



GECF

**ANNUAL SHORT TERM  
GAS MARKET REPORT**

**2022**



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# **2022**

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## Foreword

The third edition of the GECF's Annual Short Term Gas Market Report (ASTGMR) is published at a time when the world is facing a multifaceted crisis, and one of the worst energy crises in history, as epitomised by the huge supply deficit and record natural gas spot prices.

Energy security and affordability have moved to the top of the priority list of policymakers, to ensure that the economy is kept running, the homes warm and the lights on.

This Report provides a comprehensive analysis of the developments of the global natural gas markets in 2021 and the first half of 2022. It also presents short-term prospects for the second half of 2022 and 2023. The main areas of focus in the Report include global developments related to the economy, energy policies and investment, natural gas consumption, production, trade and underground storage, as well as energy and commodity prices. The 2022 ASTGMR features several new facets compared to previous editions, such as natural gas and LNG price spreads, cross-commodity prices, commodity price indices, global inflation, investment in the oil and gas industry, natural gas consumption in the residential, commercial and industrial sectors, natural gas reserves, and LNG storage.

The year 2021 was characterised by a strong global economic recovery from the COVID-19 pandemic, a rebound in natural gas consumption amidst colder-than-normal winter, warmer-than-usual summer, slowdown in the growth of renewables output, and drought conditions in some regions. The stronger growth in global natural gas consumption compared to natural gas production, slower recovery in pipeline natural gas imports, and multi-year low natural gas storage inventories in Europe, compounded with supply constraints at several LNG facilities, led to the tightening of the global natural gas market. As a result, spot and hub natural gas prices in Asia and Europe began rapidly increasing from the middle of 2021. By the fourth quarter, weaker spot LNG demand in Asia as well as stronger demand and more competitive prices in Europe resulted in a shift in LNG cargo deliveries away from Asia to Europe.

As the world entered into 2022, a warmer-than-normal winter season offered little relief to the global natural gas market as the geopolitical tensions in Europe sent shockwaves across the global energy and commodity markets. Subsequent announcements by the European Union to reduce its dependency on Russian pipeline gas by diversifying natural gas supply sources, increasing renewables output, and reducing demand, led to a surge in regional spot natural gas and

LNG prices to record highs. This contributed, along with other drivers, to increased inflationary pressures not seen in decades, and to heightening risks of recession, particularly in Europe.

The short-term prospects are for market tightness to continue unabated in 2023. The risks are particularly high if faced with a colder-than-usual winter in the Northern Hemisphere, when large physical curtailments will be necessary to balance the market. Furthermore, the competition for the marginal LNG volumes will make it impossible for some developing countries to attract cargoes, a situation that will impose havoc on their economies, adversely impacting the standard of living of their populations.

While understandably, the focus today is on the security of supply and the security of demand, it is nevertheless important to stress the need for a balance between energy security, affordability, and sustainability. At the GECF, we strongly believe that natural gas will play a pivotal role in the attainment of the Sustainable Development Goals in 2030, and in reaching the Paris Agreement long-term temperature goal. Clean, available, and versatile, natural gas is an enabler of the energy transition, a transition that is smooth, just, cost-effective and leaves no one behind.

It should be noted that extreme market volatility and continuing uncertainties made it particularly challenging to produce this Report. I would thus express my sincerest appreciation to all the contributors and reviewers of the third edition of the Annual Short Term Gas Market Report.

**Eng. Mohamed HAMEL**  
Secretary General

## About the GECF

The Gas Exporting Countries Forum (GECF or Forum) is an intergovernmental organisation established in May 2001 in Tehran, the Islamic Republic of Iran. The GECF Statute was signed in 2008 in Moscow, Russia. The GECF became a fully-fledged organisation in 2008 with its permanent Secretariat based in Doha, Qatar.

As of October 2022, the GECF comprises eleven Members and eight Observer Members (hereafter referred to as the GECF Countries). The Member Countries of the Forum are Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago and Venezuela (hereafter referred to as Members). Angola, Azerbaijan, Iraq, Malaysia, Mozambique, Norway, Peru and the United Arab Emirates have the status of Observer Members (hereafter referred to as Observers).

The GECF is a gathering of the world's leading gas producers, whose objective is to increase the level of coordination and to strengthen the collaboration among Member Countries. The Forum provides a framework for the exchange of views, experiences, information and data, and cooperation and collaboration amongst its Members in gas-related matters.

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.

In accordance with the GECF Long-Term Strategy, approved during the 19th GECF Ministerial Meeting, the priority objectives of the GECF are as follows:

- To maximize gas value, namely, to pursue opportunities that support the sustainable maximisation of the added value of gas for Member Countries.
- To develop the GECF view on gas market developments through short-, medium- and long-term market analysis and forecasting.
- To promote cooperation, namely, to develop effective ways and means of cooperation amongst GECF Member Countries in various areas of common interests.
- To promote natural gas, namely, to contribute to meeting future world energy needs, to ensure sustainable global development, and to respond to environmental concerns, particularly regarding climate change.

- To reinforce the international positioning of the GECF as a globally recognized intergovernmental organization, which is a reference institution for gas market expertise and a benchmark for the positions of gas exporting countries.

The GECF Annual Short Term Gas Market Report is among the main key initiatives and instruments identified in the GECF's Long-Term Strategy.

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## CHAPTER 01

# Executive Summary

The global gas industry recovered strongly in 2021 from the negative impacts of the COVID-19 pandemic. However, the pace of recovery across the gas value chain has been unsynchronised and resulted in significant turbulence in the global gas market. Underinvestment in the gas industry over the past few years and geopolitical tensions have contributed to an imbalance between gas supply and demand in H1 2022. This imbalance has pushed spot gas and LNG prices to record highs accompanied by extreme volatility. Despite the current challenges facing the gas industry, gas has a major role to play in the global energy transition to a low carbon future and for sustainable development.

### Global Economy

The global economy rebounded by 6.1% in 2021, driven by easing of COVID-19 restrictions, expansion of fiscal and monetary policies and a recovery in international trade. However, global economic growth is estimated to slow to 3.2% in 2022 due to escalating geopolitical tensions, supply chain disruptions, China's zero-COVID policy, high energy and commodity prices, rising inflation and tightening financial conditions. In 2023, global economic growth is expected to slow further to around 2.9%, driven by soaring prices and rising inflation. Meanwhile, global inflation is expected to rise by 8.3% in 2022 after which it eases to 4.8% in 2023.

### Energy Policies

The ramifications of the COVID-19 pandemic, geopolitical developments and energy security concerns influenced recent energy policies. Governments implemented financial supporting mechanisms for energy producers and consumers to cope with the negative impact of the pandemic. There has since been a shift in focus to security of supply concerns, following the recovery in energy demand and tightening market conditions in H2 2021. On the supply side, the countries have incentivised domestic gas production while on the demand side, the energy policy developments have mostly focused on enhancing energy security and reducing the burden of high-energy prices on consumers.

## Investment in the Oil & Gas Industry

There has been significant underinvestment in the oil and gas industry since 2014, which has contributed to the gas supply concerns and high prices. Global oil and gas investment in 2021 increased by 17% to around \$673 billion and is expected to further increase by 7% in 2022 to around \$718 billion. This favourable investment climate has driven by energy security concerns, extremely high spot prices and growing gas demand. However, there are some risks to the investment including rising inflation as well as more investment into low-carbon energies by energy companies.

## Gas Consumption

Global gas consumption expanded by 4.5% in 2021 to above the pre-pandemic level. This was supported by recovery in economic growth and industrial activity, as well as abnormal weather conditions. In 2022, global gas consumption is forecasted to rise by up to 1%, driven by the stronger gas burn in the U.S. and coal-to-gas switching in China's residential sector, which could offset a decline in Europe. Further in 2023, consumption is forecasted to increase by up to 1.1% driven by China, South and South East Asia and the Middle East. Coal and oil switching to gas, infrastructure development and higher industrial activity will boost gas consumption.

## Gas Production

Global natural gas production rose by 4% in 2021 due to the recovery in gas demand, rebound in associated gas production and the commissioning of new gas fields. At a country level, the increase came mainly from Russia, Algeria, the U.S. and China. For 2022 and 2023, global gas production is forecasted to increase by 1% and 1.5% respectively driven mainly by stronger production from North America, Asia and Middle East. The global gas rig count continues to recover in 2022, which is expected to support the higher gas production. However, increasing costs and geopolitical tensions are downside risks.

## Pipeline Natural Gas Trade

Global net pipeline gas trade increased by 8% in 2021, to reach 568 bcm. The overall increase was supported by the recovery in global gas consumption. This rise in pipeline imports was driven largely by the European region, which accounted for 61% of the global market share. Meanwhile, GECF Member Countries together accounted for 75% of global net pipeline gas exports in 2021. In 2022 and going forward, it is anticipated that global pipeline gas trade will decrease, as the EU reduces its reliance on Russian pipeline gas. This has already been observed in H1 2022.

## LNG Trade

In 2021, global LNG imports expanded by 6% to 378 million tonnes driven by stronger gas demand in China, Brazil and South Korea. Since Q4 2021, there has been a shift in LNG flows away from Asia to Europe due to tight spot LNG price spreads between both markets. In 2022 and 2023, global LNG exports are forecasted to expand by 4-5% and 6-7% respectively, driven by higher LNG exports from GECF and non-GECF countries. The stronger LNG exports is supported by the start-up of new liquefaction projects, improvement in feedgas availability and lower maintenance.

## LNG Infrastructure

2020, with Qatar accounting for more than 60%. The development of new LNG liquefaction projects continued apace in 2022, with 30 Mtpa of capacity reaching FID between January and September mainly from the U.S. High gas and LNG prices and strong LNG contracting for new projects supported the FID on new projects. Between October 2022 and December 2023, almost 160 Mtpa of new liquefaction capacity are targeting FID, mostly in the U.S.

## LNG Shipping Cost

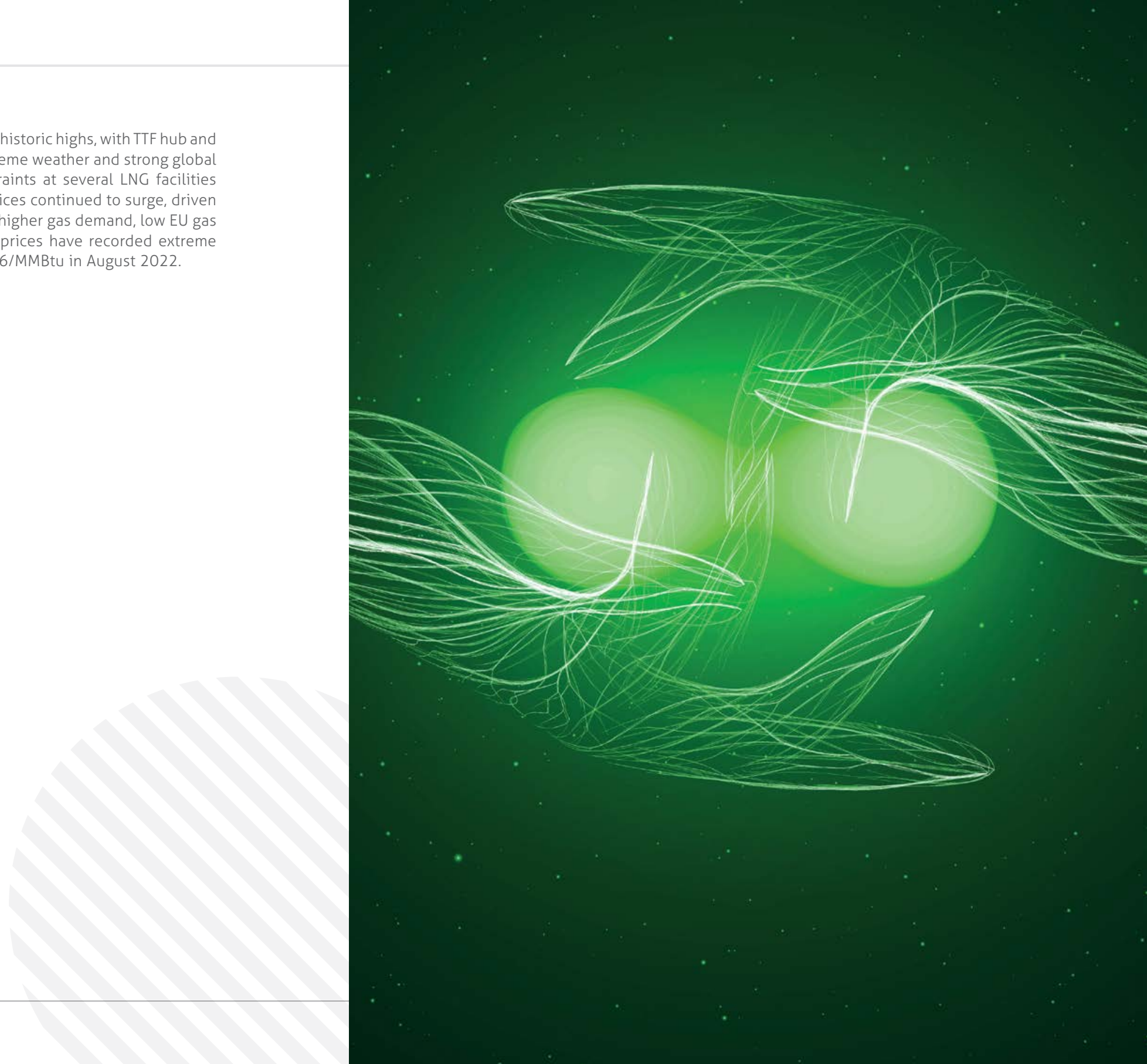
LNG spot charter rates for steam-powered carriers experienced extreme highs at the start and towards the end of 2021. On average, charter rates in 2021 reached \$66,000 per day, which was an increase of 50% over the average level of the previous year. The average price for leading shipping fuel oil also increased from 2020 to 2021, by 78%, to reach \$514 per tonne. Consequently, these two factors combined to have the effect of a doubling of spot LNG shipping costs from 2020 to 2021. In 2022, charter rates returned to more historically-experienced levels, while robust price growth in the oil market continued to drive prices in shipping fuels.


## Gas Storage

Underground natural gas storage in the EU in 2021 was greatly influenced by the high gas prices at the time. As a consequence, replenishment of gas stocks was muted, and the storage levels during H2 2021 were the lowest observed in the previous five years. In 2022, the gas crisis in the region forced policymakers to impose gas storage filling regulations. These measures ensured that despite gas prices in the region reaching record highs, underground storage sites across the continent were filled to at least 80% in preparation for the upcoming winter.

### Energy Prices

Gas and LNG spot prices in 2021 were characterized by historic highs, with TTF hub and Asian LNG prices skyrocketing. This was driven by extreme weather and strong global economic recovery, higher gas demand, while constraints at several LNG facilities invoked limits on the supply side. In H1 2022, spot prices continued to surge, driven by escalating geopolitical tensions, tight LNG market, higher gas demand, low EU gas storage and gas supply concerns. Furthermore, spot prices have recorded extreme volatility, with TTF reaching an all-time high above \$96/MMBtu in August 2022.





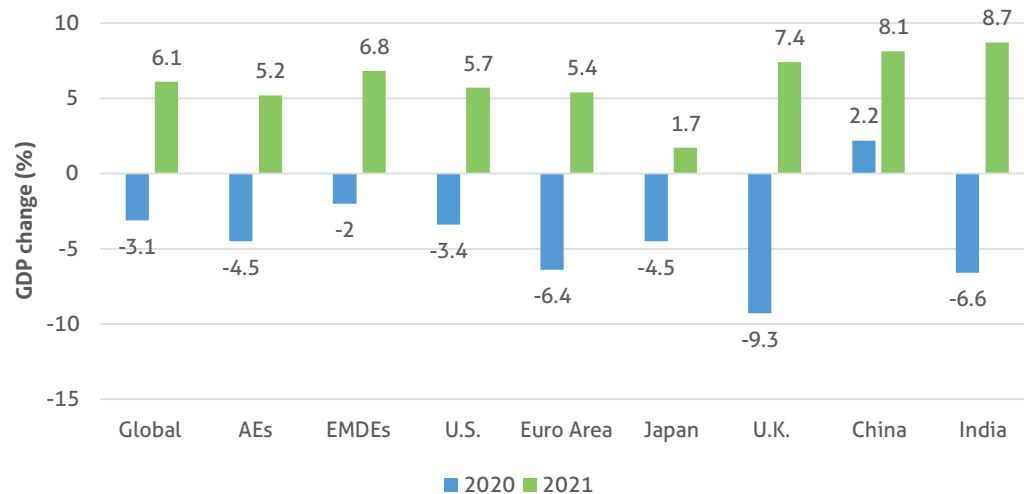
CHAPTER  
**02**

## Global Developments

### 2.1 Global Economy

In 2021, global economic activities rebounded driven by vaccination rollout and supportive policy measures in major advanced and developing economies. Indeed, the pace of recovery, which started in the second half of 2020, gained momentum in the first half of 2021 due to positive impacts of vaccination on the financial and commodity markets. Gradual vaccination rollout and sizeable fiscal policy measures in some major advanced economies, particularly in the U.S., supported the global recovery in 2021. Meanwhile, some major developing economies in Asia, in particular China and India, experienced a substantial growth in 2021 as a result of the easing of the pandemic-related restrictions. However, discrepancies in vaccination rollout and access to financial support was reflected in diverging economic recovery across the world. While advanced economies were able to vaccinate the majority of their populations and support their economies by additional policy packages, most of the developing economies struggled to contain the pandemic due to slower vaccination and significant budgetary constraints. This was reflected in the uneven recovery and widening gap among advanced economies and emerging countries.

As a result, the global economy experienced a substantial, albeit uneven, recovery in 2021. The global economy grew by 6.1% in 2021, after posting 3.1% of decline in 2020, according to the World Economic Outlook released by the IMF in July 2022. Advanced economies experienced 5.2% of economic growth, with the U.S. growing by 5.7%, the UK by 7.4%, the EU by 5.4% and Japan by 1.7%. Among the emerging markets and developing economies, China and India's economies expanded by 8.1% and 8.7% respectively (Figure 1).

**Figure 1: Global and Regional Economic Growth**

Source: GECF Secretariat based on data from IMF World Economic Outlook July 2022

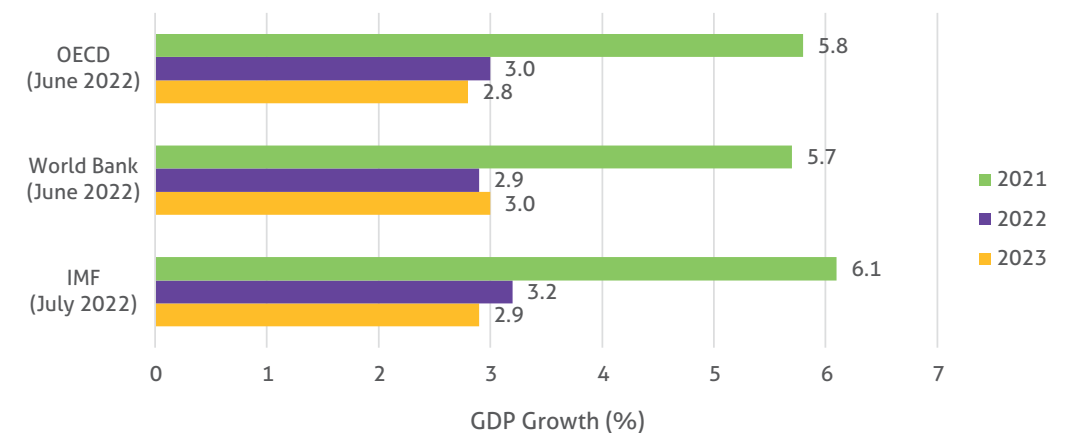
Note: AEs (Advanced Economies) and EMDEs (Emerging Markets and Developing Economies)

Global economic recovery faced several challenges in 2021. Surging number of COVID-19 cases, spread of the Delta variant of COVID-19 and re-imposing of restrictions caused concerns about the pace of the global recovery. Budget deficits reached record highs in many advanced countries, while most of the developing economies faced a rise in domestic and external debt. Expansionary monetary policies supported recovery and led to increasing liquidity in major economies. These resulted in increasing money base and higher inflation. In addition, supply chain disruptions affected the global trade, especially in the second half of the year. Accordingly, Consumer Price Index (CPI) reached 4.7% in 2021, higher than 3.2% in 2020. CPI in advanced economies surged to 3.1% from 0.7% in the previous year, while in emerging markets and developing economies, CPI reached 5.9%.

In 2022, the pace of global recovery began losing momentum due to spread of the Omicron COVID-19 variant, disruption of economic activities and prolonged supply-demand imbalances. While Omicron was considerably milder than the Delta variant, its emergence affected public health, production of goods and services as well as international trade flows. The Zero COVID-19 policy in China and implementation of lockdown measures in its large cities have taken a heavy toll on the economy, specifically labour-intensive businesses such as service and manufacturing sectors, and led to lingering supply disruption. Labour shortages in the U.S. due to lower participation rates, which indicate the number of persons employed or seeking jobs, have contributed to the rise in inflation. Disrupted migrant labour flows in the U.S. and Europe have also boosted inflation.

Moreover, the global economic growth has lost momentum due to escalating geopolitical tensions in eastern Europe. While the global economy has not yet fully recovered from the COVID-19 pandemic, heightened tensions have aggravated the already struggling economic conditions. The global economy has been affected through three main channels: financial sanctions, commodity prices and supply-chain disruptions. Financial sanctions have restricted trade and business activities with Russia, affecting both Russian and international companies. Meanwhile, soaring commodity prices are expected to remain elevated, since Russia is a major producer and exporter of oil, gas, coal, metals and agricultural products. Moreover, disruption in the global supply chain is expected to worsen due to restrictions on air, sea and land trading routes.

With rising inflation, tightening financial conditions, elevated debt, COVID-19 restrictions, geopolitical tensions and supply chain disruptions, the global outlook is expected to deteriorate further in the rest of 2022. IMF revised down its projections regarding the global economic growth by 0.4 percentage points for 2022 and 0.7 percentage points for 2023 in its July 2022 outlook, projecting the global economy to grow by 3.2% and 2.9% in 2022 and 2023, respectively (Figure 2). Furthermore, the IMF also downgraded their forecast for economic growth in the U.S. by 1.4 percentage points to 2.3% in 2022, driven by tighter monetary policy and reduced household purchasing power. Similarly, in China, IMF's forecast was reduced by 1.1 percentage points to 3.3% in 2022, driven by extensive lockdowns and deepening real estate crisis.

**Figure 2: Global Economic Outlook**

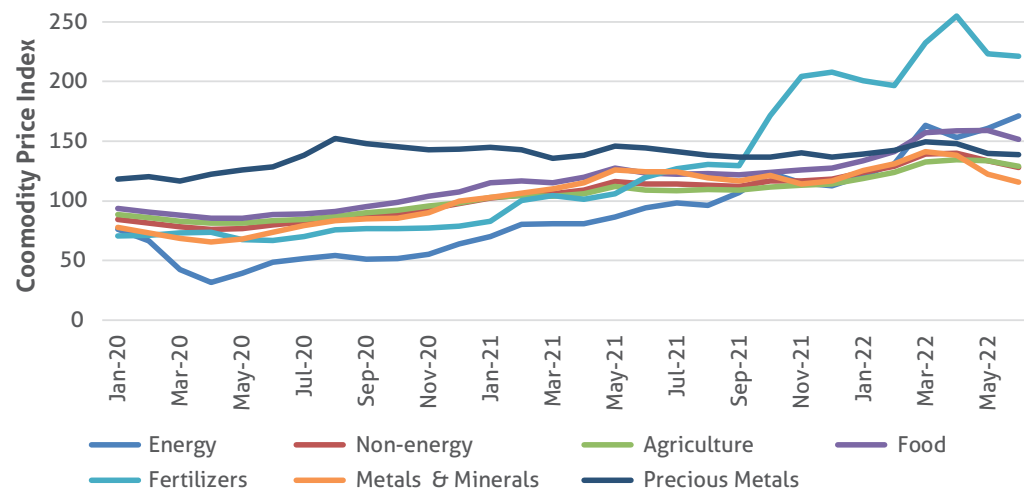
Source: GECF Secretariat based on data from IMF World Economic Outlook July 2022, World Bank Global Economic Prospects June 2022 and OECD Economic Outlook June 2022

Geopolitical tensions in eastern Europe exacerbated pre-existing global inflation through hiking commodity prices and disruption in global trade. In June 2022, commodity prices were slightly lower compared to the previous month. However, energy and fertilizer prices



remained significantly higher than the previous year. The energy price index reached 171 in June 2022, showing an 82% increase compared with the same month last year. Non-energy price index also increased by 12% y-o-y, reaching 128 in June 2022. Among the non-energy group, fertilizers soared by 85%, followed by food prices (23%) and agriculture prices (18%) compared to the previous year. However, metals and minerals group and precious metals fell by 7% and 4%, respectively, in June 2022 compared with the same month a year ago (Figure 3).

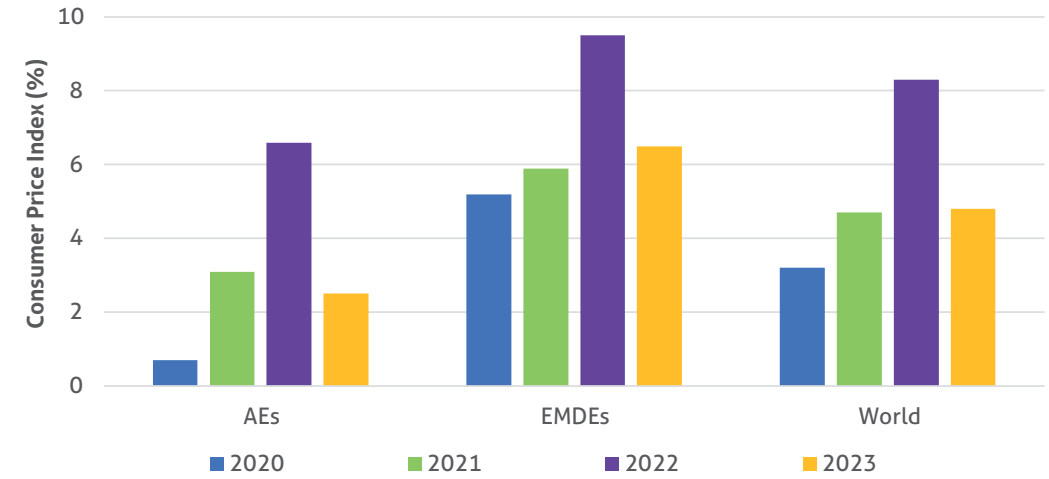
**Figure 3: Monthly Commodity Price Indices**



Source: GECF Secretariat based on data from World Bank Commodity Price Data  
 Note: \*Monthly indices based on nominal US dollars, 2010=100, 1960 to present

Soaring energy prices resulted in increasing inflation in the first half of 2022, with inflation in Europe reaching the highest level in 40 years. According to the IMF World Economic Outlook July 2022, the global inflation is expected to rise by 8.3% in 2022. Inflation in advanced economies is projected to reach 6.6% in 2022 and to hike to 9.5% in emerging markets and developing economies (Figure 4).

**Figure 4: Consumer Inflation (CPI)**



Source: GECF Secretariat based on data from IMF World Economic Outlook July 2022  
 Note: Figures for 2022 and 2023 are forecasts from IMF. AEs (Advanced Economies) and EMDEs (Emerging Markets and Developing Economies)

The surge in prices and increasing inflation caused central banks in major advanced and developing economies to tighten their monetary policies. In the U.S., the Federal Reserve (Fed) increased its benchmark interest rate by 0.75 percentage points for the third straight time in September 2022, taking the range up to 3-3.25%. In addition, the Fed announced a program, in which it would eventually reduce its bond holdings by \$95 billion per month. The Bank of England increased the UK interest rate by 0.5 percentage points to 1.75% in August 2022, its first half percentage point increase since 1995. The European Central Bank (ECB) also raised its key interest rates by 0.75 percentage points in September 2022. Likewise, some Asian economies have announced contractionary fiscal and monetary policies to fight rising inflation and support their national currencies.

## 2.2 Energy Policies

Energy policies are one of the main drivers of natural gas demand and supply. The demand for natural gas is greatly affected by the effectiveness of energy efficiency, decarbonization, energy substitution and market liberalization policies. On the other hand, upstream fiscal policies are the driving force of natural gas supply.

Two main subjects have influenced the energy policy trajectory of countries in 2021 and H1 2022. Firstly, the ramifications of the COVID-19 pandemic, and secondly, the geopolitical tensions and energy security concerns. Since the start of the COVID-19 pandemic, governments have implemented supporting mechanisms to cope with the

negative impacts of the pandemic. However, with recovering demand and tightening market conditions in H2 2021, countries concentrated their policies on energy security issues. On the demand side, most energy policy developments have focused on enhancing energy security and reducing the burden of high-energy prices on consumers. On the supply side, the countries have incentivized domestic production and stimulated investment in the domestic upstream.

At the global level, in June 2021, the G7 announced new measures to decarbonize the energy sector while recognizing the role of natural gas in the global energy scene. In June 2022, the G7 committed to “increase energy efficiency, accelerate renewable and other zero emissions energy deployment, reduce wasteful consumption, leverage innovation all whilst maintaining energy security”. The group pledged to “rapidly scale-up technologies and policies that further accelerate the transition away from unabated coal capacity, consistent with their 2030 NDCs and net zero commitments”.

COP26 was a major international event at the end of 2021. The parties agreed to “accelerate efforts towards the phase-down of unabated coal power and inefficient fossil fuel subsidies” and “consider further actions to reduce by 2030 non-carbon dioxide greenhouse gas emissions, including methane”. On the side-lines of COP26, over 100 countries, representing 70% of the global economy and half of anthropogenic methane emissions, pledged to collectively mitigate global methane emissions by 30% from 2020 levels by 2030.

However, it should be noted that despite the ongoing environmental push, some countries have increased their coal consumption in recent months, and some banks have continued funding coal projects. At the same time, some institutional investors have allocated a significant portion of their portfolios to the coal industry.

This section provides the latest energy policy developments in major regions, reflecting developments since January 2021.

### 2.2.1 Europe

In Europe, decarbonization policies and GHG emission reduction targets have been the main drivers of the countries’ energy policies and related energy plans. However, recent developments in energy markets have affected their energy policies, with new trends registered. Amidst the rising uncertainties in gas markets, the EU countries decided to move toward joint purchasing of natural gas and LNG. The European Commission (EC) launched a new platform that facilitates joint purchases of natural gas and hydrogen. It aims to enhance cooperation with suppliers to refill underground gas storage (UGS) facilities in a timely basis and develop an international hydrogen market.

In the meantime, the EU is implementing a minimum natural gas storage level mandate, to be prepared for the next winter season and to avoid an energy crisis. The European

Council and European Parliament announced in May 2022 that they agreed on a new target for gas storage. Based on the mandate, the storage facilities should be 80% full by 1 November 2022 and 90% full for the following years.

In January 2022, the EC drafted a plan to label natural gas and nuclear energy as green projects in the EU Taxonomy if they meet some requirements. Natural gas-fuelled power plants will be considered as green projects if they produce less than 270 gCO<sub>2</sub> per Kwh. The European Parliament backed the plan after an investigation done by a group of experts.

In March 2022, the European Council approved the Carbon Border Adjustment Mechanism (CBAM), which is one of the main components of the Fit for 55 package. It aims to reduce the EU carbon emissions from imported products such as fertilizers, cement and metals and prevent the offshoring of carbon emissions by moving production outside the EU. However, the European Parliament postponed the final approval of the initiative until further notice.

In May 2022, the EC presented the plan REPowerEU, aimed at mitigating EU dependence on Russian fossil fuels before 2030. Specifically, the plan targets EU gas imports from Russia to be reduced by 100 bcm by the end of 2022, with some 60 bcm/y replaced by natural gas from other sources, largely in the form of LNG. The EU could increase its LNG imports by 50 bcm, with the U.S., Qatar, Egypt and West African countries providing additional supply. Pipelines from Azerbaijan, Algeria and Norway could deliver another extra 10 bcm of natural gas. The plan also envisages biogas production rising by 3.5 bcm by the end of 2022. Energy efficiency measures, in particular, for example “turning down the thermostat for buildings’ heating by 1 degree”, could allow natural gas demand to be reduced by 14 bcm by the end of this year. The power sector could also contribute to gas demand reductions of 20 bcm through the end of 2022 by increasing the average utilisation rate of wind and solar capacity. However, much of the remaining reduction may have to come through gas-to-coal fuel switching.

Meanwhile, countries have also taken policy measures at a national level. In Germany, the government unveiled a new plan to deal with high energy prices. The policy package includes a tax cut on fuel prices for three months and direct payment to social workers and low-income families, to reduce the negative impacts of rising energy prices. In addition, the country will provide further support for biogas and renewables and will ease the approval process for LNG procurement. In addition, in line with the EU mandates, Germany’s government set a minimum natural gas storage fulfilment level by August 1st (65%), October 1st (80%) and December 1st (90%).

In a similar move to reduce the impact of high natural gas prices on consumers, the Italian government passed a new policy package. It includes measures to increase domestic energy production, set a minimum storage level of 90% of total capacity and provide

financial aid to consumers. Meanwhile, the Turkish government announced plans to spend €6.5 billion to subsidize natural gas and electricity prices to reduce the impact of high energy prices on citizens. In the UK, following huge profits of upstream companies due to high prices of oil and gas in the market, the government requested companies active in the North Sea to reinvest profits in the upstream sector with a view to boost oil and gas output from domestic sources.

Table 1 summarizes some of the European policies that emerged from the recent developments in energy markets and significantly affected the natural gas markets.

**Table 1: Major Natural Gas-Related Policies in Europe**

EU
- Fit for 55 carbon market package of proposals
- Approval of 55% GHG reduction target by 2030 compared to 1990 levels
- New legislation to curb methane emissions from energy sector
- Labelling of natural gas investment as green
- Minimum natural gas storage level obligation
- Endorsement of joint purchase of natural gas
- Presentation of REPowerEU plan
- Postponement of CBAM
NETHERLANDS
- Cap on Groningen output at 3.9 bcm for 2021-2022
GERMANY
- Approval of conversion of some gas pipelines to hydrogen
- Growing reliance on coal-fired power plants
ITALY
- Decrease in GHG emissions by 60% by 2030 compared to 1990
UK
- Cap on energy bills for households
- Windfall tax on oil and gas producers
- Easing of pipeline gas quality rules
NORWAY
- Increase in carbon tax by 28% in 2022 and by 200% by 2030

Source: GECF Secretariat based on countries' updates

## 2.2.2 Americas

The U.S. administration is preparing a regulatory framework to reduce GHG emissions by 50% by 2030 from 2005 levels, in particular by supporting electric vehicles (EVs) and power generation from renewable sources. The U.S. Department of Energy (DOE) unveiled its plan to allocate a portion of the infrastructure bill to support hydrogen projects to reduce carbon emissions from industrial sectors like cement and steel.

In Latin America, Argentina's government is trying to stimulate domestic natural gas production, mainly from its Vaca Muerta shale basin. However, some projects have been delayed due to the pandemic and the country's ongoing economic challenges.

In Mexico, the government announced plans to invest \$3.2 billion in gas-fired power generation by 2024 and set a new target to increase renewable capacity by 50% by 2024. Meanwhile, in Brazil, the energy policies focus on natural gas market liberalization.

Table 2 summarizes some of the Americas' policies that emerged from the recent developments in energy markets.

**Table 2: Major Natural Gas-Related Policies in the Americas**

NORTH AMERICA
United States
- Announcement by DOE of funding for 31 hydrogen projects
- Updated GHG emissions reduction target of 50%-52% by 2030 compared to 2005 levels
- Suspension of Arctic refuge drilling permits
- New environmental requirements for gas infrastructure approval
- Resumption of drilling in public lands
LATIN AMERICA
Argentina
- New subsidy program to stimulate natural gas production
- New wealth tax to fund natural gas projects
- Easing of foreign exchange limitations for gas producers
BRAZIL
- New regulatory framework for offshore wind development
MEXICO
- Investment of \$3.2 billion in gas-fired power generation by 2024

Source: GECF Secretariat based on countries' updates

### 2.2.3 Africa

In Africa, given the continent's considerable discoveries in recent years, the government's energy policies were mainly focused on boosting investment to develop those natural gas resources in addition to updating the emission reduction targets in some African countries.

South Africa updated its GHG mitigation targets to a new range of 350 to 420 Mt CO<sub>2</sub>e by 2030 with a final goal of reaching net zero emissions by 2050, according to the Low-Emission Development Strategy. Tunisia also updated its GHG emission reduction target to 27% by 2030 compared to 2010 levels. It should be noted that the previous target was 13% reduction from 2010 levels.

In Egypt, the energy policies are mostly focused on increasing natural gas production and promoting natural gas consumption in different sectors. For instance, the government affirmed its plans to expand natural gas consumption in the transportation sector. According to the plan, the government set ambitious targets to convert vehicles to run on natural gas. In line with the government's new plan, Egypt's central bank introduced a financial support mechanism for car owners to convert their vehicles to run with natural gas. The support mechanism includes providing car owners with low-interest loans.

The below table summarizes some of the new developments in African countries' energy policies related to natural gas.

**Table 3: Major Natural Gas-Related Policies in Africa**

<b>EGYPT</b>
- To offer incentives to convert cars fuel into natural gas
- To rationalize domestic electricity consumption to boost natural gas export
<b>TUNISIA</b>
- New GHG emission reduction of 27% by 2030 on 2010 levels
<b>NIGERIA</b>
- Passed new Petroleum Industry Bill
<b>SOUTH AFRICA</b>
- New GHG emission reduction target of 350-420 Mt CO <sub>2</sub> e by 2030

Source: GECF Secretariat based on countries' updates

### 2.2.4 Asia Pacific

The policy agenda of most of the countries in the region was driven mainly by measures to reduce carbon emissions. The Asian Development Bank unveiled its plan to limit financing of fossil energy projects only to natural gas projects with lower environmental footprint. However, in the post-pandemic period, the countries have shifted the focus to the security of energy supply to their nations.

According to a newly released five-year plan on energy conservation in China, the country targets an 18% reduction in CO<sub>2</sub> intensity and a 13% decrease in energy intensity from 2021 to 2025 compared to 2020 levels. It should be reminded that China has significantly decreased its energy intensity level in the past 20 years and plans to become carbon neutral by 2060. The government plans to develop a nationwide unified electricity market to prevent any power crisis and add more resilience and flexibility to the country's power grid by 2025. The regional markets will operate coherently, which will result in a more flexible power market.

Japan announced its new GHG emissions reduction target of 46% by 2030 compared to the 2013 levels. It should be noted that Japan's previous GHG emission reduction target was 26%. Moreover, Japan's Ministry of Economy, Trade, and Industry (METI) announced its plan to launch a pilot Emission Trading Scheme (ETS) in September 2022, with a view to create a fully operational carbon market in the second quarter of 2023.

Another major Asian country, South Korea, revised its GHG emission reduction target. South Korea updated its target to reduce GHG emissions by 40% by 2030, from the 2018 level.

In India, energy policies were related to energy security issues and incentivising domestic production of natural gas amidst the price volatilities in energy markets. The government increased the wholesale price of locally produced natural gas to support the domestic upstream companies.

Table 4 summarizes some of the Asia policies that emerged from the recent developments in energy markets.

**Table 4: Major Natural Gas-Related Policies in Asia Pacific**

CHINA
- Halting of subsidies for some renewable projects
- Revision of gas pipeline tariff mechanism
- Launch of Emission Trading Scheme
- Reduction in energy intensity by 13% by 2025 on 2020 levels
- Launch of the nationwide electricity market by 2025
- Production of 33% of electricity from renewables by 2025
INDIA
- Increase in the wholesale price of domestically produced gas
SOUTH KOREA
- Tax rebate to LNG-fueled ships bunkering
- Change in minimum LNG inventory rules
- Cut in GHG emission by 40% by 2030 on 2018 levels
- Classification of LNG as green energy
JAPAN
- New GHG emission reduction target of 46% by 2030 on 2013 levels
- Launch of pilot Emission Trading Scheme
INDONESIA
- Diversion of LNG cargoes for domestic consumption
AUSTRALIA
- Widening of the scope of renewable funding to hydrogen and CCUS
- New GHG emissions reduction target of 43% by 2030 on 2005 levels

Source: GECF Secretariat based on countries' updates

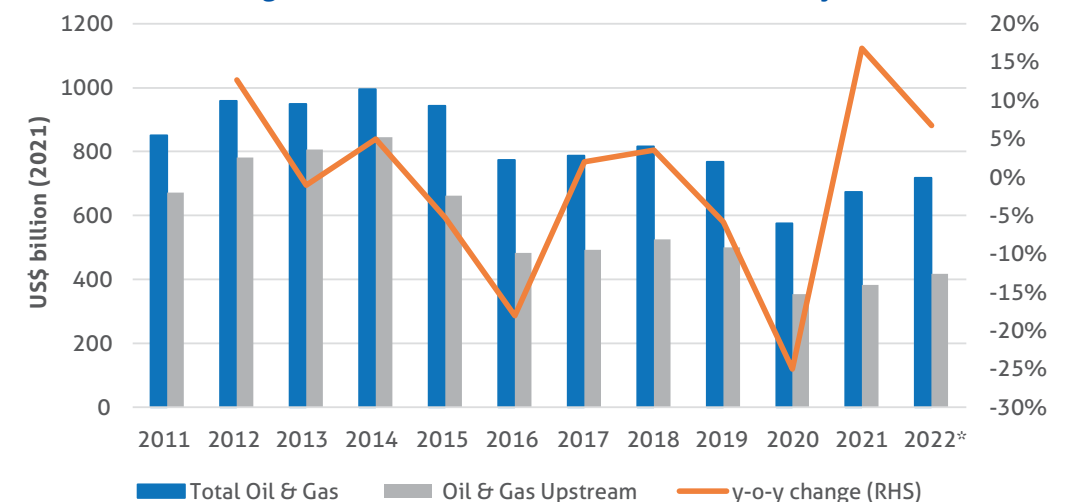
## 2.3 Investment in the Oil and Gas Industry

### 2.3.1 Global Oil and Gas Industry

Global oil and gas investment in 2021 was \$673 billion, an increase of 17% y-o-y, following 25% y-o-y decline in 2020 when total investment dropped to \$576 billion. However, it remained below the pre-pandemic levels. On the upstream side, oil and gas investment in 2021 was \$384 billion, accounting for 57% of total oil and gas investment. In 2020, investment in upstream oil and gas dropped sharply by 29% y-o-y to \$353 billion. While there was a rebound in investment in the oil and gas industry in 2021 as the world recovered from the pandemic, there was a significant drop in investment from the level of 2014 when total oil and gas investment reached a high of around \$996 billion (Figure 5).

The deficit of oil and gas investment since 2014 was driven by the oil price collapse over the period 2014-2016, as well as the push for decarbonisation. Over the past few years, this underinvestment has negatively impacted the supply side and may continue to put upward pressure on prices amidst growing global gas demand. The low-price environment during the pandemic and the accelerated energy transition have put additional pressure on financing for oil and gas projects. Banks and financial institutions have opted for more stringent regulations and, in some cases, not provided any funding to such projects. However, in 2021, the rebound in investment was stimulated by post-pandemic global economic recovery, increasing energy demand, and a high price environment.

**Figure 5: Global Investment in Oil & Gas Industry**



Source: GECF Secretariat based on data from IEA World Energy Investment 2022

Note: Figures for 2022 are estimates from IEA

In 2022, this favourable investment climate has been further exacerbated by escalating geopolitical tensions, energy security concerns and extremely high prices. Total oil and

gas investment is expected to further increase by 7% y-o-y to \$718 billion, according to estimates from IEA. A large share of investment will be focused on short-cycle projects that can deliver volumes relatively quickly through maximizing existing capacities and brownfield expansions for instance using tiebacks and infill drilling. Revival of LNG projects, U.S. shale gas production and recovery in deep-water oil investments are some key developments to watch in 2022. However, cost escalations due to rising global inflation as well as supply chain bottlenecks may diminish the effect of higher spending. This is particularly affecting upstream investment with cost increases of over 25% since 2020, largely due to higher cost of materials such as steel, aluminium, nickel and copper. Thus, the supply side may not ultimately reflect the rising investment levels.

Oil and gas investment in 2022 may also be challenged by uncertainties surrounding the geopolitical tensions in eastern Europe and fears of global economic recession, as well as company strategies to direct more investment in low-carbon energy sources as the energy transition unfolds. Regarding huge capital investment in hydrocarbon projects, and in particular those with longer payback periods, difficulties in financing and policy uncertainties may continue to deter such investments.

Oil and gas companies have been changing their strategies to widen their market reach and rebrand themselves as energy companies. In 2021, oil and gas companies invested over \$10 billion in clean energy technologies. This is expected to double in 2022.

### 2.3.1.1 Carbon Abatement Projects

Investment in carbon abatement projects has been relatively low over the past decade however, there has been a recent revival in these projects with net zero commitments and climate change policies are the centre. In 2021, six CCUS projects took FID including Qatar Petroleum's North Field East LNG Liquefaction Project which is expected to capture and store 2.9 Mt CO<sub>2</sub> per year starting from 2025 with an investment of around \$200 million. The other CCUS projects are located in Australia, China and Netherlands.

The Moomba CCS Project in Australia is expected to capture and store 1.7 Mt CO<sub>2</sub> per year by 2024 with an investment of around \$165 million. In China, two projects took FID including a large-scale CCUS project at the Qilu petrochemical plant is expected to capture 1.7 Mt CO<sub>2</sub> per year and inject it into nearby oil wells, and a smaller project at the Taizhou Power Plant. In the Netherlands, two projects also took FID including a waste-to-energy plant and a biofuels project to start in 2023 and 2024 respectively. In addition to these projects, announcements were made for 130 commercial-scale CO<sub>2</sub> capture projects in 20 different countries, which aim to capture CO<sub>2</sub> from several applications, including hydrogen and biofuel production.

CCUS projects are capital intensive and may be perceived as high risk thus, governments have an important role to play in creating an enabling environment for such investment. This can be done directly through special grants or by mandating development banks to support CCUS projects. In 2021, there has been increased government support for

CCUS projects with several countries including the U.S, Denmark, Canada and South Korea, announcing nearly \$18 billion in new public funds for the development of CCUS. Furthermore, around \$3 billion of existing public funds have been allocated to CCUS projects in the EU and UK.

IEA expects investment in CCUS projects to increase to around \$1.8 billion in 2022, and rise sharply over the next two years to exceed \$40 billion by 2024. In this regard, policy support and favourable investment conditions will be essential.

### 2.3.1.2 Developments in Financing of Hydrocarbon Projects

The landscape for financing of hydrocarbon projects have changed over the past few years driven by the global energy transition and net zero commitments. One such initiative has been the Task Force on Climate-Related Financial Disclosure (TCFD), which has pushed the inclusion of some environmental considerations related to carbon risk and emissions assessments into the investment decision-making process.

The EU has led the way with the implementation of sustainable finance regulations (Sustainable Finance Disclosures Regulation, the Corporate Sustainability Reporting Directive and EU Taxonomy for Sustainable Activities) which require companies and investors to report on sustainability practices. As a part of the EU Taxonomy which is expected to be implemented in January 2023, the EU Parliament agreed to add gas and nuclear projects to its definition of 'green' projects with some conditions. One of these conditions for gas projects is that they must contribute to the transition from coal to renewables.

In addition, the UK, US and China also introduced some forms of mandatory reporting as it relates to climate risk. In the UK, TCFD reporting for large companies and financial institutions became mandatory in April 2022. The Securities and Exchange Commission in the US proposed regulations on climate risk and carbon emissions disclosure and on prevent 'greenwashing' in March 2022. In China, since February 2022, listed companies are required to publish their carbon emissions and other environmental data. Other countries have also proposed some regulations, which are focused on data availability regarding carbon emissions.

In recent years, banks and financial institutions have also faced increasing pressure to place lending restrictions on hydrocarbon projects. In 2021, the world's largest banks formed the Net-Zero Banking Alliance (NZBA), convened with United Nations support and represents around 40% of global banking assets. This alliance aims to support decarbonization strategies and align its lending and investment portfolios with the targeted net-zero emissions by 2050.

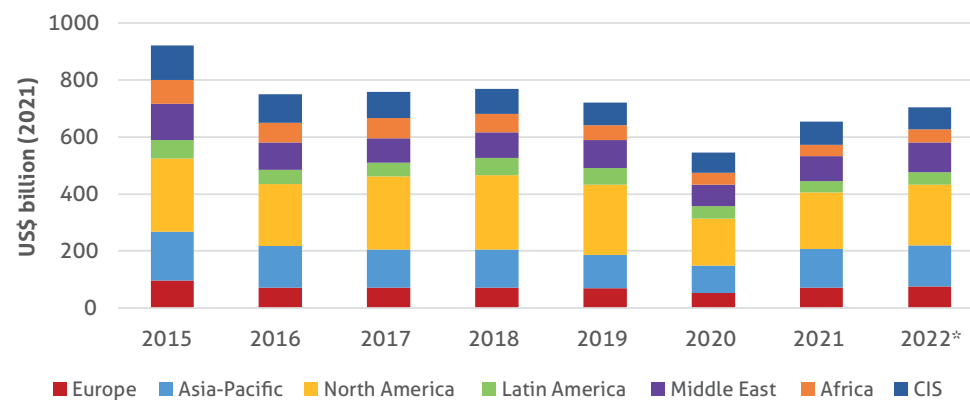
Furthermore, in 2022, capital-intensive oil and gas projects are facing increasing pressure from rising costs due to increasing inflation and interest rates, as well as supply chain

disruptions. While the high price environment will encourage greater investments in projects across the value chain, the higher cost of financing may deter or delay some investment decisions.

### 2.3.2 Regional Oil and Gas Industry

In 2021, North America maintained its position with the highest level of oil and gas investment. Europe and Asia experienced the largest upticks in total oil and gas investments, while in Latin America and Africa, oil and gas investment decreased slightly. Moreover, in 2022, investment in the oil and gas industry is expected to increase further in all regions except for CIS where it is expected to decrease slightly. Middle East is expected to experience the largest annual increase amongst all regions (Figure 6).

