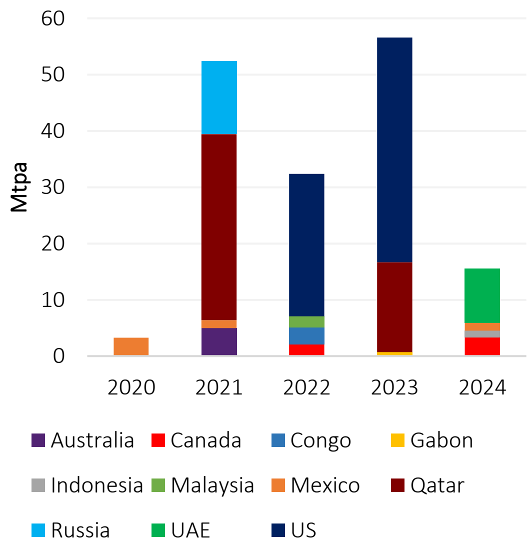
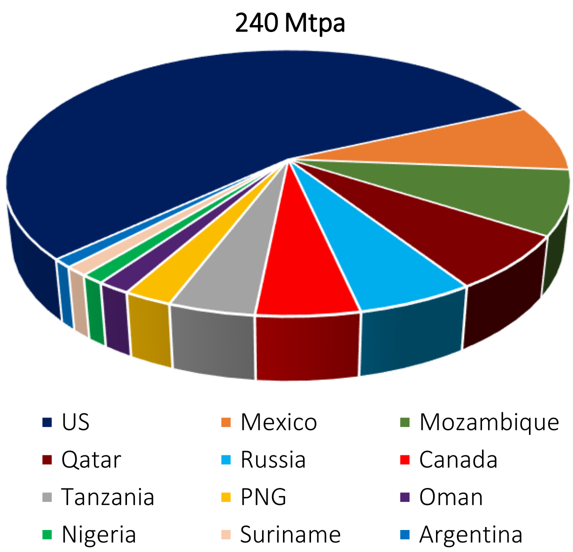


Figure 128: Countries targeting FIDs on LNG liquefaction capacity in 2025-2026



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG, Rystad Energy and Project Updates

4.2.1.5 LNG Liquefaction Plants Outages

The impact of liquefaction plant outages on global LNG production fell to a multi-year low, due to a reduction in planned maintenance activity

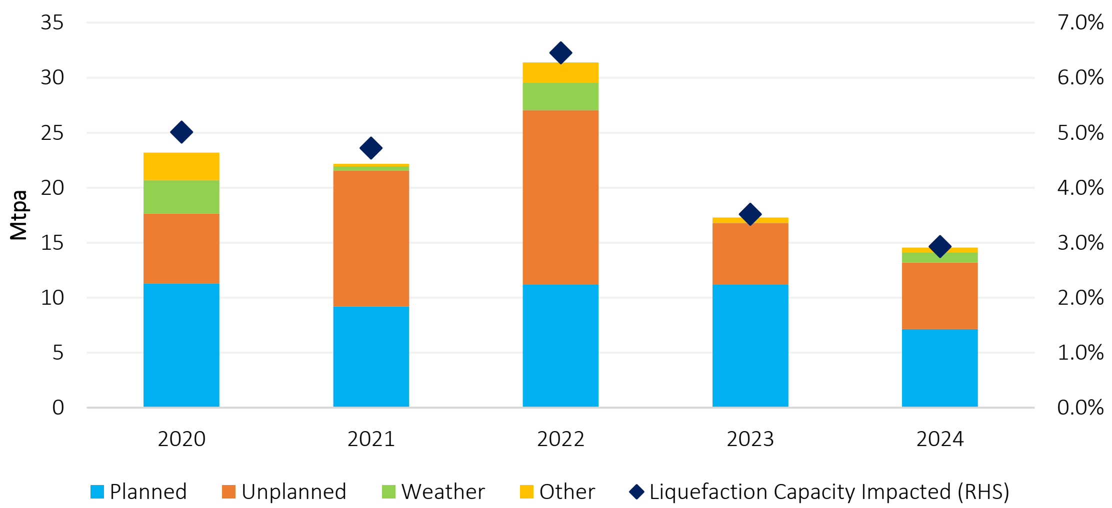
The utilisation of liquefaction facilities is influenced by various factors, including planned maintenance, unplanned outages, weather-related disruptions, and other unforeseen incidents, all of which impact LNG supply. However, the analysis on liquefaction plant outages does not account for feedgas constraints or economic factors, which can also affect liquefaction capacity utilisation. The impacted LNG volumes refer to liquefaction capacity that is either temporarily offline or operating at a reduced utilisation rate.

The total impact from these factors on LNG liquefaction facilities fell to 14.6 Mt in 2024 (Figure 129), marking a 16% (2.7 Mt) decline from 2023 and the lowest level since 2017. This reduction was primarily driven by lower planned maintenance activity, which offset the rise in unplanned outages and weather-related disruptions.

The decline in planned maintenance activity was primarily driven by reduced maintenance at Prelude LNG (Australia), NLNG (Nigeria), Qalhat LNG (Oman), Ras Laffan (Qatar), Portovaya and Yamal LNG (Russia), Atlantic LNG (Trinidad and Tobago) and Sabine Pass LNG (US). These reductions offset increased planned maintenance at Arzew LNG (Algeria), GLNG (Australia) and Freeport LNG (US).

Meanwhile, unplanned outages rose at Gorgon and Ichthys LNG (Australia), Tangguh LNG (Indonesia), Bintulu LNG (Malaysia) and Sabine Pass LNG (US), partially offset by fewer disruptions at QCLNG (Australia), Hammerfest LNG (Norway) and Freeport LNG (US). Additionally, the increase in weather-related disruptions was largely due to the impact of Hurricane Beryl on Freeport LNG (US) in July 2024.

Figure 129: Global LNG liquefaction plant outages



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

Note: "Other" refers to activities not associated with the LNG facility, such as pipeline and upstream maintenance and industrial action by workers

4.2.2 LNG Demand

4.2.2.1 Global LNG Imports

Global LNG imports reached a record high, driven by stronger demand in Asia

Global LNG imports increased by 1.1% (4.5 Mt) in 2024, reaching a record high of 411 Mt, though the growth rate slowed compared to previous years (Figure 130). The increase was driven by Asia, with contributions from Latin America and the Caribbean (LAC) and the Middle East and North Africa (MENA), while Europe experienced a sharp decline (Figure 131).

Figure 130: Global LNG imports by region

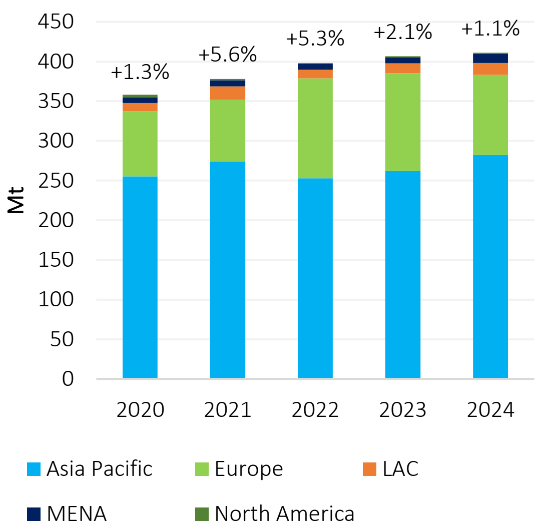
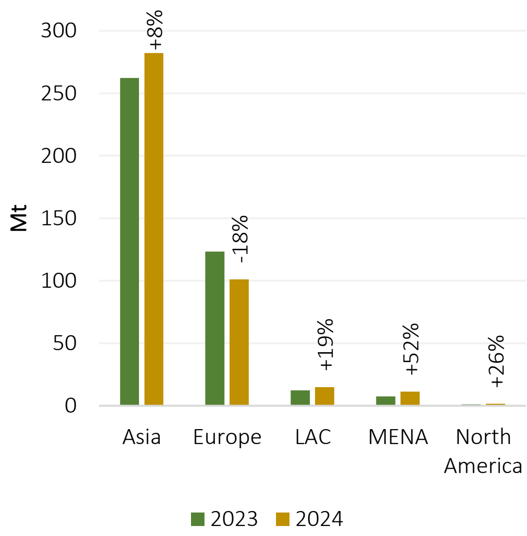


Figure 131: Regional LNG imports (2023 & 2024)



Source: GECF Secretariat based on data from ICIS LNG Edge

Asia strengthened its position as the largest LNG import market (Figure 132), increasing its global share from 65% in 2023 to 69% in 2024. Europe remained the second-largest market, though its share declined from 30% to 25%. At the country level, China remained the largest LNG importer, followed by Japan, South Korea, India and Taiwan (Figure 133).

Figure 132: Share of regional LNG imports in 2024

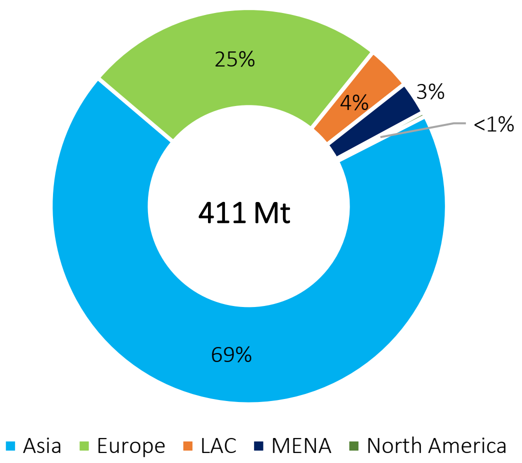
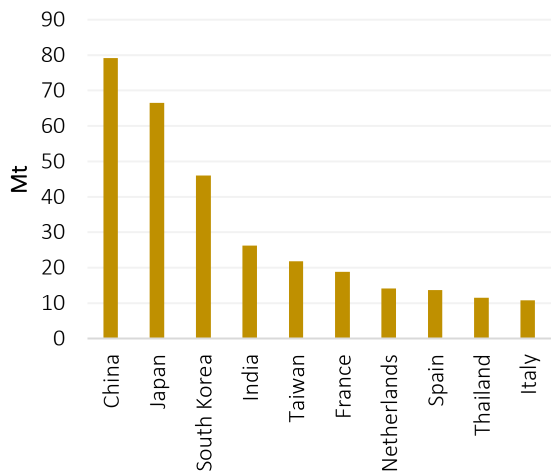


Figure 133: Top 10 LNG importing countries in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.1 Europe

LNG imports declined due to increased pipeline gas imports and higher gas storage

Europe's LNG imports declined by a significant 18% (22 Mt) to 101 Mt in 2024, marking the second consecutive annual drop. However, despite the decrease, imports remained above 2021 levels. The decline was primarily driven by high gas storage levels at the end of the 2023/2024 winter season, which reduced the need for mid-year storage injections, along with an increase in pipeline gas imports. France, the Netherlands, Spain, Italy and Türkiye were the top LNG importers in the region (Figure 134). At the country level, the largest declines were recorded in the UK, Spain, France, the Netherlands, Belgium, Türkiye and Italy, while Finland was the only European country to register an increase in LNG imports (Figure 135).

EU countries experienced a decline in LNG imports due to weaker gas consumption during the 2023/2024 winter season, which kept gas storage levels higher than the previous year, thus reducing storage injection requirements. Additionally, increased pipeline gas imports contributed to the drop in LNG imports in some countries. In Belgium, LNG imports fell due to increased pipeline gas imports and lower exports of regasified LNG to Germany and the Netherlands. In France, the decrease in LNG imports was driven by higher pipeline gas imports from Norway, while in Italy, increased pipeline gas imports similarly curbed LNG imports. The Netherlands saw lower LNG imports due to reduced pipeline gas exports to Germany, whereas in Spain, stronger pipeline gas and regasified LNG imports led to the decline in its LNG imports.

Non-EU countries also recorded a drop in LNG imports. In Türkiye, despite higher overall gas consumption, increased domestic gas production and higher pipeline gas imports reduced LNG demand. Meanwhile, in the UK, despite a decline in domestic gas production, LNG imports fell due to weaker gas consumption and higher pipeline gas imports from Norway, in addition to reduced exports of pipeline gas and regasified LNG to mainland Europe.

Figure 134: Europe's LNG imports by country in 2024

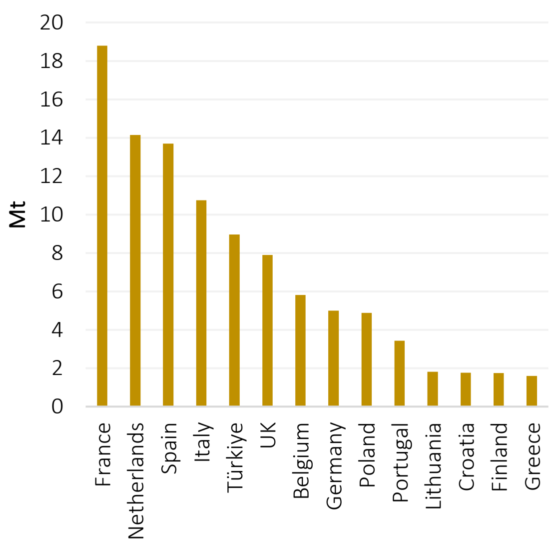
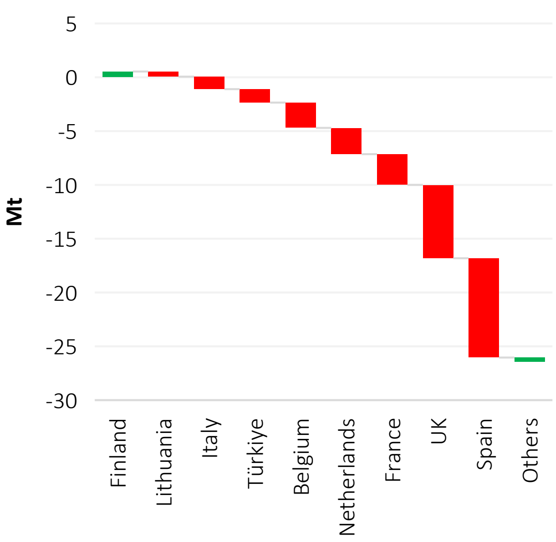


Figure 135: Variation in Europe's LNG in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.2 Asia

LNG imports hit a record high, due to stronger gas demand and lower spot prices

LNG imports in Asia soared by 7.6% (20 Mt) to a record 282 Mt in 2024, surpassing the previous high of 274 Mt in 2021. This growth was fuelled by rising gas demand, declining domestic gas production in some countries, and lower spot LNG prices during H1 2024.

The top LNG importers in the region were China, Japan, South Korea, India and Taiwan (Figure 136). Among the region's top five LNG importers, South Korea and Taiwan reached record-high LNG imports in 2024. While China and India also saw growth, their imports remained below their record levels from 2021 and 2020, respectively. Meanwhile, Japan's LNG imports remained relatively stable but were significantly lower than its peak in 2014. Every country in the region recorded an increase in LNG imports, with notable growth in China, India, South Korea, Taiwan, Singapore, Pakistan, Indonesia and the Philippines (Figure 137).

In China, stronger gas demand, the commencement of new long-term LNG contracts, and the commissioning of new LNG import terminals boosted LNG imports. China's contractual LNG imports from medium and long-term contracts increased by 8 Mt to 59 Mt in 2024. Meanwhile, India's LNG imports surged due to rising gas demand and lower spot LNG prices in H1 2024. As a price-sensitive market, India's LNG demand was stimulated by cheaper spot LNG, with spot LNG imports increasing by 2.2 Mt to 9 Mt in 2024.

In South Korea and Taiwan, LNG imports grew due to higher gas consumption in the electricity sector, with the additional retirement of Taiwan's nuclear reactors, following the expiration of their 40-year operating licences, driving greater gas demand for electricity generation. The rise in Singapore's LNG imports was driven by weaker pipeline gas imports and higher LNG demand for bunkering.

