



GECF

Gas Exporting
Countries Forum

GECF's Annual Short Term Gas Market Report 2021



**Road to Recovery from COVID-19
and Transition to a Carbon Neutral World:
Dawn of a New Era for Natural Gas**

Gas Market Analysis Department



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Foreword



Yury P. Sentyurin

We are delighted to present the second edition of the GECF's Annual Short-Term Gas Market Report (ASTGMR) 2021, which reflects our independent assessment and short-term prospects on the global gas industry. The publication of ASTGMR 2021 coincides with post-COVID-19 recovery of the global economy and energy market amidst the transition to a low carbon future. In this context, we have chosen the title for the second edition of ASTGMR: "Road to Recovery from COVID-19 and Transition to a Carbon Neutral World: Dawn of a New Era for Natural Gas".

The GECF's ASTGMR 2021 provides a comprehensive analysis of the developments in the gas industry in the year 2020 and 2021, as well as the short-term prospects for the full year 2021 and 2022. The main topics covered include global economy, energy policies, natural gas consumption and supply, trade, natural gas prices and carbon mitigation strategies. The combination of these factors defines the evolving architecture of the natural gas market. In addition, considering the latest developments of the global energy scene, we have added new subsections in the second edition ASTGMR, including carbon mitigation strategies, EU's Fit For 55 package and its potential impact on natural gas demand, Asian LNG price indices in consuming countries as well as greater coverage of natural gas vehicles and underground natural gas storage.

Natural gas proved itself as a reliable, clean and versatile source of energy even in the face of the negative impacts of unprecedented global health crisis, which resulted in market volatility, economic recession and a drop in energy demand. Although the global natural gas consumption recorded its first annual decline in more than a decade, dropping by 2% in 2020, natural gas demand appears to have been less impacted by the pandemic as compared to other fossil fuels. Despite the decline across most segments of the natural gas value chain, global LNG trade grew by 1.4% in 2020 overcoming numerous challenges related to coronavirus pandemic, supply chain and commercial issues across the world.

Gas and LNG spot prices has shown extreme volatility, oscillating from unprecedented lows below \$2/MMBtu in 2020 to sky-high peaks above \$40/MMBtu in 2021. This type of volatility is unfavourable for both producers and consumers alike. Oil-indexed prices, on the contrary, has proven its stability and predictability which is preferred for long-term security

of investment in the industry and stable revenue streams for economic growth. In this regard, GECF Member Countries will continue to promote long-term oil-indexed contracts for the mutual benefit of all parties concerned.

In 2021, we witness a strong global recovery, albeit uneven and unsynchronized. Resuming economic activities in major advanced and developing economies along with abnormal weather conditions reflected in a strong recovery in natural gas demand. Global LNG trade has grown substantially since the beginning of 2021 driven by increasing demand in Asia and Latin America. The favourable LNG prices has led to a rebound in investment in new LNG projects. For 2021, we expect natural gas production will rebound to 2019 level, supported by price recovery, and demand expansion, which encourages suppliers to produce more natural gas.

We are strongly optimistic about future of gas industry driven by the key role of natural gas in maintaining energy security and meeting the energy requirements sustainable development needs gains importance. The natural gas is well equipped to contribute to emission reduction, decarbonisation as well as hydrogen industry in coming decades.

We believe that “natural gas is one of the global enablers for reducing emissions quickly, cost-effectively and steadfastly by replacing carbon-intensive fuels and backing up intermittent renewables,” as stated at the recent COP26 held in Glasgow in November 2021. Furthermore, the GECF supports building a circular carbon economy and developing CCUS technologies, while at the same time our Member Countries remain committed to improving data accuracy and abating methane emissions along the gas value chain.

The GECF, by publishing this report under the title mentioned above, draws the attention of all market stakeholders to the need for dialogue, cooperation, and collaboration to establish a resilient roadmap based on the lessons learnt from the impact of the COVID-19 pandemic on the gas industry. The GECF is an instrumental platform to share the challenges of the gas industry and identify the opportunities for a greater value of natural gas and fair access to natural gas for all.

I would like to express my sincerest appreciation to all contributors of the second edition of the GECF Annual Short-Term Gas Market Report.

I encourage you to explore this GECF flagship publication.

Yury P. Sentyurin
Secretary General
Gas Exporting Countries Forum

About the Gas Exporting Countries Forum (GECF)

The Gas Exporting Countries Forum (GECF) is an international governmental organization, which provides the framework for exchanging experiences and information among Member Countries. GECF is a gathering of the world's leading gas producers and was set up as international governmental organization in May 2001 in Tehran, Iran. It became a full-fledged organization in 2008, with the statutes and agreement of its functioning as a Forum signed in Moscow, Russia. The GECF Secretariat, a permanent organ of the Forum, was formally established in 2009, with its headquarters based in Doha, Qatar.

The Secretariat is an important platform that supports Member Countries' objectives to increase the level of coordination and strengthen collaboration as they move towards achieving the five strategic objectives that they have agreed upon in the long-term strategy around the core value of cooperation.

The Secretariat is carrying out its activities in accordance with the Statutes of the Forum and under the guidance of its governing bodies.

Such governance is enshrined in the long-term strategy of the Forum that stipulates five objectives that are recalled as follows:

Objective No. 1: Maximizing gas value, namely to pursue opportunities that support the sustainable maximization of the added value of gas for Member Countries. Objective No. 2: Developing the GECF view on gas market developments through short, medium and long-term market analysis and forecasting. Objective No. 3: Cooperation, namely to develop effective ways and means for cooperation amongst GECF Member Countries in various areas of common interests. Objective No. 4: Promotion of natural gas, namely to contribute to meeting future world energy needs, to ensure global sustainable development and to respond to environmental concerns, in particular with regard to climate change. Objective No. 5: International positioning of the GECF as a globally recognized intergovernmental organization. Furthermore, the Forum agreed on strategic goals allowing GECF Member Countries to cooperate on strategic areas for common projects of interest including:

1. To promote natural gas as the fuel of choice;
2. To provide support for Member Countries in assessing and forecasting natural gas market developments, with the objective to become a reference for the outlook for natural gas, and keep Member Countries informed and prepared to address the challenges and to benefit from the opportunities that may arise in the future;
3. To develop a shared understanding of market conditions in order to establish common views and positions on global gas market development and to promote them internationally;
4. To provide a framework for cooperation amongst GECF Member Countries.

One of the instruments identified to carry out the above mentioned objectives is the Annual Short-Term Gas Market Report, which is the fruit of the research work undertaken by the Gas Market Analysis Department of the GECF Secretariat over the course of a whole year. This report provides an understanding of the drivers of the dynamics occurring in gas market, a short-term outlook, and also provides some recommendations of cooperation as the core value of the GECF Long-Term Strategy, for the consideration of GECF Member Countries.

In accordance with the GECF Statute, the organization 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 people, through the exchange of experience, views, information and coordination in gas-related matters.

As of today, the GECF comprises eighteen Member Countries, out of which eleven (11) are full Members, Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, and Venezuela; and seven (7) Observer Members countries, Angola, Azerbaijan, Iraq, Malaysia, Norway, Peru and United Arab Emirates.

The Forum welcomes any country producing and exporting natural gas that shares the same principles stipulated in the GECF statutes to join the GECF family of leading gas exporting countries, and benefit from the expertise of its Members.

With its current composition of membership, the GECF accounts for more than 70% of the world's proven gas reserves and contributes more than half of global gas trade (by pipeline and in LNG form), which shows the dominant role of GECF on the global gas market.

GECF Member and Observer Countries

MEMBERS



GECF: A Prominent Organization of Leading Gas Exporting Countries

- Resilience
- Long-term expertise in gas industry
- Solid long-term partnerships
- Good history in gas industry
- Proven expertise and commitment of GECF Countries to serve their clients/partners.

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CHAPTER

01

Executive Summary

Global Economy

In 2020, the global economy was drastically impacted by the COVID-19 pandemic. Before the pandemic, the global economy was projected to grow by more than 3% in 2020, however, the outbreak of the coronavirus and implementation of containment measures resulted in the lockdown of economic activities in most countries across the world. As a result, the global economic growth dramatically declined in the first half of 2020, particularly in the second quarter of the year, when the lockdown measures implemented across the globe. However, easing of restrictions and resuming economic activities led to the recovery of economic activities during the second half of 2020. As a result, a stronger than expected recovery has been realized during the 3rd and 4th quarters of 2020. Nevertheless, the significant fallout in the first half of 2020 has not been compensated by the recovery in the second half of the year. As such, the global GDP shrank by 3.2% in 2020, according to the latest estimation by IMF. The OECD and World Bank also estimated a 3.4% and 3.5% of economic decline in 2020 respectively.

During the 1st quarter of 2021, the positive implications of vaccine deployment on the economic activities as well as a fiscal stimulus by major advanced economies brought some hope to global recovery. However, outbreak of new variants of coronavirus and surging number of cases in some major developing economies including India, Brazil and Mexico as well as reinstating lockdowns in most countries, to contain the virus, weighed on the pace of global recovery.

The pace of recovery gained momentum during the 2nd quarter of 2021 driven by gradual vaccination rollout in advanced economies and implementing fiscal policy measures in advanced economies. Some advanced economies have announced a new fiscal stimulus plan for 2021. However, the surging number of COVID-19 cases, spreading of the Delta variant of COVID-19 and re-imposing restrictions have caused concerns about the pace of the global recovery. Indeed, the situation has worsened in some parts of the world due to spread of the Delta variant and increasing caseloads. Discrepancy in vaccination rollout and access to financial support have been reflected in diverging economic prospects across the world. While advanced economies managed to vaccinate the most part of their population and supported their economies by additional policy packages, most of developing economies have been struggling to contain the pandemic due to slower vaccination. Although the negative impacts of recent lockdowns are expected to have weaker impact on the economic activities, the recovery of the global economy in 2021 is expected to be accompanied by delays and downside risks. If vaccines are deployed swiftly across the world in 2021, the global economy is expected to recover by 5.9% in 2021 and 4.9% in 2022, according to IMF.

Energy Policy Developments

As the main determinant of the countries' future natural gas supply and demand trajectory, the energy policies were affected by the decarbonization process and COVID-19 pandemic. The countries' intention to decarbonize their energy sector coupled with the COVID-19 pandemic, recorded new trends in the energy realm. Some countries designated a significant portion of their stimulus packages to green recovery and energy transition and announced their plans to become carbon neutral and updated their carbon emission reduction targets.

For instance, Canada, Japan, China, and Brazil announced their plans to become net-zero carbon economies and South Korea updated its NDC during the pandemic. Regarding energy policies, a more global focus on carbon emission mitigation is becoming evident by recovering from the COVID-19 pandemic.

Meanwhile, the post-pandemic policies are expected to focus mainly on making the balance between inflation control, job creation and climate change issues. By recent energy crisis in Europe, East Asia and the Southern States of the US, it is expected that in the recovery period, natural gas will play a very crucial role in countries energy policy agenda to respond to their energy needs and prevent energy crisis with the lowest impact on the environment.

Global Natural Gas Consumption

Global gas consumption in 2020 recorded its first annual decline in more than a decade, dropping by 2% in 2020 to reach 3.87 Tcm, which corresponds to a decline of 80 Bcm compared to 2019. The outbreak of the COVID-19 pandemic and above-average seasonal temperatures observed in the winter period in the northern hemisphere were the main drivers of the decline. At the regional level North America, Europe and Eurasia accounted for the bulk of the decline in global gas consumption. The drop in gas consumption was driven by a combination of mild weather during Q1 2020 and the lockdown measures implemented by governments across the world to contain the spread of the virus. The COVID-19 measures impacted mainly the power generation sector as well as the distribution and industrial sectors. Even the accelerated coal-to-gas switching in some regions did not help to reduce the effect of the lockdown in gas consumption during the year 2020.

At the country level, the U.S., Russia, the UK, Italy Australia and Japan drove the decline in gas consumption. In contrast, China is one of the few countries that witnessed an increase in gas consumption globally, although it was the first country to be affected by the COVID-19 pandemic. China remained the driver of gas consumption growth in the world and the growth was driven by higher consumption in the city gas, petrochemical and power generation sectors. For the U.S., the decline in gas consumption was recorded in the residential, commercial and industrial sectors but was partially offset by an increase in gas consumption in the power sector, which was driven by the intensification of the coal-to-gas switching due to low gas prices. Furthermore, the decrease in gas consumption in Russia was attributed to mild winter weather that curbed gas consumption in the power and distribution sectors and the COVID-19 restrictions implemented by the government.

For 2021, we forecast an increase in gas consumption by around 3%. We project cold weather during the winter season will contribute to around 1% in the growth of gas consumption. Besides, we considered a hotter than normal summer period which will contribute to the increase in air-conditioning use that will boost gas consumption in the power generation sector. Moreover, we have considered the easing of the lockdown measures beginning from the second half of 2021, with a successful vaccination campaign in the majority of the consuming countries. Meanwhile, the remaining growth is mainly attributed to higher consumption in the power and industrial sectors. China is forecasted to drive growth, supported by a rebound in economic and industrial activity. All regions,

except North America, are forecasted to record a surge in gas consumption in 2021, with the majority expected to rebound to 2019 levels or higher.

For 2022, we are forecasting growth of between 1.4% to 1.8%, taking into consideration the supporting policy of the coal-to-gas switching in China, India and Germany as examples. The extension of the gas grid in China and India and some new players in south and southeast Asia such as Pakistan, Bangladesh and Thailand will contribute to boost gas consumption. Moreover, the entrance of the Nord Stream 2 pipeline will displace some coal or nuclear in the German electricity mix. Furthermore, we considered that the majority of the COVID-19 restrictions will be removed for the whole year 2022 with a successful vaccination campaign.

Global Natural Gas Production

Natural gas production in 2020 was affected by the COVID-19 pandemic. Upstream activities declined significantly across the globe due to weak demand for natural gas and low oil and gas prices in global markets. As a result, global natural gas production dropped by 3% in 2020 compared to the 2019 level. CIS and North America experienced the highest level of decline among the regions. Among the countries, the US experienced the highest level of decline. Meanwhile, natural gas production in China, Iran and Azerbaijan increased in 2020.

Some oil and gas companies reported huge losses in 2020 and some others filed for bankruptcy. By recovering from the negative impacts of COVID-19 pandemic, oil and gas companies are trying to stabilize their cash flows and balance their financial statements rather than invest in new development projects. Accordingly, it is expected that upstream investment in 2021 to remain at the same levels of 2020. This may cause a shortage of natural gas supply due to the lack of investment in the upcoming years.

For 2021, it is forecasted that global production will recover to the 2019 production level and will continue to grow in 2022.

Natural Gas Trade Global Pipeline Gas Trade

In 2020, global pipeline gas trade, based on the net flows approach, declined by 4% to 525 Bcm, driven by a drop in global gas demand amid the COVID-19 restrictions (based on the gross flows approach, global pipeline gas trade dropped by 7% to 766 Bcm). In net pipeline gas imports, Europe was the leader with 58% of the market, while Asia Pacific and North America represented 14% and 11%, respectively. In net pipeline gas exports, C.I.S. dominated with 48% of the market, while Europe and North America represented 20% and 11% of the market, respectively.

In 2021, higher gas demand, driven by the colder-than-usual winter season, lower gas inventories and easing of the COVID-19 restrictions, as well as a drop in LNG imports resulted in a recovery of pipeline gas imports in Europe, which is a main driver of global pipeline gas trade.

In the short-term, global pipeline gas trade is expected to rise consistently, driven by an uptick in gas demand amid the lifting of COVID-19 restrictions and, possibly, colder-than-usual winter seasons. The completion of new gas pipelines in Europe, China and Mexico may contribute to a growth in global pipeline gas trade.

Global LNG Trade

In 2020, despite the devastating impact of the COVID-19 pandemic, the global LNG trade was resilient recording an increase of 4.8 Mt as compared with a year before. The global LNG trade reached 358.4 Mt in 2020, representing around 1.4% growth in comparison with 2019. However, this has been lowest growth rate of the global LNG trade since 2016, which was caused by the pandemic

The global LNG demand had kept growing by 11% y-o-y in the 1st quarter of 2020, reaching to 97.4 Mt. However, global LNG trade stood below 2019 level during the second and third quarters of 2020 driven by the lockdown measures and declining energy demand due to slowdown in the economic activities. The global LNG demand stood at 85 Mt in the second quarter of 2020, almost 1% less the same period the year before. Similarly, the global LNG trade decreased by 4% y-o-y to 84.1 Mt in the 3rd quarter of 2020 reflecting lagged impacts of the pandemic on the LNG demand. However, LNG trade started recovering in the 4th quarter of 2020 driven by resuming economic activities during the second half of the year and colder than expected winter in the Northern hemisphere. The global LNG trade reached 92.2 Mt, almost 0.5 Mt below the same quarter in 2020.

During the first 3 quarters of 2021, the global LNG trade reached 266.4 Mt, representing 5.9% growth as compared with the same period last year. Surging LNG demand in Asia and Latin America resulted in global LNG trade growth during the first 9 months of 2021, while LNG demand in Europe and MENA region declined (see Figure 66).

Asia imported 185.3 Mt of LNG in the first 9 months of 2021, showing 11.2% y-o-y growth, driven by surging gas demand in China, Japan and South Korea. Latin America's LNG imports also increased by 68.8% during January to September 2021, reaching 14.3 Mt from 8.5 in the same period last year. However, LNG imports into Europe stood at 55.1 Mt during the first 9 months of 2021, falling by 15.8% as compared with the same period last year. LNG imports by MENA region declined by 4.8% y-o-y during the first 9 months of 2021.

Global LNG Supply

Global LNG supply remained resilient in 2020, despite the decline in global gas consumption and weakened growth in LNG demand. The growth in global LNG supply slowed to around 0.8% (2.9 Mt) y-o-y, from 11.6% in 2019, to reach 358 Mt. The slower growth was mainly due to the impact of the COVID-19 pandemic restrictions on the LNG industry. The increase in LNG supply was notably driven by Non-GECF countries (7.2% or 11.0 Mt) y-o-y to 164 Mt, and to a lesser extent from reloads, which rose by 75.0% (1.3 Mt) y-o-y to almost 3 Mt. In contrast, GECF's LNG exports fell by 4.7% (9.4 Mt) y-o-y to 192 Mt. The U.S., whose exports rose by 34.0% (12.0 Mt) y-o-y in 2020, drove the jump in Non-GECF LNG supply. The surge

in U.S. LNG exports occurred despite the loss of around 10 Mt of LNG supply from the country, which was due to the cancellations of a vast number of LNG cargoes amidst the record low spot prices witnessed last year. In GECF countries, the decline was as a result of lower feedgas availability in some countries, planned and unplanned maintenance activity and reduced exposure to the low-priced spot market.

In the short-term, global LNG exports (excluding reloads) are forecasted to grow by 5.5-6% (21 Mt) in 2021 and 2022 to 376 and 397 Mt in respectively. The increase in LNG exports in 2021 is driven mainly by Non-GECF countries (25 Mt), which is expected to offset a small decline in GECF's LNG exports (4 Mt). The recovery in lost LNG supply, due to weak spot prices in 2020, and the ramp-up and start-up of new LNG projects in the U.S. are expected to boost Non-GECF's LNG exports. Despite the recovery in LNG exports in Egypt and start-up of new projects in Malaysia and Russia, feedgas issues and planned and unplanned maintenance activity in other GECF member countries have a negative impact on GECF's LNG exports in 2021.

Further ahead in 2022, GECF member countries are forecasted to drive the growth in global LNG exports with an increase of 12 Mt while Non-GECF countries LNG exports are expected to increase by 9 Mt. The improvement in feedgas availability in some GECF member countries, lower maintenance activity, and the ramp-up in LNG production in Egypt, Malaysia and Russia are expected to push GECF's LNG exports higher next year. Meanwhile, the start-up and ramp-up in LNG exports from Indonesia, Mozambique and the U.S. coupled with the debottlenecking at Oman's LNG facility would support the stronger exports from Non-GECF countries. In 2021 and 2022, GECF's share of global LNG exports are forecasted to average 50% in both years.

New LNG Exporting Capacity

Although global LNG exports grew meagerly last year, 20 Mtpa of new LNG capacity started to export LNG globally and represented an increase of 4.5% y-o-y to reach 463 Mtpa. The start-up of projects came solely from the U.S. In 2021, the start-up of new LNG export projects is forecasted to dip to around 5 Mtpa, which includes projects from Malaysia, Russia and the U.S. However, in 2022, the commissioning of new LNG export projects is forecasted to rebound to 18 Mtpa, with projects from Indonesia, Mozambique and the U.S. The majority of new LNG projects expected to be commissioned this year and next year are from Non-GECF countries.

In terms of LNG FIDs, around 170 Mtpa of projects targeting FIDs last year were postponed, mainly due to weak market conditions and lack of long-term contracts to secure financing. More than 60% of the FID postponement came from the U.S. Only one LNG project reach FID last year, the Energia Costa Azul project (3.25 Mtpa) in Mexico, which represents a slump in FIDs from 71 Mtpa in 2019. During the first seven months of 2021, around 47 Mtpa of LNG capacity reached FID including Qatar's First Phase of its LNG expansion, Fast LNG project being developed by the U.S. company, New Fortress Energy, and Russia's Baltic LNG project. In the short-term, almost 180 Mtpa of new LNG export capacity are targeting FID, with 64% of the projects in the U.S. followed by Qatar (9%), Mozambique

(9%) and others. The improving market conditions and healthy outlook for LNG demand are expected to support more FIDs in the short-term.

LNG Shipping Cost

In 2020, the average LNG spot charter rate for steam turbine vessels declined by 11% to 43,000 USD/day, mainly driven by a slowdown in the growth of LNG cargoes amid the COVID-19 pandemic and a high number of the commissioned LNG carriers. Meanwhile, the average leading shipping fuels price plummeted by 29% y-o-y to 289 USD/t, driven by a fall in global oil prices. The combination of these two factors resulted in a fall in shipping costs for spot LNG cargoes. However, in 2021, LNG shipping costs rebounded, driven by a rise in the average LNG charter rate (49,600 USD/day, or 45% higher y-o-y, in the first nine months of 2021) and an increase in the average leading shipping fuels price (490 USD/t, or 79% higher y-o-y, between January and September 2021).

Natural Gas Prices

Gas and LNG spot prices were hit by the perfect storm in 2020, reaching unprecedented lows and converged below \$2/MMBtu. An already mild 2019/2020 winter and lockdown measures due to the COVID-19 pandemic diminished gas demand. Prices in 2020 can be characterized by two distinct trends: a gradual decline in H1 and a quick rebound in H2. The rebound was driven by robust consumer demand ahead of the winter season, easing of lockdown measures and supply constraints at several LNG facilities.

Gas and LNG spot prices over the first nine months of 2021 have soared way above the lows of 2020, and even surpassed 2018 levels, favoured by supply/demand dynamics. On the demand side, there was robust recovery due to an intense winter season, warmer-than-usual summer, global economic recovery, increased LNG imports particularly in China, South Korea and Brazil and record high EU carbon prices which increased coal-to-gas switching. In terms of supply, there was reduced supply coming to the market due to several different factors including outages at some LNG facilities, more planned and unplanned maintenance due to postponements from last year, congestion at the Panama Canal which delayed cargo deliveries during the winter, slower recovery in pipeline gas supply to Europe, feedgas supply issues from some existing suppliers and reduced US gas production due to the passing of Hurricanes Ida and Nicholas during the summer and very low European storage levels.

Spot prices are expected to continue its bullish trend in Q4 2021 on the anticipation of strong gas demand, as the global economy slowly heals from the impact of the COVID-19 pandemic. Gas and LNG spot prices are also expected to remain bullish until Q1 2022. However, prices will be at the mercy of weather conditions. If we experience extremely cold temperatures similar to this year, we can expect significant price spikes during the winter 2021/2022. On the other hand, if we experience a mild winter, prices are expected to soften, but would still be relatively high.

Carbon Mitigation Strategies

Carbon Neutral LNG Cargoes

Carbon Neutral LNG (CNL) cargoes are a relatively new concept in the gas industry but have gained global interest in a short period of time. These refer to those cargoes in which the greenhouse gas (GHG) emissions have been offset through the purchase of carbon credits from nature-based or renewable projects and is used as a carbon mitigation strategy in the LNG industry. In terms of the carbon emissions across the LNG value chain, the final consumption accounts for around 75% of the total emissions. Around twenty-seven (27) CNL cargoes have been traded since July 2019, mainly in Northeast Asia and the remainder in Europe, Latin America and the Caribbean and the Middle East. Shell was the first mover in the trade of CNL cargoes but other market players, such as TotalEnergies, Gazprom, Petronas, Cheniere, INPEX and others, have since become involved in the trade. Based on the average carbon credit price of \$4.06/tCO₂e in 2021 thus far, the average cost of carbon offset for a standard size cargo is \$0.26/MMBtu, which is negligible compared to the current LNG prices of more than \$40/MMBtu.

This new concept is regarded as a carbon reduction mechanism as many countries across the world adopt policies to reduce carbon emissions and achieve carbon neutrality. As such, the trade of CNL cargoes is expected to grow significantly in the short to medium-term. This is evident by the recent signing of a five year contract between Shell and PetroChina for the supply of carbon neutral LNG.

Contractual Reporting of Emissions

The increasing scrutiny on GHG emissions along the LNG value chain has led to the introduction of a carbon reporting clause in LNG contracts where the LNG seller is obligated to provide a statement of associated GHG emissions for LNG cargoes, from the wellhead to the discharge port. Qatar Energy, Chevron and BP have recently entered into medium to long-term LNG contracts with Pavilion Energy of Singapore, which include this contractual obligation for the reporting of GHG emissions for each LNG cargo delivered. In addition, Cheniere has also committed to providing the statement of GHG emissions to buyers for LNG cargoes produced from its LNG facilities in the U.S. These developments are expected to support the creation of a global standard for measuring and reporting GHG emissions across the LNG value chain.

Carbon Reduction Strategies in the LNG Industry

As many countries across the world adopt long-term carbon neutral policies, several LNG suppliers, including those from GECF member countries, have started to implement strategies to reduce their carbon footprint along the LNG value chain. The main carbon reduction strategies include the CCS/CCUS technology, electrification of upstream operation and the liquefaction process using renewable electricity and jetty boil-off recovery system. The acceleration of the energy transition is expected to further support the implementation of similar or other carbon reduction strategies across the gas industry. Such strategies are vital for the expansion of natural gas demand in a low carbon future.



CHAPTER 02

Introduction

The Annual Short Term Gas Market Report 2021 is one of GECF's flagship publications and is the second public edition. The report reflects the impartial views of the GECF Secretariat and covers a retrospective analysis and current state of the gas industry until September 2021, in most sections, as well as short-term forecasts for 2021 and 2022. It also assesses the potential opportunities and threats for the gas industry in the short-term.

The following gives an overview of the eight (8) main sections of the report:

- **Global Economy** reflects the latest estimates of the world economy with an assessment of its significance for the natural gas market in particular.
- **Energy Policy Developments** provides an overview of the latest energy policy developments in specific countries and their possible impacts on the natural gas market.
- **Global Natural Gas Consumption** analysis of the global and regional natural gas demand trends in OECD countries and a focus on some key Non-OECD countries. This section also analyses the natural gas consumption by sector, including the electricity generation and transportation sector, in specific markets.
- **Global Natural Gas Production** reflects the latest natural gas production trends on a regional and country basis as well as upstream activities. In addition, natural gas storage developments on the global level, with a focus on the European Union and United States are also analysed.
- **Natural Gas Trade**
 - **Pipeline natural gas** – trade at a global level, with a focus on the European Union, and GECF's performance in this major market. The developments of new pipeline natural gas export projects in GECF member countries are also assessed.
 - **LNG trade** – this section focuses on regional imports of LNG, LNG exports by supplier, spot and short-term LNG trade, development of new LNG export projects and a LNG supply/demand balance until 2030. It also zooms on GECF's performance in the global and regional LNG markets and LNG shipping cost based on GECF's shipping cost model.
- **Natural Gas Prices** – analysis of the trends in gas, LNG and oil prices at a regional level, key drivers and expected short-term outlook. In addition, it includes a comparison on spot, hub and oil-indexed prices.
- **LNG Contracting Pricing Mechanisms** – recent developments in LNG contracting, such as pricing mechanisms, with a focus on oil-indexation, contract duration and expiration of LNG contracts.
- **Carbon Mitigation Strategies** – the trade of carbon neutral LNG as a carbon mitigation mechanism and contractual obligations to report the GHG emissions associated with LNG cargoes are analysed. In addition, this section also assesses LNG suppliers' strategies to reduce their carbon footprint.

The forecasts in the report were assessed using bottom-up in-house models developed using Excel. The assumptions for each forecast are detailed in the individual sections of the report. In terms of data sources for the analysis, a combination of primary data from GECF member countries and secondary data from public sources and GECF Secretariat's subscriptions were used. In comparison to the Annual Short Term Gas Market Report 2020, there has been some new content included in the report and are highlighted below:

- EU's Fit For 55 package and its potential impact on natural gas demand
- Greater coverage on the development of natural gas vehicles
- Natural gas storage developments in the U.S.
- Asian LNG price indices in consuming countries
- Carbon neutral LNG cargoes as a carbon mitigation strategy
- Contractual obligation to report GHG emissions associated with LNG cargoes
- Carbon reduction strategies in the LNG industry



CHAPTER
03

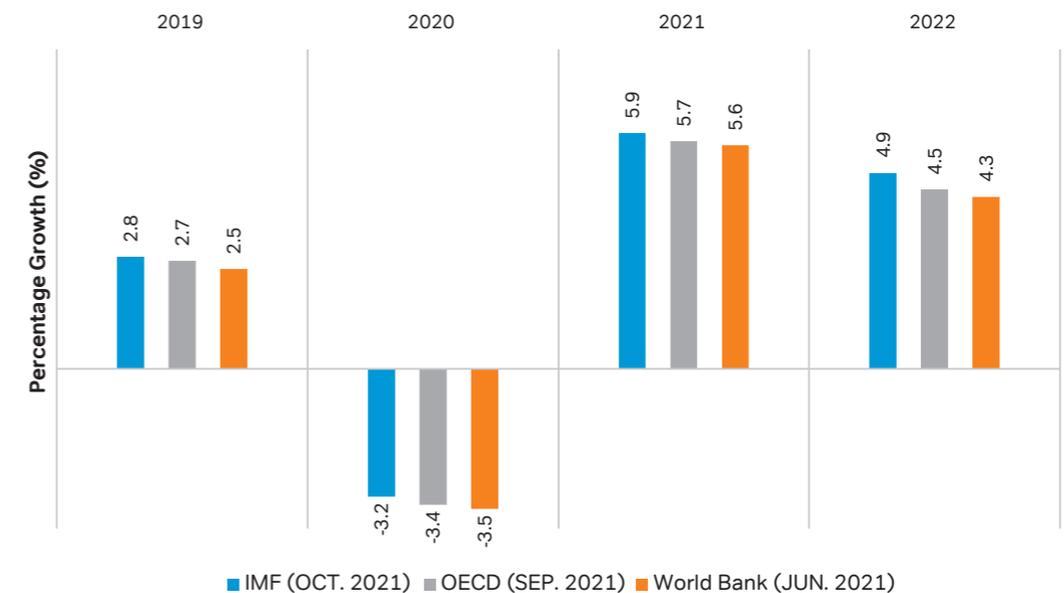
Global Economy

3.1 Review of 2020

In 2020, the global economy was drastically impacted by the COVID-19 pandemic. Before the pandemic, the global economy had been projected to grow by more than 3% in 2020, however, the outbreak of the coronavirus and implementation of containment measures resulted in the lockdown of economic activities in most countries across the world. As a result, the global economic growth dramatically declined in the first half of 2020, particularly in the second quarter of the year, when the lockdown measures implemented across the globe. However, easing of restrictions and resuming economic activities led to the recovery of economic activities during the second half of 2020. As a result, a stronger than expected recovery has been realized during the 3rd and 4th quarters of 2020. Nevertheless, the significant fallout in the first half of 2020 has not been compensated by the recovery in the second half of the year. As such, the global GDP shrank by 3.2% in 2020, according to the latest estimation by IMF. The OECD and World Bank also estimated a 3.4% and 3.5% of economic decline in 2020 respectively (see Figure 1).

Although the rebound in economic activities in the second half of 2020 along with supportive policy packages have prevented further exacerbation of the global economy in 2020, the longer-term impacts of the pandemic have remained destructive. The pandemic has severely affected developing economies with weak financial situations leading to increase in sovereign debts, budget deficit and poverty.

Figure 1: Review of Global GDP Growth and Projections for 2021 and 2022



Source: GECF Secretariat based on data from IMF, OECD and World Bank

3.2 Outlook for 2021

During the 1st quarter of 2021, the positive implications of vaccine deployment on the economic activities as well as a fiscal stimulus by major advanced economies brought some hope to global recovery. The initial implications of vaccine deployment were reflected in the growing global financial and commodity markets. Vaccine deployments have gradually increased in major advanced and developing economies. In addition, some major economies in Asia, including China, Japan and South Korea, have grown substantially in the 1st quarter of 2021. In particular, China's economy has experienced 18% of growth in the 1st quarter of 2021 supported by strong exports and rising business confidence. However, outbreak of new variants of coronavirus and surging number of cases in some major developing economies including India, Brazil and Mexico as well as reinstating lockdowns in most countries in to contain the diseases weighed on the pace of global recovery.

The pace of recovery gained momentum during the 2nd quarter of 2021 driven by gradual vaccination rollout in advanced economies and implementing fiscal policy measures in advanced economies. Some advanced economies have announced a new fiscal stimulus plan for 2021. The largest plan was the American Rescue Plan Act, which consists of a \$1.84 trillion policy stimulus package intending to facilitate the recovery of the U.S. economy from the devastating economic and health effects of the COVID-19 pandemic. However, the surging number of COVID-19 cases, spreading of the Delta variant of COVID-19 and re-imposing restrictions have caused concerns about the pace of the global recovery. Indeed, the situation has worsened in some parts of the world due to spread of the Delta variant and increasing caseloads. Discrepancy in vaccination rollout and access to financial supports have been reflected in diverging economic prospects across the world. While advanced economies managed to vaccinate the most part of their population and supported their economies by additional policy packages, most of developing economies have been struggling to contain the pandemic due to slower vaccination. Although the negative impacts of recent lockdowns are expected to have weaker impacts on the economic activities, the recovery of the global economy in 2021 is expected to be accompanied by delays and downside risks. If vaccines are deployed swiftly across the world in 2021, the global economy is expected to recover by 6% in 2021 and 4.9% in 2022 according to the latest World Economic Outlook released by IMF in July 2021. However, if the vaccine rollout does not occur as expected, the global recovery would lose momentum in 2021. The global community needs a wider vaccination rollout to ease ongoing lockdowns and resume economic activities in full capacity. Additionally, there should be a supportive fiscal stimulus to back up the recovery. In this regard, international cooperation is a key factor to mitigate unequal recovery and cope with the outbreak of new variants of coronavirus. All of these conditions are necessary for a strong recovery, while any shortcoming in each of those would be reflected in a weaker recovery.

Among Advanced Economies, the US economy is expected to grow by 6% in 2021, according to the IMF. The strong recovery is supported by continues vaccine rollout, growing economic activities along with fiscal policy support. The US economy is projected to keep growing by 5.2% in 2022 according to the IMF.

Economic Activities in European Union is estimated to recover by 5.0% in 2021 and 4.3% in 2022, against the economy declining by 6.3% in 2020 due the outbreak of coronavirus. The recovery in Japan is expected to rebound by 2.4% in 2021 and 3.2% in 2022, after declining by 4.6% in 2020.

The consistent growth between both major advanced and developing economies is expected to realize in China, the country that experienced 2.3% of economic growth in 2020 amid the COVID-19 pandemic. The economy is estimated to grow by 8.0% in 2021 thanks to boosting trade and industrial activities. However, the pace of growth is projected to moderate to 5.6% in 2022 due scaling back of public investment and fiscal supports.

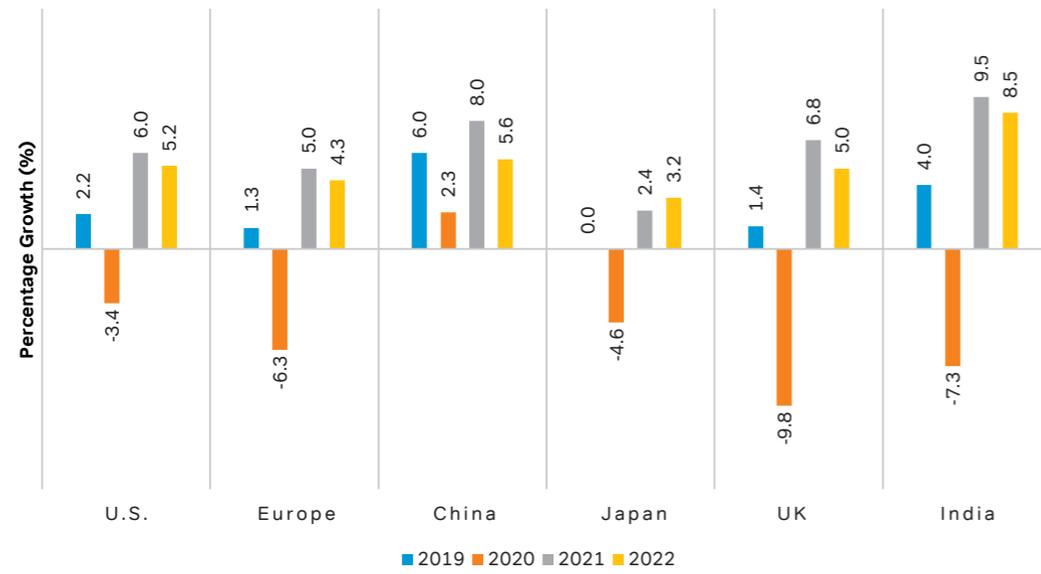
India's economy is estimated to rebound by 9.5% in 2021 and 8.5% in 2022. However, the projected figures seem fragile due to critical situation of India in controlling the new waves of the pandemic (see Figure 2).

Having said that the global economic growth is gaining momentum in the second half of 2021, the expected strong recovery remains highly uncertain, concentrated only in few major economies, with developing economies lagging behind. Downside risks to the global economy are unequal vaccine access, insufficient supporting policy and geopolitical tensions. The spread on new Delta variant of coronavirus added more uncertainties to the global recovery. The latest outlooks released by IMF, World Bank and the OECD are expecting a strong recovery in 2021. The GDP growth is expected to recover by 5.9% in 2021, followed by 4.9% in 2022 according to the IMF.

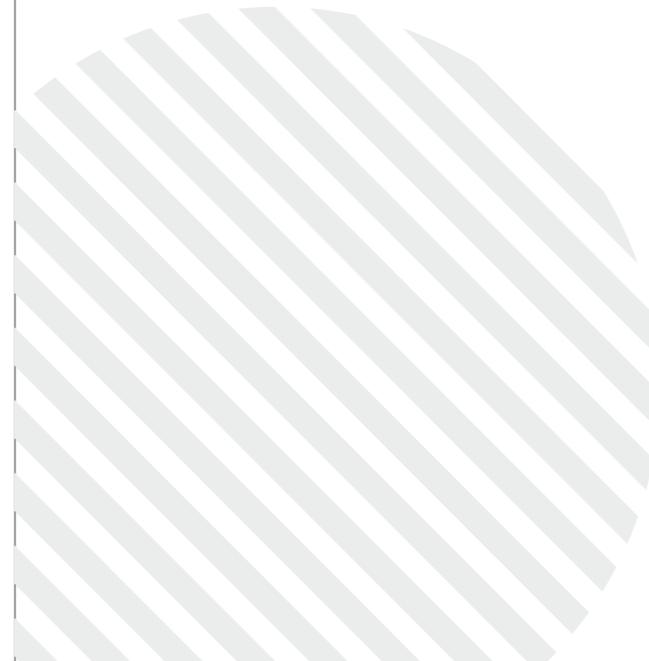
However, this recovery is on an unstable equilibrium, due to the high uncertainty to this economic regain, which is concentrated only in few major economies, with developing economies lagging behind.

There are downside risks such as the unbalanced access to vaccine, resurgence of new variants and new waves, insufficient fiscal policy support in low-income countries as well as geopolitical tensions.

Figure 2: GDP Growth in Major Advanced and Developing Economies



Source: GECF Secretariat based on data from IMF World Economic Outlook (July 2021)





CHAPTER

04

Energy Policy Developments

4.1 Recent Developments in Energy Policies

Two main subjects have influenced the energy policy of the countries in 2020 and 2021. First, COVID-19 pandemic and second, the global movement to reduce carbon emissions. Since the COVID-19 pandemic started in the first quarter of 2020, the governments implemented policies and stimulus packages to cope with the negative impacts of the pandemic. Furthermore, the governments tried to learn from the previous crisis, such as the financial crisis of 2007-2008, to implement the most relevant policies on a timely basis. Some of the supporting mechanisms such as fiscal programs, and tax rebates affected the countries energy policy trajectory resulting in reducing domestic energy prices for consumers and relaxing the energy sector's rules and requirements in some countries.

Meanwhile, the countries' intention to decarbonize their energy sector coupled with the COVID-19 pandemic, recorded new trends in the energy realm. For instance, preliminary estimations of the investment level in 2020 indicate that the fossil energy sector was hit severely by the pandemic, while investment in renewables shows more resilience during the pandemic. Some estimations show that investment in the oil and gas upstream sector declined by 30% in 2020 while investment in clean energy remained constant. This may cause a shortage of fossil energy supply in the future due to the lack of investment.

Regarding the decarbonization policies, some countries announced their plans to become net-zero carbon economies, such as Canada and Japan by 2050 and China and Brazil by 2060. In addition, several countries have updated their Nationally Determined Contribution (NDC) during the pandemic, such as South Korea.

4.1.1 Europe

In addition to decarbonization policies, gas market reforms and clean gas policy initiatives gained momentum in European Union (EU) member states. Some of the measures, such as European Green Deal and Next Generation EU, are drivers to accelerate the energy transition.

Some EU member states started to set up measures to support the penetration of hydrogen in their energy systems. In addition to France, which allocated a portion of its stimulus package for hydrogen production, Germany set up a national hydrogen council. It also approved some natural gas pipelines to be used to transport hydrogen.

EU member states also agreed to increase their previous 40% emission reduction to 55% compared with the 1990 emission level by 2030. Accordingly, some of the EU member states updated their emission reduction targets to reach the objectives set by the union.

The European Central Bank (ECB) unveiled its 750 billion Euros package to purchase bonds and support financial markets. The instrument and stimulus package is aimed at boosting recovery after the pandemic, which guarantees a more digital, greener, and more resilient EU to cope with the challenges imposed by the COVID-19 pandemic. This temporary

recovery instrument's main objective is to help repair the socio-economic damages brought by the COVID-19 pandemic. A significant portion of this stimulus package (around 40 billion EUR) is designated to green recovery plans. The stimulus package's first steps started by proposing the Next Generation EU package on 27th May 2020. The last step was adopting the Next Generation EU on 17th December 2020, after which the European Parliament and the Council reached an agreement on the budget. Germany, the leading European economy, also unveiled its game-changing fiscal stimulus to increase the lending level and fund industries that suffered from the pandemic. In addition, the government adopted its new investment plan of 11.5 billion Euros to be directed to energy transition during the years 2021 to 2027.

Regarding energy policies in Europe, Table 1 summarizes some of the policies that emerged from the pandemic management and significantly affected the natural gas market in the continent.

Table 1: Major Energy Policies in Europe

EU
Fit for 55 carbon market package of proposals
Plans to establish Carbon Border Adjustment Mechanism (CBAM)
Coal phase out by 8 countries (2022-2030)
Approval of 55% GHG reduction target by 2030 compared to 1990 levels
To prolong funding some natural gas projects
Incorporation of Green Recovery in COVID-19 stimulus package
Green Deal to become the pillar of economic recovery plans
FRANCE
Allocation of part of economic stimulus package for hydrogen production
The UK
To maintain existing carbon tax (GBP18/mt) for power producers in 2021-2022
New GHG emissions reduction target of 68% by 2030
THE NETHERLANDS
New plan to cut CO2 emissions in short term
New cap on Groningen output at 3.9 bcm for 2021-2022
GERMANY
Approval of 65% renewables share in power sector by 2030
To remove cap on solar subsidies
To set up National Hydrogen Council
Approval of conversion of some gas pipelines to hydrogen
To invest 11.5 billion euros in energy transition (2021-2027)

ITALY

To reduce GHG emissions by 60% by 2030 compared to 1990

NORWAY

To give more tax relief to oil and gas companies

To triple its national carbon tax by 2030

Source: GECF Secretariat based on country updates

4.1.2 Asia Pacific

In the Asia Pacific region, the decarbonization policies and GHG emission reduction targets are the main drivers of the countries' energy policy measures based on their energy plans (see Table 2). In May 2021, China's government has set a new target for renewables to account for half of the installed capacity by the end of the 14th five-year plan (2025). It is worth mentioning that China added 70 GW of wind and 40 GW of solar power capacity in 2020 and is planning to add 140 GW of new capacity in 2021.