**Figure 6: Regional Investment in Oil & Gas Industry**



Source: GECF Secretariat based on data from IEA World Energy Investment 2022

Note: Figures for 2022 are estimates from IEA

Oil and gas investment in Europe declined sharply in 2016 to around \$72 billion, after which it remained relatively stable until 2020 when it dropped to a low of \$52 billion. It increased by 35% y-o-y in 2021 to \$71 billion, and is expected to increase further to \$75 billion in 2022. The share of upstream investment dropped from 64% in 2020 to 38% in 2021, indicating the shift away from oil and gas, with more investment focused on renewables.

Oil and gas investment in Asia-Pacific has been on a steady decline since 2015, and reached a low of \$98 billion in 2020. In 2021, investment rebounded sharply by 40% y-o-y to \$136 billion. This is expected to increase further to \$145 billion in 2022. Upstream investment increased by 36% in 2021 to \$66 billion, largely due to China's developments.

Investment in the oil and gas industry in North America increased 22% y-o-y to almost \$200 billion in 2021. It is expected to increase further by 7% y-o-y to \$212 billion in 2022, with about 70% of investment accounted by the upstream sector. This will be driven by U.S. shale gas production, as well as LNG export projects.

In Latin America, oil and gas investment was \$40 billion in 2021, decreasing 8% y-o-y. Investment in the oil sector declined from \$37 billion in 2020 to \$33 billion in 2021, with more than 70% of this investment in the upstream sector. In 2022, oil and gas investment in the region is expected to rebound by 12% y-o-y to \$45 billion.

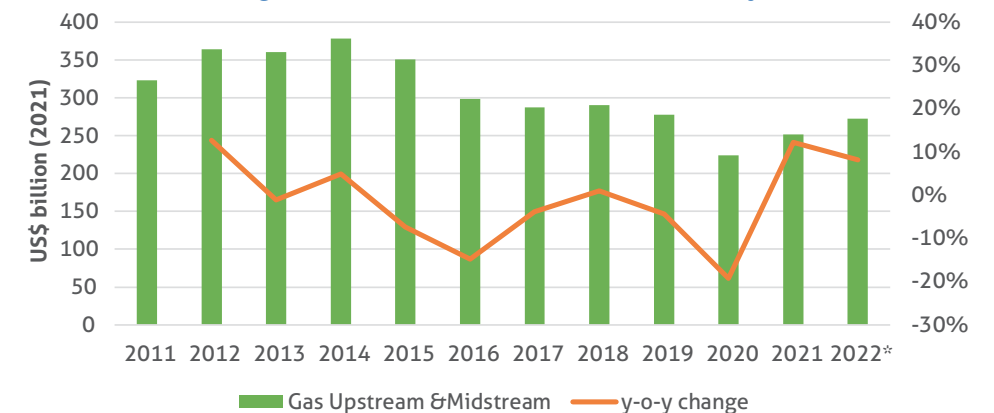
In the Middle East, oil and gas investment was \$87 billion in 2021, an increase of 14% y-o-y. This is expected to increase sharply in 2022 by 20% to above \$100 billion. A large portion of this will come from NOCs in the region with announcements from Saudi Aramco and ADNOC for increased spending on oil and gas activities.

Oil and gas investment in Africa has been on a steady decline since 2015, and reached a low of \$40 billion in 2021. However, in 2022, investment is expected to rebound to \$46 billion. In the CIS region, oil and gas investment has also been on a steady decline since 2015, and is expected to decline further in 2022.

### 2.3.3 Global Gas Industry

With regard to investment in the gas industry considering upstream and midstream (pipelines and LNG) segments of the gas value chain, this was \$252 billion in 2021, increasing 12% y-o-y. In 2020, it experienced a significant drop of 19% y-o-y to \$224 billion. In 2022, upstream and midstream gas industry investment is estimated to reach around \$272 billion, increasing 8% y-o-y (Figure 7).

**Figure 7: Global Investment in Gas Industry**



Source: GECF Secretariat based on data from IEA World Energy Investment 2022

Note: Figures for 2022 are estimates from IEA

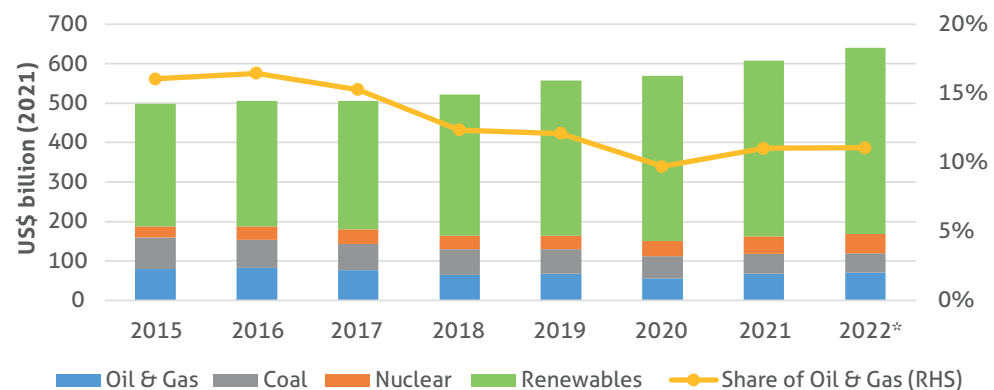
In 2021, capital spending in LNG projects reached \$23 billion, with the U.S. accounting for nearly half. With the next large wave of LNG projects expected to come online in 2025, including Qatar's North Field expansion and U.S. Gulf Coast projects, Europe is in need of fast-track LNG solutions in the short-term. The role of LNG has come to forefront as Europe undergoes rapid diversification of its gas supply from Russia, and changes its

traditional role of being the 'sink' market. Thus, we may expect to see more investments in debottlenecking or modular liquefaction in the short-term.

### 2.3.4 Global Power Generation

Global investment in power generation was \$608 billion in 2021, increasing 7% y-o-y. Investment in oil and gas power plants experienced the largest increase of 21% y-o-y, followed by nuclear with 11% y-o-y and renewables with 7% y-o-y, while investment in coal-fired generation decreased by 9% in 2021. Despite the increase in oil and gas generation to \$67 billion in 2021, the share of investment in oil and gas generation has declined from 16% in 2015 to 11% in 2021. On the contrary, the share of renewable power generation increased from 62% in 2015 to 73% in 2021 to \$446 billion (Figure 8).

**Figure 8: Global Investment in Power Generation**



Source: GECF Secretariat based on data from IEA World Energy Investment 2022  
 Note: Figures for 2022 are estimates from IEA

In 2022, investment in power generation is expected to grow by 5% to an estimated \$640 billion. Investment in oil and gas power generation is also expected to increase by 6% y-o-y to \$71 billion. Renewables will continue to account for the major share of investment in power generation and is likely to increase by 6% y-o-y to reach \$472 billion in 2022. Furthermore, investment in electricity grids and battery energy storage is expected to increase to \$318 billion and \$20 billion respectively, with investment in storage almost doubling from 2021 levels.

This will be supported by policies from advanced economies for electrification of buildings, industry and transport. In Europe in particular, concerns about energy supply security and the drive to reduce reliance on Russian gas supply have fast-tracked renewable capacity additions in 2022. However, there are some uncertainties and challenges ahead for investment in renewables in the form of inflationary pressure, supply chain bottlenecks and increasing cost of critical minerals.

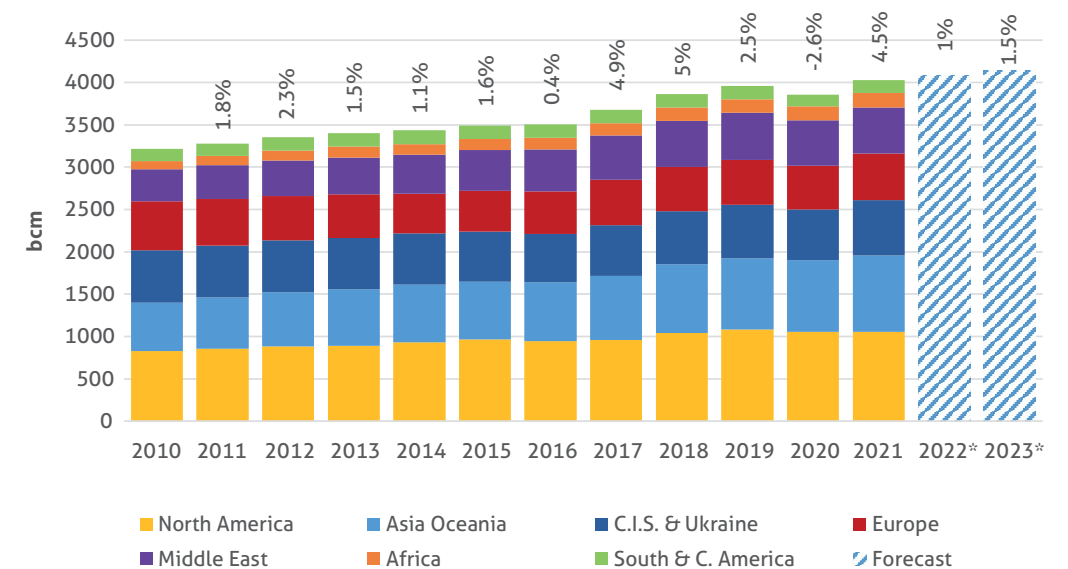


## Natural Gas Consumption

### 3.1 Natural Gas Consumption by Region

After the eventful year 2020 with the outbreak of the COVID-19 pandemic and warmer weather, the year 2021 recorded a rebound in global gas consumption. Global gas consumption is estimated to have increased by 4.5% in 2021 to reach 4.01 Tcm. This corresponds to a growth of 173 bcm compared to 2020, with all gas demand lost in 2020 (80 bcm) being recovered in 2021. The key drivers of the growth were global economic recovery, as well as abnormal weather conditions, with a very cold winter and a warmer summer. All regions, except North America, witnessed an increase in gas consumption, with Asia Oceania, Europe and Eurasia accounting for the bulk of the growth. The decrease in gas consumption in the U.S. was due to high gas prices that boosted gas-to-coal switching (Figure 9).

Figure 9: Trend in Global Gas Consumption by Region

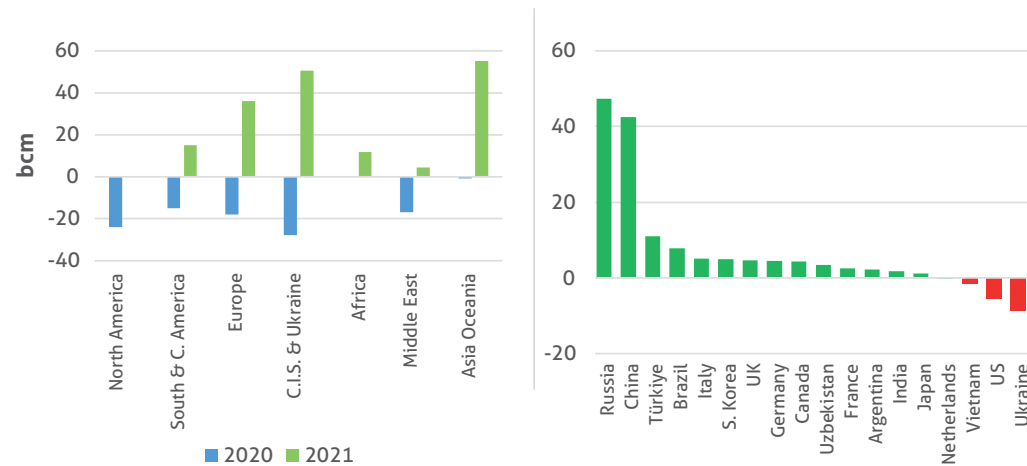


Source: GECF Secretariat based on data from BP Statistical Review 2021, Cedigaz and IEA Monthly Gas Statistics (\*): GECF Secretariat's forecast for 2022 and 2023

At a country level, Russia, China, Türkiye, Brazil and Italy recorded huge growth in gas consumption, driven by a quick recovery from the pandemic and the introduction of stimulus packages that revived economies. In contrast, the U.S., Vietnam, and Ukraine recorded significant declines in gas consumption (Figure 10).

In 2022, global gas consumption is predicted to record a rise of up to 1% compared to 2021. The growth will be driven by the US, mainly by the power generation sector, as a consequence of the tightening coal supply and rising coal prices that have limited the fuel switching ability of power generators. In addition, Asia and Southeast Asian countries will contribute to the growth of global gas consumption in the industrial and power generation sector. In 2023, global gas consumption is forecasted to increase by up to 1.5% y-o-y. China and some emerging countries such as Indonesia, Thailand, Pakistan, and Bangladesh will drive the demand growth.

**Figure 10: Variation in Gas Consumption in Major Regions and Countries in 2021**



Source: GECF Secretariat based on data from Cedigaz, India's PPAC and Refinitiv

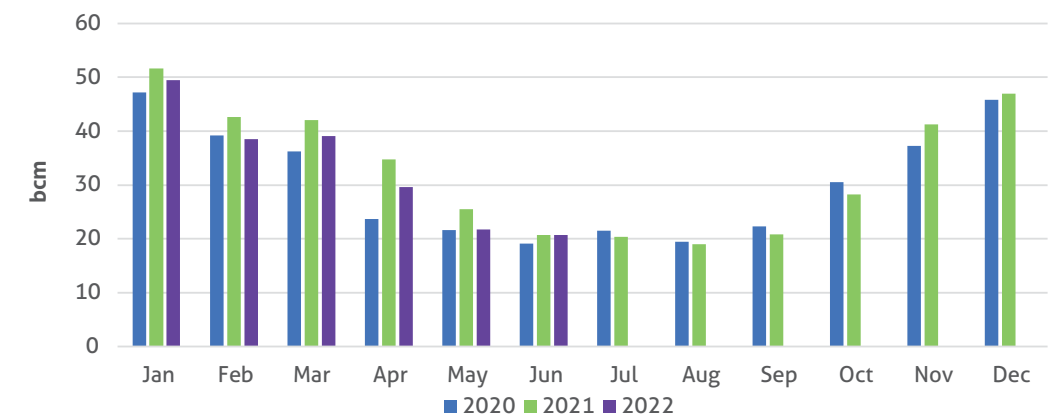
### 3.1.1.1 Europe

In 2021, Europe's gas consumption was up by 7% y-o-y to reach 551 bcm, which represents the highest y-o-y growth recorded in Europe in the last decade. The rise in gas consumption was mainly seen in Türkiye, Italy, Germany, France, Spain and UK with increases of 23.0%, 7.9%, 7.3%, 6.6%, 4.9% and 3.1% y-o-y respectively. The growth was mainly attributed to the post-pandemic economic recovery, colder-than-usual winter and warmer-than-usual summer, which boosted gas consumption in the power generation and residential sectors. Lower wind and hydro generation across Europe also contributed to higher gas consumption in the power generation sector, which rose by 3% y-o-y. Meanwhile, Europe's electricity production grew by 3.9% y-o-y to 4773 TWh.

In 2022, gas consumption is predicted to record a decrease of 5% compared to 2021, as sustained high gas prices will make the fuel less competitive against coal in the power generation and industrial sectors. In addition to that, the strong expansion of renewables will further impact gas demand in the power generation sector. Residential sector demand is also expected to fall, assuming that weather conditions are normal. In the first half of 2022, gas consumption in the EU declined by 8.3% y-o-y to 200 bcm, driven by above-normal temperatures during Q1 2022, high wind and solar output in the power generation mix, and low industrial activities that were impacted by high gas prices (Figure 11).

In 2023, gas demand in Europe is forecasted to record the same level as 2022, or a slight decrease. This will be driven by the continuing trend of high gas prices due to tight gas market conditions, which will boost gas-to-coal switching. Furthermore, the recent EU policy to reopen some coal power plants to reduce the dependency on Russian gas will impact the share of gas in the European energy mix. Another factor that could harm gas consumption in Europe is the continuous rise of wind and solar installed capacity, which will increase the share of renewables in the electricity mix.

**Figure 11: Trend in the EU's Monthly Gas Consumption**

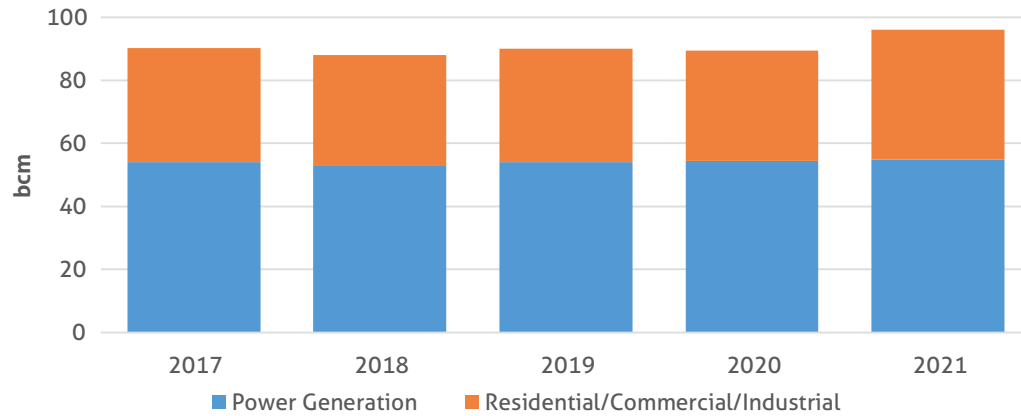


Source: GECF Secretariat based on data from McKinsey

### 3.1.1.1.1 Germany

In 2021, gas consumption in Germany increased by 7.3% y-o-y to reach 96 bcm. The residential/commercial/industrial sectors were up by 17.6% y-o-y to reach 41 bcm, driven by the post-COVID-19 economic recovery and cold winter during Q1 and Q4 2021. Gas consumption in 2021 increased by 6.7% compared to 2019 (Figure 12).

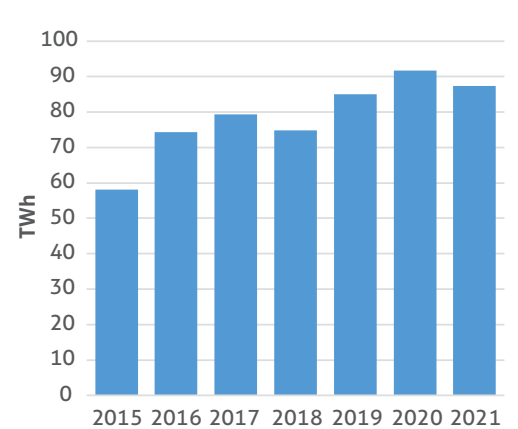
**Figure 12: Trend in Germany's Annual Gas Consumption by Sector**



Source: GECF Secretariat based on data from Refinitiv

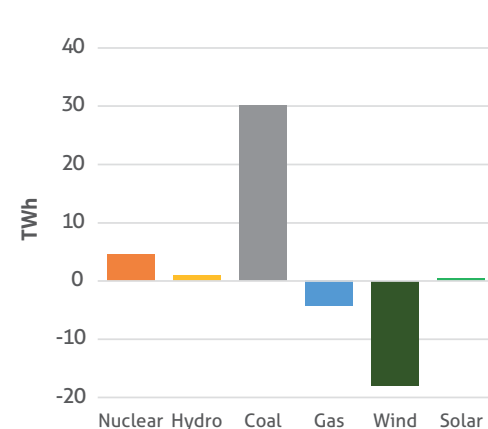
However, gas consumption in the power generation sector declined by 4.7% y-o-y due to gas-to-coal switching (Figure 13). The coal consumption in the sector increased by 24% y-o-y, which offset the decline in gas consumption. This was due to high gas prices, which increased the competitiveness of coal over gas (Figure 14).

**Figure 13: Trend in Germany's Gas Consumption in the Power Generation Sector**



Source: GECF Secretariat based on data from Refinitiv

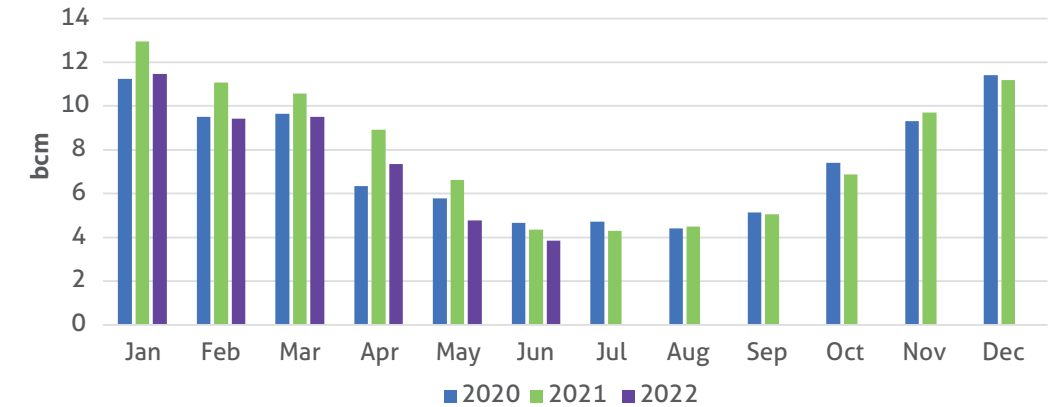
**Figure 14: Y-o-Y Variation in Germany's Power Generation Production Mix**



In the first half year of 2022, Germany, the biggest gas consumer in Europe, recorded a decline in gas consumption of 15% to reach 46.4 bcm (Figure 15). The decline was

driven by a mild winter, lower industrial activities due to high gas prices, high wind output and strong gas-to-coal switching. The residential/commercial, industrial and power generation sectors recorded a decrease of 16% (3.9 bcm) and 14% (4.3 bcm) respectively compared to the same period of last year.

**Figure 15: Trend in the Germany's Monthly Gas Consumption**

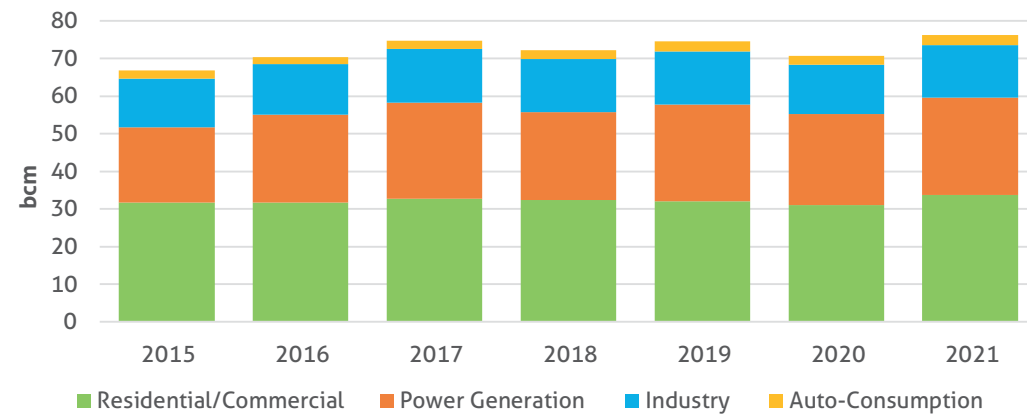


Source: GECF Secretariat based on data from Refinitiv

### 3.1.1.2 Italy

In 2021, gas consumption in Italy increased by 7.9% (5.5 bcm) y-o-y to reach 76 bcm. The industrial, residential/commercial and power generation sectors were up by 6%, 8.2% and 7.7% y-o-y, respectively. This was driven by the recovery of gas consumption in the post-COVID-19 era, colder winter, warmer summer season and recovery of the national economy. Following the decline in gas consumption in 2020, due to COVID-19, Italian gas consumption rebounded and surpassed the 2019 level by 2.2% (Figure 16). The rise in gas consumption in Italy in 2020 was driven by the residential and power generation sectors, with a growth of 2.5 bcm and 1.8 bcm y-o-y, respectively.

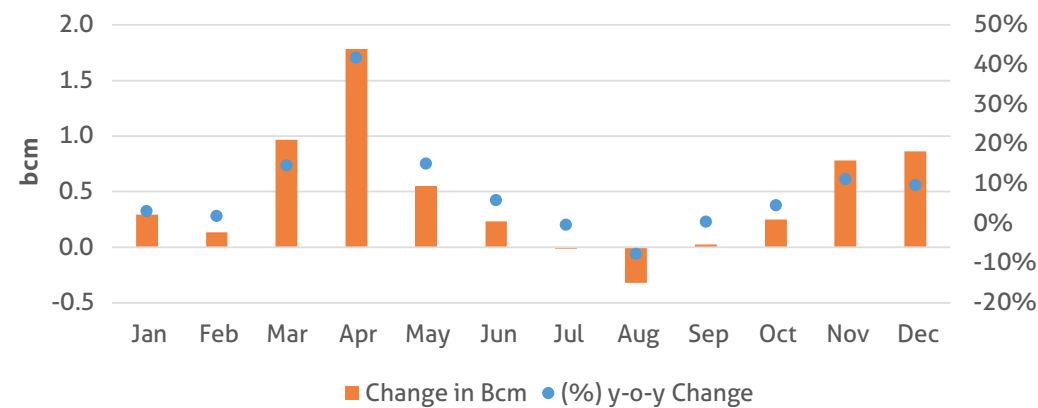
**Figure 16: Trend in Italy's Annual Gas Consumption by Sector**



Source: GECF Secretariat based on data from Snam

The bulk of the growth occurred during March-May and Q4 2021 when gas consumption recorded a rise of 3.3 bcm and 1.9 bcm, respectively (Figure 17).

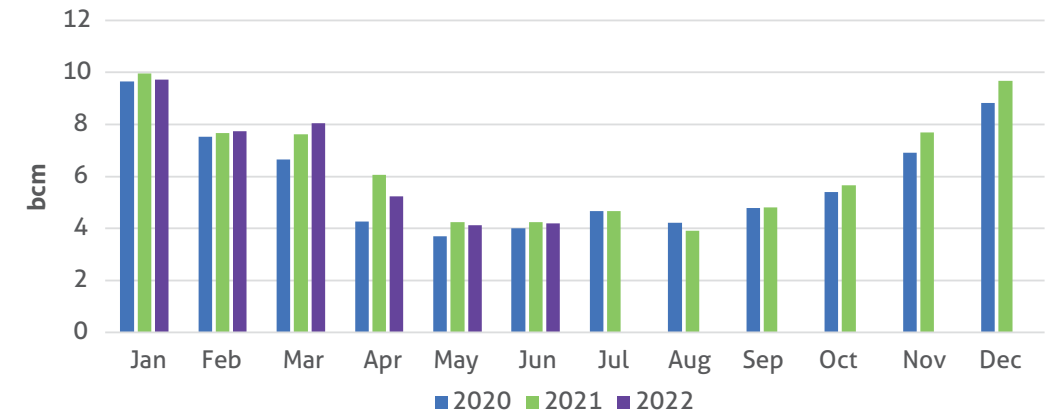
**Figure 17: Y-o-Y Comparison of the Monthly Gas Consumption in Italy (2020-2021)**



Source: GECF Secretariat based on data from Snam

From January to June 2022, gas consumption in Italy declined by 2% y-o-y to reach 39 bcm (Figure 18). The industrial, power generation and residential sectors were down by 8%, 7% and 6% y-o-y respectively. That was attributed to a mild winter in Q1 2022, high renewable output, gas-to-coal switching and high gas prices that affected the gas consumption in the industrial sector.

**Figure 18: Trend in Italy's Monthly Gas Consumption**

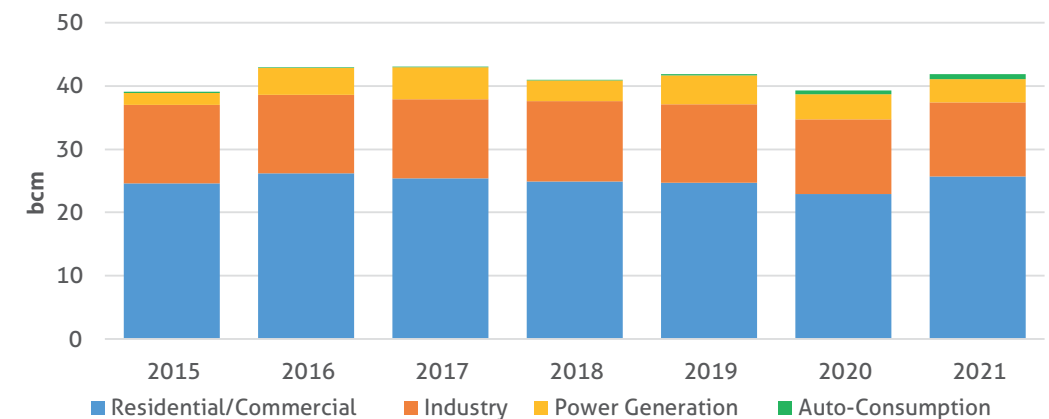


Source: GECF Secretariat based on data from Snam

### 3.1.1.3 France

In 2021, gas consumption in France increased by 6.6% (2.6 bcm) y-o-y to reach 42 bcm (Figure 19). The residential sector represented the majority of the rise, with an increase of 12% (2.75 bcm) to reach 26 bcm. This was driven by below-normal temperatures during the winter season; specifically, the average temperature was down by 1.4°C compared to 2020. Meanwhile, the industrial sector recorded the same level as in 2020 with a total gas consumption equal to 11.8 bcm.

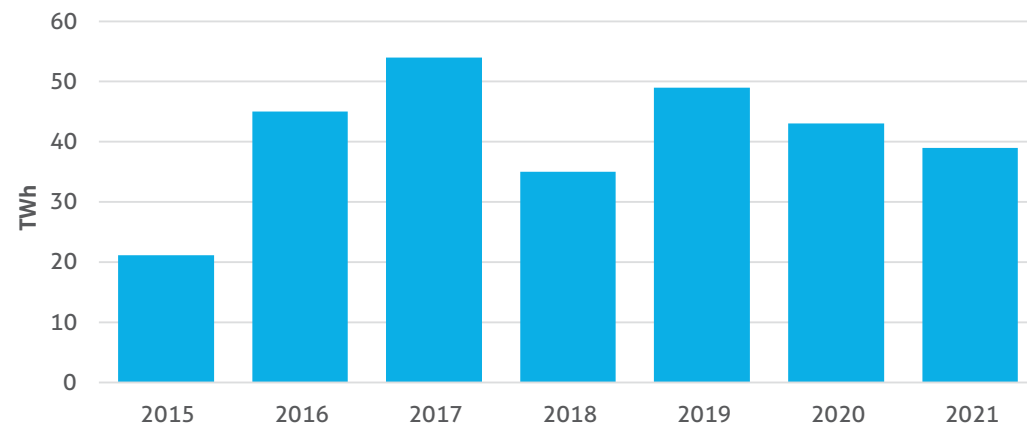
**Figure 19: Trend in France's Annual Gas Consumption by Sector**



Source: GECF Secretariat based on data from GRTgaz

In contrast, gas consumption in the power generation sector was down by 10%, reaching 3.6 bcm and recorded the second consecutive year of decline (Figure 20). The reduction of gas consumption in the power generation sector was mainly due to higher nuclear availability (7.2%) and stronger coal (87%) output during the year due to high gas prices.

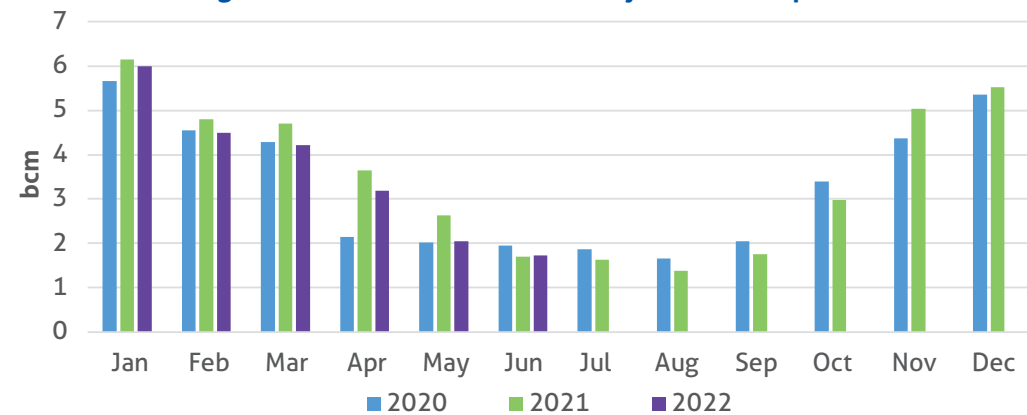
**Figure 20: Trend in France’s Gas Consumption in the Power Generation Sector**



Source: GECF Secretariat based on data from GRTgaz

Between January and June 2022, gas consumption in France decreased by 9% y-o-y to reach 20 bcm (Figure 21). The residential and industrial sectors recorded a decrease in gas consumption of 14% and 11% y-o-y, respectively, driven by a combination of mild winter and high gas prices. However, gas consumption in the power generation sector was up by 44% to reach 2.7 bcm, as a consequence of low nuclear and renewables output.

**Figure 21: Trend in France’s Monthly Gas Consumption**

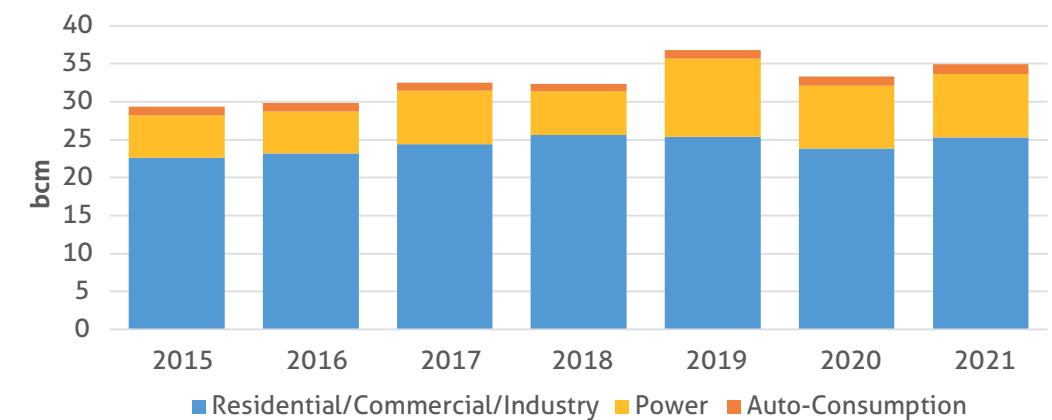


Source: GECF Secretariat based on data from Grtgaz

### 3.1.1.4 Spain

In 2021, gas consumption in Spain increased by 4.9% y-o-y to reach 35 bcm (Figure 22). The residential/commercial/industrial sector represented the majority of the rise in gas consumption during the year, with an increase of 6.1% (1.5 bcm) y-o-y. The power sector consumption showed a growth of 1.1% y-o-y to reach 8.3 bcm, which is the second-highest level since 2011. The economic recovery, extreme weather conditions and low hydro output during the year (-3.4% y-o-y) were the main drivers of Spanish gas consumption during the year 2021. However, when compared to 2019, gas consumption in Spain did not reach the pre-COVID-19 level and recorded a decline of 5% compared to 2019.

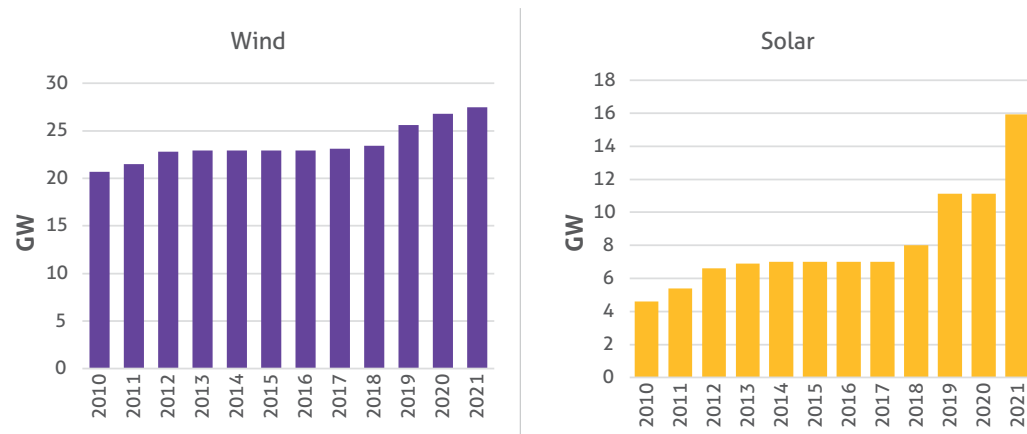
**Figure 22: Trend in Spain’s Annual Gas Consumption by Sector**



Source: GECF Secretariat based on data from Enagas

Natural gas consumption in the Spanish electricity mix was resilient even with the increase of wind and solar output by 10% and 37% y-o-y respectively in 2021. Spain’s wind and solar capacity increased by 2.6% (0.7 GW) and 43% (4.8 GW) respectively. Spain is the biggest solar capacity holder in Europe (Figure 23).

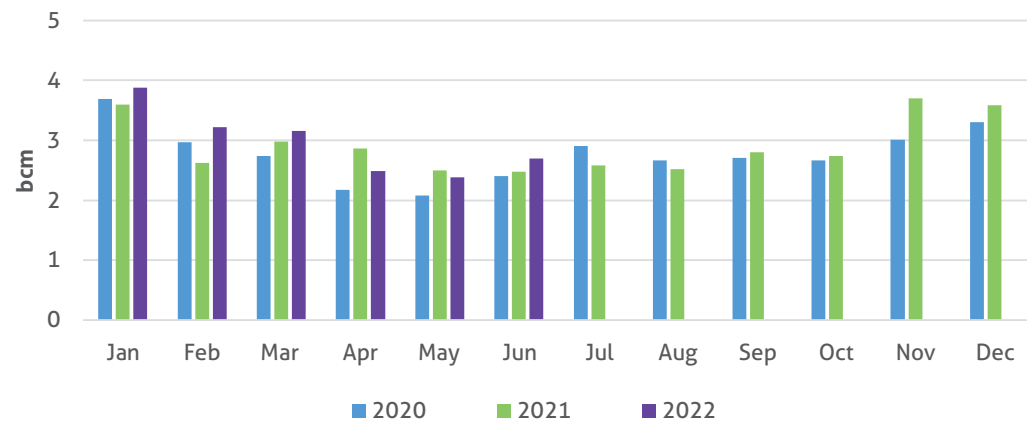
**Figure 23: Installed Wind and Soar Capacity in Spain (2010-2021)**



Source: GECF Secretariat based on data from Ree.es

In the first half year of 2022, gas consumption in Spain increased by 5% y-o-y to reach 17.8 bcm (Figure 24). The conventional market, which represents both industrial and residential sectors, was down by 9.8% y-o-y, driven by above-normal temperatures during the winter, as well as high gas prices that offset gas consumption in the industrial sector. However, consumption in the power generation sector recorded a growth of 76% y-o-y to reach 5.2 bcm. The rise in the power generation sector was mainly driven by a combination of record high summer temperatures that drove up the cooling demand and the decline of the hydro and wind output in the Spanish electricity mix, which fell by 49% and 2.5% y-o-y, respectively. This lower hydro output was due to the drought that hit the country, which boosted gas consumption in the power generation sector.

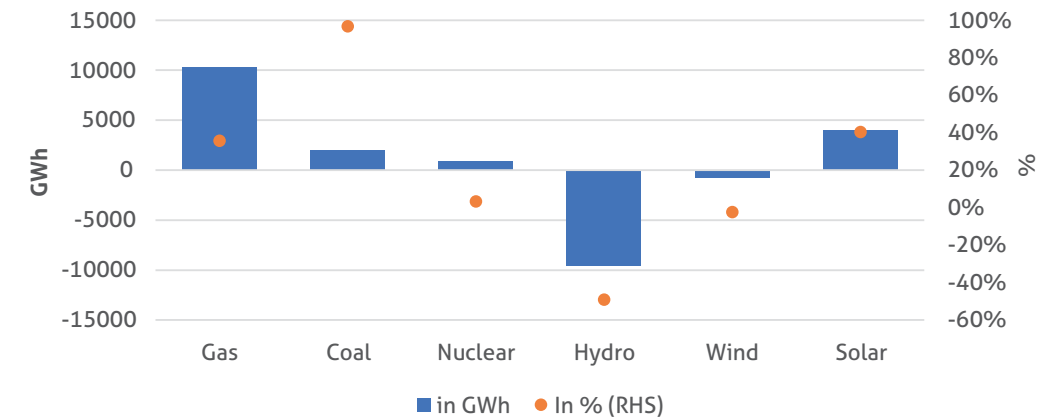
**Figure 24: Trend in Spain's Monthly Gas Consumption**



Source: GECF Secretariat based on data from Enagas

In the meantime, coal and solar output rose by 97% and 40% y-o-y respectively (Figure 25).

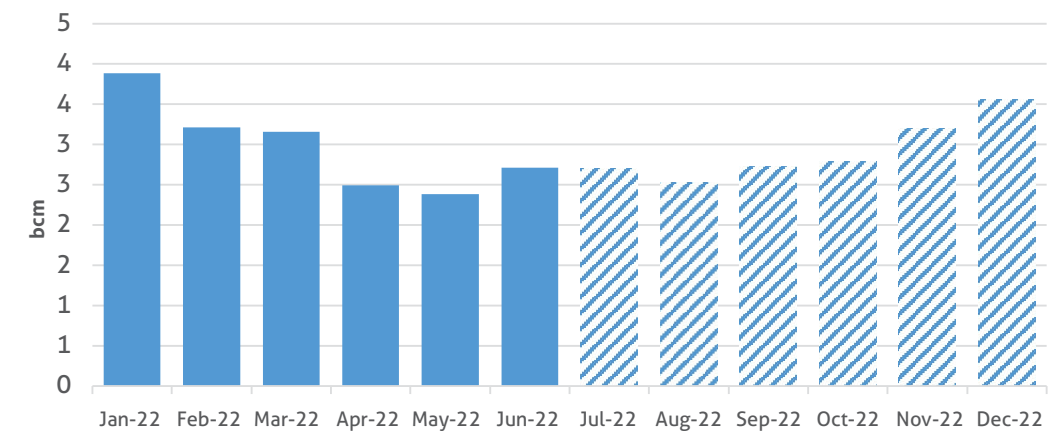
**Figure 25: Variation in the Span's Electricity Mix in H1 2022**



Source: GECF Secretariat based on data from Ree.es

According to the data published by the Spanish gas transporter Enagas, gas consumption for the full year 2022 is estimated to reach 35.4 bcm (+1.1% y-o-y) in the mid scenario (Figure 26).

**Figure 26: Spain's Forecasted Monthly Gas Consumption 2022**



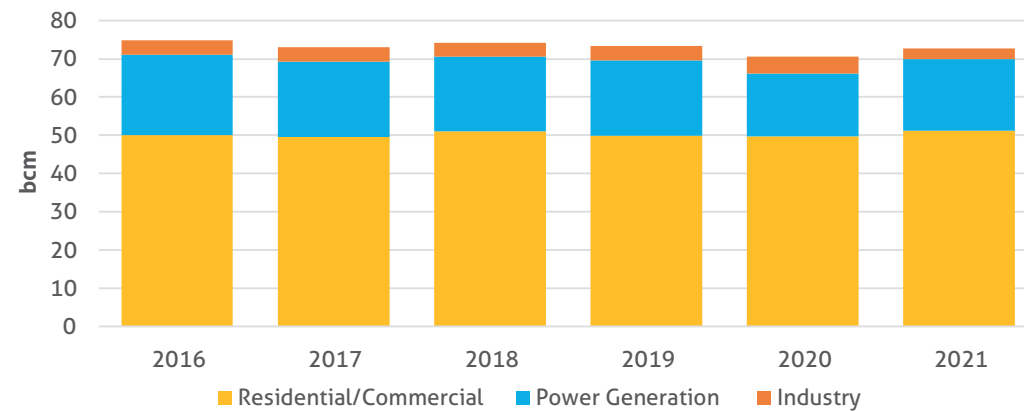
Source: GECF Secretariat based on data from Enagas

**3.1.1.5 UK**

In 2021, gas consumption in the UK increased by 3.1% y-o-y to reach 73 bcm (Figure 27). Gas consumption in the residential and power generation sectors rose by 2.7%

and 14.2% to reach 51 bcm and 19 bcm respectively. That was driven by a combination of cold weather and low renewables output in the power generation mix. In contrast, gas consumption in the industrial sector declined by 34% (1.5 bcm) to reach 3 bcm, which was driven by high gas prices, with industrial users switching to alternative fuels or reducing output. Companies in energy-intensive sectors, such as fertilizers, glass and steel, either reduced or suspend production.

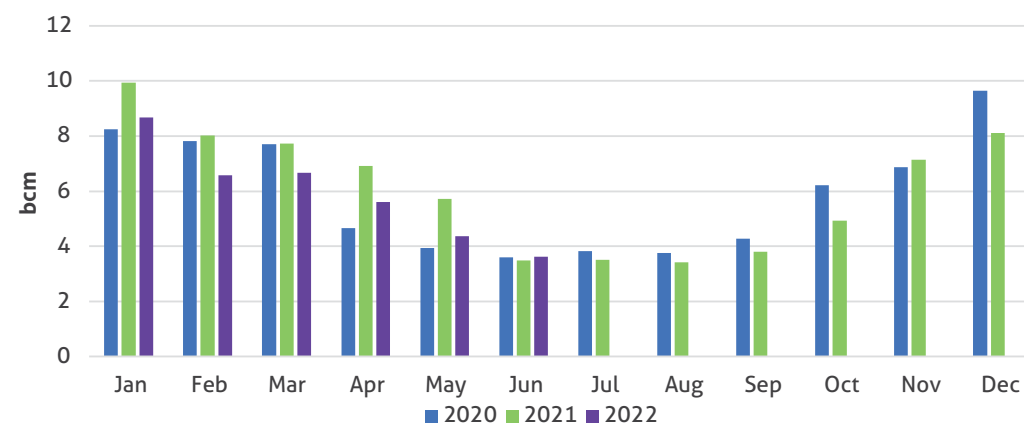
**Figure 27: Trend in the UK's Annual Gas Consumption by Sector**



Source: GECF Secretariat based on data from Refinitiv

From January to June 2022, the UK recorded a decrease of 15% y-o-y in gas consumption, which reached 35.5 bcm (Figure 28). The decline was driven by the residential sector (-5.2 bcm y-o-y), followed by the power generation sector (-0.3 bcm) and industrial sector (-0.7 bcm), as consequence of a mild winter and high gas prices which affected gas demand in the industrial sector.

**Figure 28: Trend in the UK's Monthly Gas Consumption**

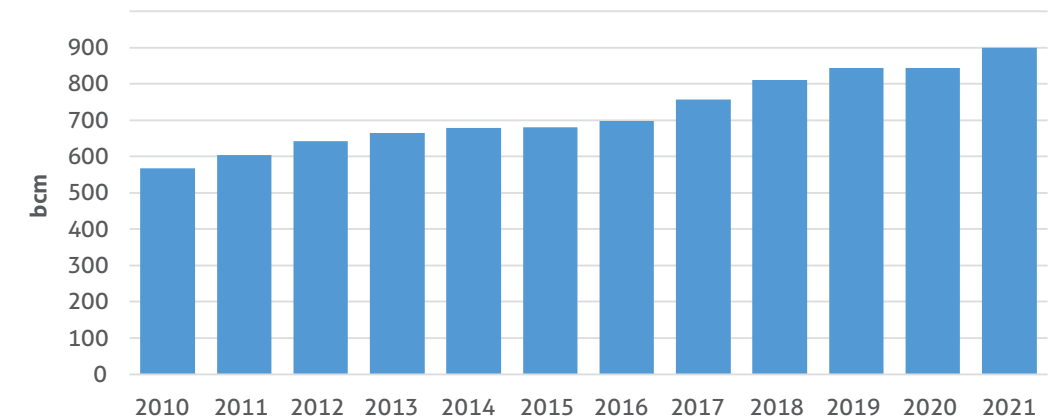


Source: GECF Secretariat based on data from Refinitiv

### 3.1.2 Asia Pacific

In 2021, gas consumption in the Asia Pacific region recorded an increase of 6.5% y-o-y (55 bcm) to reach 899 bcm. China led the growth with an increase of 13% y-o-y (42 bcm), followed by South Korea, Bangladesh, India, Australia and Japan with increases of 9% (+4.9 bcm), 6.6% (+1.9 bcm), 3% (+1.8 bcm), 2.5% (+1.3 bcm) and 1.1% (+1.2 bcm) y-o-y respectively (Figure 29).

**Figure 29: Trend in the Asia Pacific's Annual Gas Consumption**



Source: GECF Secretariat based on data from Cedigaz

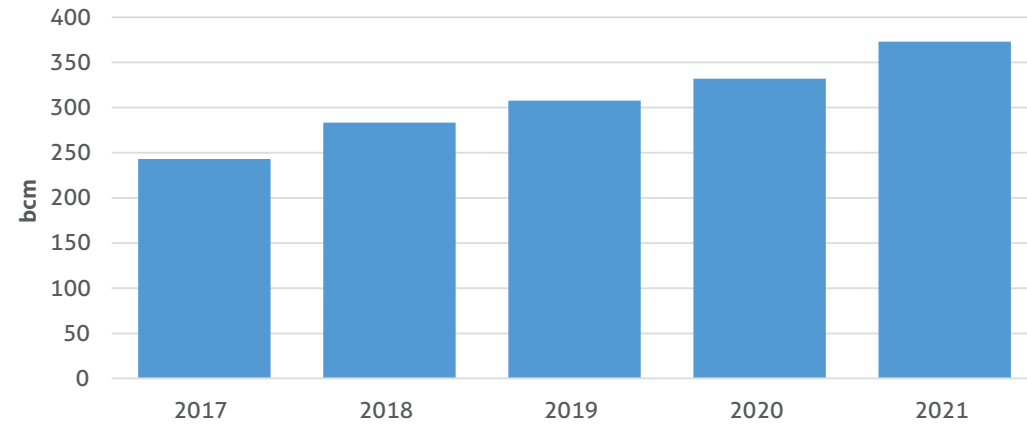
In 2022, gas demand in the region is expected to increase by 5%, driven by economic recovery and increased electricity demand. China will continue driving demand growth. Emerging countries such as Indonesia, Thailand, Pakistan, and Bangladesh will contribute to more than one quarter of the regional gas demand. Even with high gas prices, coal-to-gas switching will carry on in the power generation sector.