Figure 136: Asia's LNG imports by country in 2024

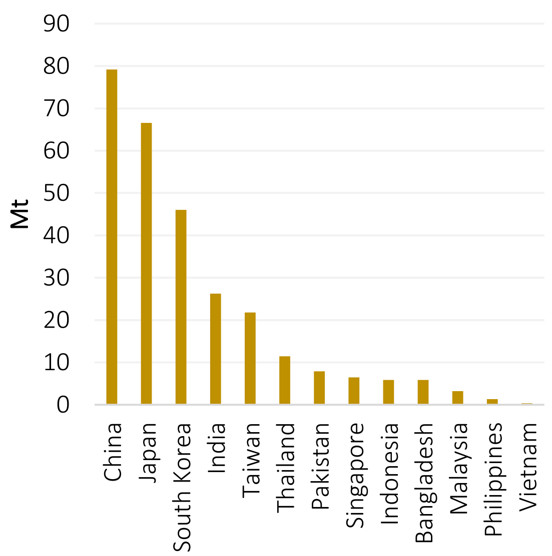
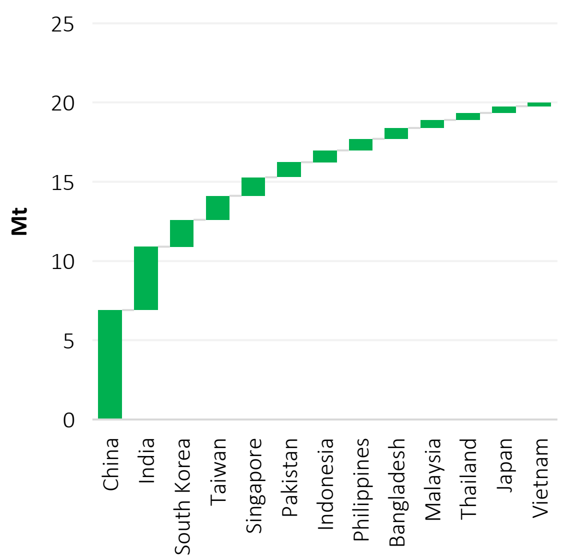


Figure 137: Variation in Asia's LNG imports in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.3 Latin America and the Caribbean (LAC)

LNG imports in LAC surged by 19% (2.4 Mt) to 15 Mt in 2024, marking the highest level since 2021 and the second highest on record. Brazil, the Dominican Republic, Chile and Colombia were the top LNG importers in LAC (Figure 138). The increase was mainly driven by Brazil and Colombia, where lower hydro output led to higher gas demand for electricity generation (Figure 139). In contrast, Argentina saw a decline in LNG imports, driven by increased domestic gas production.

Figure 138: LAC's LNG imports by country in 2024

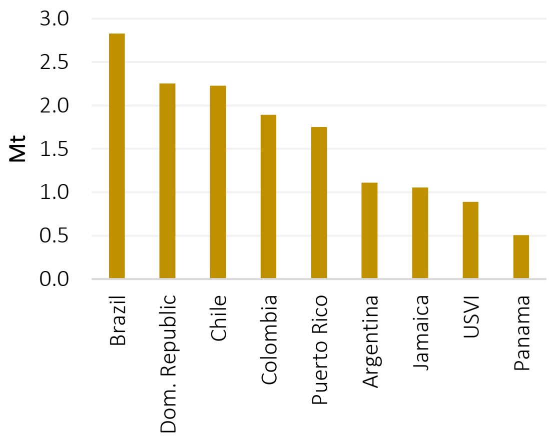
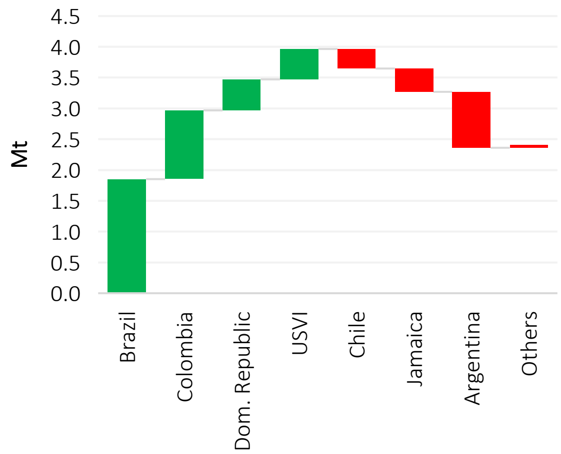


Figure 139: Variation in LAC's LNG imports in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.4 Middle East and North Africa (MENA)

LNG imports in the MENA region surged by 52% (3.8 Mt) to 11 Mt in 2024, the highest level since 2017. The stronger imports were primarily driven by higher LNG imports in Egypt, Jordan and Kuwait (Figure 140).

4.2.2.1.5 North America

LNG imports in North America rose by 26% (0.3 Mt) to 1.5 Mt in 2024, though they remained significantly below pre-2021 levels. The increase was due higher LNG imports in Mexico, while Canada and the US saw relatively stable import levels (Figure 141).

Figure 140: MENA region's LNG imports by country

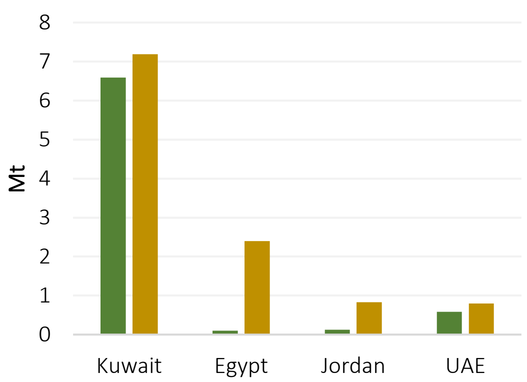
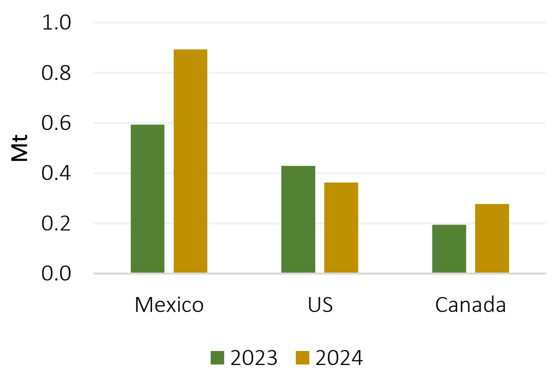


Figure 141: North America's LNG imports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Start-up of New LNG Regasification Capacity

The commissioning of LNG regasification capacity reached the third-largest annual growth

Global LNG regasification capacity from import terminals expanded by 62 Mtpa in 2024, reaching a total of 1,016 Mtpa (Figure 142). This increase marked the third-largest annual growth on record, surpassed only by the 74 Mtpa added in 2023 and 64 Mtpa in 2008. Notably, around 28 Mtpa of the new capacity came from floating storage and regasification units (FSRUs). By the end of 2024, Asia held the largest share of LNG regasification capacity, totalling 640 Mtpa, followed by Europe with 240 Mtpa and LAC with 70 Mtpa.

Asia led the global expansion of regasification capacity in 2024, adding 30 Mtpa, followed by Europe (16 Mtpa), Latin America and the Caribbean (LAC) (13 Mtpa) and Africa (3 Mtpa) (Figure 143). The global regasification capacity utilisation rate averaged 41% in 2024, slightly down from 42% in 2023, remaining below half of the global liquefaction capacity utilisation.

At the country level, China led the regasification capacity additions, contributing 28 Mtpa, followed by Brazil (13 Mtpa), Germany (7 Mtpa), Belgium (5 Mtpa) and Greece (4.5 Mtpa). Notable regasification projects that began operations in 2024 included Deutsche Ostsee FSRU 2 (6.5 Mtpa) in Germany; Chaozhou Huaying LNG Phase 1 (6 Mtpa), Suntien Tangshan Phase 2 (6 Mtpa), and Tianjin Phase 2 (6 Mtpa) in China; Barcarena FSRU (5.6 Mtpa) in Brazil; Zeebrugge Expansion Phase 1 (4.7 Mtpa) in Belgium; and Alexandroupolis FSRU (4.5 Mtpa) in Greece.

In the short-term, more than 140 Mtpa of new regasification capacity is set to come online, with 104 Mtpa scheduled for 2025 and 38 Mtpa for 2026. Asia will lead this expansion, contributing 98 Mtpa, driven by China (54 Mtpa), India (24 Mtpa) and the Philippines (7 Mtpa). Europe will follow with 26 Mtpa, largely from Germany (9 Mtpa), Italy (4 Mtpa) and the UK (4 Mtpa). LAC will add 9 Mtpa, with 5 Mtpa planned for Nicaragua and 4 Mtpa for Brazil.

Figure 142: Start-up of new LNG regasification capacity by region

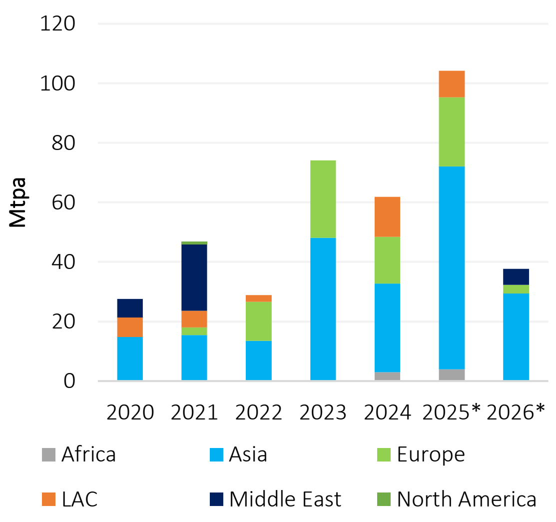
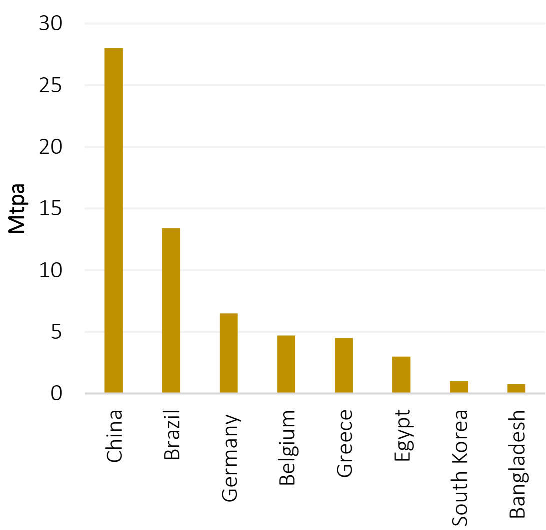


Figure 143: Start-up of new LNG regasification capacity by country in 2024



(*): GECF Secretariat's forecast for 2025 and 2026

Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG, Rystad Energy and Project Updates

4.2.3 Trend in Global LNG Trade by Duration

Medium and long-term LNG trade continued to dominate global LNG trade

LNG cargoes traded were categorised into spot and short-term (spot|ST) or medium-term and long-term (MT|LT). Spot and short-term LNG trade encompasses LNG cargoes traded under contracts of two years or less. However, for several cargoes, the sales basis data was unavailable, leading to their classification as “others”. Consequently, the actual spot|ST and MT|LT trade may be higher than the data provided in this report.

In 2024, global spot|ST LNG trade saw a slight decline of 1.1% (1.2 Mt) to reach a total of 102 Mt, while its share of the global LNG trade remained stable at 25% (Figure 144). This overall decline was driven by a significant drop in Europe’s spot|ST LNG imports, which decreased by 5.5 Mt to reach 25 Mt. Europe had previously ramped up its spot|ST LNG purchases to offset reduced pipeline gas imports, but this trend reduced in 2024. On the other hand, Asia experienced a rise in spot|ST LNG imports, increasing by 3.2 Mt to reach 69 Mt, the highest level since 2021, largely driven by attractiveness of more favourable spot LNG prices in the region.

At the country level, France, Spain, China and Türkiye saw significant declines in spot|ST LNG imports, mainly due to weaker LNG demand (Figure 145). China’s imports initially increased in H1 2024, benefiting from lower spot LNG prices, but declined sharply in H2 2024 as prices surged, dragging down its annual spot|ST LNG imports. Additionally, a rise in MT|LT contractual imports contributed to the decline in China’s spot LNG purchases. In contrast, India, Japan, Egypt and the UK recorded higher spot|ST LNG imports. India's spot|ST imports were boosted by lower spot LNG prices in H1 2024, while Japan and the UK increased spot|ST LNG imports to offset declines in MT|LT imports following the expiration of contracts. Meanwhile, Egypt’s return as an LNG importer led to a rise in spot|ST LNG imports, as the country lacks medium and long-term contracts.

Figure 144: Global LNG trade by contract duration

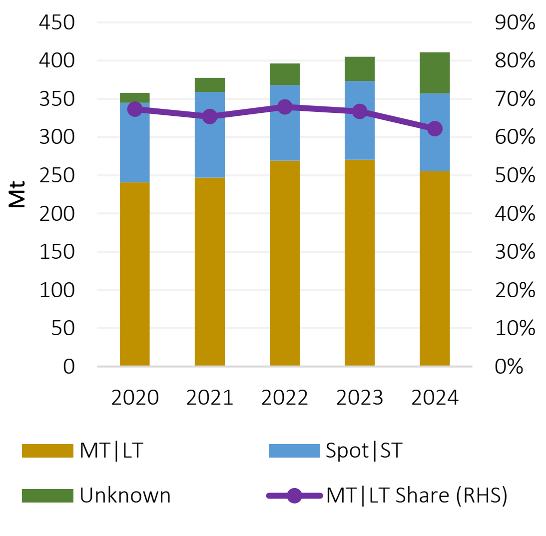
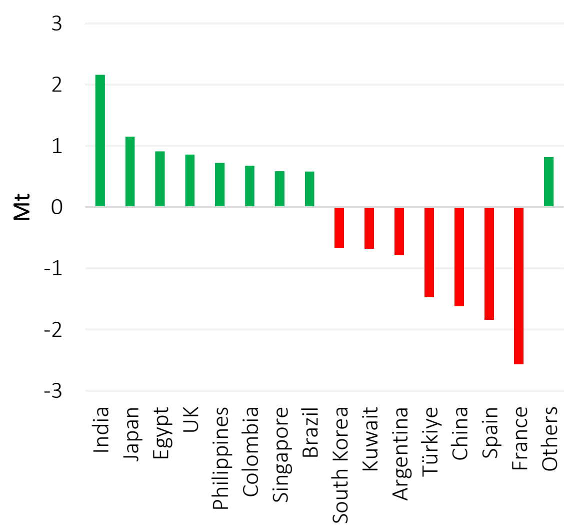


Figure 145: Variation in spot|ST LNG trade in 2024



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.4 Expiration of Global LNG Contracts

The analysis of LNG contract expirations for importing countries considers only sale and purchase agreements (SPAs) with a specified destination market, excluding memorandums of understanding (MoUs), heads of agreements (HoAs), and SPAs with portfolio companies or traders with no defined destination. Between 2025 and 2030, 131 Mtpa of contracted LNG volumes are set to expire. Asia leads with 66 Mtpa, followed by Europe (33 Mtpa), North America (24 Mtpa), Latin America and the Caribbean (LAC) (4.4 Mtpa), Africa (3.5 Mtpa) and the Middle East (1 Mtpa) (Figure 146). The tear 2028 is projected to see the highest volume of expirations at 27 Mtpa, while 2026 will have the lowest at 16 Mtpa.

At the country level, Japan has the largest LNG contract expirations with 22 Mtpa set to expire by 2030, followed by China (16 Mtpa), the US (15 Mtpa), South Korea (10 Mtpa), Spain (9 Mtpa) and India (9 Mtpa) (Figure 147). Japan is unlikely to renew all expiring contracts due to stable short-term LNG demand and an expected decline in medium to long-term demand. However, Japanese LNG importers are expanding their portfolios to operate as global traders, which could support the renewal of some LNG SPAs with destination flexibility. Additionally, the contract expirations in the US stem from pre-shale gas revolution SPAs, reflecting agreements established before the country's shift to domestic LNG production dominance.

