GECF

GLOBAL GAS OUTLOOK 2050 SYNOPSIS

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ABOUT THE GECF

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

As of December 2019, the GECF comprises twelve Members and seven Observer Members (hereafter referred to as the GECF Countries). The Member Countries of the Forum are Algeria, Bolivia, Egypt, Equatorial Member Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, the United Arab Emirates and Venezuela (hereafter referred to as Members). Angola, Azerbaijan, Iraq, Kazakhstan, Norway, Oman and Peru have the status of Observer Members (hereafter referred to as Observers).

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

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 peoples, through the exchange of experience, views, information and coordination in gas-related matters.

In accordance with the GECF Long-Term Strategy, adopted during the 18th GECF Ministerial Meeting, the priority objectives of the GECF are as follows:

1. To maximize gas value, namely to pursue opportunities that support the sustainable maximization of the added value of gas for Member Countries.
2. To develop the GECF view on gas market developments through short-, medium- and long-term market analysis and forecasting.
3. To promote cooperation, namely to develop effective ways and means of cooperation amongst GECF Member Countries in various areas of common interest.
4. To promote natural gas, namely to contribute to meeting future world energy needs, to ensure sustainable global development, and to respond to environmental concerns, particularly regarding climate change.
5. To reinforce the international positioning of the GECF as a globally recognized intergovernmental organization, which is a reference institution for gas market expertise and a benchmark for the positions of gas exporting countries.

The GECF Global Gas Outlook and its Synopsis are among the main key initiatives and instruments identified in the GECF's Long-Term Strategy.

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Table of Contents

List of Figures

List of Tables

Foreword

Since its establishment, the Gas Exporting Countries Forum (GECF) has recorded notable milestones and transformed into a credible, fully-fledged international organization and energy coalition that plays a crucial role in the stability of natural gas markets globally. The GECF has become a well-respected authority for insights into the gas markets and a trustworthy platform for the promotion of cooperation and dialogue on key aspects of the gas industry.

The culmination of that is the Forum's flagship publication, Global Gas Outlook 2050 and its Synopsis, based on the Global Gas Model developed by the Forum. The GECF perceives the importance of digital technology and digitalization in achieving a low-carbon energy transition.

For the GECF, the outgoing decade has not only seen the Forum attain its goal of uniting some of the world's top gas exporters towards a common purpose of making natural gas a viable member of the world's energy mix, it has also been a decade of consolidation of its status as a reference point on matters pertaining to natural gas. No discussion about the global energy mix would be complete without considering the shift towards cleaner energy and mitigating the effects of climate change. It is imperative that the natural gas industry shall adapt and address the issue of sustainability in order to maintain and expand its share in the global energy mix.

This has been due to the commitment of the nineteen nations from across four continents that make up the Forum. These countries have, through thick and thin, thrown their support behind the organization and its activities. Recalling the Declarations of the GECF Summits, the Forum works to protect the interests of its Member Countries and to support Sustainable Development Goals, in particular Goal 7, to promote naturalt gas as an environmentally friendly, affordable, reliable, accessible and flexible natural resource for ensuring economic development and social progress. In the era of energy transitions, introduction of discriminatory regulations against cleaner hydrocarbon fuels such as natural gas, disturbs gas markets design, undermines investment in crucial gas infrastructure and new gas supply projects.

The GECF expresses its deep concerns and disagreement with regard to unilateral economic restrictions undertaken without the approval of the UN Security Council and extraterritorial application of national laws and regulations against GECF Member Countries that negatively affect the development and trade of natural gas.

The GECF mission and priority objectives are centred on fostering cooperation and dialogue and we would like to invite all parties involved to continue the positive dialogue to build intergovernmental and inter-disciplinary bridges towards a sustainable future.

At the heart of the GECF Long-Term Strategy, is the idea that information exchange and dialogue are the primary mechanisms behind coordinated gas market development. Coordination and cooperation among GECF Member Countries and fostering dialogue between gas producing and consuming countries are important to ensure unimpeded functioning and stability of the gas markets.