In 2023, the regional gas demand is anticipated to continue growing, although with a slower pace compared to 2021. The growth will be driven by China and India even though high gas prices will lead to a slower coal to gas switching.

#### 3.1.2.1 China

In 2021, China was still the demand driver of gas consumption in the region and was one of the countries that witnessed a huge increase in gas consumption. China's apparent gas consumption (production + PNG imports + LNG imports) increased by 13% y-o-y to reach 373 bcm (Figure 30). That is attributed to a fast recovery of the Chinese economy after the pandemic, continuing coal-to-gas switching policy, rise in gas consumption in the industrial sector, low hydro output in Q2/Q3 2021, above-normal temperatures in Q1 2021, and warm summer in the southern regions, which boosted gas cooling demand. In addition, gas consumption in 2021 increased by 23% when compared to 2019.

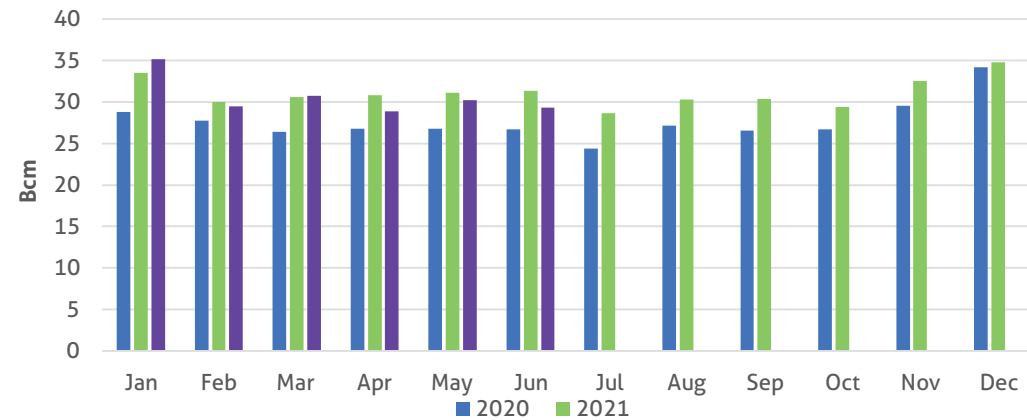
**Figure 30: Trend in China's Annual Gas Consumption**



Source: GECF Secretariat based on data from Refinitiv

In H1 2022, China's apparent gas consumption stood at 184 bcm, which represents a decline of 1.9% y-o-y (Figure 31). The decline in gas consumption in China has been driven by the lockdown imposed in the country and mild weather in the first quarter of 2022 in the northeast region, which impacted gas consumption in the power generation and residential sectors.

**Figure 31: Trend in China's Monthly Gas Consumption**



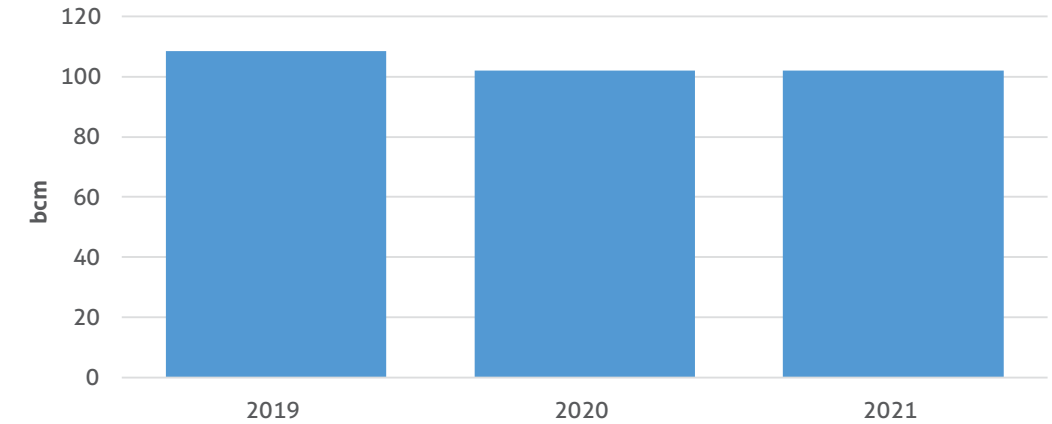
Source: GECF Secretariat based on data from Argus and Refinitiv

### 3.1.2.2 Japan

In 2021, gas consumption in Japan recorded a similar level to 2020 to reach 102 bcm (Figure 32). Gas consumption witnessed a 10.9% growth in the first half of the year, however, with the restart of several nuclear plants and high LNG prices, gas demand in

Japan declined in the second half of the year. Although total electricity production in the country increased by 3% y-o-y, gas consumption in the power generation sector recorded a decline of 8.6% y-o-y. However, gas remained the leader in the electricity production mix with 32%.

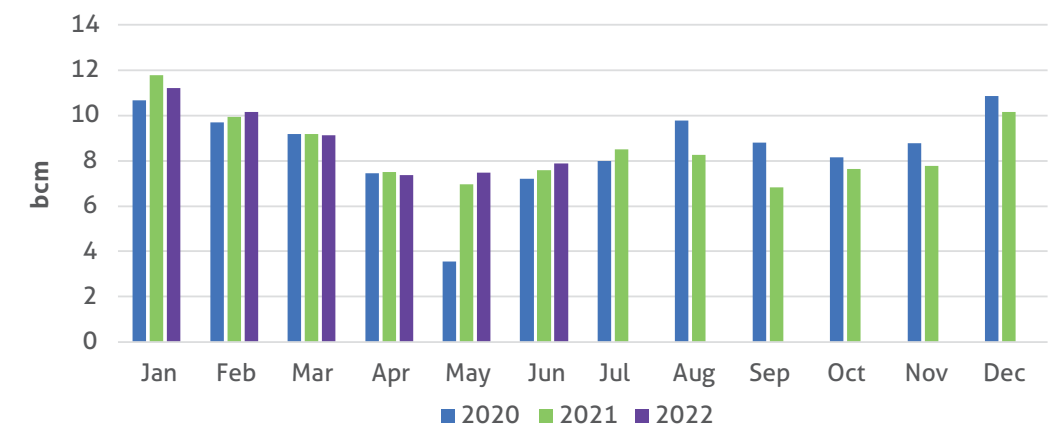
**Figure 32: Trend in Japan's Annual Gas Consumption**



Source: GECF Secretariat based on data from Refinitiv

Between January and June 2022, gas consumption in Japan is estimated to grow by 0.7% y-o-y to reach 53.3 bcm (Figure 33). This is driven by a significant increase in Japan's economic activities, as well as lower nuclear output caused by the shutdown of some reactors, in particular reactor Genkai No.3 of Kyushu Electric Power, which has a capacity of 1.18 GW. In addition, gas consumption was driven by the city gas sector with an increase of 4% y-o-y compared to the same period of last year to reach 24 bcm.

**Figure 33: Trend in Japan's Monthly Gas Consumption**



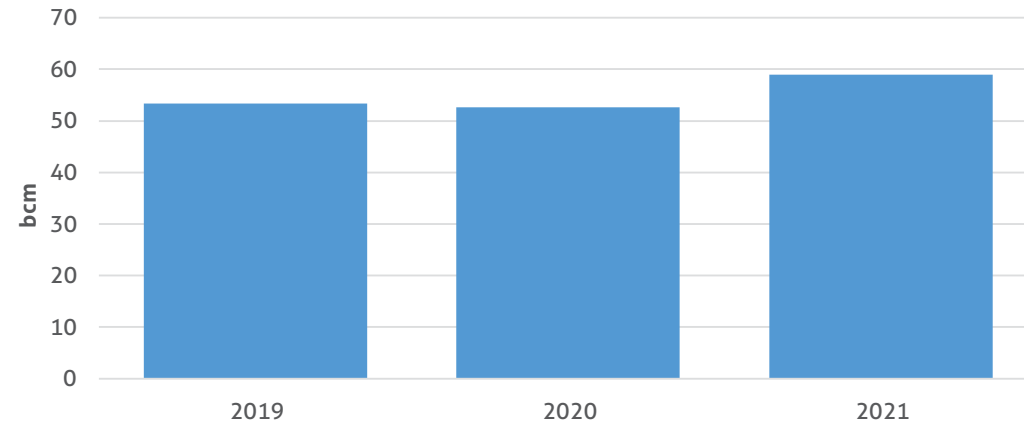
Source: GECF Secretariat based on data from Refinitiv



### 3.1.2.3 South Korea

In 2021, gas consumption in South Korea increased by 11.5% y-o-y to reach 59 bcm, driven by robust economic recovery, restrictions on coal-fired power plants as part of the winter fine-dust management policy, and shutdown of some nuclear reactors (Figure 34). Gas consumption in city gas and power generation sectors grew by 4.3% and 17.5% y-o-y respectively.

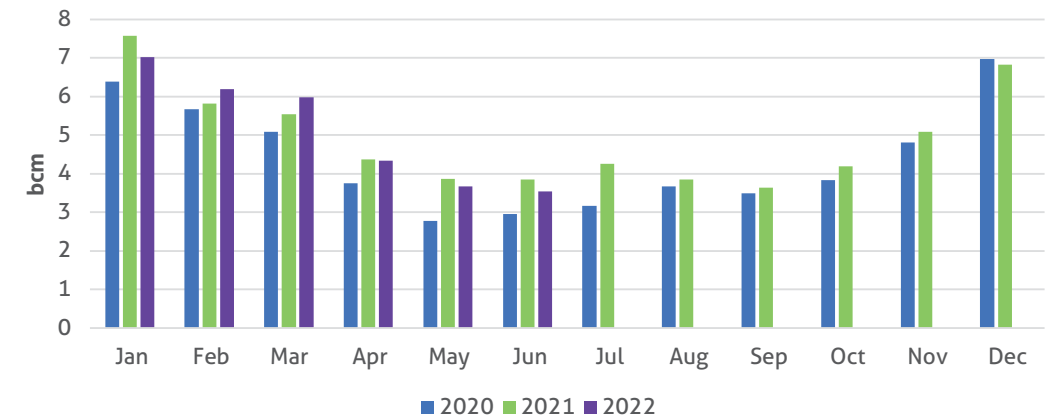
**Figure 34: Trend in South Korea's Annual Gas Consumption**



Source: GECF Secretariat based on data from Refinitiv

In the first half of 2022, gas consumption in South Korea is estimated to decline by 0.8% y-o-y to reach 31 bcm, driven by lower gas burn in the power generation sector, which fell by 6.8% to 14 bcm (Figure 35). The drop was due to the removal of the restrictions on coal-fired power plants, restart of some nuclear reactors and warm weather, with South Korea's Heating Degree Days (HDD) during the period averaging 8.1, up by 7.6% y-o-y.

**Figure 35: Trend in South Korea's Monthly Gas Consumption**

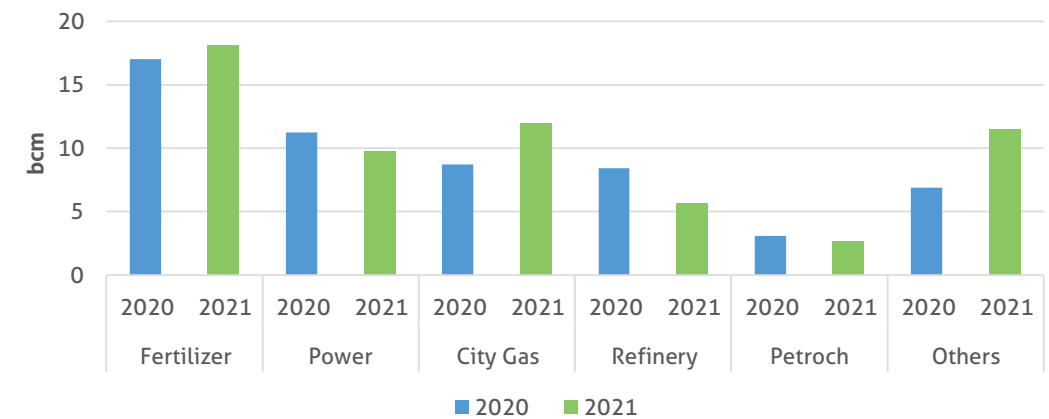


Source: GECF Secretariat based on data from Refinitiv

### 3.1.2.4 India

In 2021, gas consumption in India increased by 7.8% y-o-y to reach 60 bcm, driven by higher gas consumption in city gas (+3.2 bcm) and fertilizer (+1.1 bcm) sectors. In contrast, gas consumption declined in the power generation (-1.4 bcm) and refinery (-2.7 bcm) sectors (Figure 36).

**Figure 36: Trend in India's Annual Gas Consumption by Sector**



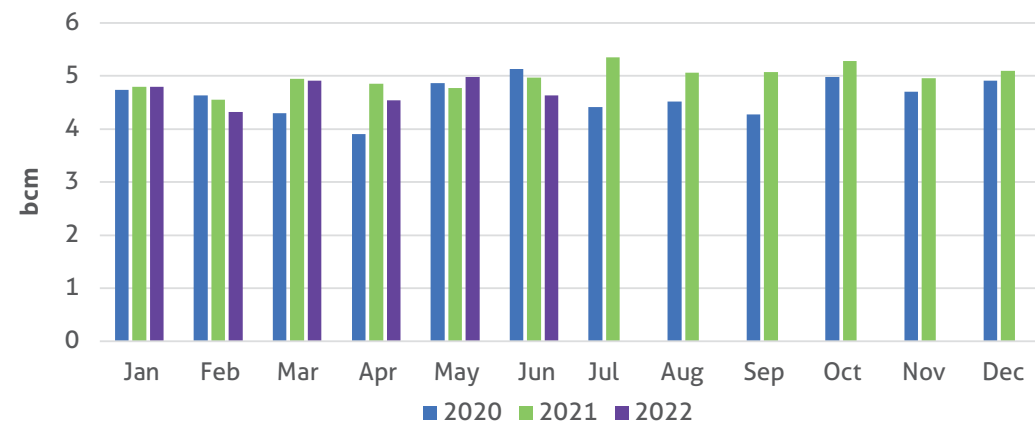
Source: GECF Secretariat based on data from India's PPAC

In terms of total gas consumption by sector, the fertilizer sector continues to dominate with a share of 30.3%. Compared to 2020, this sector remained stable, while the share of gas consumed in the city gas sector increased from 16% to 20%. The shares of gas consumption in the power generation, refinery and petrochemicals sectors declined from 20%, 15% and 6%, to 16%, 10% and 5% respectively.

Regasified LNG (R-LNG) represented 54% of the gas consumed in the country, which declined from 57% in 2020. Meanwhile, domestic gas production represented 46% of the national gas supply.

In January-June 2022, gas consumption in India stood at 28.2 bcm, down by 2.5% y-o-y (Figure 37). The power generation, refinery and petrochemicals sectors declined by 30%, 29.5% and 25.6%, respectively, mainly caused by high gas prices.

**Figure 37: Trend in India's Monthly Gas Consumption**

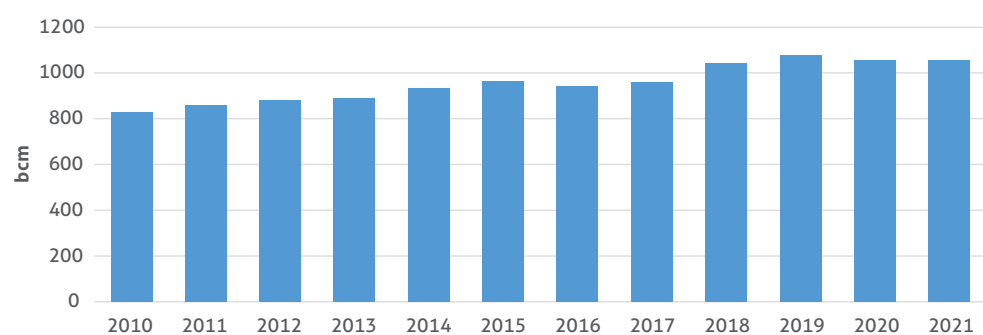


Source: GECF Secretariat based on data from India's PPAC

### 3.1.3 North America

In 2021, gas consumption in North America recorded the same level as 2020, with total gas consumed reaching 1,055 bcm. Canada led the growth of gas consumption in the region with an increase of 4% y-o-y (+4.3 Bcm), followed by Mexico with an increase of 1.5% (+1.3 bcm) y-o-y. By contrast, gas consumption in the US recorded a decline of 0.6%, corresponding to 5.4 bcm (Figure 38).

**Figure 38: Trend in North America's Annual Gas Consumption**



Source: GECF Secretariat based on data from Cedigaz

In 2022, gas demand in the region is forecast to increase by 2%, driven mainly by the US power generation sector, as a consequence of the tightening coal supply and rising coal prices that have limited fuel switching ability of power generators.

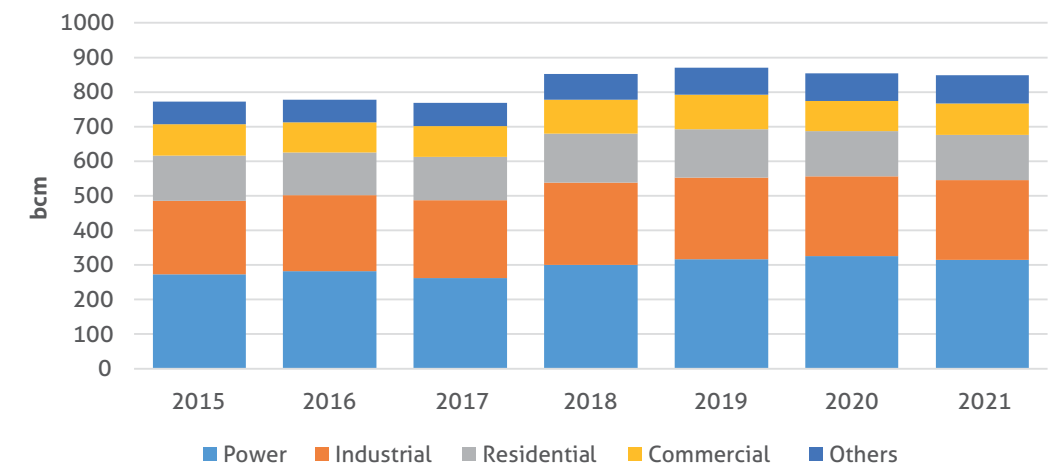
#### 3.1.3.1 U.S.

In 2021, the U.S. gas consumption recorded a slight decline to 850 bcm. Weaker gas consumption was observed in the power generation (-10 bcm) and industrial (-2 bcm) sectors, driven by high Henry Hub (HH) prices that boosted gas-to-coal switching. On the other hand, the commercial and residential sectors recorded an increase of 3.7% (+3 bcm) and 0.1% (+0.2 bcm), respectively (Figure 39). The slight growth in the residential sector was due to the cold weather during the winter season. As an indicator, the average Heating Degree Days (HDD) in 2021 was 323, up by 0.2% y-o-y, which implies an increase in gas consumption for heating in the residential sector.

In terms of gas consumption by sector, the power sector consumed the largest amount of gas with a share of 37%, followed by the industrial (27%), residential (15%) and commercial (11%) sectors.

Electricity production in the U.S. increased by 2.9%, and higher generation from coal (+16%), solar (+25%) and wind (+12%) offset a slump in gas burn (-3%), hydro (-9%) and nuclear (-1.5%). However, gas was the leading fuel in the power mix with a share of 40%, followed by nuclear (19.4%), coal (19.9%) and renewables (18.9%).

**Figure 39: Trend in the U.S.' Annual Gas Consumption by Sector**

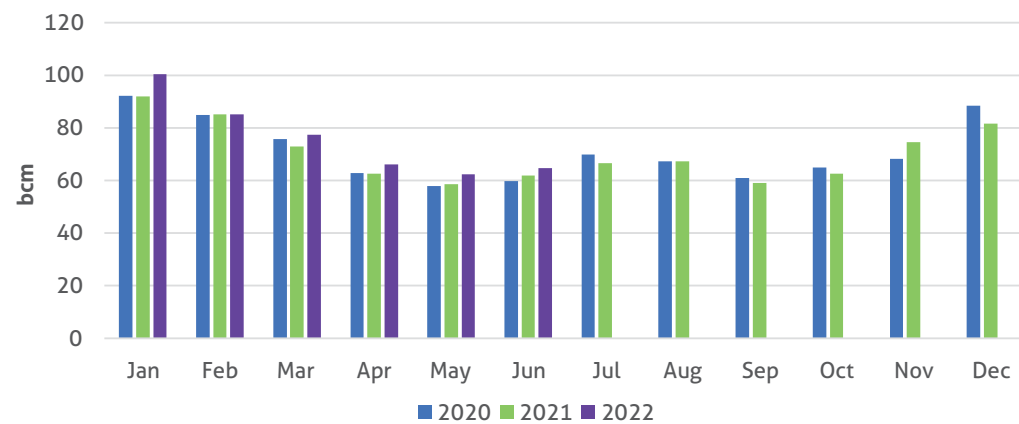


Source: GECF Secretariat based on data from EIA

For the first half of 2022, the U.S. natural gas consumption increased by 5.2% compared to last year. Gas use in power generation, which climbed by almost 7%, or 10bcm, year on year for the same period, was the main factor contributing to the expansion of gas consumption in the U.S. A limited supply of coal and rising coal prices hampered power companies' ability to switch fuels (Figure 40).

In terms of gas consumption by sector, the power sector consumed the largest amount of gas with a share of 33%, followed by the industrial (26%), residential (18%) and commercial (12%) sectors for the first half of the year 2022.

**Figure 40: Monthly Trend in U.S. Gas Consumption**

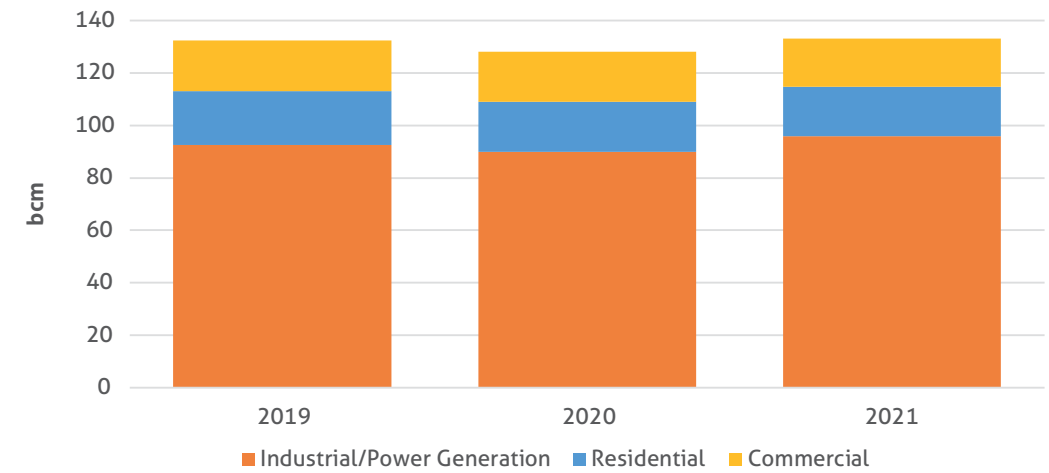


Source: GECF Secretariat based on data from EIA

### 3.1.3.2 Canada

In 2021, Canada's gas consumption increased by 3.8% to reach 115 bcm. The growth of gas consumption is attributed to the economic recovery on post-COVID-19. In terms of consumption by sector, the industrial sector was up by 6.5% (+5 bcm) y-o-y. However, gas consumption in the residential and commercial sector declined by 3.6% (-0.6 bcm) and 2.1% (-0.4 bcm) respectively (Figure 41). Regarding the assessment of the HDD in Canada, during the year 2021, it averaged 682, down by 4% y-o-y.

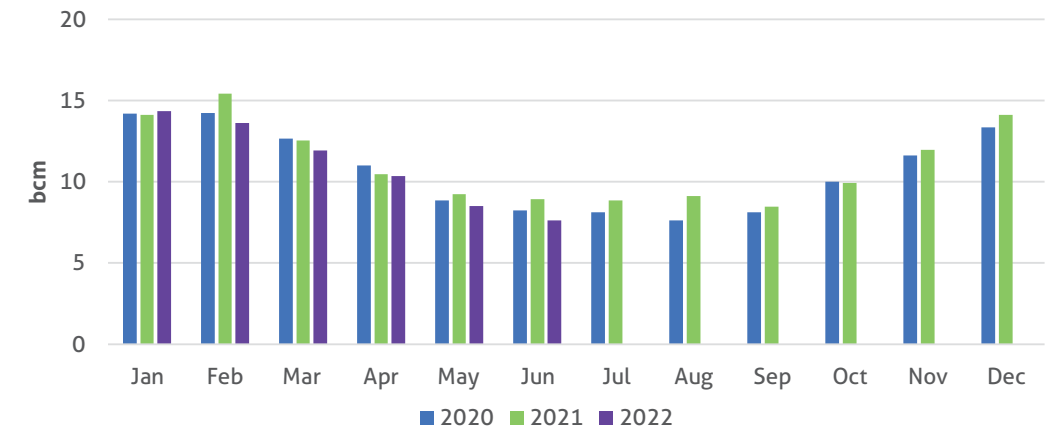
**Figure 41: Annual Comparison of the Gas Consumption in Canada by Sector**



Source: GECF Secretariat based on data from Statistics Canada

For the first half of 2022, Canadian natural gas consumption declined by 6.1% year-on-year to reach 66.4 bcm (Figure 42). The decline was driven by a reduction in natural gas consumption in the power generation and commercial sectors by 6.5% and 19% y-o-y, respectively.

**Figure 42: Trend in Canada's Monthly Gas Consumption**

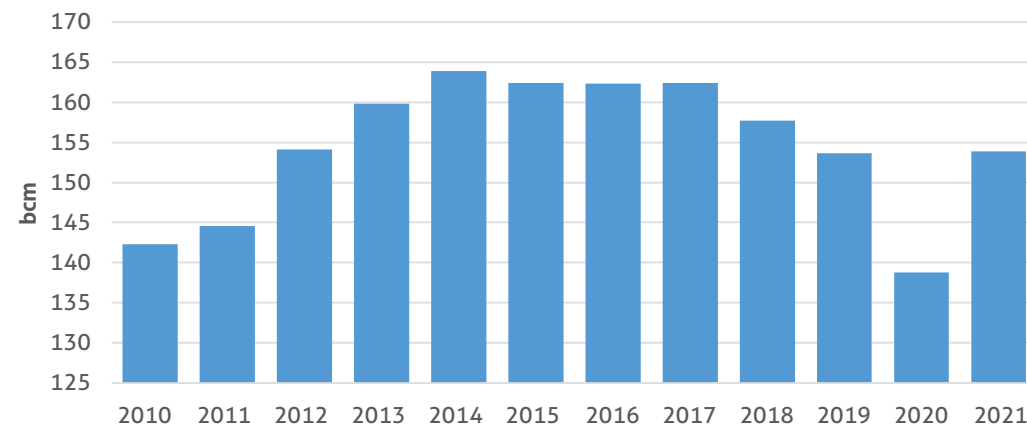


Source: GECF Secretariat based on data from Statistics Canada

### 3.1.4 South & Central America

In 2021, gas consumption in South & Central America recorded an increase of 11% y-o-y to reach 154 bcm. Brazil led the growth with an increase of 27% y-o-y (+7.8 bcm) followed by Argentina, Venezuela and Peru with an increase of 5% (+2.3 bcm), 11% (+1.6 bcm), and 17% (+1.2 bcm) y-o-y respectively (Figure 43). In 2022, the regional gas demand is forecasted to decline by 1%, driven mainly by the recovery in hydro output and high gas prices that will affect LNG imports.

**Figure 43: Trend in the South & Central America's Annual Gas Consumption**

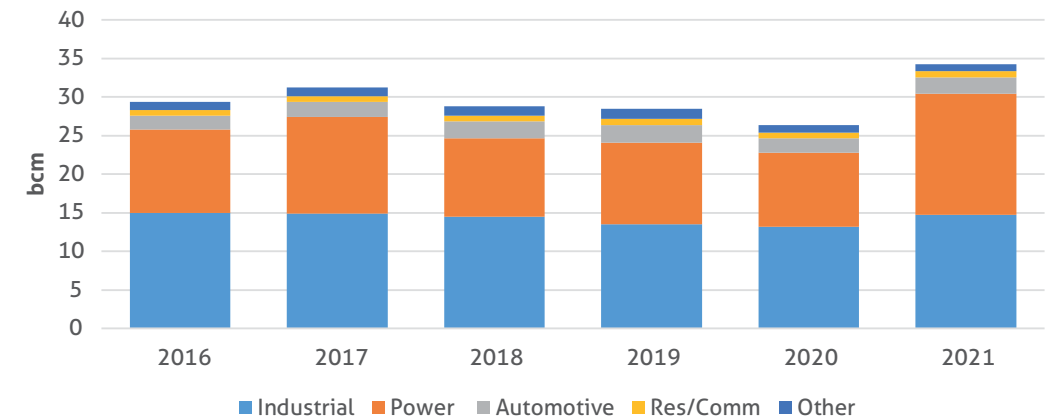


Source GECF Secretariat based on data from Cedigaz

#### 3.1.4.1 Brazil

In 2021, Brazil was a driver of growth in South America. Brazil recorded a jump in gas consumption of 26%, equivalent to 7.8 bcm. The bulk of growth was observed during Q2 and Q3, with incremental supplies at 2.8 and 3.4 bcm, respectively (Figure 44). In terms of gas consumption by sector, power generation recorded growth of 64% (6.1 bcm), followed by the industrial sector 11.5% (1.5 bcm) and the automotive sector 15% (0.3 bcm). Growth was mainly driven by a severe drought in Brazil and post pandemic economic recovery.

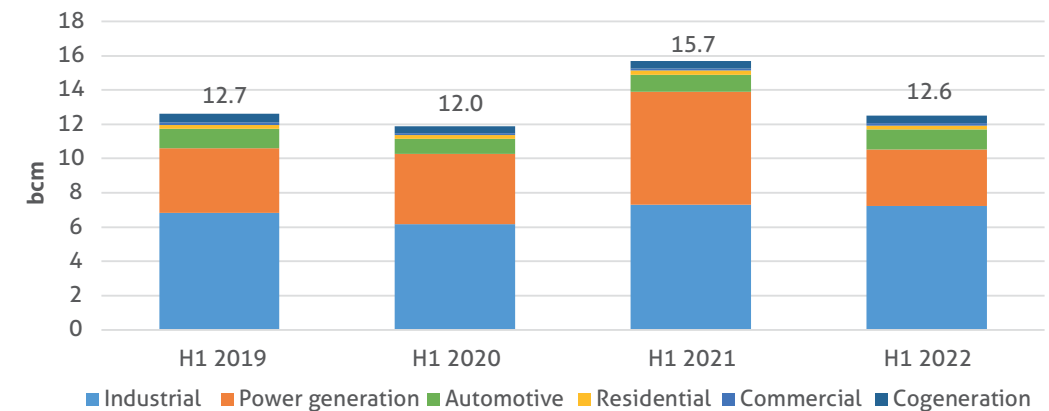
**Figure 44: Trend in Brazil's Annual Gas Consumption by Sector**



Source GECF Secretariat based on data from MINISTÉRIO DE MINAS E ENERGIA

In the first half of 2022, gas consumption in Brazil declined by 20% y-o-y. In terms of gas consumption by sector, power generation recorded a decline of 50% (-3.3 bcm), followed by the industrial sector 0.8% (-0.1 bcm) – mainly driven by the recovery of hydro output in the power generation mix (Figure 45).

**Figure 45: Trend in Brazil's H1 Gas Consumption by Sector in H1**



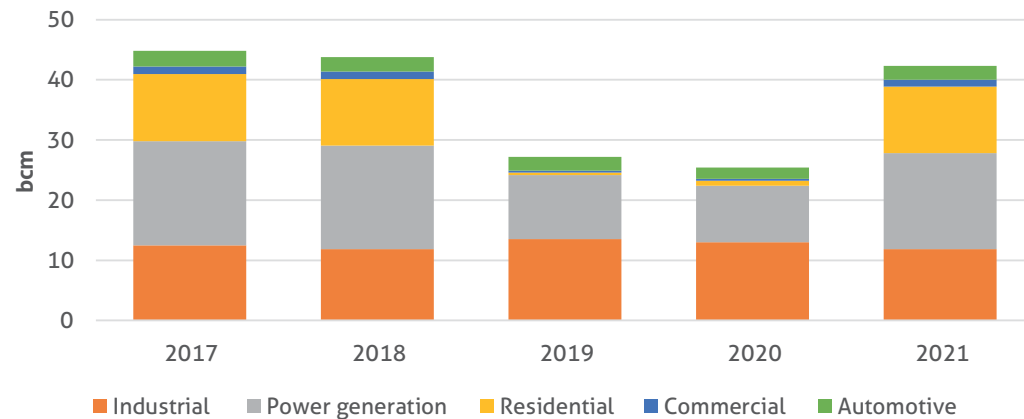
Source GECF Secretariat based on data from MINISTÉRIO DE MINAS E ENERGIA

#### 3.1.4.2 Argentina

In 2021, gas consumption in Argentina increased by 59.6% (+15.8 bcm) y-o-y to reach 42.4 bcm (Figure 46). The residential, power generation, commercial and automotive sectors were up by 1214% (+10.2 bcm), 68.4% (+6.5 bcm), 290% (+0.9 bcm) and 24.4% (+0.5 bcm) y-o-y respectively, while the industrial sector declined by 8.4% (-1.1

bcm) y-o-y. The growth was due to low hydro output, very cold weather during winter time and hot temperature in the summer season. The increase in gas consumption was supported by the application of the 4th Gas Plan in Argentina to boost the use of gas after the increase of domestic production from the Vaca Muerta basin.

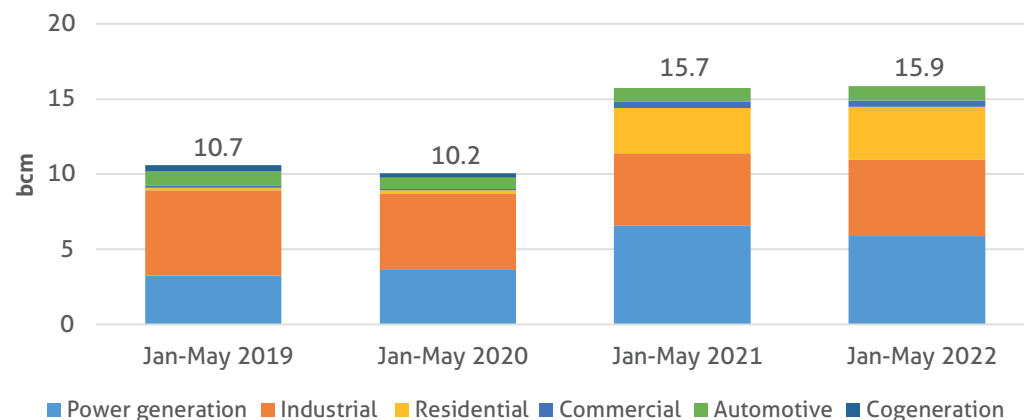
**Figure 46: Trend in Argentina's Annual Gas Consumption by Sector**



Source GECF Secretariat based on data from MINISTÉRIO DE MINAS E ENERGIA

In the first five months of 2022, gas consumption in Argentina increased by 0.9% to reach 15.9 bcm (Figure 47). Growth was driven by recovery in the industrial sector, representing a rise of 6% (0.3 bcm). Moreover, the residential sector recorded growth of 17% compared to the same period last year, at 3.5 bcm. In contrast, the recovery of hydro output offset the use of gas in the power generation mix.

**Figure 47: Trend in Argentina's Gas Consumption by Sector (Jan-May)**

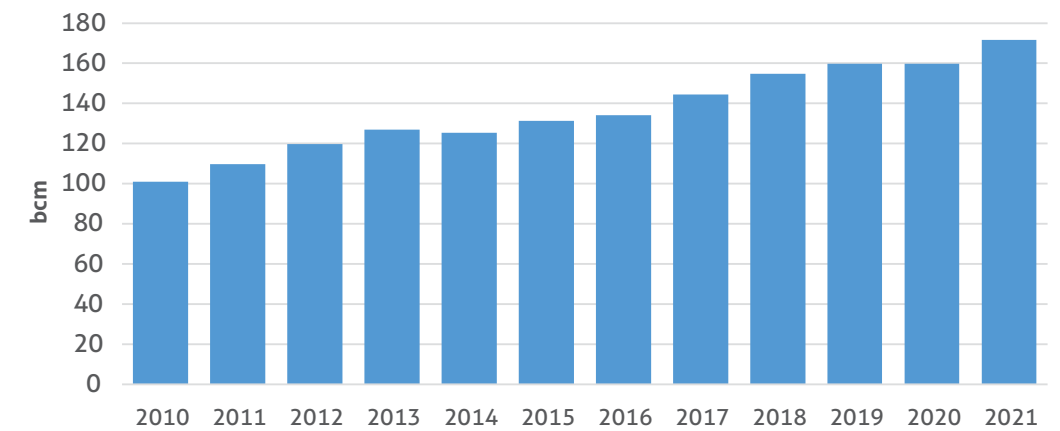


Source GECF Secretariat based on data from MINISTÉRIO DE MINAS E ENERGIA

### 3.1.5 Africa

In 2021, gas consumption in Africa recorded a growth of 7.3% compared to 2020 (11.6 bcm) to reach 124.6 bcm (Figure 48). Egypt led the growth of the regional gas consumption with an increase of 5.7% y-o-y (3.5 bcm), driven mainly by the electricity sector. In the meantime, Nigeria increased gas consumption by 3.3 bcm (17% y-o-y), while Libya, South Africa and Tunisia recorded a growth of 2.6 bcm (74%), 0.4 bcm (7%), and 0.2 bcm (3%) y-o-y respectively. In 2022, gas demand in Africa is forecasted to carry on rising, driven mainly by the power generation sector.

**Figure 48: Trend in the Africa's Annual Gas Consumption**



Source: GECF Secretariat based on data from Cedigaz

## 3.2 Natural Gas Consumption by Sector

### 3.2.1 Power generation

The trends in natural gas consumption in the power sector, as well as the power generation mix, on a global and regional basis are analysed in this section. Data from several sources were used and benchmarked, together with relevant policy announcements that will shape the short-term outlook.

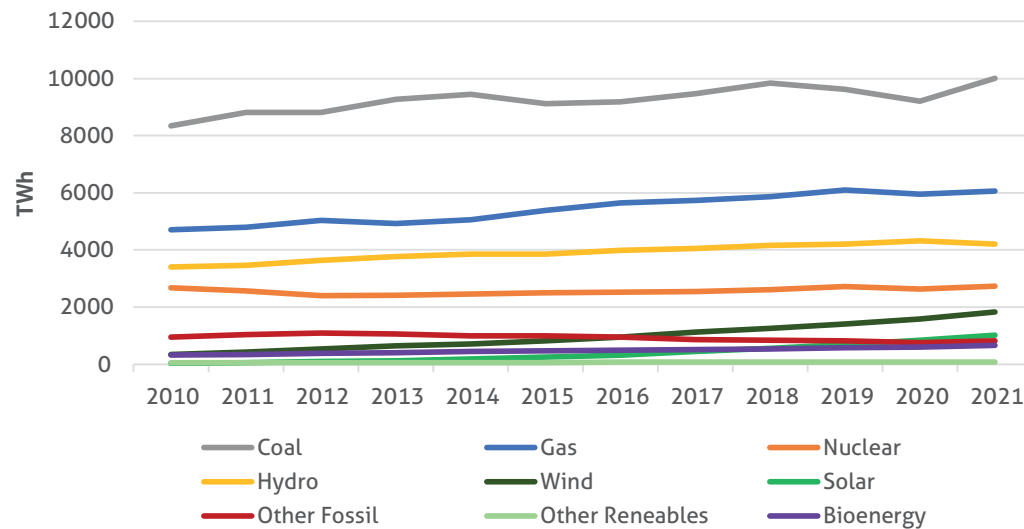
In 2021, in the wake of the post-pandemic economic recovery, energy consumption in the global power generation sector jumped by 5.5% y-o-y, reaching a total of 27,433 TWh, as a consequence of economic recovery, upsurge of the industrial and commercial activity, and expansion of the grid in many countries.

The power generation sector proved to be the driver of gas consumption, accounting for 40% of global natural gas consumption in 2021, an increase of 1% y-o-y. Gas

consumption in the power sector was 6,518 TWh (Figure 49), up by 2.6% y-o-y. The growth was due to the expansion of the natural gas grid in China and some emerging countries, as well as coal-to-gas switching policy in some regions.

In the meantime, the global renewable power generation experienced its largest annual increase, up by 16% y-o-y (+500 TWh) to reach 3,657 TWh. Over the past five years, renewables output has more than doubled, driven by increasing policy support. Coal power generation recorded a strong growth of 8.5% y-o-y (+805 TWh), with coal power plants benefiting from the high gas prices and gas-to-coal switching boosting in some regions, particularly in the US. Coal still maintains the largest share of the power generation mix at 36% in 2021. Hydropower production decreased by 2.5% y-o-y to reach 4,273 TWh. Some nuclear power plants went back online in Japan and South Korea, offsetting a decline in gas consumption in the power generation.

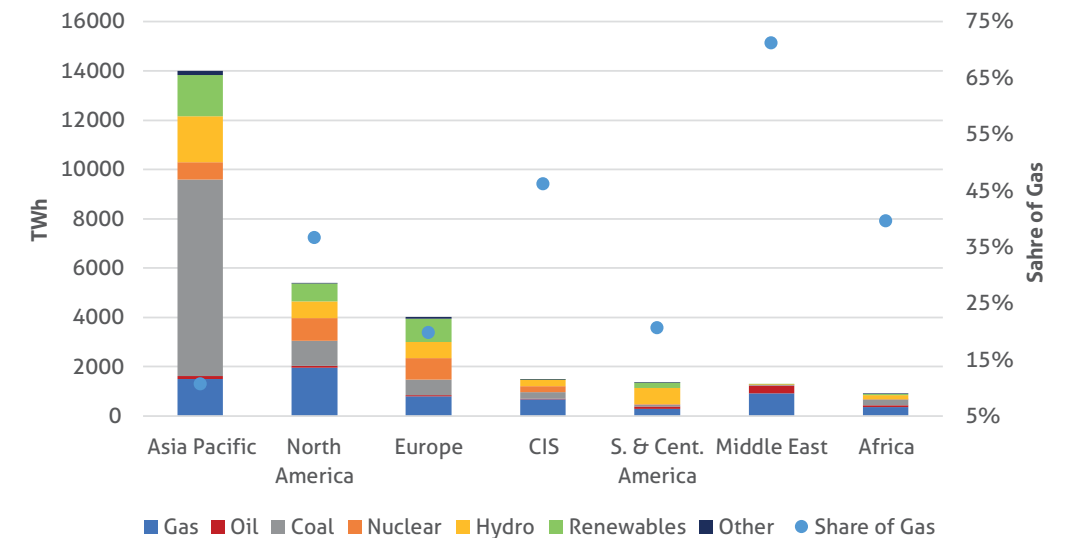
**Figure 49: Trend in the Global Power Generation Mix**



Source: GECF Secretariat based on data from Ember, BP Statistical Review 2021

In 2021, the power generation mix of each region continued to be influenced by several factors, including availability of resources, cost of competing fuels, regulatory framework, subsidies, environmental policies and available technologies (Figure 50). We are witnessing a marked shift to cleaner fuels for power generation, which can boost global natural gas demand, as it will play a crucial role in providing a backup supply for intermittent renewables and supporting the substitution of coal and oil.

**Figure 50: Power Generation Mix by Region in 2021**



Source: GECF Secretariat based on data from BP Statistical Review 2021

In North America, total power generation increased by 2.4% y-o-y to 5,383 TWh. Renewable generation rose by 14% y-o-y. Gas consumption in the power sector was 1,973 TWh, representing a decrease of 2.3% y-o-y. Its main competing fuel, coal, increased sharply by 14% y-o-y. This consumption pattern was mainly driven by high gas prices, which decreased its competitiveness and encouraged gas-to-coal switching.

In Asia Pacific, total power generation increased by 8% y-o-y to 13,994 TWh. There was strong growth in renewables, with an increase of 28% y-o-y, followed by coal and oil with an increase of 8% and 10% y-o-y respectively. Gas consumption recorded a slight increase of 1% to 1,493 TWh, with a slowdown driven by a rise in renewables and gas-to-coal switching because of high gas prices. The share of natural gas in the power generation mix remained at 11%, which is lower compared to most regions.

In the Middle East, total power generation increased by 5% y-o-y to 1,306 TWh). Natural gas consumption in the power sector was 930 TWh, up by 4.4% y-o-y. Gas continued to account for the largest share in the power generation mix at 72%. There have been increasing efforts in the region to diversify the power generation mix, with renewables increasing by 18% y-o-y to 19 TWh.

In Europe, total power generation decreased by 4% y-o-y to 4,032 TWh. Renewables accounted for 24% (947 TWh) of the power generation mix. Nuclear was close behind, accounting for 22% (883 TWh). Gas followed with a share of 20% (799 TWh), and hydro with 16% (650 TWh). Coal-fired generation witnessed a huge increase by 11% (632 TWh) y-o-y due to a rise in gas-to-coal switching because of high spot gas and LNG prices.

In the CIS, total power generation increased by 6% y-o-y to 1,488 TWh. Natural gas continued to dominate the power generation mix with a share of 46% (686 TWh). Moreover, natural gas consumption increased by 6% y-o-y. While renewable energy remains at a very low level, with the share in the power generation mix at less than 1%, its production increased by 42% y-o-y.

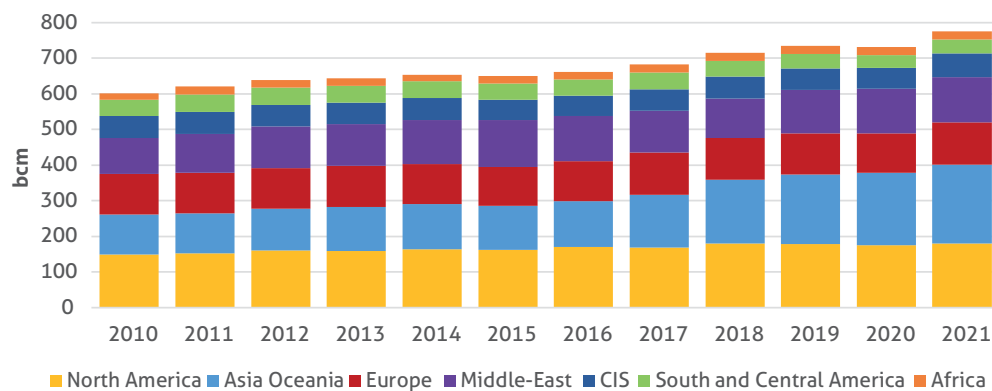
In South & Central America, total power generation grew by 4.8% y-o-y to 1,365 TWh. Hydropower, although declining by 4.5% y-o-y, maintained the lion's share of power generation in this region (48%) and stood at 660 TWh. Natural gas represented the second highest share of 21%, while rising by 21% y-o-y to 281 TWh. Coal consumption increased by 1.7% y-o-y, while renewables rose by 15% y-o-y.

In Africa, total power generation increased by 5% y-o-y to 898 TWh. It remains the smallest power production region despite having the second largest population, as a result of low connectivity and little access to electricity in the region. Natural gas accounted for 40% of the power generation mix (356 TWh). Coal had the second largest share of 28% (247 TWh).

### 3.2.2 Industrial Sector

The year 2021 recorded a significant recovery in natural gas consumption in the industrial sector. Global gas consumption in the industrial sector is estimated to have increased by 5.8% in 2021 to reach 775 bcm. This corresponds to a growth of 42 bcm compared to 2020. The natural gas consumption in the industrial sector was even higher than the pre-pandemic level by 5.2%. The key drivers of the growth were global economic recovery in all the regions of the globe. At a regional level, Asia Oceania recorded growth of 9%, representing a rise of 18 bcm compared to 2020. Europe and CIS followed with a growth of 8% (8.5 bcm) and 14% (8 bcm), respectively. North America recorded a growth of 3% compared to last year, representing an increase of 5 bcm compared to 2020. (Figure 51).

**Figure 51: Trend in Annual Gas Consumption in the Industrial Sector by Region**

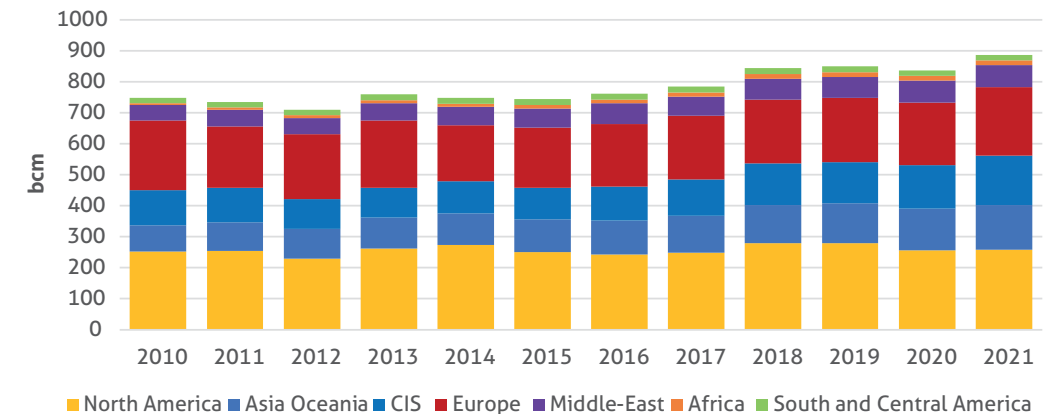


Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), Cedigaz and IEA Monthly Gas Statistics

### 3.2.3 Residential and Commercial Sector

The global natural gas consumption in the residential and commercial sector for the year 2021 recorded an increase of 6% compared to last year to reach 886 bcm. This corresponds to a growth of 50 bcm compared to 2020. The natural gas consumption in the residential and commercial sector was even higher than the pre-pandemic level by 4.3%. The key drivers of the growth were the abnormal weather conditions witnessed in 2021, with a very cold winter that boosted gas demand for heating and a warm summer that implies high cooling demand in the summer period. At a regional level, Europe recorded growth of 9%, representing a rise of 19.1 bcm compared to 2020. CIS and Asia Oceania followed with growth of 9% (19 bcm) and 8% (11 bcm), respectively. North America recorded slight growth of 0.4% compared to last year, representing an increase of 1 bcm compared to 2020. (Figure 52).