Figure 146: LNG import contract expirations by region

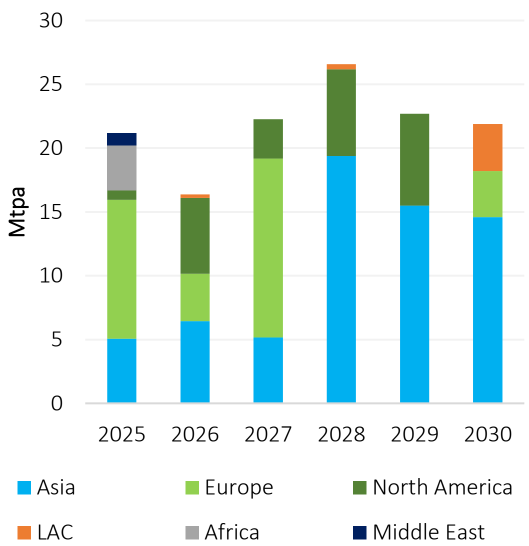
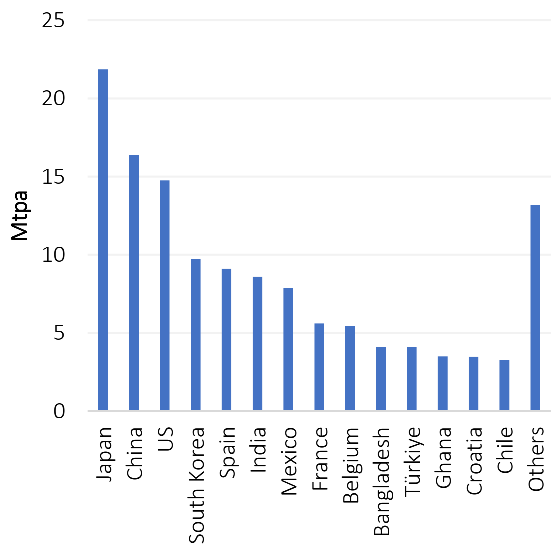


Figure 147: LNG import contract expirations by country (2025-2030)



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG and Rystad Energy

On the supply side, GECF member countries account for the largest share of expiring LNG SPAs, with 65 Mtpa set to expire, followed by non-GECF countries (37 Mtpa) and portfolio players/traders (29 Mtpa). The higher number of expirations of contractual LNG supply from GECF member countries is expected, as these countries are legacy LNG producers with exports dating back more than two decades. In contrast, newer LNG projects in Australia and the US have been in operation for only about a decade, resulting in fewer contract expirations during this period.

4.2.5 LNG Shipping

4.2.5.1 LNG Shipments

The number of LNG shipments continued to grow, albeit at a muted rate

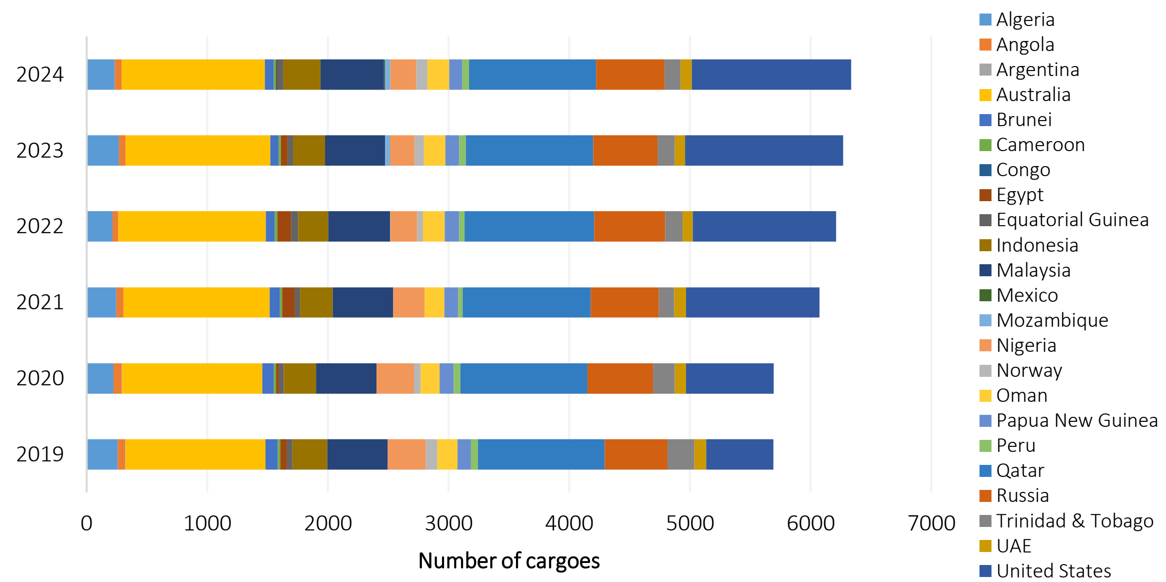
The number of LNG shipments increased by 1%, adding 66 cargoes, to reach a total of 6,336 cargoes in 2024 (Figure 148). Although the number of LNG shipments have been consistently increasing in recent years, the past three years marked a slowdown in the growth rate of the sector, following the 7% expansion in 2021.

The leading LNG exporters were the US, Australia and Qatar, each delivering over 1,000 shipments. These three countries accounted for 56% of the global LNG shipments, maintaining the same market share as in the previous four years.

GECF members made up six of the top ten exporters: Qatar, Russia, Malaysia, Algeria, Nigeria and Trinidad & Tobago. Together, GECF countries were responsible for 48% of all LNG cargoes exported globally.

New entrants to the LNG shipping sector, namely Congo and Mexico, delivered 14 LNG cargoes. Indonesia exported 45 more cargoes than the previous year, marking a 17% increase. Russia followed with a 7% rise, or 36 more cargoes, reflecting its efforts to diversify gas exports. Mozambique saw the largest percentage increase at 24%, adding 9 cargoes as it ramped up its export operations.

Figure 148: Number of LNG cargoes by exporting country



Source: GECF Secretariat based on data from ICIS LNG Edge

Looking ahead to 2025, the number of LNG shipments is expected to rise, driven by increased LNG exports, new export facility startups, ramped-up supply from existing producers, and new market entrants like Canada, Mauritania and Senegal.

4.2.5.2 LNG Shipping Cost

New carrier additions have prompted a loosening of the LNG shipping market

LNG shipping costs depend on three key factors, in particular the cost of chartering the LNG carrier, shipping fuel expenses, and the distance between the loading and receiving ports. 2024 proved to be exceptional for the LNG shipping market, as the average annual spot charter rate for steam turbine LNG carriers plummeted to a record low of $25,000/day, down from $43,000/day in 2020, $65,000/day in 2021, $72,000/day in 2022 and $53,000/day in 2023 (Figure 150). Similar declines were seen across other segments of the global LNG carrier fleet. The average spot charter rate for TFDE carriers was $40,000/day, while two-stroke carriers averaged $55,300/day—53% and 49% lower than the five-year average, respectively.

Spot charter rates were notably atypical in 2024. Typically, charter rates follow a seasonal pattern, remaining stable during periods of regular LNG demand and rising in Q4 as Europe and Asia compete for cargoes ahead of the winter season. However, in 2024, rates declined from August onward, reaching an average low of $6,400/day in December (Figure 149).

Figure 149: Monthly average spot charter rate for steam turbine LNG carriers

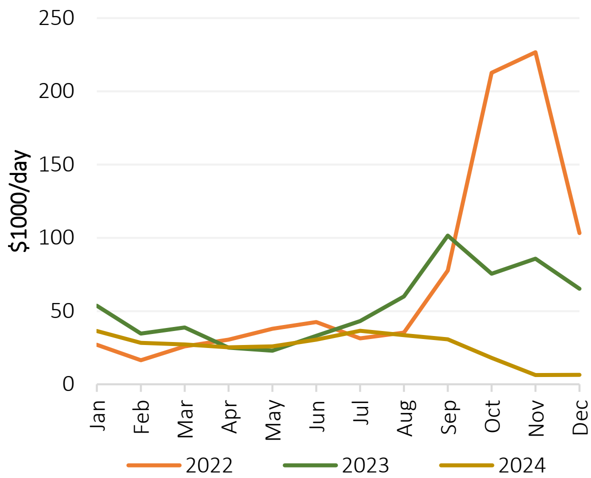
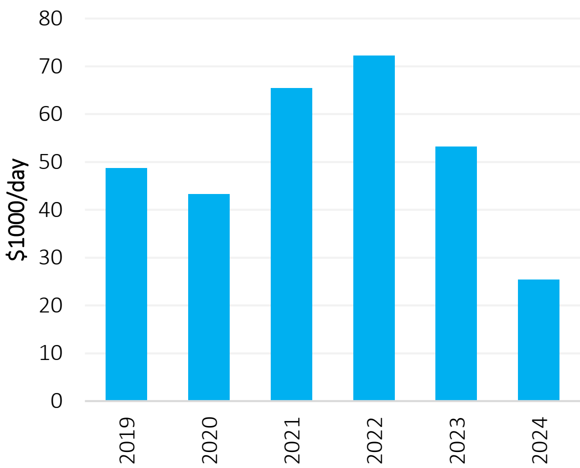


Figure 150: Annual average spot charter rate for steam turbine LNG carriers



Source: GECF Secretariat based on data from Argus

The decline in spot charter rates was driven by three main factors. Firstly, the LNG shipping market experienced a record-breaking expansion of the carrier fleet, with the number of newly commissioned vessels reaching 70 and with the rate of these additions significantly outpacing the growth of global LNG export capacity. Secondly, many of these newly commissioned LNG carriers were initially ordered for long-term charter contracts linked to upcoming liquefaction projects. However, due to the common practice of commissioning vessels before the commercial operations of LNG liquefaction plants commence, coupled with delays in the startup of some projects, many of these carriers have been temporarily redirected to the spot charter market. Thirdly, the decline in LNG cargoes used for floating storage contributed to the slump in spot charter rates in Q4 2024. Floating storage was nearly non-existent in Europe in Q4 2024, compared to around 20 carriers used for floating storage in Europe in Q4 2023.

The monthly average shipping fuel price demonstrated very little volatility in 2024, matching the stability of the oil markets (Figure 151). The annual average price was $580/t, which was almost unchanged from 2023, and 13% greater than the five-year average price (Figure 152).

Figure 151: Monthly average shipping fuel price

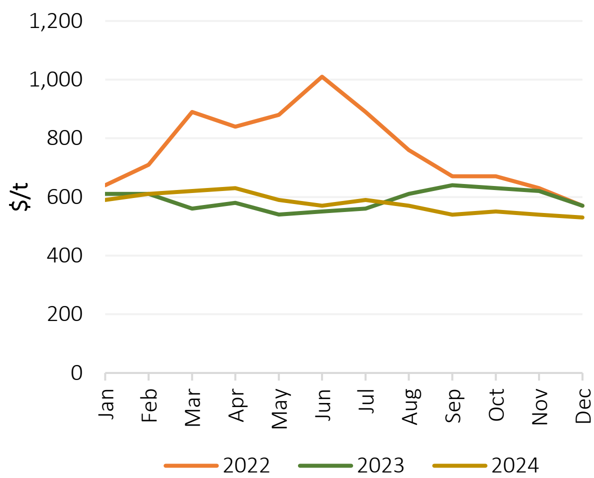
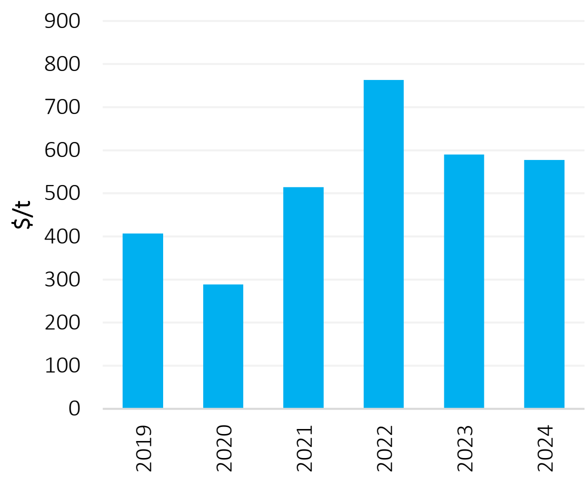


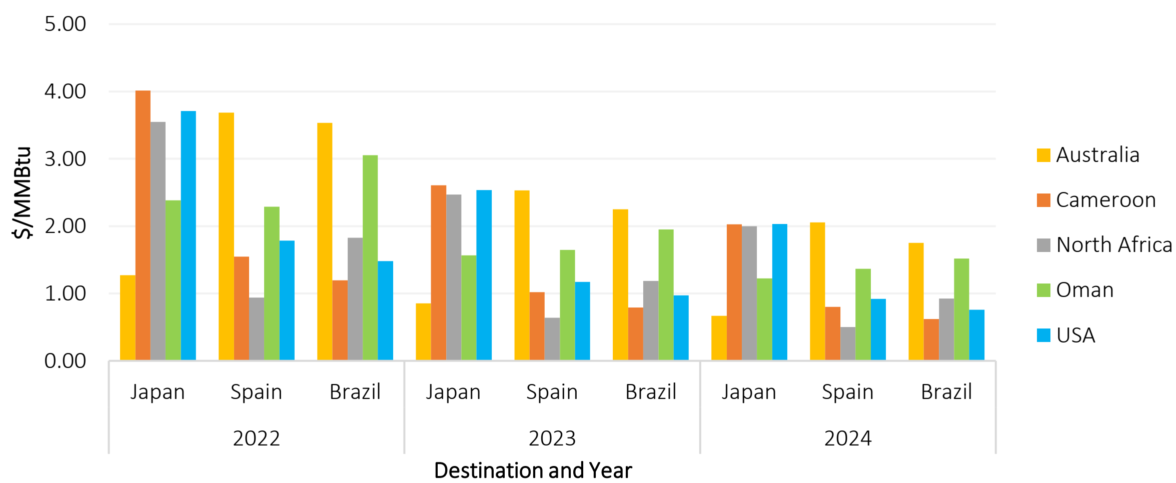
Figure 152: Annual average shipping fuel price



Source: GECF Secretariat based on data from Argus

In 2024, traditional LNG shipping routes were partially disrupted due to developments around the Suez and Panama Canals. Geopolitical tensions in the Red Sea raised security concerns, impacting LNG flows from the Middle East to Europe. As a result, shipments were rerouted around Africa via the Cape of Good Hope, adding 12 extra sailing days. Furthermore, low precipitation conditions reduced water levels in the Panama Canal and imposed transit restrictions, forcing most LNG cargoes originating from Trinidad and Tobago and the US Gulf Coast to be delivered in East Asia to be rerouted around Africa during the first three quarters of the year, resulting in an additional 14 sailing days. Despite the transit challenges, the market saw an overall decrease in spot shipping costs for steam turbine LNG carriers in 2024, by up to $0.60/MMBtu on certain routes, driven primarily by lower charter rates (Figure 153).

Figure 153: Spot shipping costs for steam turbine LNG carriers



Source: GECF Secretariat based on the GECF Shipping Cost Model

4.2.5.3 LNG Carriers

LNG carrier fleet expanded rapidly in the anticipation of a new wave of LNG projects

The LNG carrier fleet experienced significant expansion in 2024, growing to 774 vessels due to new vessel construction and limited scrappage rates. Of this total, 711 vessels were active LNG carriers, while the remaining 63 were used as FSRUs, FSUs, or floating power ships deployed at various global locations.

A record 70 LNG carriers were commissioned in 2024, adding 12 million cubic metres of shipping capacity, nearly double the volume seen in 2023 (Figure 154). As a result, the total capacity of the global LNG carrier fleet reached an all-time high of 126 million cubic metres by the end of the year, marking a major milestone in the sector's growth.

The LNG carrier fleet may be categorised into three main segments based on their propulsion technology: steam turbine, TFDE (tri-fuel diesel electric), and two-stroke engines. While all types of carriers use LNG boil-off for propulsion, they also rely on other fuels: steam turbine vessels use HFO (heavy fuel oil), TFDE vessels consume marine diesel oil and HFO/ LSFO (low-sulphur fuel oil), and two-stroke vessels use marine gasoil, LSFO and LNG bunker fuel.

Steam turbine LNG carriers, the first generation of the fleet, account for 30% of the total fleet (Figure 155). While these vessels are being gradually replaced by newer, larger, and more fuel-efficient carriers (two-stroke engines became the dominant option this decade), steam turbine carriers continue to play a crucial role in spot LNG trade, especially during peak demand periods such as the winter months in the Northern Hemisphere. As new-generation LNG carriers are primarily deployed for long-term chartering, a growing number of steam turbine vessels, once dedicated to long-term contracts, are being redirected to the spot market.