Amidst the COVID-19 pandemic and in the first quarter of 2020, China's central bank decided to promote lending mechanisms to support small businesses and maintain liquidity in the financial sector to cope with the negative impacts of the pandemic. Later in the second quarter of 2020, as the pandemic came under control, the Chinese government announced its plans to cut domestic gas prices for non-residential users to support the industry resume their activities.

Other Asian countries, Japan and South Korea revised up their GHG emission reduction targets. South Korea updated its target to reduce GHG emissions by 24.4% by 2030, from their 2017 level. Japan also announced its new GHG emission target of 46% on 2013 levels by 2030. It should be reminded that Japan's previous GHG emission reduction target was 26%.

The energy policies of India were highly affected by the ramifications of the COVID-19 pandemic. In addition to the fiscal package and direct payments to the households who suffered from the lockdowns, the government reduced natural gas prices produced from domestic sources, below the imported LNG prices for domestic consumers during the pandemic. In the Pacific, the Australian government has reiterated its intention to put natural gas in the heart of its post-pandemic economic recovery plans.

Table 2: Major Energy Policies in the Asia Pacific

CHINA
To ease back on coal to gas conversion policy
To halt subsidies for some renewable projects
Decision to introduce the country's first energy law
New obligation to three national oil and gas companies to share LNG terminals
To increase renewable power subsidy by 4.9% in 2021

To increase oil and gas exploration in five year development plan (2021-2025)
To increase nuclear power generation capacity to 70 GW by 2025
Setting stricter carbon emission targets by 2030
To add 140 GW of new renewable capacity in 2021
Launched emission trading scheme
Setting new target for renewables to account for half of installed capacity by 2025
To cut natural gas prices for non-residential consumers to offset the negative impacts of the pandemic
INDIA
To revise natural gas pipeline tariffs for remote areas
To increase renewable capacity to 220 GW by 2022
To ease requirements to set up LNG filling station
To increase share of natural gas in energy mix to 25% by 2030
To cut domestically produced gas prices to cope with negative impacts of the pandemic
SOUTH KOREA
To scale up restrictions on coal power plants
To increase the share of renewables in the power mix from the current 15% to 40% by 2034
New GHG emission reduction target of 24.4% by 2030 on 2017 levels
Financial support to hydrogen businesses
JAPAN
To halt coal power plant export
New GHG emission target of 46% on 2013 levels by 2030
AUSTRALIA
To lift moratorium on onshore gas drilling in Victoria
To put natural gas in the heart of its economic recovery plan

Source: GECF Secretariat based on country updates

4.1.3 Americas

North America

The policy agenda of the U.S. in 2020 was driven mainly by the measures to offset the impacts of the COVID-19 pandemic; however, in 2021, the energy policy agenda undergoes some fundamental changes by President Biden. Right after taking over the presidency, Biden signed several executive orders to unwind Trump's energy agenda. The main items of President Biden's policy agenda include returning Paris Agreement (see Table 3), to halt oil and gas development in the Arctic region and federal lands, rescinding the permit for the Keystone pipeline from Canada to the US and reviewing more than 60 rules and actions related to energy industry.

In March 2020, the US Senate passed a 2 trillion USD bill to support the US economy battling the COVID-19 pandemic. The package covered tax rebates, direct payments, and loans

to individuals and businesses who suffered from the pandemic. Later in 2021, President Biden unveiled a 2 trillion USD infrastructure and economic recovery stimulus plan with an especial focus on decarbonization and green recovery.

Meanwhile, during the pandemic, the federal government and states supported the oil and gas industry by implementing policies to offset the negative impacts of the COVID-19 pandemic on oil and gas producers. The support mechanisms include lowering offshore royalty rates and a waiver for producers to keep wells uncompleted.

Table 3: Major Energy Policies in the Americas

North America	
UNITED STATES	
Announcement by DOE to fund 31 hydrogen projects	
Executive orders by Biden to unwind previous energy agenda and official return to Paris Agreement	
New GHG emissions reduction target of 50%-52% on 2005 levels in 2030	
DOE extended US LNG export licenses by 2050	
To lower offshore royalty rates during the pandemic	
Waiver for Bakken producers to keep wells uncompleted	
Latin America	
ARGENTINA	
New subsidy program to stimulate natural gas production	
To lift foreign exchange limitations for gas producers	
To cut shale gas production incentives due to the pandemic	
BRAZIL	
Approval of new Natural Gas Law to liberalize natural gas market	
To streamline LNG import regulation	
To postpone power generation and transmission auctions because of the pandemic	
MEXICO	
To increase renewable capacity by 50% by 2024	
To cut Pemex taxes to offset the negative impacts of the pandemic	
To invest 3.2 billion USD in gas-fired power generation by 2024	

Source: GECF Secretariat based on country updates

Latin America

In Latin America, Argentina's government is trying to stimulate domestic natural gas production mainly from its Vaca Muerta shale basin (see Table 3); however, some projects have been delayed due to the COVID-19 pandemic. In Brazil, the energy policies focus on natural gas market liberalization; meanwhile, the government decided to postpone the power generation and transmission auctions due to the pandemic. In Mexico, the government announced plans to cut Pemex taxes to support the company during the COVID-19 pandemic. In addition, the

Mexican government unveiled its plans to invest 3.2 billion USD in gas-fired power generation by 2024 and set a new target to increase renewable capacity by 50% by 2024.

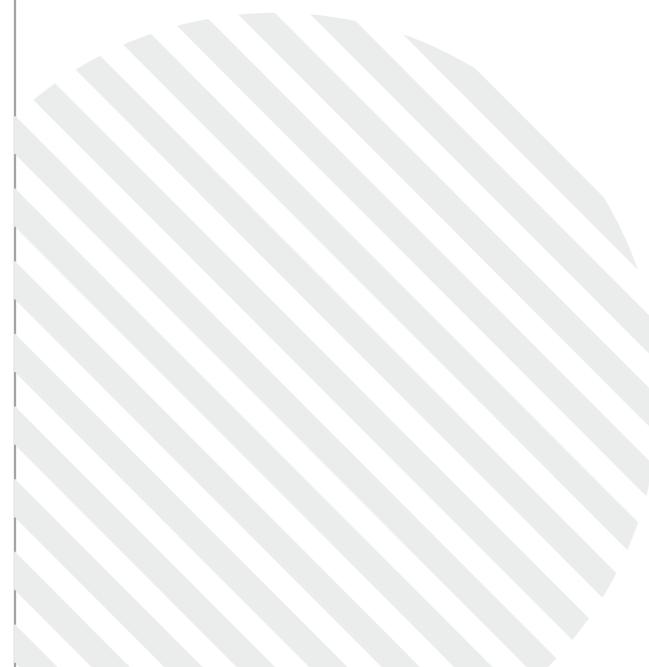
4.2 Impacts of COVID-19 Pandemic and implications on energy policy developments

As the main determinant of the countries' future natural gas supply and demand trajectory, the energy policies were affected by the decarbonization process and COVID-19 pandemic. Some countries designated a significant portion of their stimulus packages to green recovery and energy transition, and announced their plans to become carbon neutral and updated their carbon emission reduction targets.

GECF member countries are also taking a leading role in the energy transition. Some member countries updated their NDC's, while others set new targets to reduce emissions from their energy sector. Besides, other than plans to supply carbon-neutral LNG cargoes, some GECF member countries are exploring the hydrogen economy. For instance, Qatar joined some other nations to form Net Zero Producers Forum. In addition, Iran announced its plans to reduce its gas industry emissions by 70% in three years. On the other hand, Russia aims to take hydrogen and carbon-neutral LNG supply lead.

The post-pandemic policies are expected to focus mainly on making the balance between socio-economic factors and climate change issues. For instance, many people lost their job due to the pandemic, and the government's attempts will be focusing on job creation. On the other hand, they should consider the possible impacts of this recovery on the climate. In this critical recovery period, natural gas could play a crucial role in making the balance between the socio-economic factors, as a low-cost and efficient energy source, with least environmental impact among fossil energy sources.

Besides, the main trends of energy transition remain resilient despite the changes imposed by the COVID-19 pandemic. Even in some countries, the pandemic accelerated the energy transition. In this regard, focusing on the development of decarbonization technologies in natural gas, such as converting natural gas to hydrogen, could consolidate its role in the energy transition period.





CHAPTER
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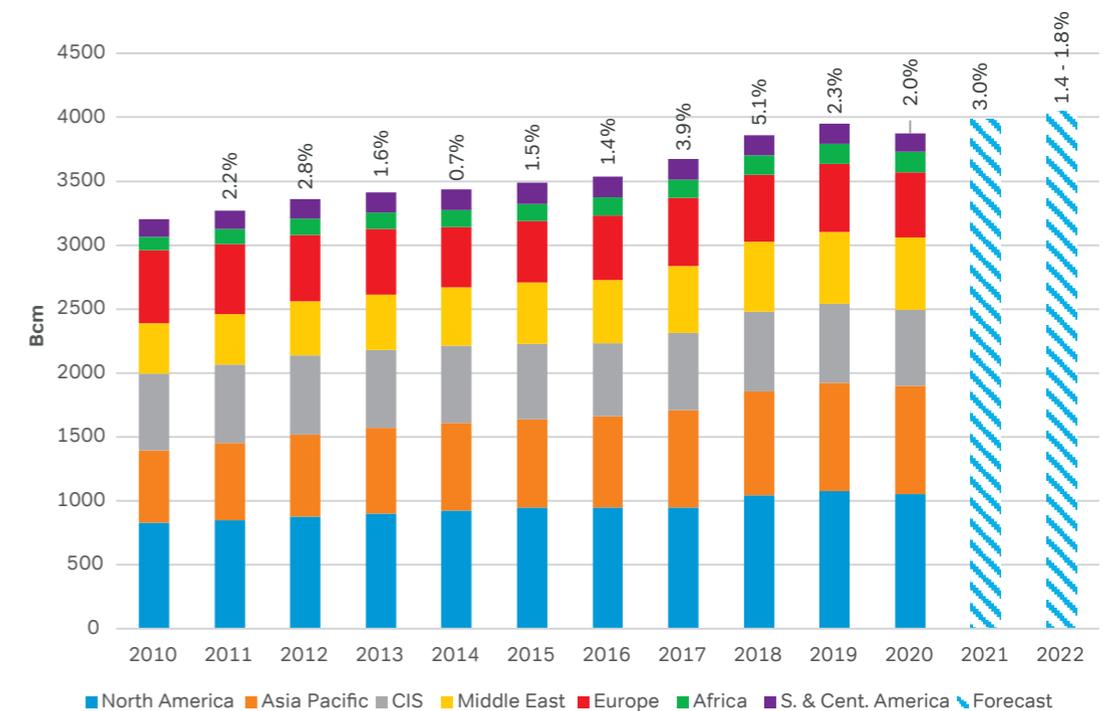
Natural Gas Consumption

5.1 Global Natural Gas Consumption

5.1.1 Recap of 2020

During the year 2020, global gas consumption saw the first decline in more than decades, caused mainly by the outbreak of the COVID-19 pandemic and above seasonal temperatures recorded in the winter period in the northern hemisphere. Global gas consumption is estimated to have declined by 2% in 2020 to reach 3.87 Tcm, which corresponds to a decline of 80 Bcm compared to 2019. The decline in gas consumption was driven by a combination of mild weather during the first quarter of 2020 and the global impact of the COVID-19 pandemic in the gas sector essentially in the second and third quarters. At a regional level, North America, Europe and Eurasia accounted for the bulk of the decline in global gas consumption. Although gas consumption in several Asian countries was negatively impacted, this was mostly offset by the increase in gas consumption in China who has recovered rapidly from the COVID-19 pandemic. As shown in Figure 3, European gas consumption represented one of the most impacted regions by the COVID-19 where the European gas consumption comes back to the 2016 level.

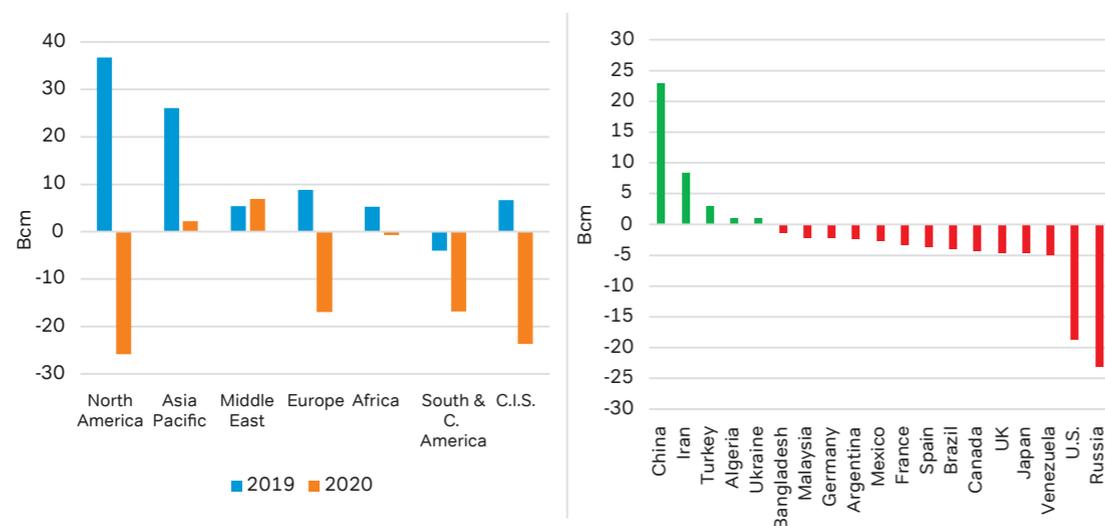
Figure 3: Trend in Global Gas Consumption by Region



Source: GECF Secretariat based on data from BP Statistical Review 2021, Cedigaz and IEA Monthly Gas Statistics

At the country level, the U.S., Canada, the UK, Germany, Russia and Japan recorded a huge decline in gas consumption whereas; China and Turkey recorded significant growth in gas consumption driven by quick recovery from the pandemic driven by a prompt decision on easing lockdown restrictions and introducing stimulus packages that aimed to revive economies (see Figure 4).

Figure 4: Trend in Gas Consumption & Incremental Gas Consumption in Major Markets in 2020



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

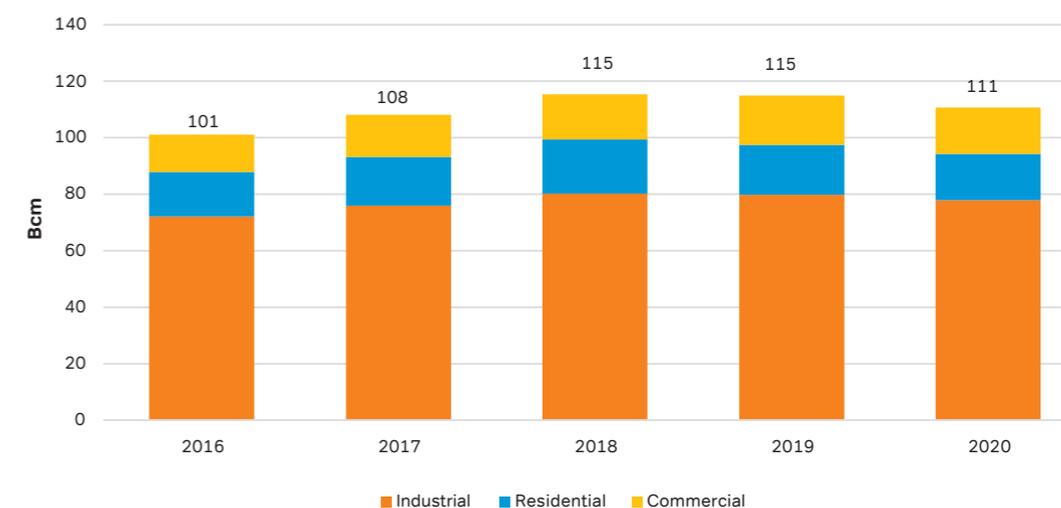
North America

Going deeper in the analysis at the country level, the U.S. gas consumption fell by 2% (17.3 Bcm) y-o-y to reach 853.5 Bcm for the year 2020. The weaker gas consumption came mostly from the residential (-10.3 Bcm), commercial (-10.2 Bcm) and industrial (4.58 Bcm) sectors. Whereas, the power generation sector recorded an increase of 2.7% (8.6 Bcm) y-o-y driven by low Henry Hub prices that boosted the coal-to-gas switching. The decline in total gas consumption was due to the lockdown measures taken in some states and the mild weather recorded during the winter period. As an indicator, the average Heating Degree Days (HDD) in 2020 was 323.2 down by 9.6% y-o-y, which implies a drop in gas consumption for heating in the residential sector.

In terms of share of gas consumption by sector, in 2020, the power sector consumed the largest amount of gas with a share of 38.1% followed by industrial (27.1%), residential (15.2%), commercial (10.3%) and transport (9.2%) sectors. In 2020, electricity production in the U.S. fell by 2.8% to 350.9 TWh, higher generation from gas (2.4%) and renewables (8.6% y-o-y) offset a slump in coal burn (-19.8% y-o-y) and nuclear (-2.4%). Gas was the leading fuel in the power mix with a share of 38.9% followed by renewables (20.6%), coal (19.9%), nuclear (19.4%).

Meanwhile, Canada's gas consumption decreased by 3.8% to reach 110.6 Bcm. The decline of gas consumption is attributed to the mild weather recorded during the year and lockdown measures taken by the Canadian government in most of the provinces starting from March 2020. In terms of consumption by sector, the industrial, residential and commercial sectors were down by 2.6% (2.1 Bcm), 6.2% (1.1 Bcm) and 7.3% (1.3 Bcm) respectively as shown in Figure 5. Regarding the assessment of the HDD in Canada, during the year 2020, it averaged 710.5 down by 5% y-o-y.

Figure 5: Annual Comparison for the Gas Consumption in Canada by Sector



Source: GECF Secretariat based on data from Statistics Canada

Asia

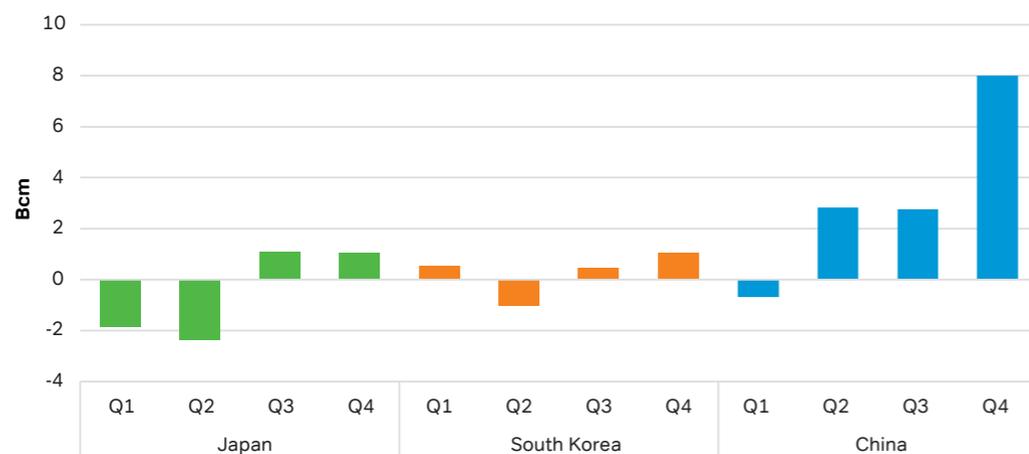
In Asia, China was still the demand driver of gas in the region in 2020 (see Figure 6) and it is one of the few countries that witnessed an increase in gas consumption in the world in 2020, although China was the first country to be hit by the COVID-19 pandemic. China's natural gas apparent demand (Production + NG imports + LNG imports) increased by 7.6% y-o-y to reach 326 Bcm. The gas consumption in the city gas, petrochemical and power generation sectors increased by 10.1%, 6.1% and 4% y-o-y respectively. In contrast, gas consumption in the industrial sector declined by 1.5% compared to 2019. The overall rise in gas consumption is attributed to the fast recovery of the Chinese economy after the pandemic and cold weather recorded during the fourth quarter of 2020.

Similar to China but to a lesser extent, South Korea recorded a slight increase in gas consumption during the year 2020 to reach 51.8 Bcm, which represents a growth of 2% y-o-y. South Korea recorded a huge decrease in gas consumption during Q2 2020 of 1 Bcm due to the COVID-19 lockdown restrictions in the country. In Q3 and Q4 2020, gas consumption increased, driven by the restart of the economy and the imposition of coal fired restrictions in December 2020 as part of the winter fine-dust management policy imposed by the Korean government.

In contrast, gas consumption in Japan recorded a decline of 1.8% to reach 112 Bcm. The lockdown measures were taken by the Japanese government to reduce the spread of the COVID-19 virus, mild winter in Q1 and the higher availability of nuclear output impacted drastically the gas consumption in the country with a decline of 1.8 Bcm and 2.4 Bcm y-o-y in Q1 and Q2 respectively. In 2020, the electricity consumption in Japan declined by 3.4% compared to 2019, gas consumption in the power generation sector recorded a decline of 4.9% for the year 2020 compared to 2019 but remain the leader in the electricity production mix with 33.8% of the electricity were produced from gas.

Similar to Japan, Australia's gas consumption declined by 0.5% (-0.26 Bcm) y-o-y to reach 57.1 Bcm in 2020. This was driven by a decrease in gas consumption in its own domestic market as a consequence of the COVID-19 pandemic and the decline of feed gas for many LNG facilities such as Gorgon and Prelude LNG terminals, that were down for maintenance for more than six months during 2020. Gas in the power generation sector recorded a decline of 13.6% y-o-y.

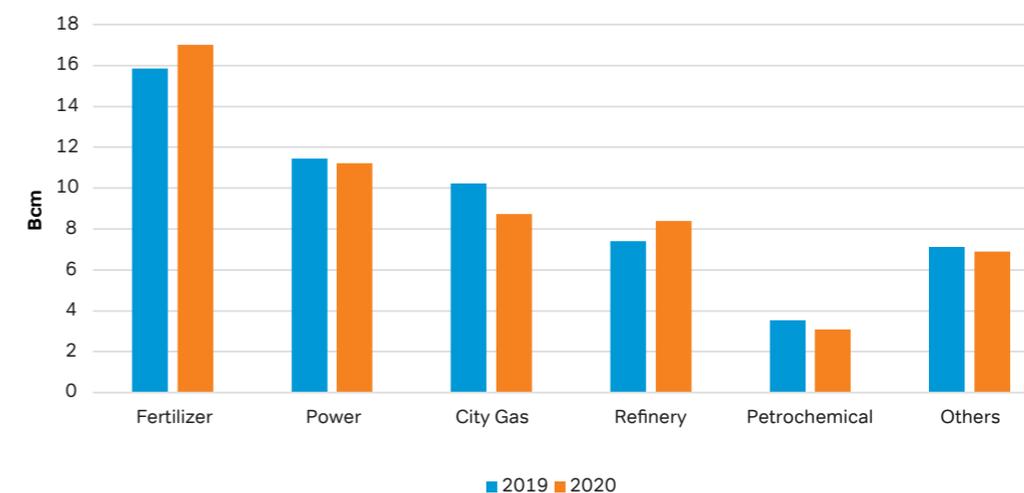
Figure 6: Quarterly Variation in Gas Consumption in Japan, South Korea and China in 2020



Source: GECF Secretariat based on data from IEA Monthly Gas Statistics and Refinitiv

In India, for the year 2020, gas consumption decreased by 0.4% y-o-y to 55.4 Bcm. The decline was driven by lower consumption in city gas (1.5 Bcm), petrochemical (0.44 Bcm) and power (0.21 Bcm) sectors. By contrast, gas consumption in the fertilizer (+1.14 Bcm) and refinery (+1.01 Bcm) sectors recorded an increase as shown in Figure 7.

Figure 7: Gas Consumption by Sector in India (2019 vs. 2020)



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

In terms of the share of gas consumption by sector, the fertilizer sector continues to dominate with a share of 30.7% followed by power (20.3%), city gas (15.8%), refinery (15.2%) and petrochemical (5.6%). Compared to 2019, the share of gas consumed by the fertilizer and refinery sectors increased from 28.5% and 13.3% respectively while the share of gas consumed by city gas and petrochemical decreased from 18.4% and 6.4% respectively.

During 2020, regasified LNG (R-LNG) represented 57% of the gas consumed in India, which represents an increase from 54% in 2019. Meanwhile, domestic gas production supplied 43% of the gas consumed in the country.

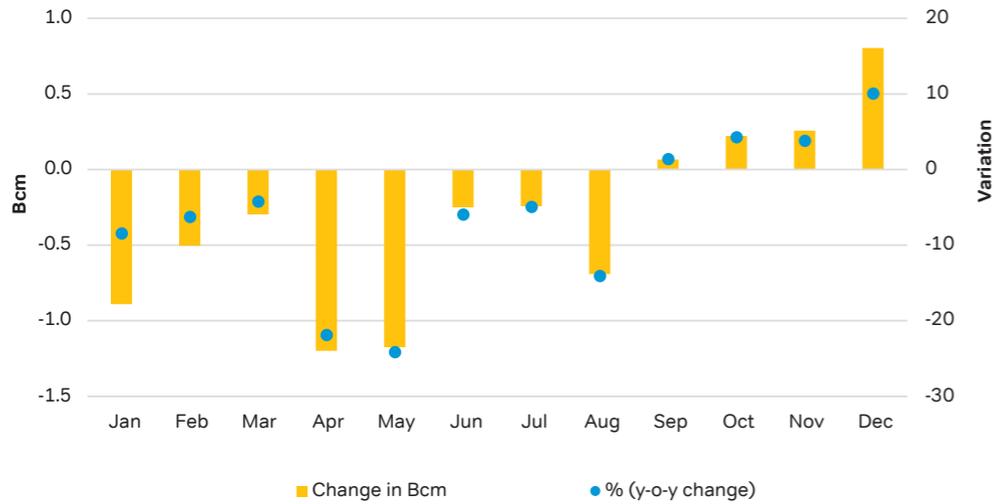
Europe

In 2020, Europe's gas consumption was down by 3.0% y-o-y to reach 506.8 Bcm, which represents the first decline after a decade of y-o-y growth. The decrease in gas consumption was mainly seen in the UK, Italy, France and Spain with a fall of 3.9%, 5.2%, 6.1% and 9.5% y-o-y respectively. Both above seasonal normal temperatures, which affected the heating demand, and the COVID-19 lockdown measures taken by the European governments to reduce the spread of the virus drove the decline in gas consumption during the year. Europe electricity production fell by 3.2% y-o-y to 312.7 TWh. Higher electricity production from wind, solar and hydro by 10.6%, 17.4%, 5.3% y-o-y respectively offset the electricity production from gas, coal and nuclear with a decline of 4%, 18% and 11.3% y-o-y respectively.

In Italy, gas consumption for the year 2020 decreased by 5.2% (3.9 Bcm) y-o-y to reach 70.6 Bcm. The Industrial, distribution and power generation sectors were down by 6.9%, 2.7% and 6.8% y-o-y respectively. This was caused by both mild weather and the impact of the COVID-19 lockdown measures taken by the Italian government. The bulk of the decline occurred during Q1 and Q2 2020 where gas consumption recorded a drop of 1.7 Bcm and 2.6 Bcm respectively (see Figure 8). After the easing of the restrictions in Italy from July

2020, gas consumption showed a slight recovery in Q4 of 1.3 Bcm boost by cold weather during December 2020.

Figure 8: Trend in Italian Gas Consumption (2018-2020)

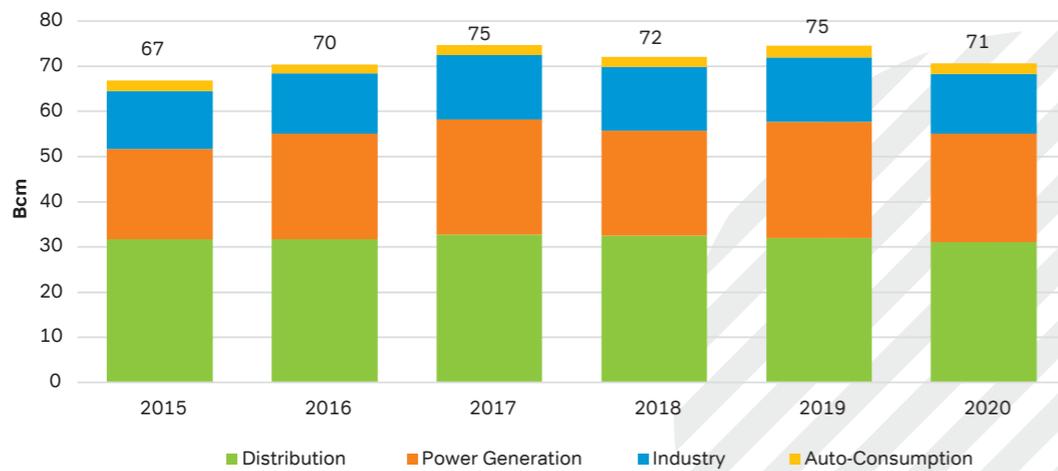


Source: GECF Secretariat based on data from Snam

The drop in gas consumption in Italy was driven by the power sector (see Figure 9) with a decline of 1.8 Bcm y-o-y as a result of a weaker gas consumption due to COVID-19 and robust production from photovoltaic.

Despite the re-implementation of lockdown measures in December 2020, Italy recorded a recovery of gas consumption by around 1 Bcm compared to the same period of last year, driven by below normal temperature recorded during the month.

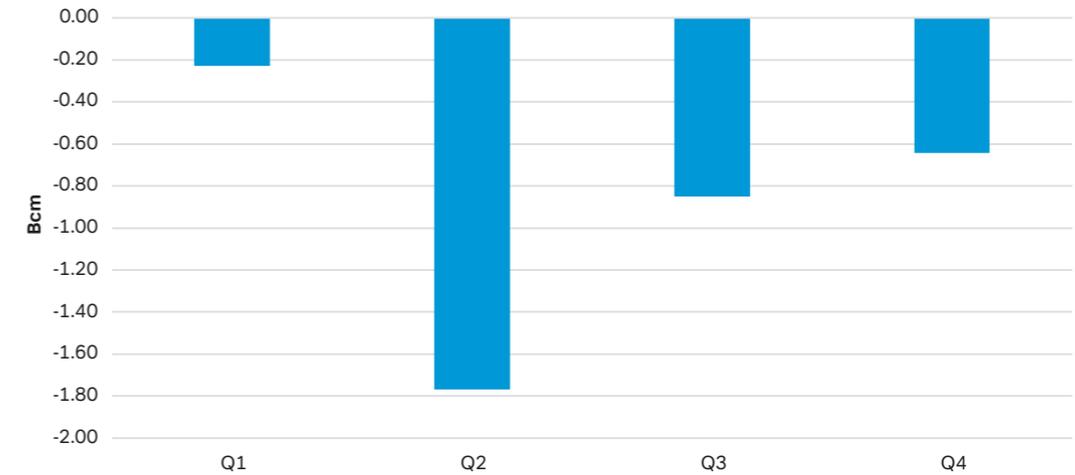
Figure 9: Annual Comparison for the Gas Consumption in Italy



Source: GECF Secretariat based on data from Snam

In Spain, for the year 2020, gas consumption decreased by 9.5% (37.7 TWh) y-o-y to reach 359 TWh (around 33.3 Bcm) (see Figure 10). Both the conventional (industrial and distribution) and power generation sectors recorded a decline in gas consumption. The conventional sector represented the majority of the decline in gas consumption during the year, with a decline of 6% (1.5 Bcm) y-o-y. The power sector consumption showed a decline of 19.9% y-o-y to reach a level of 8.2 Bcm caused by the COVID-19 lockdown measures and the rise of output from hydro, wind and solar photovoltaic during the year by 1% (0.45 TWh), 36% (1.9 TWh) and 42% (0.2 TWh) y-o-y respectively.

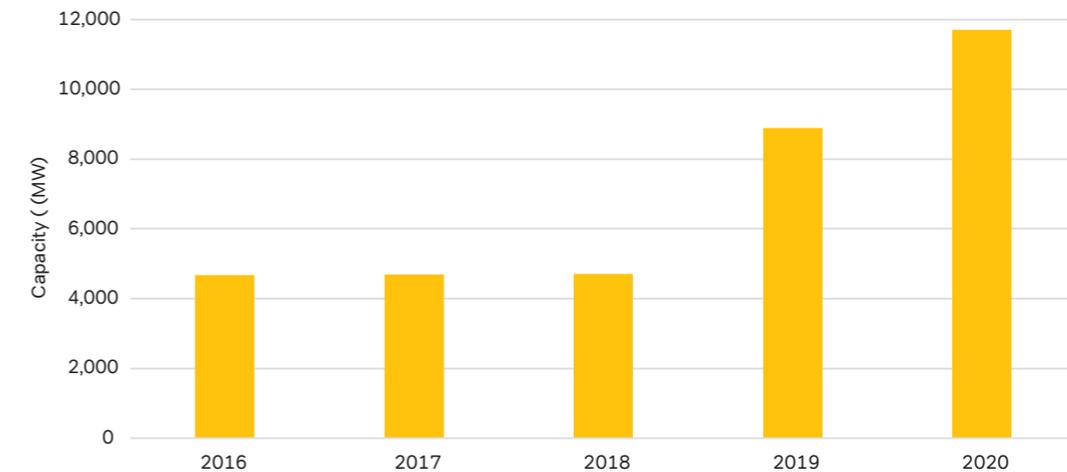
Figure 10: Quarterly Comparison for the Gas Consumption in Spain (2020)



Source: GECF Secretariat based on data from Enagas

It is worth mentioning that Spain's photovoltaic capacity increased by 88.7% (2.8 GW) and 31.6% (4.2 GW) in 2019 and 2020 respectively and Spain is the biggest solar capacity holder in Europe (see Figure 11).

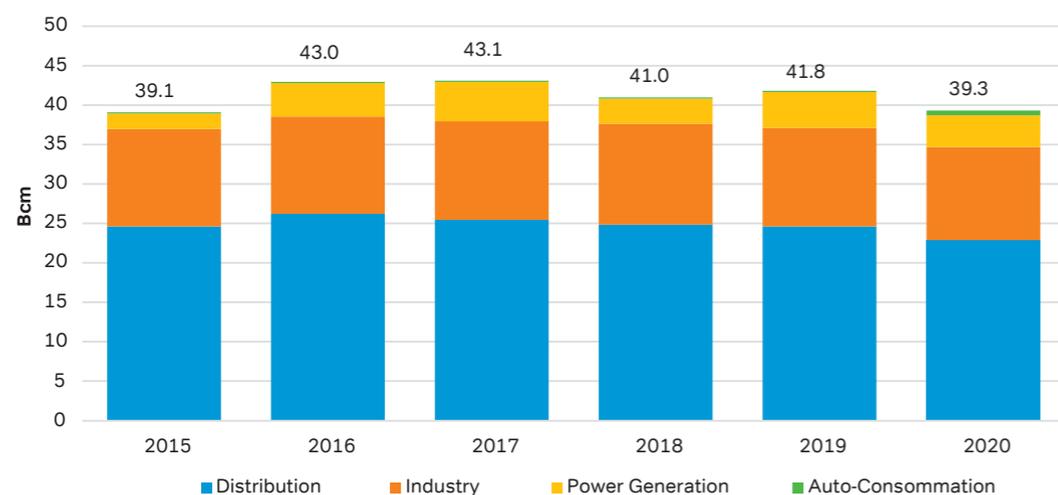
Figure 11: Installed Photovoltaic Capacity in Spain (2016-2020)



Source: GECF Secretariat based on data from Ree.es

In France, gas consumption in 2020 declined by 6.1% (27.3 TWh or 2.5 Bcm) y-o-y to reach a total consumption equal to 424.4 TWh or 39.3 Bcm as shown in Figure 12. The Industrial, distribution and power generation sectors were down by 5.6% (7.5 TWh or 0.7 Bcm), 7.1% (19 TWh or 1.76 Bcm), and 11.6% (5.7 TWh or 0.53 Bcm) y-o-y respectively.

Figure 12: Trend in French Gas Consumption by Sector

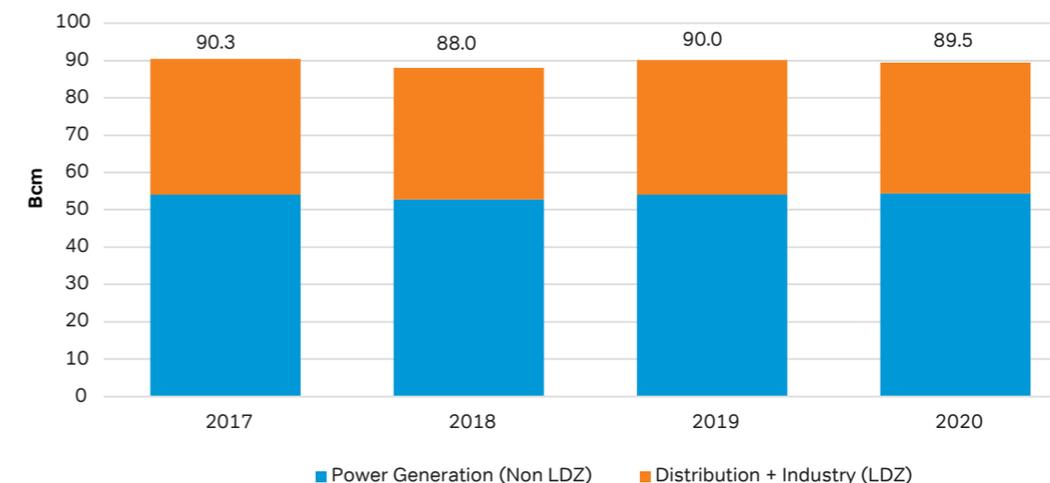


Source: GECF Secretariat based on data from GRTgaz

The main reasons for the decline are the effect of the COVID-19 lockdown measures imposed in France and mild weather that was witnessed during the winter season. The year 2020 was highlighted to be the hottest year on record in France since 1900. The majority of the drop came from the distribution sector with a decrease of around 1.8 Bcm.

In Germany, gas consumption for the year 2020 decreased by 0.5% y-o-y to reach a level of 966.8 Twh (around 89.5 Bcm). The LDZ sector, which represents both industrial and distribution sectors, was down by 2.3% y-o-y (-0.83 Bcm). The power sector consumption showed an increase in 2020 of 0.6% (0.34 Bcm) y-o-y to reach a level of 54.4 Bcm (see Figure 13).

Figure 13: Trend in German Gas Consumption by Sector



Source: GECF Secretariat based on data from Refinitiv

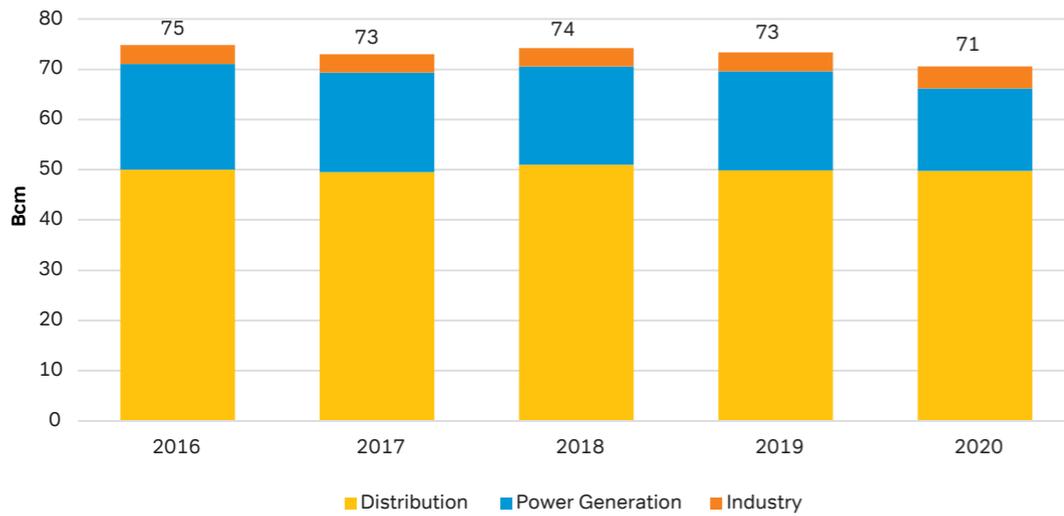
The decline in German gas consumption is relatively low compared to the size of the market. The rise of gas consumption in the power sector was driven by the German policy shift from coal to gas and the attractive gas prices recorded during 2020. The latter reduced the impact of the COVID-19 in the German gas industry.

As in Europe's mainland, global gas consumption in the UK fell by 3.9% compared to 2019 to reach 70.5 Bcm (see Figure 14). Gas consumption fell in the power generation and distribution sectors by 16.9% (3.3 Bcm) and 0.2% (0.01 Bcm) respectively. The decline in gas consumption was driven by the lockdown measures imposed in the UK during the second quarter to reduce the spread of the COVID-19 where we recorded a decline of 3.1 Bcm y-o-y.

In addition to the COVID-19 impact, warm weather during the first quarter of 2020 affected negatively the gas consumption in the UK, with a decline of around 1 Bcm in Q1 2020 compared to Q1 2019.

Whereas, the gas consumption in the industrial sector increased by 0.6 Bcm in 2020 compared to the previous year (15.7%).

Figure 14: Trend the UK Gas Consumption by Sector

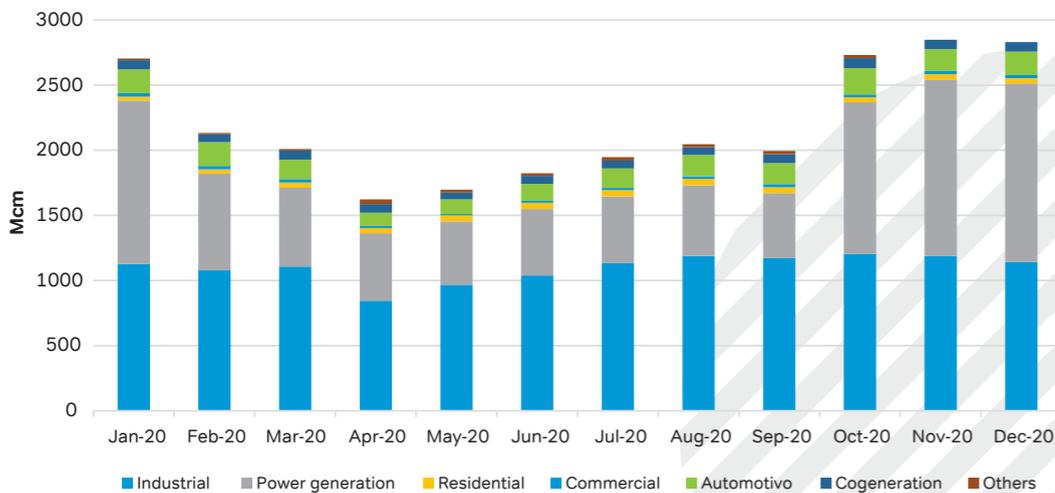


Source: GECF Secretariat based on data from Refinitiv

Latin America

In Latin America, Brazil was one of the main countries impacted by the COVID-19 and this was reflected in the gas consumption during the year 2020. Brazil recorded a slump in gas consumption of 7.5% equivalent to 2.1 Bcm. The bulk of the decline was observed during Q2 and Q3 with a decline reaching 1 and 1.8 Bcm respectively. In terms of gas consumption by sector, power generation sector recorded a decline of 10% (-1.1 Bcm) followed by automotive use 17.8% (-0.4 Bcm) and industrial sector 2.5% (-0.3 Bcm). The decline was mainly driven by the lockdown measures taken by the Brazilian government during the second and third quarters of 2020 in Brazil (Figure 15).