We hope that this multilateral dialogue helps to improve the shared understanding of energy policies to unlock the full potential of natural gas as the fuel of choice during digitalization and the energy transition period.

Yury P. Sentyurin
Secretary General
Gas Exporting Countries Forum

Executive Summary

Population growth and economic prospects

As population growth in the next three decades will be two-thirds of the 2000-2018 rate, and 500 million less workers will join the labour force, labour productivity will need to increase at over 2.5% per year to sustain a GDP growth of 3.2% per year. The expanding urban population is expected to provide all the additional population, and is expected to be a primary energy demand driver.

Global growth will decelerate significantly towards 2050, as the largest developing economies are expected to increase labour-intensive growth and many others will see less additional employment.

For the developed economies, growth prospects are supported by the knowledge-intensive growth model, while for developing economies closing the labour productivity gap will be the main growth driver.

The Outlook sees a medium-term deceleration of global GDP growth slowing down to the range of 3.0-3.2% in 2020-2025, on the back of a trade war and cyclical deceleration of the global economy, while policy space to address the slowdown will be very limited.

For the long-term, this Outlook assumes an evolutionary shift in the institutional setting and structure of the global economy, with relatively strong economic growth centred on the emerging markets, with an average global GDP growth rate of 3.2% through to 2050. The escalating geopolitical situation, specifically the US-China multilateral standoff, remains the main uncertainty in the medium- and longer-term perspectives.

Energy price projections

This Outlook assumes no major changes to the structure of the oil market, with the real price in the long-term tracking marginal costs. In the long-term OPEC keeps the role of the swing producer, and US tight oil supply stays firmly placed in the marginal cost curve. Long-term oil prices will reflect the falling costs of extraction for new tight oil projects, which are expected to decrease to USD 70/bbl.

The structure of the natural gas market over the outlook period will remain largely geographically segmented. As storage capacities grow and gas grids expand, LNG shipments will be increasingly used to eliminate between-region intra-year price arbitrage. So far, a sizeable volume of Europe-Asia LNG diversions requires a price differential of over USD 4-5/mmBtu depending on transport costs.

Asian natural gas prices will rise in the long-term, fuelled by increasing demand, a policy push for better air quality and expanding consumption infrastructure and uses. However, increasing market integration and a growing LNG market will put a cap on price increases.

European natural gas prices will be under strong price pressure in the long-term, as carbon mitigation policies and global gas market integration increases competition between European and Asian consumers.

The long-term outlook for thermal coal prices is to a lesser extent shaped by the supply-demand balance, as capacity is expected to adjust to the accelerating decline in global demand.

The more important price driver is the competitiveness of coal vis-à-vis alternative fuels. Hence, we expect that in the long-term prices will be driven by those factors, and global prices for coal will fall below USD 80/t on average.

The launch of carbon trading schemes in many countries is expected to provide significant support to the competitiveness of natural gas versus coal in the long-term. After 2030, prices are expected to increase gradually under the policy pressure as the larger scope of emissions is tackled by carbon emission mechanisms. We assume by 2050, that the price of CO_2 will reach USD 85/t CO_2 in the ETS and USD 40/t CO_2 in the JTS respectively. The Chinese national carbon price is projected to be a material factor in national emissions policy at above USD 25/t CO_2 but much less restrictive than elsewhere, as industrial competitiveness challenges will hinder the introduction of stricter climate targets.

Energy policy developments and emissions trends

Natural gas continues to receive positive policy support in several countries as an alternative to polluting and carbon-intensive fuels and as flexible option complementing intermittent renewables. However, this policy support is challenged, especially by governments setting more ambitious renewables targets and decisions by several lenders, including the World Bank to discontinue financing gas projects.