Figure 154: Annual capacity additions to the global LNG fleet

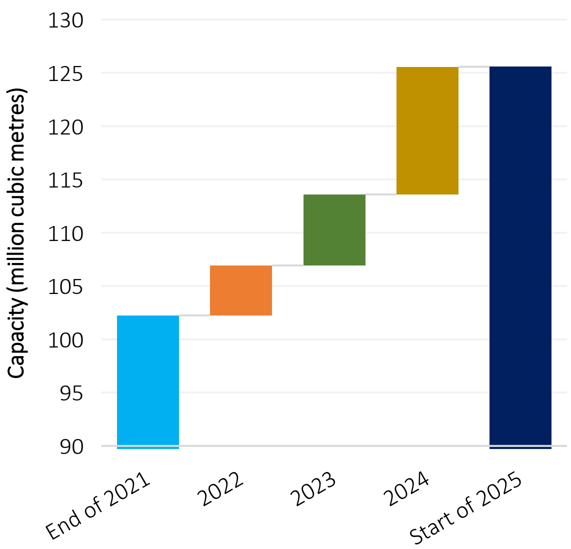
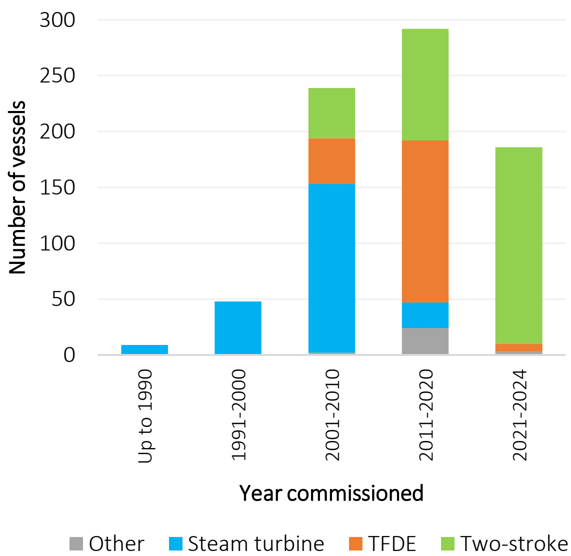


Figure 155: Distribution of the LNG carrier fleet by build year and propulsion system

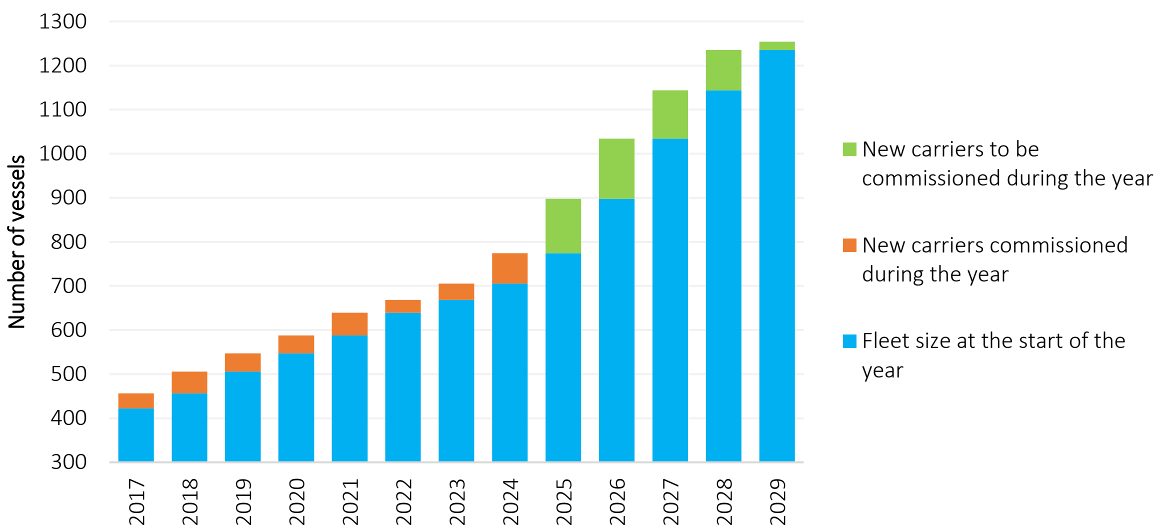


Source: GECF Secretariat based on data from Argus, ICIS LNG Edge and IGU

In the medium-term, between 2025 and 2028, global LNG liquefaction capacity is expected to grow from 500 Mtpa to 710 Mtpa. This significant increase in liquefaction capacity will necessitate a corresponding expansion of LNG shipping capacity to transport the additional volumes of LNG to the global market. Consequently, a key question arises regarding whether the LNG shipping industry will be able to effectively manage the challenges associated with accommodating this surge in LNG supply.

In this context, the year 2025 marks the beginning of a period during which approximately 500 new LNG carriers are expected to enter service by the end of the decade, representing an increase of over 50% in the total number of vessels compared to current levels. Notably, the next four years will set new annual records for the commissioning of LNG carriers (Figure 156).

Figure 156: Growth of the LNG carrier fleet



Source: GECF Secretariat based on data from ICIS LNG Edge

The building of new LNG carriers is closely tied to the commissioning of new liquefaction plants, with market players placing vessel orders assigned to specific projects well in advance. LNG carrier construction is a highly specialised process, which requires a skilled and experienced workforce and typically takes between 18 to 24 months. South Korea, home to prominent shipyards such as Samsung Heavy Industries, Hyundai Heavy Industries and Hanwha Ocean, has historically been the global leader in LNG carrier construction. However, China has steadily gained ground in the market, offering additional shipyard capacity, improving quality and reducing costs. As a result, Chinese shipyards now account for a quarter of the LNG carrier orderbook through the end of the decade.

On the demand side, GECF member countries account for a substantial portion of the global LNG carrier orderbook. Notably, Qatar has placed orders for 128 new LNG carriers to support the North Field expansion and other projects. Russia and the UAE have also ordered new vessels to support the commissioning of LNG export projects in their respective countries. Additionally, other countries, such as Nigeria, have announced plans to modernise and expand their fleets.

CHAPTER

05

GAS STORAGE

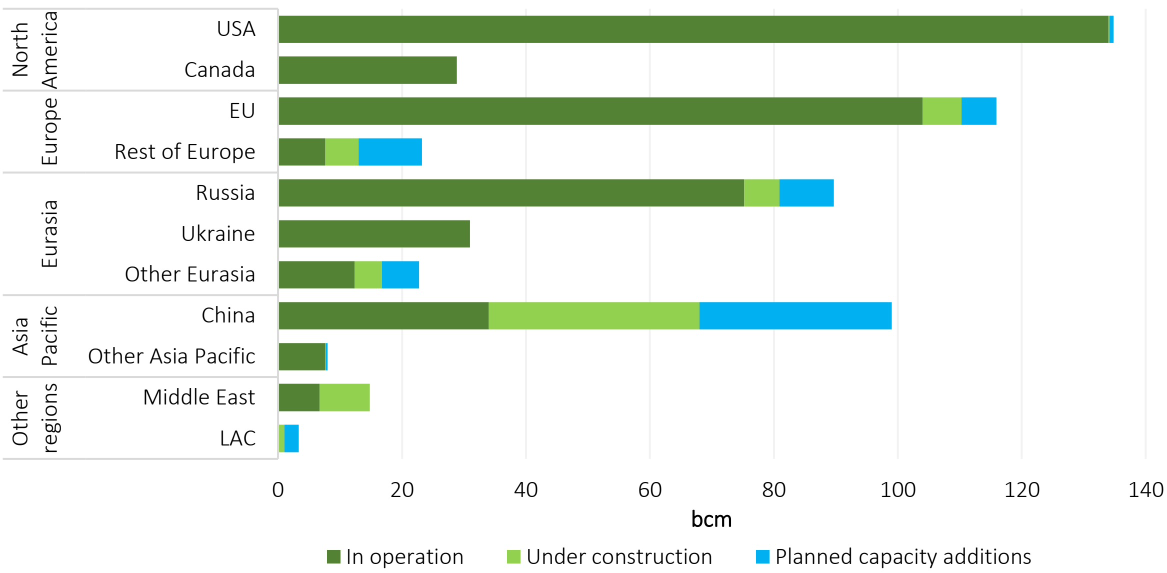
As a vital component of the global energy infrastructure, gas storage helps balance markets by providing a buffer against seasonal demand changes, supply disruptions, price volatility and other market shocks. With a total capacity of 500 bcm, global gas storage comprises both underground gas storage (UGS) and LNG storage facilities, with underground storage accounting for 90% of the total storage capacity.

5.1 Underground Gas Storage

Surge in new facilities in China boosted the global underground gas storage capacity

In 2024, global underground gas storage capacity reached 442 bcm, marking a 3% increase compared to the previous year. The US, EU and Russia are the leading players in this sector, with capacities of 134 bcm, 104 bcm and 75 bcm, respectively (Figure 157). Notably, China made significant strides, boosting its storage capacity by 62% to 34 bcm in 2024, leading the global expansion of underground gas storage. Currently, 65 bcm of new capacity is under construction worldwide, with China at the forefront of these developments as well.

Figure 157: Global underground gas storage capacity by region/country



Source: GECF Secretariat based on data from Argus and Cedigaz

5.1.1 Europe

High gas storage levels helped ensure gas security supply

Gas storage played a vital role in Europe amid recent market changes. At the start of 2024, the EU's gas storage was at 90 bcm, 14.5 bcm above the five-year average (Figure 158). This healthy level was driven by high storage levels at the beginning of the 2023/2024 winter season, with gas storage peaking at a record 103 bcm, or 99% of capacity. This strong foundation helped sustain elevated gas stocks throughout the winter. Furthermore, the commissioning of new LNG import terminals across Europe kept storage levels near the top of the five-year range during the entire gas injection season.

Despite significant gas withdrawals in January, net gas withdrawals during Q1 2024 were below the five-year average, mainly due to mild winter temperatures resulting in lower gas demand for heating (Figure 159). As a result, storage levels remained high at 61 bcm by the end of the 2023/2024 winter season, reducing the pressure on EU countries to refill storage sites during the injection season, unlike in previous years.

Figure 158: Daily UGS level in the EU

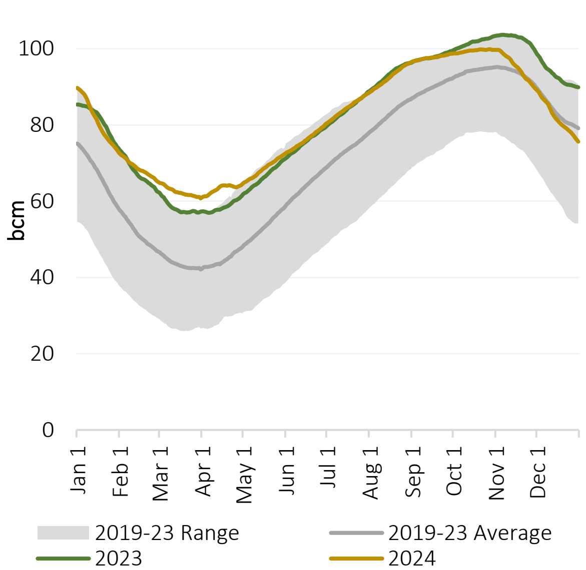
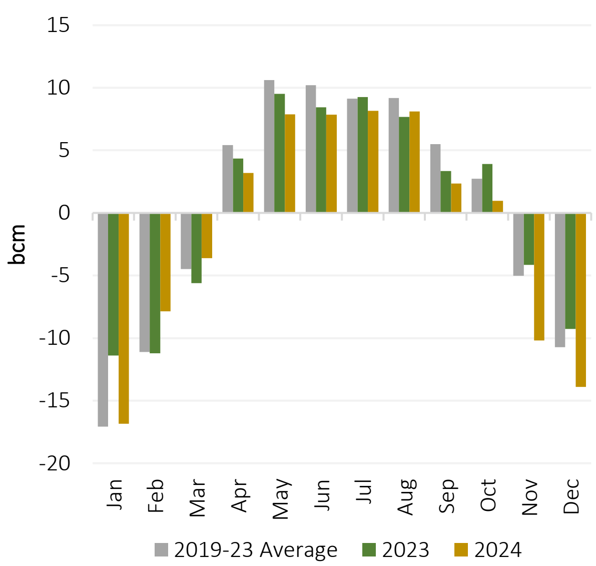


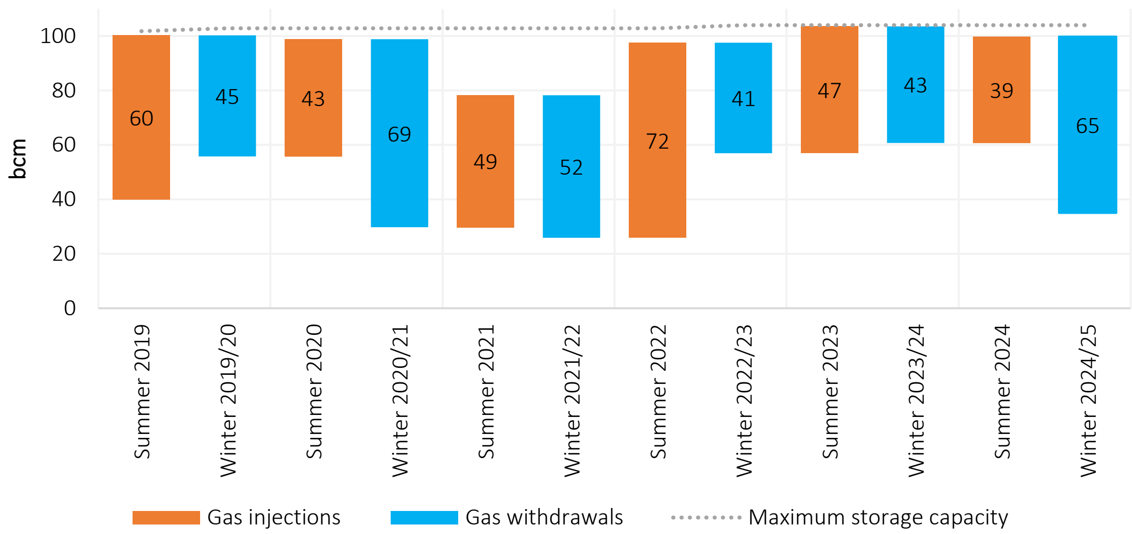
Figure 159: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

During the 2024 net gas injection season, the EU restocked a total of 39 bcm, marking the lowest volume in twelve years (Figure 160). Since 2022, EU member states followed the gas storage regulations set by the European Commission, with key checkpoints to monitor progress. Throughout 2024, storage levels exceeded expectations at each checkpoint, with regional capacity reaching 90% more than two months ahead of the November 1 target date. However, the 2024/2025 winter season began earlier than the previous year, and gas withdrawals started just after mid-October from a peak storage level of 96%, compared to initial withdrawals from the first week of November in 2023. With increased demand driven by Dunkelflaute periods and several cold spells, significant net gas withdrawals occurred in November and December 2024, bringing the EU's gas storage level down to 76 bcm by the year's end.

Figure 160: UGS injections and withdrawals in the EU



Source: GECF Secretariat based on data from AGSI+

The new gas storage regulations have contributed to a shift in pricing trends over the last two years. Under regular market conditions, market players purchase lower priced gas to inject it into storage facilities during the summer months, in anticipation of withdrawing it in the winter season, when gas prices tend to be higher due to the surge in gas demand for heating. However, the winter-summer price spread was almost non-existent in 2023/2024 and not sufficient to incentivise such commercial operations in 2024, with the same development expected in 2025.

With colder-than-usual winter weather and higher gas demand, combined with the expiration of the pipeline gas transit agreement between Russia and Ukraine, Q1 2025 saw net gas withdrawals surpassing the five-year average. Approximately 65 bcm of gas were withdrawn during the 2024/2025 winter season, marking a 51% increase from the previous year and the highest level in the last four years.