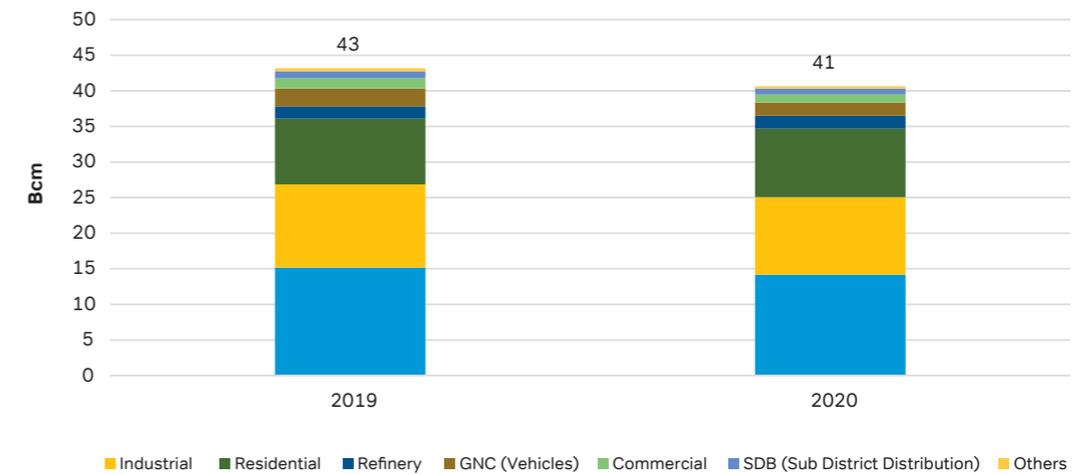
Figure 15: Evolution of Gas Consumption by Sector in Brazil



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

In Argentina, gas consumption for the year 2020 decreased by 5.9% (2.5 Bcm) y-o-y to reach 41 Bcm (see Figure 16). The Industrial, power generation and automotive sectors were down by 6.9% (-0.8 Bcm), 6.5% (-1 Bcm) and 24.8% (-0.6 Bcm) y-o-y respectively. Whereas, the residential and refinery sectors offset the decline with an increase of 3.9% (0.4 Bcm) and 5.5% (0.1 Bcm) y-o-y respectively. This was due to the high hydro output, mild weather and the impact of the COVID-19 lockdown measures taken by the Argentinian government..

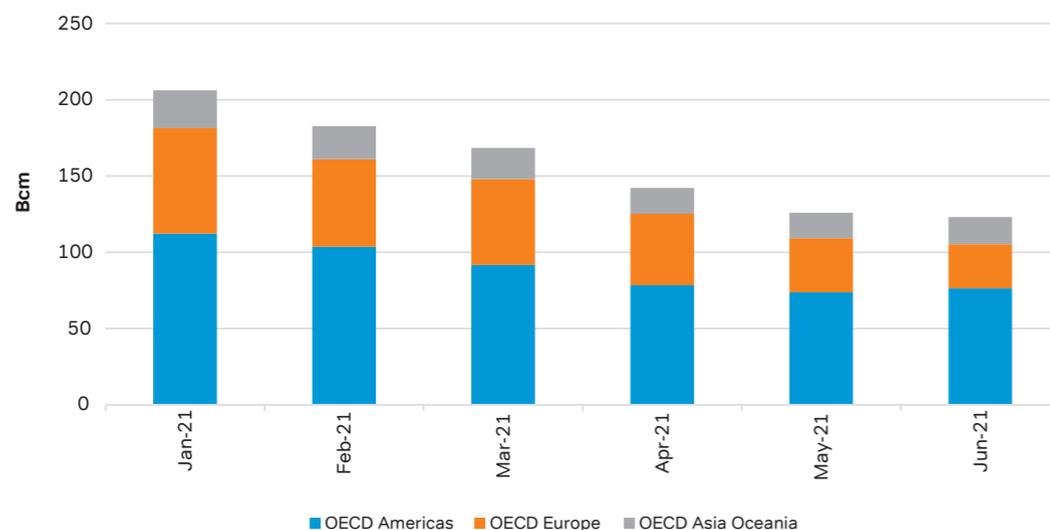
Figure 16: Comparison of Gas consumption by Sector in Argentina (2019 vs. 2020)



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

5.1.2 Current Developments in Gas Consumption OECD Countries

For the period January-June 2021, gas consumption in the OECD Countries, which accounts for ~46% of global gas consumption, increased by 4.5% (40.5 Bcm) y-o-y to 948.8 Bcm. The overall progress was driven by high gas consumption in OECD Europe and Asia Oceania due to freezing temperature during Q1 and high temperature in the summer season, which increased gas and electricity demand for heating. In addition, the economic recovery that was witnessed all over the world boosted gas demand in the industrial sector (see Figure 17).

Figure 17: Evolution of Gas Consumption in OECD Countries

Source: GECF Secretariat based on data from IEA Monthly Gas Statistics

In OECD Europe, the majority of the increase in gas consumption in the region came from the UK and Germany. Despite the implementation of total lockdown in many countries in Europe, it experienced a surge in gas demand compared to last year with an increase of 13.5% (34.9 Bcm) for the period January-June 2021. This was mainly driven by a very cold winter season, which increased heating demand from gas and electricity and low wind and hydro output that played in favor of gas in the electricity generation mix.

For OECD Americas, gas consumption stood at 536.2 Bcm during the period January-June 2021, representing an increase of 0.5% y-o-y. This was offset by a slump in gas consumption in the U.S. and Chile by 0.05 Bcm and 0.45 Bcm y-o-y respectively. However, Canada and Mexico recorded an increase of 0.34 Bcm and 2.55 Bcm respectively. The increase in Canada's gas consumption during the H1 2021 is mainly attributed to the rise in the industrial sector by 3.3% y-o-y. The rise in the industrial sector was driven by the economic recovery on post COVID-19 era. However, milder-than-normal weather during winter time in Canada curbed gas demand for heating in the residential (-2.5%) and commercial (-2.2%) sectors. The first half of the year 2021 were generally milder on average across Canada compared with last year, with a heating degree day (HDD) averaging 818 for the period Jan/June 2021, down by 6.2% y-o-y.

In OECD Asia Oceania, a cold winter season in North-East Asia offset the decline in gas demand for heating in Japan. Higher gas demand in South Korea maintained the overall gas demand in the region at the same level as last year for the same period. Similar to last year, the South Korean government restricted electricity generation from coal between December 2020 and February 2021, which supported the uptick in the gas burn. The South Korean government's imposition of coal-fired restrictions across December- February 2021 was driven by the willingness to reduce emissions in the country. The latter resulted

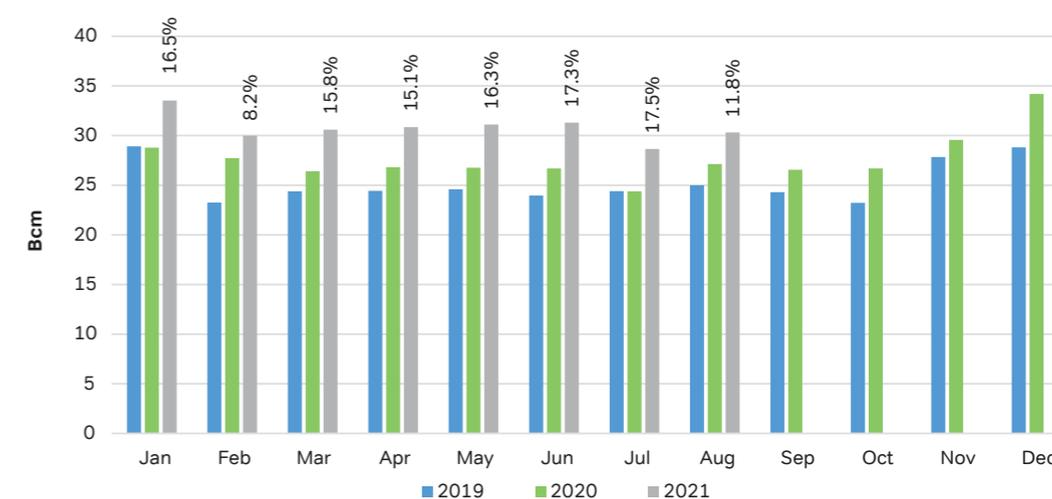
in greater dependence on LNG for power generation at the beginning of the year 2021, contributing to the rise in imports and this may continue to play in favor of the gas in the country energy mix.

Australia's gas consumption declined for the period January-June 2021 by 7.5% to reach 26.14 Bcm. The downturn in gas consumption was due to the warm weather recorded in January 2021 and lockdown measures still in place in the whole continent that impacts the gas industry's own use.

Non-OECD

China's apparent gas consumption (national production + Pipe imports + LNG imports) for the period January – August 2021 stood at 246.4 Bcm, which represents a growth of 14.8% y-o-y (see Figure 18). The growth in gas consumption is a result of the economic recovery in the country. Gas consumption was also driven by higher demand for urban gas and power sectors due to low temperatures recorded during the winter period and high temperature in the summer time, which boost cooling demand mainly in the southern part of China.

In comparison to 2019, the pace of gas consumption growth has been moving up significantly (23.8%) due to the recovery in economic growth, an increase of the coal-to-gas switching policy, and higher expansion of industrial activity in the country.

Figure 18: Trend in China's Monthly Apparent Gas Consumption

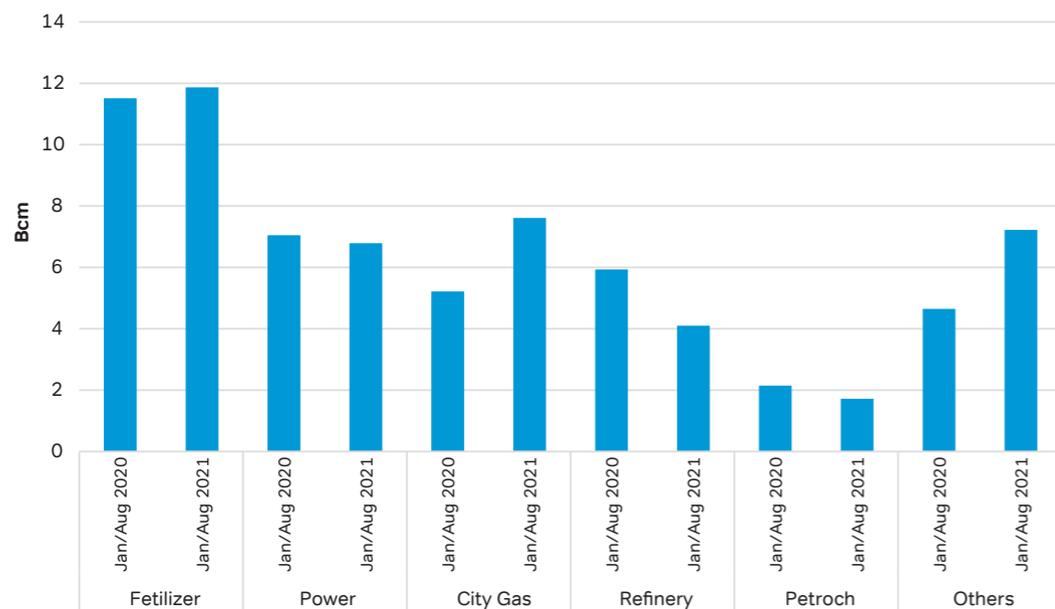
Source: GECF Secretariat based on data from Refinitiv

During the period January to August 2021, gas consumption in India stood at 39.3 Bcm, up by 7.7% y-o-y, as shown in Figure 19, driven by an uptick in gas consumption in the city gas and fertilizer sectors by 45.9% and 3.1% respectively. Whereas, gas consumption in the refinery and petrochemicals sectors recorded a decrease of 30.8% and 20.1% respectively. In terms of the share of gas consumption by sector, the fertilizer sector maintained its

dominant share of 30.2% in the first eight months of 2021. The share for the city gas increased from 14.3% to 19.4%. In contrast, the share of India's gas consumption delivered to refinery and petrochemicals sectors fell from 16.2% and 5.9% to 10.4% and 4.4% respectively.

The share of regasified LNG (R-LNG) in India's gas consumption declined from 55% in Jan/Aug 2020 to 55.9% in Jan/Aug 2021. Meanwhile, the share of domestic gas dropped from 45% to 44.1%.

Figure 19: India's Natural Gas Consumption Jan-Aug (2020 vs. 2021)



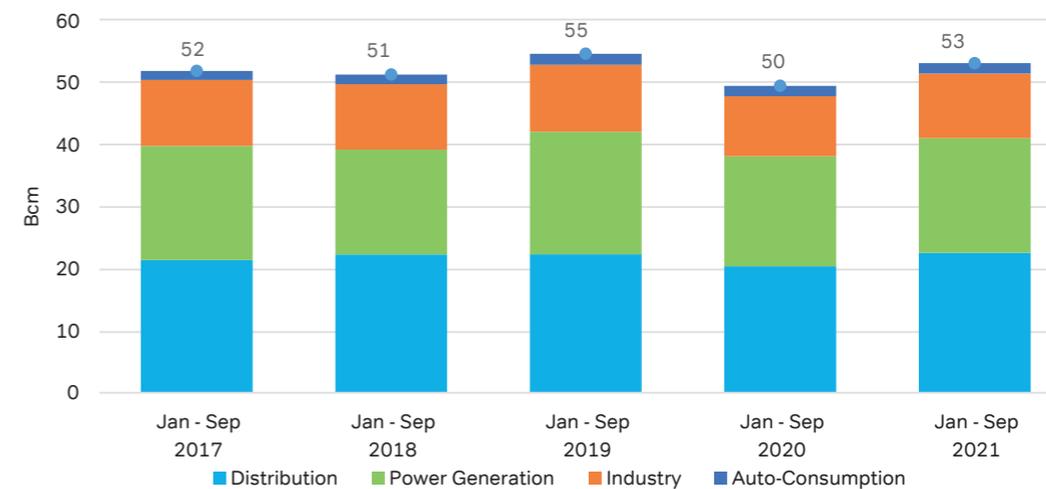
Source: GECF Secretariat based on data from India's PPAC

Europe

In Europe, we focused only on the main gas consuming countries, which represent around 80% of the total European consumption.

Italy's gas consumption for the period January to September 2021 rose by 7.4% compared to 2020 but declined by 2.8% compared to 2019. The total consumption for the period January to September 2021 reached 53.2 Bcm (see Figure 20). The industrial, power generation and distribution sectors were up by 8.1%, 4% and 10.7% y-o-y, respectively. The growth in gas consumption is attributed to cold weather recorded during the first quarter of 2021, low hydro output and a recovery in the gas demand in the country after the COVID-19 pandemic.

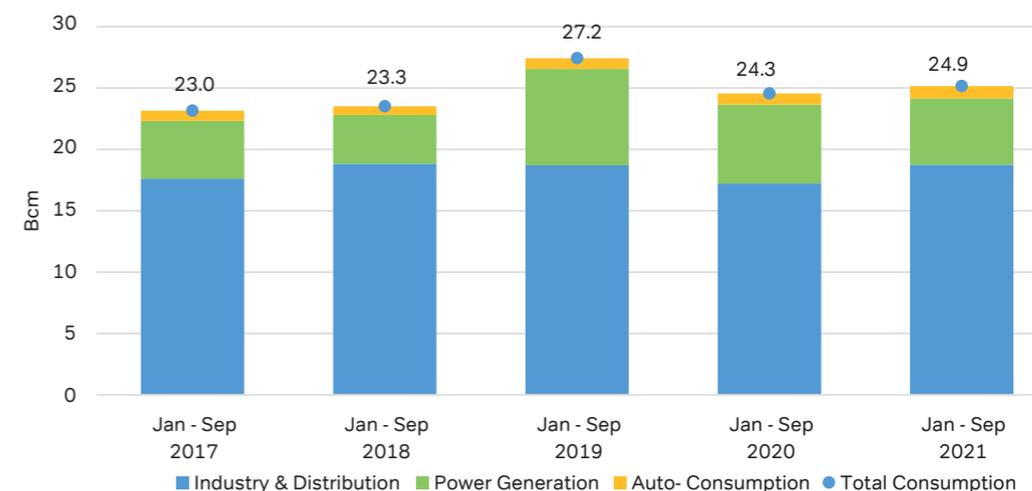
Figure 20: Trend in Italy's Gas Consumption by Sector for Jan-Sep (2017 – 2021)



Source: GECF Secretariat based on data from Snam

In Spain, gas consumption for the first nine months of 2021 increased by 2.5% y-o-y to reach 269.5 TWh around 24.9 Bcm (see Figure 21). The conventional market, which represents both industrial and distribution sectors, was up by 8.9% y-o-y. However, power generation sector consumption recorded a decline of 16.1% y-o-y during the period, to reach a level of 57.8 TWh around 5.4 Bcm. The drop in the power generation sector was mainly caused by the rise of the hydro, wind and solar output during the period Jan/Sep 2021 in the Spanish electricity mix.

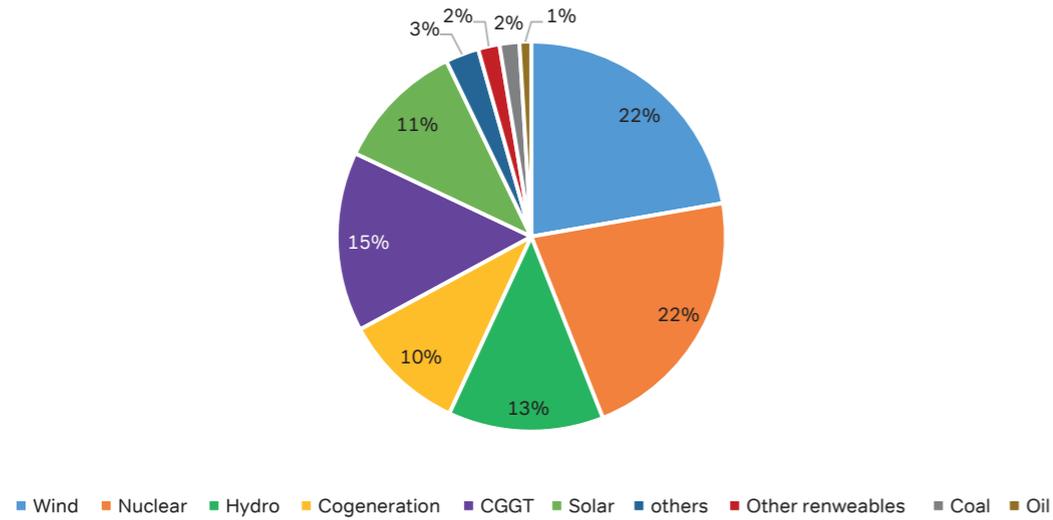
Figure 21: Trend in Spain's Gas Consumption by Sector Jan-Sep (2017 – 2021)



Source: GECF Secretariat based on data from Enagas

For the period January to September 2021, wind and solar output rose by 14% and 34% y-o-y respectively, representing around 33% of the Spanish electricity mix (see Figure 22).

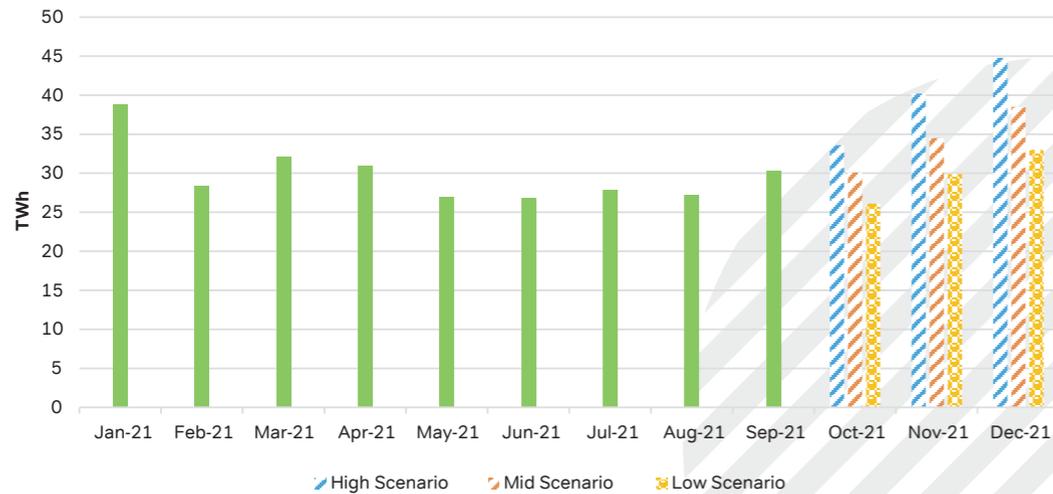
Figure 22: Spain Electricity Mix in Jan-Sep 2021



Source: GECF Secretariat based on data from Ree.es

According to the data published by the Spanish gas transporter Enagas, gas consumption for the year 2021 is estimated to reach 372 TWh (+3.5% y-o-y) in the mid scenario, whereas it is expected to reach 387.9 TWh (7.8% y-o-y) and 358.4 TWh (-0.4% y-o-y) for the high and low scenarios respectively (see Figure 23).

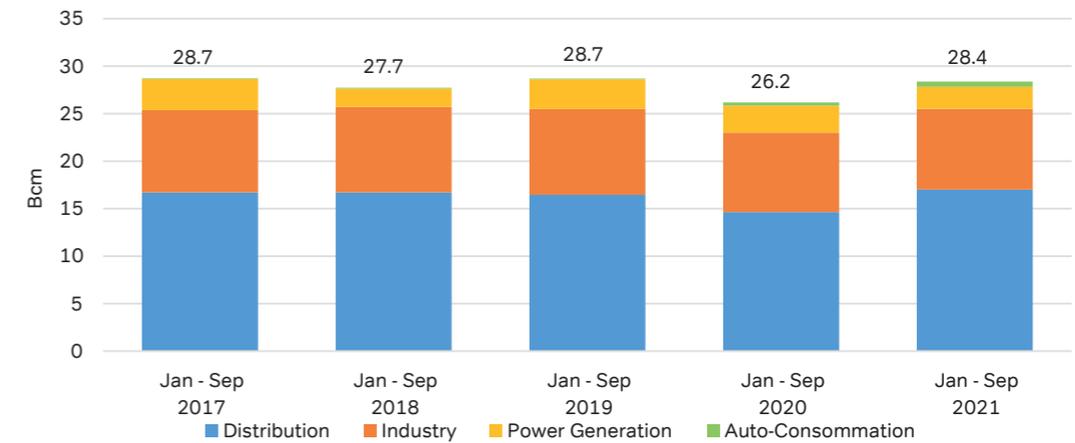
Figure 23: Spain's Forecasted Monthly Gas Consumption 2021



Source: GECF Secretariat based on data from Enagas

In France, gas consumption for the period January-September 2021 rose by 8.4 % y-o-y with a total consumption equal to 306.4 TWh (28.4 Bcm). However, when compared to 2019, natural gas consumption in France declined by 1.1%. In the same period, the industrial and distribution sectors recorded an increase in gas consumption of 0.1% and 15.3% y-o-y respectively (see Figure 24). The increase in gas consumption was driven by the below-normal temperature recorded in the first months of the year 2021 and a good economic recovery in the country.

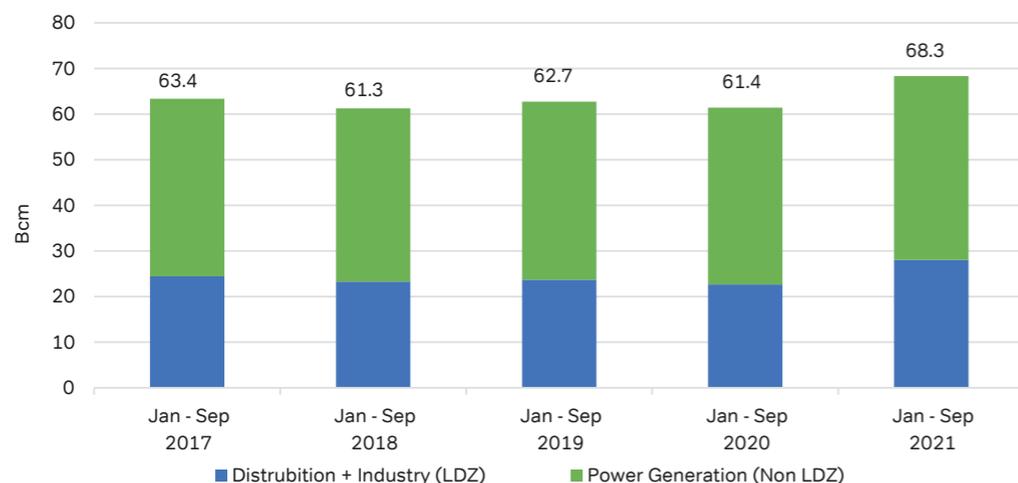
Figure 24: Trend in France's Gas Consumption by Sector Jan-Sep (2017 – 2021)



Source: GECF Secretariat based on data from Grtgaz

For Germany, the biggest gas consumer in Europe, the country recorded a growth in gas consumption of 11.3% to reach 737.9 TWh equivalent to 68.3 Bcm in the first nine month of 2021 (see Figure 25). The LDZ (Distribution and industrial) and power generation sectors recorded an increase of 23.8% (5.4 Bcm) and 3.9% (1.5 Bcm) compared to last year.

Figure 25: Trend in Germany's Gas Consumption by Sector in Jan-Sep (2017 – 2021)

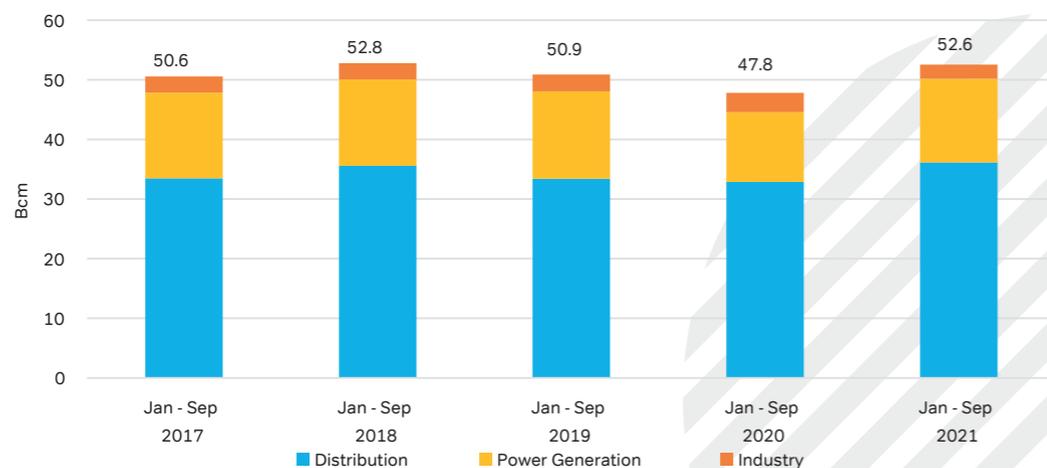


Source: GECF Secretariat based on data from Refinitiv

The growth in gas consumption was driven by very cold weather recorded during the first quarter 2021, robust economic recovery on post COVID-19 era and the ongoing German policy of coal/nuclear-to-gas switching. In addition, during some weeks, wind output was at a very low level, which played in favour of gas in the German electricity mix.

As far as the UK is concerned, during the period January- September 2021, the UK recorded an increase of 9.9% in gas consumption compared to the same period of last year. The total gas consumption reached 52.6 Bcm in the first nine months of 2021(see Figure 26). The gas consumption was driven by the distribution sector with an increase of 3.3 Bcm y-o-y followed by the power generation sector with a jump of 20% (2.3 Bcm) y-o-y.

Figure 26: Trend in UK's Gas Consumption by Sector in Jan-Sep (2017 – 2021)

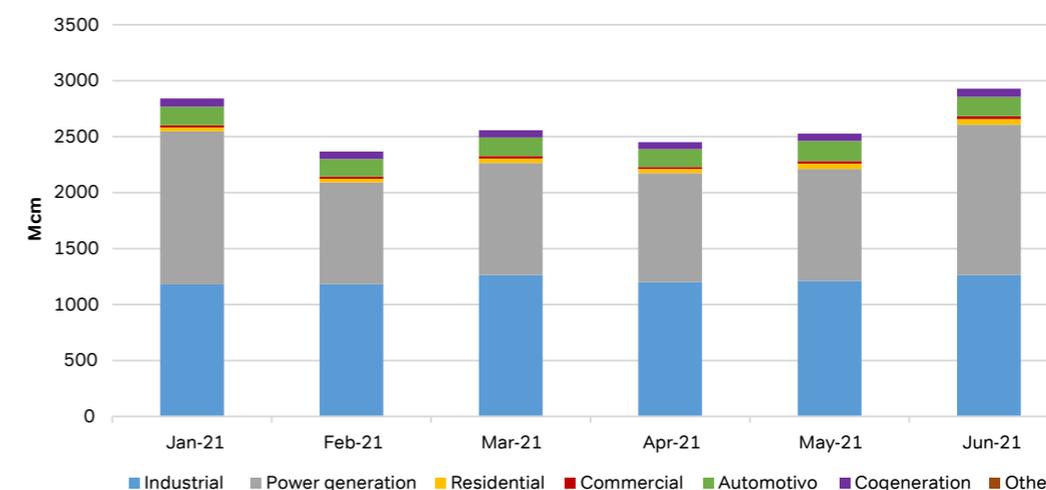


Source: GECF Secretariat based on data from Refinitiv

Latin America

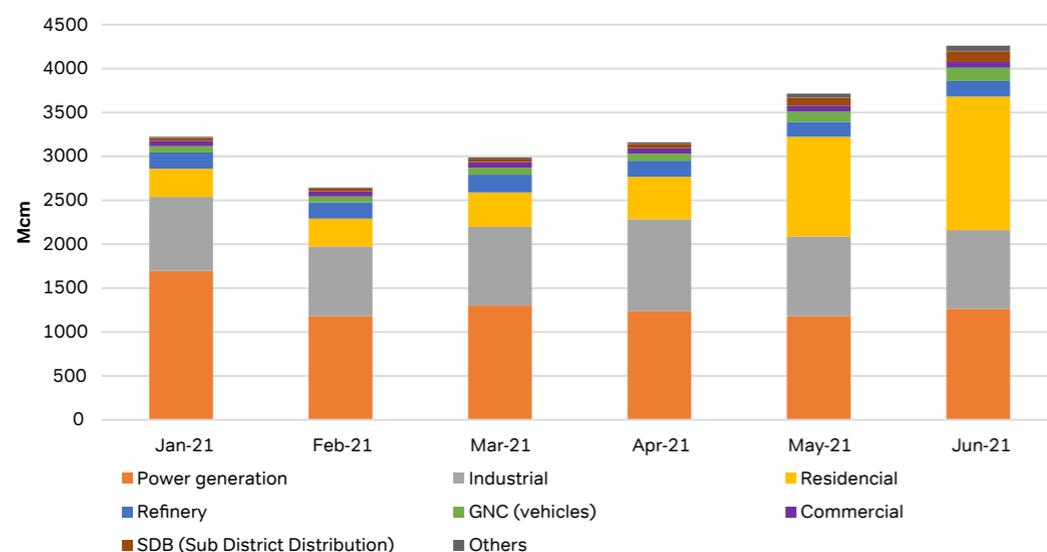
Regarding the Latin American countries, gas consumption in Brazil during the first half of the year increased by 23.6% and 30.7% compared to 2019 and 2020 respectively. In terms of gas consumption by sector, power generation sector recorded a growth of 60.3% (2.5 Bcm) followed by industrial sector 18.5% (1.1 Bcm) and automotive use 16.7% (0.14 Bcm). The rise of gas consumption during the period January – June 2021 was mainly driven by the recovery of the gas demand on post COVID-19 and the rise of gas use in the power generation mix to substitute hydro output as Brazil recorded one the driest year in the last decades (see Figure 27).

Figure 27: Evolution of Gas Consumption by Sector in Brazil H1 2021



Source: GECF Secretariat based on data from MINISTÉRIO DE MINAS E ENERGIA BRAZIL. In Argentina, gas consumption for H1 2021 increased recorded the same level as 2020 to reach 20 Bcm (see Figure 28). The power generation, residential and automotive sectors were up by 6.4%, 5.5% and 14.5% y-o-y respectively. However, the industrial sector declined by 1.6% y-o-y.

Whereas, the industrial sector offset the growth with a decline of 18% (0.6 Bcm) y-o-y. The increase in gas consumption was due to the low hydro output and the economic recovery in the Argentina on post COVID-19.

Figure 28: Evolution of Gas Consumption by Sector in Argentina H1 2021

Source: GECF Secretariat based on data from ENARGAS

5.1.3 Short-Term Perspectives

In the following point, we are describing the scenarios and assumptions used for GECF's short-term outlook for gas consumption (see Figure 3). In our short-term forecast, we are expecting growth in gas consumption for the year 2021 and 2022:

2021 Gas consumption assumptions: In this scenario, we forecast an increase in gas consumption by around 3% for the year 2021. We project cold weather during the wintertime that will contribute to around 1% in the growth of gas consumption. Besides, we considered a hotter than normal summer period which will contribute to the increase of air-conditioning use that will boost gas consumption in the power generation sector. Moreover, we have considered the easing of the lockdown measures beginning from the second half of 2021, with a successful vaccination campaign in the majority of the consuming countries.

Meanwhile, the remaining growth is mainly attributed to higher consumption in the power and industrial sectors. China is forecasted to drive growth, supported by a rebound in economic and industrial activity.

All regions, except North America, are forecasted to record a surge in gas consumption in 2021, with the majority expected to rebound to 2019 levels or higher.

2022 Gas consumption assumptions: For 2022, we are forecasting growth of between 1.4% to 1.8%, taking into consideration the supporting policy of the coal to gas switching in China, India and Germany as an example. The extension of the gas grid in China and India and some new players in south and southeast Asia such as Pakistan, Bangladesh and Thailand that will contribute to boost gas consumption. Moreover, the entrance of the

North Stream 2 pipeline will displace some coal or nuclear in the German electricity mix. Also, we considered that the majority of the COVID-19 restrictions will be removed for the whole year 2022 with a successful vaccination campaign.

5.2 Natural Gas Consumption by Sector

5.2.1 Recent Trends

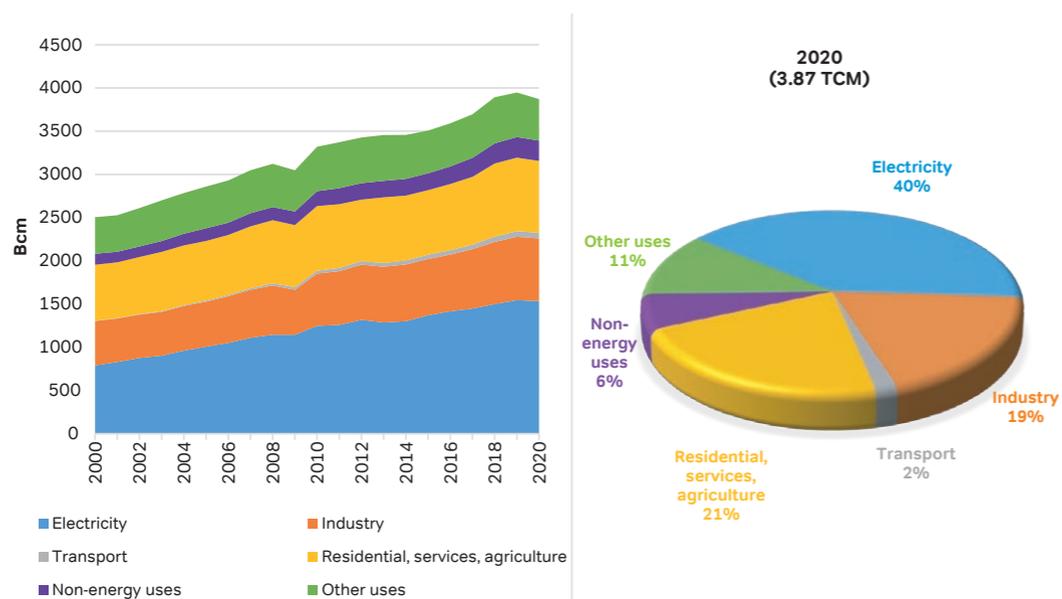
Global

This section provides an overview of global natural gas consumption by sector with a focus on the two main consuming regions, Europe and Asia-Pacific. Analysis of data from several sources were used and benchmarked to shape the short-term outlook.

Following steady growth since 2009, global natural gas consumption dipped in 2020. Global gas consumption in 2020 was estimated at 3.87 Tcm. Mild winter conditions in the northern hemisphere weighed on gas consumption for heating in the residential and commercial sectors in the first quarter of the year. The implementation of nationwide lockdowns led to a sharp drop in gas consumption in both the power and industrial sectors mainly in the first half of 2020, with the power sector being the most affected. Lifting of lockdown measures and other restrictions in the second half of the year supported gas consumption in these sectors. This lessened the expected decline in gas consumption to around 2% y-o-y or about 80 Bcm. It is worth noting that natural gas proved its resilience and was the least impacted fossil fuel.

In terms of sectors, global gas consumption continues to be driven by the power sector (see Figure 29) which accounted for the lion's share with 40% totalling 1.53 Tcm in 2020. This was followed by the residential and commercial sector with 22% with a total of 0.83 Tcm. The industrial sector accounted for 19% of the total gas consumption with 0.73 Tcm. The transportation sector accounted for a mere 2% of gas consumption or 65 Bcm. Furthermore, the residential and commercial sector experienced the largest annual decline of 2.3% (19 Bcm), while the power sector had the smallest annual decline of 0.7% (11 Bcm).

Figure 29: Global Natural Gas Consumption by Sector



Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), Cedigaz, BP Statistical Review 2021
 Note: Other uses include district heating, energy industry own use and transmission/distribution losses

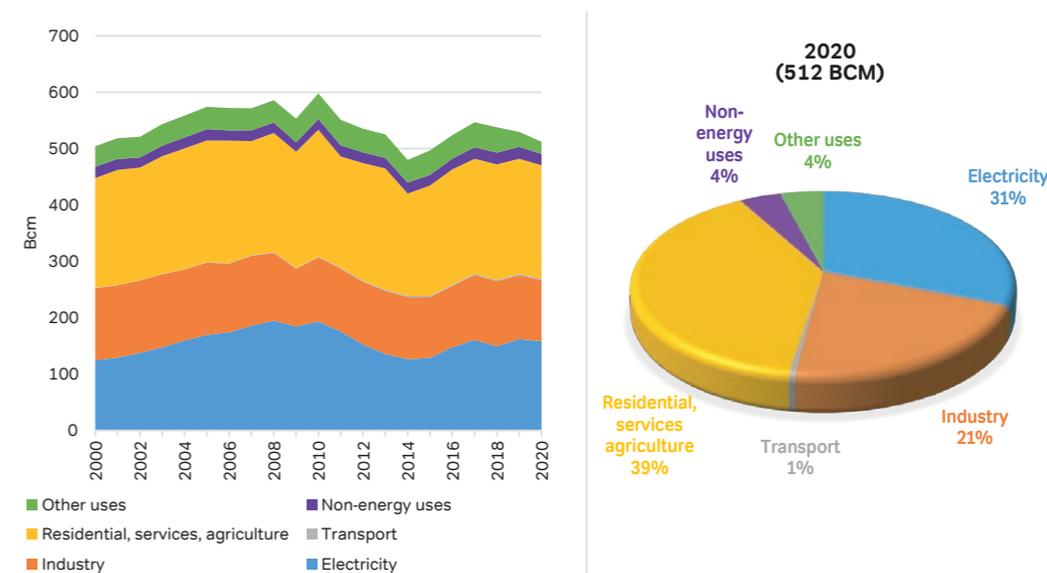
Europe

Natural gas accounted for 24% of the primary energy mix in Europe in 2020, a 1% decrease in its share y-o-y. Primary consumption of all energy sources, with the exception of renewables and hydropower, decreased y-o-y, with coal suffering the largest decline of 18% y-o-y.

Gas consumption in Europe experienced modest growth from 2015-2017, after which it slowed to less than 1% annual growth in 2018 and 2019. In 2019, Europe acted as a sink for excess LNG resulting in record high storage levels. In 2019, gas consumption in the power sector remained strong, driven by significant coal-to-gas switching, while consumption across all sectors were relatively stable or showed a slight decline.

In 2020, gas consumption in the region experienced a 3.4% decline y-o-y to an estimated 512 Bcm, with consumption decreasing across all sectors as seen in Figure 30 below, mostly due to mild weather and the impact of the COVID-19 pandemic. Temperatures in northwest Europe were about 2-4°C above seasonal norms in the first quarter of 2020, an indication of a very mild winter, resulting in reduced gas demand for heating. Moreover, there were significant declines in gas consumption in the power and industrial sectors particularly in Spain, the UK and Italy as commercial and manufacturing activities were directly stunted by lockdown measures. The residential and commercial sector still accounted for the highest share of gas consumption with 39% (201 Bcm), followed by the power sector with 31% (158 Bcm) and the industrial sector with 21% (109 Bcm) as shown in Figure 30.

Figure 30: Europe's Natural Gas Consumption by Sector



Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), Cedigaz, BP Statistical Review 2021
 Note: Other uses include district heating, energy industry own use and transmission/distribution losses

Asia-Pacific

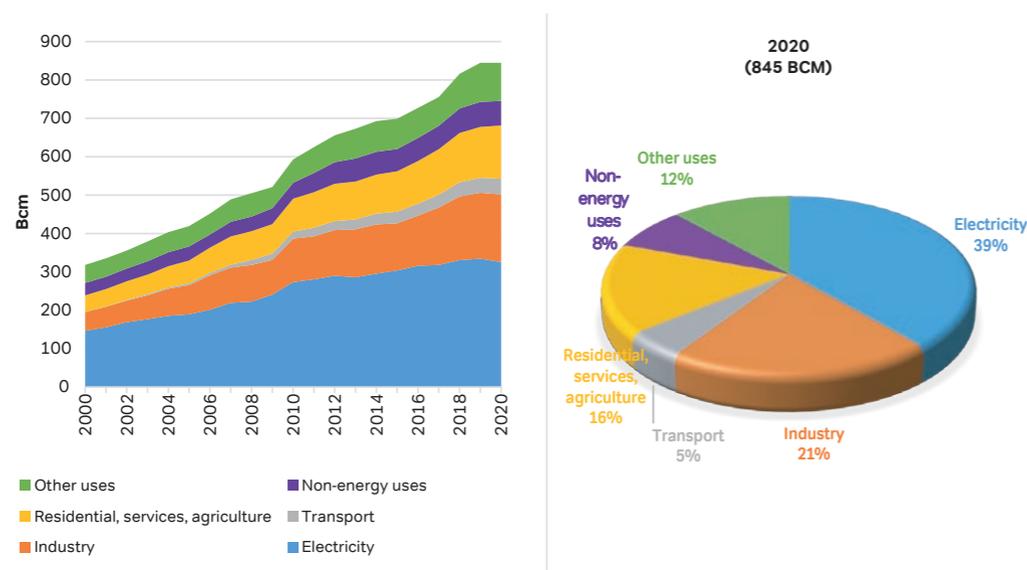
Natural gas accounted for 12% of the primary energy mix in Asia-Pacific, a 1% increase in its share y-o-y. Primary consumption of all energy sources increased compared to 2019, with the exception of oil and coal, which decreased slightly by 1% and 2% respectively. However, coal maintained its share of 47% in the energy mix.

Gas consumption in Asia-Pacific has been steadily growing for the past two decades, with its largest jump recorded in 2010 (11.6% y-o-y), after which there was another major jump in 2018 (7.4% y-o-y). In 2019, the annual growth rate was cut by half and then in 2020, total gas consumption was estimated at 845 Bcm which was relatively stable y-o-y.

In Asia-Pacific, gas consumption in the power sector experienced the biggest decline, by 2.6% y-o-y, while gas consumption in industrial, transportation, residential and commercial

sectors increased y-o-y. China, in particular did not experience any major lockdowns and saw a strong rebound in gas consumption in 2020 as economic and industrial activity recovered. In this region, the gas consumption in the power sector accounts for the lion's share (39% in 2020) followed by industry (21% in 2020) as shown in Figure 31.