Over the long-term, gas will still benefit from such policy support in many countries. Furthermore, the Outlook assumes that supply-side policy measures will contribute to improving the long-term availability and accessibility of natural gas. These measures, which might materialise through advanced gas market reforms and strengthened partnerships and cooperation, help to mitigate the observed technical and financial challenges, and therefore to support developing gas production and infrastructures, including specifically LNG infrastructure.

The Outlook expects that enhanced climate commitments by countries, supplemented by the efforts of sub-national governments and business actors, will drive further reduction of CO_2 emissions compared to the 2018 GGO forecasts. However, it anticipates that the implemented policies will not be sufficient to meet the ambitious Paris Agreement targets while satisfying the energy needs of a growing global population and economy.

Energy and natural gas demand trends

This Outlook expects that energy markets will undergo a significant transformation over the next three decades, as energy accessibility unlocks an additional 28% of demand.

Climbing from 14,538 Mtoe in 2018, global primary energy demand will reach 18,645 Mtoe by 2050 which corresponds to an annual average growth rate of 0.8%. Nevertheless, this indicates a slower pace than the historic average of 2.1% between 2000 and 2018, when total energy consumption expanded by 45%.

Fossil fuels will continue to dominate the global energy mix and will amount to 71% of the total energy used in 2050, against 81% in 2018. Oil will remain an important source of energy, but its share is expected to fall to 26%. Coal's share will drop sharply, providing only 18%. Natural gas will be the only hydrocarbon resource to increase its share, from 23% today to 27% in 2050.

Natural gas, the fastest growing fossil fuel, is projected to rise by 1.3% per annum from 3,924 bcm in 2018 to 5,966 bcm by 2050 driven by environmental concerns, air quality issues, coal-to-gas switching as well as economic and population growth.

From a sectoral perspective, the power generation and industrial sectors will be the biggest contributors to global natural gas demand growth, accounting for about 66% of additional volumes between 2018 and 2050. Transport will emerge as a significant new area, responsible for almost 16% of the demand growth over the projection period. Nevertheless three sectors –the power generation, industrial and domestic– will continue to be the main consumers, constituting 40%, 17% and 15% respectively of total natural gas demand in 2050.

The rise of gas demand in land and marine transport is projected to be particularly robust, surging by 5.4% per annum. Increasingly stringent air pollution restrictions will lead to switching from heavy fuel oil in the maritime industry. The use of LNG in heavy trucks and CNG in cars will have even more potential for growth, partially through policy initiatives aimed at offsetting transportation emissions.

Natural gas supply

Gas production will rise by 1.3% per year to 2050, with North America accounting for the largest share of this growth, followed by Eurasia, Africa and the Middle East. Total gas supply is estimated to reach almost 6 tcm per year by the end of the period.

Over the mid-term global gas production will increase by 400 bcm to slightly more than 4,330 bcm by 2025, an average annual growth rate of 1.4% that is marginally above the average annual growth rate for the period till 2050. North America is set to be the largest contributor to the escalation of medium-term natural gas production with a share of almost 50%, followed by Eurasia.

Global gas production will become more diversified, with 13 countries producing more than 100 bcm per year by 2050, compared to 9 countries at present. Recent discoveries of large gas fields in Africa mean that the region has huge production growth potential, with overall output from the continent expected to rise from below 250 bcm to over

600 bcm by 2050, accounting for 20% of the global gas production increase during the period.

Production from unconventional resources will become increasingly important, and their share of overall output is expected to rise from 25% to 38% by 2050. In addition, Yet-to-Find production will be vital, highlighting the need for increased exploration for new gas reserves.

Total gas production from the current combination of GECF Member Countries will rise by 47%, reaching approximately 2,530 bcm by 2050. This translates to a 1.2% average annual growth rate over the period between 2018 and 2050. The GECF share in global gas production will fall slightly till 2025 due to the increase in non-GECF production, including from the US and Australia. Maintaining the production capacity in GECF Member Countries in the longer-term will enable the GECF to keep its share in global gas production at more than 42% by 2050.