**Figure 52: Trend in Annual Gas Consumption in the Residential/Commercial Sector by Region**



Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), Cedigaz and IEA Monthly Gas Statistics

### 3.2.4 Transportation Sector

The transportation sector remains a niche end use of natural gas, accounting for less than 2% of global consumption in 2021. Nevertheless, the sector offers great potential for growth in the coming years due to the advantages from an environmental and energy transition perspective. Specifically, vehicles fuelled by some form of natural gas are proven to have lower emissions of carbon dioxide, sulphur, and particulates. They are often also quieter than conventional petrol or diesel-fuelled vehicles.

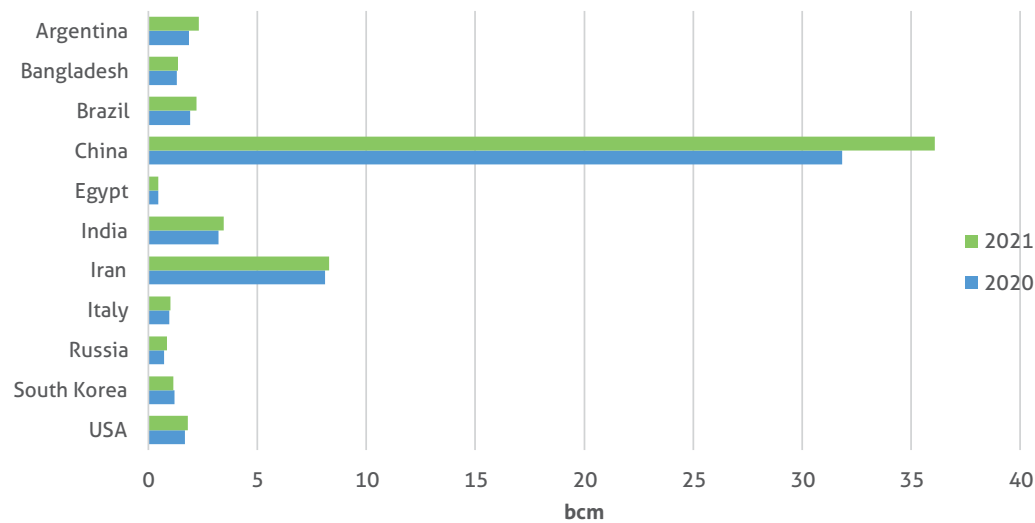
With respect to contemporary natural gas-fuelled vehicles, the options are based largely on the market application: Compressed Natural Gas (CNG) systems are well suited for passenger vehicles, whereas LNG-fuelled engines are gaining popularity with heavy duty usage, specifically commercial transportation via trucks. In the maritime

industry, the tightening environmental policies with regard to ship emissions, such as the International Maritime Organisation’s target to reduce emissions of greenhouse gases in their operations by 40% by 2030, and 70% by 2050, has encouraged the growth in LNG bunkering as a viable fuel option.

### 3.2.4.1 Automotive industry

On a global level, China leads in utilising natural gas within the road transportation sector (Figure 53). With 36 Bcm consumed in 2021, this amount was greater than all other major countries, and represented a 13% increase y-o-y. Other key players in the natural gas vehicle industry are Iran and India, propelling Asia as the most dominant region for market activity and growth. By 2021, an estimated 30 million natural gas vehicles were in operation globally, increasing 5% from a year earlier.

**Figure 53: Gas Consumption in the Road Transportation Sector in Selected Countries**



Source: GECF Secretariat based on data from Enerdata ([www.enerdata.net](http://www.enerdata.net))

GECF Member Countries continue to promote the utilisation of natural gas as an automotive fuel, particularly through the adoption of CNG-fuelled passenger vehicles. In this respect, Egypt has been one of the major proponents of this initiative in recent years, with additional investments made in 2021 to increase the number of CNG stations by the end of the year to 1000. This is in furtherance of the government’s drive to continue the conversion of vehicles, aiming to reach 768,000 CNG vehicles (both converted and new) by 2023. Cooperation between Member Countries has also been extended to this arena, with transfer of CNG expertise from Egypt to Equatorial Guinea. Vehicle conversion has been trialled there recently, with the goal being to have 50% of passenger vehicles operating on this fuel.

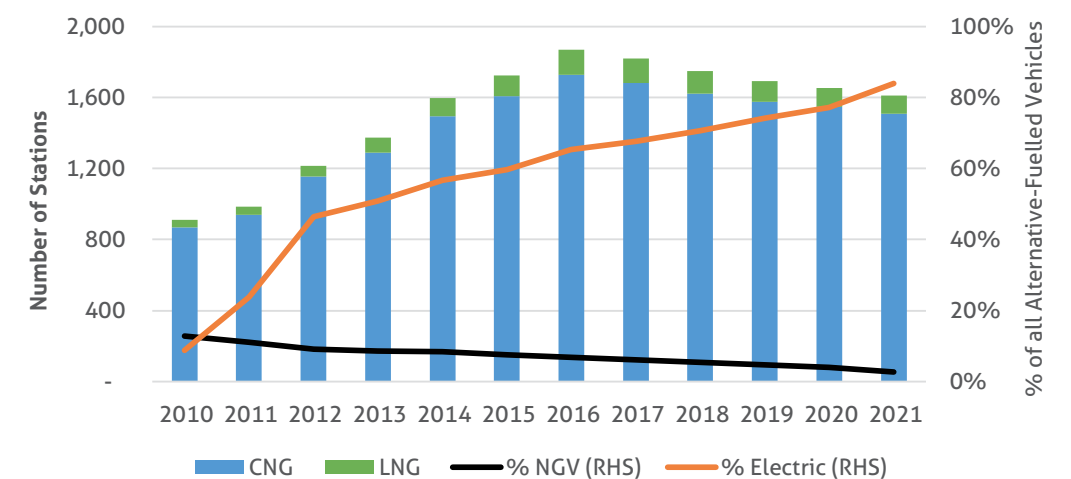
Another GECF Member Country, Iran, has continued to invest in its established natural gas vehicle sector. The number of natural gas vehicles on the road total over four million, supported by around 2500 CNG refuelling stations. Further strides towards this programme are being targeted through an agreement between the state and a major local automotive company for the manufacture of 45,000 dual-fuelled (petrol and CNG) public transportation vehicles, in addition to the 165,000 public transportation vehicles which have recently been converted for CNG use.

In 2021, Bolivia relaunched its nationwide conversion scheme for natural gas vehicles. Over 7500 vehicles have undergone the conversion to CNG, which represents around half of the projection for the end of 2022.

India is another established marketplace for natural gas vehicles, particularly CNG cars. Due to government policy initiative, there continues to be encouraging demand growth and consumer switching from conventional fuelled vehicles. In 2021, there were over 125,000 CNG vehicles sold in India, which represented a four-fold increase from the year before. Moreover, this is supported by 3,700 refilling stations across the country.

The U.S. is a growing market for alternative fuelled and electric vehicles. Currently there are over 175,000 vehicles powered by natural gas in the U.S., with the majority of the application developed around fleets, such as buses and long-haul trucking. Such an approach provides the advantage of coordinating the service route with fuelling and maintenance stations. The refuelling infrastructure can be a viable metric to measure the penetration of competing fuel technologies. By the end of 2021, there were 1,600 public and private stations in the U.S. (Figure 54) for filling CNG and LNG vehicles.

**Figure 54: Natural Gas Refuelling Infrastructure in the United States**



Source: GECF Secretariat based on data from AFDC



When compared with all alternative-fuelled vehicles in the U.S. market (including electric, methanol, hydrogen, and biodiesel), the percentage share of NGV stations has been in steady decline, reaching just 3% in 2021. The major competition to natural gas vehicles in the automotive industry in the United States is electric vehicles, as demonstrated by the surge in charging stations over the same period.

In Europe, the “Fit for 55” package enacted by the European Union contains a number of initiatives aimed at decarbonising the transportation sector. Of particular note is the target to reduce carbon emissions from new vehicles entering the market in the bloc, by 55% for cars and 50% for vans by 2030, and by 100% from all vehicles from 2035. Moreover, in 2022, there has been agreement to establish a separate Emissions Trading Scheme for the road transportation sector. To support these programs, there are currently over 4,100 CNG refuelling stations and 566 LNG refuelling stations in operation within the region. The vast majority of this infrastructure has been developed in Italy and Germany, but there is growth in the sector in Western European countries. There are around one million CNG vehicles in operation in the region. In particular, Germany is strongly promoting the use of LNG in its trucking industry, with federal incentives such as a road toll exemption for such vehicles. The European Commission envisions a further 500,000 gas powered trucks in operation within the region by 2030.

Natural gas vehicles are presently faced with two major drawbacks. The first is that the price of the fuel is linked to hub prices, which have been experiencing significant volatility since 2020. In periods of high prices, as in recent times, the relative competitiveness against traditional automotive fuels is diminished, and is contrary to the major selling factor of natural gas vehicles to consumers.

The second threat to the natural gas vehicles industry are electric vehicles. With respect to passenger vehicle applications, CNG-fuelled vehicles are confronting market competition, with many of the globally recognised car manufacturers investing in electric models to complement their conventional internal combustion engine counterparts. Electric vehicles are already gaining market share in North America and Europe, primarily from internal combustion engine vehicles. The rate of the energy transition will dictate the extent to which electric vehicles will compete with natural gas vehicles for market share. Ultimately, an increase in electricity demand for vehicles may correspond to increased utilisation of natural gas in the power generation sector.

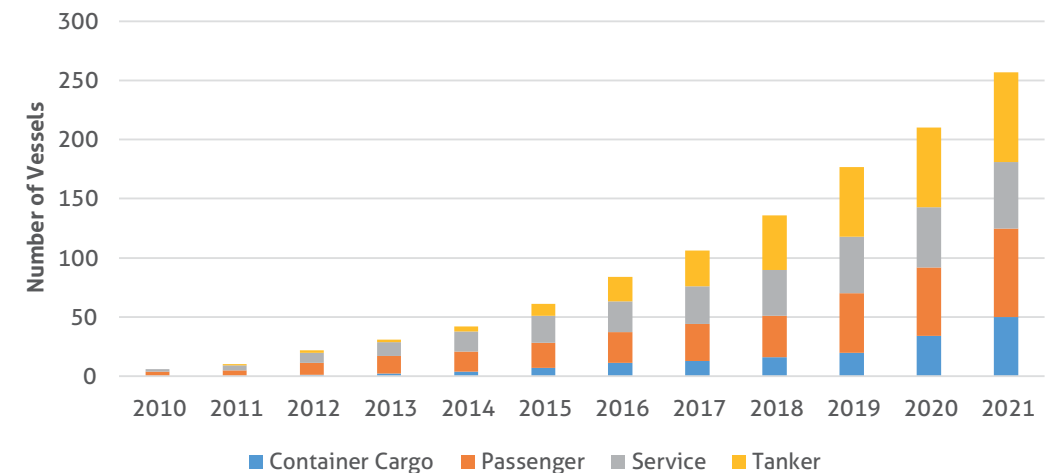
Hydrogen is emerging as a fuel alternative, with promise for light to heavy applications. In spite of this, many of the hydrogen propulsion systems are only within the preliminary prototype phase, and as such would require time before such technologies become commercially feasible and widespread. In this regard, LNG-fuelled engines for truck transportation will continue to increase market share, driven by environmental policy initiatives from regions such as China and the European Union. Another interesting application for future development is LNG-powered rail; in April 2022, an Estonian firm began trials on a prototype freight locomotive that has dual-fuel capability.

### 3.2.4.2 Maritime industry

The maritime sector offers promising growth for continued natural gas penetration. In particular, standards for particulate and carbon emissions set forth by the International Maritime Organisation, as well as the more stringent regulations enacted by the European Union, will promote the use of LNG as a shipping fuel. When compared with heavy fuel oils, traditionally used as maritime fuel, LNG bunker fuel presents substantial advantages, namely: up to 20% reduction in carbon emissions, up to 80% reduction in NOx emissions, and virtually zero emissions of SOx and particulate matter.

In 2021, the number of LNG-fuelled vessels worldwide increased by 22% y-o-y to reach 257 vessels (Figure 55). Tankers currently represent the majority of the global LNG-powered fleet. In recent times, a number of cruise ship firms and ferry owners have been switching to LNG systems, and this is reflected by a 29% increase in passenger vessels from 2020 to 2021. The container cargo ship segment has been the fastest growing in recent times, adding 16 new vessels in 2021.

Figure 55: Growth in the Global LNG-Fuelled Fleet

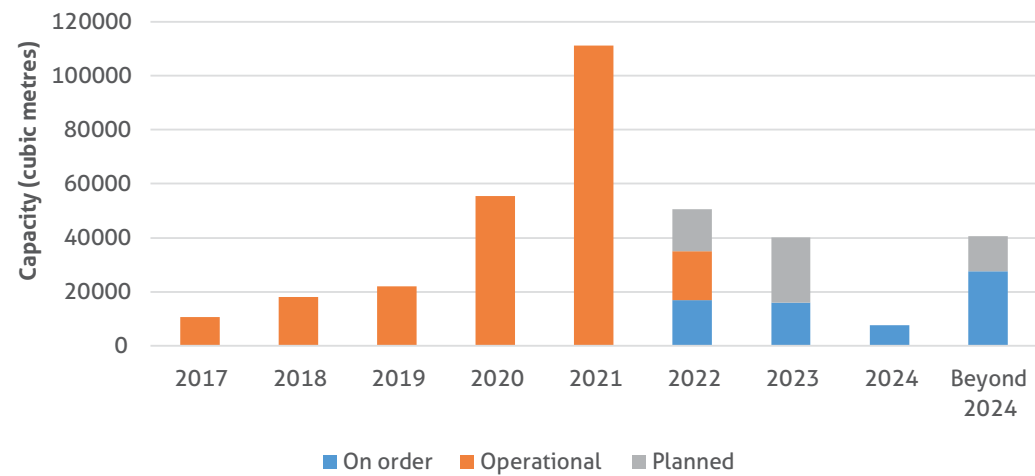


Source: GECF Secretariat based on data from Argus

To provide refuelling capabilities to these vessels, there has also been a commensurate growth in LNG bunkering vessels. In 2021, over 110,000 cubic metres of capacity was brought onto the market, which more than double the amount entering in 2020. There has been one 18,000 cubic metre vessel that has been commissioned in 2022 thus far, with a further 32,000 cubic metres expected for the remainder of the year (Figure 56), followed by a further 100,000 cubic metres in the coming years.

LNG as a fuel in the maritime industry will continue its established growth within the sector. With a number of LNG-fuelled ships already on order, as well as environmental factors such as tightening emissions from the International Maritime Organisation, and the inclusion of shipping within the Emissions Trading Scheme of the European Union, LNG bunkering will increase in dominance.

**Figure 56: Annual Capacity Additions for LNG Bunkering Vessels**



Source: GECF Secretariat based on data from Argus



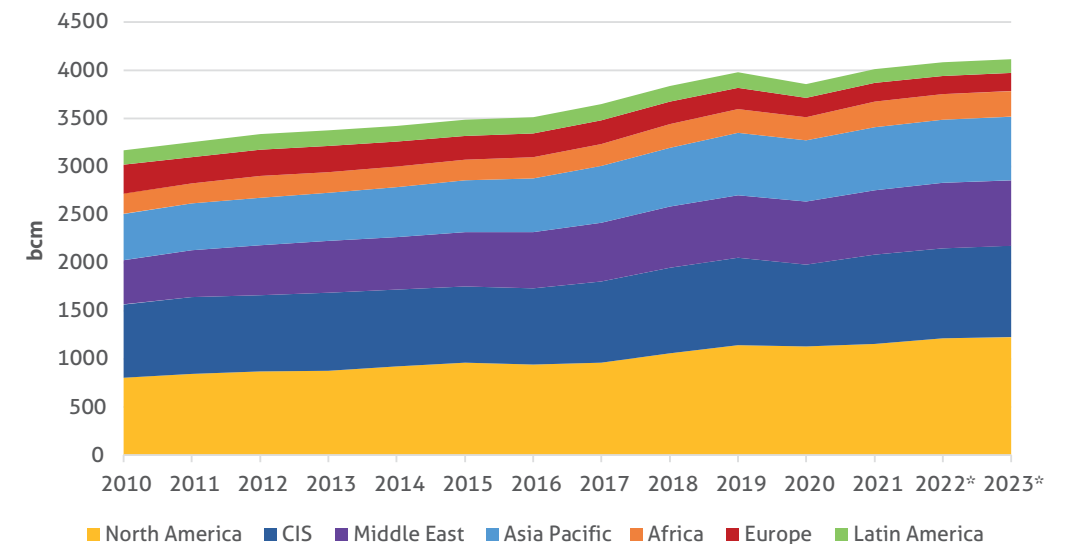
# CHAPTER 04

## Natural Gas Production

### 4.1 Natural Gas Production by Region

In 2021, the global natural gas production rose by 4% (+153 bcm) to stand at 4,007 bcm, driven by the recovery in gas demand, rebound in associated gas production, commissioning of new gas fields, and increase in well productivity (Figure 57). This is well above the average annual growth rate between 2010 and 2020, which was 2%. The increase in global production was driven by Russia (+64 bcm), the US (+19 bcm) and China (+16 bcm).

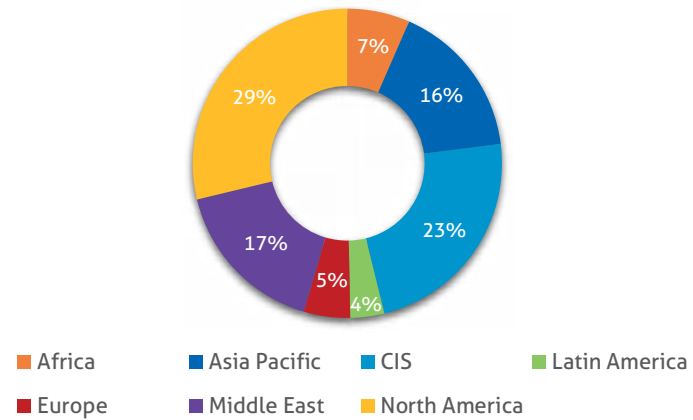
Figure 57: Trend in Global Gas Production by Region



Source: GECF Secretariat based on data from Cedigaz, and BP Statistical Review  
(\*): GECF Secretariat's forecast for 2022 and 2023

On a regional basis, Africa, CIS, and the Asia Pacific regions were the dominant sources of global gas production growth at 11%, 9%, and 3%, respectively. Among the regions, North America, CIS, and the Middle East, with 1,152 bcm, 928 bcm and 668 bcm respectively, had the highest production (Figure 58).

**Figure 58: Regional Shares of Global Gas Production (2021)**

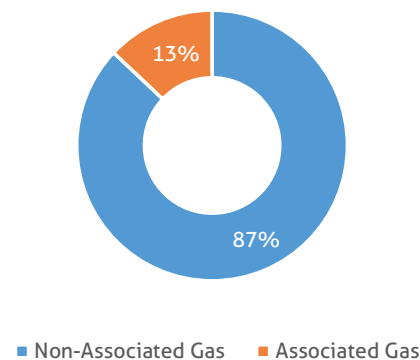


Source: GECF Secretariat based on data from Cedigaz, and BP Statistical Review

High gas prices encouraged many oil and gas companies worldwide to pump more gas into the markets and increase their activities in 2021. However, increasing exploration and production costs in H1 2022 hampered upstream activities while reducing companies' profit margins. Therefore, many companies followed strict financial discipline to increase their cash flow and balance their financial statements.

Around 13% of total global natural gas production (520 bcm) came from associated-gas sources (Figure 59). Due to global oil production decline, stemming from the COVID-19 pandemic, global associated gas production dropped in 2020, mainly in the US. However, in 2021 with recovering oil production, the associated gas output also started to recover to pre-pandemic levels.

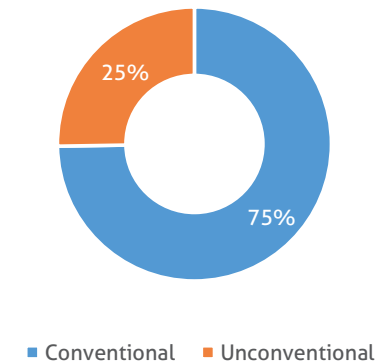
**Figure 59: Shares of Associated & Non-Associated Gas in Global Gas Production (2021)**



Source: GECF Secretariat

The share of natural gas production from unconventional sources such as shale gas and Coal Bed Methane (CBM) stood at 25% of the global gas output (Figure 60).

**Figure 60: Shares of Conventional & Unconventional Gas in Global Gas Production (2021)**



Source: GECF Secretariat

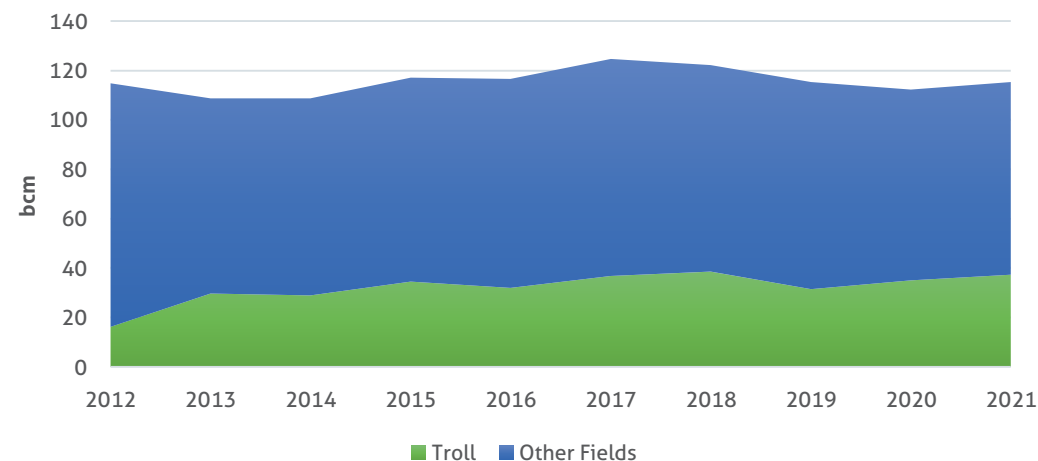
Despite the oil and gas price recovery in 2021, the upstream oil and gas companies, particularly those producing from higher-cost shale plays, were cautious in spending. They tried to stabilize their cash flows and balance their financial statements rather than investing in new development projects. Preliminary estimations of the global oil and gas upstream investment in 2021 indicate that the sector started to recover slightly after being hit by the pandemic in 2020. Based on the projections by Rystad Energy, the upstream investment in the oil and gas upstream sector increased by 6% in 2021 compared to 2020 to stand at \$362 billion. It should be reminded that based on pre-pandemic projections, upstream investment was supposed to exceed \$500 billion in 2021. Current gas market conditions imply that continuous investment is needed in the upstream sector to meet global demand in the upcoming years.

In 2022, our forecasts reveal a further growth of up to 1% in global gas production, driven by production growth in North America, the Middle East, and CIS. The positive factors witnessed in 2021 will support this growth. However, various factors will have downward pressure on gas production. With the pandemic-driven restrictions eased and in a high inflation environment, many companies follow strict financial discipline to increase their cash flow and balance their financial statements rather than invest in drilling new wells. For 2023, global gas production is estimated to grow by up to 1.5%, driven mainly by North America and the Asia Pacific regions.

### 4.1.1 Europe

In 2021, natural gas output in Europe dropped by 3.5% to stand at 194 bcm, which is 7 bcm lower than the 2020 production level. Among major European producers, Norway’s production increased by 2.6% y-o-y (+3 bcm) to reach 115 bcm (Figure 61)

**Figure 61: Trend in Norway’s Gas Production**



Source: GECF Secretariat based on data from Refinitiv, Cedigaz

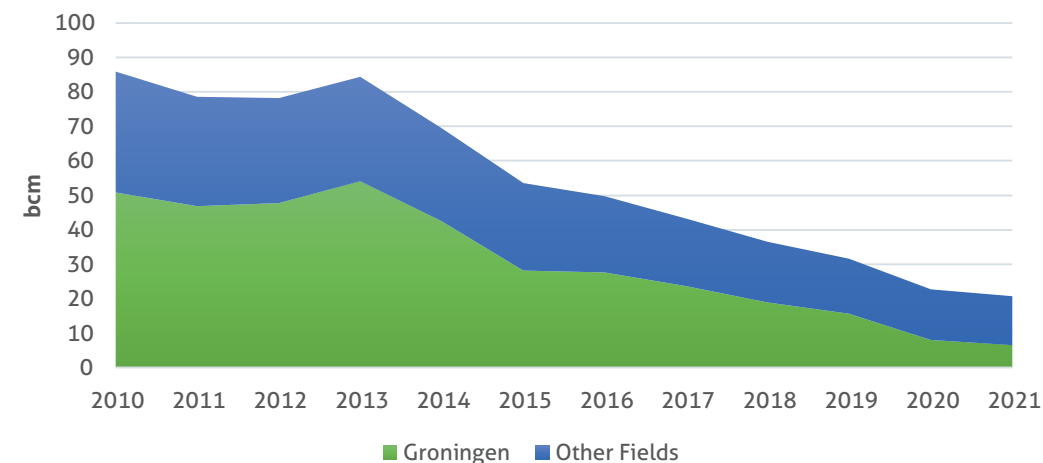
Based on a survey by the National Statistics Office, the Norwegian oil and gas companies increased their investment estimates to \$17.5 billion for 2022. This was encouraged by high oil and gas prices and tax incentives, with the tax rebate policy implemented in 2020 by the Norwegian government to boost upstream activities in the pandemic period.

Meanwhile, the production decline in the continent is mainly due to the gas output decrease in the UK and Netherlands by 6 and 2 bcm, respectively.

In the Netherlands, Groningen field production dropped by 19% to stand at 6.5 bcm (Figure 62), primarily due to the Dutch Government’s implementation of a production cap in 2014, in response to seismic activity associated with natural gas extraction from the field. The cap has been continuously lowered since, to end natural gas production from the field entirely in 2023 or 2024.

In the UK, gas production declined by 17% y-o-y due to extensive maintenance in major natural gas production facilities. In H1 2022, the government announced its plan to impose a 25% windfall tax on the oil and gas companies due to their extraordinary profits in the high-price environment. It is expected the levy would raise 5 billion pounds in the next 12 months. According to the Finance Minister, the policy will be phased out if the oil and gas prices return to normal.

**Figure 62: Trend in Netherlands’ Gas Production**



Source: GECF Secretariat based on data from Refinitiv, Cedigaz

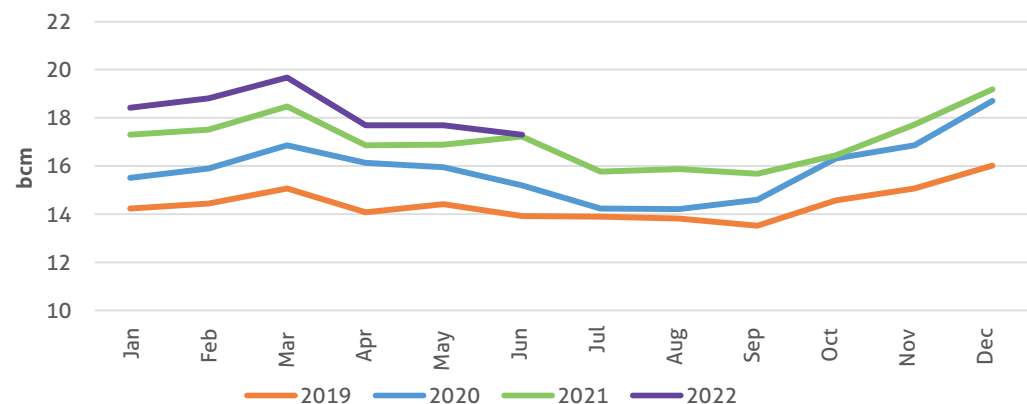
In 2022, European natural gas production is estimated at 194 bcm. Other European producers will offset the production increase from Norway and Denmark. Norway’s natural gas production is projected to increase by 5 Bcm to stand at 120 Bcm, supported by higher production targets for major fields such as Troll. The ultimate closure of the Groningen field in the Netherlands is expected to occur in 2024, and the annual natural production level from the field is expected at 5 bcm in 2022. Denmark also will slightly increase its natural gas production in 2022 to help Europe deal with the energy security concerns.

### 4.1.2 Asia Pacific

In 2021, natural gas production in the Asia Pacific increased by 22 bcm to 659 bcm, representing a 16% share of global gas production. The increase in Asia Pacific production was driven by China (+16.2 bcm), India (+4.6 bcm), Malaysia (+4.3 bcm), and Australia (+3.4 bcm).

In China, gas production rose by 8% to reach 204 bcm (Figure 63). Shale gas production accounted for around one-tenth of the country’s gas production. China’s coalbed methane (CBM) production increased by 3% y-o-y to 10.3 bcm.

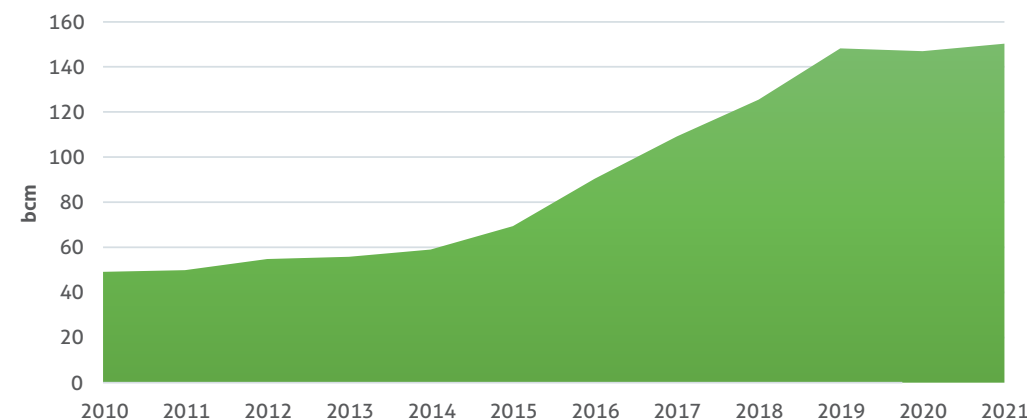
**Figure 63: Trend in China’s Monthly Gas Production**



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

In Australia, gas production increased by 3.4 bcm to reach 150.5 bcm (Figure 64) due to recovering demand. Meanwhile, the Australian government unveiled its plans to invest \$173 million in Beetaloo Shale Basin exploration activities. Beetaloo is estimated to hold 5,700 bcm of shale gas. The basin could potentially supply gas to the eastern coast of Australia and LNG plants for export purposes.

**Figure 64: Trend in Australia’s Gas Production**



Source: GECF Secretariat based on data from Cedigaz

In India, gas production increased by 17% y-o-y to stand at 32.3 Bcm. Furthermore, India’s largest oil and gas producer, Oil and Natural Gas Corporation (ONGC) announced its plans to increase its natural gas output by 25% in the next three years after a decade of production decline.

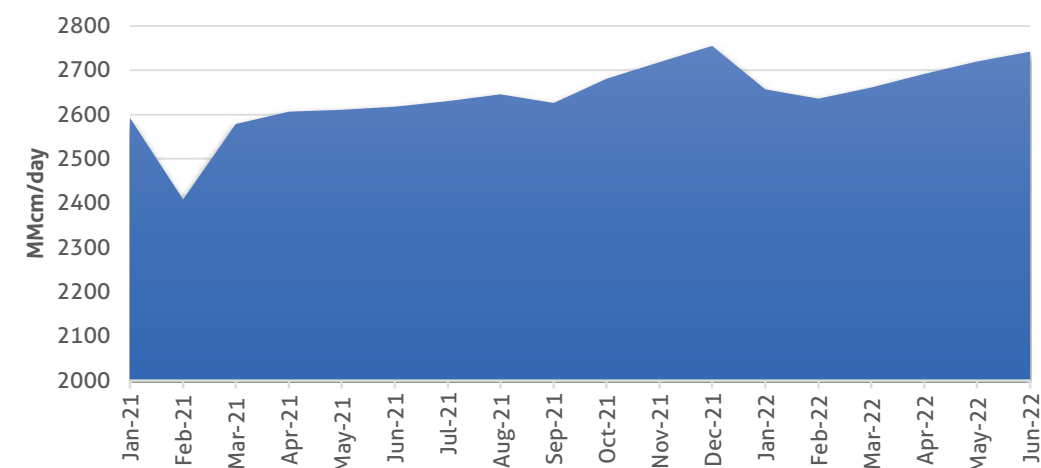
In 2022, gas production in the Asia Pacific region is expected to rise. Australia’s production will increase by 2.5 bcm to stand at 153 bcm. Indonesia and India will increase their natural gas output by 3.4 and 3 bcm to reach 60 and 35 bcm, respectively. China’s gas production will also continue growth.

**4.1.3 North America**

In North America, the U.S. has been the largest source of natural gas production in recent years thanks to shale gas production growth, as well as increasing domestic gas demand and LNG exports. Total gas production in the U.S. jumped from 948 bcm in 2020 to 967 bcm in 2021, experiencing an increase of 2%. Cumulative dry gas production for January-June 2022 reached 485 bcm in the lower 48. On a daily average basis, total dry natural gas production in the U.S. lower 48 stood at 2742 mmcm/day, representing a y-o-y increase of 5% in June 2022 (Figure 65). High natural gas prices and recovering demand, particularly from LNG export facilities, encouraged producers to pump more gas into the markets.

Meanwhile, shale gas production from seven key shale gas/oil regions (Anadarko, Appalachian, Bakken, Eagle Ford, Haynesville, Niobrara, and Permian) jumped by 6% (+4 bcm) y-o-y to reach 77.7 bcm in June 2022. Also, the associated gas output of the oil shale fields in Permian jumped by 10% y-o-y to reach 17.2 bcm, representing 22% of total domestic shale gas production. The Appalachian region, consisting of Marcellus and Utica plays, remains the dominant shale gas-producing region, representing 38% of the total shale gas production.

**Figure 65: Trend in the U.S.’ Average Monthly Dry Gas Production**



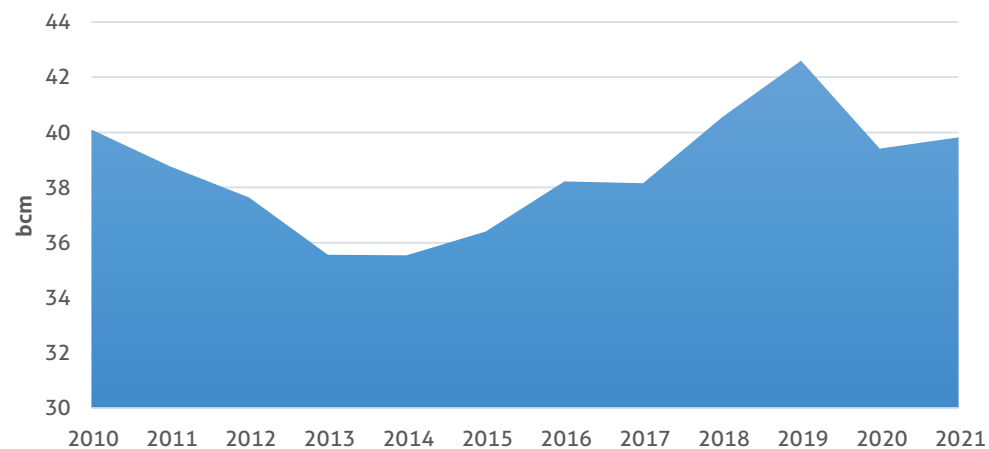
Source: GECF Secretariat based on data from Refinitiv

In North America, natural gas production is expected to increase by 5% in 2022 to stand at 1,210 bcm and will continue to grow in 2023. The U.S. natural gas output is estimated at 1,012 bcm in 2022 (+46 bcm), with high gas prices encouraging U.S. producers to pump more gas into the markets. However, shale gas - the main driver of U.S. natural gas output - faces headwinds from inflation in upstream costs, supply chain constraints and inadequate pipeline infrastructure in some fields. Inflation increased upstream costs for producers, from steel to fracking sands. In this context, upstream companies seek new methods to further reduce their production costs.

#### 4.1.4 South & Central America

In 2021, gas production in South & Central America dropped by 2.3 bcm to 142 bcm. This production level is still well below the pre-pandemic level in 2019 (162 bcm). Production in the region's major gas-producing country, Argentina, remained unchanged at 39 bcm, accounting for 28% of the region's total output (Figure 66). A significant amount of investment is needed to achieve the production targets in Argentina's Vaca Muerta shale play. Given the country's economic situation, Argentina's government faces some limitations in investment in its shale plays. The country had already been in financial hardship before the pandemic. The government reviewed and reduced the previous years' incentives for shale gas companies to allocate the funds to other issues with higher priorities during the pandemic. Meanwhile, in February 2021, YPF - the state-run oil company - restructured its debt to free up more sources to spend on its shale plays. However, most of the company's creditors did not welcome the change. Later the government announced its plans to revert to subsidizing shale gas production in the Vaca Muerta region to support domestic production and prevent the country from relying on imported gas. The subsidy amount will be \$1 billion annually for the upcoming years.

**Figure 66: Trend in Argentina's Gas Production**



Source: GECF Secretariat based on data from BP Statistical Review

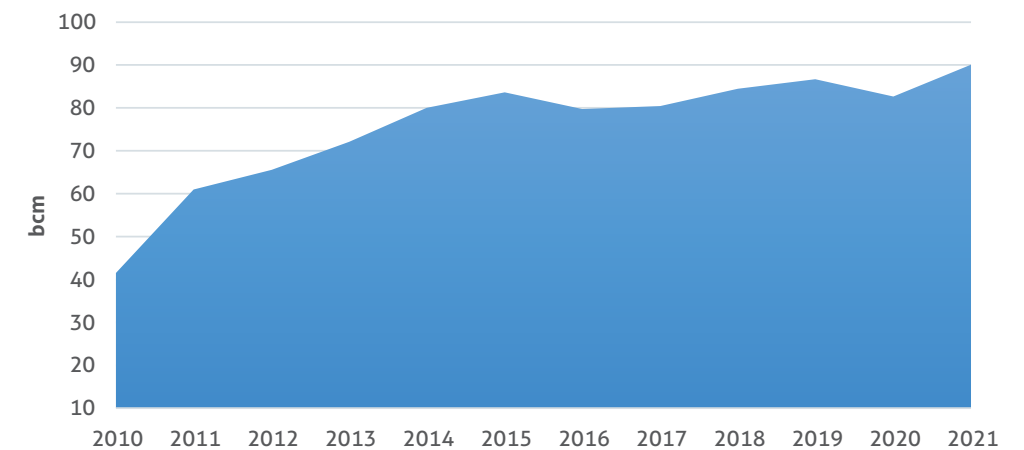
Argentina's Vaca Muerta shale play is expected to drive the region's production increase in upcoming years. Argentina announced its plan to build a new gas pipeline to deliver natural gas from the Vaca Muerta shale play with a view to resolve the pipeline infrastructure constraint. The pipeline is estimated to be completed in the first half of 2023 and will support domestic consumption. Another major regional gas-producing country, Trinidad and Tobago, is expected to contribute significantly to the region's natural gas production growth from 2021 to 2025 as a result of planned development projects in the fields such as Manatee field (Colibri project), Bounty & Endeavour fields (Barracuda project) and Zandolie field.

#### 4.1.5 CIS

In 2021, the CIS gas production rose by 9% (+80 bcm) to reach 928 bcm, representing 23% of the global gas production. The production increase was mainly due to the recovering demand as well as gas exports from the region. The production increase in CIS was driven primarily by Russia, Azerbaijan, and Turkmenistan (Figure 67), which raised their production by 64 bcm, 7 bcm, and 6 bcm, respectively. The gas production growth in Azerbaijan was driven by the development of the Shah Deniz field, which supported natural gas exports to Türkiye through the TANAP pipeline.

In 2022, the CIS gas production is estimated at 940 Bcm, representing a 1.2% increase compared to the previous year. Russia will dominate the region's natural gas production, followed by Turkmenistan and Azerbaijan.

**Figure 67: Trend in Turkmenistan's Gas Production**



Source: GECF Secretariat based on data from Cedigaz

#### 4.1.6 The Middle East and Africa

In 2021, gas production in the Middle East increased by 2% (+11 bcm) to stand at 668 bcm. While gas output was resilient during the pandemic, escalating production in 2021 following the easing of pandemic-induced restrictions increased the region's share in global gas production to 17%. Iran, Oman and Qatar were the primary sources of production increase in the region, with the first two countries' production rising by 4 bcm each and the third country's output raising 1.5 bcm.

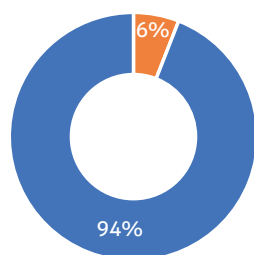
In 2021, gas production in Africa jumped by 11% (+25 bcm) to reach 263 bcm due to production increases mainly from Algeria and Egypt. Algeria's gas output increased by 15 bcm to stand at 106 bcm. The production in Egypt increased by 9 bcm to reach 71 bcm. Africa's natural gas production was affected severely during the pandemic, but the output recovered in 2021 and surpassed the pre-pandemic level.

In 2022, natural gas production in the Middle East and Africa is estimated to increase by 8 bcm and 3 bcm, respectively, to stand at 677 bcm and 265 bcm. In Sub-Saharan Africa, the development of offshore deep-water resources will drive production in the upcoming years. However, development of new discoveries will require a significant amount of investment. Major gas-producing countries in both regions are increasing licensing rounds significantly to increase their output. Meanwhile, the Middle East is driving the rising demand for jack-up rigs in 2022 and 2023.

### 4.2 Proven Natural Gas Reserves

The global proven gas reserves were estimated at 202 tcm at the end of 2021, with unconventional gas resources such as shale gas and CBM accounting for 6% (Figure 68). Shale gas reserves are the largest source of unconventional gas reserves in all regions and basins. Shale gas reserves dominate the share of the unconventional at 86%. Shale gas reserves support gas production in the Asia Pacific region due to abundant resources in China, while coalbed methane supports gas production for the LNG plants in Australia.

**Figure 68: Share of Conventional and Unconventional Gas Reserves (2021)**



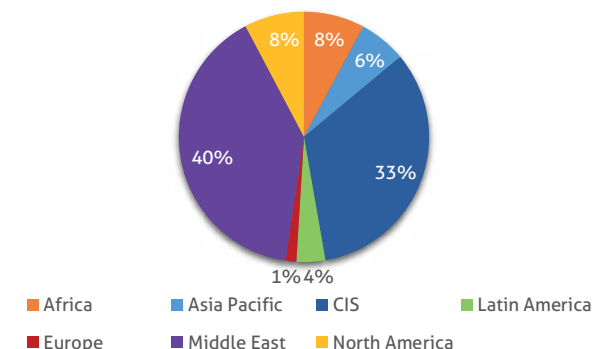
■ Proven unconventional gas reserves ■ Proven conventional gas reserves

Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), BP Statistical Review 2022

The Middle East holds the world’s highest volume of proven natural gas reserves accounting for 40% of global reserves. Other regions, in particular, CIS, North America, Africa, Asia Pacific, Latin America, and Europe, hold 33%, 8%, 8%, 6%, 4%, and 1% of global proven reserves, respectively (Figure 69).

The global discoveries in 2021 were the lowest over the last 75 years, according to Rystad Energy. The total discovered volumes (liquids and gas) in the first 11 months of November 2021 stood at 4.7 Billion boe, which compares to discoveries of 12.5 billion barrels of oil equivalent (boe) in 2020.

**Figure 69: Regional Shares of Proven Gas Reserves (2021)**

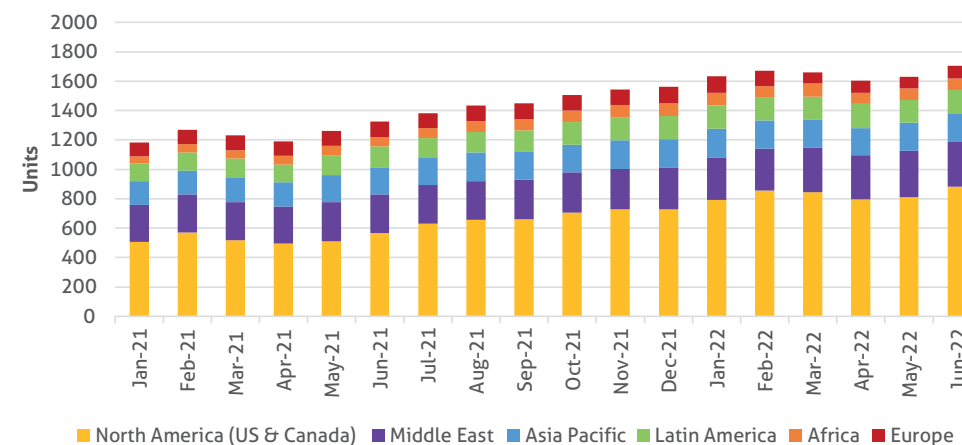


Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), BP Statistical Review 2022

### 4.3 Global Rig Count

By the end of H1 2022, the global rig count, as an indicator of upstream activities, increased by 381 units compared to H1 2021 to average 1,706 (Figure 70). The increase in the active rig count is due to higher prices of natural gas and oil and recovering demand in the post-pandemic period, encouraging oil and gas companies to increase their activities. The increase in rig activity was driven by North America, Middle East, Latin America, Africa, and Asia Pacific, which jumped by 315, 41, 17, 13, and 13 units, respectively. Europe is the only region where the active rig count dropped by 18 units to stand at 87 units. The US rig count stood at 739 units, representing 43% of the global rig count.

**Figure 70: Trend in Monthly Regional Rig Count**



Source: GECF Secretariat based on data from Baker Hughes  
 Note: Excludes data for FSU region and Iran





CHAPTER  
**05**

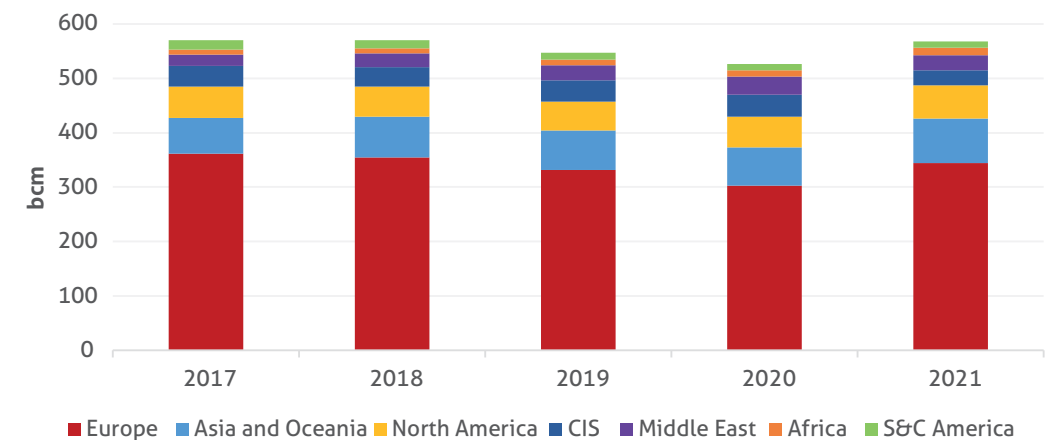
## Natural Gas Trade

### 5.1 Pipeline Natural Gas Trade

On a global perspective, the analysis of pipeline natural gas (PNG) trade can be determined via two techniques: the gross flows approach and net flows approach. The gross flows approach considers the total amount of gas imported or exported by means of pipeline systems. A more representative basis is the net flows approach, since it removes flows which artificially overestimate the trade figures, such as bidirectional pipeline gas movements, transit pipeline gas, re-exports of pipeline gas, and exports of regasified LNG.

In 2021, global net pipeline gas trade increased by 8% to reach 567 bcm (Figure 71). This increase was in line with the global economic recovery, which followed the suppression of gas demand as a result of the pandemic that was experienced in 2020.

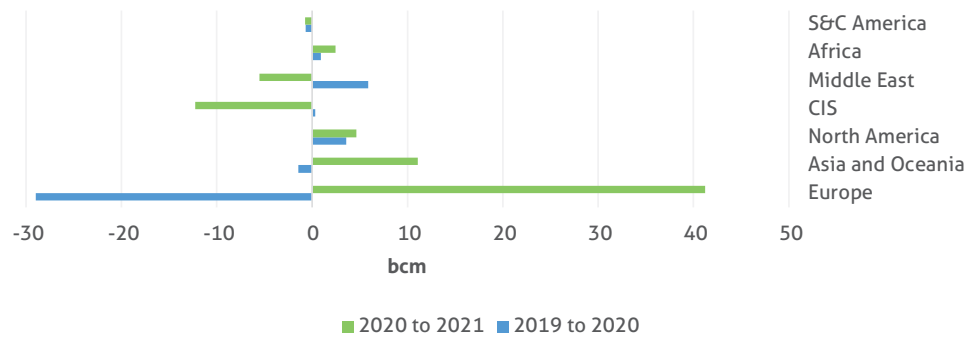
**Figure 71: Trend in Net Pipeline Gas Imports by Region**



Source: GECF Secretariat based on data from Cedigaz

Europe remained the top importing region of pipeline natural gas, accounting for 61%. The European and Asian regions experienced increases in pipeline imports amounting to 41 bcm and 11 bcm, respectively, whereas in the CIS there was a contraction of 12 bcm (Figure 72).