Figure 31: Asia-Pacific's Natural Gas Consumption by Sector



Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), Cedigaz, BP Statistical Review 2021

Note: Other uses include district heating, energy industry own use and transmission/distribution losses

In the first half of 2021, the region recorded significant recovery in gas demand majorly due to an extremely cold winter which has increased gas demand in the power sector, and the robust economic recovery in China which will continue to strength gas demand in the industrial sector. Furthermore, as many countries in the region focus more on supply security to prevent any shortages (as experienced during the Q1 2021), gas consumption is expected to remain strong.

5.2.2 Short-Term Perspectives

Global gas demand has rebounded in 2021 following the impact of the COVID-19 pandemic in 2020 as the global economy recovered fueling gas demand particularly in the power and industrial sectors. Furthermore, an unexpected extremely cold winter season boosted gas demand for heating.

Industrial sector growth in emerging economies such as China and India are expected to continue to drive gas consumption. As India expands its city gas distribution networks, gas demand in the residential, commercial and transportation sectors are expected to increase. Furthermore, growing electricity demand and supply security in the region will also contribute to gas demand in the short term.

Gas consumption in the power sector, particularly in Europe is expected to increase as high carbon prices make it more attractive than coal and incentivize coal-to-gas switching. However, this may be limited based on the price competitiveness of gas. Coal and nuclear power plants phase-out in Europe and Asia are also expected to boost the demand for natural gas in the power sector.

As many countries begin to implement new energy policies and regulations in alignment with their carbon emissions reduction and net-zero targets, the growth of natural gas may be reduced in favour of alternative energy sources such as renewables and green hydrogen. However, there are still many challenges to be overcome if these energy sources are to compete with natural gas.

In spite of this, natural gas can continue to expand its reach into niche sectors and support net-zero targets, through technological advancements in the areas of energy efficiency of combined-cycle gas turbines, digitalization and CCUS.

5.3 Natural Gas Consumption in the Power Sector

5.3.1 Recent Trends

Recap of 2020

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

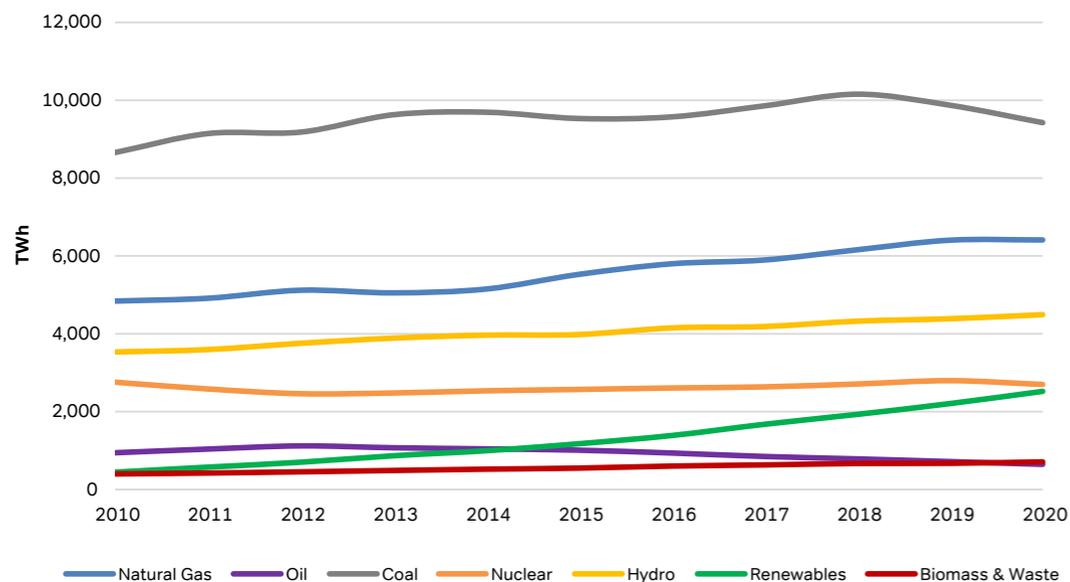
In spite of the COVID-19 pandemic, the power sector proved to be resilient mainly due to the nature of lockdown measures where remote work became a new part of life, increasing electricity consumption in homes. Global energy consumption in the power sector fell by a mere 0.6% y-o-y, reaching an estimated total of 26,900 TWh in 2020, as a consequence of lockdown measures and reduced industrial and commercial activity.

Power generation also maintained its place as the top driver for global natural gas demand, accounting for 40% of global natural gas consumption in 2020, an increase of 1% y-o-y. Natural gas consumption in the power sector was 6,411 TWh in 2020 (see Figure 32), which was relatively stable y-o-y, mainly due to competitive gas and LNG spot prices. Gas-fired power generation is highest in North America, followed by Asia-Pacific and Middle East.

Renewable power generation experienced the strongest growth, increasing 14% y-o-y to 2,521 TWh. Furthermore, it recorded its largest ever annual increase of above 300 TWh. Over the past five years, renewables have more than doubled driven by increasing policy support. Hydro also increased by 5% y-o-y.

While coal still maintains the largest share of the power generation mix at around 35% in 2020, it recorded its largest ever annual decline of above 400 TWh. Coal power plants were squeezed out by gas and renewables.

Figure 32: Global Power Generation Mix



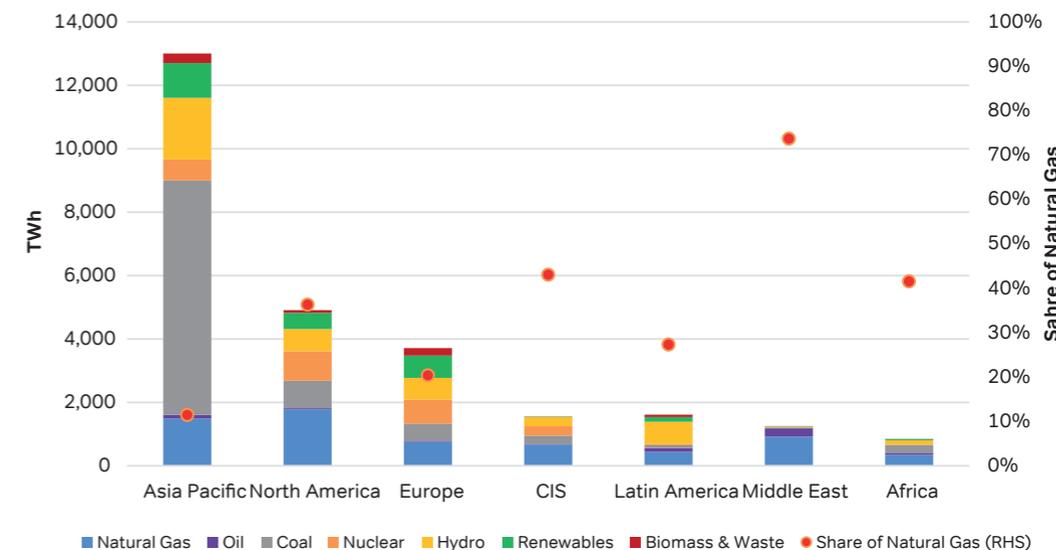
Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), BP Statistical Review 2021

High carbon prices in the EU also supported coal-to-gas switching. Nuclear power generation also declined as many Japanese reactors remained out of service and some plants in Europe were closed. Oil was the hardest hit fossil fuel, suffering an annual decline of 10%.

The power generation mix of each region continues to be influenced by several factors including availability of resources, cost of competing fuels, regulatory framework, subsidies, environmental policies and available technology. Furthermore, the impact of COVID-19 on energy consumption in the power sector varied across the regions. It should be noted that Asia-Pacific was the only region that saw annual consumption growth.

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 also support the substitution of coal and oil.

Figure 33: Power Generation Mix by Region 2020



Source: GECF Secretariat based on data from Enerdata (www.enerdata.net), BP Statistical Review 2021

North America

Total consumption in the power sector decreased by 3% y-o-y to around 4,911 TWh (see Figure 33). Renewable generation experienced a large growth, increasing by 14% y-o-y. Gas consumption in the power sector in North America was 1,782 TWh in 2020, representing an increase of 3% y-o-y. Its main competing fuel, coal decreased drastically by 22% y-o-y. This consumption pattern was mainly driven by low gas prices, which increased its competitiveness and encouraged fuel switching.

Asia-Pacific

Energy demand in power generation increased by 2% y-o-y to 13,007 TWh (see Figure 33). There was strong growth in renewables, with an increase of 16% y-o-y, while consumption of all fossil fuels declined compared to 2019. Gas demand decreased by 3% y-o-y to around 4,911 TWh.

The Asia-Pacific region had the second highest gas consumption in the power sector with 1,489 TWh in 2020, decreasing by around 1% y-o-y. The share of natural gas in the power generation mix in the Asia-Pacific remained the lowest at around 11%. The drop in consumption was less than anticipated due to the low impact of COVID-19 on China’s gas demand, as well as strong recovery in other countries in the region in the second half of 2020.

Middle East

In the Middle East, energy consumption in the power sector was relatively stable, increasing only by 0.2% y-o-y to 1,250 TWh (see Figure 33). Natural gas consumption in the power

sector was 921 TWh in 2020, increasing 3% y-o-y. Gas continued to account for the largest share in the power generation mix with 74%. There has been increasing efforts in the region to diversify the power generation mix, with renewables increasing 17% y-o-y to 14 TWh in 2020.

Europe

Energy consumption in the power sector decreased 3% y-o-y to 3,713 TWh in 2020 (see Figure 33). Natural gas and nuclear each accounted for 20% of the power generation mix in Europe in 2020. Renewables was close behind accounting for 19% (704 TWh), and hydro with 18% (683 TWh). Coal-fired generation suffered an 18% y-o-y decline due to a rise in coal-to-gas switching, as well as generally reduced demand. Gas-fired generation also declined by a lesser extent of 2% y-o-y to 756 TWh. Low spot gas and LNG prices and stronger commitments to cleaner energy sources fuelled this dynamic.

CIS

In the CIS region, total power consumption decreased by 3% y-o-y to 1,557 TWh in 2020 (see Figure 33). Natural gas continued to dominate the power generation mix, and has a share of 43% or 670 TWh. However, natural gas consumption decreased by 6% y-o-y. While renewable energy remains a meagre share of the power generation mix at around 1%, it increased 62% y-o-y in 2020.

Latin America

Total power consumption in Latin America fell slightly by 2% y-o-y to 1,615 TWh in 2020 (see Figure 33). Hydro maintained the lion's share of power generation in this region and stood at 708 TWh in 2020 or 44%. However, hydropower declined by 2% y-o-y. Natural gas accounted for the second highest share with 27% or 441 TWh, and also declined by 3% y-o-y. Coal consumption decreased by 16% y-o-y, while renewables increased by 13% y-o-y.

Africa

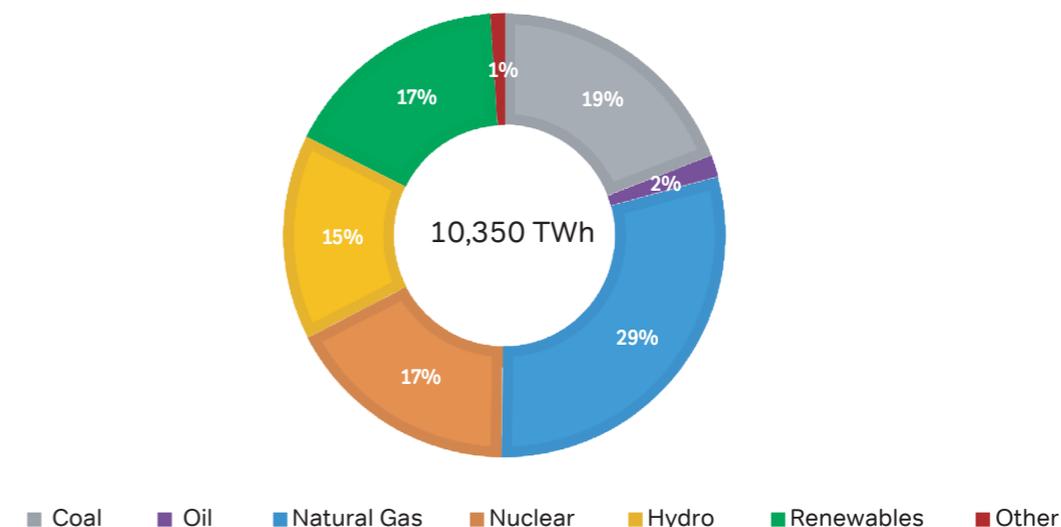
In 2020, total power consumption in Africa decreased by 3% y-o-y to 848 TWh (see Figure 33). This region remains the smallest regional power consumption in spite of having the second largest population due to low connectivity and access to electricity in the region. Natural gas accounted for 42% of the power generation mix in 2020 or 352 TWh. Coal had the second largest share of 29% or 244 TWh. Similar to the other regions, there was also an increase in the share of renewables by 14% y-o-y.

OECD 2020

Total energy demand in power generation in OECD countries declined by 2% y-o-y in 2020 to 10,350 TWh, likely a direct impact of COVID-19 lockdown measures, as well as mild weather conditions last year. Gas-fired generation decreased slightly by 0.3% while coal-fired generation was hit hard, decreasing by 15% compared to 2019. Renewables increased by 11% y-o-y, with wind and solar generation increasing by 11% and 20% respectively. This general trend shows the effect of energy transition policies in these developed economies.

Figure 34 shows the share of fuels in OECD electricity production in 2020. The share of natural gas in the power generation mix remained stable at 29% (3,048 TWh). The share of renewables (excluding nuclear and hydro) increased to 17% (1,714 TWh), mainly driven by solar and wind generation. On the other hand, the share of coal decreased 19% (1,981 TWh).

Figure 34: OECD Power Generation Mix 2020



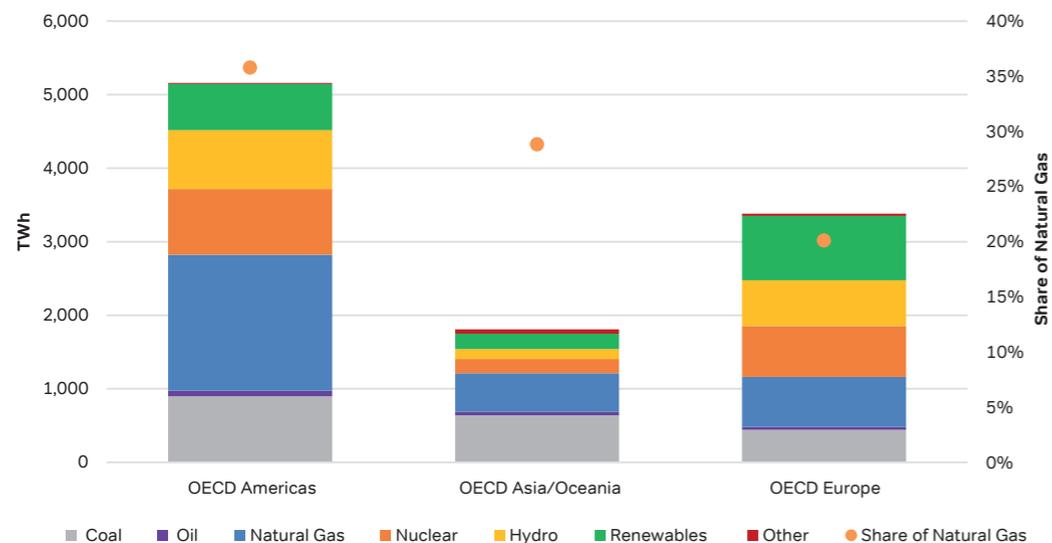
Source: GECF Secretariat based on data from IEA

Figure 35 below illustrates the power generation mix in OECD countries by region in 2020, as well as the corresponding shares of natural gas in the mix.

In OECD Americas, energy demand in the power sector decreased by 2% y-o-y to 5,161 TWh, with the power generation from gas and renewables increasing by 1% and 10% respectively, and that of coal decreasing by 19% y-o-y. Furthermore, natural gas accounted for the highest share of 36% in the power generation mix, an increase of about 15 TWh y-o-y. The U.S. and Mexico maintained high gas-fired generation at 39% and 60% respectively, while in Canada the electricity mix was dominated by hydropower which had a share of 61%.

In the OECD Asia/Oceania region, energy demand in the power sector was relatively stable y-o-y at 1,808 TWh. Coal and natural gas accounted for 35% and 29% of the power generation mix respectively. Coal-fired generation was 7% lower y-o-y, while renewables increased by 13% y-o-y. Gas-fired generation remained relatively stable y-o-y. In Australia and South Korea, coal accounted for about 54% and 37% of power generation mix respectively. In Japan, natural gas maintained the highest share of 34% while coal's share was slightly lower at 31%. The share of nuclear power was also very low at around 4%.

In OECD Europe, energy demand declined by 3% y-o-y to 3,382 TWh. Natural gas maintained its share of around 20% in the power generation mix in 2020. Gas and coal consumption in the power sector dropped by 4% and 18% respectively, while renewables increased by 11%.

Figure 35: OECD Power Generation Mix by Region 2020

Source: GECF Secretariat based on data from IEA

Non-OECD 2020

In China, coal accounted for 63% of the power generation mix, while natural gas accounted for a mere 3%. Electricity generation from gas and coal increased by 4% and 1% y-o-y respectively. Similarly, in India, the share of coal was 72%, while that of natural gas was around 5%. Coal-fired generation in India declined by 5% y-o-y due to coal-to-gas switching as buyers took advantage of low spot LNG prices.

In 2020, natural gas accounted for 56% of Argentina's power generation mix, followed by hydropower with 21%. Gas-fired generation declined by 4% y-o-y to around 80 TWh. However, there was a significant dip in Argentina's hydropower by 17% due to drought conditions. On the other hand, in Brazil, hydropower accounted for 64% of the power generation mix, followed by renewables with 19% and natural gas with 9%. Gas-fired generation in Brazil dropped by 10% y-o-y to around 56 TWh.

OECD 2021

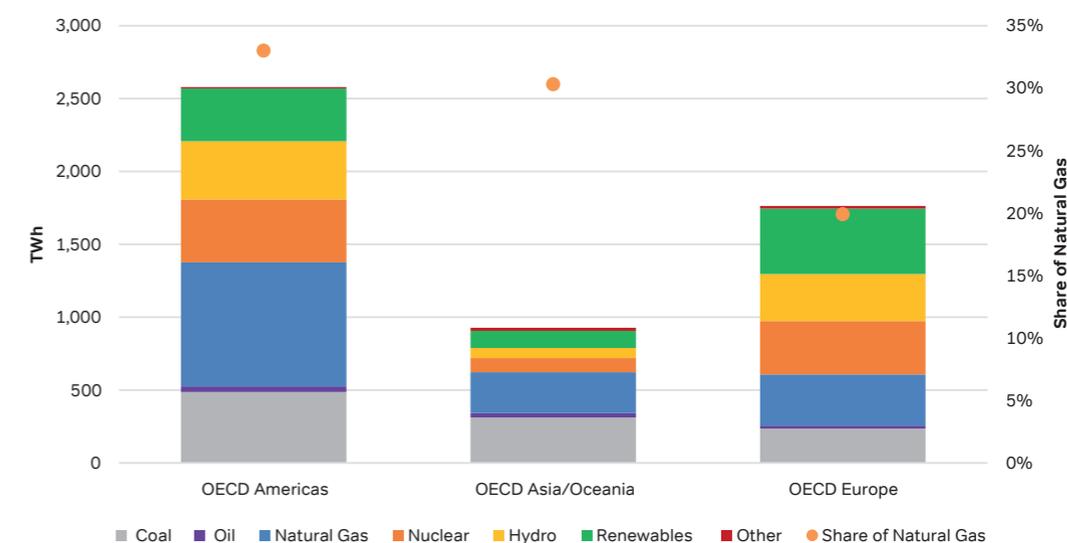
For H1 2021, total OECD power generation was 5,272 TWh, which was 4% higher y-o-y. This was mainly attributed to colder-than-usual temperatures and increased global economic activity as lockdown measures were eased. Coal power output was 15% higher y-o-y while gas was only 2% higher y-o-y.

Natural gas had the highest share in the OECD Americas with 37% of the power generation mix, followed by OECD Asia/Oceania with 29% and OECD Europe with 21% (see Figure 36).

Coal-fired generation in OECD Americas, increased by 29% y-o-y, while gas-fired generation decreased by 5% y-o-y closely mirroring trends in the U.S.

In OECD Asia/Oceania, gas-fired generation increased 6% y-o-y respectively, while coal output decreased by 3%. Higher wind and solar output in Australia, increase 19% and 23% y-o-y respectively also contributed to the rise in renewables in the region. In Japan, the gas-fired generation was 4% higher y-o-y, while nuclear power generation was 14% lower y-o-y.

In OECD Europe, gas and coal-fired generation increased by 14% and 18% y-o-y respectively, while the share of renewables dropped slightly by 1% y-o-y.

Figure 36: OECD Power Generation Mix by Region in H1 2021

Source: GECF Secretariat based on data from IEA

5.3.2 European Union Allowance (EUA) Price and its Impact on Coal-to-Gas Switching

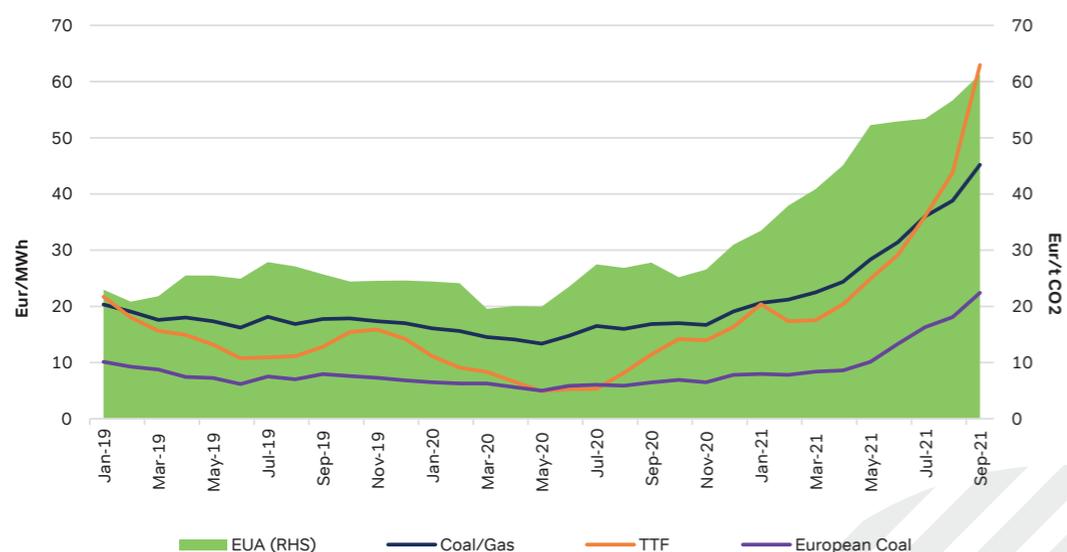
The European Union Allowance (EUA) unit, which is equivalent to one tonne of carbon dioxide (CO₂), is traded on the European Union's (excluding the UK) Emissions Trading Scheme (EU ETS) and is aimed at reducing GHG emissions. In the electricity sector, industry participants purchase EUA carbon allowances to be able to emit CO₂. Since coal emits almost twice the amount of CO₂ when burnt for electricity generation compared to gas, the cost of emitting CO₂ for coal-fired power plants is significantly higher than gas-fired power plants. This increases the competitiveness of gas-fired electricity generation over coal.

Since the start of 2019, the TTF prices have remained significantly lower than the coal-to-gas switching prices in EU (see Figure 37). 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. The competitive gas-fired electricity generation was supported by strong EUA prices and relatively low TTF prices. A large disparity between the TTF and coal-to-gas switching prices was observed in Q2 and Q3 2020 driven by the record low spot gas prices in the market last year. The TTF prices even dropped below the European coal prices between May and July 2020. However, the gap between the coal-to-gas switching price in EU and the TTF price shrank considerably from Q4 2020 and continued to decline in H1 2021. During Q3 2021, the TTF price surpassed the coal-to-gas switching price making coal-fired generation more competitive than gas and could lead to a switch from coal to gas in the electricity sector.

The average TTF month-ahead price last year was Eur8.44/MWh, down 42% y-o-y. meanwhile, the coal, coal-to-gas switching and EUA prices also declined by 23%, 14% and 3% y-o-y to Eur6.09/MWh, Eur15.48/MWh and Eur23.89/MWh respectively. The weaker EUA prices last year was driven by lower demand for emissions allowance as the COVID-19 pandemic reduced electricity demand in Europe and consequently CO2 emissions. Electricity production in the EU fell by 4% (119 TWh) y-o-y to 2,658 TWh last year.

Figure 37: Coal-to-Gas Switching, TTF, European Coal and EUA Prices



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

Although the TTF prices were well below the coal-to-gas switching price in 2020, gas burn in the EU fell by 3% (18 TWh) y-o-y to 519 TWh. Despite the decline in gas consumption in the EU's electricity sector, the share of gas increased from 19% in 2019 to 20% in 2020. Coal was the biggest loser due to the impact of COVID-19 on electricity demand in the EU, with coal burn recording a slump of 21% (96 TWh) y-o-y to 357 TWh. Its share also dropped significantly from 16% in 2019 to 13% last year. Nuclear power was the second most impacted source of fuel in the EU in 2020 and fell by 11% (80 TWh) to 648 TWh. Similar to coal, the share of nuclear in electricity production decreased from 26% to 24% during this period. The lower nuclear output was mainly due to the phasing out of nuclear

power in Germany and the impact of maintenance activity on nuclear reactors in France, as a result of COVID-19 restrictions.

In contrast, renewable energy and hydro output increased by 11% (54 TWh) and 8% (26 TWh) y-o-y to 547 and 366 TWh respectively. The share of renewables and hydro in the electricity mix increased from 18% and 12% to 21% and 14% respectively. Renewables overtook gas in the EU's electricity mix to become the second largest source of electricity production behind nuclear.

Moving ahead into 2021, between January and September, the EUA price doubled from the same period in 2020 to Eur48.21/tCO2 and has been trading above Eur60/ tCO2 since September 2021. The surge in the EUA price was supported by the Market Stability Reserve (MSR), which removes 24% of allowances in circulation and places it in reserve when the allowances in circulation exceed 833 million allowances during the period 2019-2023. Before 2019, 12% of excess allowances were placed in reserve. In addition, to tackle the market imbalance of allowances, the annual emissions cap will be reduced at an annual average rate of 2.2% from 2021, which also contributed to the higher EUA price.

Meanwhile, the TTF month-ahead price during the first nine months of 2021 almost quadrupled to Eur30.28/MWh, supported by strong gas demand and tight gas supplies. Similarly, the coal-to-gas switching and coal prices in Europe also rose by 95% and 110% y-o-y to average Eur29.83/MWh and Eur12.56/MWh respectively.

During H1 2021, electricity production in the EU rose by 5% (69 TWh) y-o-y to 1,398 TWh. Although gas-fired electricity generation was generally more economical than coal during this period, coal-burn jumped by 22% (36 TWh) y-o-y to 197 TWh while electricity production from gas increased by 4% (9 TWh) y-o-y to 255 TWh. The stronger growth in coal burn compared to gas is driven by the strong recovery in electricity demand in the EU and tight gas supply for electricity generation. Meanwhile, the increase in gas-burn until June 2021 has offset half the decline recorded for the whole of 2020.

In contrast, renewables output declined by 1% (3 TWh) y-o-y to 360 TWh in H1 2021, due to weak wind output (-16 TWh) but was partially offset by higher solar (7 TWh) and combustible renewables (6 TWh). Furthermore, hydro and nuclear output rose significantly from January to June 2021 by 5% (10 TWh) and 5% (16 TWh) y-o-y to 203 TWh and 348 TWh respectively.

For the rest of 2021 and into Q1 2022, coal-to-gas switching in the EU appears to be limited considering that the TTF gas prices are hovering above the coal-to-gas switching price. In fact, if this condition persists, there could be a switch from gas to coal in EU's electricity sector, which could disrupt the recovery in gas demand in the EU.

5.3.3 Short Term Perspectives

In going forward, the power sector will be shaped by several influencing factors including the economic recovery, government policies towards net-zero emission targets and inter-fuel competition.

According to the IEA's Global Energy Review 2021, global electricity demand in 2021 is expected to increase by 4.5%. This will be supported by the widespread and speedy deployment of vaccination programs which will in turn boost economic recovery. Colder temperatures in the first quarter of 2021 have already increased electricity demand. In addition, strong growth in major developing economies, particularly China and India, will fast-track consumption in the power sector above pre-COVID levels in 2021.

Furthermore, we expect to see major changes in the global power generation mix in the next decade as the global energy transition accelerates and government policies, financing and investment are aimed towards achieving net-zero emissions. Structurally, the share of coal will diminish, while gas and renewables will continue to capture a greater market share.

In Europe, we expect coal-to-switching to continue to drive gas demand in the power sector particularly with the high levels of carbon prices. About 50% of Europe's coal power plants are expected to be closed by 2030, with some already shutdown, and others with an announced closure date. In 2020, Austria and Sweden closed their last coal-fired plants. Germany, the EU country with the highest coal-fired power plant capacity approved its coal exit law in July 2020 which aims to close all coal-fired power plants by 2038, in addition to nuclear phase-out by 2022. Poland, with only two coal plants, aims to shutdown these down in 2021 according to its 2030 climate change program. France has legislated coal phase-out by 2022. Other countries have announced plans to phase-out coal by 2030 including Denmark, Hungary, Netherlands, Slovakia and Spain. While Ireland and Italy close their coal-fired plants by 2025, and Greece by 2028.

Gas demand in the Asian power sector will be driven by the phase-out of coal power plants, as well as continued delays in the restart of nuclear power plants. In 2020, Japan introduced new energy policies which are expected to increase the call on LNG imports. These include power sector reforms to increase market competition and the shutdown of inefficient coal power plants (those not equipped with clean coal technologies). The Ministry of Trade and Industry (METI) is targeting new measures for producers to achieve an efficiency of more than 43% by 2030 in coal-fired power plants. Furthermore, power shortages in January 2021 have prompted a proposal for new fuel guidelines for power generation aimed at supply security which should be finalized this year. Moreover, the restart of some nuclear reactors remain uncertain as both technical problems and required anti-terrorism measures continue to extend downtime on these facilities.

The China Electricity Council (CEC) forecasts its power consumption to increase by 10-11% y-o-y driven by strong economic activity. China is also expected to decommission more than 100 GW of inefficient coal power plants (about 18% of its total coal plants), and phase out the rest by 2045, in order to meet its carbon-neutrality goal by 2060. This will increase the calls on natural gas and renewables to meet higher electricity requirements.

The South Korean government has committed to continuing its quest to close aging coal-fired power plants and aims to reduce its capacity to 38.3 GW by 2022 and then 29 GW by 2034. Furthermore, five state-owned KEPCO utilities have volunteered to cut annual coal-fired generation by 18.0-23.8% compared to the average of 2017-2019, which could ultimately reduce its generation by 3.8TWh.

In the US, we expect to see a higher share of coal-fired generation as electricity demand rebounds. The share of coal in the U.S. power generation mix is expected to increase from 20% in 2020 to 24% in 2021 and 2022, while that of natural gas is expected to drop from 39% in 2020 to 35% in 2021 and 34% in 2022, according to the EIA Short Term Energy Outlook September 2021. This declining share of natural gas may be attributed to the expected higher gas prices for 2021, and also increased generation from coal and renewables.

While the global electricity demand was significantly impacted by the COVID-19 pandemic, it also underscored the necessity for affordable, reliable, flexible and secure electricity supply in each country. In this regard, natural gas will continue to play increasingly important role in the global power generation mix.

The power sector is expected to continue its recovery in Q4 2021 as global economic activity recovers. In the short term, we expect the share of natural gas to grow in existing markets and penetrate new markets as it serves to improve the quality of lives and meet the basic energy requirements.

5.4 Natural Gas Consumption in the Transportation Sector

5.4.1 Recent Trends

The transportation sector has been strengthening its position as an emerging consumer of natural gas.

Natural Gas Vehicles (NGVs)

NGVs may play a crucial role in reducing GHG emissions in the ongoing energy transition, since they are more environmentally friendly compared to gasoline and diesel vehicles, which dominate in the market today. Two types of NGVs operate in the market, in particular vehicles operating on compressed natural gas (CNG), with most of them being passenger cars, and vehicles operating on liquefied natural gas (LNG), with most of them being commercial trucks. Various countries in Europe and Asia, mainly China and India, have ambitious policies for promoting the use of natural gas for the automotive industry, with a special focus on LNG-fuelled trucks. With lower emissions and noise, LNG is a perfect alternative option over diesel in road freight transportation.

At the beginning of 2020, global NGV fleet reached 28.5 million vehicles, with annual sales reaching around 2 million vehicles. Asia Pacific countries had 20.5 million NGVs, Latin America – 5.5 million and Europe – 2.1 million. Among GECF Member Countries, Egypt stands out, with its current number of CNG vehicles reaching 0.36 million vehicles and its plan to convert other 0.4 million vehicles to CNG over the next three years.

Natural gas consumption by NGVs has been consistently increasing all over the world, in line with the growth in the number of NGVs. For instance, gas consumption in the US rose to 1.7 Bcm in 2020, which is compared to 1.1 Bcm in 2015 and 0.8 Bcm in 2010.

Multiple countries continue to develop the appropriate fuelling infrastructure for CNG and LNG-fuelled vehicles, since its shortage remains an inhibiting factor for NGV expansion. As

of March 2021, Europe had over 3,974 CNG stations (1,408 in Italy, 817 in Germany, 217 in Czech Republic, 201 in Sweden) and 390 LNG stations (92 in Italy, 66 in Spain, 57 in Germany, 49 in France) compared to 3,785 and 270 stations, respectively, in March 2020. In the meantime, the US has around 2,000 CNG/LNG stations.

However, there are some impeding factors for the expansion of NGVs. The first factor may have a short-term nature: a surge in gas hub prices in H2 2021 lowered a price competitiveness of CNG and LNG compared to gasoline and diesel fuels, while lower gas price has always been considered as a key advantage of CNG and LNG. The second factor has rather a medium and long-term nature: the sales of electric vehicles (EVs) have been gaining a momentum. In 2020, global EVs sales reached 3.2 million units compared to 2.3 million a year earlier, with the global fleet amounting to 10.7 million vehicles. The EVs sales growth rate reached 39% y-o-y, implying a path to recovery after 9% growth in 2019 (from 2016 to 2018, the average annual sales growth rate reached 63%). EVs still represent a small share of global vehicle sales, with its share reaching only 3%. EVs will gain a market share mainly from internal combustion engine vehicles and ultimately displace potential gasoline and diesel consumption. However, EVs sales will be able also to suppress NGVs sales, which otherwise would replace gasoline and diesel vehicles. It is worth noting that the growing electricity demand to charge EVs could be met by gas-fired power plants, thus potentially increasing gas demand.

LNG Bunker Fuel

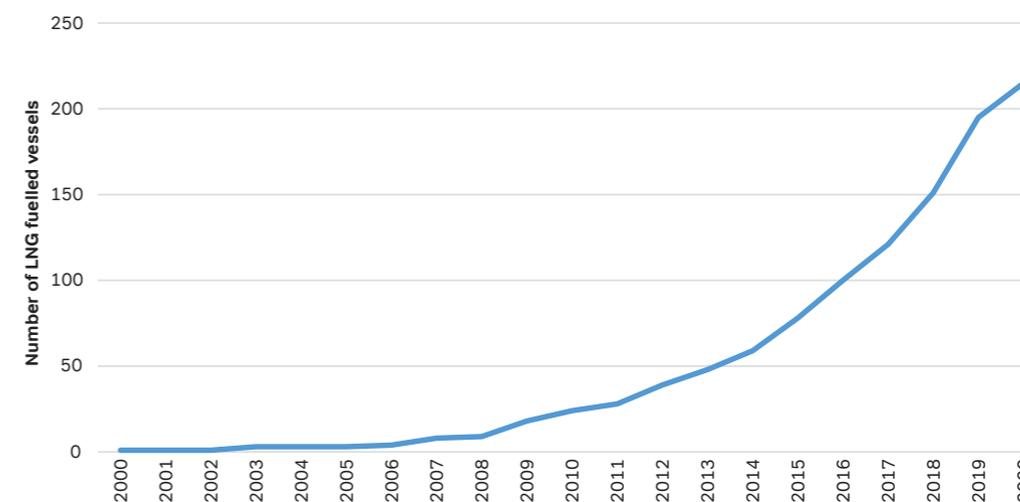
At the beginning of 2021, 215 LNG-fuelled vessels (excluding LNG carriers) operated in the global shipping market (see Figure 38). Of that amount, 198 were newbuilt vessels and 17 were retrofitted vessels. Among various types of vessels, the most popular were as follows: passenger – 68, tanker/bulk – 67, supply/service – 53, container cargo – 27.

LNG-fuelled vessels retain a tiny share in the global shipping market. Moreover, 2020 witnessed a slowdown in the commissioning of vessels, with only 20 vessels coming online compared to the record 44 vessels in 2019. The slowdown was partially driven by the COVID-19 pandemic, with the completion of some vessels being put on hold because of supply and logistics issues. However, a high number of vessels on the order book gives a reason to believe that LNG bunker fuel will gain a momentum in the medium term. Of over 200 vessels on the current order book, 27 vessels were ordered in Q1 2021, of which 14 were tankers and nine were container vessels. This growing trend gives a reason to think that LNG bunker fuel will play a crucial role in the energy transition that the shipping industry will undergo. The consumption of LNG bunker fuel will robustly increase, since larger vessels, including very large crude carriers, containerships and bulkers, have been ordered.

The tightening environmental policy on the global level is a crucial regulatory driver. Starting from January 2020, the International Maritime Organization (IMO) introduced a new sulphur cap of 0.5% (compared to the previous 3.5% limit). LNG bunker fuel enables almost complete reduction of sulphur oxide emissions as well as a major reduction of NOx and CO2 emissions.

Price competitiveness of LNG bunker fuel and its rising availability have always been considered as crucial economic drivers of the growth in its consumption. However, gas markets developments in 2020-2021 questioned this common wisdom. A drop in oil prices in H1 2020 undermined LNG price competitiveness, however a rebound of oil prices in H2 2020 revived LNG competitiveness. In the meantime, a sharp rise in gas hub prices in H2 2021 once again undermined LNG price competitiveness.

Figure 38: Trend in Global LNG-Fuelled Vessels (Excluding LNG Carriers)



Source: GECF Secretariat based on data from Argus and ICIS

5.4.2 Short Term Perspectives

In the short term, the transportation sector is likely to retain positions of a niche market for the gas industry, with its consumption representing around 1% of the global gas demand. A sharp rise in gas hub prices in H2 2021 may undermine the competitiveness of gas in the automotive and shipping industries in the short term, however the tightening of environmental regulations may encourage gas consumption by the transportation sector in the medium term.

After a slowdown in sales amid the COVID-19 pandemic, NGVs sales may rebound to 2 million units per year, with LNG-fuelled trucks gaining a momentum.

The building of LNG-fuelled vessels may accelerate over the next five years, as LNG bunker fuel infrastructure develops and environmental regulations become stricter. The announced inclusion of CO2 emissions from the shipping industry into the EU's Emissions Trading Scheme by 2023 may further encourage the usage of LNG bunker fuel, since emissions fees may put LNG at an advantage over oil-based shipping fuels. In the meantime, there will remain some constraining factors for the promotion of LNG bunker fuel, including the ones of regulatory nature. IMO is aiming at adopting limitations of CO2 emissions by the shipping industry. LNG bunker fuel is not so much effective in reducing CO2 emissions, as in the

case of sulphur oxide emissions. In this context, the LNG industry should step up efforts to mitigate the carbon footprint attributable to the gas industry chain, mainly by developing CCUS and decreasing methane leakages.

5.5 EU's Fit For 55 package and its potential impact on gas demand

The EU's 'Fit for 55' package is designed to provide a roadmap to reach the EU's aggressive target of reducing greenhouse gas emissions by 55% by 2030 from 1990 levels with the aim of carbon neutrality by 2050. This package which was revealed on 14 July 2021 and comprises of 17 separate draft regulations and directives, however these are not yet legal obligations. The all-encompassing package includes a combination of initiatives such as extending the EU ETS to new sectors, tightening of the existing EU ETS, growth of renewables, improving energy efficiency, acceleration of zero-emission and low-carbon fuel in transportation and measures to prevent carbon leakage.

The new package will lower the overall emissions cap, accelerate the annual reduction rate and widen the scope of emissions to include those from the maritime sector. Furthermore, it will create a new ETS which will be applicable to the buildings and transport sectors. In this case, the carbon price will directly impact the consumer with the aim of encouraging the switch the low-carbon alternatives and energy efficiency measures.

The widening of the existing ETS to the maritime sector and high carbon prices may encourage the use of LNG as a fuel instead of traditional fuel oil. The introduction of a new ETS for the buildings and transport sector may reduce the share of natural gas in the medium-to-long term. Consumers may opt for renewables, low-carbon alternatives and energy-saving appliances to reduce their overall consumption and utility bills, which can threaten the share of gas demand in the residential sector. With regard to gas demand in the transportation sector, it is relatively small, therefore there may not be a major impact on demand in this sector. However, further growth may be inhibited.

Other EU targets to ultimately reduce total primary and final energy consumption and increase the share of renewables in the energy mix. Low-carbon gas and blue hydrogen are also expected to form part of the EU's Renewable Energy Directive (RED). Further details on the decarbonization of gas and gas market reform is expected to be presented in legislative proposals later this year. While gas is poised to act as a backup to renewable power generation, this regulation may threaten the share of gas across the different sectors. However, the current energy crunch and unprecedented spikes in energy prices is also building concern about EU's climate change agenda and its impact on energy security and more so, on the most vulnerable in society.

The EU has also proposed a new regulation to establish an EU Carbon Border Adjustment Mechanism (CBAM). This policy is aimed at regulating greenhouse gas emissions through the implementation of a carbon emissions cost on some imported goods with the intention of preventing the risk of carbon leakage. The CBAM is expected to apply to some goods in the following segments: cement, electricity, fertilizers, iron and steel, and aluminum.

This regulation is expected to be phased in from 2023, with full implementation from 2026. Importing companies will have to provide data on the related carbon emissions of the imported goods and purchase digital certificates (each certificate will represent one tonne of CO₂ emissions embedded in the good) to cover the calculated CO₂ emissions. Some countries may be exempted from this levy including those with similar carbon pricing mechanisms to Europe and some less developed countries.

It is the first type of mechanism like this in the world and ultimately aims to encourage other countries to initiate similar mechanisms to create a level playing field for all companies. This initiative can potentially be step in the formation of a global carbon price.

Natural gas is still expected to account for a major share of the EU's energy mix in the next decade, particularly in the power sector as coal-fired generation is phased out and as it acts as a complimentary fuel for renewables. EU carbon prices have been on an upward trajectory, surpassing its historic prices, and is expected to continue to increase as the EUAs are reduced annually and the emissions cap is lowered. High gas prices have also resulted in some gas-to-coal switching which increases the demand for EUAs.

Consequently, the carbon market is expected to tighten further as these policies are phased-in. The impact of high gas and carbon prices on households and industries is already being felt in the current tight market conditions ahead of the winter season. In the short-term, both gas and carbon prices will continue to be heavily influenced by weather conditions, economic recovery post-COVID and competition for supply in Asia.