To meet the EU's minimum storage target of 90% by November 1, around 55 bcm of gas injections will be required during the 2025 summer season (Table 4). This large volume, combined with supply uncertainties and a tight LNG market, is expected to place upward pressure on spot gas prices.

Table 4: Gas storage targets in the EU in 2025

2025 Date	Minimum Storage Target	
	Percentage	Volume (bcm)
February 1	49%	51
May 1	30%	32
July 1	48%	50
September 1	74%	77
November 1	90%	94

Source: GECF Secretariat based on data from the European Commission and Cedigaz

5.1.2 Asia Pacific

Gas storage infrastructure expanded in China to support the stability of the domestic market

Despite being the world leader in gas consumption, the Asia Pacific region represents only 9% of global working gas capacity for underground storage. The key players in the region are China with 34 bcm of storage capacity, and Australia with 7 bcm.

China has made significant progress in expanding its gas storage infrastructure, in line with its strategic goal of increasing storage capacity to 13% of its annual gas demand. Currently, China ranks as the third-largest country globally in underground gas storage capacity, with 34 bcm of storage capacity, following the US and Russia. China's storage sites were nearing full capacity ahead of the 2024/2025 winter season, which contributed to reduced LNG imports during that period. The country aims to achieve a combined gas storage capacity (underground and LNG) of approximately 55 bcm by 2025, with further expansions expected to increase underground storage capacity to around 100 bcm by 2035.

Australia's gas storage volumes followed seasonal trends, with stock levels building up before the peak withdrawal period, which is during the Southern Hemisphere winter, lasting from June to August (Figure 161). In 2024, storage levels consistently remained below the five-year average, even dipping beneath the five-year range, as LNG exports increased. Despite this, winter withdrawals in 2024 were 70% higher than the five-year average (Figure 162).

India, which has already made significant progress in developing LNG regasification and storage infrastructure, also plans to build underground gas storage facilities with a projected capacity of approximately 4 bcm.

Figure 161: Monthly average UGS level in Australia

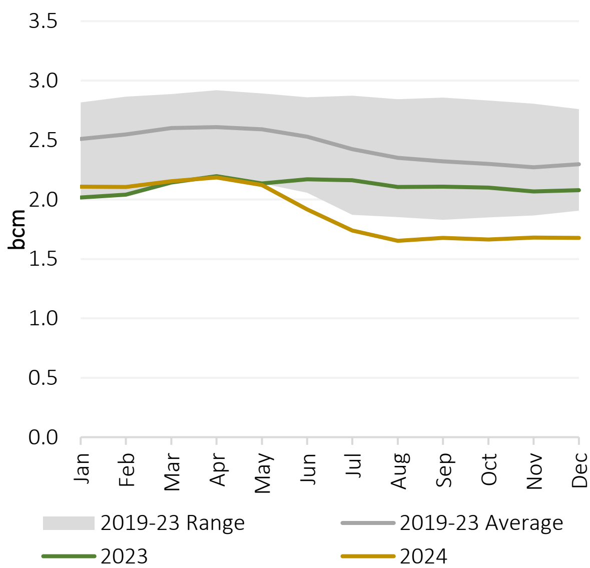
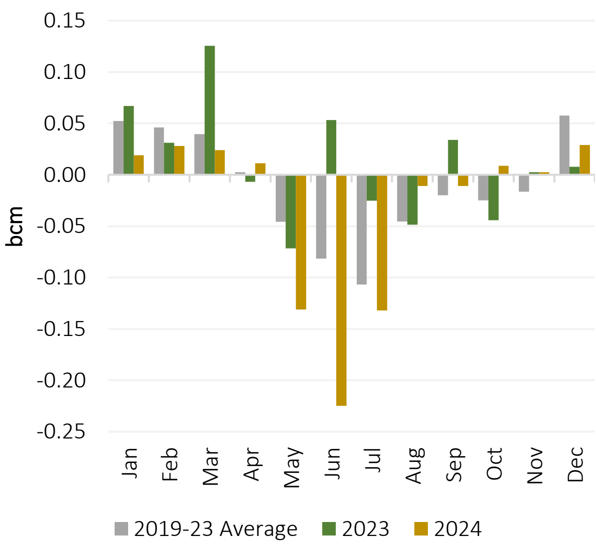


Figure 162: Net gas injections in Australia



Source: GECF Secretariat based on data from AEMO

5.1.3 North America

Gas storage was key to balance the domestic market amidst production shortfall

The US underground gas storage capacity reached 134 bcm in 2024. For most of the year, storage levels were higher than both the previous year and the five-year average, aided by strong storage levels at the end of 2023 and moderate heating demand during the 2023/2024 winter season (Figure 163). Net gas injections slowed after May, partly due to reduced gas production (Figure 164). In total, 49 bcm of gas was restocked over the summer of 2024, bringing the storage level to 84% by the start of the 2024/2025 winter season.

Figure 163: Monthly average UGS level in the US

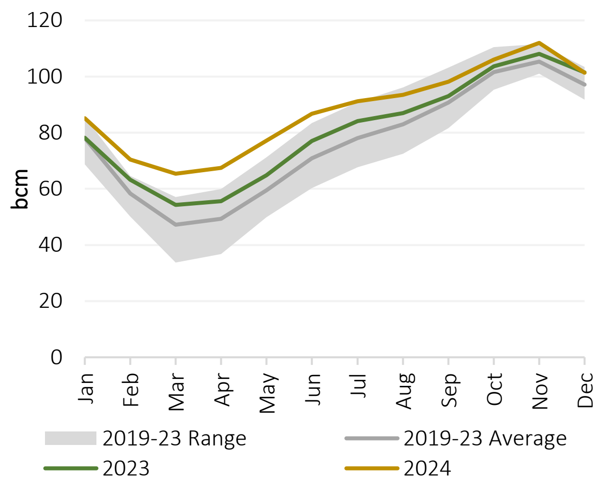
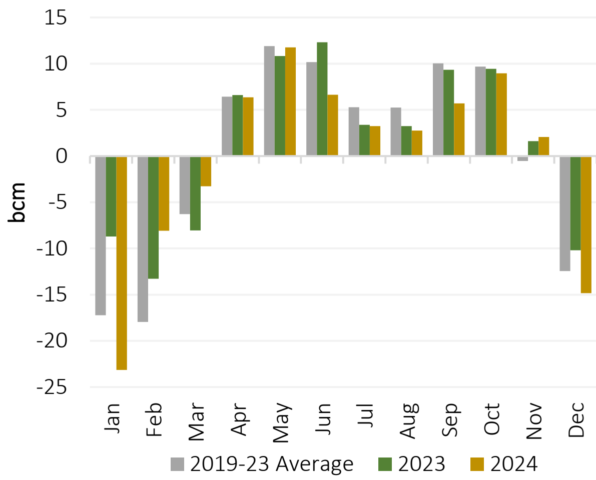


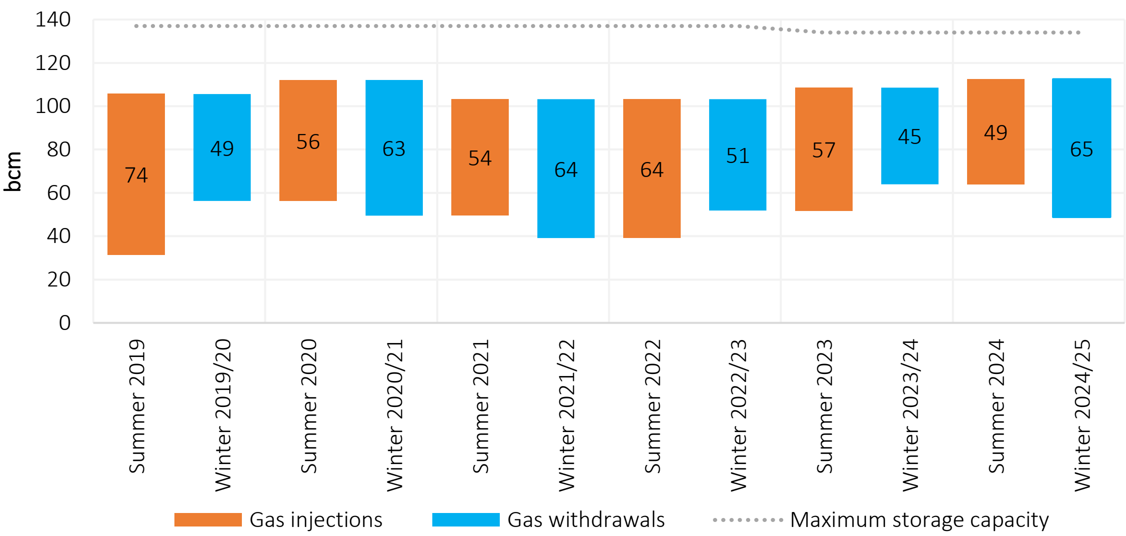
Figure 164: Net gas injections in the US



Source: GECF Secretariat based on data from US EIA

Although net gas withdrawals began around mid-November, later than in Europe, significant withdrawals occurred in December 2024, as well as January 2025, amidst winter heating demand and declining domestic gas production. Around 65 bcm was withdrawn during the 2024/2025 winter season, a notable increase compared to the previous year (Figure 165).

Figure 165: UGS injections and withdrawals in the US



Source: GECF Secretariat based on data from US EIA

5.2 LNG Storage

5.2.1 Europe

LNG storage contributed to balancing the regional gas market

By the end of 2024, EU countries operated LNG storage sites with a combined capacity of 5.4 bcm, up from 5.2 bcm at the start of the year. Spain and France hold the largest shares of the region's LNG storage capacity, at 38% and 16%, respectively. Germany, with its rapid expansion of LNG infrastructure, has 0.4 bcm of storage capacity, on par with the Netherlands and Italy.

Unlike underground gas storage, LNG storage in the EU follows a more flexible seasonal pattern, with the five-year range rising ahead of the winter season (Figure 166). In 2024, LNG storage levels went through three distinct phases: near the top of the five-year range at the start of the year, matching the five-year average during mid-year, and declining towards the lower end of the range in Q4 as winter heating demand increased. Almost 1 bcm of LNG was withdrawn in November and December 2024, around 2.5 times higher than both the previous year and significantly above the five-year average (Figure 167).

In 2025, LNG storage will remain a critical buffer for the EU's gas market, especially in light of reduced pipeline gas imports and the need for LNG to meet both domestic demand and replenish underground gas storage sites.

Figure 166: Monthly average EU LNG storage

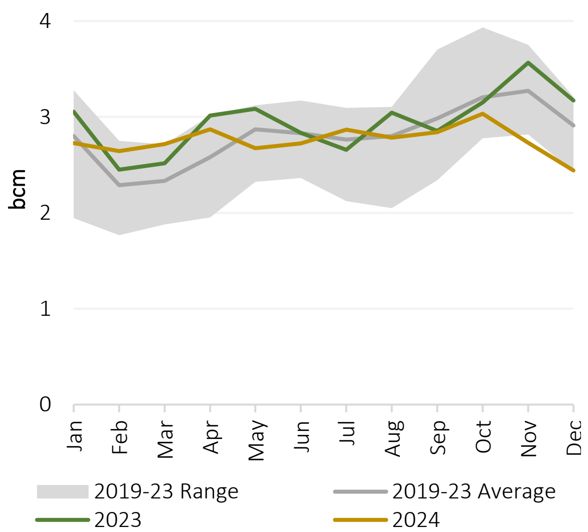
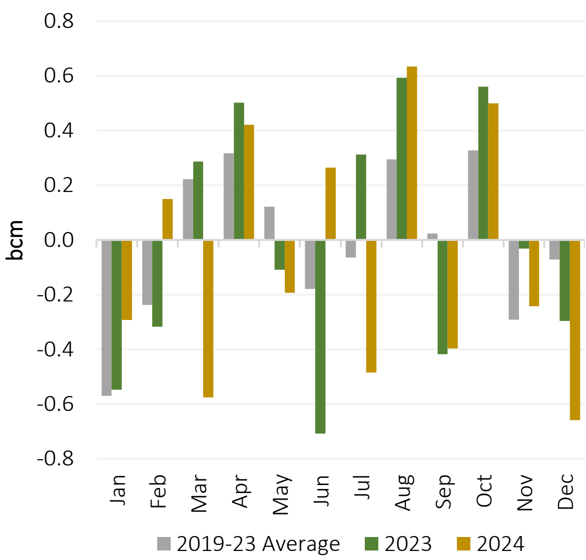


Figure 167: Monthly EU LNG stock changes



Source: GECF Secretariat based on data from ALSI

5.2.2 Asia Pacific

Summer cooling emerged as an additional driver for LNG storage

The Asia Pacific region leads the world in LNG storage, comprising 65% of global capacity. The countries in this region operate nearly 500 LNG storage tanks, with a total capacity of 36 bcm.

Japan and South Korea are key regional players, with LNG storage capacities of 11.5 bcm and 8.3 bcm, respectively. The combined LNG storage levels in these two countries generally follow a seasonal pattern, rising through the year in preparation for the winter season.

In Q1 2024, LNG storage levels declined due to reduced LNG imports, but were followed by a period of restocking in Q2 2024 (Figure 168). During the summer season, 1.5 bcm was withdrawn, with warmer temperatures in July and August creating an additional gas demand period, as gas-fired electricity was needed for summer cooling (Figure 169). However, gas storage levels remained above the five-year average by the end of the summer. Stocks were further replenished in October and November, reaching nearly 2 bcm above the five-year average by the end of the year.

Figure 168: Combined average LNG storage level in Japan and South Korea

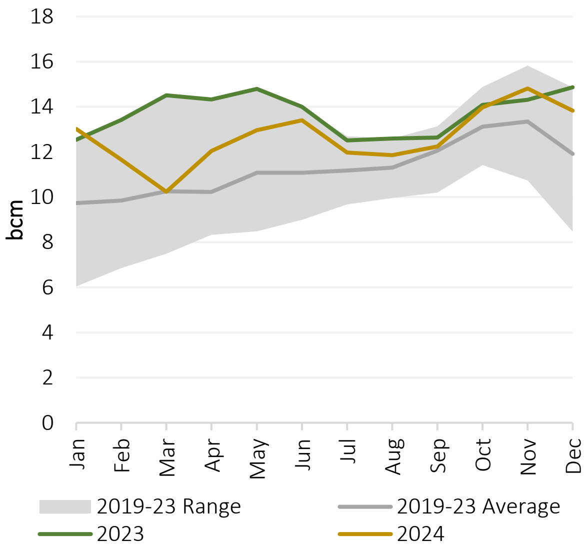
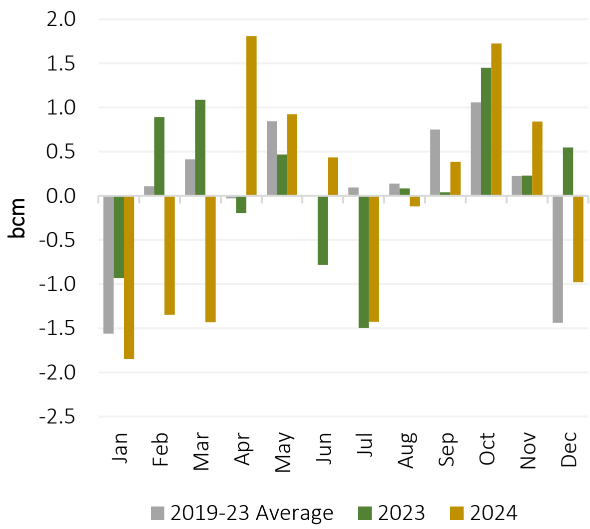


Figure 169: Monthly LNG stock changes in Japan and South Korea combined



Source: GECF Secretariat based on data from LSEG

China increased its LNG storage capacity to over 10 bcm as part of its national goal to ensure gas storage meets 13% of domestic gas demand. This capacity spans over 120 tanks at various sites across the country, including the ten-tank Jiangsu facility, which holds 1.4 bcm and features six of the world's largest LNG storage tanks.

India also expands its LNG storage capacity, driven by growing gas demand. Currently it operates 19 tanks at its import terminals with a combined capacity of 1.4 bcm.