**Figure 72: Change in Net Pipeline Gas Imports**

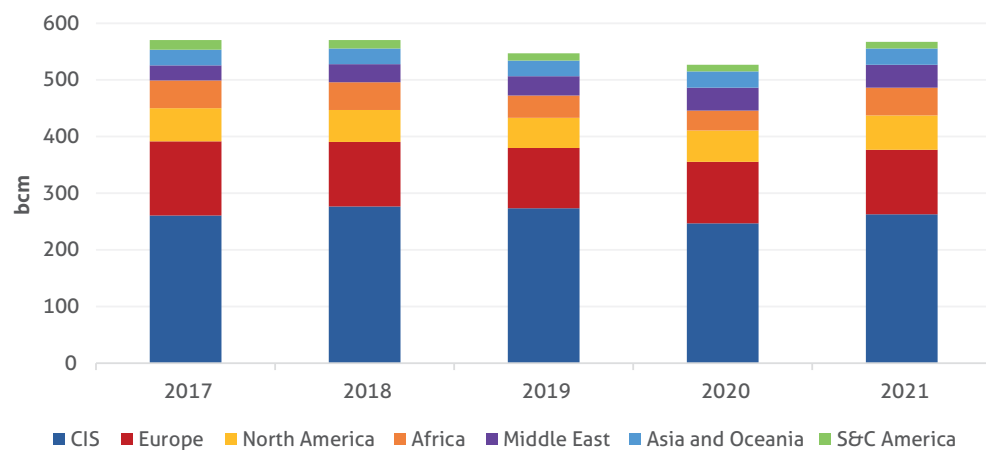


Source: GECF Secretariat based on data from Cedigaz

In 2022 and the short term, the trend will be defined by the impasse between the European Union and the Russian Federation. As a result, it is anticipated that there will be a diversion of pipeline volumes from Europe to Asia as Russia switches markets. The resulting shortfall in Europe is targeted to be met largely by increased LNG imports, but there is expectation for increased pipeline gas supply from GECF Member Countries Norway, Algeria and Azerbaijan.

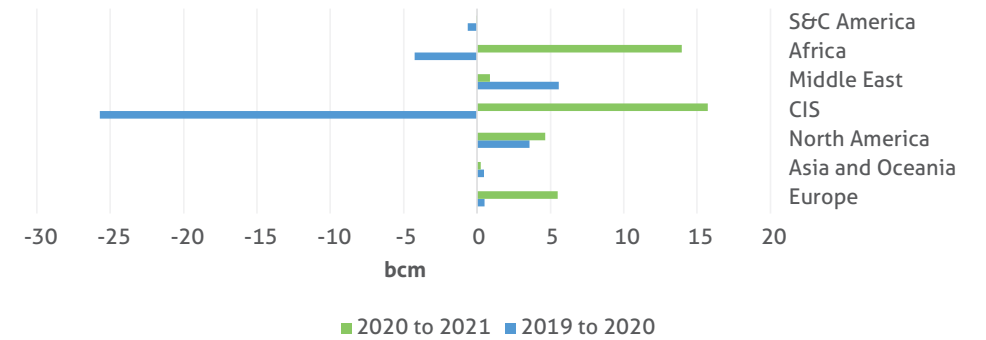
On the export side, Russia and Norway continued to drive the world’s top pipeline gas exporting regions, CIS (46%) and Europe (20%), respectively (Figure 73). CIS and Africa experienced substantial growth, of 16 bcm and 14 bcm respectively (Figure 74).

**Figure 73: Trend in Net Pipeline Gas Exports by Region**



Source: GECF Secretariat based on data from Cedigaz

**Figure 74: Variation in Net Pipeline Gas Exports by Region**

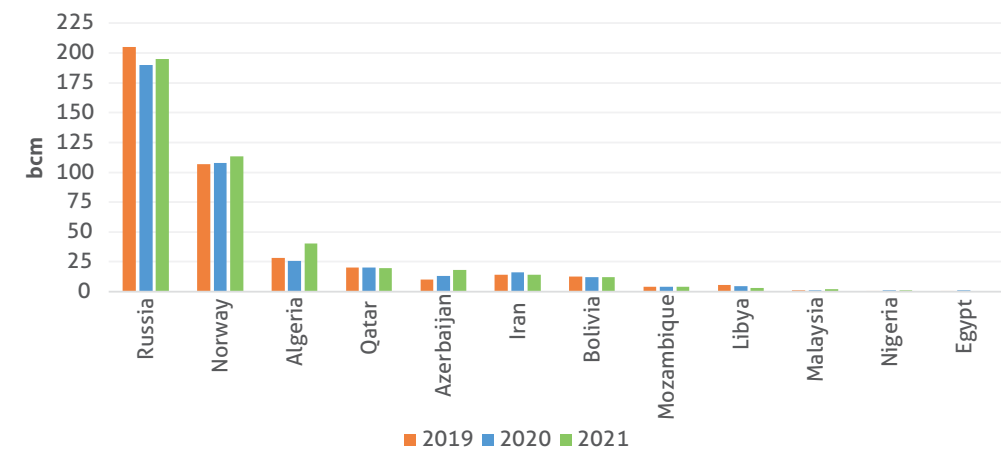


Source: GECF Secretariat based on data from Cedigaz

In 2022 and the short term, exports from the CIS may decrease as the shift in market from Europe to Asia will be limited by the current pipeline capacity between Russia and China. There will be an increase in flows in the opposite direction as Europe has targeted greater pipeline supply from Norway, Algeria and Azerbaijan. Finally, there may be more net exports from North America as the region steps up its LNG output to capitalise on demand in Europe and Asia.

In 2021, eleven GECF Member Countries were involved in pipeline gas trade (Figure 75). Net exports from this group totalled 423 bcm, which represented 75% of global net exports. The GECF share of net exports has averaged between 73% and 75% each year since 2017.

**Figure 75: Trend in GECF Member Countries Pipeline Gas Exports**

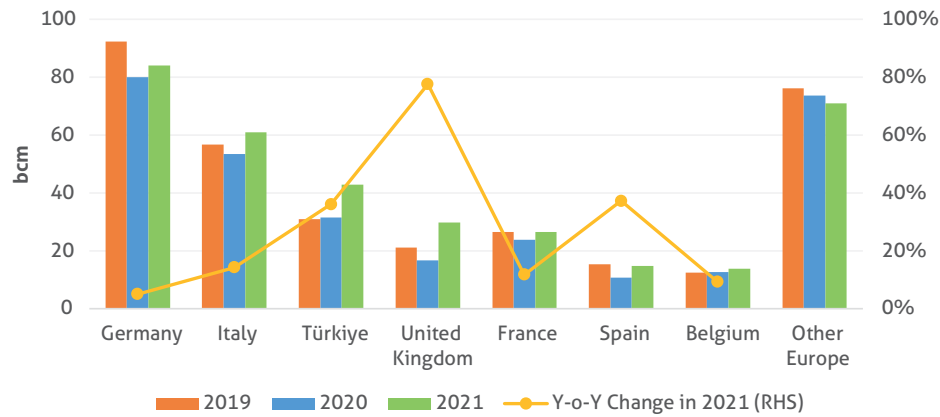


Source: GECF Secretariat based on data from Cedigaz

### 5.1.1 Europe

In 2021, there was a 14% y-o-y increase in pipeline gas imports in Europe to reach 344 bcm, as the region demonstrated considerable recovery following the impact of the COVID-19 pandemic in 2020. The major industrial economies of Germany and Italy remained the top demand centres (Figure 76), accounting for 42% of imports. Nevertheless, there were large relative percentage increases observed in the United Kingdom, Spain and Türkiye.

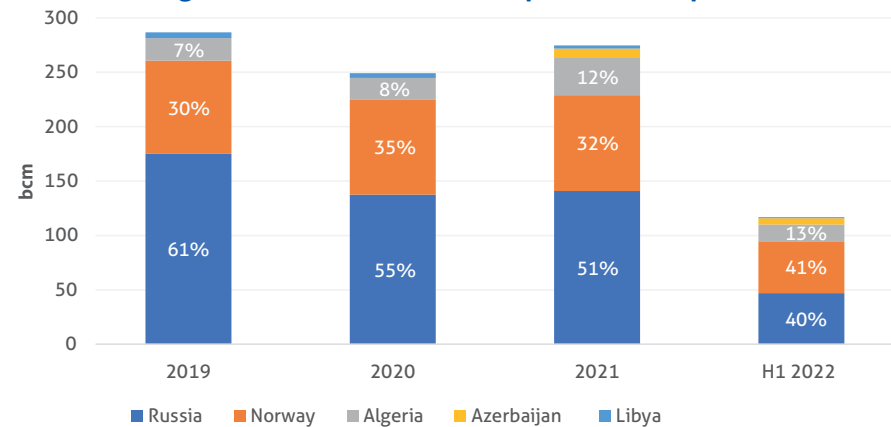
**Figure 76: Trend in Europe's Net Pipeline Gas Imports**



Source: GECF Secretariat based on data from Cedigaz

The European Union is completely supplied by GECF Member Countries, specifically Russia, Norway, Algeria, Azerbaijan and Libya. In 2021, the EU imported 275 bcm of pipeline gas, representing a 10% increase above 2020 levels (Figure 77). Russia and Norway accounted for the bulk of this supply, although it was supported by a substantial increase in exports from Algeria, and start-up of imports from Azerbaijan.

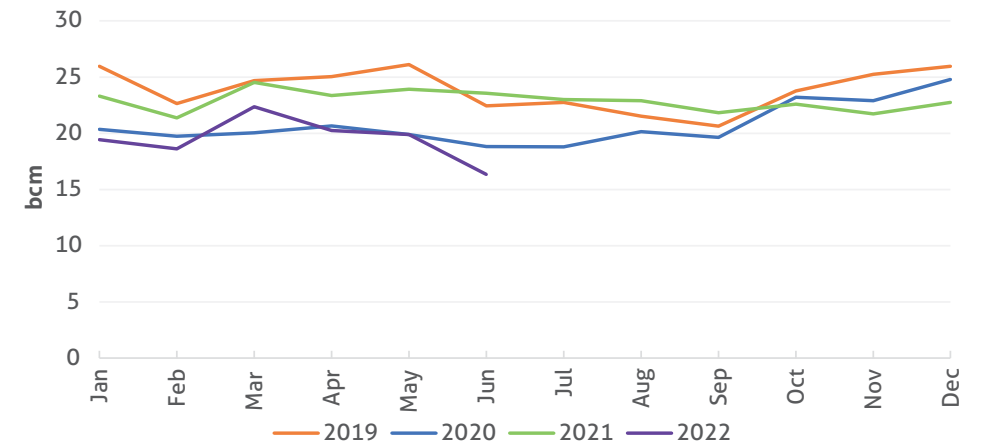
**Figure 77: Trend in Extra-EU Pipeline Gas Imports**



Source: GECF Secretariat based on data from McKinsey

In H1 2022, gas imports to the EU have been lower than in the same period a year ago, resulting in a cumulative deficit of 23 bcm, down by 17% y-o-y (Figure 78).

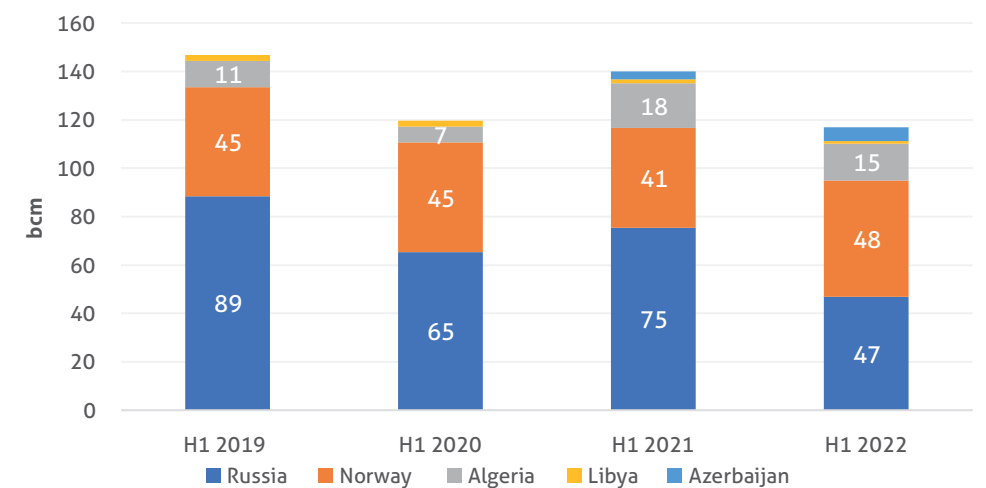
**Figure 78: Trend in EU's Monthly Pipeline Gas Imports**



Source: GECF Secretariat based on data from McKinsey

Furthermore, during this period, there has been a shift as the traditional major supplier to the region, Russia, has been displaced by Norway (Figure 79). This comes as a result of a reduction of Russian pipeline flows, increased LNG imports, and increased production and exports from Norway.

**Figure 79: Trend in EU's H1 Pipeline Gas Imports**



Source: GECF Secretariat based on data from McKinsey

For the remainder of 2022, both of these trends are expected to continue. The EU has developed the REPower EU initiative to reduce its dependence on Russian energy imports. Core targets for this plan include a two-thirds reduction of Russian gas imports by the end of 2022. Pipeline gas replacement is envisioned from increased imports from the remaining suppliers to the region.

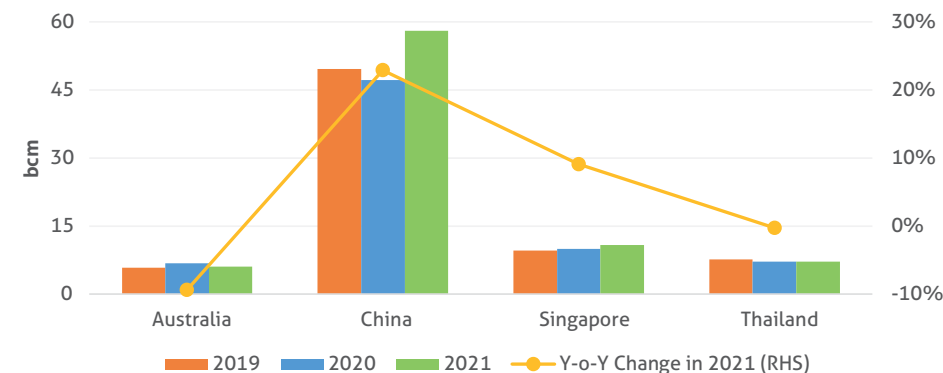
Norway has announced that it will increase gas exports by 8%, with the majority of the expected 122 bcm supply for 2022 being directed to PNG. Moreover, the Baltic Pipe is on track to be commissioned in October 2022, bringing 10 bcma of additional connectivity between Norway and Poland. Italy has signed an agreement for the supply of 1.2 bcm from Algeria in 2022, ramping up to 9 bcm by 2025. Azerbaijan plans to increase its supply of PNG to Europe this year by 1.5 bcm, and it aims to ramp up its supply to the region to 20 bcm by 2027. In total, an additional 10 bcm has been targeted for delivery to the region from these three sources in 2022. However, this would not be enough to match the level of supply lost from Russia, and so much of that shortfall will have to be met through increased LNG imports.

This raises a different issue with regard to the movement of gas entering the continent from different sources. Specifically, the constituent nations within the region have different reliance upon, and access to, LNG and pipeline gas. Russian pipeline gas enters the European gas grid primarily through Germany, Poland and Slovakia, while Norway's entry points are Germany, the UK, the Netherlands, France and Belgium. This is in contrast to the locations of the major LNG import terminals with spare regasification capacity within the region, mainly in the Iberian Peninsula. The problem is that pipeline connection between this area and the rest of the European gas grid is limited to the very low capacity interconnectors between Spain and France. Moreover, there is also a lack of sufficient connectivity between France and Germany. To confront this challenge, there has been exploration of solutions such as the revival of the Midi-Catalonia pipeline project between France and Spain, as well as an offshore pipeline between Spain and Italy.

### 5.1.2 Asia Pacific

In 2021, net pipeline gas imports in the Asia Pacific region grew by 16% y-o-y to reach 82 bcm. The main driver for this growth was the very high demand for energy in China, as that country was one of the first to emerge from the first wave of lockdowns associated with the pandemic. All of the importing countries recorded volumes greater than pre-pandemic levels except for Thailand, which actually decreased slightly each year since 2019 (Figure 80).

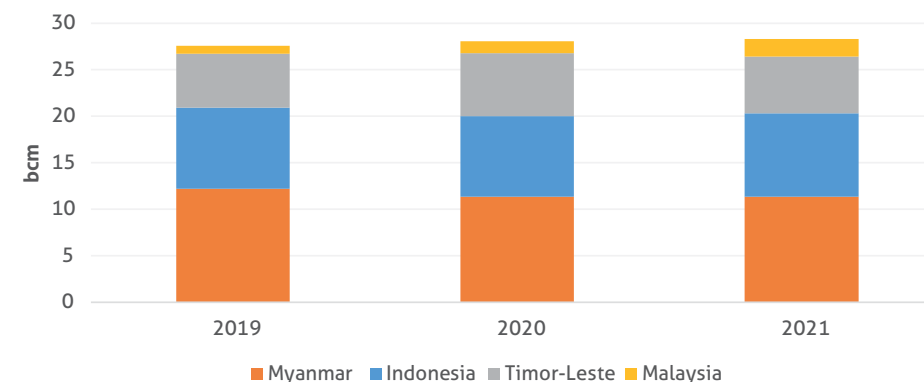
**Figure 80: Trend in Asia Pacific's Net Pipeline Gas Imports by Country**



Source: GECF Secretariat based on data from Cedigaz

Net pipeline gas exports have remained relatively stable since 2019, averaging around 28 bcm. Myanmar was the primary exporter, accounting for 40% of the volumes traded in 2021 (Figure 81).

**Figure 81: Trend in Asia Pacific's Net Pipeline Gas Exports by Country**



Source: GECF Secretariat based on data from Cedigaz

In 2022 and going forward, it is expected that there will be continued growth in pipeline gas imports to China. The main drivers behind this would be energy demand across industrial and transportation sectors, as well as coal-to-gas switching in the power sector. Likewise, the reduction of Russian pipeline gas imports to Europe will encourage increased volumes being exported to China, but the quantity will be limited by two factors. First, gas imports via the Power of Siberia pipeline between both countries is expected to ramp up incrementally over the coming years, up to the maximum of 38 bcm by 2025. Secondly, there is currently a lack of full pipeline interconnectivity

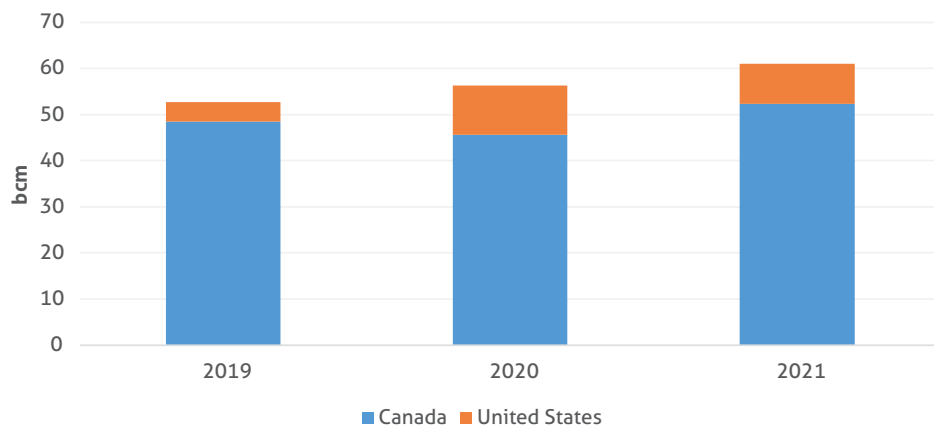
between the regions of natural gas supply in northern Russia and the demand centres in the Far East. Notwithstanding these factors, during the first half of 2022, Russia increased its exports to China via the Power of Siberia pipeline, by 63% y-o-y.

### 5.1.3 North America

In 2021, net pipeline gas trade in North America increased by 8% y-o-y to reach 61 bcm (Figure 82). Due to the very large distances between production zones and demand centres across the continent, there is a very high degree of interconnectivity and bidirectional pipeline gas flows between the individual countries. Canada and the U.S. are net exporters. Canada observed an increase in net exports by 7 bcm, while the U.S. experienced a decline of 2 bcm. Mexico increased its imports by 5 bcm.

Going forward, the LNG export terminals in the U.S. would be poised to take advantage of short- to medium-term demand in Europe as a result of their plan to diversify their energy supply. Additionally, resilient demand in the Far East has spurred the development of LNG export terminals across all three North American nations. It is envisioned that these factors will promote increased gas trade within the region as pipeline gas volumes are converted to LNG for export.

**Figure 82: Trend in North America’s Net Pipeline Gas Exports by Country**

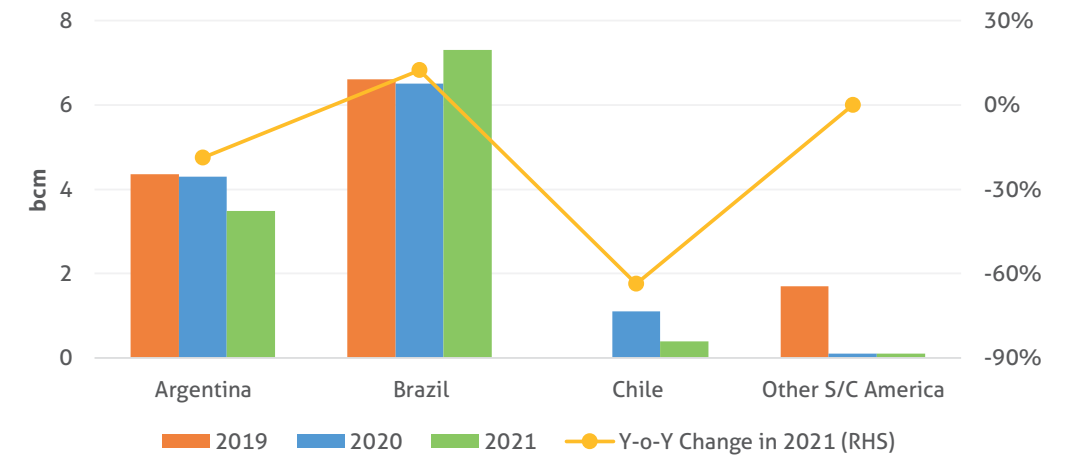


Source: GECF Secretariat based on data from Cedigaz

### 5.1.4 South & Central America

In 2021, net pipeline gas imports to the South & Central America decreased by 6% annually to reach 11 bcm. Brazil increased pipeline imports from 2020 to 2021, while there was reduction observed in Argentina and Chile (Figure 83) due to increased domestic gas production and LNG imports, respectively. With respect to pipeline gas exports, the major player in the region is Bolivia, and their net send out remained at the same level of 12 bcm.

**Figure 83: Trend in South & Central America’s Net Pipeline Gas Imports by Country**



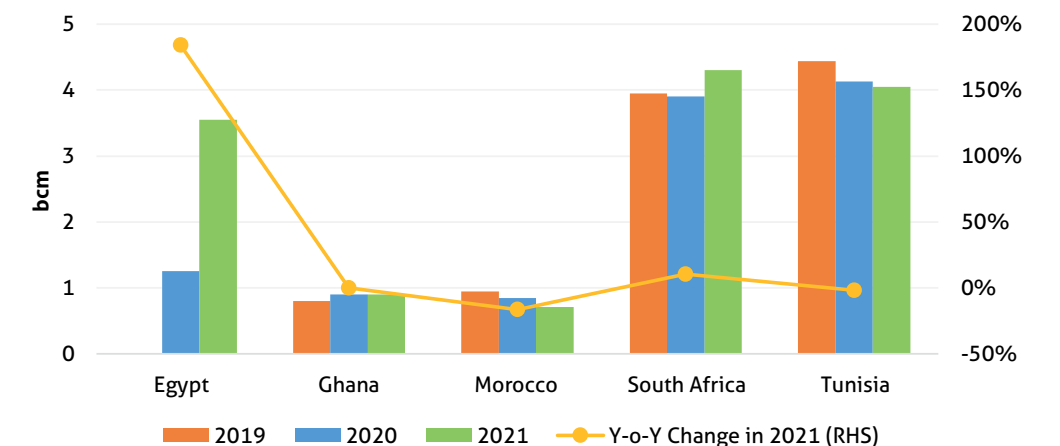
Source: GECF Secretariat based on data from Cedigaz

In 2022 and the short term, there is expectation for more gas production from Argentina. This coupled with greater pipeline connectivity with Chile, as well as LNG imports into the region, will result in an increase in pipeline gas trade on the continent.

### 5.1.5 Africa

In 2021, net pipeline imports in Africa increased by 22% annually to reach 14 bcm. The growth was almost completely attributed to a rise in volumes supplied to Egypt (Figure 84), which almost tripled its imports in 2021.

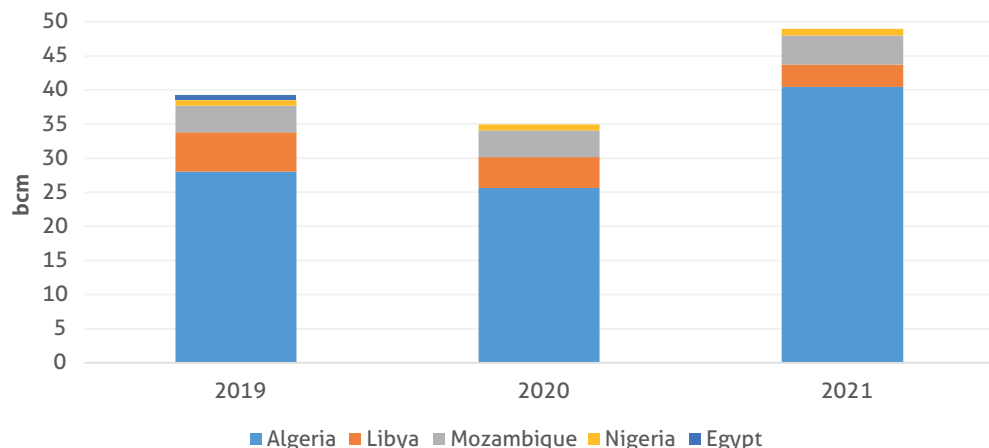
**Figure 84: Trend in Africa’s Net Pipeline Gas Imports by Country**



Source: GECF Secretariat based on data from Cedigaz

Regarding net pipeline gas exports, the region experienced a 40% increase y-o-y to 49 Bcm. Algeria has traditionally been the major pipeline exporter on the continent, and increased its supply share from 73% in 2020 to 83% in 2021 (Figure 85).

**Figure 85: Trend in Africa's Net Pipeline Gas Exports by Country**



Source: GECF Secretariat based on data from Cedigaz

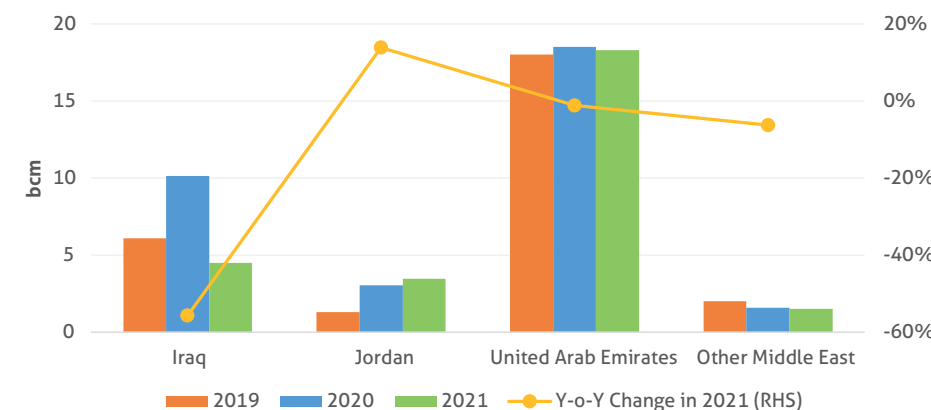
In 2022 and the short term, net pipeline exports are expected to increase. Algeria has already signed agreements to increase its supply to Italy. Egypt is expected to increase its pipeline gas imports as part of an arrangement with other Middle Eastern countries to monetise natural gas reserves through Egypt's LNG liquefaction facilities at Damietta and Rosetta, for export primarily to Europe. In fact, in Q1 2022, pipeline gas exports to Egypt were 35% higher than during the same period in 2021.

Moreover, Nigeria is increasing its exports to West Africa and pushing ahead with plans to increase connectivity with North Africa and beyond into Europe. In this regard, plans are underway for a 5.4 bcma capacity pipeline which will transport Nigerian gas some 7,000 km to Morocco and may eventually enter the European market. Likewise, in 2022, Nigeria, Algeria and Niger agreed upon restarting the Trans-Saharan Pipeline. This project is expected to allow up to 30 bcma of Nigerian supply access to Europe, via connection to the Medgaz Pipeline, which links Algeria to Spain.

### 5.1.6 Middle East

In 2021, the Middle East region experienced a 17% annual reduction in net pipeline gas imports, with the majority of this decrease being attributed to Iraq (Figure 86). Other major importers in the region such as the United Arab Emirates and Jordan maintained their positions from 2020.

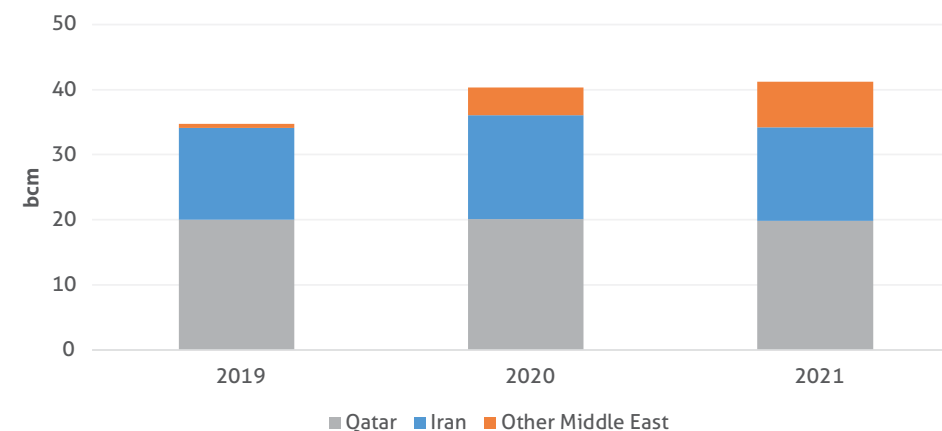
**Figure 86: Trend in the Middle East's Net Pipeline Gas Imports by Country**



Source: GECF Secretariat based on data from Cedigaz

On the other hand, net pipeline gas exports were at 41 bcm (Figure 87), remaining at almost the same level as the year before, although the individual supply share was different.

**Figure 87: Trend in the Middle East's Net Pipeline Gas Exports by Country**



Source: GECF Secretariat based on data from Cedigaz

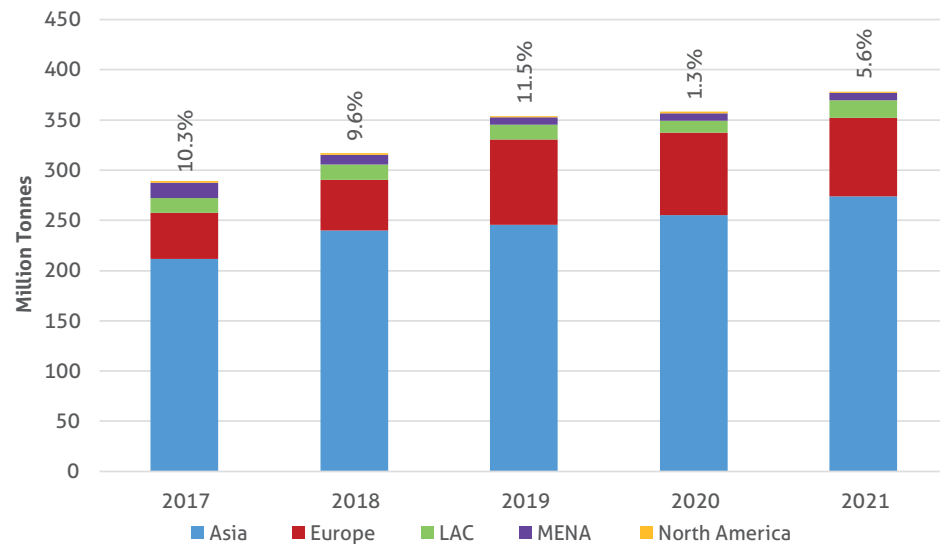
In 2022 and the short term, pipeline gas volumes across the border for export as LNG at Egypt's liquefaction facilities are expected to increase. Additional flows will also be provided to Egypt through Jordan via the Arab Gas pipeline. The level of imports within the region is influenced by having the option to receive gas via LNG cargoes as well.

## 5.2 LNG Trade

### 5.2.1 LNG Imports

In 2021, global LNG imports grew by 5.6% (19.9 Mt) y-o-y to 378.0 Mt (Figure 88), driven by stronger demand in Asia and LAC, which offset a decline in Europe. This represents an acceleration in the pace of growth from 1.3% (4.4 Mt) y-o-y recorded in 2020. It should also be noted that the increase in LNG imports last year was significantly lower than the annual increase recorded between 2017 and 2019. Stronger LNG imports in 2021 was supported by the post-COVID-19 recovery in gas demand, colder-than-normal winter season, warmer-than-usual summer season in the northern hemisphere, drought conditions, coal-to-gas switching and weaker domestic gas production in some countries.

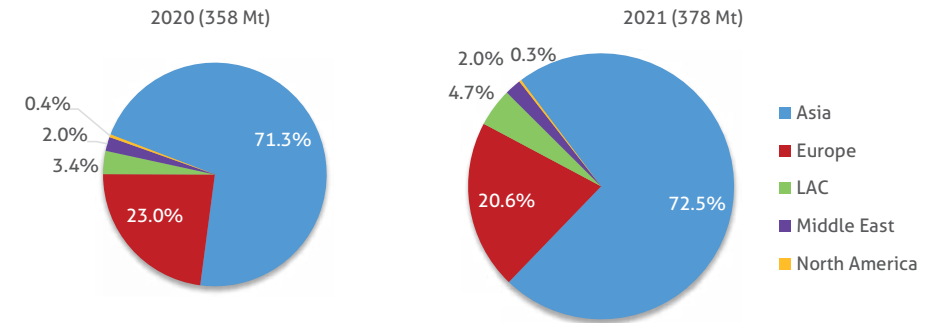
**Figure 88: Trend in Global LNG Imports by Region**



Source: GECF Secretariat based on data from ICIS LNG Edge

In terms of the share of LNG imports by region, Asia was the largest importer of LNG in 2021 with a share of 72.5%, followed by Europe (20.6%), LAC (4.7%), MENA region (2.0%) and U.S./Canada (0.3%). In comparison to 2020, the share of regional LNG imports increased in Asia and LAC but fell in Europe (Figure 89). This was attributed to the higher LNG imports in Asia and LAC to the detriment of Europe. Meanwhile, the share of MENA region and U.S./Canada in LNG imports were relatively unchanged from 2020.

**Figure 89: Share of LNG Imports by Region in 2020 and 2021**

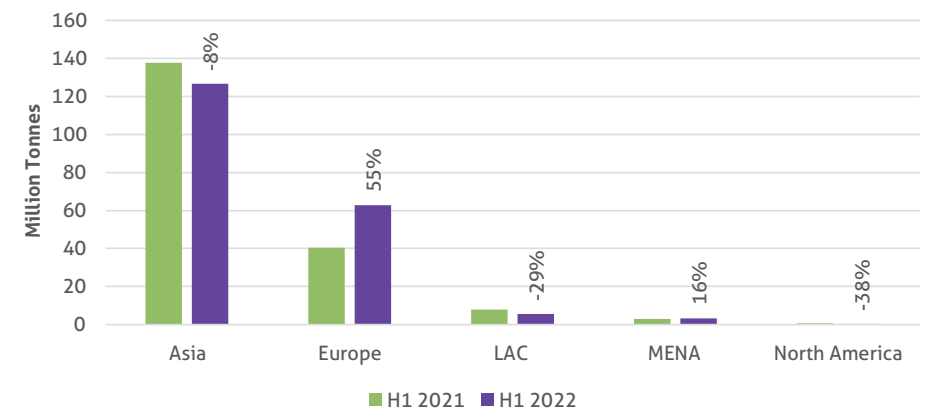


Source: GECF Secretariat based on data from ICIS LNG Edge

In H1 2022, global LNG imports grew by 4.7% (8.8 Mt) to 198.7 Mt. Unlike previous years when Asia was the driver of global LNG imports, Europe has become the premium market for LNG imports and absorbed significant volumes of flexible LNG cargoes to the detriment of Asia (Figure 90). The increase in LNG demand this year was mainly driven by Europe, amidst multi-year low gas storage levels and a reduction in pipeline gas imports from Russia. This led to the convergence in spot LNG prices in Asia and Europe, which resulted in a higher netback for U.S. LNG delivered into Europe over Asia. MENA region's LNG imports continued to rise while LAC and North America recorded declines in LNG imports.

In H2 2022 and 2023, global LNG imports are forecasted to continue rising y-o-y. Europe, and to a lesser extent Asia, are expected to account for the bulk incremental LNG imports during this period. The LNG market is forecasted to remain tight in the short-term, which is expected to support the convergence in spot LNG prices between Asia and Europe and hence support more LNG deliveries from the U.S. to Europe.

**Figure 90: Regional LNG Imports by Country (H1 2021 & H1 2022)**



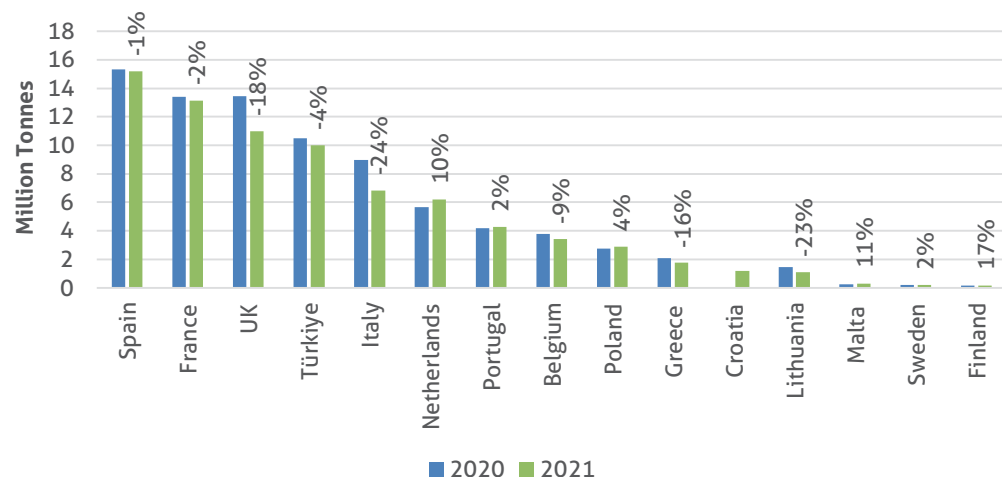
Source: GECF Secretariat based on data from ICIS LNG Edge

### 5.2.1.1 Europe

In 2021, LNG imports in Europe fell by 5.3% (4.4 Mt) y-o-y to 77.82 Mt. The weaker LNG imports was mainly due to stronger LNG demand in Asia and LAC, with spot LNG prices in both region maintaining a significant premium over prices in Europe. This resulted in LNG cargoes being pulled away from Europe for delivery to Asia and LAC. At a country level, the UK, Italy and Türkiye drove the decline in the region’s LNG imports (Figure 91). Meanwhile, Croatia and Netherlands recorded a significant increase in LNG imports last year.

In the UK, a recovery in pipeline gas imports from Norway in 2021 compensated for the decline in LNG imports in the country. Similarly, the drop in Italy’s LNG imports last year was offset by the stronger pipeline gas imports from Algeria. On the other hand, Croatia joined the club of LNG importers last year, with total imports reaching 1.2Mt. In the Netherlands, LNG imports increased in 2021 to compensate for a significant decline in domestic gas production, which fell by around 10% (2 bcm) y-o-y.

**Figure 91: Europe’s LNG Imports by Country (2020 & 2021)**



Source: GECF Secretariat based on data from ICIS LNG Edge

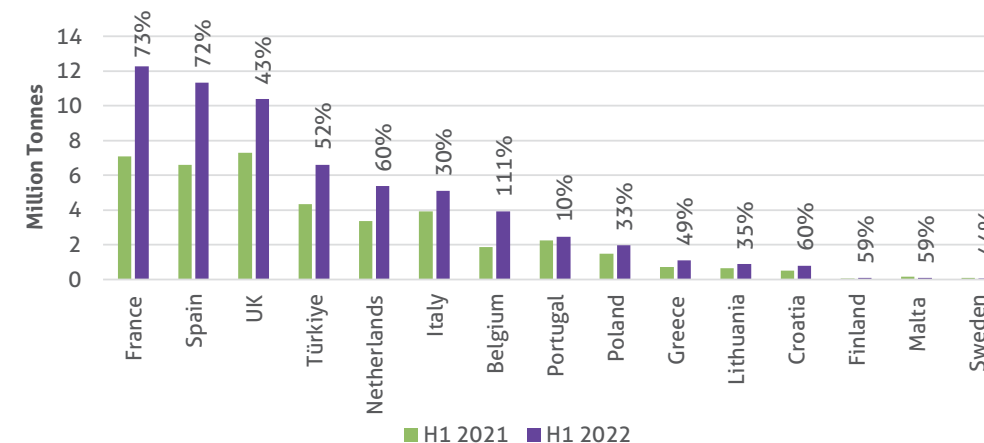
During H1 2022, Europe’s LNG imports surged by 54.9% (22.2 Mt) y-o-y to 62.7 Mt. This is a record high for Europe’s LNG imports during the first half of any year. The influx of LNG into the region was driven by strong demand to replenish underground storage and the EU’s REPowerEU policy to reduce its dependence on Russian gas supply. As part of the REPowerEU policy, the EU is targeting an increase in LNG imports of around 50 bcm in 2022 to partially compensate for a targeted reduction of 100 bcm in pipeline gas imports from Russia. The strong LNG demand in Europe has contributed to significant tightness in the LNG market, which significantly reduced the spot LNG price spreads between Asia and Europe. This resulted in a shift in U.S. LNG cargoes away from Asia to Europe, since it was more profitable for U.S. LNG to be delivered to Europe.

At a country level, France, Spain, UK, Türkiye, Netherlands, Belgium and Italy contributed for the bulk incremental LNG imports in Europe (Figure 92). The lower pipeline gas imports from Russia and weaker nuclear availability resulted in the strong demand for gas reinjection that increased the need for LNG importation in France. Spain’s LNG imports was boosted by stronger demand for reinjection into gas storage, lower pipeline gas from Algeria and stronger demand for electricity generation. In H1 2021, the UK imported significant volumes of gas via the BBL and IUK interconnectors from continental Europe. However, this flipped in H1 2022 with the UK exporting significant volumes of gas via both pipelines, supported by the higher LNG imports and stronger domestic gas production in the country.

In the Netherlands, lower pipeline gas imports from Russia and weaker domestic gas production resulted in stronger demand for gas reinjection into storage, which drove the country’s LNG imports higher. Similarly, a decline in pipeline gas imports from Russia drove higher demand for gas storage injection, which boosted Belgium’s LNG imports. In the case of Italy, the uptick in LNG imports was driven by lower pipeline gas imports from Russia and Libya. Meanwhile, the jump in Türkiye’s LNG imports was mainly attributed to higher gas consumption in the residential and commercial sectors and a drop in pipeline gas imports from Azerbaijan and Iran.

In H2 2022, Europe’s LNG imports are forecasted to remain elevated compared to previous years, supported by strong demand for reinjection into gas storage and the lower pipeline gas imports from Russia. However, during Q4 2022, the pace of LNG import growth compared to Q4 2021 is expected to slow down since Europe LNG imports started to increase significantly at the end of 2021. In 2023, Europe’s LNG imports are forecasted to continue expanding, driven by the further targeted reduction in pipeline gas imports from Russia, in line with the REPowerEU policy. It should be noted that Europe’s annual growth in LNG imports in 2023 is expected to be lower than 2022 since the reduction in Russian pipeline gas in 2023 will be lower.

**Figure 92: Europe’s LNG Imports by Country (H1 2021 & H1 2022)**



Source: GECF Secretariat based on data from ICIS LNG Edge



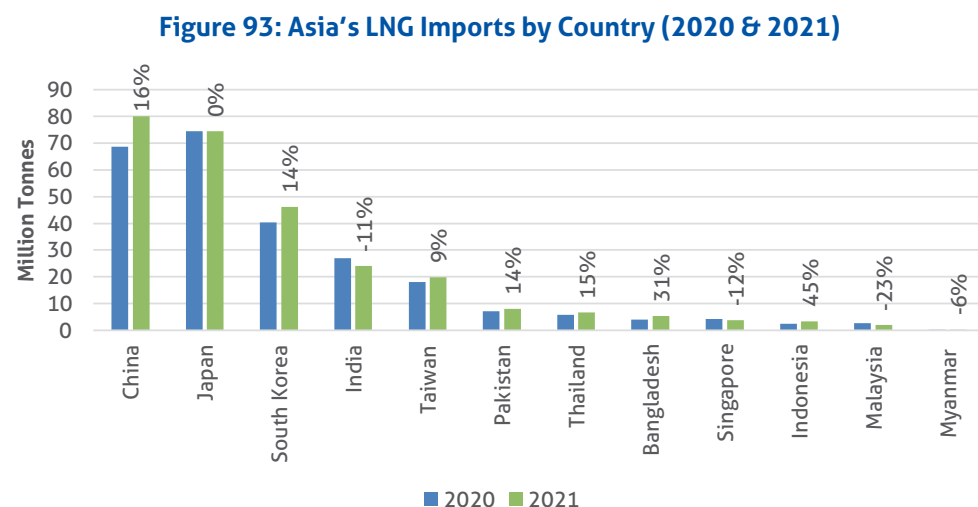
### 5.2.1.2 Asia Pacific

In 2021, Asia's LNG imports rose by 7.4% (18.9 Mt) y-o-y to reach 274.0 Mt. China and South Korea accounted for the bulk incremental LNG volumes imported last year in Asia, which offset a significant decline in India (Figure 93).

China's LNG imports jumped by 16.5% (11.3 Mt) y-o-y to 80.0 Mt and overtook Japan to become the world's largest LNG importer. Stronger gas demand in China, which was supported by the post-COVID-19 recovery, higher industrial activity, coal-to-gas switching in the residential sector and stronger gas burn, boosted the country's LNG imports. In South Korea, the higher gas demand in the power sector, amidst the warmer-than-usual weather during the summer season and post-COVID-19 rebound in electricity demand, drove the rise in the LNG imports. Meanwhile, stronger electricity demand in Taiwan and lower nuclear output contributed to the increase in gas burn, and hence LNG imports.

In Bangladesh and Pakistan, the uptick in LNG imports was due to higher increase in gas demand compared to the growth in domestic gas production. On the other hand, weaker domestic gas production and a small increase in gas demand drove the rise in Thailand's LNG imports. Furthermore, robust intra-country LNG trade in Indonesia led to increasing LNG imports.

In contrast, the drop in India's LNG imports was attributed to higher domestic gas production. Additionally, India is a price sensitive market, and the record high spot LNG prices may have curbed spot LNG demand in the country.



Source: GECF Secretariat based on data from ICIS LNG Edge

In H1 2022, Asia's LNG imports fell by 8.1% (11.2 Mt) y-o-y to 126.5 Mt. Asia's monthly LNG imports have declined consistently y-o-y since November 2021. China's LNG imports, which dropped by 22.1% (8.8 Mt) y-o-y in H1 2022, drove the decline in the region's LNG imports (Figure 94). Weaker imports in India, Japan, South Korea and Pakistan also contributed to the decrease in Asia's LNG imports. In contrast, LNG imports were up significantly in Thailand, Taiwan and Indonesia.

The drop in China's LNG imports this year was mainly driven by weaker economic and industrial activity, as a result of the reimplementing of COVID-19 restrictions in line with the zero-COVID policy in the country. In addition, stronger domestic gas production and higher pipeline gas imports, which were more competitive than the high spot LNG prices, displaced LNG imports in the country. In India, higher domestic gas production and high spot LNG prices led to the decline in LNG imports. India is a price sensitive market, and the unsustainable high spot prices curbed the spot LNG demand in the country.

Meanwhile, the lower LNG imports in Japan during Q1 2022, as a result of ample LNG inventory, high spot LNG prices, higher nuclear availability and a shift in U.S. LNG flows away from Asia to Europe, weighed on LNG imports in the country in H1 2022. Furthermore, less restrictions on coal-fired power plants, stronger nuclear availability and high spot LNG prices, which were less competitive with coal in the electricity sector, drove South Korea's LNG imports higher. In Pakistan, which is also a price sensitive market like India, high spot LNG price resulted in a drop in LNG imports to the country.