CHAPTER
06

Natural Gas Supply

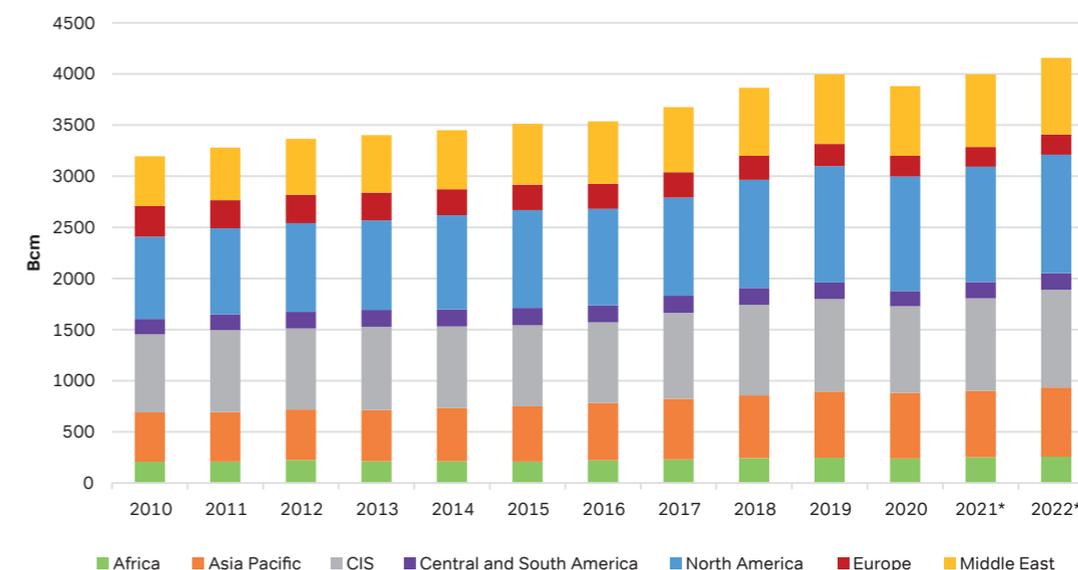
6.1 Natural Gas Production

6.1.1 Review of 2020

Natural gas production in 2020 was affected by the COVID-19 pandemic. Upstream activities declined significantly across the globe due to weak demand for natural gas and low prices of oil and gas in global markets. While some oil and gas companies reported huge losses in 2020, some others filed for bankruptcy. They tried to reduce costs and cut spending to balance their financial status and offset the negative impacts of COVID-19 on their balance sheets. Meanwhile, oil and gas equipment manufacturing shutdowns and shipment restrictions have caused delays in some upstream projects in 2020.

As a result, global natural gas production dropped by 3 % in 2020 to stand at 3,880 Bcm (see Figure 39), which is 115 Bcm lower than the production level in 2019. CIS and North America experienced the highest level of decline among the regions. In terms of volume, the two regions accounted for around 63% of global natural gas decline.

Figure 39: Trend in Global Natural Gas Production by Region



Source: GECF Secretariat based on data from Cedigaz
 (*) GECF's forecast for 2021 and 2022

While global natural gas production experienced an average annual increase of 2% during the years 2010 to 2019, the production decline in 2020 is the first annual drop in global gas production in years. Among the countries, US experienced the highest level of decline. While natural gas production in China (16Bcm), Iran (5Bcm) and Azerbaijan (1.5Bcm) increased in 2020.

Preliminary estimations of the global oil and gas upstream investment in 2020 indicate that the sector was hit severely by the pandemic. Based on the projections before the COVID-19 pandemic, the upstream investment level in 2020 was supposed to remain at the same

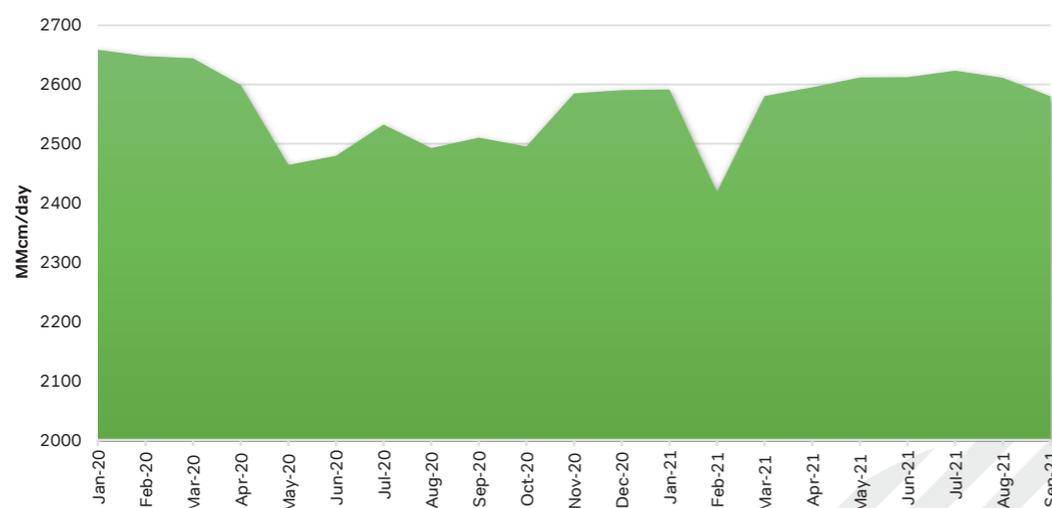
investment level of 2019 at around 530 billion USD. In contrast, recent estimations show that investment in the oil and gas upstream sector declined by 26% in 2020. Despite the oil and gas price recovery in 2021, the upstream oil and gas companies, particularly those producing from higher-cost shale plays, are trying to stabilize their cash flows and balance their financial statements rather than investment in new development projects. Accordingly, it is expected that the upstream investment in 2021 to remain at the same levels of 2020. This may cause a shortage of natural gas supply in the upcoming years due to the lack of investment.

6.1.2 Natural Gas Production by Regions and Countries

Americas

The US has been the largest source of global natural gas production in the recent years thanks to the shale gas production growth and supported by increasing domestic natural gas demand and LNG export. However, dry natural gas production of the US dropped from 2667 MMcm/day pre-pandemic in January 2020 to 2463 MMcm/day in May 2020 (see Figure 40) experiencing a decrease of 8%. Since then, dry natural gas production recovered to 2580 MMcm/day in September 2021.

Figure 40: Dry Natural Gas Production Trend in the U.S. (Monthly Average)



Source: GECF Secretariat based on data from Refinitiv

The cold snap in the US southern states in February 2021 also hit the production level temporarily in the month. The decline in the US dry natural gas production in 2020 is mainly due to the impacts of the COVID-19 pandemic and low prices of natural gas in the markets which reduced the producers appetite to produce more gas from the fields. Also associated gas output in the US declined due to lower oil production.

On the other part of the continent, South and Central America natural gas production dropped by around 15 Bcm in 2020 compared to 2019 due to lower domestic demand in the region.

In Argentina, the main natural gas producing country in the region, due to the negative impacts of the COVID-19 pandemic on Vaca Muerta Shale play's investment plans, YPF's shale gas production targets seem unrealistic in the midterm. To achieve those targets a significant amount of investment is needed. Given the country's economic situation, Argentina's government faces some limitations in investment in its shale plays. The country was already in financial hardship before the pandemic. The government of Argentina reviewed and reduced the previous years' incentives for the shale gas companies to allocate the funds to other issues with higher priorities. Meanwhile, YPF in February 2021 restructured its debt structure to free up more sources to spend on its shale plays. However, the change is not welcomed by the most of the company's creditors.

However, later the government announced its plans to revert back to subsidize shale gas production in the Vaca Muerta region to support domestic production and prevent the country from relying on imported gas. The amount of subsidy will be around 1 billion USD annually for the upcoming years.

The region's other major gas producing country, Trinidad and Tobago is expected to contribute significantly to the continent's natural gas production growth during the years 2021 to 2025 due to its planned development projects. Also, in Guyana, several hydrocarbon discoveries took place in recent years, which increased the estimations of the region's recoverable resources. Furthermore, the commissioning of new oil and gas projects in the upcoming years will transform Guyana's position into one of the leading players in the region's energy scene.

CIS

The total CIS natural gas production contracted by 55 Bcm to reach 849 Bcm in 2020 representing 22% of global natural gas production, as indicated in Figure 41. The production decline in the region was driven mostly by the weak domestic demand as well as less pipeline gas export.

The production decline in the region was mainly driven by Russia and Turkmenistan, while Azerbaijan natural gas production increased in 2020 and recorded new levels. The natural gas production growth in Azerbaijan is due to the production increase from Shah Deniz field, which supported natural gas export to Turkey and Europe through TANAP and TAP pipelines.

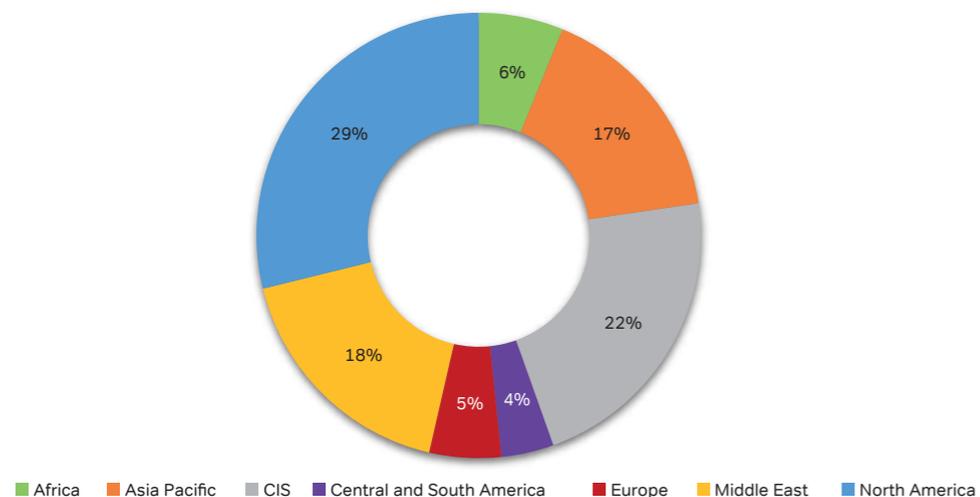
The Middle East and Africa

In Africa, preliminary data indicates that total natural gas production declined by around 8 Bcm in 2020 to stand at 239 Bcm mainly due to lower pipeline gas export to Europe, resulting in production decline in main African natural gas producing countries. Natural gas production recovered to 2019's levels in the fourth quarter of 2020 in major producing countries with recovering demand.

Natural gas production in the Middle East in 2020 remains unchanged at 680 Bcm, representing 18% of the global output (see Figure 41), despite the outbreak of COVID-19. The associated gas output decline in the OPEC member countries due to oil production limits was offset by the natural gas production increase from new projects coming online.

Based on preliminary estimations, Iran was the main source of production stability in the Middle East. The country's natural gas production increased by around 5 Bcm thanks to the commissioning of new projects in the South Pars gas field. Natural gas production in other major producing countries in the Middle East in 2020 was slightly lower than 2019 levels.

Figure 41: Share of Regions in Global Natural Gas Production in 2020

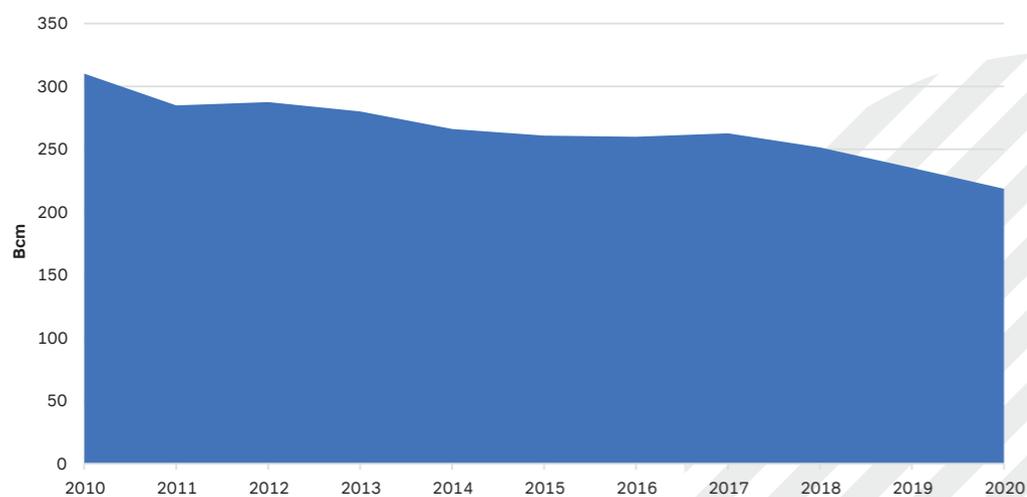


Source: GECF Secretariat based on data from Cedigaz

Europe

Natural gas output in Europe dropped by 7% in 2020 to stand at 218 Bcm, which is around 16 Bcm lower than the 2019 production level as indicated in Figure 42.

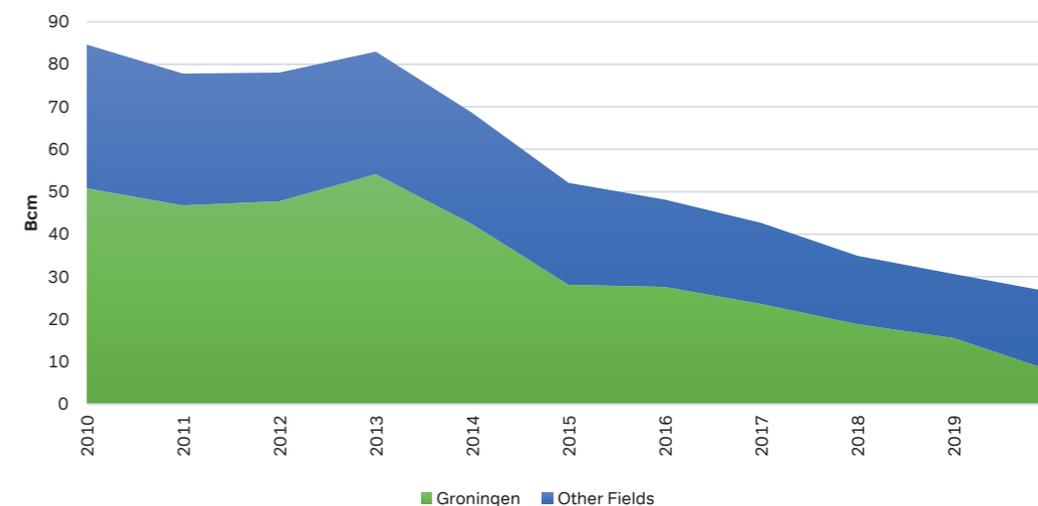
Figure 42: Trend in Natural Gas Production in Europe



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

The production decline in the continent is mainly due to the production decline in the Netherlands. The countries' production declined by 14% to stand at 26 Bcm in 2020 (see Figure 43). Accordingly, the Groningen field production dropped by 50% in 2020 to stand at 8 Bcm due to the implementation of the production cap on the field by Dutch government. It should be reminded that the production cap was lowered gradually from 2014, with the ultimate goal of shutting it down entirely.

Figure 43: Trend in Natural Gas Production in the Netherlands



Source: GECF Secretariat based on data from Refinitiv

Asia Pacific

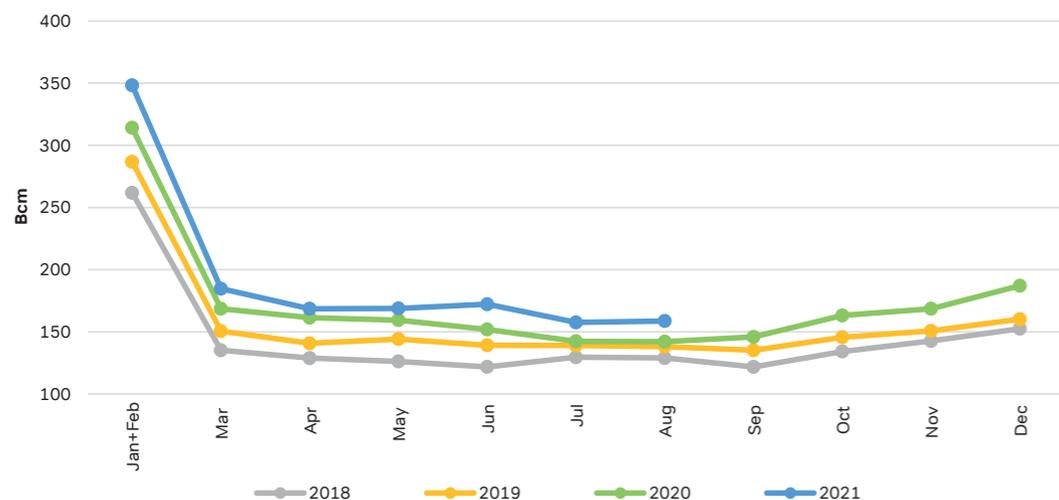
In the Asia Pacific, natural gas production declined by 6 Bcm y-o-y to reach 640 Bcm in 2020, representing a 17% share in global gas production. The decrease in Asia Pacific production was driven by Indonesia and Malaysia due to the negative impacts of the COVID-19 pandemic on upstream activities. At the same time, the natural gas output of China increased by 10% y-o-y to reach 190 Bcm in 2020 (see Figure 44).

Regarding shale gas output in China, based on the government's five-year plan, shale gas production in 2020 was supposed to reach 30 Bcm. However, due to the complexity of shale formations and the proximity of the shale plays to mountainous and densely populated areas, the target was not materialized. Shale gas production in China in 2020 reached 20 Bcm accounting for around a tenth of the country's natural gas production.

Meanwhile, Sinopec has announced its shale gas discovery in the Sichuan basin, adding 192 Bcm to its proven natural gas reserves and increasing the total Sichuan basin's reserves to around 800 Bcm.

In Australia, the government unveiled its plans to invest 173 million USD in Beetaloo Shale Basin exploration activities. Beetaloo is estimated to hold around 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 44: Trend in Natural Gas Production in China

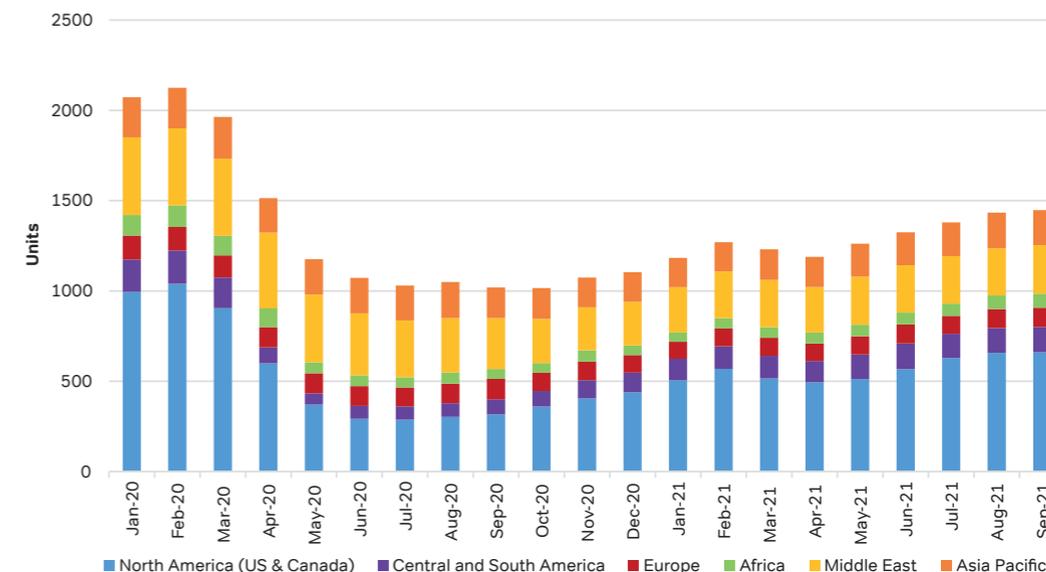


Source: GECF Secretariat based on data from National Bureau of Statistics of China

6.1.3 Global Rig Count

COVID-19 pandemic severely affected oil and gas upstream activities. The number of active oil and gas rigs, as an indicator of upstream activities, dropped by 51 % from 2073 units at the end of January 2020 to 1016 units at the end of October 2020 and then gradually started to increase to stand at 1448 units by the end of September 2021 (see Figure 45).

Figure 45: Trend in Global Rig Count since January 2020



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

The decrease in rig activity was driven by all the regions (the US, the Middle East, Canada, Central & South America, Africa, Asia Pacific, and Europe), which dropped by 283, 161, 51, 39, 36, 28, and 27 units to average 508, 269, 153, 140, 78, 194, and 106 units, respectively. By the end of September 2021, the North American (the US and Canada) rig count increased by 344 units, y-o-y, to stand at 661 units, representing 46% of the global rig count. Meanwhile, the international rig count (excluding North America) increased by 85 units, y-o-y to stand at 787 units by the end of September 2021.

6.1.4 Short Term Perspectives

The COVID-19 pandemic harmed upstream activities and global gas production in 2020 due to the negative impacts of the pandemic on global demand and lower prices of natural gas. The investment level in upstream projects declined significantly in 2020, and oil and gas companies cut their spending to balance their financial status. All these developments affect the global natural gas supply in the years to come. While the US was the main source of natural gas production growth in non-GECF countries in recent years, its production declined in 2020.

To estimate the natural gas production in 2021, it is assumed that the price of natural gas will remain above the average marginal cost in the US in the remaining months of 2021. As the demand side is a constraint for natural gas production, it is also assumed that the demand for natural gas in 2021 will be recovered by recovering economic activities.

Therefore, for 2021, it is forecast that global production will recover to the pre-pandemic, 2019 production level and will continue to grow in 2022. By the gradual lifting of the restrictions, the global natural gas production is expected to grow by around 3% in 2021 to stand at 3,994 Bcm, driven by CIS, North America, the Middle East, and Africa.

6.2 Underground Gas Storage

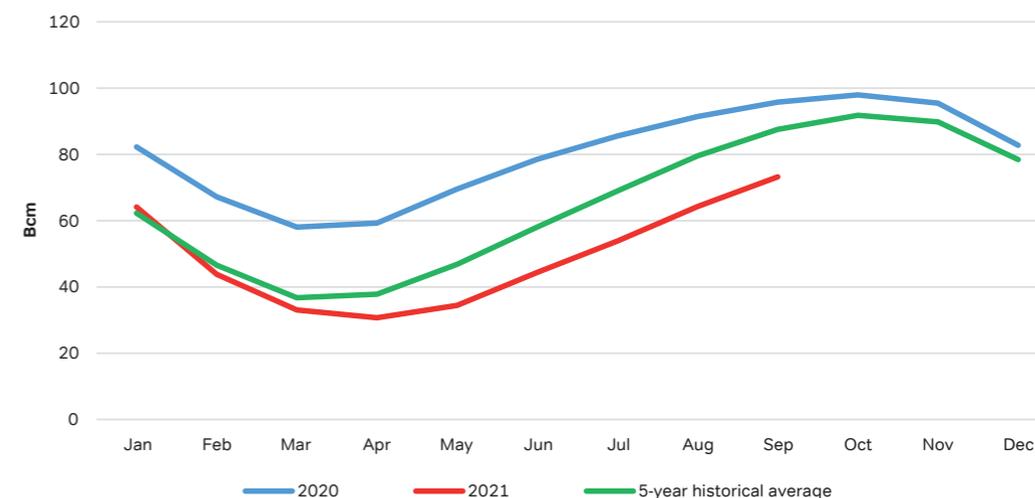
6.2.1 Recent Trends

Global underground storage capacity reaches 421 Bcm, with capacity in the US and EU staying at 137 Bcm and 103 Bcm, respectively. Over 660 underground storage facilities operate in the world, with the US and EU accounting for 58% and 21% of them. Storage-to-consumption ratio, representing a correlation between effective working gas storage capacity and gas consumption, reaches 11% on the global level, while amounting to 22% in the EU and 16% in the US.

In 2020, the level of gas in storage in the EU and US was abnormally high because of a decline in gas demand against the backdrop of the warmer-than-usual 2019/2020 winter season and COVID-19 related restrictions. In the meantime, a drop in gas supply was not as big as a fall in gas demand. In this context, gas injections into underground storage facilities helped to balance the regional markets. The average daily level of gas in storage in the EU reached 80 Bcm in 2020, compared to 73 Bcm in 2019 and 66 Bcm for the 5-year historical average. In the meantime, the average daily level of gas in storage in the US amounted to 86 Bcm, compared to 70 Bcm in 2019 and 79 Bcm for the 5-year historical average.

In 2021, the level of gas in storage in the EU has been at abnormally low level. The regional gas demand has recovered, driven mainly by colder-than-usual 2020/2021 winter season and lifting of the COVID-19 related restrictions. By the end of the winter season, which lasted one month longer than usual until late April, gas in storage fell to a low level of 30 Bcm. That compares to 55 Bcm in 2020 and 35 Bcm for the 5-year historical average, with net gas withdrawals from underground storage throughout the winter season reaching 65 Bcm (see Figure 46).

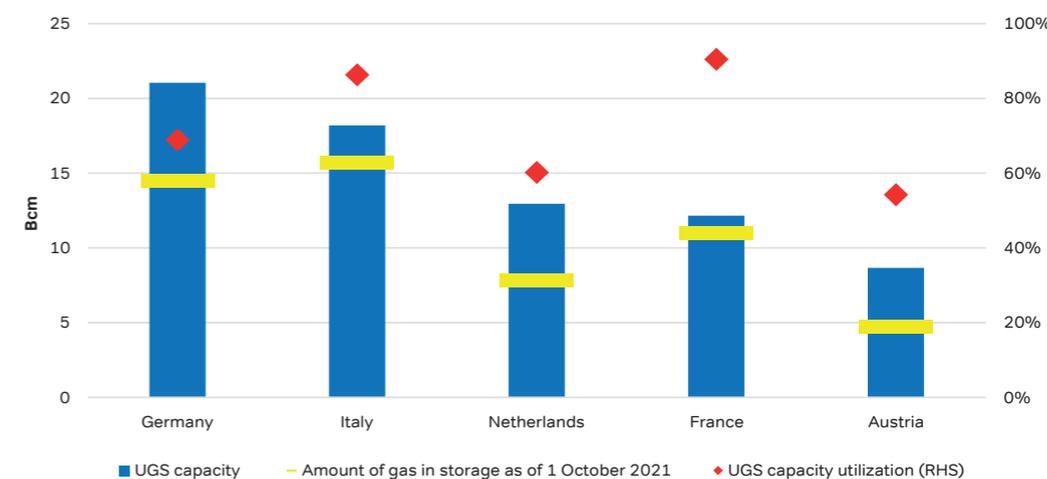
Figure 46: Gas in Storage in the EU



Source: GECF Secretariat based on data from AGSI+

The pace of replenishing gas in storage in the summer season lagged behind the indicators of the previous years (as of 1 October 2021, gas in storage was 14 Bcm lower than the 5-year historical average). That was driven by high hub prices in the 2021 summer season, which prevented gas operators from buying gas on the market for injecting it into underground storage, and an uptick in gas demand for cooling because of the hot summer. Besides, LNG supply to Europe decreased in 2021, while PNG supply suffered various disruptions driven by planned and unplanned maintenance operations. As a result, low level of gas in storage has had a strong upward pressure on gas hub prices. Germany, Italy, France, Netherlands and Austria have remained major EU countries in terms of storage capacity and its utilization (see Figure 47).

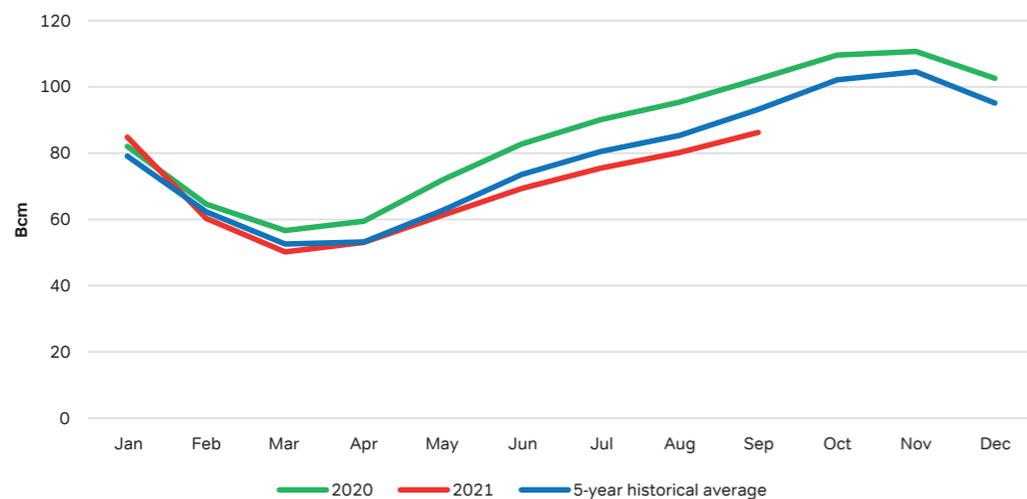
Figure 47: Storage Capacity vs Gas in Storage in Major EU Countries



Source: GECF Secretariat based on data from AGSI+

In 2021, similar trends have been observed in the US, where a colder-than-usual winter also contributed to higher gas demand and higher gas withdrawals from underground storage. By the end of the winter season, gas in storage fell to 50 Bcm, which is compared to 56 Bcm in 2020 and 52 Bcm for the 5-year historical average (see Figure 48).

Figure 48: Gas in Storage in the U.S.



Source: GECF Secretariat based on data from U.S. EIA

Higher gas demand in the 2020/2021 winter season in both EU and U.S. as well as gas supply disruptions in the US in February 2021, driven by abnormally cold temperatures, demonstrated once again a crucial role, which gas storage plays in ensuring security of gas supply. Gas storage in the EU and US once again balanced gas markets, while smoothing out seasonal fluctuations in gas demand and supply.





CHAPTER
07

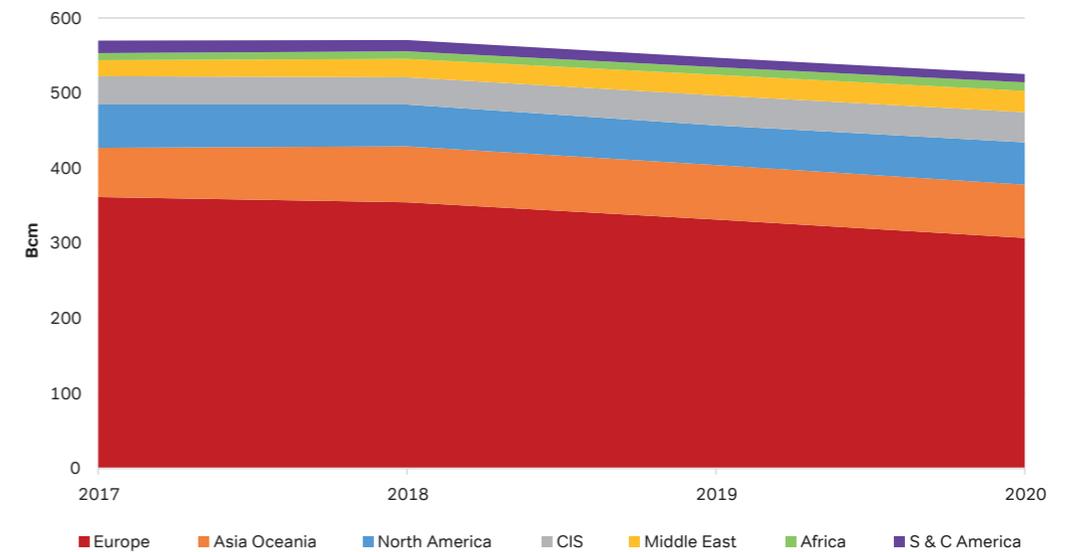
Natural Gas Trade

7.1 Global Pipeline Gas Trade

7.1.1 Recent Trends

In 2020, global pipeline gas trade, based on the net flows approach, declined by 4% to 525 Bcm, driven by a drop in global gas demand amid the COVID-19-related restrictions. The net flows approach enables us to avoid double counting of some pipeline gas flows, including re-exports of pipeline gas and exports of regasified LNG. Based on the gross flows approach, global pipeline gas trade dropped by 7% to 766 Bcm. In net pipeline gas imports, Europe was the leader with 58% of the market, while Asia Pacific and North America represented 14% and 11%, respectively (Figure 49).

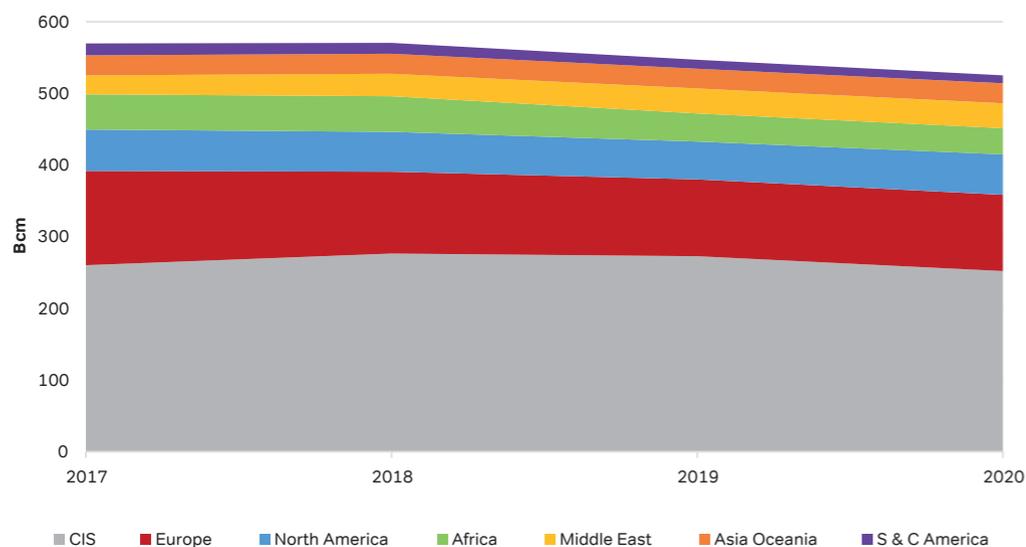
Figure 49: Net Pipeline Gas Imports by Region



Source: GECF Secretariat based on data from Cedigaz

In net pipeline gas exports, C.I.S. dominated with 48% of the market, while Europe and North America represented 20% and 11% of the market, respectively (Figure 50).

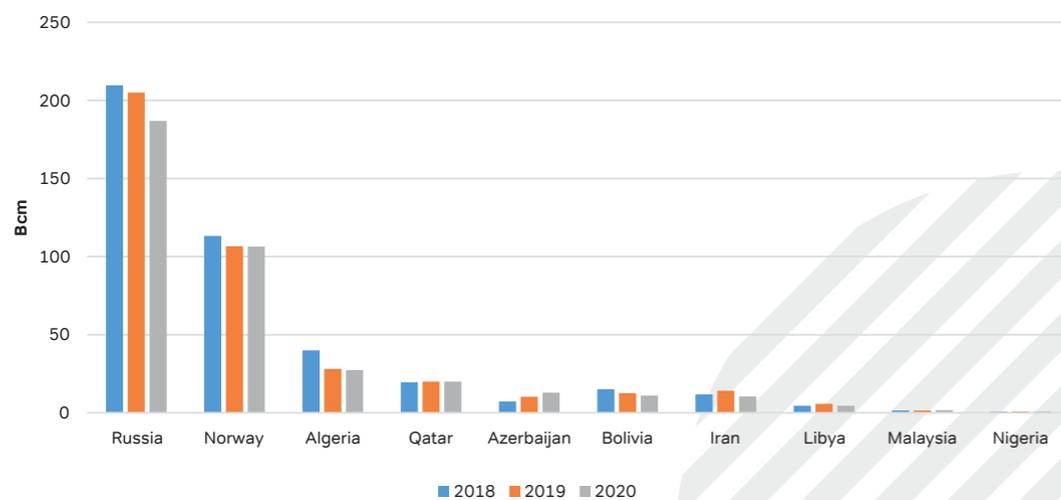
Figure 50: Net Pipeline Gas Exports by Region



Source: GECF Secretariat based on data from Cedigaz

In 2020, GECF Member Countries exported 400 Bcm of pipeline gas. Russia, Norway, Algeria, Qatar, Azerbaijan, Bolivia, Iran, Libya, Malaysia and Nigeria were involved in its exports (Figure 51).

Figure 51: Pipeline Gas Exports of GECF Member Countries



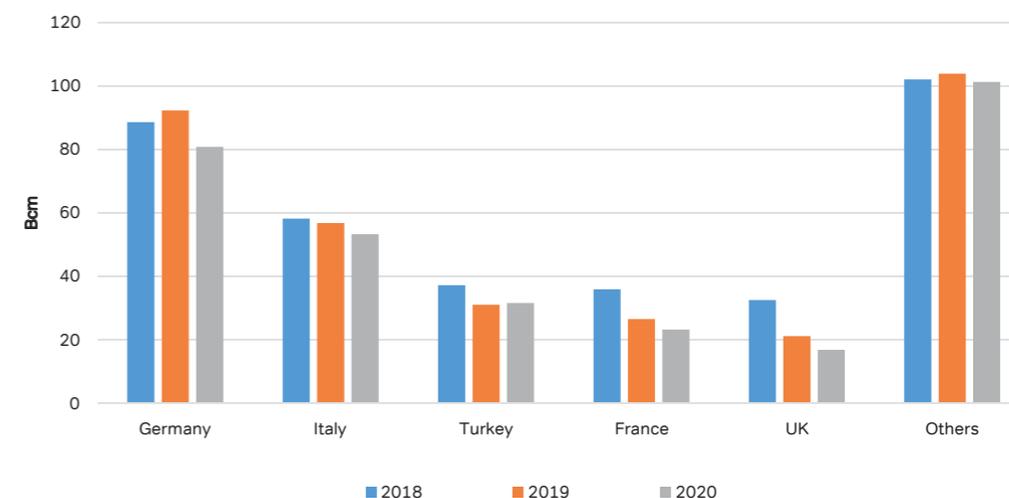
Source: GECF Secretariat based on data from Cedigaz

Europe

In 2020, regional net pipeline gas imports fell by 7% to 307 Bcm, mainly driven by a fall in gas demand, high gas inventories and large LNG imports. A drop in imports was even higher in the first three quarters of 2020, however a colder-than-usual 2020/2021 winter season and partial easing of lockdown measures related to the COVID-19 pandemic led to a recovery of pipeline gas supply in Q4 2020.

Germany, Italy, Turkey, France and UK were the largest import markets, accounting together for 67% of regional net pipeline gas imports (Figure 52).

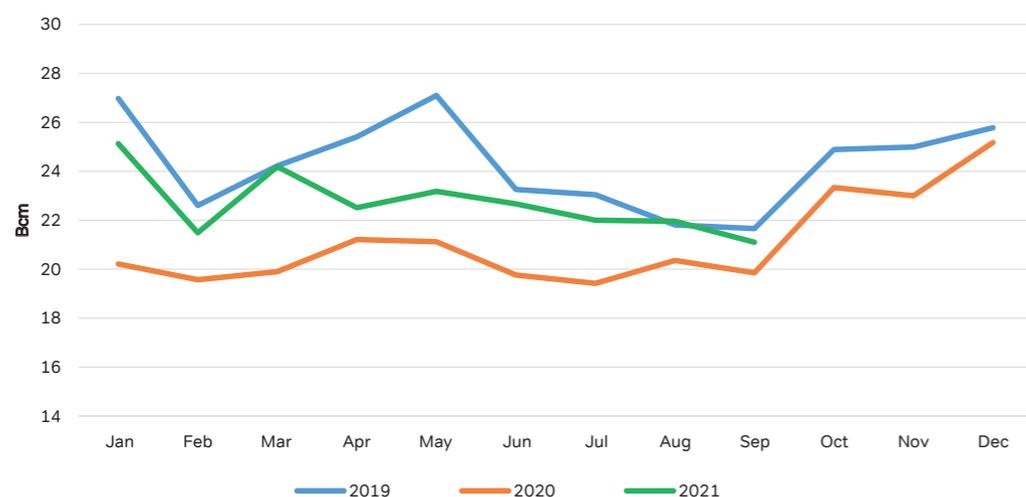
Figure 52: European Net Pipeline Gas Imports by Importing Country



Source: GECF Secretariat based on data from Cedigaz

In 2021, higher gas demand, driven by the colder-than-usual winter season, lower gas inventories and easing of the COVID-19 related restrictions, as well as a drop in LNG imports resulted in a recovery of PNG imports in the EU, which represents 90% of the European market (Figure 53).

Figure 53: Extra-E.U. Pipeline Gas Imports



Source: GECF Secretariat based on data from McKinsey Energy Insights

North America

In 2020, net pipeline gas trade rose by 7% to 56 Bcm. The US was a net exporter of pipeline gas for the second year in a row, with its net exports reaching 11 Bcm. Canada's net exports fell to 45 Bcm, while Mexico's net imports increased to 56 Bcm.

Asia Pacific

In 2020, pipeline gas imports fell by 2% to 71 Bcm. China decreased its imports to 47 Bcm, of which Turkmenistan supplied 28 Bcm, however it stepped up supply from Russia to 4 Bcm delivered by the Power of Siberia pipeline. Singapore, Thailand, Australia and Malaysia were other regional importers. In the meantime, Myanmar, Indonesia, Timor-Leste and Malaysia were regional pipeline gas exporters.

Africa

In 2020, pipeline gas exports fell by 9% to 37 Bcm, with 26 Bcm supplied to Europe and 11 Bcm to the region. Algeria, Libya, Mozambique, Nigeria and Egypt were pipeline gas exporters, while Tunisia, South Africa, Ghana and Morocco were major importers.

Middle East

In 2020, pipeline gas exports rose by 1% to 35 Bcm, with most of the supply going to the region and remaining part to Europe. Qatar, Iran and Israel were exporters, while UAE, Iraq, Egypt, Jordan and Oman were major regional importers.

Latin America

In 2020, regional net pipeline gas trade dropped by 13% to 11 Bcm, with Bolivia dominating on the regional market by supplying gas to Argentina and Brazil.

7.1.2 Short-Term Perspectives

In the short term, global pipeline gas trade is expected to rise consistently, driven by an uptick in gas demand amid the lifting of COVID-19 related restrictions and, possibly, colder-than-usual winter seasons. The completion of new gas pipelines in Europe, China and Mexico may contribute to pipeline gas trade growth. GECF Member Countries account for a major part of new export pipeline gas projects. In 2019 and 2020, GECF Member Countries commissioned 85.5 Bcma of new export capacity, with Russia completing the Power of Siberia (38 Bcma) in December 2019 and TurkStream (31.5 Bcma) in January 2020 and Azerbaijan completing the Southern Gas Corridor (16 Bcma) in November 2020. In 2021 and 2022, 65 Bcma of new export capacity will be commissioned by GECF Member Countries, with Russia completing Nord Stream 2 (55 Bcma) and Norway completing Baltic Pipe (10 Bcma). The contractual obligations of European importers under take-or-pay clauses will facilitate PNG trade growth.

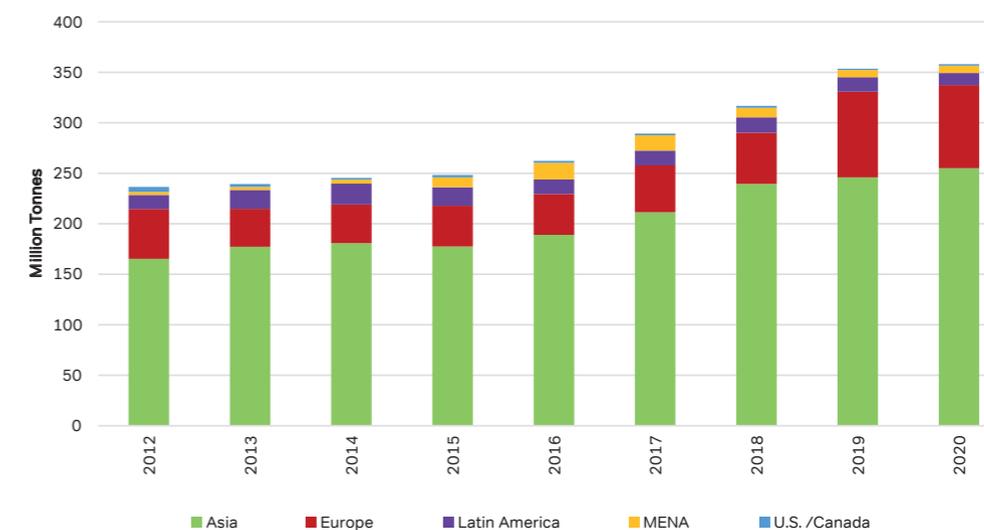
In Asia, China is expected to step up PNG imports from Russia through Power of Siberia pipeline and increase gradually supply from Turkmenistan, Uzbekistan, Kazakhstan and, possibly, Myanmar amid a robust growth in the domestic gas demand. In the Middle East, Israel may increase PNG supply to its neighbors. In Latin America, PNG trade will depend largely on shale gas developments in Argentina and dynamics of regional LNG imports.

7.2 Global LNG Trade

7.2.1 Global LNG Imports in 2020

In 2020, despite devastating impacts of the COVID-19 pandemic, the global LNG trade was resilient showing an increase of 4.8 Mt as compared with a year before. The global LNG trade reached 358.4 Mt in 2020, representing around 1.4% growth in comparison with 2019. However, this has been lowest growth rate of the global LNG trade since 2016, which was caused by the pandemic (see Figure 54).