Feb
Mar
Apr
May

CHAPTER

06

ENERGY PRICES

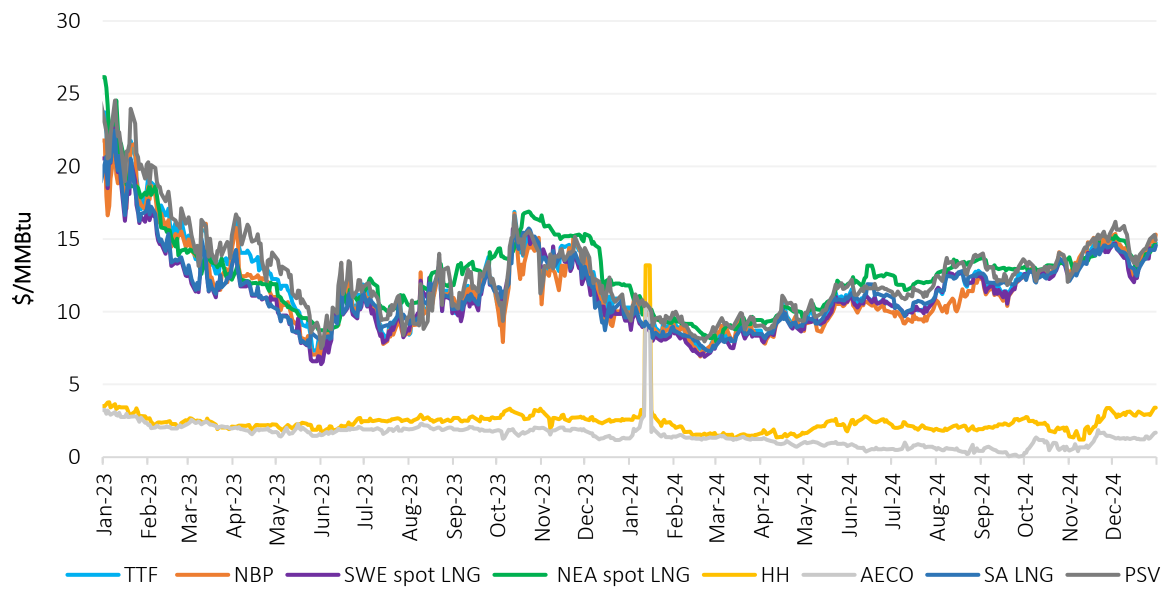
6.1 Gas Prices

6.1.1 Gas & LNG Spot Prices

Gas and LNG spot prices stabilised but remained elevated relative to pre-energy crisis levels

Global gas and LNG spot prices stabilised in 2024, offering a stark contrast to the extreme lows and record highs, as well as the unprecedented volatility experienced over the previous four years. This stabilisation was supported by a balanced supply-demand dynamic, with growing gas consumption matched by sufficient production growth, robust global trade, and higher storage levels in key regions such as Europe and Asia. Although global gas market fundamentals were relatively stable, geopolitical tensions and extreme weather events triggered some short-term price spikes throughout the year. Despite this stabilisation, gas prices remained elevated compared to pre-energy crisis levels (Figure 170).

Figure 170: 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 in Argentina, Brazil and Chile based on Argus assessment

In Q1 2024, spot prices in Europe and Asia initially followed a downward trend in January and February, driven by bearish market fundamentals, including strong supply, high storage levels, and weak demand due to above-normal temperatures. Despite some supply disruptions, volatility remained low, and prices were largely unaffected by geopolitical tensions. However, in March, spot prices reversed course, rising in response to colder weather forecasts, supply constraints caused by outages in the UK and Norway, as well as maintenance at the US Freeport LNG Trains 2 and 3, scheduled until May 2024. In the first quarter of the year, TTF and NEA LNG spot prices averaged $8.72/MMBtu (48% decline y-o-y) and $9.32/MMBtu (44% decline y-o-y), respectively.

In Q2 2024, this upward trend continued with spot prices steadily increasing, driven primarily by colder weather, maintenance activities in Norway, and increased interest from Asian buyers. In May, prices were further fuelled by geopolitical instability, outages at major LNG facilities in Australia, Malaysia and the US, and emerging demand in Northeast Asia. By June, supply constraints from extended maintenance and outages, coupled with rising LNG demand in South Asia due to heatwaves, sustained the bullish sentiment. However, high European gas storage levels and subdued demand from some major Asian importers moderated price increases. In the second quarter of the year, TTF and NEA LNG spot prices averaged $10.02/MMBtu (12% decline y-o-y) and $11.00/MMBtu (3% increase y-o-y), respectively.

In Q3 2024, spot prices in Europe and Asia exhibited mixed trends. In July, prices declined following a four-month rally due to subdued demand and ample supply, despite some bullish sentiment from concerns over Freeport LNG supply. However, in August, prices surged driven by escalating geopolitical tensions and increased cooling demand. Despite this, high storage levels and strong LNG supply helped cap further price increases. By September, prices declined again as supply concerns eased and demand weakened, even amid bullish factors such as extended maintenance at several Norwegian facilities and continued outages at LNG facilities in Australia and Malaysia. In the third quarter of the year, TTF and NEA LNG spot prices averaged $11.40/MMBtu (8% increase y-o-y) and $12.76/MMBtu (7% increase y-o-y), respectively.

In Q4 2024, spot prices regained upward momentum, driven primarily by weather-related demand and supply concerns. In October, European prices increased due to unplanned Norwegian outages and rising geopolitical tensions, while Asian prices remained stable amid soft demand and high storage levels. November saw prices rise further, fuelled by colder weather, supply concerns, and reduced wind power generation. By December, European prices stabilised, and Asian prices saw a slight increase, with colder temperatures boosting heating demand. In the fourth quarter of the year, TTF and NEA LNG spot prices averaged $13.48/MMBtu (5% increase y-o-y) and $13.79/MMBtu (5% decrease y-o-y), respectively.

In 2024, annual gas and LNG spot prices were 12-15% lower y-o-y with TTF, NEA LNG and HH spot prices averaging $10.9/MMBtu, $11.7/MMBtu and $2.2/MMBtu, respectively. Moreover, spot prices were much lower compared to the record high prices observed in 2022, when TTF, NEA LNG and HH spot prices averaged $37.6/MMBtu, $33.2/MMBtu and $6.4/MMBtu, respectively (Table 5).

Table 5: Annual gas and LNG spot prices in 2014-2024 ($/MMBtu)

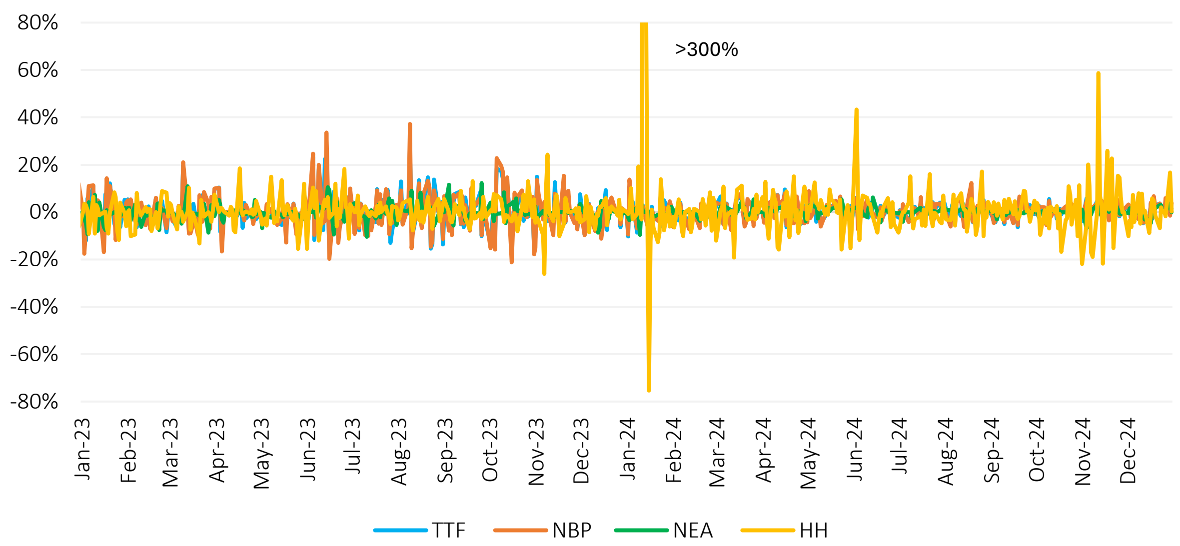
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TTF	8.1	6.4	4.5	5.7	7.9	4.5	3.2	15.9	37.6	12.9	10.9
NEA spot LNG	12.3	7.6	5.8	7.2	9.8	5.4	4.4	18.6	33.2	13.5	11.7
HH	4.4	2.6	2.5	3.0	3.2	2.6	2.0	3.9	6.4	2.5	2.2

Source: GECF Secretariat based on data from Argus and LSEG

Spot prices in Europe and Asia demonstrated significantly lower volatility in 2024 compared to 2023. Daily variations in TTF and NBP spot prices tracked each other closely ranging from -9% to 14%. NEA LNG spot prices showed slightly lower volatility, with daily variations ranging from -10% to 7%. In contrast, Henry Hub spot prices experienced higher volatility, with daily swings ranging from -75% to 319% throughout the year (Figure 171).

The cumulative annual price variability, which represents the total of absolute daily price changes over the year, offers a clear measure of price volatility. In 2024, the annual variability of TTF and NBP spot prices was 72 and 78, respectively, marking a significant decline from 169 and 186 in 2023. In Asia, the annual variability of NEA LNG spot prices was 38, down from 80 in 2023. As a result, spot price volatility in 2024 for both Europe and Asia was more than 50% lower than in 2023. Notably, the annual variability of Henry Hub spot prices was 51, increasing from 26 in 2023.

Figure 171: 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

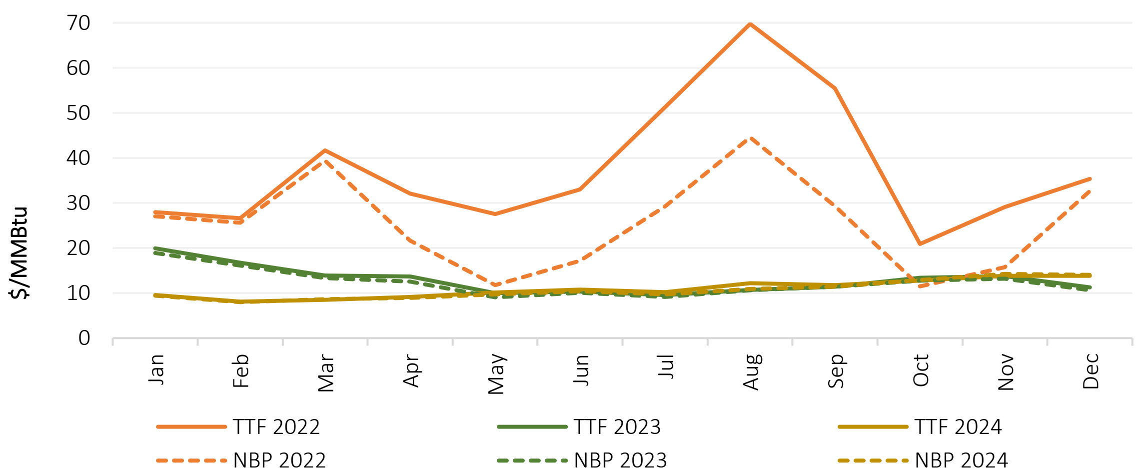
Spot prices in Europe declined due to high gas storage levels and milder winter weather

The TTF spot gas price averaged $10.90/MMBtu in 2024, reflecting a 15% decrease from the 2023 average of $12.90/MMBtu. Similarly, the NBP spot gas price declined to an average of $10.71/MMBtu, marking a 13% drop from the 2023 average of $12.33/MMBtu (Figure 172).

In January-February 2024, European spot prices dropped primarily due to mild weather, balanced market fundamentals, and ample gas and LNG supplies. This trend persisted despite minor disruptions, such as strong winds affecting LNG deliveries at the UK's Dragon regasification terminal and unplanned maintenance at Norway's Troll gas field and Nyhamna gas processing plant. However, in March, prices rose as colder-than-usual weather and supply outages in the UKCS and Norway exerted upward pressure. This bullish trend continued from April to June, driven by factors including ongoing cold weather, escalating geopolitical instability, planned maintenance in Norway, and outages at key LNG facilities, including US's Cameron LNG.

In July 2024, prices declined as strong supply, subdued demand, and steady Norwegian output outweighed bullish factors such as the delayed restart of Freeport LNG, shut down as a precaution ahead of Hurricane Beryl. However, in August, prices surged to an 8-month high, driven by geopolitical tensions, ongoing Norwegian maintenance and heatwaves in southern Europe. By September, prices fell again as supply concerns eased and demand remained weak. In October, prices spiked due to unplanned outages in Norway, reduced US LNG feedgas flows, and seasonal maintenance at Qatar's Ras Laffan terminal. November saw further price increases, fuelled by colder temperatures, reduced wind generation, and heightened heating demand, which led to higher storage withdrawals. By December, colder-than-usual weather and continued supply concerns — including uncertainty surrounding the expiration of the Russia-Ukraine gas transit deal on 1 January 2025 — maintained upward pressure on prices, with daily prices reaching the highest level of the year at $14.91/MMBtu.

Figure 172: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

6.1.1.2 Asian Spot LNG Prices

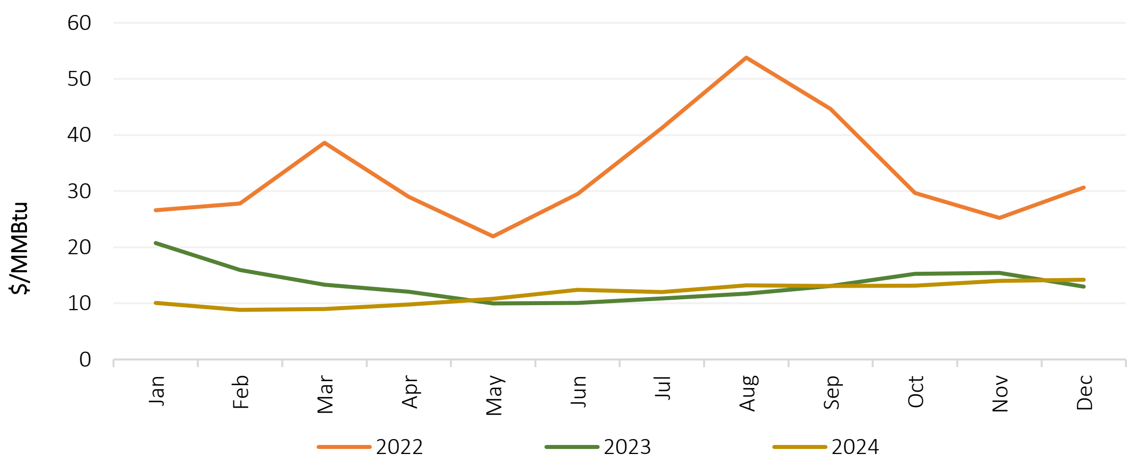
Spot prices in Asia fell amid subdued demand, ample LNG supply and high inventory levels

The Northeast Asia (NEA) spot LNG price decreased by 13% to average $11.72/MMBtu in 2024, down from $13.47/MMBtu in 2023 (Figure 173).

In January-February 2024, Asian LNG prices saw a decline influenced by mild weather, subdued demand, high inventory levels, and strong supply. Factory closures during the Chinese Lunar New Year further suppressed industrial demand, while supply issues in the US had minimal impact. Prices rebounded in March as colder weather forecasts in South Korea and Japan prompted increased buying activity. By April, spot prices continued to rise due to restocking efforts in Japan and demand from price-sensitive importers. In May, prices continued to climb, driven by storage replenishment in South Korea and Japan, while ongoing LNG facility outages tightened supply. By June, high temperatures in South Asia, reduced inventories in Japan, and supply concerns pushed prices up, though some Chinese buyers remained cautious due to unappealing spot prices.