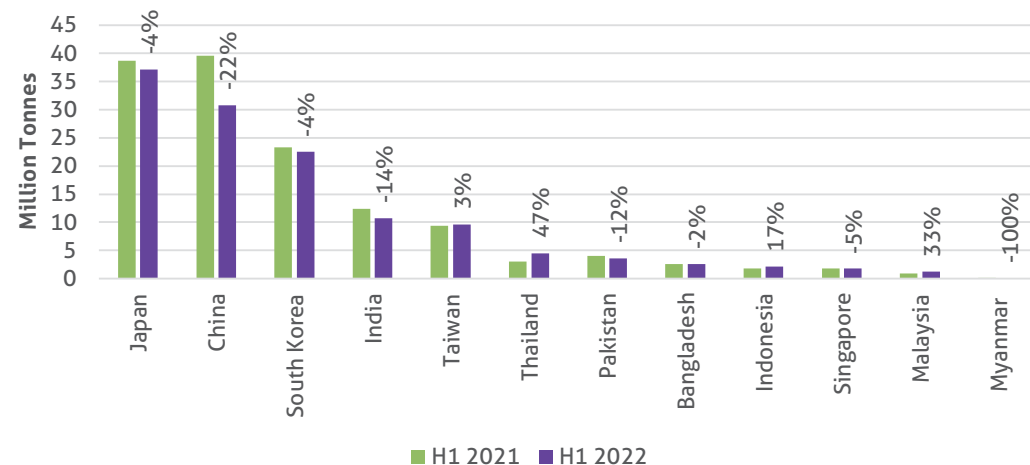
On the other hand, weaker domestic gas production in Thailand boosted LNG imports in the country. In Taiwan, the decline in nuclear availability, which boosted gas burn, coupled with strong LNG restocking at the end of the winter season contributed to the increase in LNG imports in the country. Finally, Indonesia's LNG imports was driven by strong intra-country trade, supported the government's order to divert more LNG to the domestic market amidst declining domestic gas production.

In H2 2022, Asia's LNG imports are forecasted to continue to slide. This is driven mainly by weak spot LNG demand in China despite the easing of COVID-19 restrictions in the country. Stronger pipeline gas imports and higher gas production are forecasted to curb the country's LNG imports. There is potential for higher LNG imports in other northeast Asian countries supported by LNG restocking demand following a warmer-than-usual summer season. The outlook for LNG demand in South and Southeast Asia is bleak due to the high spot prices, which could reduce spot LNG demand in price sensitive countries. In Thailand, declining domestic gas production is expected to support LNG imports in the country. For the full year 2022, Asia's LNG demand is forecasted to be significantly lower than 2021.

Further ahead into 2023, we expect a recovery in LNG imports in the region driven by firmer gas demand growth in China and India, start-up of new LNG import projects

in China, Philippines and Vietnam and lower domestic gas production in Bangladesh, Pakistan and Thailand. However, the pace of growth will be dependent on the LNG demand in Europe and the price spreads between Asia and Europe.

**Figure 94: Asia's LNG Imports by Country (H1 2021 & H1 2022)**

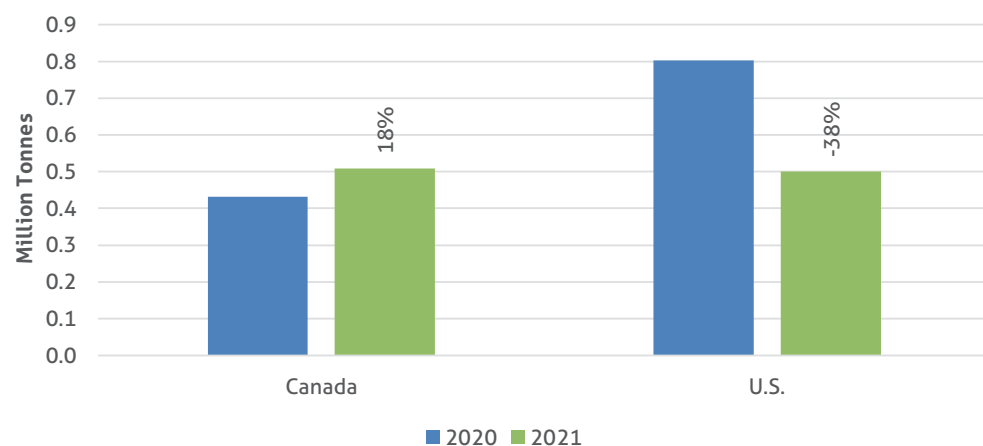


Source: GECF Secretariat based on data from ICIS LNG Edge

### 5.2.1.3 North America

In 2021, North America's (U.S. & Canada) LNG imports were down 18.2% (0.2 Mt) y-o-y and averaged 1.0 Mt. The lower LNG imports was driven by a decrease in U.S. imports (Figure 95), which has become less reliant on LNG imports over the past few years due to the significant increase in domestic gas production. Some of the LNG imports in the U.S. last year were for operational reasons to keep the LNG import facilities cool.

**Figure 95: North America's LNG Imports by Country (2020 & 2021)**

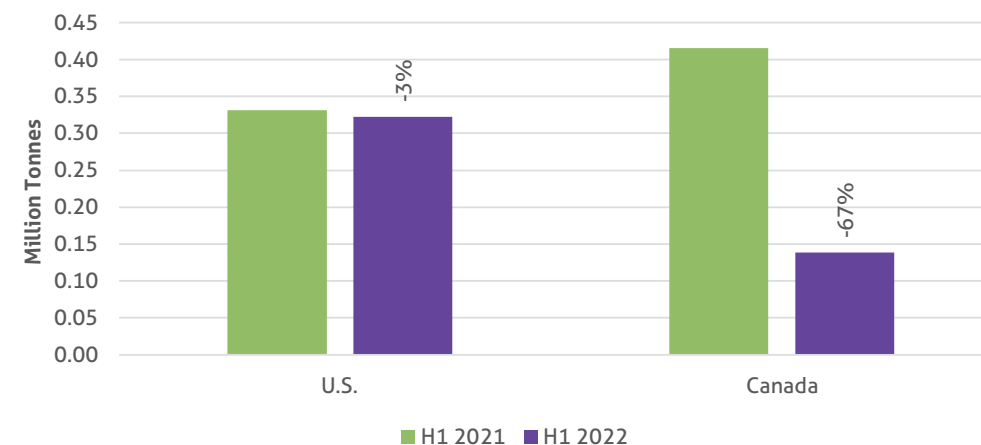


Source: GECF Secretariat based on data from ICIS LNG Edge

During H1 2022, North America's (U.S. & Canada) LNG imports fell by 38.2% (0.3 Mt) y-o-y to 0.5 Mt, driven by a slump in imports in Canada (Figure 96). The weaker imports were due to higher domestic gas production in the country, which reduced the demand for LNG imports. Meanwhile, U.S. LNG imports were relatively flat compared to the same period in 2021.

For H2 2022 and full year 2023, North America's LNG imports are forecasted to decline further due to increasing domestic gas production in U.S. and Canada.

**Figure 96: North America's LNG Imports by Country (H1 2021 & H1 2022)**

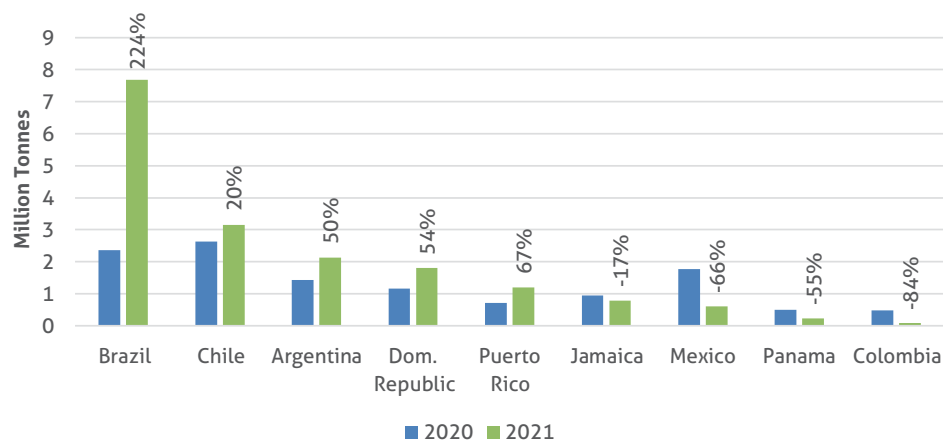


Source: GECF Secretariat based on data from ICIS LNG Edge

### 5.2.1.4 Latin America and the Caribbean (LAC)

In 2021, LNG imports in LAC jumped by 47.1% (5.7 Mt) y-o-y to 17.7 Mt. This was the highest LNG imports in the region since 2015 and was mostly attributed to record high LNG demand in Brazil (Figure 97). Furthermore, Argentina, Dominican Republic, Chile and Puerto Rico also recorded a significant increase in LNG imports, while Mexico, Colombia and Panama's imports were down sharply.

**Figure 97: LAC’s LNG Imports by Country (2020 & 2021)**



Source: GECF Secretariat based on data from ICIS LNG Edge

One of the worst droughts on record affected Brazil last year and depleted hydro levels in the country, which boosted LNG imports for electricity generation. In Argentina, the uptick in LNG imports was supported by stronger gas consumption, following the easing of COVID-19 restrictions, and weak growth in domestic gas production. Meanwhile, the higher LNG imports in Dominican Republic and Puerto Rico were driven by the post-COVID-19 recovery in gas consumption in both countries. Similar to Brazil, Chile’s hydro output was also impacted by drought conditions, which contributed to the increase in LNG imports for electricity generation.

On the other hand, the weaker LNG imports in Mexico was due to the sustained increase in pipeline gas imports from the U.S. In Colombia, a slight increase in domestic gas production and a drop in gas consumption drove LNG imports down in the country.

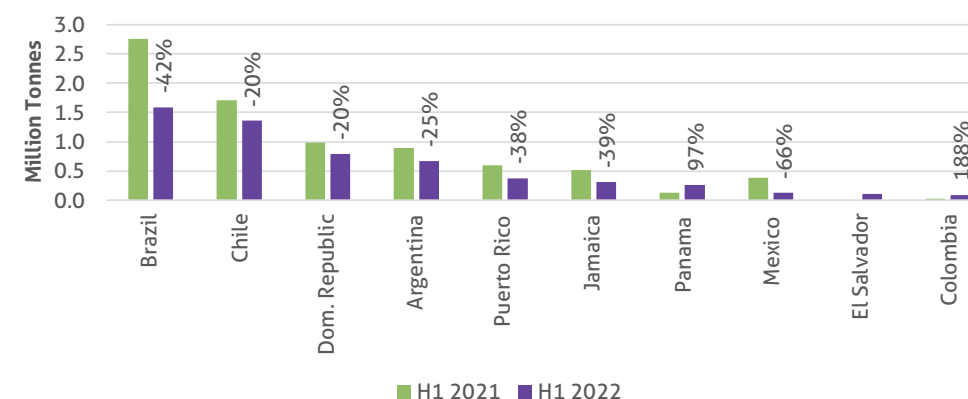
In H1 2022, LAC’s LNG imports declined by 29.1% (2.3 Mt) y-o-y to 5.7 Mt. Brazil accounted for the majority of the decline in the region’s LNG imports (Figure 98), while Chile, Puerto Rico, Mexico, Argentina, Dominican Republic and Jamaica decreased to a lesser extent.

The drop in LNG imports in Brazil and Chile was mainly attributed to normalisation in rainfall in South America, which supported an increase in hydro levels. This reduced the gas demand in the electricity sector in both countries and led to the drop in LNG imports. In Mexico, higher pipeline gas imports from the U.S. continues to displace LNG imports in the country. Meanwhile, higher domestic gas production in Argentina has curbed LNG imports so far in 2022.

In H2 2022, LAC’s LNG imports are expected to decline, mainly due to higher hydro

levels in Brazil and Chile and growing domestic gas production in Argentina. In 2023, there is some potential upside for LNG imports in the region supported by the start-up of new LNG import projects in Brazil, Ecuador, El Salvador and Nicaragua, as well as fuel oil and diesel substitution with gas in Dominican Republic’s electricity sector. In addition, increasing pipeline gas imports in Mexico from the U.S. could reduce Mexico’s LNG imports further, while higher gas production from the Vaca Muerta in Argentina could reduce the country’s LNG demand.

**Figure 98: LAC’s LNG Imports by Country (H1 2021 & H1 2022)**

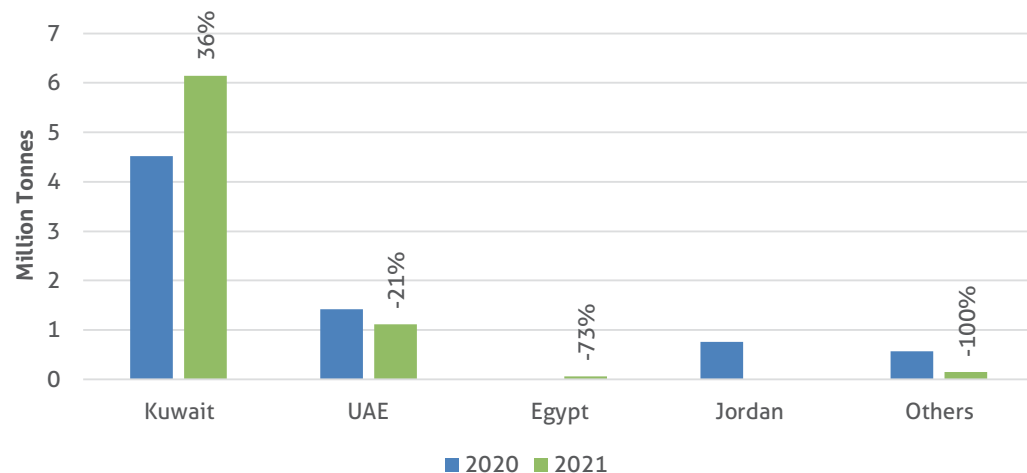


Source: GECF Secretariat based on data from ICIS LNG Edge

**5.2.1.5 Middle East and North Africa (MENA)**

In 2021, MENA region’s LNG imports moved slightly higher by 3.1% (0.2 Mt) y-o-y to 7.5 Mt. A jump in Kuwait’s LNG imports offset lower imports in the UAE, Jordan and other Middle Eastern countries (Figure 99). The start-up of the 22Mtpa Al-Zour LNG import terminal in Kuwait and oil substitution with gas in the power sector boosted LNG imports in the country last year. In contrast, Jordan’s LNG imports slumped in 2021, with no LNG cargo delivered to the country. Jordan imported its gas demand needs via pipeline from Egypt and other Middle Eastern countries. Meanwhile, the fall in other Middle Eastern countries’ LNG imports was driven by stronger domestic gas production in the country. In the UAE, higher domestic gas production and flat gas consumption curbed LNG imports in 2021.

**Figure 99: MENA's LNG Imports by Country (2020 & 2021)**

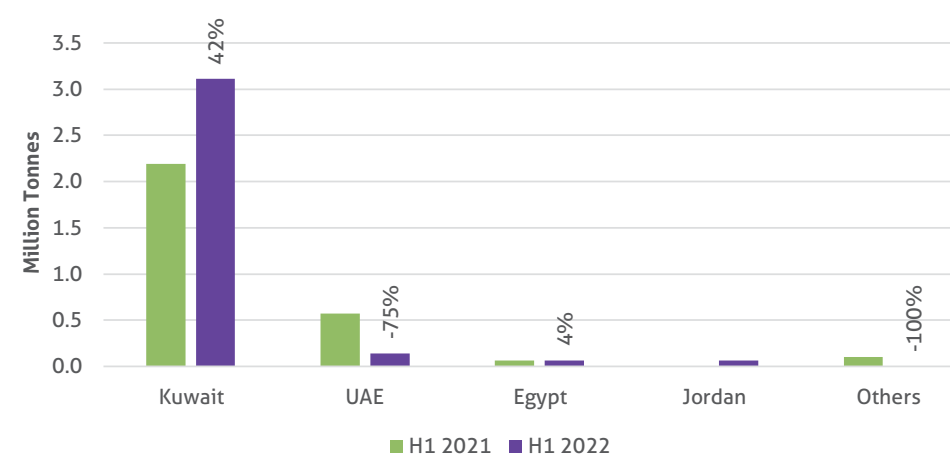


Source: GECF Secretariat based on data from ICIS LNG Edge

During H1 2022, MENA region's LNG imports grew by 15.5% (0.5 Mt) to 3.4 Mt. The sharp increase in LNG imports in Kuwait offset declines in the UAE and other Middle Eastern countries (Figure 100). Stronger gas demand from the electricity sector in Kuwait, which is supported by oil-to-gas switching, is the main driver for the rally in LNG imports in the country. The increase in imports in the country is facilitated through the recently commissioned Al-Zour LNG import terminal. On the other hand, the start-up of the second 1.4 GW unit at the Barakah nuclear plant in the UAE has reduced the LNG import needs in the country. In other Middle Eastern countries, the increasing domestic gas production has contributed to the decline in LNG imports in H1 2022. During this period, other Middle Eastern countries did not import any LNG cargo.

Kuwait is forecasted to continue driving the increase in MENA region's LNG imports in the short-term. This is supported by the oil-to-gas switching in the electricity sector. There are some downside risks to LNG imports in the region, mainly from the UAE, following the commissioning of additional units at the Barakah nuclear plant. In Jordan and other Middle Eastern countries, LNG demand is expected to remain weak due to higher domestic gas production and strong intra-regional pipeline gas trade.

**Figure 100: MENA's LNG Imports by Country (H1 2021 & H1 2022)**

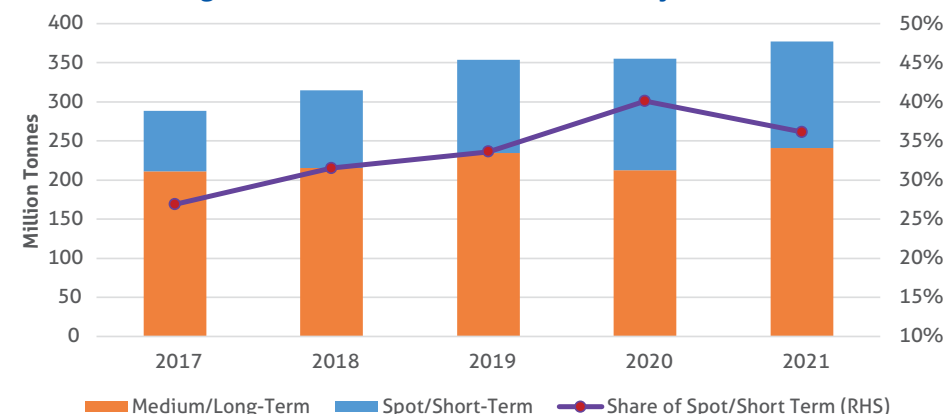


Source: GECF Secretariat based on data from ICIS LNG Edge

### 5.2.2 Trend in Global LNG Trade by Duration

In 2021, global spot and short-term LNG trade, which refers to LNG traded under contracts of 4 years or less, fell by 4.3% (6.1 Mt) y-o-y to 136.3 Mt. The weaker spot and short-term LNG trade led to a decline in its share in global LNG trade from a high of 40% in 2020 to 36% last year (Figure 101).

**Figure 101: Trend in Global LNG Trade by Duration**



Source: GECF Secretariat based on data from GIIGNL and ICIS LNG Edge

The decline in spot and short-term LNG trade was due to the record high spot gas prices, which curbed buyers' appetite for spot LNG cargoes, particularly in Asia. The situation in the spot LNG market changed significantly in 2021 from 2020. In 2020, the record

low spot LNG prices resulted in buyers requesting a reduction in long-term contractual volumes in line with the downward quantity tolerance (DQT) in contracts, to purchase cheaper spot LNG cargoes. However, in 2021 when spot LNG prices skyrocketed, buyers requested an increase in long-term contractual volumes in line with the upward quantity tolerance (UQT) in contracts, to purchase cheaper long-term contractual LNG cargoes. This contributed to the decline in spot and short-term LNG trade last year.

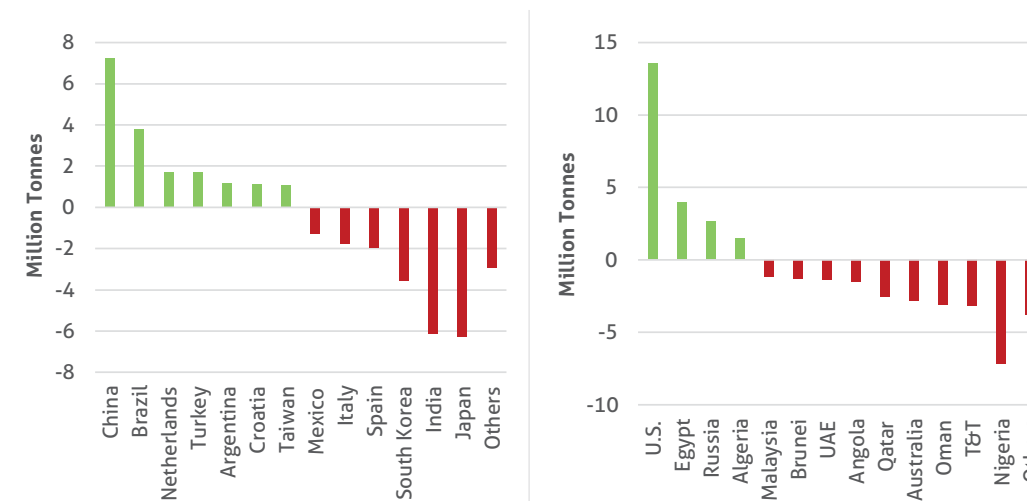
On the import side, Asia led the decline in spot and short-term LNG imports (Figure 102), which fell by 8.5% (8.6 Mt) y-o-y. MENA region's spot and short-term LNG imports also dropped significantly by 37.9% (1.1 Mt) y-o-y, while Europe's spot and short-term LNG imports were down slightly by 1.6% (0.5 Mt) y-o-y. In contrast, spot and short-term trade in LAC surged by 63.1% (4.7 Mt) y-o-y. At a country level, China and Brazil recorded the largest increase in spot and short-term LNG imports, while Japan, India and South Korea's spot and short-term LNG imports were down substantially.

The increase in China was due to the higher dependence on spot and short-term imports to meet the strong expansion in domestic gas consumption. In Brazil, spot and short-term LNG imports account for the bulk of LNG imports due to the lack of long-term sales and purchase agreements (SPAs) since gas demand varies significantly depending on the weather conditions. As the country faced one of the worst droughts on record in 2021, the reliance on gas consumption to compensate for lower hydro output boosted spot and short-term LNG imports last year.

Meanwhile, in Japan and South Korea, the stronger contractual LNG exports from the U.S. to both countries reduced their reliance on spot and short-term LNG imports in 2021. Furthermore, the decline in spot and short-term LNG imports in India, was attributed to the record high spot LNG prices. India is a price-sensitive market and if prices are too high it switches to cheaper, more polluting alternative energy sources.

On the export side, Nigeria, Trinidad and Tobago, Oman, Australia and Qatar drove the decline in spot and short-term LNG exports in 2021 (Figure 102). In contrast, the U.S., Egypt, Russia and Algeria recorded significant increases in spot and short-term LNG exports. The lower spot and short-term LNG trade in Nigeria and Trinidad and Tobago was mainly due to lower LNG exports in both countries last year. In Qatar, the start of new LNG contracts boosted its medium and long-term contractual LNG exports and hence reduced spot and short-term LNG exports. Meanwhile, the continuous growth in destination-flexible LNG exports from the U.S. contributed to the rise in spot and short-term LNG exports. Finally, the restart of the Damietta LNG facility in Egypt supported the spot and short-term LNG exports from the country.

**Figure 102: Variation in Spot & Short-Term LNG Imports and Exports by Country in 2021**



Source: GECF Secretariat based on data from GIIGNL

### 5.2.3 New LNG Importing Capacity

In 2021, around 44 Mtpa of new regasification capacity started LNG imports (Figure 103), representing a significant increase from 28 Mtpa in 2020. The Middle East accounted for more than 50% of the additional regasification capacity last year with the start-up of the Al Zour LNG facility (22 Mtpa) in Kuwait. Asia contributed an additional 12 Mtpa, driven mainly by China, which accounted for 80% of the region's new regasification capacity. Meanwhile, LAC and Europe contributed to a lesser extent with 7 Mtpa and 3 Mtpa respectively. In LAC, the new capacity came mainly from Brazil, while the start-up of Krk LNG terminal in Croatia was the only new regasification project in Europe, which started operations in 2021.

In 2022, around 72 Mtpa of new regasification capacity is forecasted to start operations. This represents a significant increase in the start-up of new LNG regasification capacity compared to 2021. The new capacity is driven mainly by Asia, which accounts for around 71% (51 Mtpa) of the global capacity addition. China leads the growth in new regasification capacity in the region with 27 Mtpa, followed by India (11 Mtpa), Thailand (7.5 Mtpa) and Vietnam (4 Mtpa).

Europe trails behind Asia with an additional 19 Mtpa of regasification capacity forecasted to start operations this year. The REPowerEU policy to increase LNG imports while reducing the bloc's reliance on Russian pipeline gas has supported the development of several new projects in the region. Germany drives the increase in new regasification capacity in Europe this year with 7 Mtpa, followed by the

Netherlands (6 Mtpa), Estonia/Finland (3.7 Mtpa) and Cyprus (1.4 Mtpa). The start-up of new projects in Cyprus, Estonia and Germany will support both countries in joining the club of LNG importers.

In LAC, only one project in El Salvador (2.25 Mtpa) is expected to be commissioned in 2022. Finally, in Africa, one new regasification project is expected to start-up Senegal (0.2 Mtpa) this year. In H1 2022, four new regasification projects with a combined capacity of 12 Mtpa have started operations in China, El Salvador, Japan and Thailand.

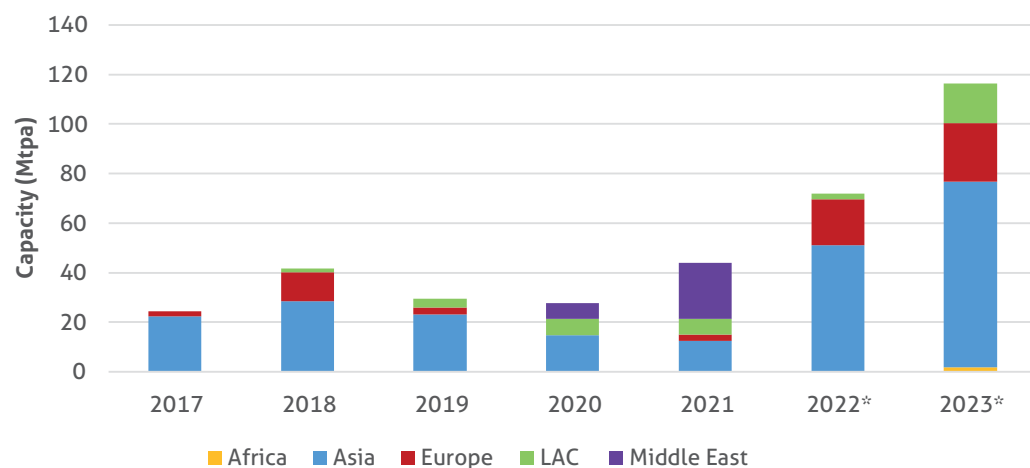
Further ahead, almost 120 Mtpa of new regasification capacity is forecasted to begin operations in 2023. Asia continues to drive the increase in new regasification capacity with 75 Mtpa driven by China (51 Mtpa) and to a lesser extent from Philippines (12 Mtpa), India (9 Mtpa).

Meanwhile, Europe is forecasted to add around 23 Mtpa of new regasification capacity, mainly from Germany (15 Mtpa), Italy (3.7 Mtpa), France (3.3 Mtpa) and Poland (1.9 Mtpa). Furthermore, 17 Mtpa of new regasification capacity in Brazil (16 Mtpa), Nicaragua (0.4 Mtpa) and Ecuador (0.2 Mtpa) contributes to the new capacity addition in LAC.

### 5.2.4 LNG Exports

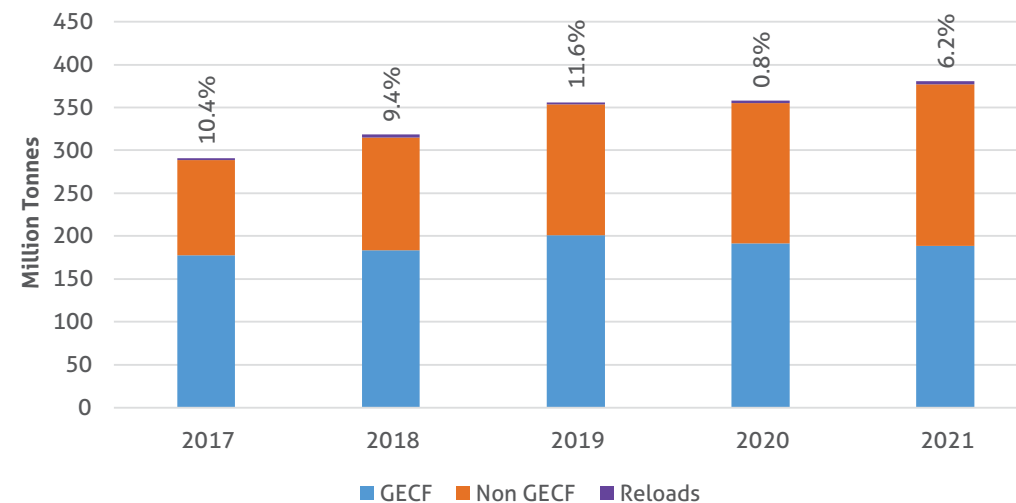
In this report, LNG exports refer to LNG volumes delivered to importing countries, excluding deliveries via ISO containers, and do not reflect the LNG volumes loaded by the exporting countries. In 2021, global LNG exports rose by 6.2% (22.2 Mt) y-o-y to 380.5 Mt (Figure 104). The stronger global LNG exports was driven by a jump in LNG exports from Non-GECF countries and higher reloading activities, which offset a decline in exports from GECF Member Countries. The growth in LNG exports in 2021 was up significantly from 0.8% (2.8 Mt) y-o-y recorded in 2020, when the LNG market was impacted by the COVID-19 pandemic. Despite the acceleration in the pace of growth last year, it is still significantly lower than annual growth during the period 2017-2019, due to a decline in the commissioning of new LNG export projects.

**Figure 103: Trend in the Start-up of New Regasification Capacity by Region**



Source: GECF Secretariat based on data from GIIGNL, ICIS LNG Edge, IGU LNG Report 2022, Refinitiv and Project Updates

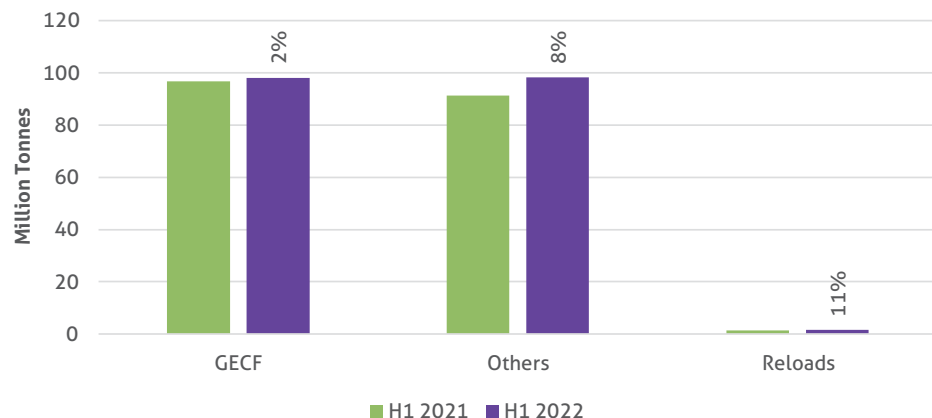
**Figure 104: Trend in Global LNG Exports by Supplier**



Source: GECF Secretariat based on data from ICIS LNG Edge

In H1 2022, global LNG exports increased by 4.5% (5.5 Mt) y-o-y to 198.0 Mt. The stronger LNG exports were led by Non-GECF countries while GECF Member Countries and higher reloading activity contributed to a lesser extent (Figure 105). The increase in LNG exports was due to a combination of factors including but not limited to the start-up and ramp-up of new LNG facilities, lower unplanned maintenance activity and higher feedgas availability in some countries.

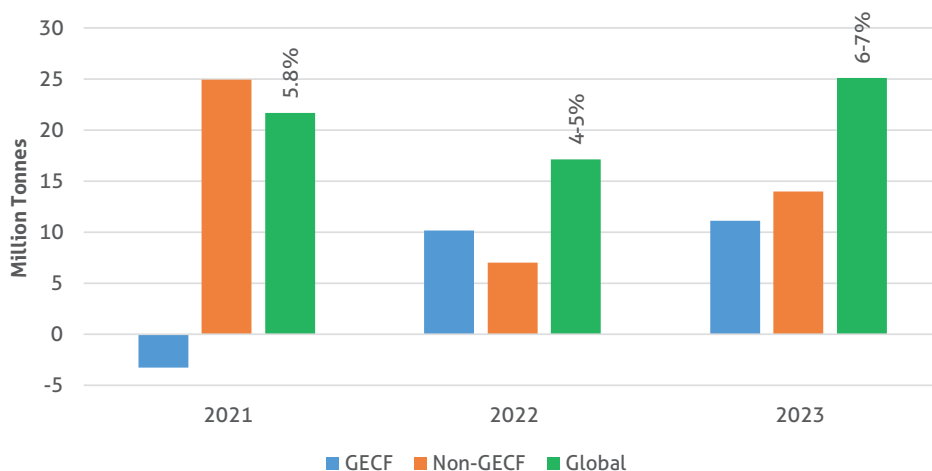
**Figure 105: Global LNG Exports by Supplier (H1 2021 and H1 2022)**



Source: GECF Secretariat based on data from ICIS LNG Edge

For the full year 2022, we forecast an increase in global LNG exports (excluding LNG reloads) of 4-5% (15-19 Mt) y-o-y to around 394 Mt. This represents a slowdown in the pace of growth from 2021. GECF Member Countries are expected to account for the bulk incremental increase in global LNG exports, while non-GECF countries contribute to a lesser extent (Figure 106). Further ahead into 2023, global LNG exports (excluding LNG reloads) are forecasted to expand at a strong pace of 6-7% (23-27 Mt) y-o-y to around 419 Mt. Non-GECF countries are forecasted to drive the increase in the expansion in LNG exports in 2023 while GECF member countries contribute to a lesser extent.

**Figure 106: Short-Term Outlook for Incremental LNG Exports by Supplier**



Source: GECF Secretariat based on data from ICIS LNG Edge, Refinitiv and Project Updates  
 (\*): GECF Secretariat's Forecast for 2022 and 2023

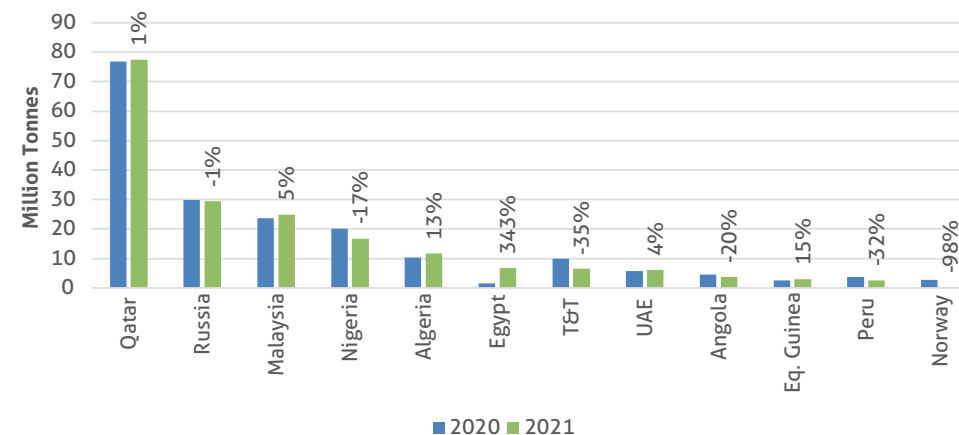
**5.2.4.1 GECF Member Countries**

In 2021, GECF's LNG exports fell by 1.7% (3.2 Mt) y-o-y to 188.6 Mt. This represents the second consecutive annual decline in GECF's LNG exports, which was driven by a combination of unplanned maintenance activity and feedgas issues in some countries. The weaker GECF LNG exports were driven mainly by Trinidad and Tobago, Nigeria, Norway and Peru (Figure 107). In contrast, Egypt recorded a surge in its LNG exports, while LNG exports in Algeria and Malaysia increased significantly.

Feedgas issues in Trinidad and Tobago and Nigeria led to the decline in LNG exports from both countries last year. In Norway, ongoing maintenance at the Hammerfest LNG facility for the whole of 2021 reduced LNG exports in the country. The LNG facility was offline since October 2020 and resumed production in June 2022. Meanwhile, several unplanned outages at the LNG facility in Peru curbed LNG exports from the country.

On the other hand, the restart of the Damietta LNG facility in Egypt in February 2021 boosted LNG exports last year. Despite an unplanned maintenance at the Skikda LNG facility in Algeria, stronger domestic gas production supported the increase in LNG exports last year. The recovery in global spot LNG prices and the start-up of the PFLNG Dua facility drove Malaysia's LNG exports higher in 2021.

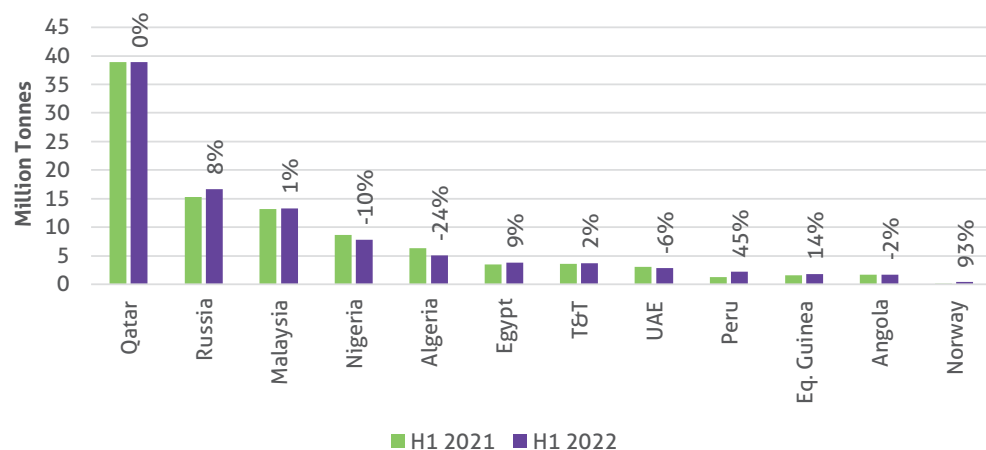
**Figure 107: GECF's LNG Export by Country (2020 & 2021)**



Source: GECF Secretariat based on data from ICIS LNG Edge

In H1 2022, GECF's LNG exports rebounded by 1.4% (1.4 Mt) y-o-y to 98.1 Mt from a decline in 2021. This was driven mainly by stronger exports from Russia, Peru, Egypt, Norway and Equatorial Guinea, which offset significant declines in Algeria and Nigeria (Figure 108).

**Figure 108: GECF's LNG Exports by Country (H1 2021 and H1 2022)**



Source: GECF Secretariat based on data from ICIS LNG Edge

The stronger LNG exports in Russia was driven by the ramp-up in production from Yamal LNG train 4 and lower maintenance activity at the Sakhalin 2 and Yamal LNG facilities. In Peru, lower unplanned maintenance activity compared to H1 2021, when the Peru LNG facility was impacted by an unplanned outage, supported the higher exports from the country. Egypt's LNG exports were boosted higher feedgas availability for LNG exports, particularly from the Damietta LNG facility. Meanwhile, the restart of the Hammerfest LNG facility in June 2022 led to the increase in Norway's LNG exports. In Qatar, higher LNG exports were attributed to lower maintenance activity compared to a year earlier. In Equatorial Guinea, the stronger LNG exports was supported by higher feedgas availability following the start-up of production from the Alen gas field.

On the other hand, an unplanned outage at the Arzew LNG facility in H1 2022 drove Algeria's LNG exports down. Finally, in Nigeria, lower feedgas availability due to vandalism of gas pipelines led to a drop in LNG exports from the country.

In 2022 and 2023, GECF's LNG exports are forecasted to rise by 5-6% (9-11 Mt) y-o-y and 5-6% (10-12 Mt) y-o-y to 199 Mt and 210 Mt, respectively (Figure 106). The assumptions for the forecasted LNG exports from GECF Member Countries are stated below:

**Assumptions for 2022**

- Restart of the Hammerfest LNG facility in Norway: 3-3.5 Mt
- Higher gas availability for LNG exports in Egypt, Equatorial Guinea and Trinidad and Tobago: 2.5-3 Mt
- Lower unplanned maintenance activity in Peru: 1-1.5 Mt
- Higher capacity utilisation at Qatar LNG facilities: 1.5-2 Mt

- Lower gas availability for LNG exports in Nigeria: 1-1.5 Mt
- Unplanned outage at the Arzew LNG facility in Algeria: 0.5-1 Mt
- Start-up and ramp-up of new projects in Malaysia, Mozambique and Russia: 1-1.5 Mt
- Lower planned maintenance activity: 1.5-2 Mt

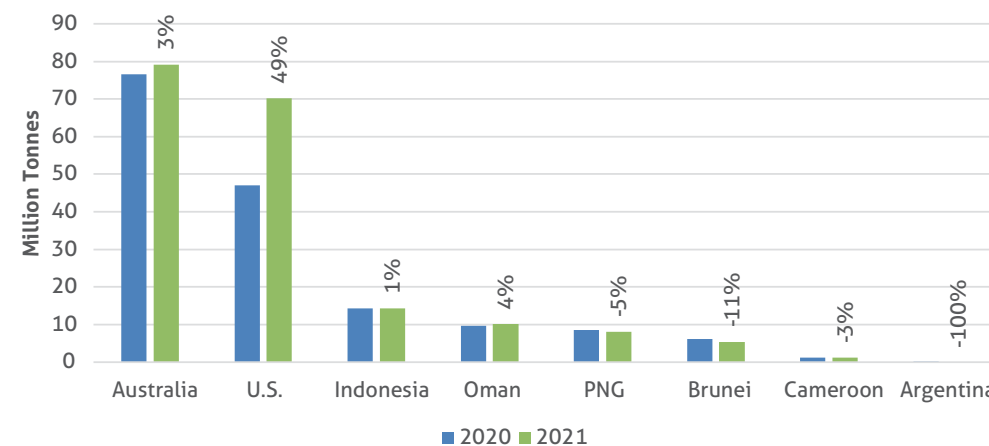
**Assumptions for 2023**

- Ramp-up in production from the Hammerfest LNG facility: 1-1.5 Mt
- Higher gas availability for LNG exports in Egypt, Nigeria and Trinidad and Tobago: 5-5.5 Mt
- Return to full production at the Arzew LNG facility: 0.5-1 Mt
- Start-up and ramp-up of new projects in Mozambique and Russia: 3.5-4 Mt

**5.2.4.2 Non-GECF Countries**

In 2021, non-GECF's LNG exports jumped by 15.3% (25.0 Mt) y-o-y to a record level of 188.6 Mt. The increase in LNG exports were driven mainly by the rebound in spot LNG prices to a record high and the start-up, ramp-up of new LNG export projects and lower maintenance activity. The U.S. accounted for more than 90% of the incremental LNG exports from non-GECF countries (Figure 109), while Australia's LNG exports were also up significantly.

**Figure 109: Non-GECF's LNG Export by Country (2020 & 2021)**



Source: GECF Secretariat based on data from ICIS LNG Edge

The surge in U.S. LNG exports was attributed to the recovery in lost LNG supply during Q2 and Q3 2020, when several U.S. LNG off-takers cancelled many LNG cargoes due to the record low spot prices, and the start-up and ramp-up of new LNG export projects. The ramp-up in LNG exports from the Cameron, Corpus Christi, Elba Island and Freeport LNG facilities boosted the LNG exports from the U.S. last year. In Australia, a drop in unplanned outages at the Gorgon LNG facility, a decline in planned maintenance

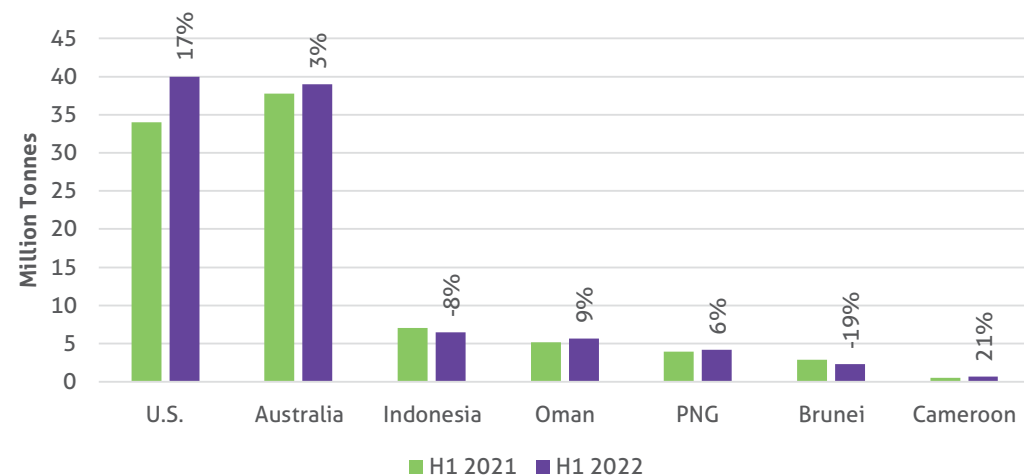


activity at the APLNG and Darwin LNG facilities and the restart in production at the Prelude LNG facility supported the uptick in LNG exports from the country. The higher LNG exports from these facilities offset weaker exports from the North West Shelf LNG facility, which was impacted by lower feedgas availability, and Wheatstone LNG facility, due to higher maintenance activity.

In contrast, the fall in Brunei's LNG exports was attributed to lower feedgas availability for LNG exports. Meanwhile, Argentina returned its Tango FLNG facility in October 2020, due to weaker domestic gas production and low spot prices in 2020, which ceased LNG exports in the country.

In H1 2022, non-GECCF's LNG exports jumped by 7.6% (6.9 Mt) y-o-y to 98.3 Mt. The U.S. accounted for the bulk incremental LNG exports in non-GECCF countries followed by Australia and Oman (Figure 110). On the other hand, LNG exports fell significantly in Brunei and Indonesia.

**Figure 110: Non-GECCF's LNG Exports by Country (H1 2021 and H1 2022)**



Source: GECCF Secretariat based on data from ICIS LNG Edge

In the U.S., the ramp-up and start-up of the Calcasieu Pass LNG and Sabine Pass LNG train 6 boosted the country's LNG exports. Meanwhile, lower maintenance activity at some LNG facilities in Australia during H1 2022, particularly the Gorgon LNG facility, drove the rise in LNG exports from the country. In Oman, the debottlenecking of the Qalhat LNG facility led to the increase in LNG exports.

In contrast, the decline in LNG exports in Brunei and Indonesia were attributed to lower feedgas availability for LNG exports. Maturing gas fields in Brunei reduced feedgas availability for LNG exports in the country. Meanwhile, the shut-in in gas production,

from a major gas field in Indonesia, during H1 2022 affected the feedgas availability for LNG exports in the country.

In 2022 and 2023, non-GECCF's LNG exports are forecasted to grow by 3-4% (6-8 Mt) y-o-y and 6.5-7.5% (13-15 Mt) y-o-y to 195 Mt and 209 Mt respectively (Figure 106). The assumptions for the forecasted LNG exports from non-GECCF countries are stated below:

#### Assumptions for 2022

- Unplanned outage at the Prelude LNG facility in Australia: 1-1.5 Mt
- Lower gas availability for LNG exports in Brunei and Indonesia: 1-1.5 Mt
- Unplanned outage at the Freeport LNG facility: 6-6.5 Mt
- Debottlenecking at the Qalhat LNG facility in Oman: 1-1.5 Mt
- Start-up and ramp up of new projects in Congo and the U.S.: 11-13 Mt
- Lower planned maintenance activity: 2-3 Mt

#### Assumptions for 2023

- Return to full production at the Freeport LNG facility: 5-6 Mt
- Higher LNG exports from Prelude LNG facility in Australia: 1-2 Mt
- Lower gas availability for LNG exports in Brunei and Indonesia: 0-1 Mt
- Start-up and ramp up of new projects in Congo, Indonesia, Mauritania/Senegal and the U.S.: 7-8 Mt

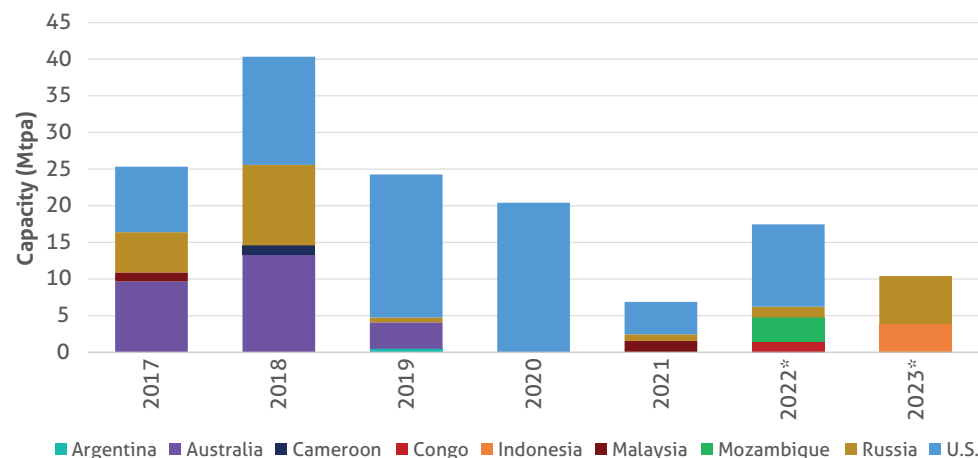
### 5.2.5 New LNG exporting capacity

#### 5.2.5.1 Start-up of new liquefaction capacity

In 2021, around 7 Mtpa of new LNG export capacity started exports mainly from the U.S. This represents a significant decline in the start-up of new LNG capacity compared to the 20 Mtpa of new capacity, which commenced operations in 2020. Three LNG projects started exports last year, including the PFLNG Dua (1.5 Mtpa) in Malaysia, Yamal LNG train 4 (0.9 Mtpa) in Russia and Sabine Pass train 6 (4.5 Mtpa) in the U.S. At the end of 2021, the global LNG export capacity was around 470 Mtpa. Considering global LNG exports of 377 Mt in 2021, excluding reloads, the capacity utilisation of LNG export facilities was around 80%. This represents an increase in capacity utilisation from around 77% in 2020.