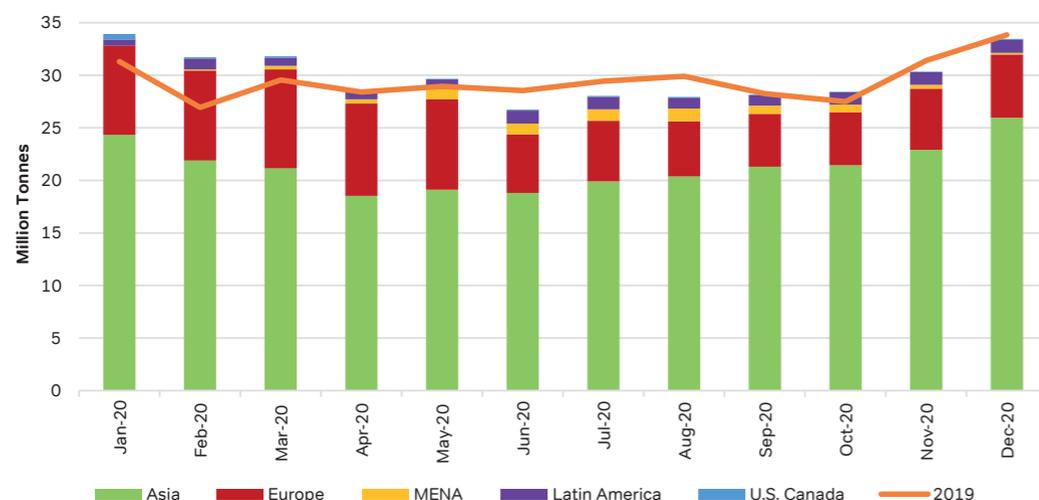
Figure 54: Trend in Global LNG Imports



Source: GECF Secretariat based on data from ICIS LNG Edge

The global LNG demand had kept growing by 11% y-o-y in the 1st quarter of 2020, reaching 97.4 Mt. However, global LNG trade stood below 2019 level during the 2nd and 3rd quarters of 2020 following the aftermath of lockdown measures and declining energy demand due to slowdown in the economic activities. The global LNG demand stood at 85 Mt in the 2nd quarter of 2020, almost 1% less the same period the year before. Similarly, the global LNG trade decreased by 4% y-o-y to 84.1 Mt in the 3rd quarter of 2020 reflecting lagged impacts of the pandemic on the LNG demand. However, LNG trade started recovering in the 4th quarter of 2020, driven by resuming economic activities during the second half of the year and colder than expected winter in the Northern hemisphere. The global LNG trade reached 92.2 Mt, almost 0.5 Mt below the same quarter a year earlier (see Figure 55).

Figure 55: Monthly Global LNG imports

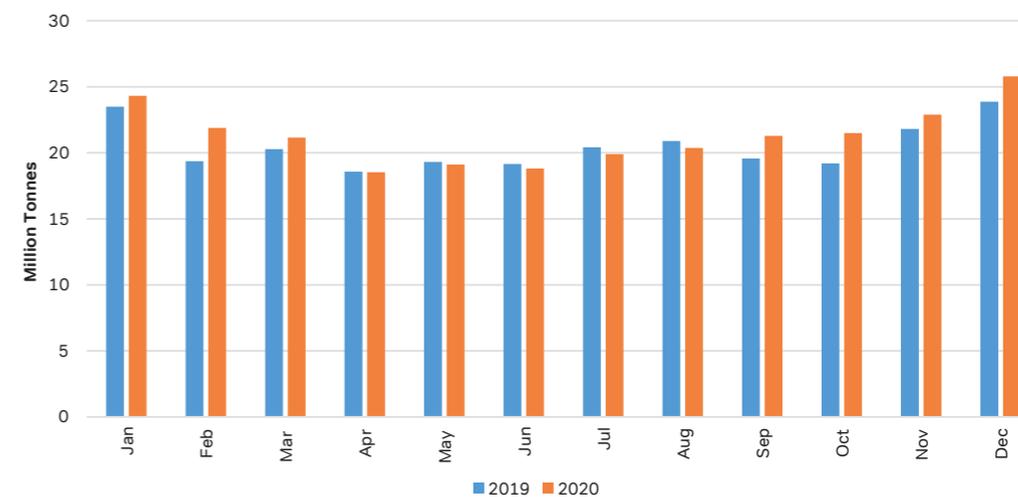


Source: GECF Secretariat based on data from ICIS LNG Edge

Asia

Total LNG imports into Asia amounted to 255.4 Mt in 2020, representing growth of 3.9% (or 9.6 Mt) in comparison with 2019 (see Figure 56).

Figure 56: Monthly LNG Imports in Asia



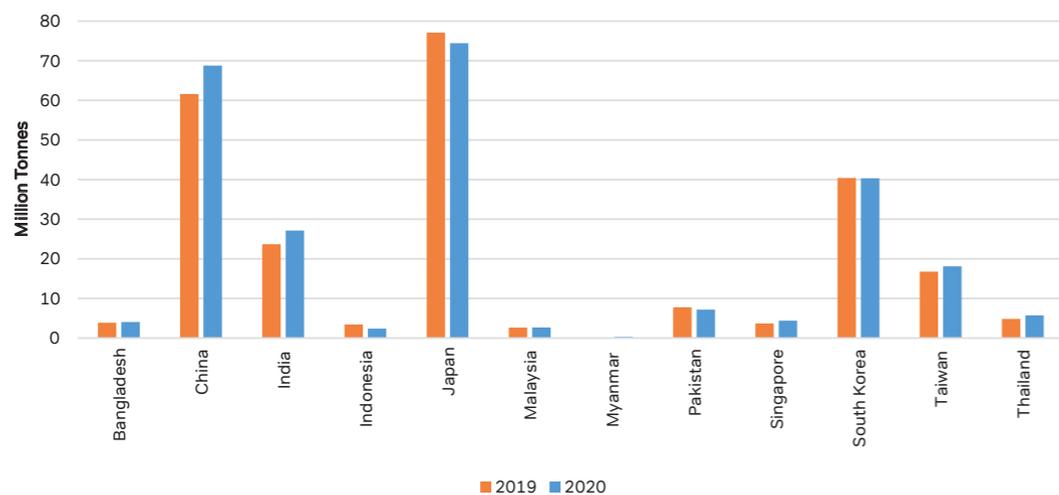
Source: GECF Secretariat based on data from ICIS LNG Edge

Japan imported 74.4 Mt of LNG in 2020, almost 3% (or 2.6 Mt) less than 2019, due to fallout in economic activities and lower energy demand.

LNG imports by South Korea almost remained flat at 40.4 Mt in 2020 when compared with a year earlier. Slowdown of economic activities curbed gas and LNG demand in the country. In contrast, LNG demand in Taiwan grew by 8% (1.3 Mt) reaching to 18.1 Mt in 2020 due to outage of nuclear power generation.

India's LNG imports picked up by 14% (3.4 Mt) recording 27.1 Mt in 2020 despite the negative impacts of the pandemic in the economic activities of India. However, LNG demand in Pakistan stood at 7.2 Mt in 2020, around 8% below the 2019 level. LNG imports by Bangladesh also fell by 5% to 3.9 Mt in 2020. Among South East Asian countries, Indonesian LNG demand slumped by 31% in 2020 as compared with a year before, while Thailand LNG demand grew by 18%. In 2020, Myanmar started to import LNG since June and imported 0.32 Mt of LNG at the end of the year (see Figure 57).

Figure 57: LNG Imports by Asian Countries

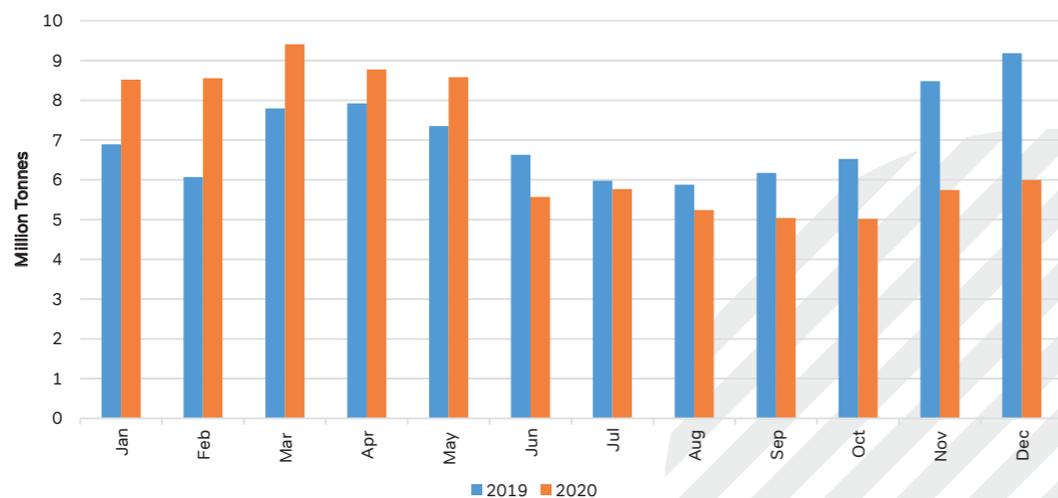


Source: GECF Secretariat based on data from ICIS LNG Edge

Europe

European LNG demand declined by 3% in 2020, falling to 82.2 Mt from 84.9 Mt in 2019. Despite growing LNG demand during 2019 and the 1st half of 2020, LNG imports had declined since June 2020. Higher storage level and declining demand induced by the pandemic have been reflected in lower LNG imports into Europe in the 2nd half of 2020 (see Figure 58).

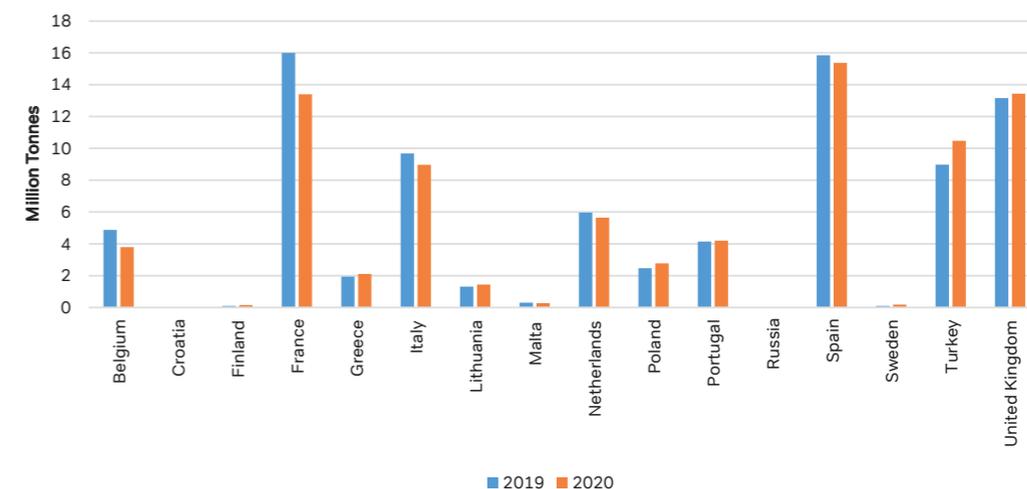
Figure 58: Monthly LNG Imports in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

LNG imports in France (-16%), Italy (-7%), the Netherlands (-5%), Spain (-3%) and Belgium (-22%) declined in 2020 in comparison with a year earlier, while LNG demand in the UK (2%), Turkey (17%), Poland (12%) and Portugal (1%) were higher than 2019 (see Figure 59).

Figure 59: LNG Imports by European Countries

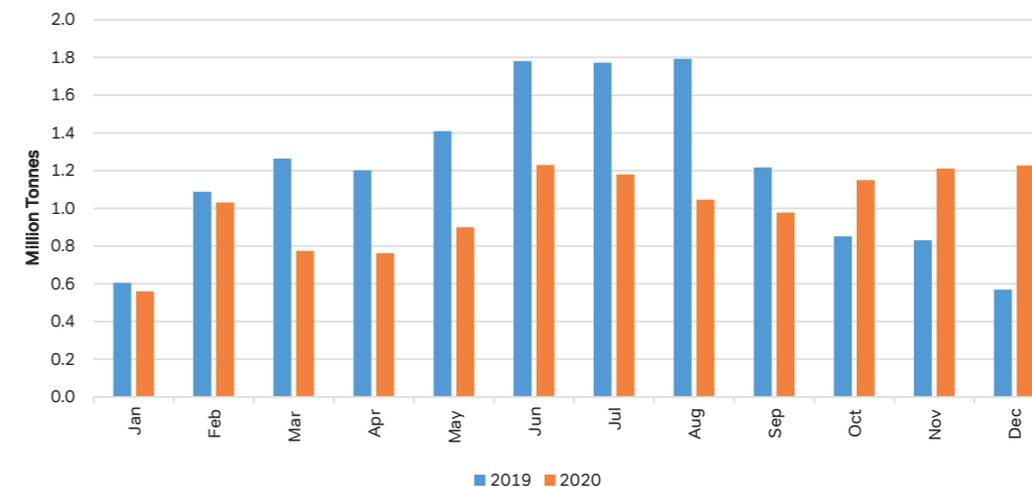


Source: GECF Secretariat based on data from ICIS LNG Edge

Latin America

In 2020, total LNG imports into the Latin American region amounted to 12 Mt, representing a 16% (or 2.3 Mt) decline when compared with 2019. LNG imports by the region had declined during the three first quarters of 2020 compared with the same period a year earlier, however the trend reversed in the fourth quarter of 2020 (see Figure 60).

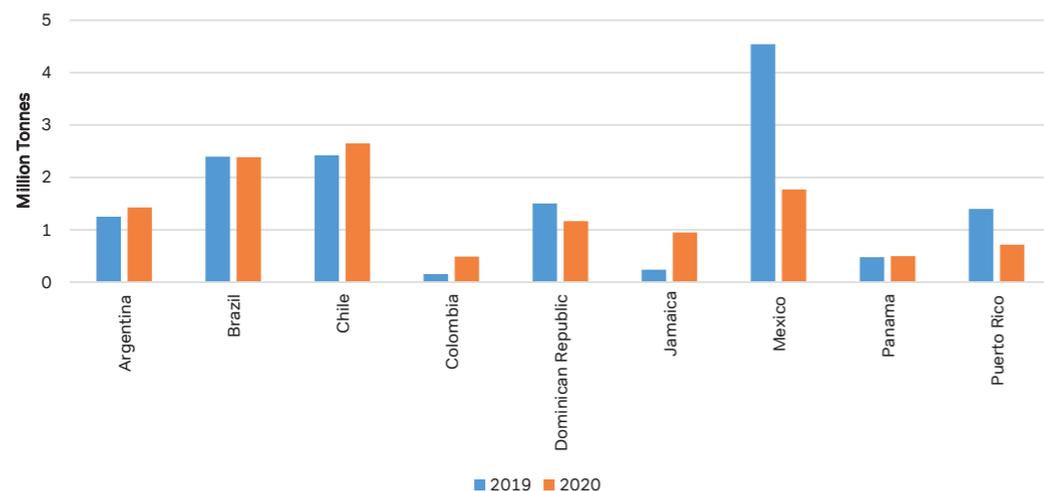
Figure 60: Monthly LNG Imports in Latin America



Source: GECF Secretariat based on data from ICIS LNG Edge

In 2020, LNG imports rose in Argentina (+14%), Chile (+9%), Colombia (+218%), Jamaica (+296%) and Panama (+4%), while LNG demand in Mexico (-61%), Dominican Republic (-22%) and Porto Rico (-49%) declined as compared with 2019. LNG demand in Brazil remained flat around 2.4 Mt in 2020 (see Figure 61).

Figure 61: LNG imports by Latin American countries

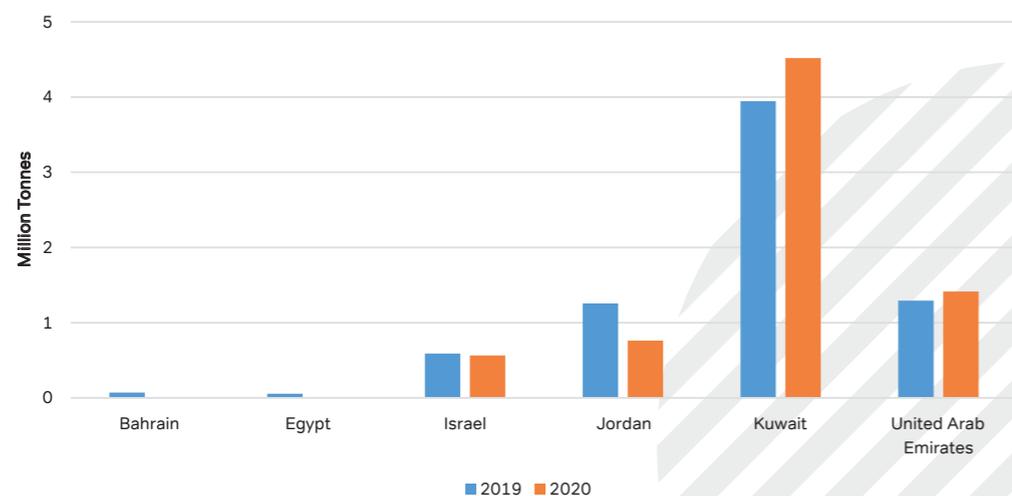


Source: GECF Secretariat based on data from ICIS LNG Edge

Middle East & North America (MENA)

Total LNG demand in the MENA stood at 7.3 Mt, slightly above 7.2 Mt imported in 2019. Increasing LNG demand in Kuwait and the U.A.E offset by decreasing demand in Egypt, Israel, Jordan and Bahrain (see Figure 62).

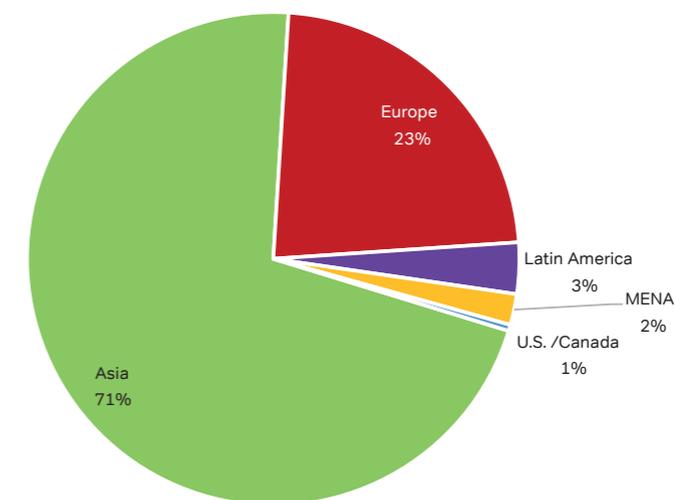
Figure 62: LNG Imports by MENA Countries



Source: GECF Secretariat based on data from ICIS LNG Edge

In terms of regional market share, Asia continued to dominate global LNG imports accounting for 71% of the total LNG trade in 2020, followed by Europe with 23%, Latin America (3%), MENA (2%) and North America (0.4%) as shown in Figure 48. In comparison with 2019, Asia gained 1% more market share while Europe lost 1% (see Figure 63).

Figure 63: Share of Global LNG Trade by Region in 2020



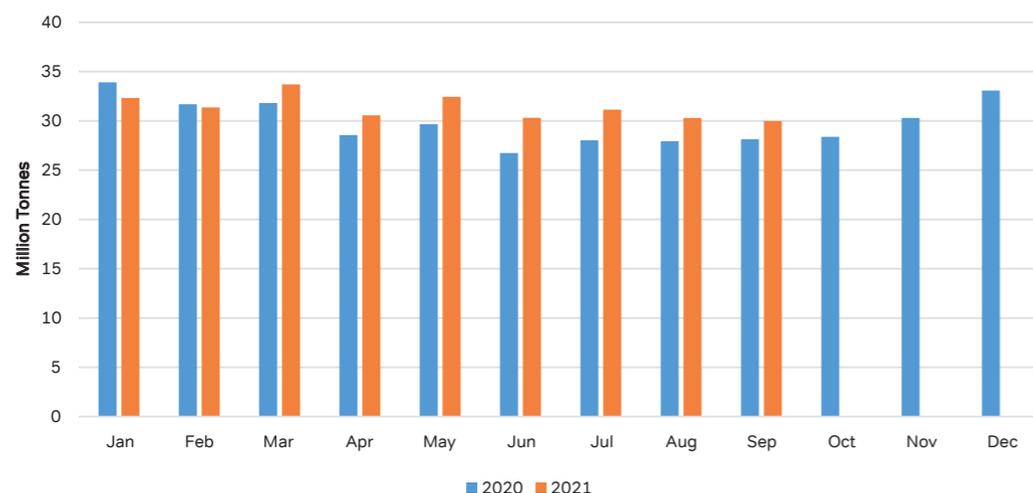
Source: GECF Secretariat based on data from ICIS LNG Edge

7.2.2 Global LNG trade in 2021

During the first three quarters of 2021, the global LNG trade reached 266.4 Mt, representing 5.9% growth as compared with the same period last year. Surging LNG demand in Asia and Latin America resulted in global LNG trade growth during the first 9 months of 2021, while LNG demand in Europe and MENA region declined (see Figure 64).

Asia imported 185.3 Mt of LNG in the first 9 months of 2021, showing 11.2% y-o-y growth, driven by surging gas demand in China, Japan and South Korea. Latin America’s LNG imports also increased by 68.8% during January to September 2021, reaching 14.3 Mt from 8.5 in the same period last year. However, LNG imports into Europe stood at 55.1 Mt during the first 9 months of 2021, falling by 15.8% as compared with the same period last year. LNG imports by MENA region declined by 4.8% y-o-y during the first 9 months of 2021.

Figure 64: Monthly Global LNG Imports in 2021



Source: GECF Secretariat based on data from ICIS LNG Edge

Asia

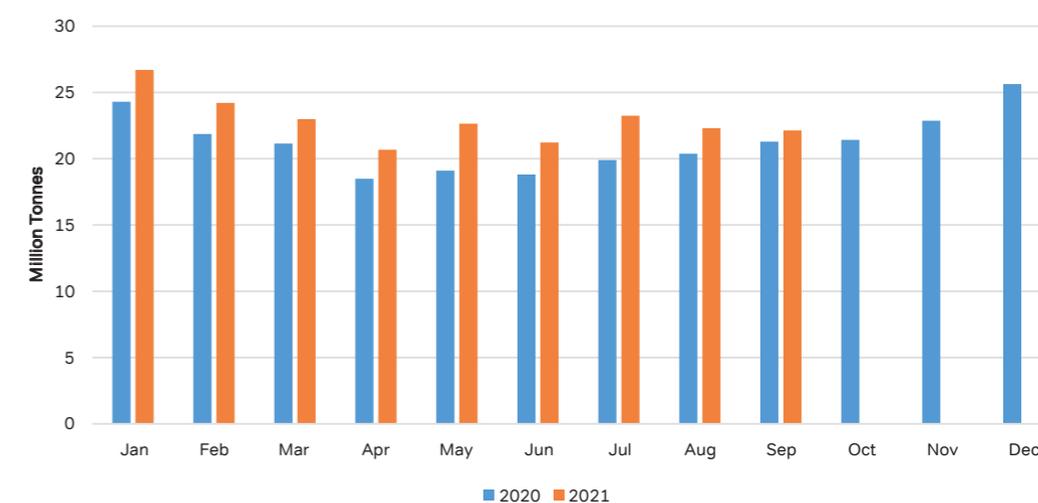
LNG imports into Asian countries recorded 26.8 Mt in January 2021 and kept growing during the first half of 2021. Growing gas demand in China and Japan and South Korea led LNG trade growth in the region. China surpassed Japan to become the largest LNG importer in the world. China's LNG demand growth supported by growing economic activities and uneven weather condition. Japan's LNG demand has been increasing since several Japanese utilities took precautionary measures to secure gas supply over the past few months. In addition, recovery of economic activities results in rising gas demand in Japan's power sector and industry.

Likewise, strong power demand and coal-to-gas switching in South Korea resulted in increasing LNG demand during the first 3 quarters of 2021.

LNG demand in Taiwan, India, Pakistan, Bangladesh and the rest of countries in Asia has been rising during the first 9 months of 2021 as compared with the same period in a year prior.

Total LNG imports by Asian countries amounted 185.3 Mt during the first 9 months of 2021, representing 11.2% y-o-y growth as compared with the same period a year earlier (see Figure 65).

Figure 65: Monthly Asian LNG Imports in 2021

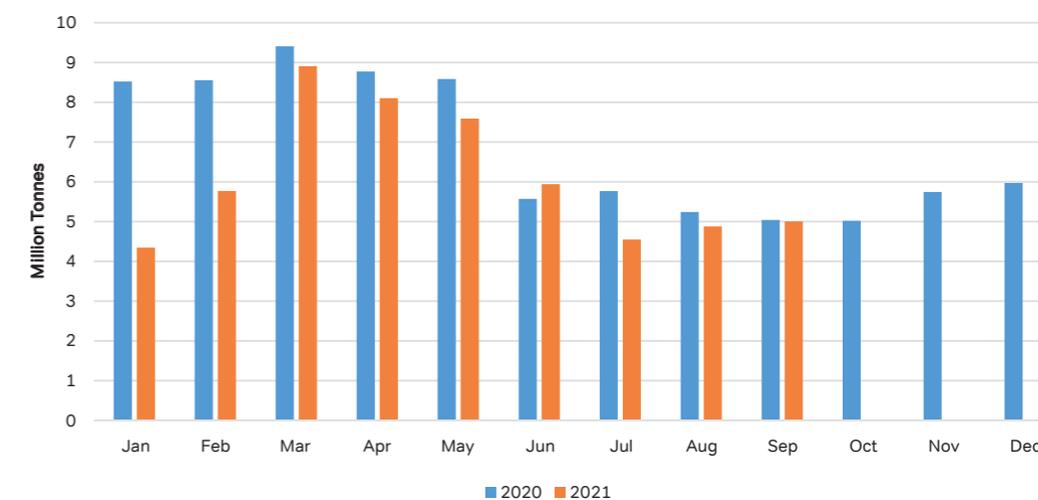


Source: GECF Secretariat based on data from ICIS LNG Edge

Europe

In contrast, European LNG imports sharply slumped during the first 9 months of 2021, declining by 15.8% y-o-y due to slowdown of economic activities and higher gas storages. European countries imported 55.1 Mt of LNG from January to September 2021, almost 10.4 Mt less than the same period last year (see Figure 66).

Figure 66: Monthly European LNG Imports in 2021

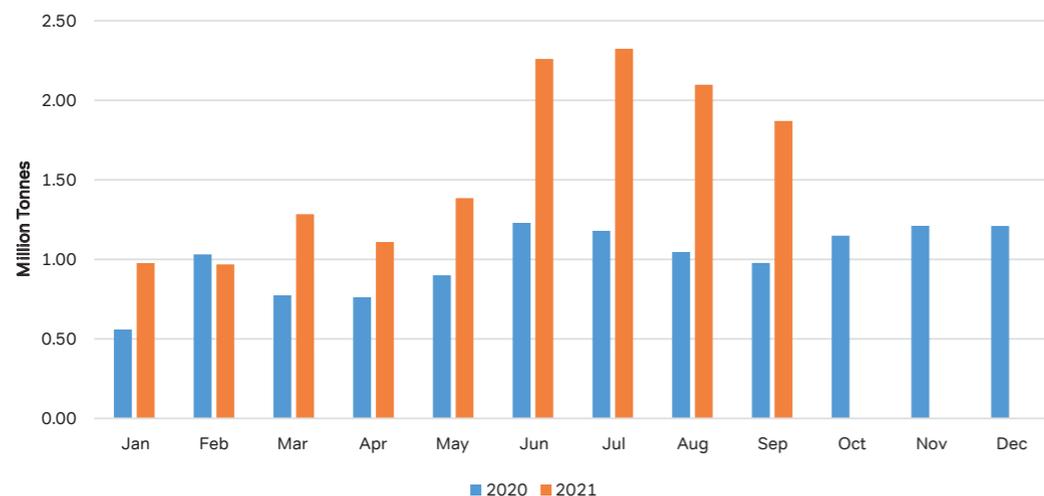


Source: GECF Secretariat based on data from ICIS LNG Edge

Latin America

LNG imports into Latin America grew substantially during the first 9 months of 2021 led by gas demand growth in Brazil, Argentina, Chile, Dominican Republic and Porto Rico. Restart of Bahia Blanca and arrival of Exemplar FSRU resulted in higher LNG imports by Argentina. Likewise, Brazil's LNG imports hiked in 2021 driven by declining hydro power and increasing gas demand for power generation. LNG imports into Latin America reached 14.3 Mt in the first 9 months of 2021, growing by 66.8% or 5.8 Mt in comparison with the same period a year before (see Figure 67).

Figure 67: Monthly Latin American LNG Imports in 2021

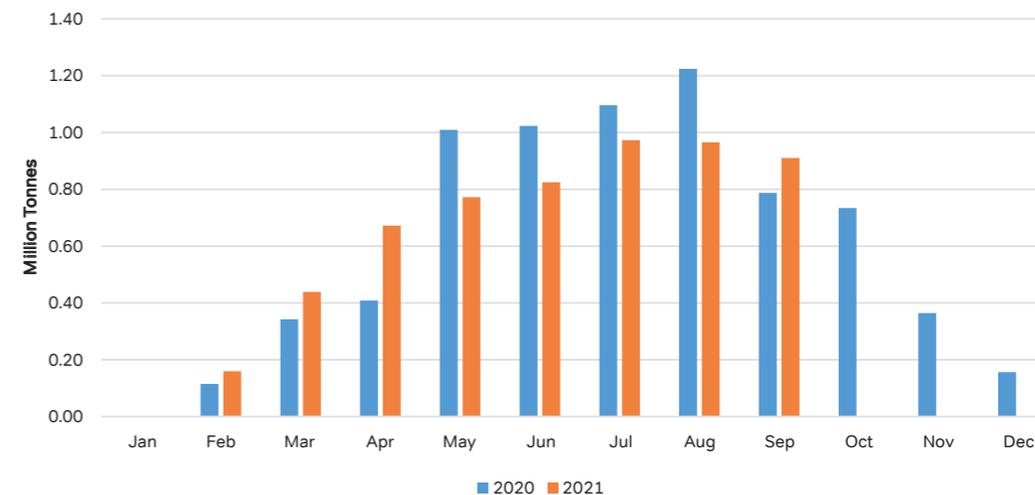


Source: GECF Secretariat based on data from ICIS LNG Edge

Middle East & North America (MENA)

Total LNG imports by MENA region stood at 5.7 Mt during the first 9 months of 2021, representing 4.8% decline in comparison with the same period last year. Declining LNG demand by Jordan, Israel and the U.A.E despite increasing LNG imports by Kuwait reflected in falling LNG trade in the region (see Figure 68).

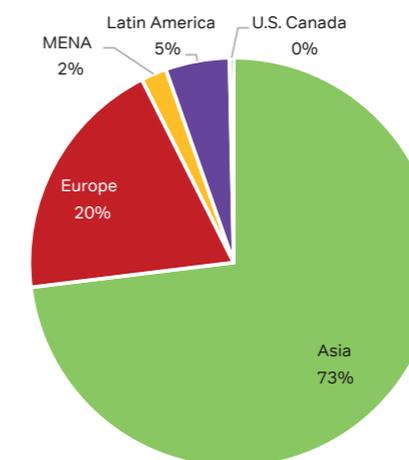
Figure 68: Monthly MENA LNG Imports in 2021



Source: GECF Secretariat based on data from ICIS LNG Edge

In terms of market share, Asia contributed to 73% of the global LNG trade from January to September 2021, followed by Europe that accounts for 20% of global LNG imports. Latin America and MENA held 5% and 2% of global LNG trade during the first 3 quarters of 2021. In comparison with the same period last year, Asia gained 3% more of market share, while Europe lost 5% of its market share. Latin America's market share increased 2% from January to September 2021 when compared with the same period last year (see Figure 69).

Figure 69: Share of Global LNG Trade by Region (Jan-Sep 2021)



Source: GECF Secretariat based on data from ICIS LNG Edge

7.3 Global LNG Supply

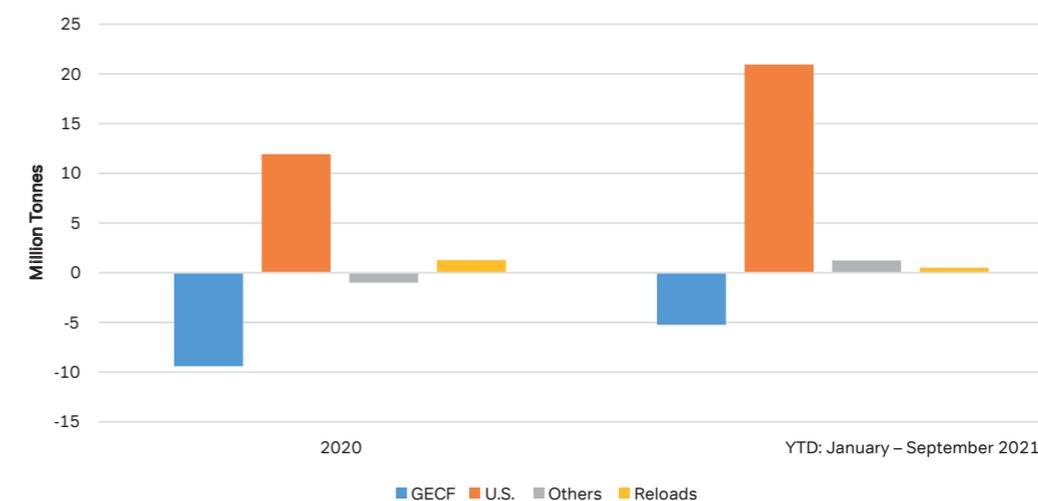
7.3.1 Global LNG Supply in 2020 and YTD 2021

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 exporting countries. As mentioned earlier, the pace of growth in global LNG trade has slowed significantly in 2020, mainly driven by the negative impact of COVID-19 on global LNG demand. From the supply side, LNG exports moved slightly higher by 0.8% (2.9 Mt) y-o-y to 358 Mt, which is down sharply from an average annual growth rate of 11% between 2017 and 2019. The slowdown in the pace of growth was driven primarily by GECF countries (see Figure 70). GECF's LNG exports, including Members and Observers, fell by 4.7% (9.4 Mt) y-o-y to 191.8 Mt. Meanwhile, Non-GECF's LNG exports jumped by 7.2% (11.0 Mt) y-o-y to 163.7 Mt, despite the large number of cargo cancellations in the U.S. last year. Reloading activity was also up 75.0% (1.3 Mt) y-o-y and averaged 2.9 Mt. Although GECF's LNG exports declined last year, it was still the dominant LNG exporter globally, with its share of global LNG exports declining from 56.6% in 2019 to 53.5% in 2020. In contrast, the shares of Non-GECF and reloads increased from 42.9% and 0.5% to 45.7% and 0.8% respectively.

In terms of the variation in LNG exports, the U.S. accounted for the largest growth in LNG exports last year (see Figure 73). LNG exports from the U.S. surged by 34.2% (12.0 Mt) y-o-y, although around 10 Mt of LNG supply was lost mainly due to the cancellation of cargoes between May and October 2020. The surge in LNG exports was driven by the ramp-up in LNG exports from the Cameron, Corpus Christi, Elba Island and Freeport LNG facilities, which offset the decline in LNG exports from Sabine Pass LNG facility. The Sabine Pass LNG facility was significantly impacted by the cancellation of LNG cargoes, due to the price convergence of global spot prices to less than \$2/MMBtu in Q2 2020. Russia's LNG exports were also up 3.0% (0.9 Mt) y-o-y, supported by the ramp-up in LNG production and production above nameplate capacity from the Yamal LNG facility. Meanwhile in Australia, higher gas supply to the GLNG and NWS LNG projects, ramp-up in LNG production at the Ichthys LNG facility and lower maintenance activity at Pluto LNG, contributed to the 1.0% (0.7 Mt) y-o-y uptick in exports from the country. The stronger exports from these projects offset the decrease in production from the APLNG LNG facility, which was due to buyers enforcing their downward quantity tolerance (DQT), and unplanned maintenance activities at the Gorgon and Prelude LNG facilities. Planned maintenance activity on the Gorgon LNG facility during Q2 2020 revealed cracks on the propane kettles. This issue was resolved for Trains 2 and 1 in November 2020 and February 2021 respectively. Similar maintenance activity was carried out on Gorgon LNG Train 3 in Q2 2021.

On the other hand, the weaker LNG exports from GECF member countries were a combination of several factors including lower feedgas availability and planned and unplanned maintenance activity in some member countries as well as reduced exposure to the low spot prices in the market during Q2 and Q3 2020. In Norway, the Snohvit LNG facility remains offline due to ongoing repair works following a fire at the facility in September 2020. The Snohvit LNG facility is expected to be offline until March 2022, which is a 6-month delay from the original scheduled restart of October 2021.

Figure 70: Variation in LNG Exports by Supplier in 2020 & YTD 2021



Source: GECF Secretariat based on data from ICIS LNG Edge

Global LNG exports between January and September 2021 grew by 6.8% (18.0 Mt) y-o-y to 283.2 Mt driven mainly by Non-GECF countries. This is significantly higher than the 1.2% (3.4 Mt) y-o-y growth recorded during the same period in 2020. Non-GECF countries led the growth in global LNG exports, increasing by 19.3% (22.7 Mt) y-o-y to 140.3 Mt. In contrast, GECF's LNG exports dropped by 3.6% (5.2 Mt) y-o-y to average 140.4 Mt. Reloading activity also increased by 24.6% (0.5 Mt) y-o-y during the first nine months of 2021 to 2.6 Mt. Despite the decline in GECF's LNG exports, GECF was still the largest LNG exporter between January and September 2021, with a share of 49.6% down from 54.9% during the same period 2020. Meanwhile, Non-GECF's share of LNG exports increased from 44.3% from January to September 2020 to 49.5% between January and September 2021. The share of reloads moved slightly higher from 0.8% to 0.9% during the same period.

With regards to the variation in LNG exports during the first nine months of 2021, the U.S. led the growth, increasing by 21.0 Mt (see Figure 70). This was driven by the ramp-up of LNG production at the Cameron, Elba Island and Freeport LNG facilities and start-up of Corpus Christi LNG Train 3 as well as the recovery in LNG exports from the large number of cargo cancellations during Q2 and Q3 2020. In Egypt, LNG exports were also up significantly by 4.0 Mt between January and September 2021, which was supported by improving market conditions and the restart of the Damietta LNG facility in the country. Additionally, the restart of the Prelude LNG facility in Australia contributed to an increase of around 1.9 Mt in LNG exports from the country. Meanwhile, the repair of the Sabah/Sarawak pipeline supplying gas to the LNG facilities in Malaysia and lower maintenance activity at LNG facilities drove the country's exports higher by 1.6 Mt between January and September 2021.

Despite the stronger LNG exports from Egypt and Malaysia, GECF's LNG exports during the first nine months of 2021 have been affected by lower feedgas availability and planned and unplanned maintenance activity in some countries.

7.3.2 Assumptions for LNG Supply in 2021 and 2022

The following are the assumptions used in the forecast of LNG exports in 2021 and 2022:

- Around 14-15 Mt of LNG lost from the market in 2020, due to weak spot prices, are expected to return to the market in 2021, mainly from the U.S.
- Higher maintenance activities at LNG facilities in 2021, which were postponed in 2020 due to COVID-19, and unplanned outages could reduce LNG exports by 1-2 Mt. This is the net LNG supply loss due to maintenance activities since some LNG facilities are expected to have lower maintenance activities in 2021.
- Feedgas issues in some legacy LNG exporting countries could reduce LNG supply by 6-7 Mt in 2021. This is the net LNG supply loss due to feedgas issues since feedgas supply are expected to increase in some exporting countries.
- Around 2.80 Mt of LNG loss from the Snohvit LNG facility in 2021, which was hit by unplanned maintenance in 2020.
- The ramp-up and start-up in LNG production from facilities in the U.S., Malaysia and Russia are expected to contribute with an additional 14-15 Mt of LNG in 2021.
- The restart of the Damietta LNG facility in Egypt and Prelude FLNG in Australia, together with the debottlenecking of Oman LNG are expected to add around 5-6 Mt of LNG supply to the market this year.
- The increase in LNG exports in 2022 is expected to come mainly from the start-up and ramp-up of LNG projects, which could contribute with an additional 12-13 Mt of LNG exports.
- The restart of the Snohvit LNG facility in 2022 could add 3-4 Mt of LNG supply next year.
- Improving feedgas supply in some legacy LNG exporting countries could add 4-5 Mt of LNG supply in 2022.
- Lower maintenance activity in 2022 could increase LNG supply by 1-2 Mt.
- For the ramp-up in new LNG facilities, we assumed a 25% utilization rate in the first month of start-up, followed by 50% utilization over the next five months, after which the facility reaches full capacity by the seventh month. For projects with multiple trains, if there are no confirmed schedule for start-up, we assumed that trains are started in 6-8 month intervals.

7.3.3 Short-Term Outlook for Global LNG Supply

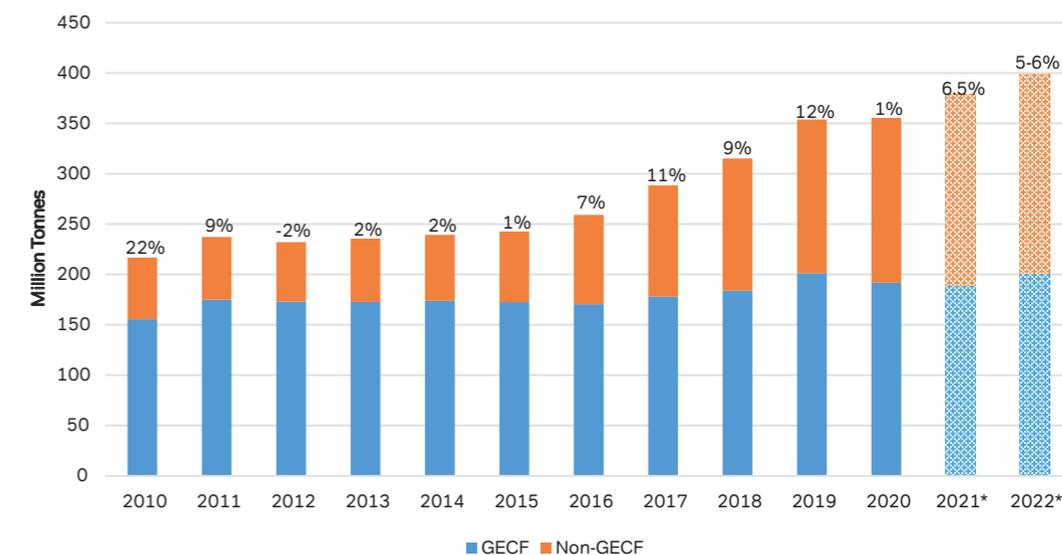
GECF forecasts a rebound in LNG exports in the short-term supported by a recovery in global natural gas and LNG demand. In 2021 and 2022, LNG exports are forecasted to grow by 6.5% (23 Mt) and 5-6% (20-21 Mt) each to 379 Mt and 399 Mt respectively, which is up significantly from the less than 1% growth recorded last year, but lower than the average pace of growth of 11% between 2017 and 2019 (see Figure 71).

In 2021, Non-GECF countries are forecasted to drive the growth in global LNG exports with an increase of 16% (26 Mt) y-o-y to 189 Mt. In contrast, GECF's LNG exports are forecasted to decline slightly by 1% (3 Mt) y-o-y to 189 Mt. The U.S. is expected to account for the bulk increase in Non-GECF's LNG exports with an additional 25 Mt (53%) y-o-y to reach 72 Mt. This is supported by the ramp-up and start-up of new LNG projects and the recovery in lost LNG supply, due to the cargo cancellations last year. Meanwhile, the decline in GECF's LNG exports is mainly attributed to lower feedgas availability for LNG exports in some member countries,

higher maintenance activity compared to 2020 and ongoing maintenance at the Snohvit LNG facility in Norway. However, this will be partially offset by the restart of the Damietta LNG facility in Egypt, recovery in exports due to improving market conditions in 2021 and start-up of new projects in Russia and Malaysia. The Damietta LNG facility in Egypt, which has been offline since 2012, restarted exports in February 2021.