In July 2024, Asian LNG spot prices fell again as subdued demand and ample supply offset concerns over Freeport LNG's supply return. August saw prices surge to an 8-month high, driven by geopolitical tensions, LNG facility outages in Australia and Malaysia, and increased cooling demand from Japan and South Korea. In September, prices slightly declined as regional demand weakened, while in October, prices remained stable with balanced market fundamentals. November saw prices rise again, with daily prices reaching the highest annual level of $15.30/MMBtu due to colder temperatures tightening supply-demand dynamics. By December, prices edged up slightly due to cold weather in some regions, though gains were tempered by weaker demand from China and healthy LNG inventories across the region.

Figure 173: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus and LSEG

6.1.1.3 North American Spot Gas Prices

The Henry Hub (HH) spot gas price averaged $2.23/MMBtu in 2024, reflecting a 12% decline from the 2023 average of $2.53/MMBtu. Meanwhile, in Canada, the Alberta Energy Company (AECO) spot gas price dropped significantly by 47%, averaging $1.04/MMBtu compared to the previous year's $1.96/MMBtu (Figure 174).

HH spot prices surged in January 2024, peaking at daily high of $13.20/MMBtu due to extreme cold weather. However, from February to April, prices dropped sharply amid mild temperatures, high storage levels and a decline in LNG exports. A rebound occurred in May and June, supported by increased power sector demand and falling domestic production. In July and August, prices fell as rising production and high storage levels dampened upward pressure. Daily HH spot prices hit a multi-year low of $1.21/MMBtu in November, before surging to a 23-month high of $3.40/MMBtu in December due to a cold spell, high heating demand and falling production.

AECO spot prices remained bearish throughout the year, dropping below $1/MMBtu from May to October 2024, reflecting strong gas production, subdued demand and reduced pipeline gas exports to the US. Subsequently, in November and December, AECO spot prices saw some upward movement rising above $1/MMBtu.

6.1.1.4 South American Spot LNG Prices

The South American (SA) LNG price averaged $10.87/MMBtu in 2024, reflecting an 11% decrease from the 2023 average of $12.16/MMBtu (Figure 175). LNG spot prices in South America followed similar trends to those observed in Europe and Asia. The average delivered LNG prices for Argentina, Brazil and Chile reached $10.87/MMBtu, $10.68/MMBtu and $11.04/MMBtu, respectively.

Figure 174: Monthly North American gas spot prices

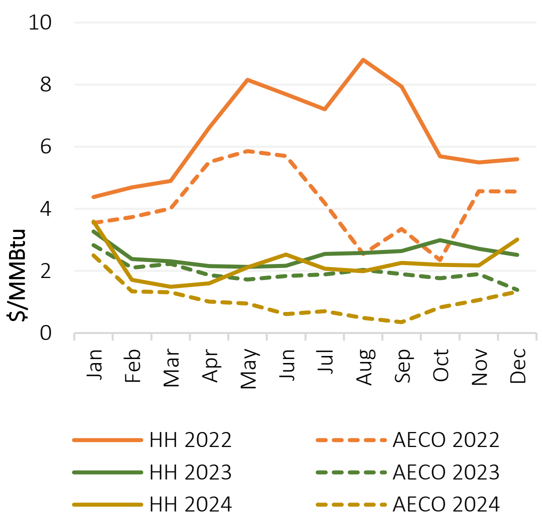
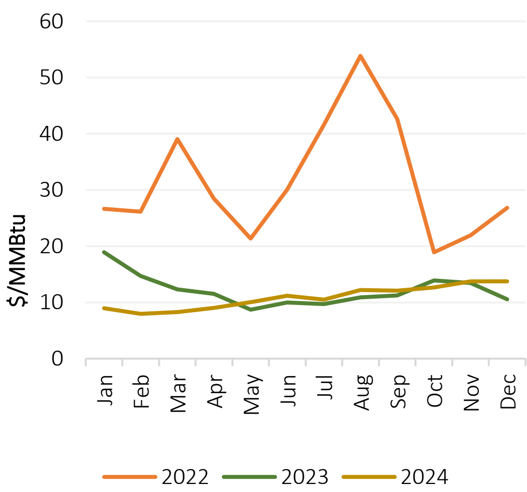


Figure 175: Monthly South American LNG spot prices



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

6.1.2 Spot and Oil-indexed Long-Term LNG Price Spreads

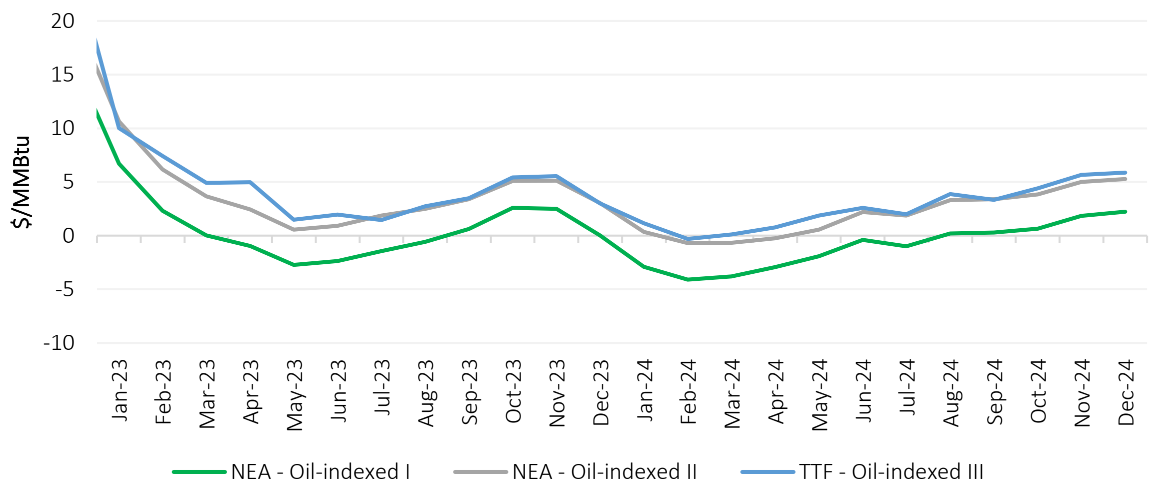
Oil-indexed LNG prices traded at a marginal discount to spot LNG prices in Europe and Asia

The Oil-Indexed I LNG price averaged $12.71/MMBtu in 2024, reflecting a 2% decrease compared to the previous year, while the Oil-Indexed II LNG price averaged $9.70/MMBtu, remaining largely stable (Figure 176). Both pricing formulas are applied to LNG supplies to Asia. The Oil-Indexed I price formula estimates oil-linked prices in traditional long-term contracts, with an average slope of 14.9% and a 6-month historical Brent price average. In contrast, the Oil-Indexed II formula, used for more recent contracts, calculates the slope annually based on a 5-year historical average from long-term agreements. In 2024, the average slope for Oil-Indexed II was 11.4%, and the formula used a 3-month historical average of the Brent price.

In terms of spot and oil-indexed long-term LNG price spreads, Oil-indexed I prices traded at an average premium of $3/MMBtu over the NEA spot LNG price in the first half of the year, as spot prices were relatively soft. However, in the second half of the year, there was a shift in the trend with Oil-indexed I prices trading at an average discount of $1/MMBtu. Overall, in 2024, the average Oil-indexed I price traded at a slight premium of $1/MMBtu, compared to an average discount of $1/MMBtu in 2023. For the Oil-indexed II prices, the average discount to the NEA spot LNG price narrowed to $2/MMBtu in 2024 compared to $4/MMBtu in 2023.

In Europe, the Oil-Indexed III price, based on Argus' assessment for long-term contracts, averaged $8.30/MMBtu in 2024, representing a 3% decline from the previous year. The average Oil-Indexed III price continued to trade at an average discount of $3/MMBtu relative to the TTF spot price, a slight reduction from the $4/MMBtu average discount recorded in 2023.

Figure 176: Spot and oil-indexed price spreads



Source: GECF Secretariat based on data from Argus and LSEG

Note: Oil-indexed I (using traditional LTC slope): 14.9% X Brent (6 0 1) + 0.5

Oil-indexed II (using 5-year historical average LTC): (2023 – 11.1%; 2024 – 11.4%) % X Brent (3 0 1) + 0.5

Oil-indexed III: Argus assessment for European LTC.

6.1.3 Regional Spot Gas & LNG Price Spreads

Asian LNG prices maintained a slight premium over TTF spot prices

The NEA-TTF inter-basin price spread in 2024 widened slightly, averaging $0.81/MMBtu, slightly higher than the spread of $0.57/MMBtu in 2023 (Figure 177).

This spread provides a good indication of LNG flows in Europe and Asia, reflecting shifts in regional supply and demand dynamics. Historically, Europe functioned as the market of last resort for LNG cargoes, with Asian LNG prices typically commanding a premium over European prices to secure a steady inflow of supply. However, in 2022, this long-standing trend changed as the energy crisis reshaped global trade flows. That year, the spread turned negative, averaging approximately -$4/MMBtu, as surging European demand pushed TTF spot prices well above NEA spot LNG prices.

Over the past two years, the annual spreads have gradually re-aligned with historical trends. In 2024, NEA spot LNG prices consistently traded a premium over TTF spot prices, with the spread peaking at $1.75/MMBtu in July. However, the monthly average spread remained below $2/MMBtu during the year, reflecting a closer alignment between spot prices in Europe and Asia. This trend towards greater price convergence was driven by relatively balanced supply and demand fundamentals in both regions, along with subdued Asian demand, which resulted in only a marginal price premium over the year. Notably, while Asia regained its premium pricing over Europe, the gap remains relatively narrow, reflecting a more integrated and flexible global LNG market. The evolving dynamics underscore the increasing interconnectivity between the two regions, where shifts in one market can rapidly influence price movements and trade flows in the other.

The average TTF-HH spread narrowed slightly in 2024 to $9.49/MMBtu, compared to $10.36/MMBtu in 2023 (Figure 178). This was largely attributed to the decline in European spot prices, as well as the uptick in Henry Hub prices.

Figure 177: NEA-TTF price spread

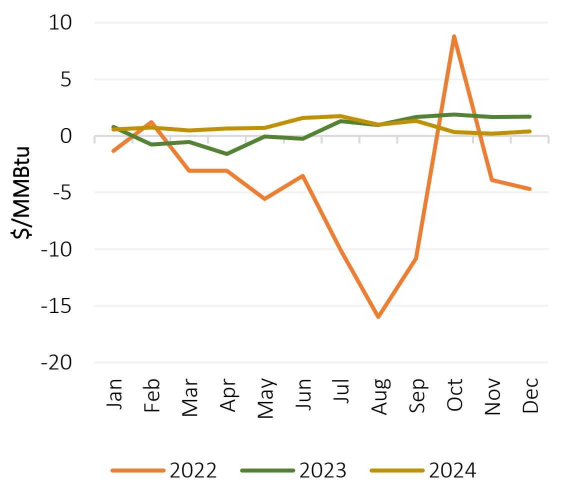
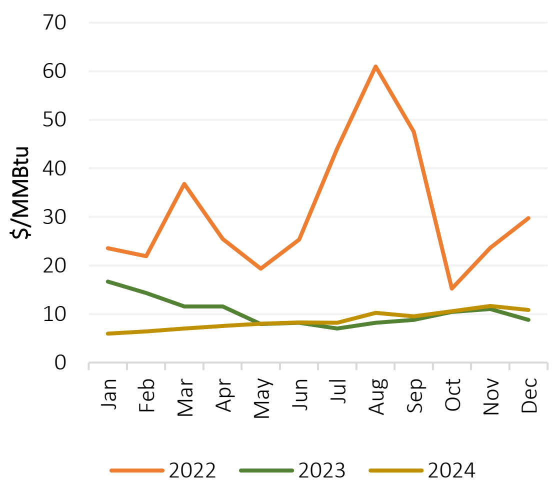


Figure 178: TTF-HH price spread



Source: GECF Secretariat based on data from Argus and LSEG

6.2 Cross Commodity Prices

Gas prices held a discount to oil parity prices but a premium over coal parity prices

6.2.1 Oil Prices

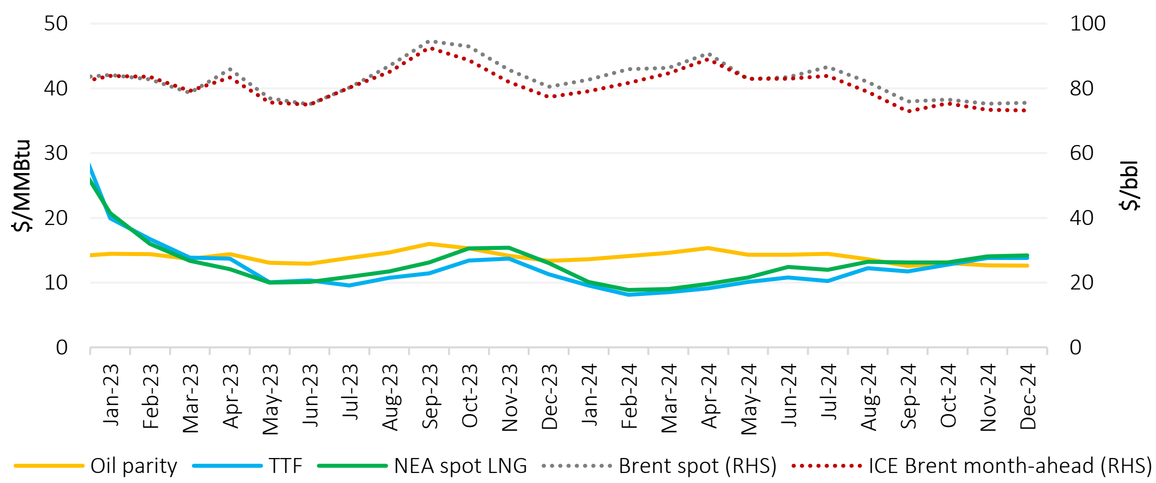
The Brent spot price averaged $82.00/bbl in 2024, reflecting a 2% decrease compared to the previous year. Likewise, the Brent month-ahead price dropped by 3% to average $79.84/bbl.

In Q1 2024, oil prices rebounded after a 3-month decline, driven by geopolitical tensions in the Middle East and expectations of tighter supply, despite concerns over global economic growth, particularly in China. Prices remained elevated in April, surpassing $90/bbl, but declined in May due to demand concerns and high inventories. In June, OPEC+ extended production cuts of 3.66 million bpd until the end of 2025, while voluntary cuts of 2.2 million bpd were extended until September 2024, with a gradual phase-out from October 2024 to September 2025. Oil prices rebounded amid geopolitical risks, weather-related supply disruptions, declining US crude inventories, and stronger manufacturing growth in China.

In Q3 2024, oil prices fluctuated due to geopolitical tensions, supply risks and demand concerns. Prices rose in July due to fears of supply disruptions from Hurricane Beryl and escalating Middle East tensions, though weak Chinese imports capped gains. In August and September, prices fell as slow demand growth, rising US crude inventories, and weak Chinese industrial activity outweighed geopolitical risks and production shut-ins related to Hurricane Helene. In October, prices rebounded on intensifying geopolitical tensions and potential supply disruptions, but resumed their decline in November and December as bearish market fundamentals and slowing Chinese demand weighed on prices.

In this context, in 2024, TTF spot prices traded at an average discount of $2.9/MMBtu compared to the oil parity price, while NEA LNG prices held a $2.0/MMBtu discount (Figure 179).