In 2022, the capacity addition from new LNG export projects is expected to rebound with an additional 18 Mtpa of new liquefaction capacity (Figure 111). This includes the Fast FLNG (1.4 Mtpa) in Congo, Coral South FLNG (3.3 Mtpa) in Mozambique, Portovaya LNG (1.5 Mtpa) in Russia and the Calcasieu Pass LNG (11.27 Mtpa) in the U.S. Several LNG trains from the Calcasieu LNG facility have already started operations in H1 2022 and the remaining trains will begin operation in the coming months. The start-up of these new facilities will boost global liquefaction capacity by 3.7% to 488 Mtpa.

**Figure 111: Trend in Start-Up of New Liquefaction Capacity by Country**



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, Refinitiv and Project Updates  
 (\*): Forecast for the start-up of new liquefaction capacity

Further ahead in 2023, 13 Mtpa of new liquefaction capacity is forecasted to become operational, including Tangguh LNG train 3 (3.8 Mtpa) in Indonesia, Tortue FLNG (2.5 Mtpa) in Mauritania/Senegal and Arctic LNG train 1 (6.6 Mtpa) in Russia. This represents a decline in capacity addition compared to 2022. At the end of 2023, the global liquefaction capacity is expected to surpass 500 Mtpa. The average annual capacity addition between 2021 and 2023 is 12 Mtpa, which is significantly lower than the average of 30 Mtpa between 2016 and 2020. This slowdown in capacity addition in the short-term is contributing to the significant tightness in the LNG market as LNG demand continues to increase at a healthy pace.

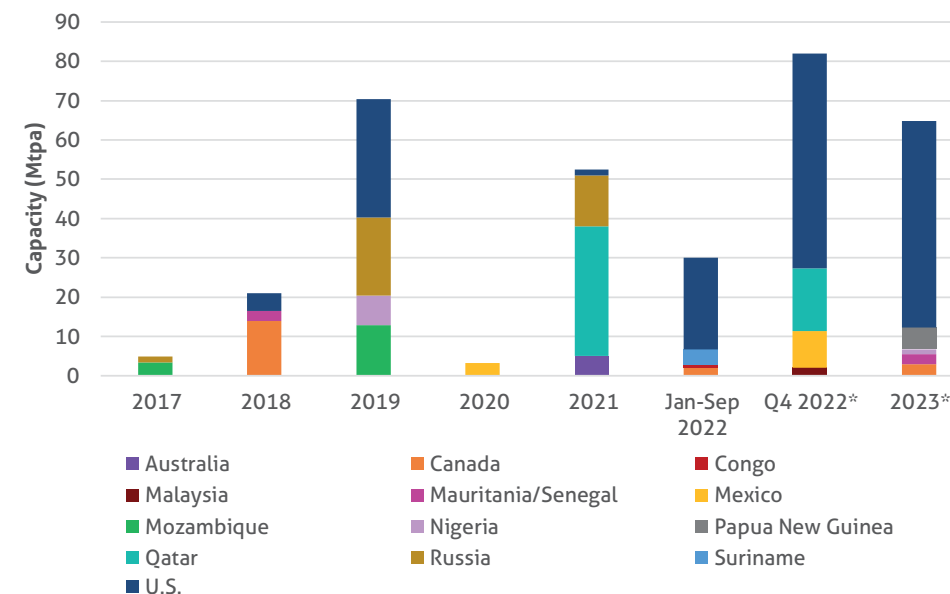
**5.2.5.2 FIDs on new LNG export projects**

In 2021, financial investment decisions (FIDs) on new LNG export projects rebounded from a record low of 3 Mtpa in 2020 to around 52 Mtpa in 2021 (Figure 112). This was driven by the recovery in global gas and LNG prices to record highs. In addition, the recovery in oil prices also supported the FIDs on new LNG export projects. Oil-indexed and HH-indexed LNG prices in Asia and Europe were significantly lower than spot gas and LNG prices in both regions, which contributed to the signing of several long-term LNG contracts and hence the financial close on new projects.

At a country level, Qatar accounted for more than 60% of the liquefaction capacity that reached FID last year, with the first phase of its LNG expansion (32 Mtpa). Meanwhile, Russia’s Baltic LNG (13 Mtpa) was the second largest project to reach FID last year, followed by Pluto LNG train 2 (5 Mtpa) in Australia and the Fast FLNG (1.4 Mtpa) in Congo. Between January and September 2022, around 30 Mtpa of new liquefaction

capacity has reached FID, including the first phase of Plaquemines LNG (13.33 Mtpa) and Corpus Christi Stage 3 (10 Mtpa) in the U.S. as well as Firebird LNG in Suriname (4 Mtpa) and Woodfibre LNG (2.1 Mtpa) in Canada.

**Figure 112: Trend in FIDs on New Liquefaction Capacity by Country**



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, Refinitiv and Project Updates  
 Note: (\*) Projects targeting FID in between Q4 2022 and in 2023

In Q4 2022, around 82 Mtpa of new liquefaction capacity are targeting FID, mainly from the U.S., where five projects are hoping to reach FID, as well as projects in Malaysia, Mexico and Qatar. In 2023, a further 74 Mtpa of new liquefaction capacity is also targeting FID. The U.S. accounts for the majority of this capacity followed by the United Arab Emirates, Papua New Guinea Canada, Mauritania/Senegal and Nigeria. The sustained period of high spot gas and LNG prices in Asia and Europe this year and energy security concerns are expected to drive LNG contracting activity, which will support the development of new LNG export projects in the short-term.

**Table 5: LNG Liquefaction projects Targeting FID In the Short-Term**

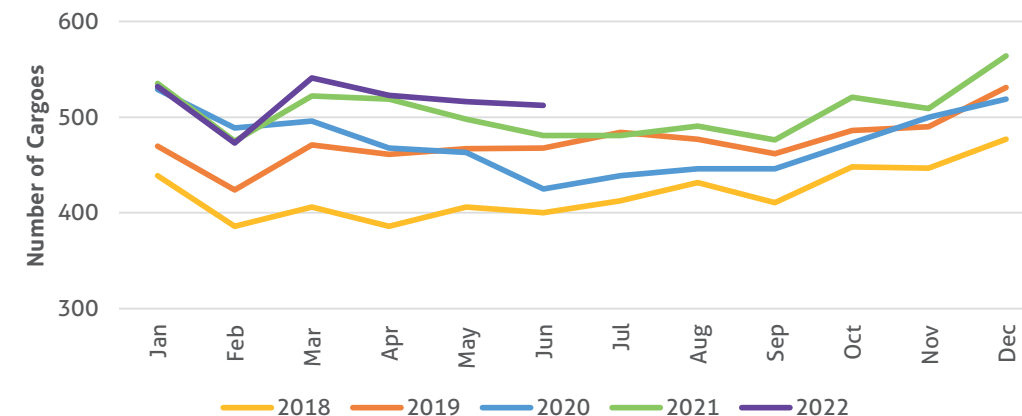
PROJECT	COUNTRY	OPERATOR	CAPACITY (MTPA)	TARGETED FID
Delfin LNG (1st FLNG)	United States	Delfin LNG	3.25	2022
Driftwood	United States	Tellurian	16.6	2022
Lake Charles	United States	Energy Transfer	16.5	2022
Mexico Pacific Ltd.	Mexico	Mexico Pacific Ltd.	9.4	2022
PFLNG 3	Malaysia	Petronas	2	2022
Qatar Phase 2 Expansion	Qatar	Qatar Petroleum	16	2022
Rio Grande LNG Phase 1	United States	Next Decade	16.2	2022
Texas LNG (Phase 1)	United States	Glenfarne	2	2022
Cameron LNG Phase 2	United States	Sempra Energy	6.75	2023
Cedar LNG	Canada	Cedar LNG	3	2023
Commonwealth LNG	United States	Commonwealth LNG	8.4	2023
CP2 LNG	United States	Venture Global	10	2023
Freeport Train 4	United States	Freeport LNG	5	2023
Fujairah LNG	United Arab Emirates	ADNOC	9.6	2023
Magnolia LNG	United States	Glenfarne	8.8	2023
Nigeria FLNG	Nigeria	UTM	1.2	2023
Papua LNG	Papua New Guinea	TotalEnergies	5.6	2023
Port Arthur	United States	Sempra Energy	13.5	2023
Tortue Phase 2	Mauritania/Senegal	BP	2.5	2023

Source: GECF Secretariat based on Project Updates

### 5.2.6 LNG shipping cost

In 2021, the volume of LNG traded globally increased by 6.2% annually to reach 518 bcm, as demand rebounded following the negative effect of the pandemic in the previous year. In terms of number of shipments, this equated to a 7% increase year-on-year from 2020 to 2021, to reach a total of 6,079 cargoes (Figure 113). This figure demonstrates a continuation of the trend of ever increasing demand for LNG cargoes.

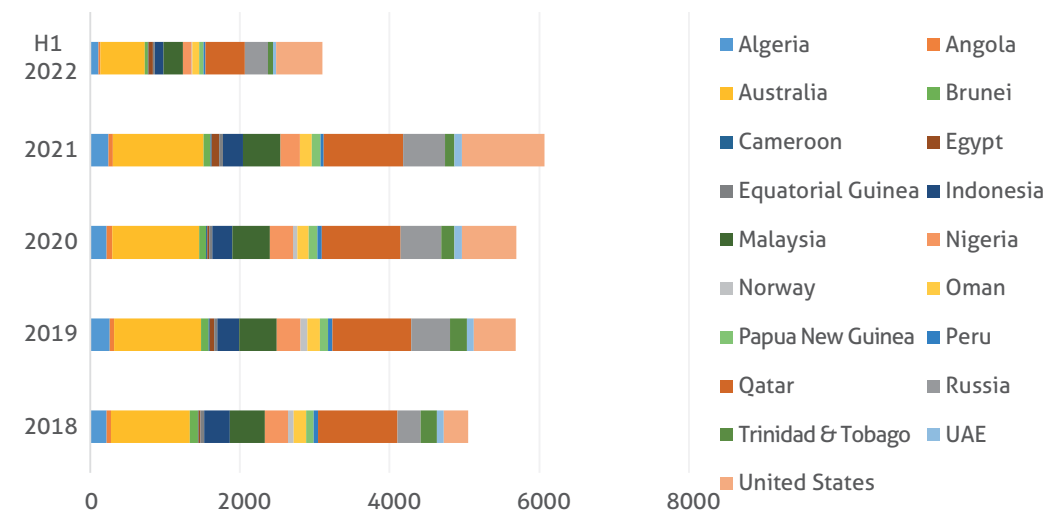
**Figure 113: Trend in Monthly LNG Cargoes Traded**



Source: GECF Secretariat based on data from ICIS LNG Edge

With respect to the breakdown of shipments by exporting countries, the United States had the largest increase from 2020 to 2021 (Figure 114), as the country seeks to consolidate its place as a major global player. Increases were also observed for Egypt, as the country returned to net LNG exports, while Norway recorded a decline as a result of the temporary shutdown of the Hammerfest LNG export terminal.

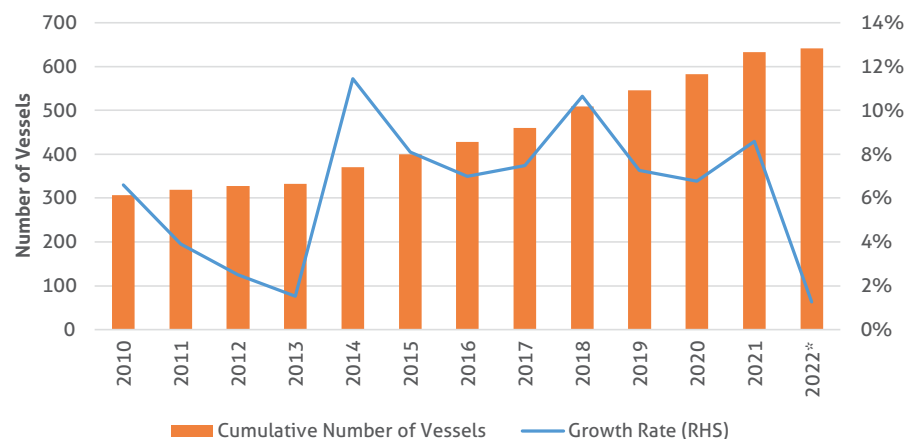
**Figure 114: Annual Number of LNG Cargoes by Exporting Country**



Source: GECF Secretariat based on data from ICIS LNG Edge

By the end of 2020, there were over 580 LNG carriers in charter worldwide (Figure 115), which at the time characterised an oversupply in the market. During 2021, however, this excess eroded, as a result of increased demand, even with the 50 new vessels which were commissioned over the course of the year.

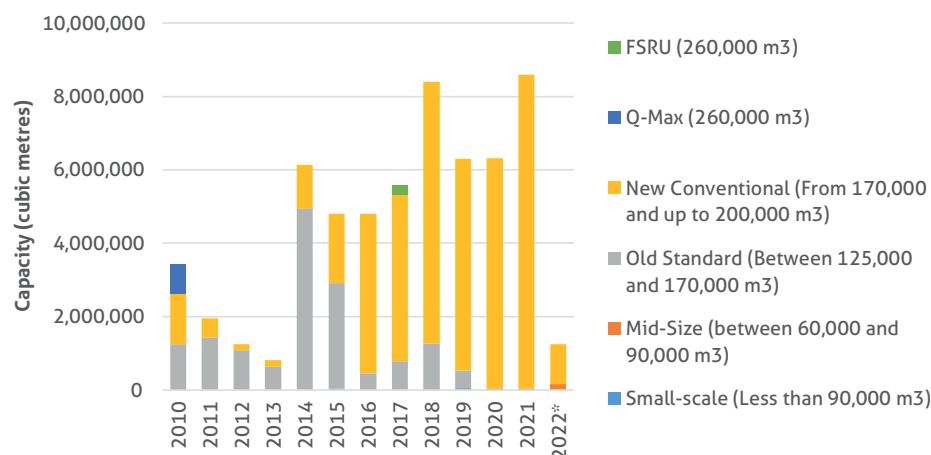
**Figure 115: Trend in Global LNG Carrier Fleet**



Source: GECF Secretariat based on data from ICIS LNG Edge

These additional carriers brought 9% more capacity onto the market in 2021 (Figure 116). This represented a continuation of the average annual percentage capacity increase in the shipping industry that has been observed over the past five years. All of these new vessels belong to the same capacity range, which constitute the contemporary conventional size of LNG carriers, with the ability to transport from 170,000 to 200,000 cubic metres.

**Figure 116: Annual Additions to the Global LNG Fleet by Capacity**



Source: GECF Secretariat based on data from ICIS LNG Edge

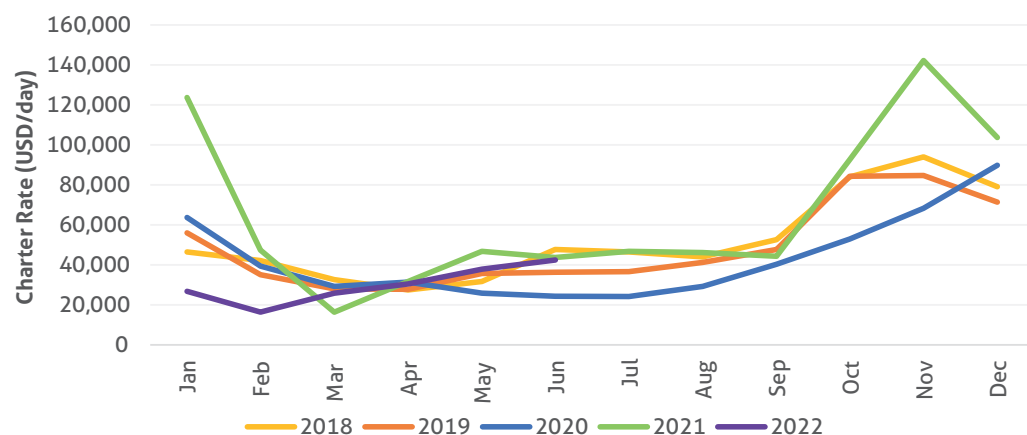
The following chart shows monthly average spot charter rate for steam turbine LNG carriers. Notwithstanding the expected seasonal trend, the industry in 2021 was characterised by extreme volatility, recording the highest and lowest monthly charter rate observed since the start of 2018. The year 2021 commenced at the high charter rate trend carried over from the ending of 2020, but this quickly plunged to just \$16,000 per day by March.

Inter-basin demand for carrier capacity is a major influencing factor on spot charter rates. This is because vessels making these long voyages essentially create short-term tightness as this capacity is effectively taken off the market. Therefore, the low spot rates observed in March was as a result of a combination of lessened demand for intra-basin charter, new builds entering into rotation, and carrier capacity being freed up due to interruptions in loading at export facilities in the United States. As activity picked up by April, charterers began pulling their capacity from the spot market and back to their primary routes, which drove rates back upwards. Further capacity tightness and, consequently, higher charter rates emerged with the blockage of the Suez Canal, which redirected carriers along the much longer route around the African continent.

There was a steady increase from that point until October, when charter rates rose as expected, with the seasonal trend of spare vessels being reallocated to primary routes for the upcoming winter. However, rates then spiked to over USD\$100,000 per day in November and towards the remainder of the year (Figure 117). This came about as a result of unexpected lower capacity availability as charterers had placed vessels in the Atlantic basin in anticipation of high spot rates towards the end of summer, thus triggering tightness in supply. Charter rates fell thereafter as activity slowed.

This unstable nature continued afterwards, with charter rates during the first six months of 2022 averaging a relatively low \$30,000 per day. This is as a result of the erosion of the inter-basin arbitrage providing little incentive to sellers in the Atlantic basin to send cargoes to the Far East.

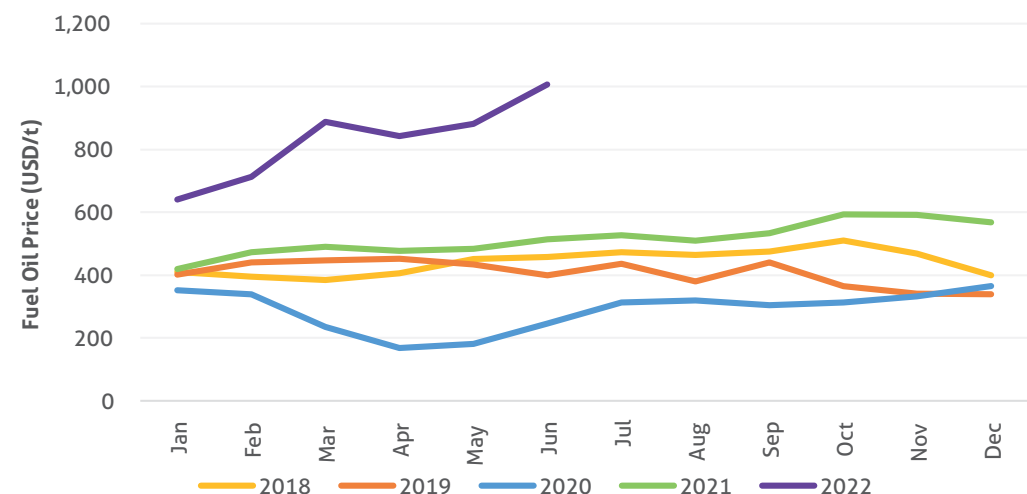
**Figure 117: Monthly Average Spot Charter Rate for Steam Turbine LNG Carriers**



Source: GECF Secretariat based on data from Argus

The monthly average of leading shipping fuel oil prices in 2021 rebounded past pre-pandemic levels (Figure 118), and were the highest observed over the past five years. At \$514/MT, the annual average fuel price in 2021, was 27% higher than in 2019, and expectedly 78% higher than during the pandemic in 2020.

**Figure 118: Monthly Average Price of Leading Shipping Fuels**

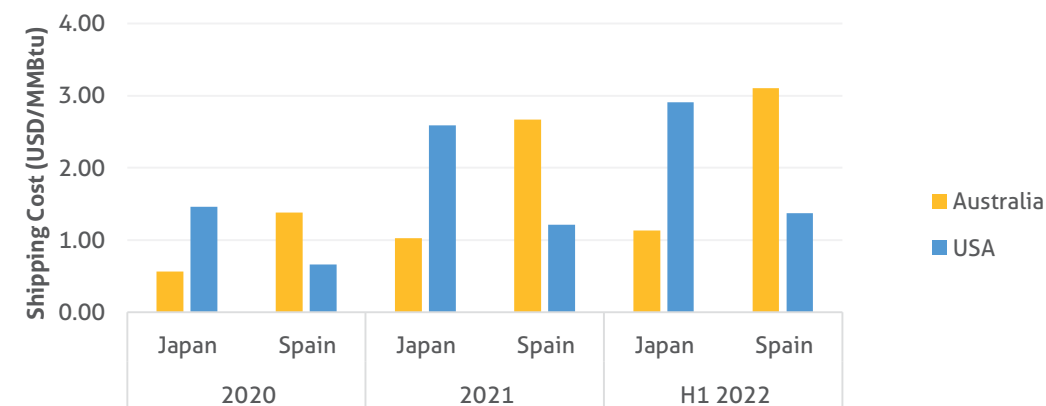


Source: GECF Secretariat based on data from Argus

Robust price growth in the oil market continued to drive prices in shipping fuels in 2022, to record highs. Over the first six months, the average of shipping fuels prices was \$830/MT, which is 74% higher than over the corresponding period in 2021.

The combination of these factors has resulted in average shipping costs increasing year-on-year since 2020 (Figure 119). Looking at LNG transport between major suppliers and consuming regions in the Atlantic and Pacific basins, spot shipping costs almost doubled from 2020 to 2021. Steady hub prices and rising shipping fuel prices have led to a slight rise in average shipping cost over the first six months of 2022.

**Figure 119: Spot LNG Shipping Costs between Selected Major Supplier and Consumer Countries**

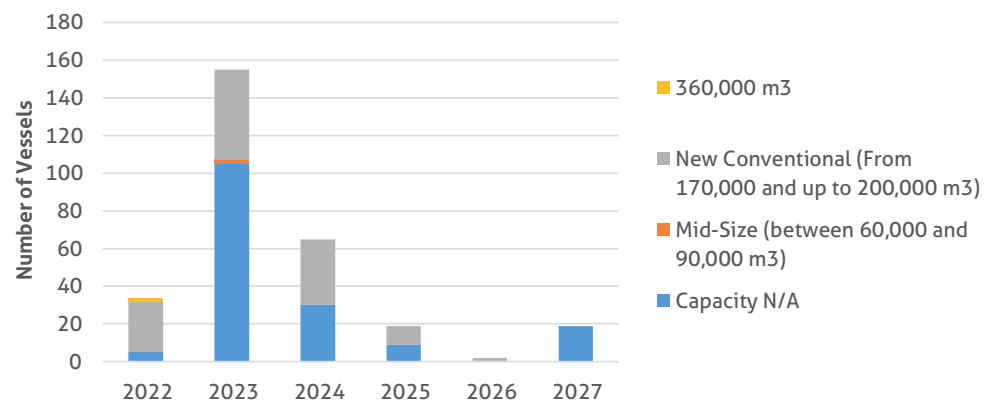


Source: GECF Secretariat based on data from Argus and ICIS LNG Edge

During the period of January to June 2022, there has been a slight increase in the number of LNG shipments, with a 2% rise in total shipments during the same period in 2021. On a capacity basis however, the increase was 4% year-on-year during the first six months of 2022. Much of this growth is attributable to the United States seeking to satisfy gas demand in Europe since Q1 2022, and is thus expected to continue rising in the short term.

Charter rates in 2022 have fallen to the lowest average level observed during the same period since 2018. However, prices have been steadily increasing since February, back towards the average range for this time of year. With the increasing demand for cargoes in Europe, it is expected that more Atlantic basis suppliers will utilise vessels for this shorter route, preventing extreme market tightness and keeping charter rates relatively within seasonal range.

For 2022, and in the following five years, there are close to 300 LNG carriers on the global order book (Figure 120). The majority of the new builds are expected to enter the market in 2023, which should alleviate capacity tightness and may have a downward impact on charter rates. During the first six months of 2022, over 100 new orders for LNG carriers were placed, with more than 50% being constructed in South Korean shipyards.

**Figure 120: Global Orderbook for LNG Carriers**

Source: GECF Secretariat based on data from ICIS LNG Edge

Of the carriers under construction for which there is details available, almost all are within the current conventional size range, within 170,000 and 200,000 cubic metres. Current prices for newbuilds of this capacity in shipyards such as Samsung Heavy Industries and Hyundai Samho, are around \$230 million each. Such an investment is characteristic of the increasing cost of LNG carriers in recent times, having grown by around ten percent since Q3 2021.

Qatar is entering into another wave of shipbuilding in anticipation of increased LNG output as part of the North Field expansion project, as well as exports from Golden Pass in the United States. Of the carriers under construction for which capacity is not yet available, 70% are known to be associated with this Qatari drive, having booked shipyard capacity with major ship building firms in South Korea and China. Around 120 of these new carriers will enter the market by 2027.

Furthermore, it is anticipated that the current demand for LNG in Europe will spur the addition of carrier capacity in the market. It is also expected that the older steam turbine powered vessels would be taken out of operation in the coming years, with an estimated 120 carriers aged over 25 years anticipated to be replaced by 2030. By January 2023, the Energy Efficiency Existing Ship Index (EEXI) regulation from the International Maritime Organisation will come into effect. Every vessel will have to obtain a one-off approval under the new guidelines, which are primarily aimed at reducing the greenhouse gas impact of ships. Due to the computation of the particular vessel's EEXI value being dependant on the capacity and propulsion system, this measure will place further pressure on the long-term usage of the remaining steam-powered vessels in the global LNG carrier fleet.



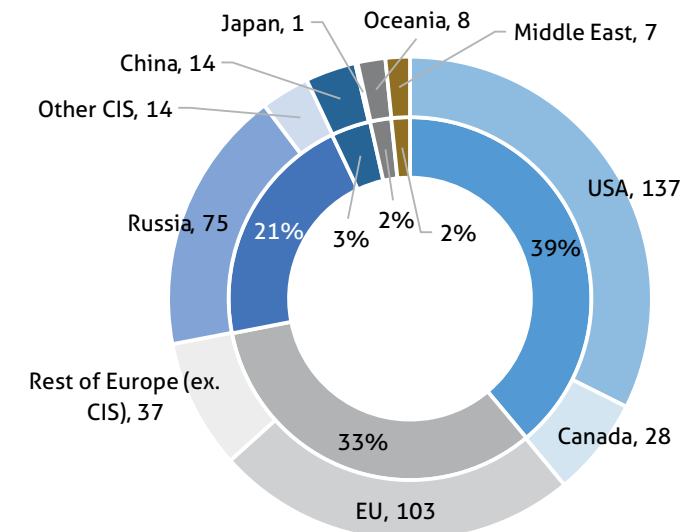
CHAPTER  
**06**

## Natural Gas Storage

### 6.1 Underground Natural Gas Storage

Working gas capacity at underground gas storage sites across the globe increased to 423 bcm. On a regional level, this can be disaggregated into North America, which holds the top spot, followed by Europe and CIS, accounting for 39%, 33% and 21% of worldwide capacity, respectively (Figure 121). On a political level, the major entities are the United States with 137 bcm of storage, followed by the European Union with 103 bcm, and the Russian Federation with 75 bcm.

**Figure 121: Underground Gas Storage Working Capacity by Region (Inner) and Country (Outer, bcm)**



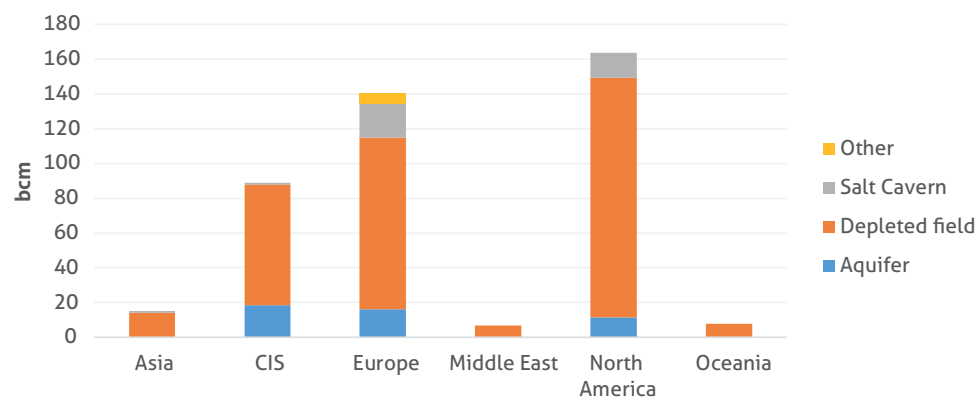
Source: GECF Secretariat based on data from Cedigaz

With respect to technical classification, underground storage sites for natural gas generally exist within the following categories: Depleted oil and/or gas fields, depleted aquifers, and salt caverns. Globally, the most widely-used method for underground gas storage has been to utilise depleted fields, with around 550 such sites worldwide, accounting for 79% of total capacity (Figure 122). Such facilities are popular because the required infrastructure is already in place (such as wells and pipelines), as well as already having the geological characteristics required for prolonged gas storage.

Depleted underground water reservoirs, or aquifers, account for the next most common gas storage method, reaching 11% of global capacity. Such formations can only be suitable for natural gas storage if the target rock layer is bounded by an impermeable cap rock seal, in the same manner as oil- or gas-bearing reservoirs.

These methods demonstrate familiarity with the conditions with which natural gas is found, specifically being stored between grains of a sufficiently permeable rock. Conversely, for salt cavern storage, water is used to dissolve and create a cavern of the required volume in a suitable underground salt formation. Around 36 bcm of such gas storage capacity exists in Europe and North America.

**Figure 122: Underground Gas Storage Working Capacity by Technical Classification**



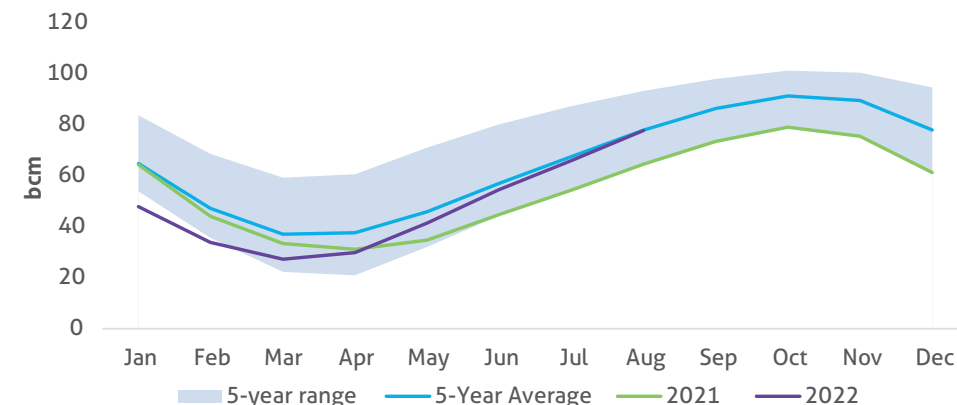
Source: GECF Secretariat based on data from Cedigaz

### 6.1.1 Europe

Underground gas storage levels in the European Union started the year at 64 bcm in 2021, the same as the 5-year average. However, during the gas injection season, the replenishment of stocks was hampered by high gas prices, as well as rebounding demand in the post-lockdown era. As a result, by May, gas storage in the bloc had fallen to the lowest monthly levels ever recorded during the 2017 to 2021 period. This development carried on for the rest of the year, which was reflected in the extremely low gas stocks on the continent during the winter of 2021/22. In fact, by the end of

2021, the delta between the 2021 storage level and the 5-year average had grown to 17 bcm (Figure 123).

**Figure 123: Underground Gas Storage in the European Union**



Source: GECF Secretariat based on data from AGSI+

These low levels of storage reserves created demand pressure over the winter, which drove up prices and forced the EU to reconsider its security of supply going forward. By 2022, market dynamics were further stressed, with extreme gas price volatility, coupled with reduction in pipeline gas imports from Russia testing the region’s market norms throughout the year.

In March 2022, the European Commission introduced a legislative proposal in response to the market forces at play in Q1 2022 in the European Union (inter alia, low underground gas storage levels, and the Russia/Ukraine conflict), and the subsequent impact on gas prices. The target of these new storage rules is to have all storage sites in the region filled to 80% of capacity at minimum by November 1, 2022, but this has largely been achieved ahead of schedule by September 2022. To continue to ensure security of supply, this target would be increased to 90% by November 1 in each year thereafter, with preliminary targets to be met throughout the year at the beginning of February, May, July and September.

By May 2022, the European Parliament and Council agreed to alter these storage rules, making some key changes aimed at making the obligations more equitable to countries with different capacity of storage, or having access to LNG imports. In this regard, the filling level will be limited by a consumption target equating to 35% of the country’s annual gas consumption over the previous five years. Thus, the obligation on EU member states would be the lower of this rule and the current 80% capacity target. This measure would be particularly applicable to EU countries having smaller working gas capacity relative to their gas consumption, such as Austria and Hungary. The third

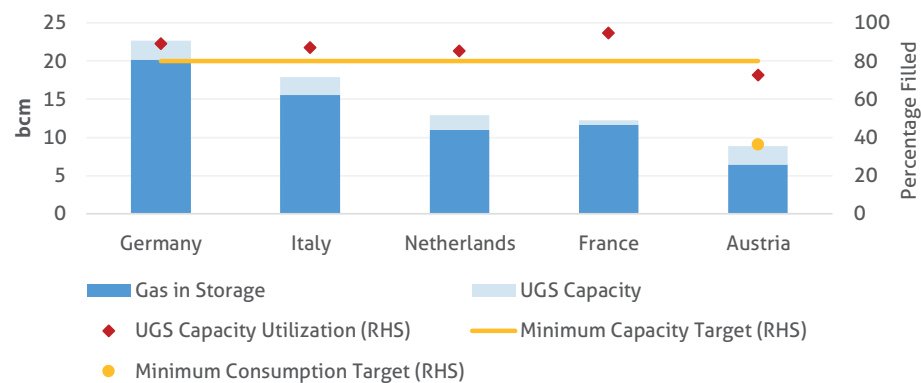


provision is with respect to member states having no underground gas storage sites of their own; these countries will be able to access storage sites in other member states, up to a capacity of 15% of their annual gas consumption over the previous five years.

Finally, further consideration was approved with respect to EU member states which have regasification terminals and associated LNG storage capacity, however limited. Under this agreement, the storage target can be partially met “by counting stocks of LNG or alternative fuels”. It is estimated that there is 4.5 bcm equivalent of LNG storage available in the region. Overall, the European Union considers these filling obligations as a minimum target.

With these regulations in place, even with the gas price volatility within the region, between March to May 2022, Member States were assiduously filling their storage sites. Storage levels reached 55% towards the end of June, with gas injections happening at a rate that took storage levels by September beyond 80% of working gas capacity.

**Figure 124: Storage Capacity vs Gas in Storage in Major EU Countries (as of Sep 15, 2022)**



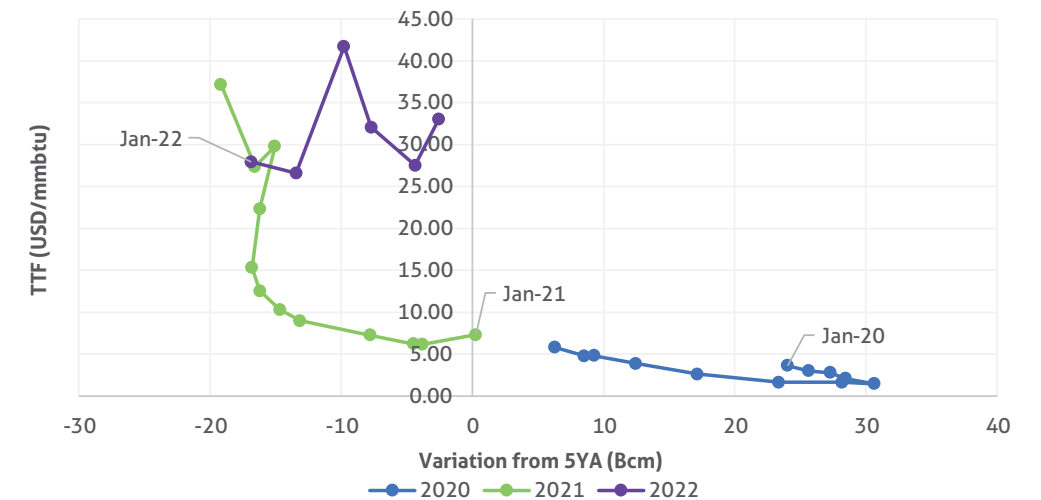
Source: GECF Secretariat based on data from AGSI+

The impact of gas prices with the filling of underground gas storage in sites within the European Union is shown in Figure 125. The TTF gas price is correlated against the level of gas in storage in the entire EU on a monthly basis since January 2020. From this illustration, it is observed that during 2020, when prices were extremely low, as well as demand muted due to the pandemic, gas in storage was much higher than the average of the five previous years, reaching as high as 31 bcm.

Gas prices in the region in 2021 were characterised by high volatility. As a consequence, as the TTF price rose, the variation against the five-year average storage level quickly became increasingly negative. In particular, during the injection season, the TTF price

rose from \$7/MMBtu to \$30/MMBtu, over which time the variation from the five-year average increased to negative 17 bcm by August.

**Figure 125: Gas Price Incentive on Gas Storage Filling in the EU**



Source: GECF Secretariat based on data from AGSI+ and Refinitiv Eikon

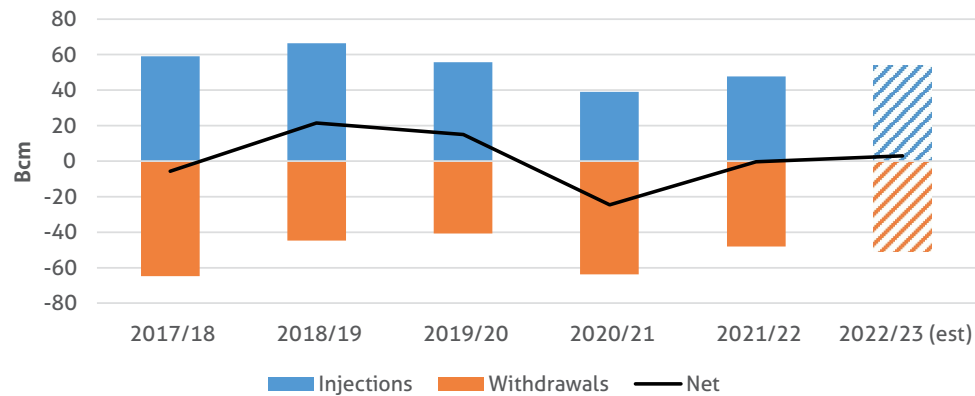
In 2022 thus far, TTF has demonstrated continued volatility at an elevated level. While in the past this would imply downward pressure of operators to fill storage sites, the rules put into effect by the European Commission have resulted in the sustained injections to meet the winter target, and thus, the variation from the five-year average has been consistently trending in a positive direction and closing throughout the year.

A historical representation of the underground gas storage balance in the European Union is shown in Figure 126. In this illustration, the net position reflects the difference between the gas stored during the injection season of a particular year, and the volumes withdrawn during the subsequent winter. Therefore, notwithstanding the relatively low storage levels during the summer of 2021, the net position by April 2022 had balanced to zero as a result of a lower gas withdrawal over the 2021/22 winter than the previous winter season. In comparison, summer 2020 recorded the lowest amount of gas injected into storage over the past five seasons, but this was as a result of storage levels being already high during that year. This worked out favourably for the bloc, since there was a record high (over the past five seasons) withdrawal from storage over the winter period which followed.

Putting together the EU filling targets for 2022, in combination with the historical average demand over the withdrawal season, it is estimated that the region will conclude winter 2022/23 at a slightly net positive position. This computation would

be influenced by the amount of LNG imported into the region during that time to meet heating demand.

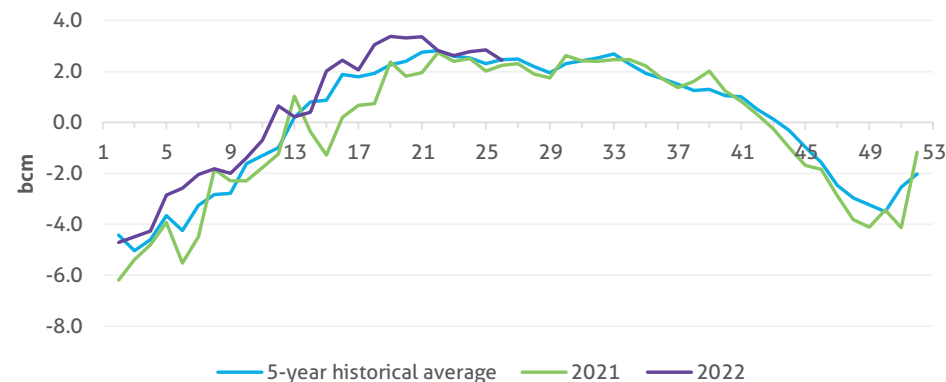
**Figure 126: Underground Gas Storage Balance in the EU**



Source: GECF Secretariat based on data from AGSI+

By June 2022, Europe experienced curtailment of gas volumes from Russia, as a result of maintenance activities on key pipelines to the region. In addition, there was a reduction of LNG cargoes being exported to the region as a result of the temporary shutdown of the Freeport LNG plant. These raised concerns about continuing the high pace of gas injections, and, furthermore, meeting the November 1 target. In response, the German Economy Ministry introduced initiatives such as gas-to-coal switching in the power sector, gas auctioning in the industrial sector, and 15 billion euros in credit lines as incentives to continue to fill underground gas storage. Germany has targeted by law, 90% of gas in storage by November 1.

**Figure 127: Weekly Rate of Gas Storage Injections and Withdrawals in the EU**

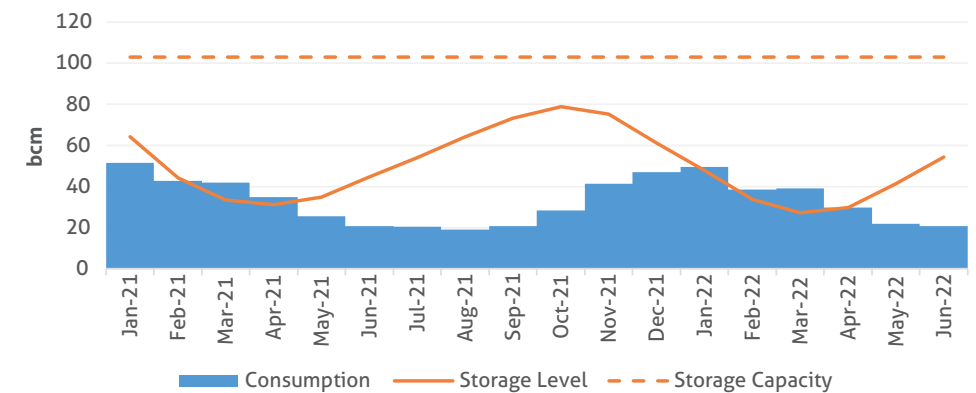


Source: GECF Secretariat based on data from AGSI+

**6.1.1.1 Underground Storage vs Consumption**

The EU region is characterized by having relatively low indigenous production, instead relying heavily on gas imports via pipeline and LNG. As such, gas storage represents a major facet of the gas infrastructure in the region. The trend of natural gas consumption and the level of underground gas storage in the European Union, from January 2021, is shown in Figure 128. Gas consumption levels during the summer are typically low, as there is reduced demand in the power generation sector, as well as no requirement for heating. Consequently, gas prices are usually lower during the months from April to October, and gas storage operators take advantage of this to refill underground facilities. In 2021, around 48 bcm of gas was stored during the net injection season, while monthly gas consumption averaged around 24 bcm.

**Figure 128: Trend of Consumption and Underground Storage in the EU**



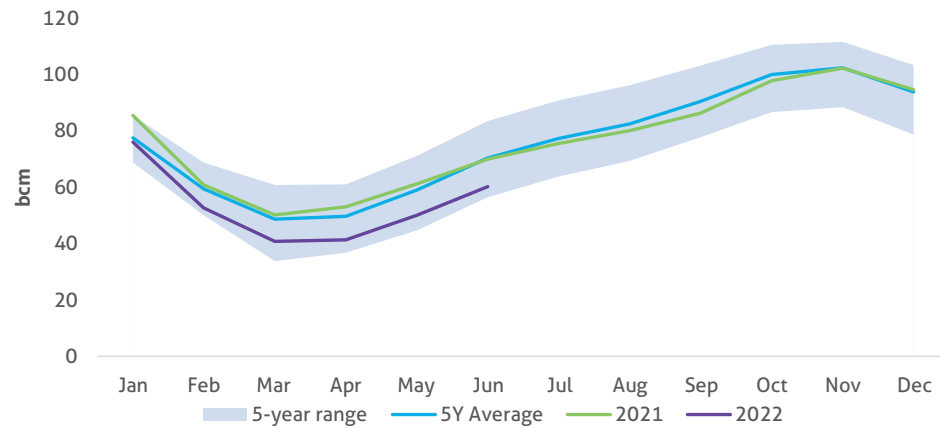
Source: GECF Secretariat based on data from McKinsey and AGSI+

In the winter, however, gas consumption in the region approximately doubles. Across the entire heating season, from November 2021 to March 2022, another 48 bcm was withdrawn from storage. Compared with the monthly consumption of 43 bcm in the same period, at maximum levels, underground gas storage alone can therefore satisfy the gas needs of the region for almost two months in aggregate, although storage capacity is not spread evenly across the region. This underlines the need for continued gas imports to augment supply during this crucial phase.

**6.1.2 North America**

In the U.S., monthly underground gas storage levels at the start of 2021 were 6 bcm greater than the five-year average (Figure 129). This delta subsequently closed and became negative, growing to 7 bcm by September, before trending back towards the five-year average by the end of the year.

**Figure 129: Underground Gas Storage in the U.S.**

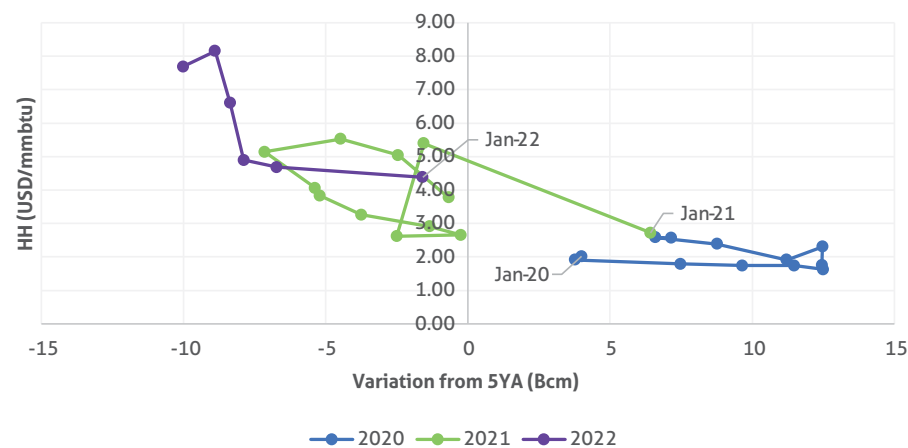


Source: GECF Secretariat based on data from US EIA

The effect of the HH gas price on the propensity to fill underground storage is demonstrated in Figure 130. Here, the monthly variation from the relative five-year historical average storage level is compared against the gas price for that particular month from January 2020 to present.

Generally, when gas prices are low, as in 2020, this encourages greater amounts of injections into storage, and thus, there is a high positive variation with the five-year average. It should also be noted that in 2020 there was reduced gas demand as a result of the Covid-19 pandemic. In 2021, HH fluctuated within a range of \$2/MMBtu, and this was reflected in the growing negative variation with the five-year average storage level as prices tracked towards \$5/MMBtu.

**Figure 130: Gas Price Incentive on Gas Storage Filling in the U.S.**



Source: GECF Secretariat based on data from US EIA and Refinitiv Eikon

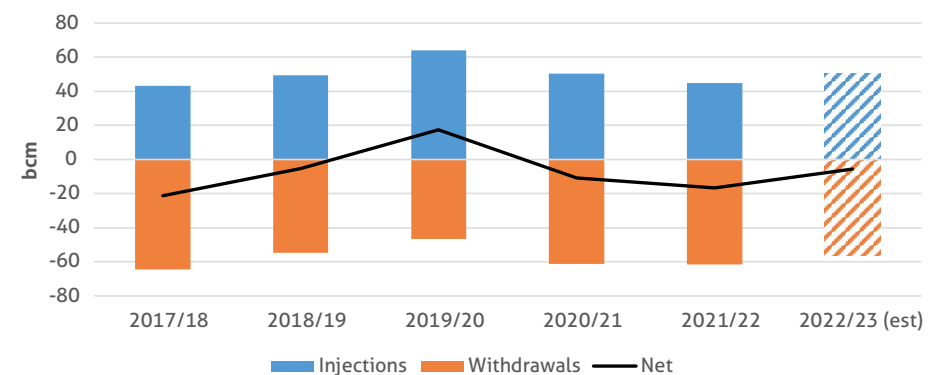
In 2022 thus far, underground gas storage levels in the US at the start of the year were close to the five-year average. However, there was a very high gas withdrawal observed during Q1 2022, widening the delta to the five-year average to 8 bcm by March. In the months which followed, there was a sharp uptick in the HH price, which effectively hampered filling incentive when the injection season commenced. As a result, the variation from the five-year average has been growing, reaching 10 bcm by June.

Another dynamic which must be noted is that when Europe began experiencing pipeline gas shortfalls during Q1 2022, the US responded by diverting large volumes of gas towards the continent in the form of LNG cargoes. This is expected to continue throughout the year and in the medium term, as per the plan by the EU to diversify their energy imports by increasing supply from the US by 15 bcm in 2022, with the intention of ramping up demand to account for an additional 50 bcm of US LNG by 2030. The explosion at the Freeport LNG terminal in June means that there would be a reduction equivalent to 6.2 bcm in the amount of gas that would be able to be exported as LNG cargoes during Q3 2022, with some of this becoming available for injection into storage.