Further ahead in 2022, GECF member countries are expected to lead the growth in global LNG exports. GECF's LNG exports are forecasted to rise by 6% (12 Mt) y-o-y to reach almost 201 Mt. Meanwhile, Non-GECF countries also contribute notably with an increase of 5% (9 Mt) y-o-y to 198 Mt. The strong uptick in GECF's LNG exports is supported by the restart of the Snohvit LNG facility, improving feedgas availability in some member countries, ramp-up in LNG production in Egypt, Russia and Malaysia and lower maintenance activity. In Non-GECF countries, the start-up and ramp-up of LNG projects in Indonesia, Mozambique and the U.S. and the debottlenecking in Oman are forecasted to drive the higher LNG exports. Despite the stronger growth in LNG exports from Non-GECF countries in the short-term, GECF's share in global LNG exports is forecasted to average 50% in 2021 and 2022.

Figure 71: Trend in Global LNG Exports by Supplier



Source: GECF Secretariat based on data from ICIS LNG Edge and Project Updates
(*): GECF Secretariat's forecast

7.4 Spot & Short-Term LNG Trade

Spot and short-term LNG trade refers to cargoes delivered under contracts of 4 years or less. In 2020, spot and short-term LNG trade jumped by 20% (24 Mt) y-o-y to around 143 Mt, as shown in Figure 72.

The surge in spot and short-term trade supported the increase in its share of global LNG trade from 34% in 2019 to 40% in 2020. This was driven by an increase in spot and short-term LNG trade to the detriment of medium and long-term LNG trade last year. The record low spot prices and weak LNG demand witnessed in the market last year resulted in several LNG buyers enforcing their downward quantity tolerance (DQT) in LNG Sales & Purchase Agreements (SPAs). As such, this resulted in several LNG sellers placing more LNG volumes in the spot market. Meanwhile, the record low spot LNG prices spurred spot LNG demand, particularly in Asia.

Figure 72: Trend in Global LNG Trade by Duration



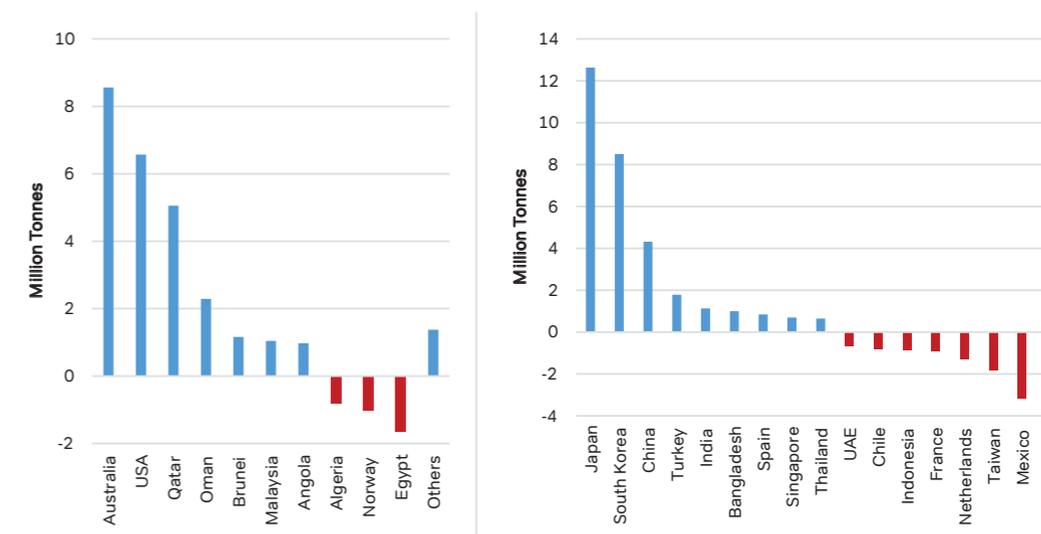
Source: GECF Secretariat based on data from GIIGNL and ICIS LNG Edge

On the export side, Australia, the U.S. and Qatar led the growth in spot and short-term LNG exports (see Figure 73). Several buyers of Australian LNG exercised the DQT in LNG SPAs, which resulted in some sellers placing additional LNG volumes in the spot LNG market. In the U.S., the increase in flexible LNG volumes, from the ramp-up in production in LNG facilities, drove the country's spot and short-term LNG exports higher last year. The growth in Qatar's spot and short-term LNG exports may also be attributed to higher volumes placed in the spot market as buyers exercised DQT in LNG SPAs. In contrast, Egypt's spot and short-term LNG trade fell sharply in 2020 since the country has a high exposure to the spot and hub prices and reduced its exports amidst the low spot prices.

On the other hand, Asia led the growth in spot and short-term LNG imports, increasing by 34% (25 Mt) y-o-y in 2020. Europe's spot and short-term LNG imports were also up by 4% (1 Mt) y-o-y while spot and short-term LNG imports slumped by 27% (3 Mt) y-o-y in the Americas. As shown in Figure 60, Japan drove the increase in global spot and short-term LNG imports, followed by South Korea, China and Turkey.

Although LNG imports fell in Japan and South Korea last year, the stronger imports of spot and short-term LNG may be due to buyers reducing their imports from long-term LNG SPAs in favour of cheaper spot supply. In China, LNG buyers capitalised on the cheap spot LNG supply in the market, which drove the increase in spot and short-term LNG imports in the country. Meanwhile, Turkey reduced their pipeline gas imports in favour of cheap spot LNG supplies in the market. In contrast, the slump in Mexico's spot LNG imports was mainly attributed to weaker LNG demand as the U.S. ramped-up pipeline gas supply to the country.

Figure 73: Variation in Spot & Short-Term LNG Exports and Imports by Country in 2020



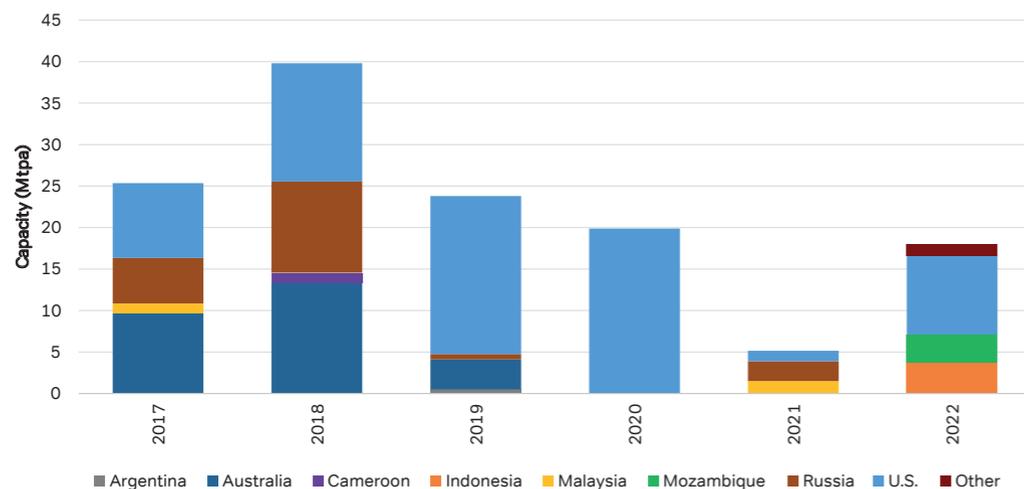
Source: GECF Secretariat based on data from GIIGNL

7.5 New LNG Export Capacity

7.5.1 Commissioning of New LNG Export Capacity

The commissioning of new LNG liquefaction capacity increased by 20 Mtpa (4.5% y-o-y) in 2020 to around 463 Mtpa, solely from the U.S. (see Figure 74). However, this is down from an increase of 24 Mt in 2019 and a peak of 40 Mtpa in 2018. The LNG facilities that exported their first LNG cargo last year include Cameron LNG Trains 2 and 3, Corpus Christi Train 3, Freeport LNG Train 3 and Elba Island LNG Trains 4-10, all from the U.S.

Figure 74: Trend in New LNG Exporting Capacity



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

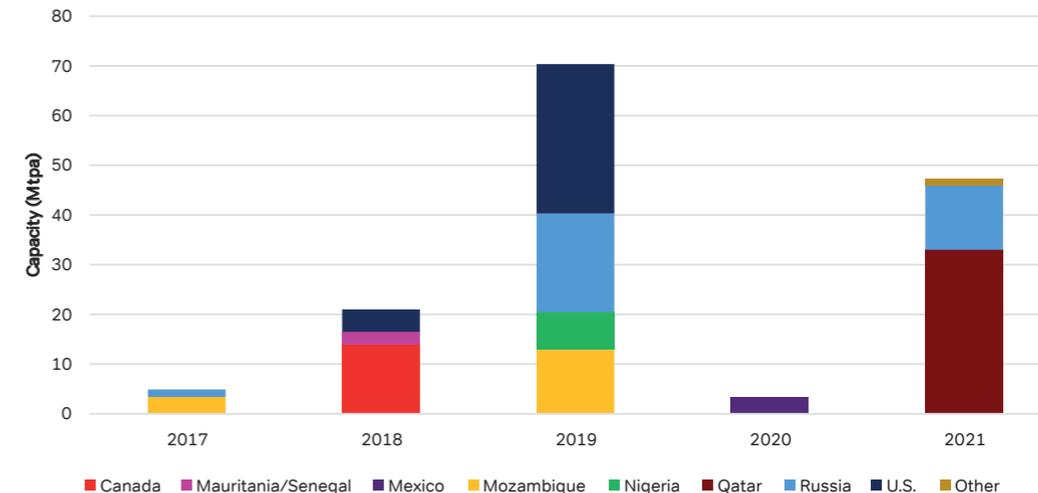
In 2021, around 5 Mtpa (1.1% y-o-y) of LNG capacity is expected to be commissioned. The Yamal LNG Train 4 in Russia and PFLNG Dua in Malaysia started operation in H1 2021. Meanwhile, the Portovaya LNG in Russia, and Calcasieu Pass LNG Train 1 from the U.S. are expected to start operations in Q4 2021. Further ahead into 2022, the Tangguh LNG Train 3 in Indonesia, Coral South FLNG in Mozambique, Calcasieu Pass LNG Trains 2-5, Sabine Pass Train 6 in the U.S. and the Fast LNG facility, which can be deployed anywhere in the world, with a combined capacity of 18 Mtpa (3.8% y-o-y) are forecasted to be commissioned.

7.5.2 Financial Investment Decisions (FIDs) on New LNG Export projects

At the start of 2020, the LNG industry was upbeat about the prospective development of new LNG projects. However, this optimism quickly faded away as the COVID-19 pandemic ravaged the world. The negative impacts of COVID-19 on the natural gas market, including weakening the natural gas and LNG demand, low prices and a reduction in capital expenditure by several energy companies, as well as a well-supplied LNG market, led to a slump in FIDs on new LNG export projects globally. Just to recall, 71 Mtpa of new LNG export capacity reached FID in 2019, however, this fell to around 3 Mtpa last year. Only one LNG project, the Costa Azul LNG project in Mexico, which will utilize natural gas from the U.S., was sanctioned last year (see Figure 75).

In 2021 thus far, three LNG projects have reached FID, majorly from GECF member countries. Qatar Energy sanctioned the first phase of Qatar’s LNG expansion in February 2021, with a capacity of 33 Mtpa, which is the single largest project in history to reach FID. The second project is New Fortress Energy’s floating LNG (FLNG) project, Fast LNG, with a capacity of 1.4 Mtpa. The FLNG can be deployed anywhere in the world and will be used for the development of stranded natural gas resources. Finally, the Baltic LNG project in Russia with a capacity of 13 Mtpa started construction in May 2021.

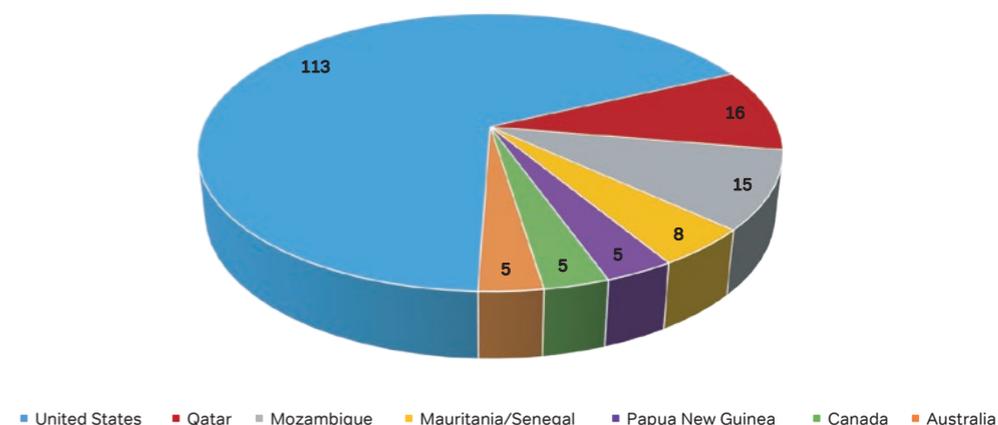
Figure 75: Trend in FIDs on New LNG Projects



Source: GECF Secretariat based on data from project updates
 (*): Includes LNG projects that have taken FID until the end of September 2021

As mentioned before, the negative impact of COVID-19 on the gas industry affected FIDs on new LNG projects. Around 170 Mtpa of new LNG capacity that were targeting FID last year were postponed to 2021 or 2022. As shown in Figure 76, more than 60% of the project FIDs that were postponed are from the U.S., with the others coming from several countries across the world.

Figure 76: Postponement of LNG FIDs by Country in 2020



Source: GECF Secretariat based on data from project updates

In the short-term, almost 180 Mtpa of new LNG capacity are targeting FID (see Table 4), which include majority of the projects that were delayed in 2020. More than 60% of the projects targeting FID is in the U.S. followed by Qatar (9%), Mozambique (9%), Mauritania/

Senegal (4%), Papua New Guinea (3%), Canada (3%), Australia (3%) and Malaysia (1%). The improving market conditions, driven by the tightening of the LNG market, with spot prices at record highs, are expected to support LNG project developments in the short-term. The majority of the projects targeting FID, particularly those not backed by major international and national energy companies, continue to rely on long-term contracts to secure project financing. As such, project developers would have to sell a significant portion of the LNG offtake through long-term SPAs before a positive FID can be reached. Although security of supply remains high priority for buyers, they are pushing for destination and pricing flexibility, prices that are more competitive and lower carbon footprint for delivered LNG cargoes. As such, the LNG projects that depend on project financing and are able to secure long-term SPAs, and projects with equity financing would be the first projects to be sanctioned. Meanwhile, the LNG projects, which are unable to secure long-term SPAs, could face further delays or even cancellation.

Table 4: LNG Projects Targeting FID in the Short-Term

PROJECT	COUNTRY	OPERATOR	CAPACITY (MTPA)	ORIGINAL FID	NEW FID
Delfin LNG (1st FLNG)	United States	Delfin LNG	3.25	2020	2021
Lake Charles	United States	Energy Transfer	16.45	2020	2021
Magnolia LNG	United States	Glenfarne	8.8	2020	2021
Plaquimines LNG Phase 1	United States	Venture Global	10	2020	2021
Pluto Expansion	Australia	Woodside	5	2020	2021
Port Arthur	United States	Sempra Energy	11	2020	2021
Rio Grande LNG Phase 1	United States	Next Decade	11	2020	2021
Woodfibre LNG	Canada	Woodfibre LNG	2.1	2020	2021
Qatar Phase 2 Expansion	Qatar	Qatar Energy	16	2020/2021	2022
Cameron LNG Phase 2	United States	Sempra Energy	10	2021	2022
Commonwealth LNG	United States	Commonwealth LNG	8.4	2021	2022
Corpus Christi Phase 3	United States	Cheniere	10	2020	2022
Driftwood	United States	Tellurian	16.6	2020	2022
Freeport Train 4	United States	Freeport LNG	5	2020	2022
Mexico Pacific Ltd. (Phase 1)	Mexico	Mexico Pacific Ltd.	9.4		2022
PFLNG 3	Malaysia	Petronas	2		2022
Texas LNG (Phase 1)	United States	Texas LNG	2	2020	2022
Tortue Phase 2	Mauritania/Senegal	BP	3.75	2020	2022
Cedar LNG	Canada	Cedar LNG	3		2023
Papua LNG	Papua New Guinea	Total	5.4	2020	2023
Tortue Phase 3	Mauritania/Senegal	BP	3.75	2020	2023
Rovuma LNG	Mozambique	Exxon Mobil	15.2	2020	2024
Total			178.3		

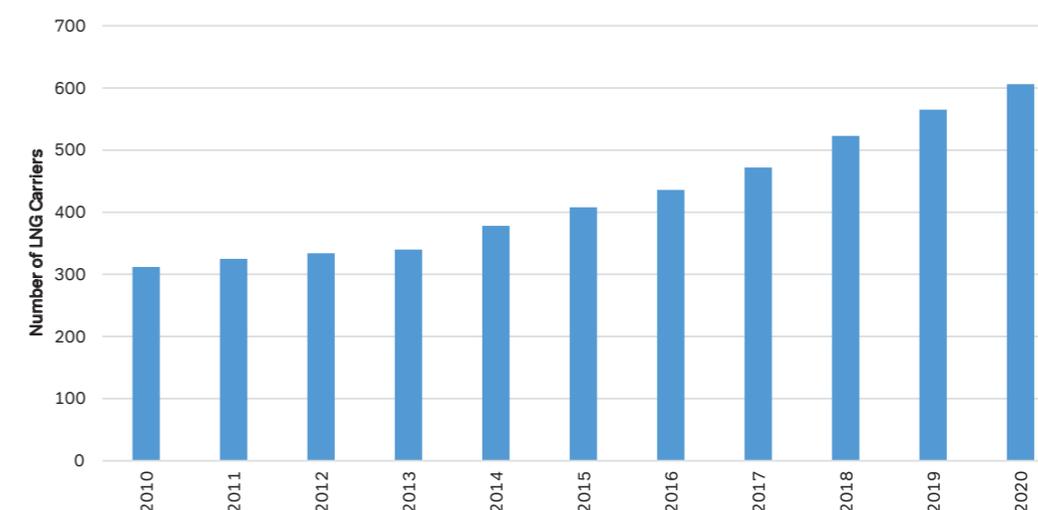
Source: GECF Secretariat based on Project updates

7.6 LNG Shipping Cost

7.6.1 Recent Trends

In 2020, the LNG shipping market was in a depressed state. LNG export cargoes fell by 0.2% y-o-y to 5,682 shipments, driven by a slowdown in LNG demand against the backdrop of the mild 2019/2020 winter season and COVID-19 pandemic. In this context, the commissioning of 41 new LNG carriers in 2020 led to a certain oversupply in the shipping market, with over 600 LNG carriers operating in the world at the beginning of 2021 (see Figure 77).

Figure 77: Trend in Number of LNG Carriers in the World



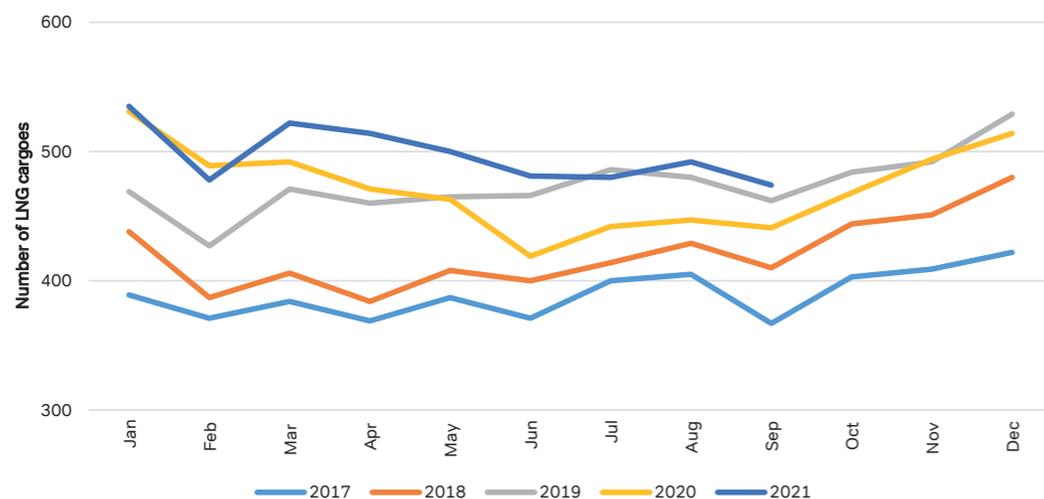
Source: GECF Secretariat based on data from GECF databank, ICIS and Argus

The subdued demand for LNG carriers led to a drop in LNG spot charter rates throughout the first three quarters of 2020. The average rate for steam turbine LNG carriers plummeted to 24,000 USD/day in June and July 2020. However, in Q4 2020 the LNG shipping market tended to recover, driven by the seasonal trends, namely by the rising LNG demand and increasing usage of LNG carriers for floating storage prior to the winter season. As a result, in the full 2020 year, the average LNG charter rate declined by 11% y-o-y to 43,000 USD/day, the lowest level since 2017.

The decrease in LNG charter rates as well as a drop in the average leading shipping fuels price by 29% y-o-y to 289 USD/t, driven by a fall in global oil prices, resulted in a decline in LNG shipping costs. For instance, in 2020, the average shipping costs from the U.S. to Japan fell by 17% y-o-y to 1.4 USD/MMBtu and from the U.S. to Europe – by 19% y-o-y to 0.7 USD/MMBtu.

In 2021, the market has witnessed a robust growth in LNG demand, which resulted in an increase in LNG shipments (see Figure 78).

Figure 78: Number of Monthly LNG Export Cargoes



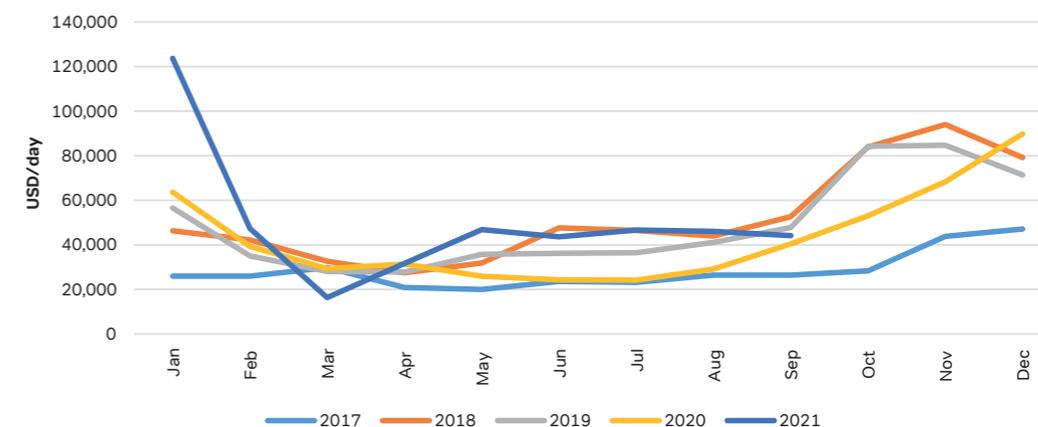
Source: GECF Secretariat based on data from GECF databank, ICIS and Argus

A strong rebound in the regional LNG markets was registered in January, with Asian spot LNG prices hitting over 30 USD/mmBtu and European hub prices reaching almost 10 USD/mmBtu, which was impressive compared to the 2 USD/mmBtu experienced in the summer of 2020. This trend was coupled with skyrocketing LNG spot charter rates, which reached the record highs of 124,000 USD/day for the month of January. Various factors contributed to a rise in charter rates. First, a shortage of LNG shipping capacity was witnessed, driven mainly by a rise in LNG exports from the US, which tripled in January 2021 compared to July 2020 to reach the record 6 Mt. LNG transportation from the US to Asia requires more LNG shipping capacity, since these deliveries result in longer trips. Second, rising supply from the US put high pressure on LNG shipping through the Panama Canal, which is critical for LNG transportation to Asia. In January 2021, LNG carriers' transit in the waterway reached the record 58 passages, including both laden and ballast voyages. That resulted in delays of the passage of LNG carriers there and reduced the amount of carriers available for spot chartering. Some carriers had to wait up to 10 days to pass through the Panama Canal. Higher-than-expected LNG traffic, weather disruptions and high number of other vessels passing through the waterway at that time drove such delays. The congestion at the Panama Canal forced various LNG suppliers to refrain from passing through the waterway in favour of bypassing the Cape of Good Hope or sailing via the Suez Canal, which takes much more time and results in higher LNG shipping costs.

Afterwards, the market stabilized, with congestions at the Panama Canal removed, shipping availability increased and LNG demand slowed down. The average LNG charter rates came back down to baseline, reaching 49,600 USD/day in 9M 2021, which, however, was 45% higher y-o-y (see Figure 79).

2. GECF Secretariat. (2021). Expert Commentary - LNG Shipping costs: a roller coaster in early 2021 after a depression in 2020.

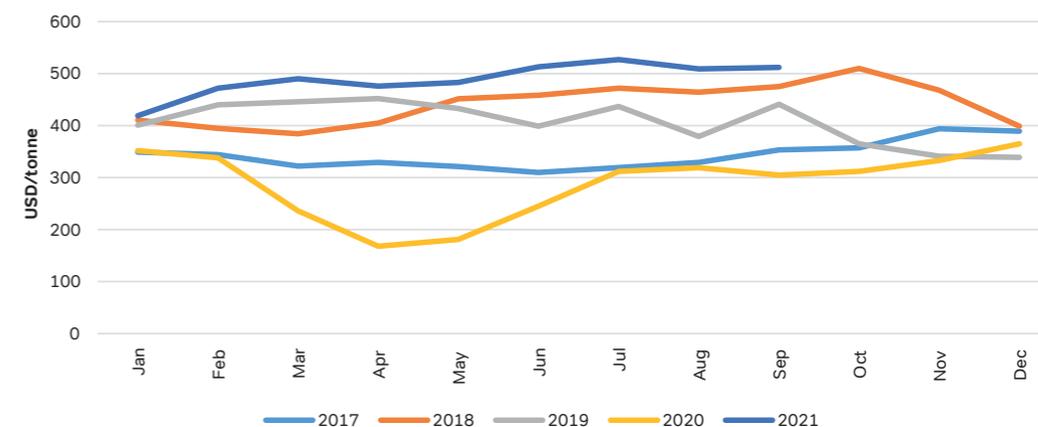
Figure 79: Average LNG Spot Charter Rates for Steam Turbine Carriers



Source: GECF Secretariat based on data from GECF databank, ICIS and Argus

In the meantime, the average leading shipping fuels price rebounded by 79% y-o-y to 490 USD/tonne in 9M 2021, driven by a recovery in global oil prices (see Figure 80). As a result, in 9M 2021 the average shipping cost from the U.S. to Japan stayed at 2.1 USD/MMBtu, while from the U.S. to Europe – at 1.0 USD/MMBtu.

Figure 80: Average Shipping Fuels Price (USD/tonne)



Source: GECF Secretariat based on data from GECF databank, ICIS and Argus

7.6.2 Short Term Perspectives

In the short term, an expected growth in the global LNG trade will require additional LNG shipping capacity. In this context, the planned commissioning of various LNG carriers will meet the growing LNG demand. However, the average LNG spot charter rates may fluctuate a lot throughout a calendar year, following common seasonal trends, specifically rising in winter seasons and dropping in summer seasons.



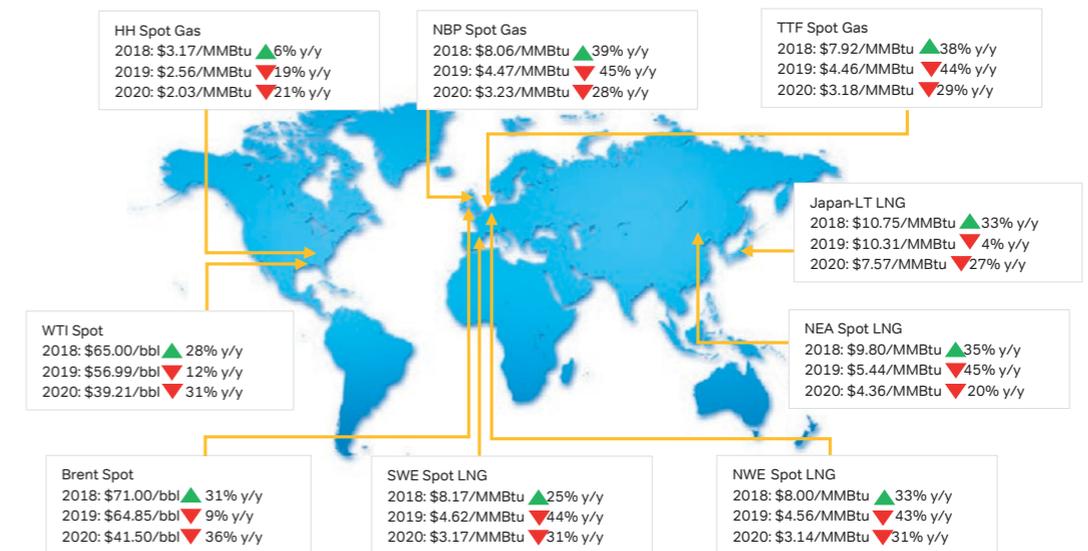
CHAPTER
08

Natural Gas Prices

8.1 Recent Trends

The price analysis in this section uses a bottom-up approach and incorporates daily, monthly and annual analyses of gas, LNG and crude oil prices. It provides the key drivers behind historical trends and shapes the short-term outlook based on a combination of futures prices, expected market fundamentals and benchmarks with forecasts published by other sources. Figure 81 below gives a brief overview and indication of the annual trend in global gas, LNG and oil prices over the past three years.

Figure 81: Annual Natural Gas, LNG and Oil Price Map



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

The trend in gas and LNG spot prices in 2020 reflect the impact of COVID-19 on the gas market quite accurately. With already low spot prices driven by a mild winter season in 2019/2020 and an oversupplied LNG market, the pandemic created the perfect storm, with a large blow to global economic activity and thus, global gas demand.

An analysis of the daily spot gas and LNG prices in 2020 reveal two distinct trends: a gradual declining trend over the first half of the year, and a relatively quick rebound in the second half of the year. In H1 2020, Asian LNG spot prices and European gas and LNG prices were more than 50% lower compared to the previous year. Daily prices in both regions also converged to below \$2/MMBtu at the end of April and start of May reflecting the great imbalance of market fundamentals.³ In H2 2020, prices showed a strong rebound which was driven by the return of robust consumer demand and several supply constraints.

3. GECF Secretariat (2020) Update on Global Gas and LNG Prices in 2020: How has it coped with recent market dynamics?

During the summer there were a large number of cargo cancellations in the U.S., as well as the shutdown of Cameron and Sabine Pass LNG facilities during the Hurricane season. There were also several operational issues and industrial strike action on the Norwegian Continental Shelf (NCS) which further reduced gas supply to Europe. There was also one major unplanned shutdown at the Hammerfest LNG facility which impacted gas supply and this is expected to remain down until March 31, 2022. In the Pacific, there were also supply uncertainty from Australia's Gorgon LNG facility due to issues with the heat exchangers. Since then Trains 1, 2 and 3 have undergone maintenance and repair works, and came back online at the end of July 2021. On the demand side, price signals were driven by winter-stocking demand, as well as the resumption of industrial and commercial activity as lockdown measures were eased in some countries.

Annual spot gas and LNG prices in Europe were down by around 28-31% y-o-y. NBP averaged \$3.23/MMBtu (down from 5-yr average of \$5.91/MMBtu). Annual Asian LNG prices were 20% lower y-o-y. The NEA spot LNG averaged \$4.36/MMBtu (down from a 5-yr average of \$7.18/MMBtu).

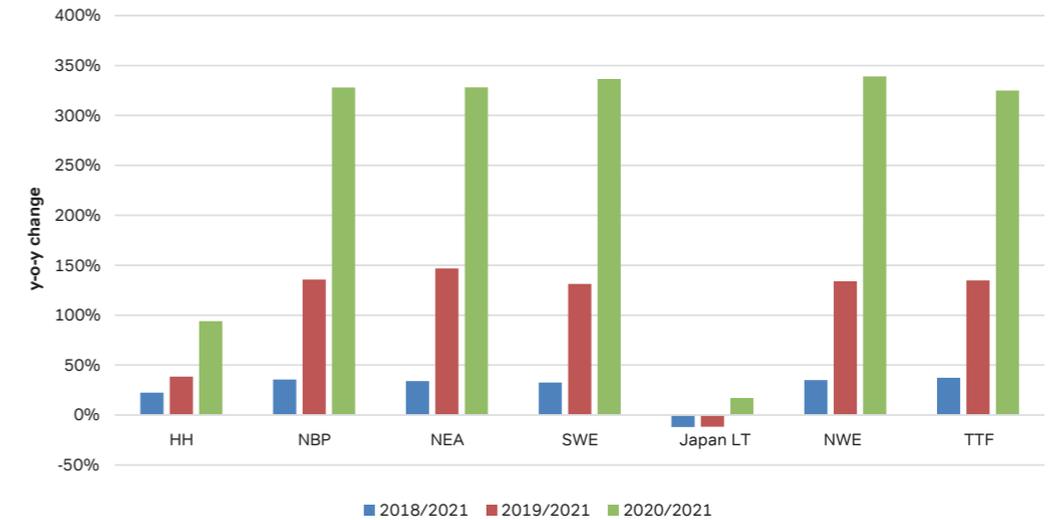
The high volatility observed in spot prices in 2020/21, with prices going from rock-bottom to all-time highs in only a few months, raises concerns about the growing price volatility and the extent of any structural changes to the market. The first half of 2021 brought positive signs for robust gas demand, driven both by improved economic activity and a very cold winter. Tight supply availability also contributed to price spikes in Asian LNG prices and Henry Hub at the start of the year. 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 Q3 2021, hotter-than-usual summer temperatures drove both Asian and European spot prices to record seasonal highs. High EU carbon prices also supported gas demand in Europe however, high gas prices will limit fuel switching demand.

Figure 82 below illustrates the swing in prices considering the period January - September 2021 compared to the previous three years. In this period, Henry Hub spot prices averaged \$3.62/MMBtu, and were 94% higher y-o-y. NEA LNG spot prices averaged \$13.23/MMBtu and was 328% higher than the average of last year. It was also 147% higher than 2019 and 34% higher than 2018 for the same period. NBP and TTF spot prices followed a similar trend and averaged \$10.78/MMBtu and \$10.73/MMBtu and increased by 328% and 325% respectively over this period. Furthermore, NBP and TTF prices were about 136% higher than 2019 and 37% higher than 2018. With regard to the European LNG prices, they averaged \$10.7/MMBtu over this period and were about 337% higher y-o-y.

The Japan LT price averaged \$9.20/MMBtu over the period January – September 2021, which was 17% higher y-o-y, but lower than the levels of 2019 and 2018.

Q1 2021 was marked by unprecedented price spikes in Asian spot LNG prices and Henry Hub. In Q2 2021, spot prices across all regions exhibited strong upward trends. Spot prices in Q3 2021 have recorded seasonal highs, surpassing the average prices for Q1 2021.

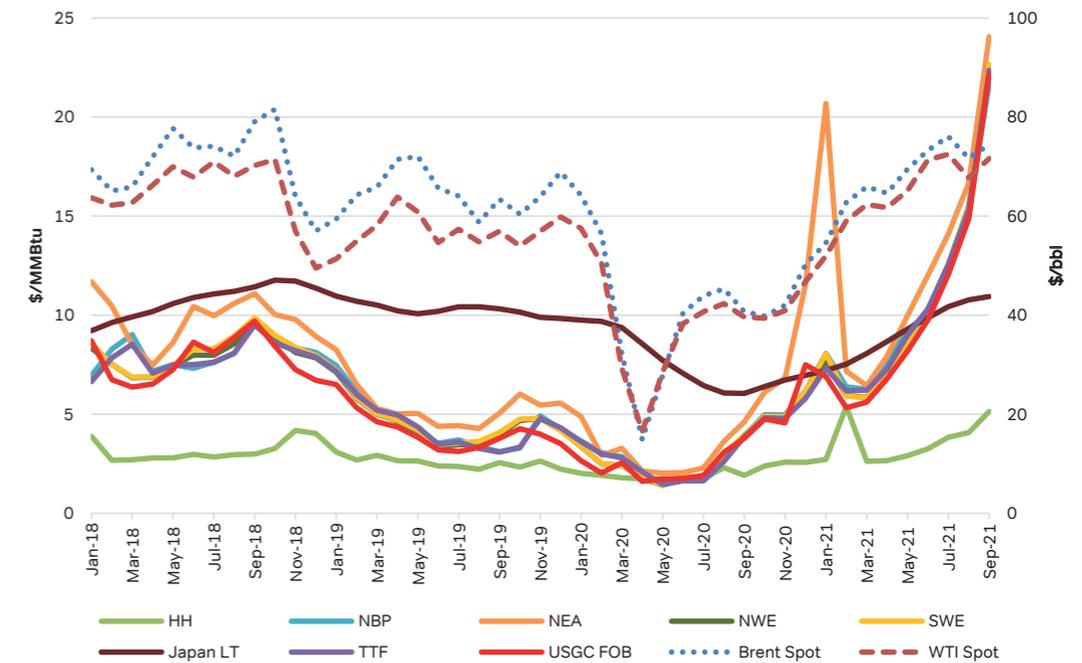
Figure 82: Annual Price Comparison (Jan – Sep 2021)



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

The next section provides a deeper analysis of gas, LNG and crude oil benchmark prices in 2020 and the first nine months of 2021. Figure 83 below illustrates the trend in monthly gas, LNG and oil prices since January 2018.

Figure 83: Monthly Natural Gas, LNG and Oil Prices



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

8.1.1 Henry Hub (HH) Spot Gas Price

The Henry Hub gas spot price averaged \$2.03/MMBtu in 2020, its lowest annual average since 1995, and was 21% lower y-o-y. After hovering around \$2/MMBtu for most of 2020, HH remained above this mark in Q4 2020 as demand in the residential and commercial sectors, as well as U.S. LNG exports recovered.

The average Henry Hub price in Q1 2021 was 87% higher compared to Q1 2020. This was driven by record low temperatures in the U.S. which forced gas production facilities to be shut-in to avoid freeze offs and at the same time, drove residential demand up. In February, daily HH prices hit its all-time record high above \$23/MMBtu and averaged \$5.39/MMBtu, its highest since February 2014. The HH spot price retreated to its seasonal norm in March as temperatures rose and production restarted, with HH dropping by 51% m-o-m.

However, HH prices were lifted by high gas demand with an unusual extreme heat during the shoulder months. HH spot price reached daily highs above \$4/MMBtu at the end of July, mainly driven by higher gas burn for cooling amidst warmer summer temperatures and gas supply constraints due to maintenance of the El Paso pipeline from the Permian Basin. Working natural gas storage in the US was also much lower than its five-year average.

Furthermore, in September, US gas production was curbed by the passing of Hurricanes Ida and Nicholas. Strong domestic consumption and demand for LNG exports lent further upward pressure, pushing HH close to \$6/MMBtu at the end of September 2021.

8.1.2 European Spot Gas Price (NBP, TTF)

TTF spot gas price recorded its lowest-ever annual average in 2020 at \$3.18/MMBtu, 29% lower y-o-y. NBP recorded its lowest annual average since 2002, with an average of \$3.23/MMBtu in 2020 which was 28% lower y-o-y.

After reaching an all-time low of around \$1/MMBtu in June 2020, NBP rebounded to around \$8/MMBtu at the end of 2020 showing the increasing volatility of spot prices in the European gas market. A mild winter, falling coal and carbon prices and weak gas demand due to COVID-19 lockdown measures weighed on prices in the first half of 2020. However, as lockdown measures eased in the second half of the year, gas demand was supported by higher commercial and industrial activity and winter-stocking demand. There was also reduced gas supply from Norway due to operational issues and strike action which boosted prices.

European spot gas prices spiked in January 2021 as colder-than-usual temperatures met a shortage of spot supply. A wide inter-basin arbitrage dictated an influx of LNG cargoes to Asia, while European storage levels were depleted with brisk withdrawals to meet high heating demand. Following this spike, prices across the region dipped in February as temperatures warmed up and LNG deliveries to the region increased.

In Q2 2021, European prices regained strength as the region was hit by colder-than-usual temperatures in April, and both planned and unplanned maintenance at several Norwegian facilities. NBP was especially strong in April driven by lower wind generation, supply

constraints from Norway and higher heating demand. TTF prices were also supported by high carbon prices which soared to a historical high above €56/tCO₂ in May 2021.

European gas and LNG prices remained bullish in Q3 2021, soaring further to record seasonal highs. This was driven by continued supply constraints due to both planned and unplanned maintenance in Norway and Russia (scheduled maintenance at Yamal and Nord Stream pipelines in July), as well as Gazprom's decision not to book any interruptible capacity through Ukraine for August. Bullish EU carbon prices also increased calls for gas in the power sector which supported gas prices. At the end of August EU carbon prices soared above €60/tCO₂ due to a reduction in supply of EU Allowances from government auctions.

NBP and TTF prices reached daily highs above \$27/MMBtu and \$31/MMBtu respectively in September 2021 driven by extended unplanned maintenance at Norway's Karsto gas field, weak wind generation and stronger demand in the power sector. Furthermore, a fire at the 2 GW IFA UK France power interconnector which halted power imports to the UK from France also buoyed prices. It was restored to half capacity by October 20, 2021, with an additional 500MW to come back incrementally from October 2022 – May 2023, and full capacity only in October 2023.

8.1.3 Europe Spot LNG Price (NWE, SWE)

European des LNG prices closely tracked gas spot prices in 2020. NWE and SWE LNG spot prices averaged \$3.14/MMBtu and \$3.17/MMBtu respectively which were both about 31% lower y-o-y. Europe continued its role as a sink for excess LNG in the market which drove storage levels to record highs and weighed on prices.

However, in 2021, European spot LNG prices were pushed upwards to all-time record highs driven by tight supply, increasing LNG demand in the region, competition for cargoes with Asian buyers and low storage levels.

European des LNG prices in April 2021 rose as demand for cargoes increased due to a number of delayed deliveries caused by the temporary blockage at the Suez Canal at the end of March. Planned maintenance at Netherland's Gate terminal from June 15 – July 10 also supported prices. An outage at France's Montoir LNG terminal halted send out on May 4 for safety reasons, so there were no LNG deliveries in May down from seven cargoes in April. At the end of September, NWE and SWE LNG spot prices reached record daily highs above \$30/MMBtu, as storage struggled to be refilled ahead of the winter season.

8.1.4 North East Asia (NEA) Spot LNG Price

After dropping to an all-time monthly low around \$2/MMBtu in May 2020, the NEA spot LNG price started its recovery driven by increased consumer demand for summer cargoes with countries in the region experiencing warmer temperatures, reduced supply availability from Australia and stocking ahead of the winter season. A strong post-pandemic economic recovery in China also played a significant role in supporting industrial demand in the region. In Q4 2020, strong price gains reflected short-covering demand amidst tight supply in the region. In December 2020, NEA spot LNG price recorded its highest monthly average since January 2018.

As the price surge continued on tight market conditions, NEA spot LNG price sky-rocketed to a record daily high of almost \$40/MMBtu in January 2021. This shocking price spike resulted from a culmination of very cold temperatures, supply constraints at several LNG facilities in Australia, Malaysia and Indonesia, Norway and congestion at the Panama Canal. Delays at the Panama Canal resulted in increased voyage durations and soaring charter rates, further tightening the market.

Prices retreated for the rest of Q1 2021 as temperatures returned to normal and supply availability to the region increased.

However, since April, Asian LNG prices have experienced sharp gains, reaching a monthly high of around \$14/MMBtu in July. This was driven by robust consumer demand, strong buying interest and supply tightness in the region. Higher-than-usual temperatures in Japan, South Korea and China boosted calls on gas for cooling demand.

Furthermore, strong economic recovery and increased demand in the industrial sector in China also bolstered gas demand in the region. The Japanese government had also implemented measures earlier this year to ensure supply security and avoid any power shortages, which led to stronger demand ahead of the summer season as buyers stocked up supplies for the period July-September.

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. Supply concerns at the Freeport LNG facility in Texas after three trains were taken offline on September 14 after tropical storm Nicholas made landfall also supported Asian LNG prices. Asian LNG prices reached above \$32/MMBtu at the end of September 2021.