Figure 179: Monthly crude oil prices



Source: GECF Secretariat based on data from 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

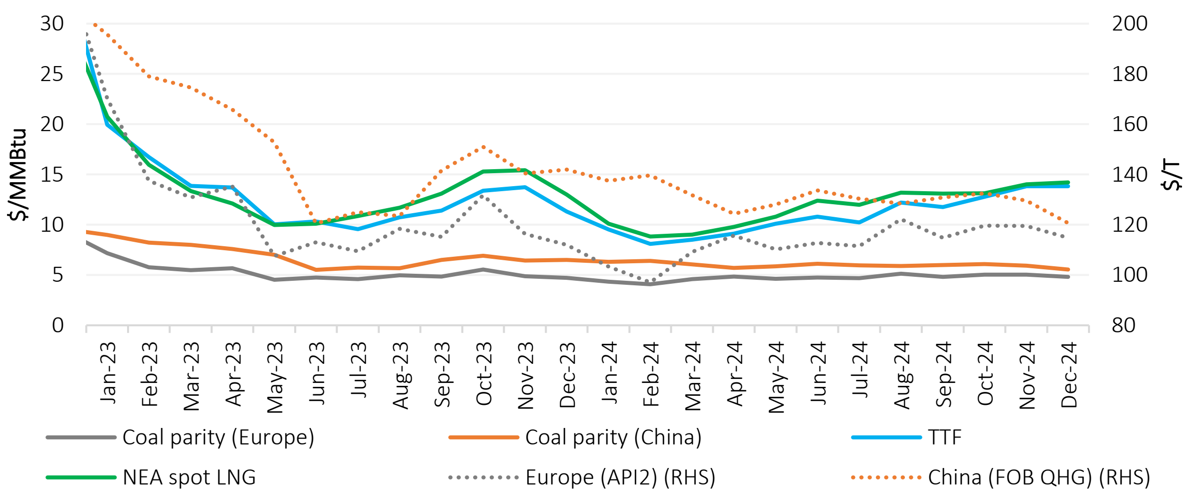
Global coal prices saw a decline in 2024, reflecting shifts in market dynamics across key regions. In Europe, the average API2 coal price dropped by 10% to reach $112.56/t, while in China, the average Qinhuangdao (QHG) coal price reduced by 13% to reach $130.62/t.

European coal prices exhibited significant volatility throughout the year, influenced by fluctuating demand, stable supply conditions, competition from alternative energy sources, gas price movements and geopolitical developments. Prices initially dropped from January to February, reaching a low of $97/t due to mild weather and lower gas prices, which encouraged a shift from coal to gas. A price rebound occurred in March and April, spurred by rising gas prices and supply disruptions, particularly following the Baltimore Bridge collapse. However, in May, coal prices declined again, driven by weak demand and a recovery in US coal exports. In August, prices surged once more, supported by climbing gas prices and expectations of colder weather, which increased demand for coal for heating and power generation in the coming months.

Chinese coal prices followed a clear pattern, shaped by domestic demand, sufficient coal supply, and ample inventory levels. In April, prices dropped significantly due to subdued demand and high stockpiles. However, they rebounded in May and June as buyers began stockpiling in anticipation of the summer season. Prices weakened again in July and August, influenced by a decline in industrial demand across China. A slight uptick in September was driven by increased energy needs, while October saw further price gains as industrial activity picked up and demand strengthened. However, by December, Chinese coal prices reached a monthly low of $121/t.

In this context, the premium of TTF spot price over the API2 parity price dropped by 19% to average $6.2/MMBtu, while the premium of NEA spot LNG price over the QHG parity price decreased by 12% to average $5.7/MMBtu (Figure 180).

Figure 180: 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

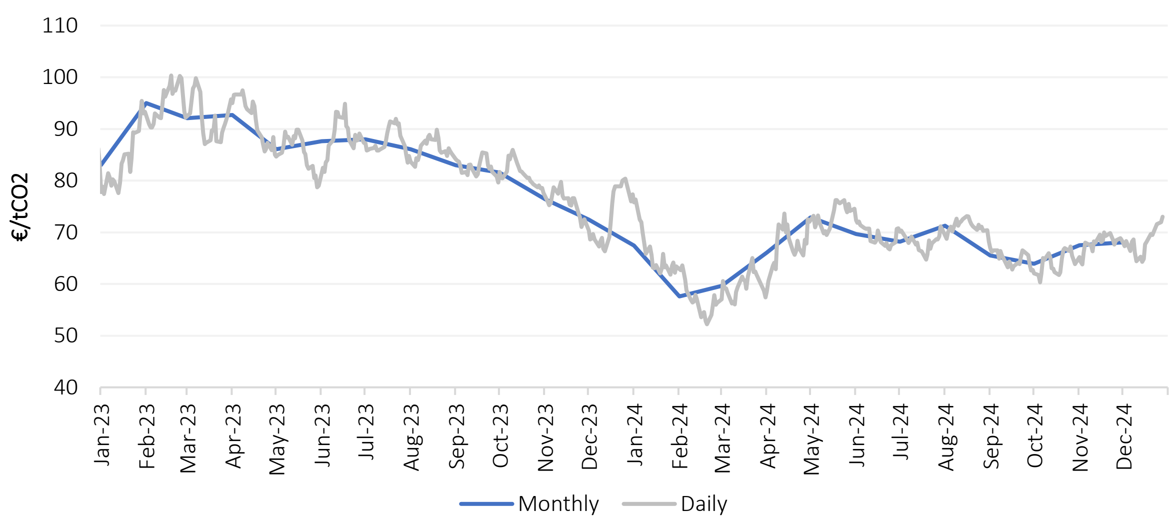
Globally, there are around 40 emissions trading systems (ETSs), covering nearly 20% of global greenhouse gas emissions, with the EU ETS being the first and largest carbon market. The EU carbon price averaged €66.47/tCO_2 in 2024, reflecting a 22% decline compared to the average of €85.33/tCO_2 in 2023 (Figure 181).

In the first half of 2024, EU carbon prices were marked by considerable volatility. The year began with prices falling sharply from a daily high of €77/tCO_2 in early January to €52/tCO_2 by mid-February, the lowest level since January 2021. This drop was primarily due to weak market fundamentals, including reduced demand from the power and industrial sectors, which led to lower demand for European Union Allowances (EUAs). However, between March and May, EU carbon prices rebounded, largely following gains in TTF spot prices, peaking at €76/tCO_2. In June, prices dipped again after a 3-month rally, as an increase in new auctions expanded the supply of EU allowances, putting downward pressure on the market.

In the second half of 2024, EU carbon prices continued to fluctuate. Prices declined in July due to softer EUA demand and strong renewable energy output, but rebounded in August as increased gas and coal consumption for cooling boosted demand. In September and October, prices fell again, reaching a 6-month low of €60/tCO_2, driven by the completion of EU ETS compliance at the end of September and mild weather that reduced heating demand. However, colder-than-usual temperatures and lower wind generation in November and December led to a surge in EUA demand, pushing prices to a 4-month high of €73/tCO_2 by year-end.

Notably, the inclusion of maritime transport into the EU ETS took effect from 1 January 2024. This inclusion is being phased in gradually, starting with 40% of verified emissions in 2024, increasing to 70% in 2025, and achieving full coverage by 2026.

Figure 181: EU carbon prices



Source: GECF Secretariat based on data from LSEG

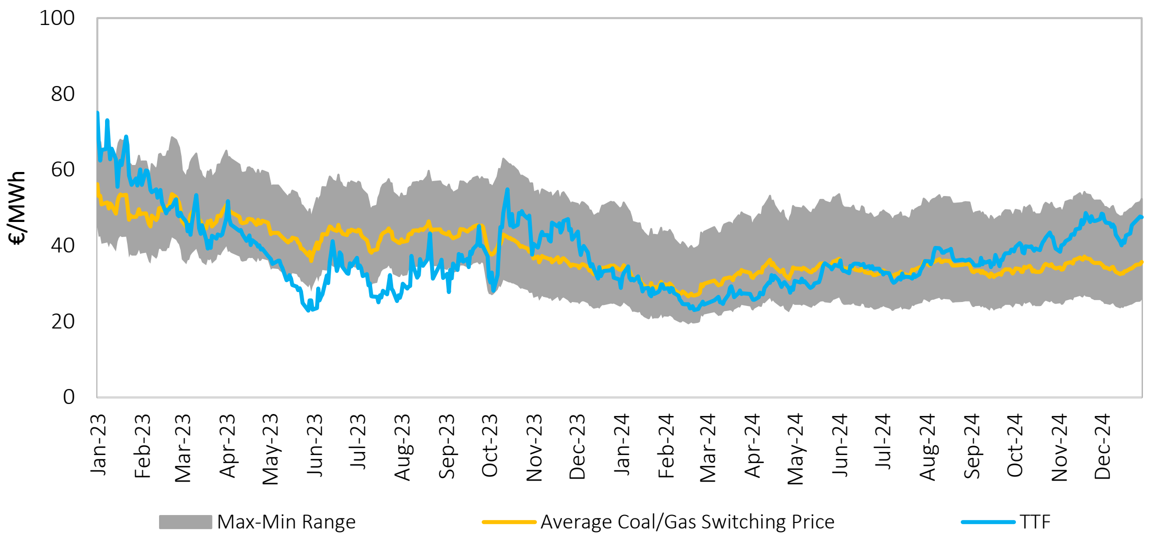
6.2.4 Fuel switching

Daily TTF spot prices generally remained within the range conducive to coal-to-gas switching in 2024. The average coal-to-gas switching price dropped by 23%, settling at €33.08/MWh, while the TTF spot price averaged €34.23/MWh. As a result, the TTF spot price held an average premium of €1.15/MWh over the coal-to-gas switching price, potentially reducing the incentive for fuel switching, particularly for less efficient coal power plants (Figure 182).

From January to July 2024, the monthly spread between the TTF spot price and the average coal-to-gas switching price was negative, encouraging coal-to-gas switching, as gas-fired power plants became more cost-effective. However, from August to December 2024, the spread shifted to positive, reaching €11/MWh in December as TTF spot prices peaked. This shift likely led to a decline in coal-to-gas switching during the latter half of the year.

Looking ahead to 2025, TTF spot prices are expected to rise, further widening the gap above the average coal-to-gas switching price. While TTF prices will remain within the coal-to-gas switching range, the incentive for coal-to-gas switching in the region is likely to diminish.

Figure 182: Daily TTF vs coal-to-gas switching prices



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

ANNEXES

Gas Market Data

Region	2019	2020	2021	2022	2023	2024
1. Gas consumption (bcm)						
Global	**3970**	**3857**	**4047**	**4062**	**4070**	**4170**
Africa	173	166	173	173	177	183
Asia Pacific	847	850	909	895	916	980
Eurasia	635	603	654	641	648	660
Europe	548	500	525	513	446	451
LAC	154	143	158	150	149	150
Middle East	533	540	551	562	581	588
North America	1079	1055	1076	1129	1138	1158
2. Gas production (bcm)						
Global	**4016**	**3905**	**4082**	**4052**	**4080**	**4179**
Africa	267	244	275	266	271	255
Asia Pacific	651	645	663	666	670	681
Eurasia	904	847	944	842	825	887
Europe	232	215	206	214	199	202
LAC	176	160	162	165	163	167
Middle East	630	644	657	661	665	697
North America	1155	1150	1174	1237	1287	1290
3. Total gas imports (bcm)						
Global	**1167**	**1131**	**1211**	**1165**	**1125**	**1165**
Africa	9	11	12	15	17	22
Asia Pacific	405	416	452	425	436	470
Eurasia	67	58	48	47	49	54
Europe	451	416	451	437	376	359
LAC	27	27	36	27	27	29
Middle East	42	46	43	43	43	45
North America	164	157	168	173	177	185

Region/Market	2019	2020	2021	2022	2023	2024
Pipeline gas imports						
Global	**686**	**644**	**697**	**624**	**572**	**606**
Africa	9	11	12	15	17	19
Asia	71	69	79	81	79	86
Eurasia	67	58	48	47	49	54
Europe	336	304	345	265	208	221
LAC	14	13	13	12	10	9
Middle East	32	36	33	34	33	33
North America	156	153	166	171	175	183
LNG imports						
Global	**481**	**487**	**514**	**541**	**553**	**559**
Africa	0	0	0	0	0	3
Asia Pacific	334	347	373	344	357	384
Europe	115	112	106	172	168	138
LAC	13	14	23	15	17	20
Middle East	10	10	10	9	10	12
North America	8	4	2	2	2	2
4. Gas & LNG spot prices ($/MMBtu)						
TTF	4.46	3.18	15.91	37.57	12.90	10.90
North East Asia (NEA) LNG	5.44	4.36	18.60	33.24	13.47	11.72
HH	2.56	2.03	3.91	6.43	2.53	2.23

Source: GECF Secretariat based on data from Argus, Cedigaz, ICIS LNG Edge, LSEG and Rystad Energy

Regional Grouping

Term	Meaning
Advanced Economies (AEs)	Australia, Austria, Belgium, Canada, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hong Kong, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Macau (China), Malta, Netherlands, New Zealand, Norway, Portugal, Puerto Rico, San Marino, Singapore, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Taiwan (Province of China), United Kingdom, United States
Africa	Algeria, Angola, Benin, Central African Rep., Congo, Democratic Republic of the Congo, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Ghana, Gabon, Ivory Coast, Kenya, Libya, Mali, Mauritania, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe
Asia Pacific	Afghanistan, Australia, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Cook Islands, Democratic People's Republic of Korea, Fiji, French Polynesia, Hong Kong, India, Indonesia, Japan, Kiribati, Korea, Lao People's Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan (Province of China), Thailand, Timor-Leste, Tonga, Vanuatu and Vietnam
Emerging Markets and Developing Economies (EMDEs)	All other countries not included in "Advanced Economies"
Eurasia	Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan
Europe	European Union and Albania, Bosnia and Herzegovina, Gibraltar, Iceland, Macedonia, Moldova, Montenegro, Norway, Serbia, Switzerland, Türkiye and the United Kingdom
European Union	Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg,

	Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden
Euro area	Austria, Belgium, Croatia, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Portugal, Slovakia, Slovenia and Spain
G7	Canada, France, Germany, Italy, Japan, the United Kingdom and the United States
G20	Argentina, Australia, Brazil, Canada, China, EU, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russia, Saudi Arabia, South Africa, South Korea, Türkiye, the United Kingdom and the United States
GECF Members	Algeria, Bolivia, Egypt, Equatorial Guinea, Libya, Iran, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela
GECF Observers	Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal
Latin America and the Caribbean (LAC)	Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belise, Bermuda, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay and Venezuela
Middle East	Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates and Yemen
Middle East and North Africa (MENA)	Algeria, Bahrain, Egypt, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, United Arab Emirates and Yemen
North America	Canada, Mexico and United States
OECD Countries	Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany,

	Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Spain, Sweden, the Slovak Republic, Slovenia, Switzerland, Türkiye, the United Kingdom and the United States
OECD Americas	Canada, Chile, Mexico and the United States
OECD Asia Oceania	Australia, Japan, Korea and New Zealand
OECD Europe	Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Sweden, the Slovak Republic, Slovenia, Switzerland, Türkiye and the United Kingdom
South America	Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, French Guyana, Guyana, Paraguay, Peru, Suriname, Uruguay and Venezuela

Abbreviations

Abbreviation	Explanation
ACQ	Annual contracted quantity
AE	Advanced economies
AECO	Alberta Energy Company
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
BOE	Bank of England
CAGR	Compound annual growth rate
CBAM	Carbon border adjustment mechanism
CBM	Coal bed methane
CCGT	Combined cycle gas turbine
CCS	Carbon, capture and storage
CCUS	Carbon capture, utilisation and storage
CNG	Compressed natural gas
CO_2	Carbon dioxide
CPI	Consumer price index
EC	European Commission
ECB	European Central Bank
EEXI	Energy efficiency existing ship index
EMDE	Emerging markets and developing economies
EU	European Union
EU ETS	European Union emissions trading system
EUA	European Union allowance
Fed	Federal Reserve
FEED	Front end engineering design
FID	Final investment decision

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 Organisation
JKM	Japan Korea Marker
LNG	Liquefied natural gas
LAC	Latin America and the Caribbean
LT	Long-term
MEA	Middle East and Africa
MENA	Middle East and North Africa
MER	Market exchange rates
METI	Ministry of Trade and Industry in Japan
MMBtu	Million British Thermal Unit
Mt	Million tonnes
Mtpa	Million tonnes per annum
MWh	Megawatt hour
NEA	North East Asia
NBP	National balancing Point
NDC	Nationally determined contribution
NGV	Natural gas vehicle
NZBA	Net-Zero Banking Alliance
OECD	Organisation for Economic Co-operation and Development
PBC	People’s Bank of China

PPAC	Petroleum Planning & Analysis Cell
PPP	Purchasing power parity
PSV	Punto di Scambio Virtuale (Virtual Trading Point in Italy)
QHG	Qinhuangdao
R-LNG	Regasified LNG
SA	South America
SPA	Sales and purchase agreement
SWE	South West Europe
T&T	Trinidad and Tobago
TANAP	Trans-Anatolian Gas Pipeline
tcm	Trillion cubic metres
tCO_2	Ton 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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