Figure 131 shows the underground gas storage balance for the U.S. over the past five years. The net position represents the difference between the volume of gas injected during the filling season of a particular year, and the amount withdrawn from storage over the following winter. The volume of gas injected during 2021 was slightly lower than the average over the previous five years. This was then followed by a very large withdrawal over the winter, which placed the net position at negative 17 bcm.

By considering the current rate of gas injections, and average storage levels in recent seasons, it can be estimated that around 51 bcm of gas will be filled over the injection season in 2022, followed by 56 bcm of withdrawal over next winter.

**Figure 131: Underground Gas Storage Balance in the US**

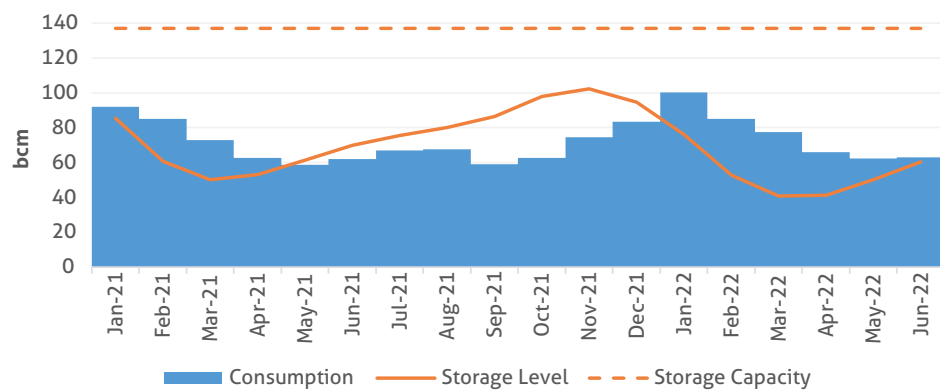


Source: GECF Secretariat based on data from US EIA

### 6.1.2.1 Underground Storage vs Consumption

In the US, the trend of gas consumption and underground storage (Figure 132) differs from that of the EU because of two main reasons. Firstly, the US is adequately supplied with production from indigenous fields, as well as from Canada. Moreover, while gas consumption is high in winter due to the requirement for heating, the US also observes higher gas utilization than Europe during the summer as a result of power demand for cooling.

**Figure 132: Trend of Consumption and Underground Storage in the USA**



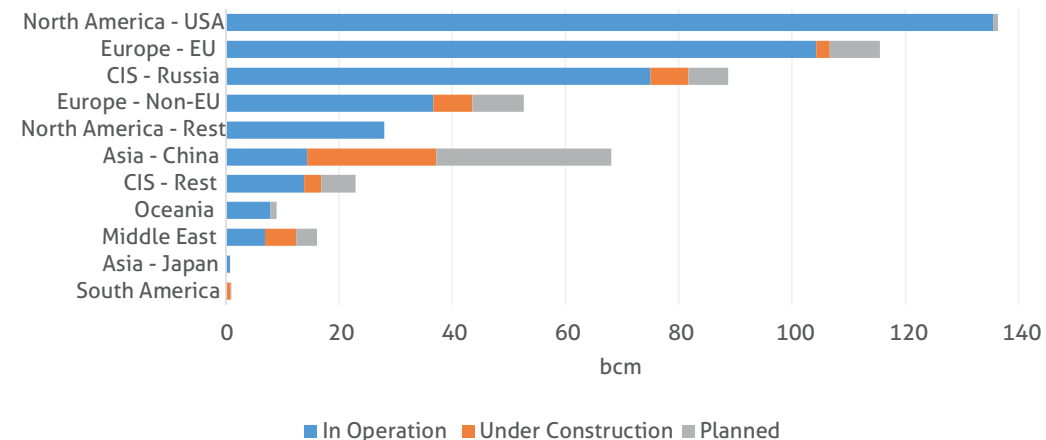
Source: GECF Secretariat based on data from US EIA and AGSI+

During the traditional injection season, from April to October 2021, 45 bcm of gas was put into storage, while the monthly consumption level averaged 63 bcm. The disparity with winter gas consumption levels is much less in the US than in Europe, with monthly gas consumption averaging just 34% higher than the summer, at 84 bcm. Over the heating season which followed (November 2021 to March 2022), 61 bcm of gas was withdrawn from storage across the U.S. Accordingly, the highest level of gas in storage can meet just around five weeks of winter consumption, although this is supported by domestic production to satisfy demand.

### 6.1.3 Asia

China has historically had a relatively low level of working capacity for underground natural gas storage, compared with other world-leading gas consumers. In fact, by the end of 2021, China had 14 bcm of gas storage available, but that capacity is expected to rise almost five-fold over the coming years with a number of projects under construction or in the proposal phase (Figure 133). China’s National Energy Administration has outlined plans under the Implementation Plan for National Gas Storage Capacity Construction to ensure that underground gas storage capacity reflects around 13% of the country’s natural gas consumption. In total, the target for the nation is to reach 60 to 70 bcm of underground gas storage by 2030, and 70 to 80 bcm by 2035.

**Figure 133: Current and Planned Underground Gas Storage**



Source: GECF Secretariat based on data from Cedigaz

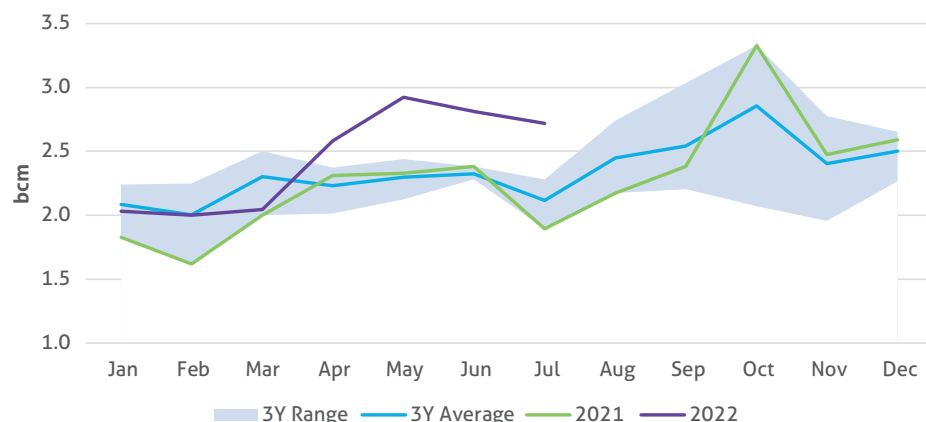
To this end, recently there has been commissioning of a few storage sites along the Power of Siberia natural gas pipeline from Russia, which brings the capacity along that important artery up to 10 bcm. In June 2022, the Sudong 39-61 natural gas storage cluster, part of China’s largest oil and gas field, Changqing, was brought online, with an operating gas capacity of 1 bcm. Additionally, there is the Liaohe gas storage facilities project, which will add another 10 bcm of gas storage as construction completes in phases over the next decade. Furthermore, as the heating season at the end of 2022 approaches, another 5 bcm of new working gas capacity was commissioned since the previous winter.

## 6.2 LNG Storage

### 6.2.1 Europe

In addition to underground natural gas storage, the European Union also has the capability to store gas in the form of LNG. The region has a total storage capacity of the equivalent of 4.5 bcm of LNG, with almost half of this availability located in Spain. The remaining capacity is distributed among the other LNG importing countries within the European Union. The recent historical LNG storage levels in the EU are shown in Figure 134.

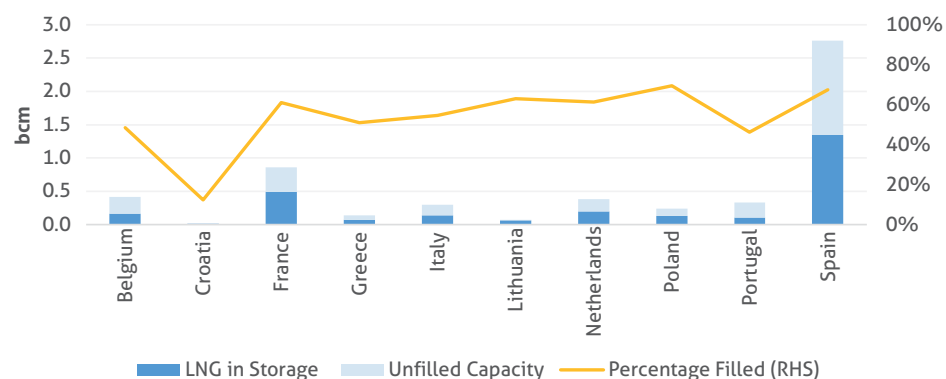
**Figure 134: LNG Storage in the European Union**



Source: GECF Secretariat based on data from McKinsey

Due to the fact that the LNG is kept stored in the liquid phase in cryogenic tanks, LNG storage is mainly utilized for a short-term basis, particularly to satisfy demand from power plants. As such, the LNG storage trend does not follow the same seasonal pattern as that for underground gas storage.

**Figure 135: Storage Capacity vs LNG in Storage in the EU (as of June 30, 2022)**



Source: GECF Secretariat based on data from McKinsey

The historical trend demonstrates a relatively stable level of storage through the first nine months of the year, followed by an appreciable spike as the winter season approaches. The year 2021 showed a particularly large swing, from the lowest July storage level to the highest October storage level recorded over the past three years. The year 2022 has been greatly influenced by the decline in pipeline natural gas imports into the region. In response to this, there was a marked increase in LNG imports to the

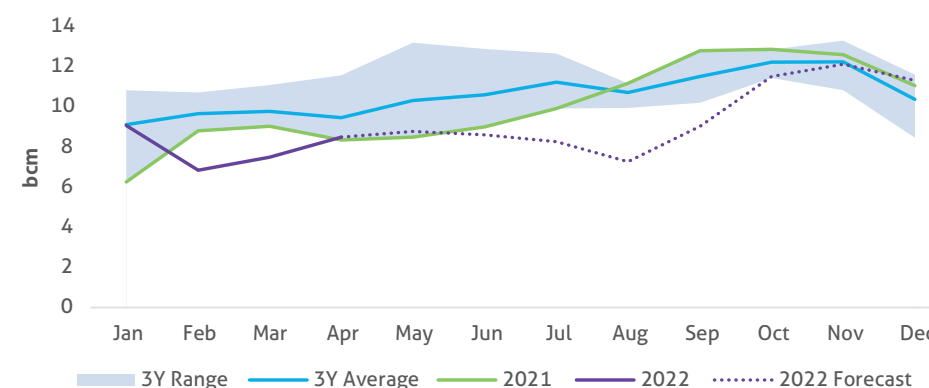
EU, particularly since Q2 2022. As Europe prepares to meet its gas storage targets for the upcoming winter season, the average level of LNG in storage shot up from 45% in Q1 2022, to over 60% thereafter.

### 6.2.2 Asia

In Asia, Japan and South Korea still represent two of the top LNG importing countries in the world. As such, together they possess a significant capacity of LNG storage, even considering that such storage is generally limited to the short-term due to the expenses necessary to keep the liquid cool. In total, Japan and South Korea have around 9.8 bcm and 6.8 bcm of LNG storage capacity, respectively.

Storage levels on a monthly basis typically averaged around 10.5 bcm over the past three years (Figure 136). In general, there is a slight increase in storage as the winter season approaches, and although stocks were lower during the summer period of 2021, this overall trend was repeated in Q4 2021.

**Figure 136: LNG Storage in Japan and South Korea (together)**



Source: GECF Secretariat based on data from Refinitiv

In 2022 thus far, LNG stocks have begun to increase sharply since February, and according to estimates will continue to increase in the short term. However, towards the end of July, there were announcements about the imminent restart of some nuclear reactors in Japan, which has the potential to reduce LNG demand going forward. Furthermore, the extremely high LNG prices in recent times have weighed heavily on demand, and will continue to have a great influence on the forecasted level of LNG in storage for the remainder of the year.



## CHAPTER 07

# Energy Prices

### 7.1 Natural Gas & LNG Spot Prices

Gas and LNG spot prices were characterized by historic highs and extreme volatility in 2021, driven mainly by tight market conditions with abnormal weather conditions and a strong global economic recovery pushing demand upwards, while supply constraints at several LNG facilities due to unexpected outages and planned maintenance activities invoked limits on the supply side. European and Asian spot prices were closely tracking each other during the year and, thus, becoming increasingly correlated due to strong competition for cargoes across the basins.

In Q1 2021, delayed LNG deliveries and high charter rates due to congestion at the Panama Canal contributed to huge price spikes with Asian LNG spot prices almost reaching \$40/MMBtu in January. While the congestion at the Panama Canal in January had a significant impact on spot prices in Asia, the temporary blockage of the Suez Canal in March did not have such an impact on prices, as the market was relatively well-supplied. In the U.S., HH also experienced historic price spikes with daily spot prices soaring above \$23/MMBtu in February due to freezing winter temperatures which caused some production to be shut-in. In Europe, an extremely cold winter increased European gas demand which was mostly satisfied through brisk storage withdrawals. A wide inter-basin arbitrage in January limited LNG deliveries to Europe, however, this narrowed significantly from February to April, causing an influx of cargoes into Europe.

In Q2 2021, spot prices gradually increased as high carbon prices as well as several outages and maintenance at Norwegian facilities also supported prices in Europe. Colder-than-usual temperatures in April also supported gas demand, which boosted prices.

Hotter-than-usual summer temperatures drove both Asian and European spot prices to record seasonal highs in Q3 2021. High EU carbon prices also supported gas demand in Europe; however, high gas prices will limit fuel switching demand. European prices remained bullish in July and August driven by continued supply constraints due to both planned and unplanned maintenance in Norway and Russia. A warmer-than-usual summer in Asia, higher industrial demand particularly in China, and lower nuclear

availability in Japan, together with supply concerns after three trains were taken offline on September 14 at the Freeport LNG facility in Texas after tropical storm Nicholas made landfall also supported prices.

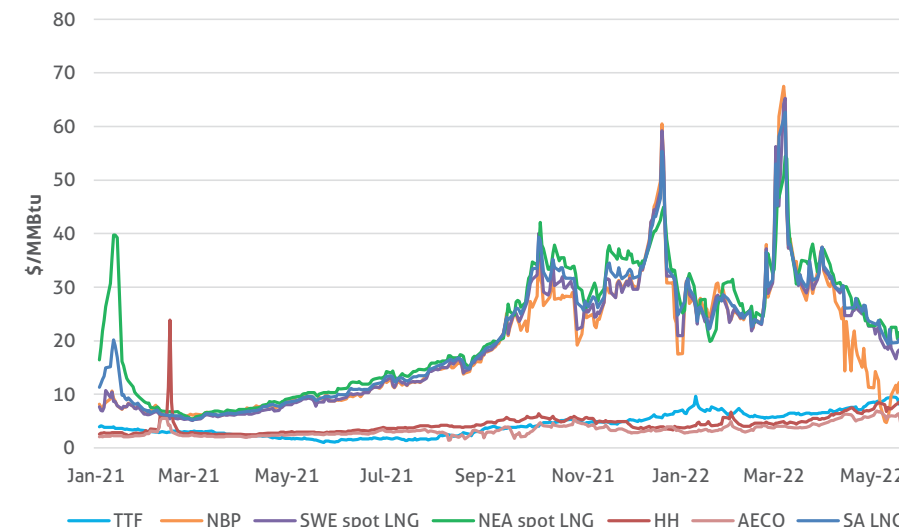
Spot prices in both regions continued to climb driven by increasing tensions at the Russia-Ukraine border, relatively low storage levels in Europe and increasing competition for cargoes between Asia and Europe in Q4 2021. Then, in December 2021, TTF spot prices spiked again, surpassing NEA LNG spot prices and reaching a then historic daily high above \$60/MMBtu.

Global gas and LNG spot prices in the first half of 2022 have been largely driven by tight market fundamentals as a result of several influencing factors including escalating geopolitical tensions, post-pandemic global economic recovery, growing concerns for gas supply availability, low EU gas storage levels and competition for cargoes between Europe and Asia.

Increasing spot price volatility has been one of the main themes on the energy landscape over the past two years. While gas supply and demand dynamics still govern the general bearish or bullish movement of prices, this recent price volatility continues to be heavily influenced by news, policy announcements and political negotiations. As we continue to monitor the evolving market situation, the uncertainty around the future of Europe's gas supply and energy security will continue to have potential upside risk on prices.

Following the escalating prices at the end of 2021, Asian and European gas and LNG spot prices declined sharply in January 2022, although still above \$25/MMBtu, due to a combination of warmer-than-usual temperatures, which reduced gas demand for heating and emerging gas supply from the U.S. Spot prices remained soft until the last week of February 2022, when there was a steep climb due to escalating geopolitical tensions in Eastern Europe. Then, in March 2022, spot prices in Asia and Europe surpassed the highs seen at the end of 2021 due to growing concerns about supply availability, with daily TTF soaring to an all-time high above \$72/MMBtu. Furthermore, TTF jumped above \$96/MMBtu in August 2022. As price volatility continued, spot prices declined sharply in April and May 2022 due to a high influx of LNG cargoes into the region, brisk LNG sendout and weakened demand during the shoulder season (Figure 137).

**Figure 137: Daily Gas & LNG Spot Prices**



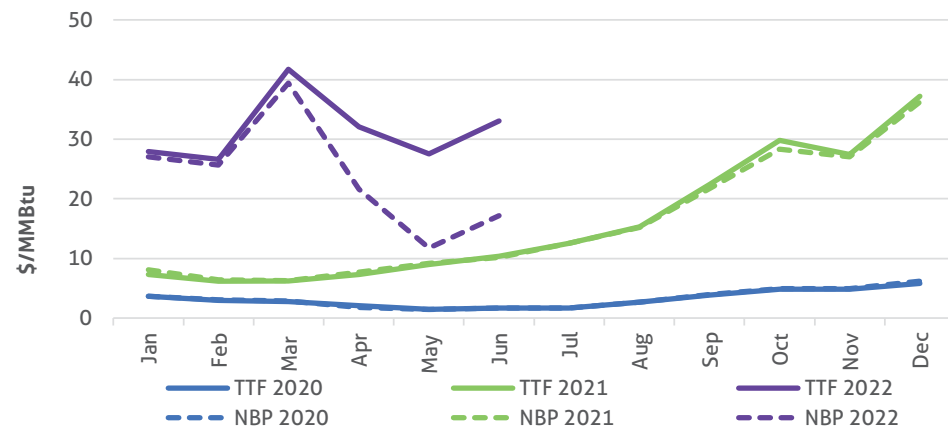
Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA

Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment.

### 7.1.1 European Spot Gas and LNG Prices

TTF and NBP spot prices averaged \$15.91/MMBtu and \$15.72/MMBtu, respectively, in 2021, and were 401% and 386% higher y-o-y. The SWE spot LNG prices averaged \$15.99/MMBtu in 2021, which was 404% higher y-o-y. European spot gas and LNG prices were elevated throughout the year. On the demand side, strong economic recovery prompted higher gas demand particularly in the industrial and power generation sectors, while high EU carbon prices resulted in increased coal-to-gas switching. On the supply side, low EU gas storage levels, lower domestic production in the region and unplanned outages kept market fundamentals tight. Both NBP and TTF rose to whopping daily highs above \$60/MMBtu in December 2021 driven by supply concerns amidst rising geopolitical tensions, low storage levels and an unplanned maintenance at Norway's Troll and Visund fields.

In H1 2022, we witnessed historically high price levels and volatility in Europe, together with a widening arbitrage between TTF and NBP (Figure 138). Escalating geopolitical tensions and concerns about Russian gas supply to Europe fuelled prices in Europe with daily TTF spot prices soaring above \$72/MMBtu in March 2022.

**Figure 138: Monthly European Gas Spot Prices**

Source: GECF Secretariat based on data from Refinitiv Eikon and OANDA

Since April 2022, we have seen a strong decoupling of TTF and NBP prices. NBP slumped to a monthly low of around \$12/MMBtu in May 2022, further exacerbating the disparity between TTF and NBP. Brisk LNG deliveries to the UK continued while demand was softer, and technical constraints at the IUK pipeline to Belgium at the beginning of May reduced flows to continental Europe, leaving a heavily oversupplied UK. In addition, easing concerns over payment in Russian roubles with some buyers complying at the end of May, also added some bearish sentiment.

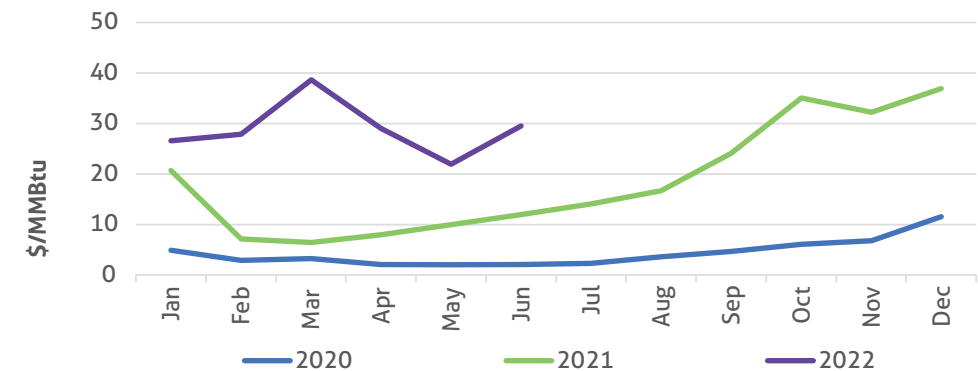
Another unexpected outage at the beginning of June 2022, due to a filter blockage at the IUK interconnector resulted in daily NBP spot prices plunging to a low of \$1.5/MMBtu in June. The NBP-TTF spread reached a high of around negative \$16/MMBtu in May and June 2022. However, reduced supply via Nord Stream I and a heatwave in some countries boosted prices during the month.

In H1 2022, NBP and TTF averaged \$23.76/MMBtu and \$31.48/MMBtu and were 199% and 308% higher y-o-y respectively. Similarly, SWE spot LNG averaged \$27.77/MMBtu and was 265% higher y-o-y.

### 7.1.2 Asian Spot LNG Prices

NEA LNG spot prices in 2021 averaged \$18.60/MMBtu, an increase of 327% y-o-y, recording two major price spikes of almost \$40/MMBtu in January and then above \$45/MMBtu in December (Figure 139). The price spike in January was a result of the culmination of very cold temperatures, supply constraints at several LNG facilities in Australia, Malaysia and Indonesia, Norway and congestion at the Panama Canal. Throughout the rest of the year, prices remained elevated driven by robust consumer demand in the region particularly from Japan, South Korea and China where they

experienced higher-than-usual temperatures. In addition, upstream production issues at Malaysia's Bintulu LNG complex in September caused buyers to turn to the spot market due to expected delays in some November-January cargoes. Asian LNG spot prices reached \$45/MMBtu tracking gains in TTF, and also due to reduced supply in the region after a fire broke out at Shell's Prelude LNG facility in Australia.

**Figure 139: Monthly Asian LNG Spot Prices**

Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA

For H1 2022, the average NEA spot LNG price was \$28.93/MMBtu, 170% higher than the average of \$10.71/MMBtu for the same period in 2021. In Q1 2022, Asian LNG prices closely tracked European hub prices, although remaining at a discount to the European prices, as the region was well-supplied, had healthy inventory levels and buying interest remained muted. Then, in April and May 2022, Asian LNG prices suffered a steep decline, also tracking losses in European hub prices. However, in June 2022, prices rebounded as global market tightness continued to increase, with an unplanned disruption at Shell's Prelude LNG facility in Australia reducing supply in the region.

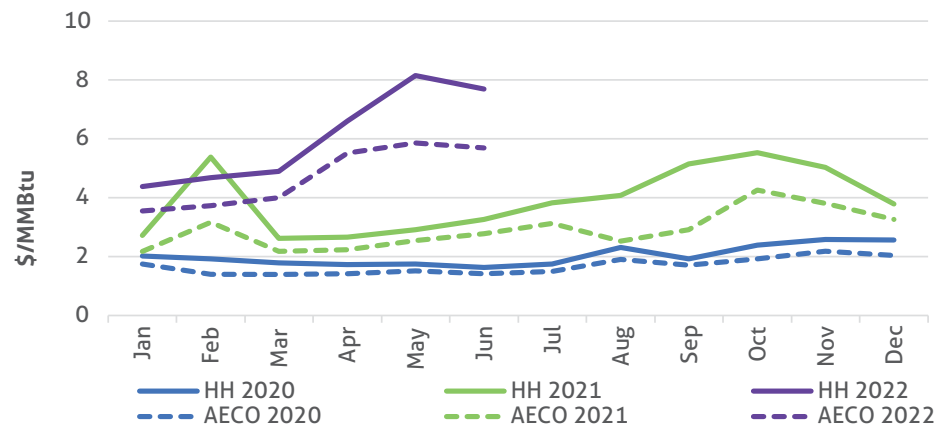
### 7.1.3 North American Spot Gas Prices

In the U.S., HH spot prices averaged \$3.91/MMBtu in 2021, an increase of 93% y-o-y driven largely by economic recovery, which lifted gas demand. While HH spot prices were higher y-o-y, its limited exposure to imports kept spot prices less volatile compared to those in Europe and Asia. In Canada, the AECO spot prices averaged \$2.91/MMBtu, which was 74% higher y-o-y.

In H1 2022, HH spot gas price increased by 86% y-o-y to average \$6.07/MMBtu (Figure 140). Furthermore, daily HH prices rose above \$9/MMBtu in May 2022 as US LNG exports reached record-high levels, keeping storage injections low. In Canada, the AECO spot price increased 88% y-o-y to average \$4.73/MMBtu.



**Figure 140: Monthly North American Gas Spot Prices**



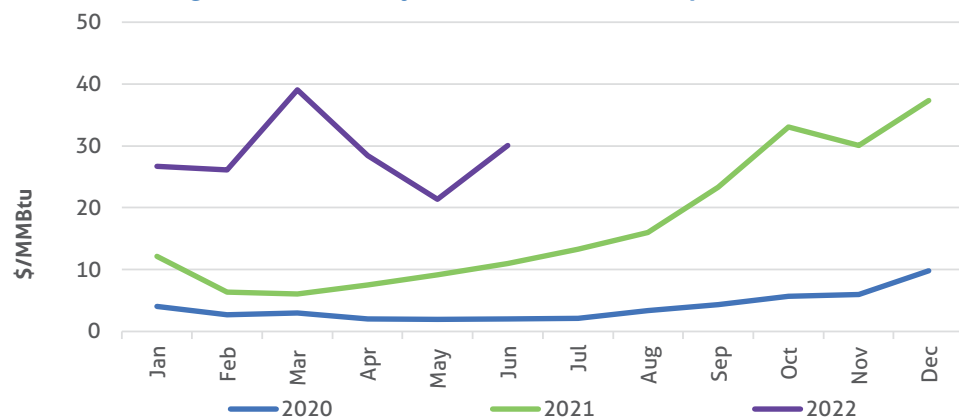
Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA

**7.1.4 South American Spot LNG Prices**

South American (SA) LNG spot prices averaged \$17.11/MMBtu in 2021, an increase of 337% y-o-y driven by increased gas demand due to lower hydropower. LNG prices in Brazil, Argentina and Chile closely tracked spot prices in Europe and Asia as buyers competed for cargoes on the spot market.

In H1 2022, SA LNG gas prices increased by 229% y-o-y to average \$28.62/MMBtu (Figure 141). Furthermore, daily LNG prices peaked above \$60/MMBtu in March 2022.

**Figure 141: Monthly South American LNG Spot Prices**



Source: GECF Secretariat based on data from Argus

Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment.

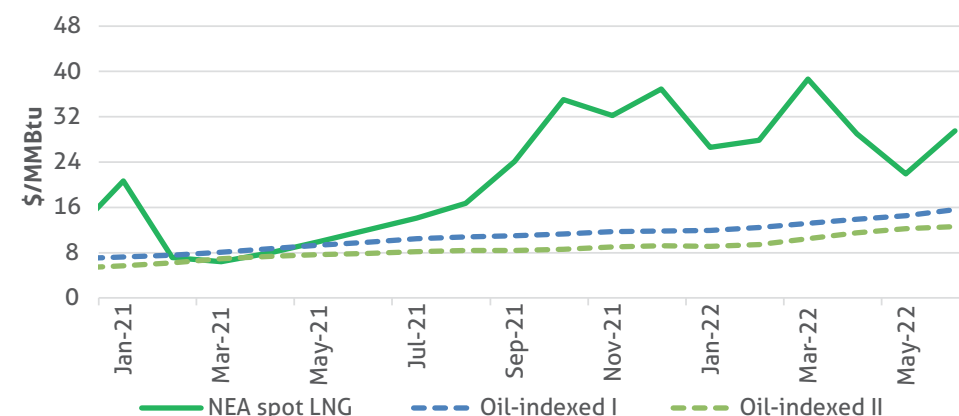
**7.2 Comparison of Spot vs Oil-indexed Long-Term (LT) LNG Prices**

In 2021, Oil-indexed I LNG price averaged \$9.80/MMBtu increasing by 30% y-o-y and the Oil-indexed II LNG price averaged \$7.78/MMBtu, increasing by 43% y-o-y (Figure 142). In Europe, the Oil-indexed III price averaged \$6.40/MMBtu, increasing by 9% y-o-y (Figure 143).

The discount of Oil-indexed I and Oil-indexed II prices to the average NEA spot LNG price was around \$9/MMBtu and \$11/MMBtu respectively, while the average SWE LNG held a high premium of around \$9/MMBtu over the Oil-indexed III price.

In H1 2022, the Oil-indexed I, II and III LNG prices averaged \$13.60/MMBtu, \$10.88/MMBtu and \$9.61/MMBtu were 61%, 57% and 60% higher y-o-y respectively.

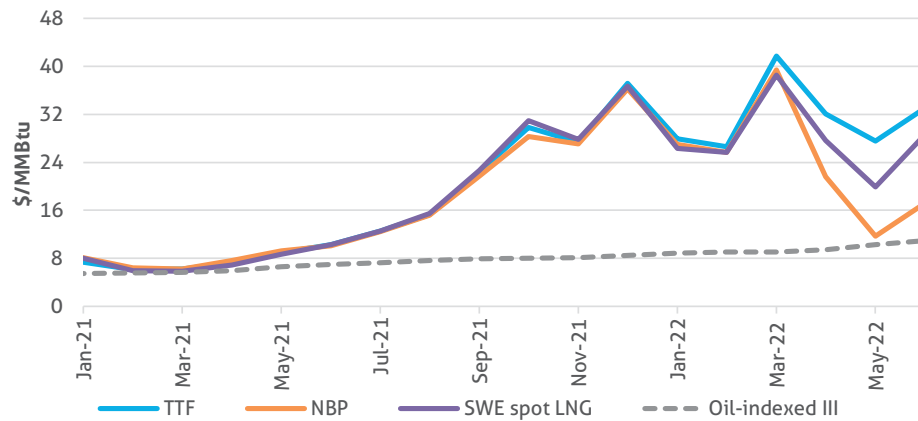
**Figure 142: Asia: Oil-indexed vs Spot Prices**



Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA

Note: Oil-indexed I (traditional LTC): 14.85% X Brent (6 0 1) + 0.5; Oil-indexed II (avg 2017-2021 LTC): 10.87% X Brent (3 0 1) + 0.5

**Figure 143: Europe: Oil-Indexed vs Spot Prices**



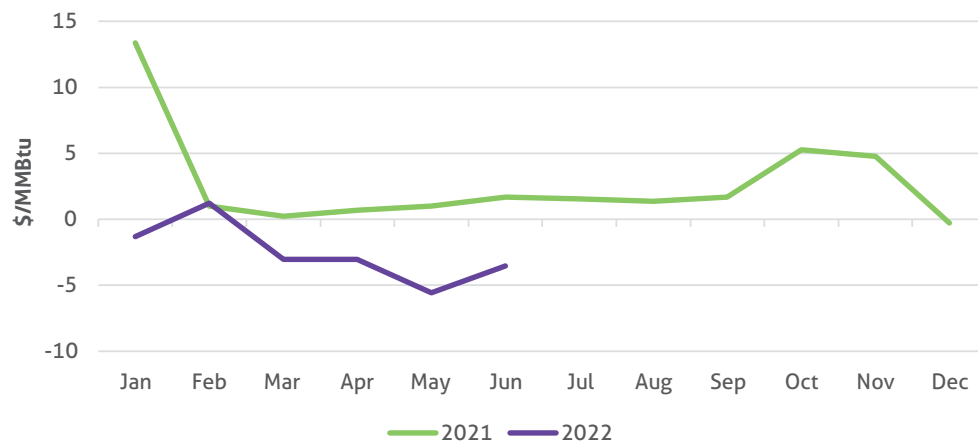
Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA  
 Note: Oil-indexed III: Argus assessment for European LTC

## 7.3 Gas & LNG Price Spreads

### 7.3.1 Inter-basin

The NEA-TTF price spread was around \$13/MMBtu in January 2021 (Figure 144). However, it remained relatively low, below \$2/MMBtu until Q4 2021, and in December, it flipped to negative due to very bullish European prices. This negative trend continued in 2022, with the NEA-TTF reaching a low of negative \$5.6/MMBtu in May 2022, which kept brisk LNG deliveries into Europe.

**Figure 144: NEA-TTF Price Spread**

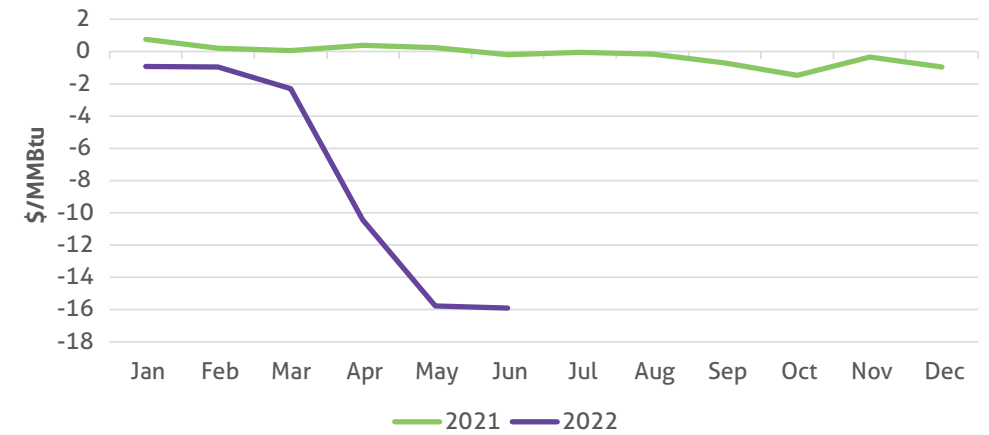


Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA

### 7.3.2 Intra-basin

In 2021, NBP and TTF spot prices tracked each other closely, driven by similar market fundamentals, maintaining a price spread below \$1/MMBtu for most of the year. However, this has changed drastically in 2022, with NBP trading at a wide discount to TTF of around \$16/MMBtu in May and June 2022 (Figure 145). The UK and NW Europe gas markets became more disconnected during the year as the UK market was heavily oversupplied due to brisk LNG sendout and weakened demand, with some supply constraints in the IUK connector to Belgium, which reduced pipeline gas flows from the UK to NW Europe.

**Figure 145: NBP-TTF Price Spread**



Source: GECF Secretariat based on data from Argus, Refinitiv Eikon and OANDA

## 7.4 Cross Commodity Prices

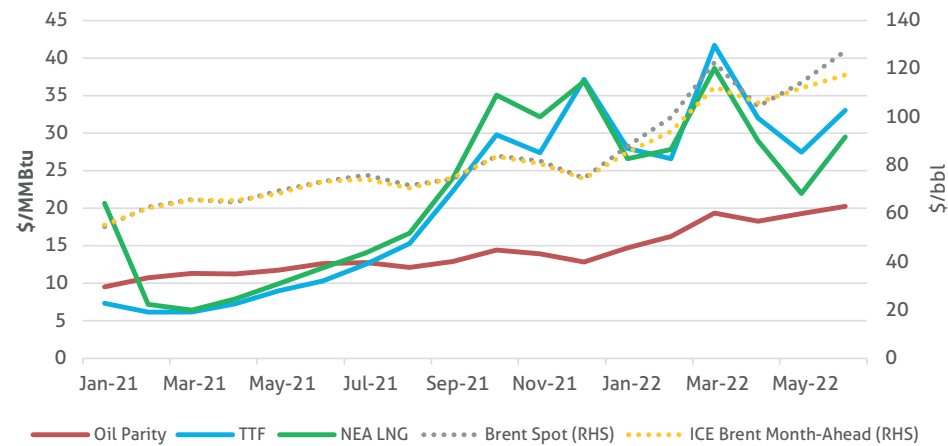
### 7.4.1 Oil Prices

Brent spot and month-ahead prices both averaged around \$71/MMBtu in 2021, which was 71% and 64% higher y-o-y respectively. This bullish trend in oil prices was largely driven by strong global oil demand on the back of global economic recovery.

This continued in 2022 as easing COVID-19 restrictions, reducing concerns about the spread of the Omicron variant and some supply disruptions buoyed prices. In March 2022, prices jumped due to rising geopolitical tensions in eastern Europe and the potential for supply chain disruptions and oil supply shortages. In H1 2022, Brent spot averaged \$109.43/bbl, 68% higher y-o-y, while Brent one month-ahead price averaged \$104.59/bbl, 61% higher y-o-y (Figure 146).

Since July 2021, the oil parity price has been significantly lower than spot gas and LNG prices. However, In June 2022, the premium of TTF and NEA spot prices over the oil parity price increased to around \$13/MMBtu and \$9/MMBtu respectively.

**Figure 146: Monthly Crude Oil Prices**



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

**7.4.2 Coal Prices**

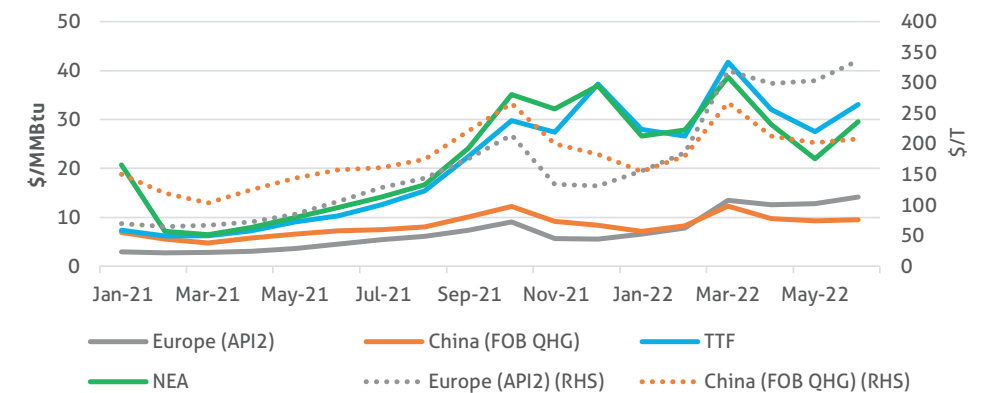
The European API2 and the China Qinhuangdao (QHG) coal prices averaged \$115.99/T and \$167.06/T in 2021 and were 126% and 88% higher y-o-y respectively.

In H1 2022, the European API2 averaged \$266.45/T, 244% higher y-o-y (Figure 147), while the Chinese QHG price averaged \$204.18/T, 53% higher y-o-y. Coal-fired power generation in Europe has increased significantly due to higher gas prices and uncertainty surrounding gas supply from Russia. Many EU countries, including Germany, who had started aggressive coal phase-out programs in line with their energy transition policies have recently announced plans to restart idle coal-fired power capacity.

Furthermore, since May 2021, the premium of spot gas and LNG prices over coal prices in Europe has been above \$5/MMBtu, with the premium in Asia slightly lower, above \$3/MMBtu. The energy crunch and high spot gas and LNG prices have put upward pressure on coal prices, with significant gas-to-coal switching taking place particularly in Europe.

In May 2022, there was a significant decline in the premium of spot gas and LNG prices in Europe and Asia over the respective coal parity prices. However, spot prices rebounded in June 2022, increasing its premium over coal prices. The TTF spot price held a premium over the API2 parity price of \$19/MMBtu. Similarly, the NEA LNG spot price held a premium over the QHG parity price of \$20/MMBtu.

**Figure 147: Monthly Coal Parity Prices**

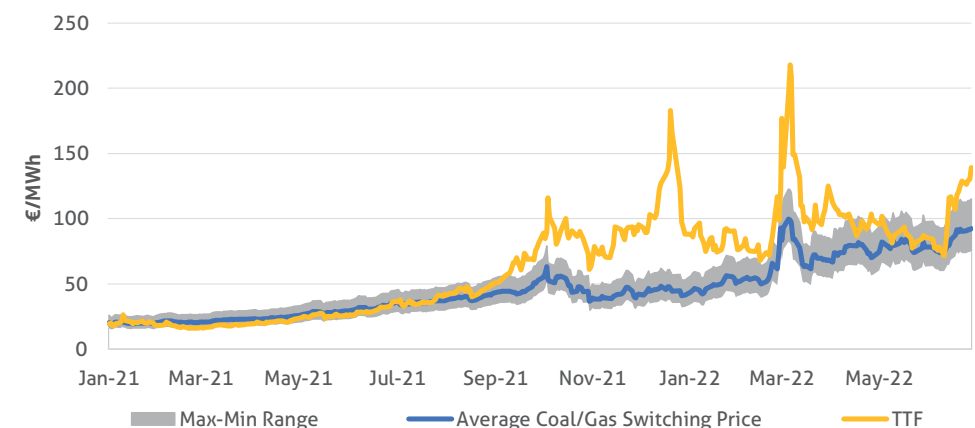


Source: GECF Secretariat based on data from Argus and Refinitiv Eikon  
 Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in \$/MMBtu for Europe (API2) and China (QHG) respectively.

**7.4.3 Fuel Switching**

TTF spot prices were largely within the coal-to-gas switching range from Q1-Q3 2021 (Figure 148), which incentivized coal-to-gas switching in Europe. However, since Q4 2021, TTF has soared out of this range driven by bullish market sentiment. TTF spot prices remained above the coal-to-gas switching range until May 2022. Daily TTF prices once again fell within the coal-to-gas switching range in May as TTF prices fell sharply due to ample supply and weaker gas demand.

**Figure 148: TTF vs Coal-to-Gas Switching Price**



Source: GECF Secretariat based on data from Refinitiv Eikon  
 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, CO2 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%.

The premium of TTF over the average coal-to-gas switching price narrowed to around \$9/MMBtu in May 2022, down from \$27/MMBtu the previous month. This was due to a combination of bullish carbon prices and bearish TTF prices, which likely resulted in some coal-to-gas switching in Europe. However, TTF price rebounded sharply in mid-June 2022, and held a premium over the average coal-to-gas switching price of around \$21/MMBtu.

Furthermore, in H2 2022, TTF is expected to maintain a significant premium over the average coal-to-gas switching price as tight market conditions continue to persist. Thus, we can expect to see more gas-to-coal switching for the rest of 2022.

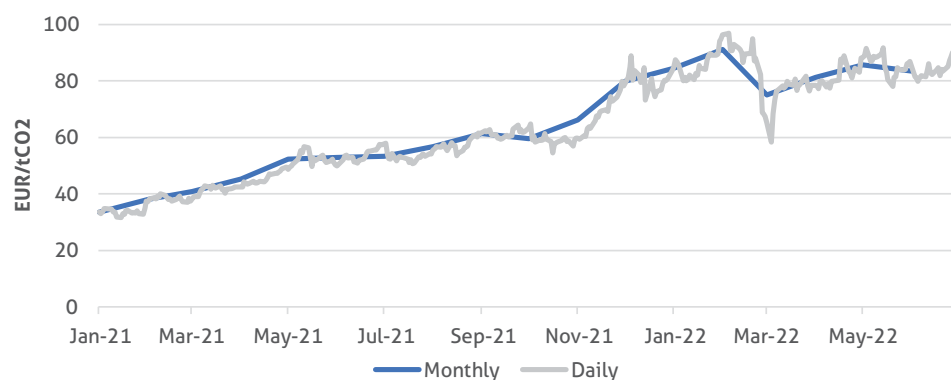
#### 7.4.4 Carbon Prices

EU carbon prices soared to historic highs in 2021, with an annual average of EUR54/tCO<sub>2</sub>, 111% higher y-o-y (Figure 149). There was higher demand for EUAs due to more aggressive climate change policies, colder-than-usual winter, increased energy demand in power and industrial sectors due to post-COVID economic recovery. This increased demand for allowances, together with an increased annual reduction rate in the number of allowances to 2.2% in 2021 as the EU ETS entered into its fourth trading phase, contributed to the tight carbon market.

Daily EU carbon prices peaked above EUR96/tCO<sub>2</sub> in early February 2022, reaching a monthly average of EUR91.18/tCO<sub>2</sub>. Carbon prices also experienced some fluctuations in the first half of the year, but averaged above EUR80/tCO<sub>2</sub> in Q2 2022. Buying interest for EUAs continued to be high as coal power plants were higher on the merit order due to the high levels of TTF prices.

In H1 2022, EU carbon prices averaged EUR83.55/tCO<sub>2</sub>, 91% higher than the average of EUR43.81/tCO<sub>2</sub>. For the rest of 2022, EU carbon prices are expected to remain elevated, with an annual average of around EUR78/tCO<sub>2</sub> based on estimates from Refinitiv Eikon (as of 2 September 2022).

**Figure 149: Trend in EU Carbon Price**



Source: GECF Secretariat based on data from Refinitiv Eikon



## Definitions

TERM	MEANING
<b>Coal-to-gas switching price</b>	The coal-to-gas switching price is the threshold price at which gas-fired electricity generation is competitive with coal-fired electricity generation and takes into account operating costs, efficiencies, fuel costs, and carbon prices. If the gas price is below the coal-to-gas switching price, gas-fired electricity generation is more economical than coal-fired electricity generation and vice versa.
<b>European Union</b>	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.
<b>Euro area</b>	Austria, Belgium, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Portugal, Slovakia, Slovenia and Spain.
<b>G7</b>	Canada, France, Germany, Italy, Japan, the United Kingdom and the United States
<b>OECD Countries</b>	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.
<b>OECD Americas</b>	Canada, Chile, Mexico and the United States.
<b>OECD Asia Oceania</b>	Australia, Japan, Korea and New Zealand.
<b>OECD Europe</b>	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
<b>Spot and short-term LNG trade</b>	This refers to the trade of LNG under contracts of four (4) years or less.

## Abbreviations

Abbreviation	Explanation
<b>AE</b>	Advanced Economies
<b>AECO</b>	Alberta Energy Company
<b>bcm</b>	Billion cubic metres
<b>bcma</b>	Billion cubic metres per annum
<b>CBAM</b>	Carbon Border Adjustment Mechanism
<b>CBM</b>	Coal bed methane
<b>CCS</b>	Carbon, Capture and Storage
<b>CCUS</b>	Carbon Capture, Utilization and Storage
<b>CDD</b>	Cooling Degree Days
<b>CIS</b>	Commonwealth of Independent States
<b>CNG</b>	Compressed Natural Gas
<b>CO2</b>	Carbon dioxide
<b>CO2e</b>	Carbon dioxide equivalent
<b>CPI</b>	Consumer Price Index
<b>DOE</b>	Department of Energy
<b>DQT</b>	Downward Quantity Tolerance
<b>EC</b>	European Commission
<b>ECB</b>	European Central Bank
<b>EEEXI</b>	Energy Efficiency Existing Ship Index
<b>EMDE</b>	Emerging Markets and Developing Economies
<b>EU</b>	European Union
<b>EU ETS</b>	European Union Emissions Trading Scheme
<b>EUA</b>	European Union Allowance
<b>Fed</b>	Federal Reserve

<b>FID</b>	Final Investment Decision
<b>G7</b>	Group of Seven
<b>GDP</b>	Gross Domestic Product
<b>GECF</b>	Gas Exporting Countries Forum
<b>GHG</b>	Greenhouse Gas
<b>HDD</b>	Heating Degree Days
<b>HH</b>	Henry Hub
<b>IEA</b>	International Energy Agency
<b>IMF</b>	International Monetary Fund
<b>IMO</b>	International Maritime Organization
<b>JKM</b>	Japan Korea Marker
<b>LNG</b>	Liquefied Natural Gas
<b>LAC</b>	Latin America and the Caribbean
<b>LT</b>	Long term
<b>mmcm</b>	Million cubic metres
<b>MENA</b>	Middle East and North Africa
<b>METI</b>	Ministry of Trade and Industry in Japan
<b>Mt</b>	Million tonnes
<b>MWh</b>	Megawatt hour
<b>NEA</b>	North East Asia
<b>NBP</b>	National Balancing Point
<b>NDC</b>	Nationally Determined Contribution
<b>NGV</b>	Natural Gas Vehicle
<b>NZBA</b>	Net-Zero Banking Alliance
<b>OECD</b>	Organization for Economic Co-operation and Development
<b>PNG</b>	Pipeline Natural Gas
<b>PPAC</b>	Petroleum Planning & Analysis Cell
<b>QHG</b>	Qinhuangdao
<b>R-LNG</b>	Regasified LNG
<b>SA</b>	South America
<b>SPA</b>	Sales and Purchase Agreement
<b>SWE</b>	South West Europe

<b>T&amp;T</b>	Trinidad and Tobago
<b>TANAP</b>	Trans-Anatolian Natural Gas Pipeline
<b>TCFD</b>	Task Force on Climate-Related Financial Disclosure
<b>Tcm</b>	Trillion cubic metres
<b>tCO<sub>2</sub></b>	Ton of carbon dioxide
<b>TTF</b>	Title Transfer Facility
<b>TWh</b>	Terawatt hour
<b>UGS</b>	Underground Gas Storage
<b>UAE</b>	United Arab Emirates
<b>UK</b>	United Kingdom
<b>UQT</b>	Upward Quantity Tolerance
<b>U.S.</b>	United States
<b>y-o-y</b>	year-on-year

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