8.1.5 Oil-indexed Long Term (LT) LNG Prices

Oil-indexed prices were less susceptible to the significant price volatility in 2020 than the spot prices. This is expected by the inherent effect of the formula which creates a smoothing effect for such LNG prices over a period of three to six months. The average Japan LT LNG price for 2020 was \$7.57/MMBtu which was 27% lower y-o-y. Similarly, the New LT LNG price for 2020 was \$5.82/MMBtu which was 28% lower y-o-y.

Japan LT LNG prices bottomed-out at around \$6/MMBtu in August-September 2020, and then increased to average around \$7/MMBtu in January 2021 as oil prices recovered, reflecting the lagged effect of low oil prices (as shown in Figure 93). The New LT LNG price experienced a more drastic effect, and reached a monthly low of around \$4/MMBtu in June 2020.

As the spot LNG prices increased at the end of 2020, the Japan LT LNG price became more competitive than the spot prices from November 2020 – January 2021. In January 2021, in particular, when spot prices soared, the Japan LT LNG price was 65% lower than the NEA spot LNG price. Bullish spot gas and LNG prices in Europe and Asia in 2021 have resulted in the oil-indexed prices, Japan LT and New LT being more competitive in January, May – September 2021. Furthermore, for the period January – September 2021, the Japan

LT averaged around \$9/MMBtu, which was 30% lower than Asian LNG spot prices for the same period.

The Japan LT LNG price has increased consecutively from \$7.21/MMBtu in January 2021 to average \$10.94/MMBtu in September 2021, tracking the lagging trend of oil prices.

8.1.6 Crude Oil Prices

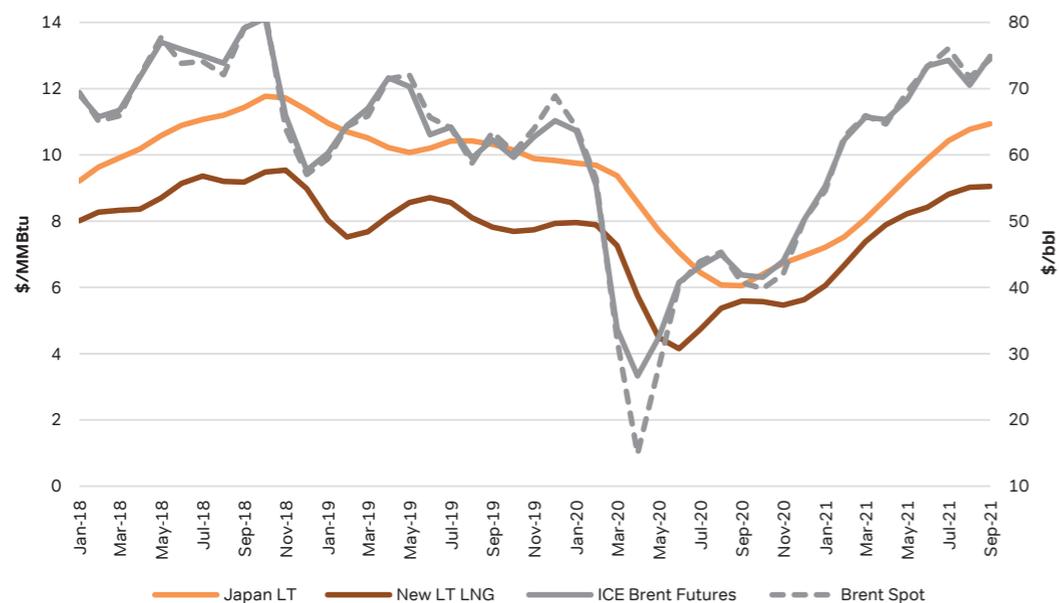
Crude oil prices also experienced record lows and high volatility in 2020, with ICE Brent Futures dropping from a monthly average of around \$64/bbl in January 2020 to \$26/bbl in April 2020 (see Figure 84). This was driven by a strong contraction in global economy resulting in weak oil demand due to COVID-19 lockdown measures and high storage levels. However, the first round of OPEC+ production cuts which took effect from May 2020 supported a rebound in prices after a rapid decline over the first four months of the year. Easing of lockdown measures and the gradual return to normal industrial and commercial activity in many countries in the second half of the year, as well as extended production cuts from OPEC+ held prices within the \$40-50/bbl range. However, uncertainties around oil demand recovery with the re-emergence of lockdown measures at the end of the year weighed on prices.

In 2020, Brent and WTI spot prices averaged \$41.50/bbl and \$39.21/bbl respectively which were 36% and 31% lower y-o-y. On the futures market, ICE Brent futures and NYMEX WTI averaged \$43.21/bbl and \$39.43/bbl respectively which were 33% and 30% lower y-o-y. Crude oil prices have experienced a strong rebound in 2021 supported by a general optimistic outlook on oil demand, improving refinery demand, declining inventory levels and easing of restrictions in many countries. In April 2021, prices dipped slightly due to a resurgence of COVID-19 cases in some countries and extended lockdowns in Europe. However, in June there was a swift rebound in prices on positive market sentiment for demand recovery.

There was some price fluctuations in July as the market awaited the OPEC+ decision on supply quotas, however the monthly average remained strong. OPEC+ decided to boost supply from August-December 2021 by 400,000 b/d each month. After a three-month rally, oil prices again dipped in August on slowed buying interest in Asia and concerns about the global demand outlook. In September, prices increased due to some supply restrictions in the US following the passing of Hurricanes Ida and Nicholas. Brent futures reached its highest since October 2018, averaging \$74.88/MMBtu. Positive market sentiment on oil demand and strong economic recovery in the US and Europe also supported prices.

Over the period January - September 2021, Brent spot and futures prices averaged \$68.10/bbl and \$67.78/bbl respectively, which was 67% and 59% higher y-o-y.

Figure 84: Oil-Indexed LT LNG Prices



Source: GECF Secretariat based on data from Refinitiv Eikon

8.2 Short-Term Perspectives

Gas and LNG spot prices over the first nine months of 2021 have soared way above the lows of 2020, and even surpassed 2018 levels, favoured by supply/demand dynamics. On the demand side, there was robust recovery due to an intense winter season, warmer-than-usual summer, global economic recovery, increased LNG imports particularly in China, South Korea and Brazil and record high EU carbon prices which increased coal-to-gas switching. In terms of supply, there was reduced supply coming to the market due to several different factors including outages at some LNG facilities, more planned and unplanned maintenance due to postponements from last year, congestion at the Panama Canal which delayed cargo deliveries during the winter, slower recovery in pipeline gas supply to Europe, feedgas supply issues from some existing suppliers, reduced US gas production due to the passing of Hurricanes Ida and Nicholas during the summer and very low European storage levels.

These factors created the perfect conditions for sky-high spot prices witnessed in 2021, with the NEA LNG spot price reaching above \$42/MMBtu and TTF price just shy of \$40/MMBtu in October 2021. European buyers have been hit hardest by the high spot prices, leading to extremely high utility bills in households and industries, which have caused protests and even the shutdown of some plants. With European storage levels still below the 5-year average ahead of the winter season, the region may be in for a tough winter season. Some trading firms have also expressed that prices are expected to remain high over the next two years as there may not be any significant production capacity additions to the market, while global demand continues to ramp up.

Spot prices are expected to continue their bullish trend in Q4 2021 on the anticipation of strong gas demand, as the global economy slowly heals from the impact of the COVID-19 pandemic. The latest forecast for winter temperatures in Japan expects below-average temperatures, which can support demand. We also expect strong demand in China driven by the power and industrial sectors, and in South Korea driven by coal curtailment policies. European prices will be supported by tight global market, stronger imports needed to replenish depleted storage and strong carbon prices. Furthermore, we may also see some supply constraints as facilities face operational issues and undergo planned maintenance which were postponed from last year. However, there may be some downside risk with growing US LNG exports and other supply coming to the market.

European and Asian prices have become very connected, but with widening seasonal spreads. Gas and LNG spot prices are also expected to remain bullish until Q1 2022. However, prices will be at the mercy of weather conditions. If we experience extremely cold temperatures similar to this year, we can expect significant price spikes during the winter 21/22. On the other hand, if we experience a mild winter, prices are expected to soften.

The volatility of the spot market has never been more evident, jumping from record lows to record highs within one year. While oil-indexed prices have also increased in 2021, they have ensured much lower volatility, greater stability in revenue streams to producers and protected buyers from exposure to high gas prices. Due to the increased competitiveness of oil-indexed prices in 2021, we have seen a greater preference for it amongst buyers. Japan LT LNG prices are expected to increase in the short-term as crude oil prices have strengthened on optimism in the global oil demand outlook and global economic recovery particularly in the US and Europe. GECF Member Countries continue to favour long-term oil-indexed contracts and maintain mutually beneficial partnerships.

8.3 U.S. LNG Spot Price on Regional Markets

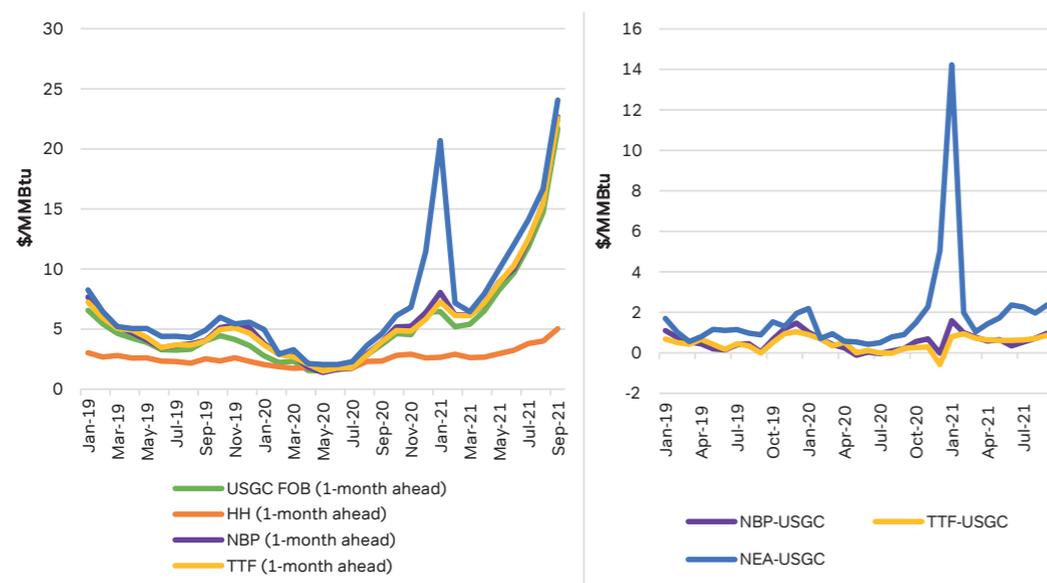
This section focuses on spot FOB LNG prices from the U.S. Gulf Coast (USGC) as quoted by some pricing agencies, Argus and ICIS. Similar to the trend in spot gas and LNG prices in 2020, the USGC spot FOB LNG prices fell by 29% y-o-y to \$2.99/MMBtu last year. The weaker USGC FOB spot LNG prices was driven by the drop in global gas and LNG demand, as a result of the COVID-19 lockdown measures, and a jump in U.S. LNG exports. Between April and July 2020, the USGC spot FOB LNG prices dropped below \$2/MMBtu and averaged \$1.60/MMBtu during this period (see Figure 85). Considering average spot shipping costs of \$1.50/MMBtu and \$0.75/MMBtu from the USGC to NEA and Western Europe respectively, USGC spot FOB LNG cargoes were generally uneconomical to Asia and Europe for most of 2020. This was due to the Asia-USGC and Europe-USGC price spreads (see Figure 85) dropping below the spot shipping costs between the markets. As such, this contributed to the vast number of LNG cargo cancellations from the U.S. in Q2 and Q3 2020.

In Q4 2020, the USGC spot FOB LNG prices started to recover and continued its recovery into 2021. Between January and September 2021, the USGC spot FOB LNG price averaged \$9.97/MMBtu, which represents a surge of 341% y-o-y from the same period in 2020. The

tight LNG market, driven by a surge in LNG demand and moderate growth in LNG supply, supported the rebound in the USGC spot FOB prices. At the end of September 2021, the USGC spot FOB LNG price surpassed \$20/MMBtu, which is the highest price ever since the U.S. started LNG exports in 2016.

During the first nine months of 2021, the spot shipping cost from the USGC to NEA and Western Europe averaged \$2.10/MMBtu and \$1/MMBtu respectively. Meanwhile, the price spreads between NEA and Western Europe with the USGC spot FOB LNG prices averaged \$3.26/MMBtu and \$0.76/MMBtu respectively during the same period. As such, the USGC spot FOB LNG supply was more economical in NEA compared to Western Europe and supported the strong influx of US LNG into Asia compared to Europe in 2021 thus far.

Figure 85: Monthly U.S. Spot LNG, Asian LNG and European Gas Prices & Spreads



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

8.4 Asian LNG Price Indices in Consuming Countries

Over the past few years, several LNG price indices and exchanges have emerged in the following Asian countries: Singapore, China, Japan and India. However, none of them have succeeded in becoming a benchmark price due to several challenges including lack of infrastructure, lack of domestic gas production, insufficient storage facilities.

In Singapore, the SGX LNG Index (Sling) was launched in 2015, jointly developed by the market operator of Singapore's wholesale electricity market, Energy Market Company (EMC) and Singapore Exchange. The Sling spot index represented the average of expert assessments from a portfolio of market participants including producers, consumers and traders. However, it was discontinued in October 2019 due to low market participation.

China currently has two gas exchanges with both pipeline gas and LNG trading, Shanghai Petroleum and Natural Gas Exchange (SHPGX) and Chongqing Petroleum and Gas Exchange (CQPGX) which have been trading since 2016 and 2017 respectively. The SHPGX launched a spot pricing index for LNG imports in September 2021. The index intends to track DES cargoes between 90,000 – 210,000 cubic metres LNG, and will be a joint effort with the General Administration of Chinese Customs. There are also plans to launch natural gas futures prices. While these exchanges may give an indication of the gas and LNG prices in the country, it is still not a recognized benchmark price.

In Japan, the Ministry of Economy, Trade and Industry (METI) began publishing its monthly spot LNG prices contracted for or delivered to Japan in 2014. However, in May 2021, the ministry announced that it will stop publishing these prices, since it had achieved its aim of gaining a better understanding the distribution dynamics for LNG demand, which spiked after the Fukushima disaster. Following the price spikes earlier this year, METI also plans to introduce new measures to minimize exposure to these high spot prices.

India recently launched its first gas electronic trading platform, the Indian Gas Exchange Ltd. (IGX) in June 2020, which is expected to play a key role in the development of India's price benchmark for gas to address the supply/demand imbalance and accelerate investment in the industry.

HIGH
EMISSIONS



LOW
EMISSIONS

CHAPTER

09

Carbon Mitigation Strategies

9.1 Carbon Neutral LNG

Over the past two years, there has been increasing momentum in the trade of carbon neutral LNG (CNL). CNL cargoes refer to those cargoes in which “the carbon emissions (including methane) associated with the upstream production, liquefaction, transportation and, if required, combustion of the gas is measured, certified and offset through the purchase and use of carbon credits, which support reforestation, afforestation or other renewable projects”⁴.

The growing concerns of greenhouse gas (GHG) emissions and their impact on the environment have resulted in several countries adopting policies to reduce carbon emissions, with the aim of achieving carbon neutrality in the long-term. CNL has been developed as a carbon reduction mechanism amidst the low deployment of commercial-scale carbon capture and storage (CCS) and carbon capture utilisation and storage (CCUS) technology across the world.

A major hurdle for the gas and LNG industry is the measurement of GHG emissions along the value chain. There is currently no industry standard for the measurement, reporting and verification (MRV) GHG emissions and LNG exporters utilise industry estimates. As such, many companies use the UK Department for Environment, Food and Rural Affairs’ (DEFRA’s) estimate of 240,000 tCO₂e (tonnes of carbon dioxide equivalent) life-cycle GHG emissions for a standard size LNG cargo of 70,000 tonnes when there is no available information⁵. According to the Greenhouse Gas Protocol, the life-cycle GHG emissions can be categorised into the following three Scopes⁶:

- “Scope 1 – emissions are direct emissions from owned or controlled sources
- Scope 2 – emissions are indirect emissions from the generation of purchased energy
- Scope 3 – emissions are all indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions.”

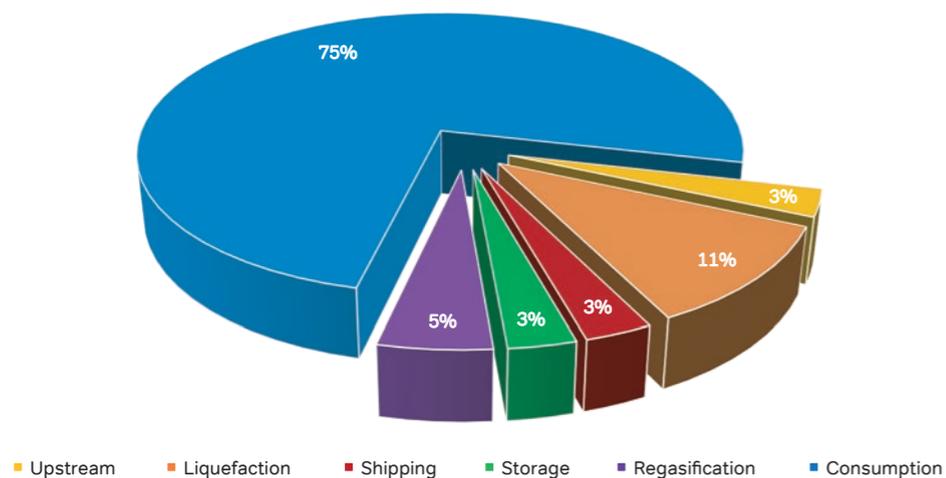
In terms of the GHG emissions along the LNG value chain, final consumption accounts for around 75% of the life-cycle emissions while liquefaction and regasification account for around 11% and 5% respectively (see Figure 86). The other segments of the LNG value chain, including upstream, shipping and storage, each account for around 3% of the life-cycle emissions.

4. Definition of Carbon Neutral LNG from Wood Mackenzie.

5. <https://www.shell.com/business-customers/trading-and-supply/trading/news-and-media-releases/first-carbon-neutral-lng-cargo-delivered-in-europe.html>

6. https://ghgprotocol.org/sites/default/files/standards_supporting/FAQ.pdf

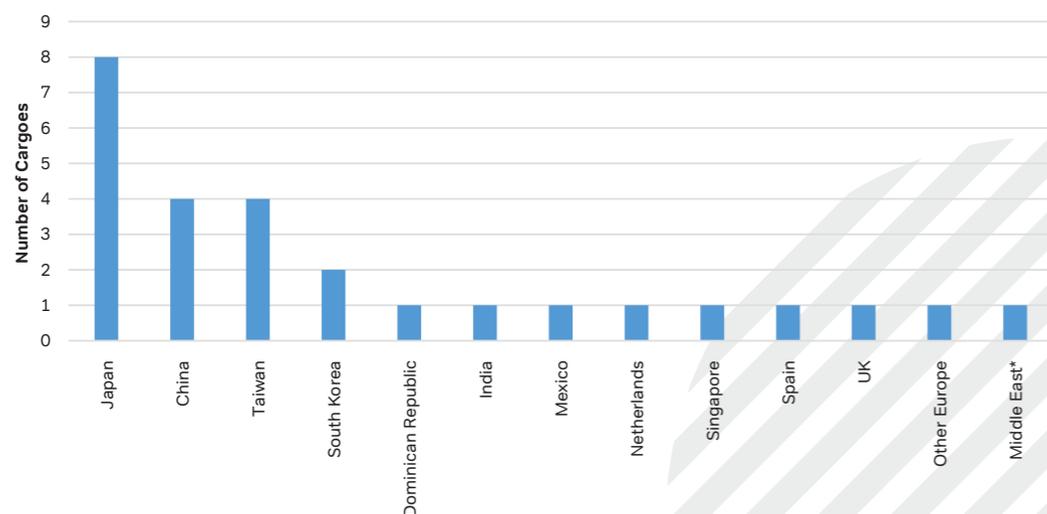
Figure 86: GHG Emissions by Segment in the LNG Value Chain



Source: GECF Secretariat based on data from Poten & Partners

Since the summer of 2019, around twenty-seven (27) CNL cargoes were traded globally. In comparison to almost 5,800 LNG cargoes traded in 2020, the share of CNL in global LNG trade is less than 1%. In terms of the buyers of CNL, Asian countries accounted for the bulk of CNL purchases globally (74%), followed by Europe (15%), Latin America and the Caribbean (7%) and the Middle East (4%). At a country level, Japan has been the first and largest importer of CNL globally. It accounted for 30% of the total CNL cargoes imported between July 2019 and August 2021 (see Figure 87).

Figure 87: Import of CNL Cargoes by Country (Jul '19 – Sep '21)

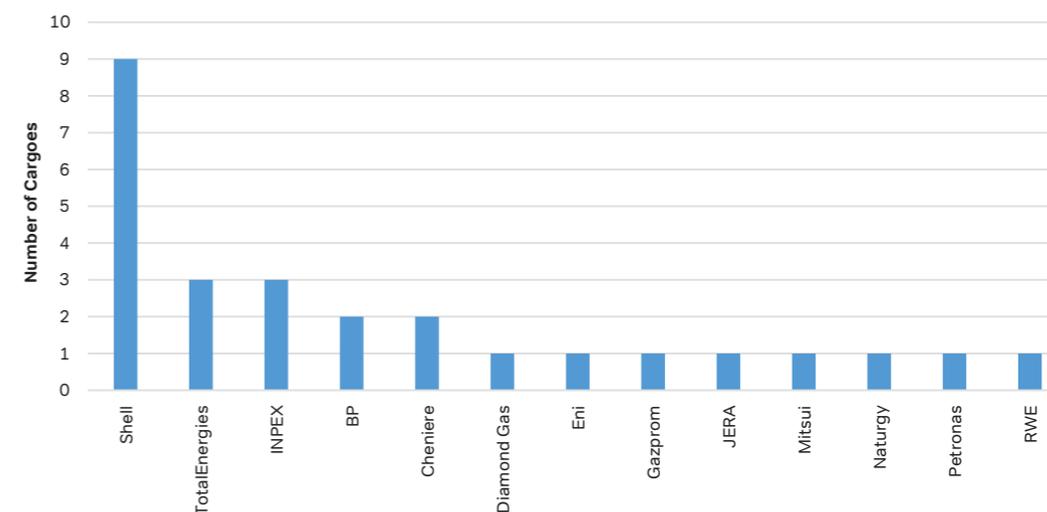


Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LNG Prime, Naturgy, S&P Global Platts, Shell and Total
 (*): There is no information available as to when and where the Middle East CNL cargo is received.

In addition to the past transactions, Sakhalin LNG has agreed to supply a carbon neutral LNG cargo to Toho Gas (Japan) in October 2021 while Petronas and Shenergy (China) signed a deal for three (3) carbon neutral LNG cargoes, for delivery between October 2021 and March 2022.

With regards to the suppliers of CNL cargoes, Shell was the first mover of this relatively new concept and has been involved in the supply of nine (9) CNL cargoes. Other LNG exporters have since become involved in the trade of CNL cargoes including TotalEnergies, Cheniere, Diamond Gas, Eni, Gazprom, INPEX, JERA, Mitsui, Naturgy, Petronas and RWE (see Figure 88). Gazprom and Petronas, both from GECF member countries Russia and Malaysia respectively, are the only National Energy Companies who are involved in the supply of CNL thus far.

Figure 88: Export of CNL Cargoes by Supplier (Jul '19 – Sep '21)

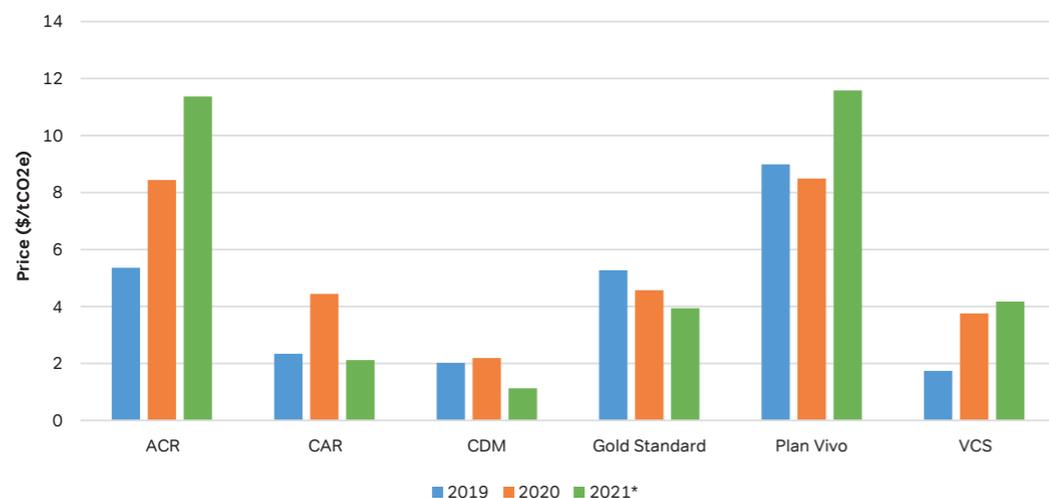


Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LNG Prime, Naturgy, S&P Global Platts, Shell and Total

Majority of the carbon credits for the offset of carbon emissions for the CNL cargoes traded were bought from nature-based projects across the world. One carbon credit is equivalent to 1 tonne of CO₂e emission removed from the atmosphere. There is currently no global market for purchasing carbon credits and are purchased from the Certified Emissions Reduction (CER) or Verified Emissions Reduction (VER) credits. The CER credits are from the emission reduction projects under the United Nations' Clean Development Mechanism (UNCDM). Meanwhile the VER credits are purchased from the voluntary market and includes emissions reduction projects with international carbon offsetting certification standards.

In terms of the price of carbon credits, this can vary significantly depending on the type of project, the location and the environmental, social and economic benefits of the project. Based on carbon credit transactions from different standards between 2019 and August 2021, the price of carbon credits range from \$1-\$12/tCO₂e. Carbon credits from the American Carbon Registry (ACR) and the Plan Vivo are the most expensive while those from the Clean Development Mechanism (CDM) are the cheapest. The prices of carbon credits from the ACR, Plan Vivo and the Verified Carbon Standard (VCS) have trended upwards since 2019 while the price of the Gold Standard carbon credits has been on the decline (see Figure 89).

Figure 89: Trend in the Price of Carbon Credits by Standard



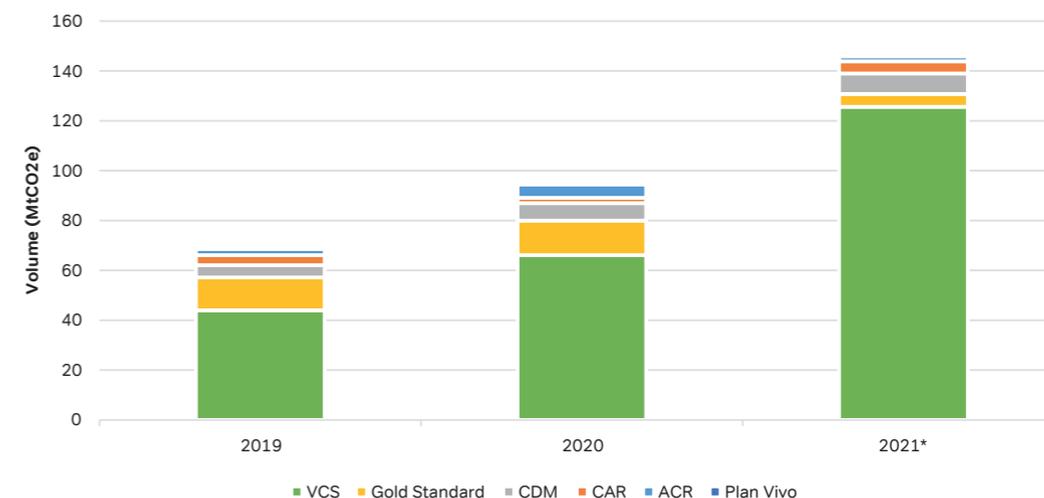
Source: GECF Secretariat based on data from Ecosystem Marketplace

(*): Based on carbon credit transactions until August 2021

Notes: ACR – American Carbon Registry, CAR – Climate Action Reserves, CDM – Clean Development Mechanism, VCS – Voluntary Carbon Standard

With regards to the volume of carbon credits traded since 2019, the total volumes have increased progressively from 70 MtCO₂e in 2019 to 96 MtCO₂e in 2020 and further to 147 MtCO₂e between January and August 2021. As shown in Figure 90, the VCS carbon credit was by far the dominant carbon credit traded globally since 2019 followed by the Gold Standard and CDM carbon credits.

Figure 90: Trend in the Volume of Carbon Credits Traded by Standard



Source: GECF Secretariat based on data from Ecosystem Marketplace

(*): Based on carbon credit transactions until August 2021

Based on the price of the carbon credits and the volumes of each type of carbon credit traded, the weighted average price of carbon credits was \$2.69/tCO₂e in 2019 and jumped to \$4.10/tCO₂e in 2020. However, in 2021 thus far, the weighted average price of carbon credits declined slightly to \$4.06/tCO₂e. Considering the average carbon credit price of \$4.06/tCO₂e in 2021, the cost to offset the full life-cycle emissions of a standard sized LNG cargo (70,000 tonnes) is almost \$1 million, which is equivalent to \$0.29/MMBtu. The cost of carbon offset is negligible compared to the current spot LNG prices of around \$40/MMBtu and represents 0.7% of the LNG price.

It should be noted that S&P Global Platts started publishing daily carbon credit prices for Nature-Based Carbon Credit Projects (Platts CNC) on June 14, 2021. In addition, CME Group launched a Nature-Based Global Emissions Offset (N-GEO) Futures on August 1, 2021.

Apart from the individual trade of CNL cargoes, energy trader Vitol also announced plans to offer green LNG to its customers in which the carbon emissions will be offset by VER credits. Furthermore, in March 2021, fifteen (15) Japanese companies established a CNL Buyers’ Alliance to promote the use CNL to achieve its long-term sustainable development goals. As such, we expect to see a gradual rise in market players and trade of CNL in the future. Another major development in the trade of CNL is the first term contract signed in the market, between Shell and PetroChina, in July 2021. The deal will be for five (5) years and the life-cycle CO₂e emissions for each cargo will be offset using high-quality carbon credits from nature-based projects. The volume of carbon neutral LNG cargoes and price details were not available.

In the short-term, there may be additional short, medium and even long-term LNG contracts for the sale of CNL as countries pursue aggressive decarbonization and carbon neutral

policies. However, one area of contention remains and is related to the cost of the carbon offset. There is no clarity as to who should pay for offsetting the carbon emissions. Considering that around 75% of the total life-cycle GHG emissions along the LNG value chain is from the downstream consumption, the final consumer would have to pay for the bulk of the carbon offset if the cost is split according to the respective carbon emissions along the LNG value chain.

9.2 Contractual Reporting of GHG Emissions for LNG Cargoes

There has been some developments regarding the mandatory reporting of GHG emissions for delivered LNG cargoes. There were three recent medium/long-term LNG contracts signed, where the seller is obligated to provide a statement of GHG emissions, from the wellhead to discharge port, for each cargo delivered. Pavilion Energy signed the three LNG deals with BP, Chevron and Qatar Energy for the supply of LNG to Singapore (see Table 5). However, it should be noted that there is currently no obligation for the seller to offset the carbon emissions. In addition to the reporting of emissions for LNG cargoes, Qatar Energy, Chevron and BP have committed to work together with Pavilion Energy to develop a methodology for measuring and reporting GHG emissions along the LNG value chain, from the wellhead to discharge port. On another note, U.S. LNG producer Cheniere has also committed to provide the emissions data for LNG cargoes from its LNG facilities in the U.S. starting in 2022.

Table 5: Recent LNG Contracts with Mandatory Reporting of GHG Emissions

SUPPLIER	BUYER	IMPORT COUNTRY	START DATE	VOLUME	DURATION	GHG EMISSIONS REPORTING
Qatar Energy	Pavilion Energy	Singapore	2023	1.8	10 years	Statement on greenhouse gas emissions from the well-head to discharge port
Chevron			2023	0.5	6 years	
BP			2024	0.8	10 years	

Source: GECF Secretariat based on information from BP, Chevron, ICIS, Qatar Energy and Pavilion Energy

9.3 Carbon Reduction Strategies by LNG Suppliers

As the world transitions to a low carbon future, LNG suppliers are committing to the global climate agenda to reduce GHG emissions. Several LNG suppliers across the globe are already involved and/or are planning to implement strategies to reduce their carbon footprint across the LNG value chain. The main carbon reduction strategies that are being adopted include:

- CCS and CCUS technology to reduce carbon emissions from feedgas to the LNG facility and the liquefaction process.
- Renewable electricity to power the upstream operations and liquefaction process, instead of gas turbines as well as the use of highly efficient gas turbines.
- Jetty boil-off gas recovery system to capture and utilise the regasified LNG during the loading process onto the LNG vessel.

As shown in Table 6, several LNG suppliers in GECF member countries, Malaysia, Norway, Qatar and Russia, are involved in the implementation of carbon reduction technologies along the LNG value chain in which they operate. This highlights GECF member countries' commitment to preserving the environment through the reduction in GHG emissions. Other LNG suppliers, including major energy companies like BP, Shell and Total, as well as other LNG suppliers globally have also announced plans to reduce their carbon footprint from their LNG operations.

Table 6: Existing and Planned Carbon Reduction Strategies by LNG Suppliers

COUNTRY	OPERATOR	PROJECT	DETAILS
Australia	Chevron	Gorgon LNG	CCS of 3.4 – 4 Mtpa of CO ₂ (2019)
	Santos	Darwin LNG	CCS of 1.7 Mtpa of CO ₂ (2025)
Canada	LNG Canada JV	LNG Canada	Electrification of upstream operations, use of renewable electricity and highly efficient gas turbines (2025)
	Woodfibre LNG Ltd.	Woodfibre LNG	The facility will run on renewable hydroelectricity (2023)
Indonesia	BP	Tangguh LNG	CCS for a total 25 Mt of CO ₂ over its lifetime (2026)
Malaysia	Petronas	Bintulu LNG Complex	CCS of 3.7 Mtpa of CO ₂ emitted via flaring (2025)
Norway	Equinor	Snohvit LNG	CCS of 0.7 Mtpa of CO ₂ (2008)
Qatar	Qatar Energy	Qatar LNG	Jetty boil-of-gas recovery system to reduce GHG emissions by 2.5 MtCO ₂ e per year (2014)
	Qatar Energy	Qatar LNG	CCS of 2.1 Mtpa of CO ₂ (2019)
	Qatar Energy	Qatar LNG Expansion	CCS of an additional 2.9 Mtpa of CO ₂ (2025) Renewable electricity from the 800 MW solar power plant will power the LNG facility (2025) Jetty boil-of-gas recovery system to reduce GHG emissions by 1 MtCO ₂ e per year (2025)
Russia	Novatek	Yamal LNG	Wind power generation to reduce carbon footprint from existing gas-fired generation facilities
U.S.	Sempra	Cameron LNG and other LNG facilities	CCUS project for 4.5 Mtpa of CO ₂ and electric motor drives for liquefaction
	Venture Global	Calcasieu Pass LNG	CCS of 0.25 Mtpa of CO ₂ (2021)
	Venture Global	Plaquemines LNG	CCS of 0.25 Mtpa of CO ₂ (2024)
	Next Decade	Rio Grande LNG	CCS of 5 Mtpa of CO ₂ (2024) Using electric drives instead of gas turbines

Source: GECF Secretariat based on information from Bloomberg, Upstream Online and Project Updates10.



CHAPTER

10

Conclusion

The world experienced an unexpected crisis in 2020, which translated into all aspects of our lives, with the gas industry being no exception. The global gas industry experienced an unprecedented decline in natural gas demand, with natural gas prices dropping to record lows, resulting in huge production and investment cuts across the entire natural gas value chain. Furthermore, the year 2020 saw a series of cancellations and postponements of LNG FIDs, where only one project was sanctioned during the year in Mexico. All these catastrophic scenarios were driven by a combination of the impact of the COVID-19 pandemic and mild weather during the year 2020. However, in the second half of 2020, the situation started to show some positive signs in terms of natural gas prices and demand driven by the easing of COVID-19 lockdown measures and optimism in the energy market with the rollout of vaccination campaigns.

Subsequently, the situation changed drastically, transforming from unprecedented low prices in 2020 to record highs in 2021, with prices soaring above \$40/MMBtu. This drastic change was the consequence of several factors for natural gas supply, including outages at some LNG facilities, more planned and unplanned maintenance at upstream and LNG facilities due to postponements from the year 2020, congestion at the Panama Canal, feedgas supply issues from some existing LNG suppliers, lower U.S. natural gas production during some periods due to hurricanes, weak natural gas inventories and slower recovery in pipeline gas supply to Europe. On the demand side, there was a very strong recovery due to a colder-than-usual winter and hotter-than-normal summer seasons, global economic recovery, rebound in industrial activity, increased calls on natural gas in some major consuming countries including China, South Korea and Brazil and strong EU carbon prices, which increased coal-to-gas switching in the first half of the year.

As the natural gas and LNG markets evolve and adapt to new market realities, there are new trends reflected in the prices, some structural and some transient. The volatility of the spot market has become even more evident. In this regard, GECF Member Countries will continue to promote long-term oil-indexed pricing to market players and highlight its role in ensuring the security of supply, stability of revenues and sufficient investment in the industry from the sellers' side. Similarly, from the buyers' side, they are protected from spot price fluctuations, and the extreme highs of today, when using an oil-indexed formula that will bring very good visibility in terms of expenditure. The record high spot natural gas and LNG prices in the market is of great concern for both producers and consumers. These prices are unsustainable and can hurt the future prospects of natural gas demand. In addition, it can drive a shift from natural gas consumption to coal and oil. Therefore, there is need for fair pricing of natural gas, with consideration of its credentials – clean, abundant, available and flexible.

The global movement to implement decarbonization policies and setting net-zero carbon targets are accelerating, particularly in developed countries. These developments could affect the share of natural gas in the global energy mix and as a result, the economies of natural gas producing countries. Knowledge and experience sharing among the GECF member countries, related to diversifying the economy helped them to preserve and improve their economy in this critical period. In this regard, natural gas decarbonization will play a crucial role in positioning natural gas in a low-carbon future, not only as a transition

fuel, but as a destination fuel. Meanwhile, the decarbonization of natural gas will result in higher penetration of natural gas use in the energy transition in both producing and consuming countries.

As such, the GECF continues to strengthen the voice of natural gas and strategies to cement its role in the energy transition. Our fourth annual workshop on the Promotion of Natural Gas Demand was held on September 29, 2021, which highlighted the prospects for natural gas, and its growing demand in new and niche sectors, including technological solutions for the development of blue hydrogen, the transportation sector and the role of small-scale LNG in reaching emerging and potential markets. In addition, it focused on the crucial environmental issues of reducing carbon and methane emissions as it relates to the gas industry, and the collaborative strategies that market players can implement to strive for net-zero emissions.

The energy transition is happening now, the world is moving to cleaner energy sources and it is imperative that natural gas be at the core of this transition. There is a need for greater cooperation among all market players including natural gas producers, natural gas consumers, financial institutions, producers of other energy sources and policymakers. Such cooperation shall be reflected in collaborative actions such as exchanging and adopting new technologies, sharing best practices in the industry, financing, transparency in emissions reporting, controlling measurement of emissions and research and development. In this regard, natural gas is well-positioned to play a role in this transformative journey as a central fuel or feedstock for alternative sources such as blue ammonia or blue hydrogen.

In the frame of the climate change agenda, the focus is gradually shifting from oil and natural gas to inhibition of GHG emissions. Indeed, many banks are reconsidering the strategy towards financing fossil fuels, including natural gas, in the frame of complying with the targets in the Paris Agreement. The Paris Agreement stipulates that international efforts need to cap global warming and prevent the global average temperatures from rising more than two (2) degrees Celsius above pre-industrial levels, thus calling for a net-zero GHG emissions by 2050. Furthermore, the World Bank is considering the increase of its climate finance target in its Climate Change Action Plan 2021-2025. Other banks, such as the European Investment Bank (EIB) are following the same pattern and are dropping fossil fuel funding, including natural gas. The list of financial restrictions by banks is expanding and this is a real threat to the sustainability and security of the supply. Furthermore, the EU's Fit for 55 package sets the stage for their commitments to addressing the global climate crisis. However, the unprecedented spikes in energy prices is also building concern about EU's climate change agenda, energy security and its impact on the most vulnerable.

These strategies have been reaffirmed at COP26 which took place from October 31 – November 12, 2021 which was aimed at securing global net-zero by mid-century to keep 1.5 degrees within reach and adapting to protect communities and natural habitats. During the COP26 event there were commitments of the international community to reaching net-zero emissions by 2050, 2060 and 2070, whether it was at the stage of political pledge, policy or enshrined into the law. With regard to financing, the EIB announced that there will be

only exemptions for funding of innovative low-carbon projects from oil and gas companies, in order to accelerate the energy transition. Several countries also committed to ending international financing for unabated fossil fuels by 2022.

However, the GECF believes that the credentials of natural gas must be recognized together with its crucial role in meeting the energy requirements of the world and also fulfilling the criteria of low-carbon emissions. Another major development from COP26 is the Coal to Clean Power Transition where many countries have committed to phase out unabated coal power in the 2030s in major economies and 2040s globally. This transition provides an opportunity for natural gas with CCS/CCUS technology to partially compensate for declining electricity supply from coal. GECF Member Countries are committed to implementing new strategies and policies towards reducing carbon and methane emissions along the natural gas value chain, as well as incorporating blue hydrogen and renewables into their energy mix. We strongly believe that natural gas and renewables are the ideal partners in the journey to a carbon neutral world.

In this regard, GECF Member Countries are initiating collaborative actions in many areas of technology, finance and notably in investment on decarbonization technologies such as CCUS, blue hydrogen, ammonia, and other products that are supported by natural gas as the essential feedstock. The GECF strongly believes in the future of natural gas and the key role it will play in achieving the United Nations' Sustainable Development Goals (SDGs) and the transition to a low carbon future. In the current market conditions, long-term natural gas contracts are the best mechanism to ensure security of supply and avoid potential energy crises. Furthermore, the GECF Member Countries are committed to their long-term partnership with buyers for the sustainable supply of natural gas and call for cooperation among all market players in the gas industry for the successful energy transition with natural gas at the core.

Definitions

TERM	MEANING
Coal-to-gas switching price	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.
European Union	Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden.
Medium-term	The medium-term outlook refers to the period of 5-10 years.
OECD Countries	Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Spain, Sweden, the Slovak Republic, Slovenia, Switzerland, Turkey, the United Kingdom and the United States.
OECD Americas	Canada, Chile, Mexico and the United States.
OECD Asia Oceania	Australia, Japan, Korea and New Zealand.
OECD Europe	Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Sweden, the Slovak Republic, Slovenia, Switzerland, Turkey and the United Kingdom
Spot and short-term LNG trade	This refers to the trade of LNG under contracts of four (4) years or less.

Abbreviations

ABBREVIATION	EXPLANATION
ACR	American Carbon Registry
Bcm	Billion cubic metres
Bcma	Billion cubic metres per annum
CAR	Climate Action Reserves
CIS	Commonwealth of Independent States
CCS	Carbon, Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CDM	Clean Development Mechanism
CEC	China Electricity Council
CNG	Compressed Natural Gas
CNL	Carbon Neutral LNG
DQT	Downward Quantity Tolerance
ECB	European Central Bank
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
FID	Final Investment Decision
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GHG	Greenhouse Gas
IMO	International Maritime Organization
JTF	Just Transition Fund
KEPCO	Korea Electric Power Corporation

LNG	Liquefied Natural Gas
LT	Long term
Mcm	Million cubic metres
MENA	Middle East and North Africa
METI	Ministry of Trade and Industry in Japan
MRV	Measurement, Reporting and Verification
Mt	Million tonnes
MWh	Megawatt hour
NCS	Norwegian Continental Shelf
NDC	Nationally Determined Contribution
NGV	Natural Gas Vehicle
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PPAC	Petroleum Planning & Analysis Cell (India)
Tcm	Trillion cubic metres
TWh	Terawatt hour
UGS	Underground Storage
USGC	United States Gulf Coast
VCS	Voluntary Carbon Standard

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