Gas trade and investment

In 2018, out of 3,924 bcm of natural gas consumed to satisfy global demand, 1,160 bcm was imported (including 685 bcm from GECF Member Countries). Total imports, comprising 29.5% of total natural gas consumption, are projected to fluctuate slightly around this level from 2018-2050. The global gas trade is expected to have grown by 84.6% by 2050, at 1.9% per year, reaching 2,141 bcm in 2050, and sourcing 35.9% of global gas demand.

LNG infrastructure will see a much faster build-up than pipelines, as it requires far fewer intergovernmental negotiations and is much less affected by geopolitical tensions. With over 120 mtpa of liquefaction capacity under construction, and another 260 mtpa planned, the share of LNG exports will rise from the current 37.2% to 45.2% of total exports by 2030, and to 50.3% by 2050.

Global regas capacity is estimated at 850 mtpa (1,170 bcm) in 2018, as compared to 380 mtpa of liquefaction capacity. By 2050, regas capacity is projected to grow to 1,270 mtpa (1,750 bcm). The highest transport capacity additions in LNG are expected to come from the US, Australia, Qatar, Russia and Mozambique.

The biggest regas capacity additions to 2050 are expected in the Asia-Pacific region, while the biggest liquefaction capacity additions are expected in North America, Africa, Eurasia and Asia-Pacific.

It is projected that USD 9.7 trillion earmarked for gas investment is required in the natural gas exploration and production sectors. Trade infrastructure still requires over USD 400 bn of capital in 2018 prices by 2050. The gas industry investment outlook is thus shaped both by trade infrastructure and upstream investment needs.

The upstream is expected to increase its share from the historical 84% to nearly 96% and is already the main driver for gas industry investment, as production shifts to capital-intensive unconventional sources both in and outside the GECF.

The rise of unconventionals in the upstream is a global driver for investment. It will lead to the increase in capital costs, the most pronounced in Africa, Asia, and Eurasia (after 2035). In North America, unconventionals will remain the only new source of gas. Most of the US unconventional sources are yet-to-find and will come at an increased capital cost as compared to the shale boom resources.

Alternative scenarios

This Outlook defined two accelerated energy transition scenarios: The Carbon Mitigation Scenario (CMS) and The Technology Advancement Scenario (TAS). The combined effect of mitigation policy and technology drivers under these scenarios is captured in the Energy Transition Scenario (ETS), which results from applying the CMS assumptions to the Reference Case (RCS) and the TAS assumptions to the CMS.

The CMS focuses on two major shifts resulting from the implementation of strengthened carbon mitigation policies: an accelerated penetration of renewables and gas in power generation, and more aggressive development of EVs and NGVs in the road transport sector. The TAS, however, examines the effect of technology-related efficiency improvements, larger development of batteries and CCS, and has a special focus on the hydrogen-related technologies.

In the CMS, natural gas demand is expected to rise marginally compared to the RCS, due to larger penetration of intermittent renewables that reduces the average utilisation rates of the gas-fired power plants and then puts pressure on gas demand in power generation. The incremental gas demand in the CMS compared to the RCS is mainly driven by the penetration of NGVs that compensates the downside effect of gas in the power sector. In the ETS, gas demand increases significantly compared to the CMS due particularly to larger deployment of blue hydrogen in various sectors.

The share of natural gas in total primary consumption reaches 28.7% and 29.2% respectively in the CMS and ETS by 2050.

Overall energy related CO_2 emissions, which are anticipated to reach 36.0 $GtCO_2$ by 2050 in the RCS, are projected to be 31.3 $GtCO_2$ in the CMS and 26.6 $GtCO_2$ in the ETS.

Introduction and Scope

The GECF Global Gas Outlook 2050 Synopsis reflects the impartial views of the GECF Secretariat and is prepared in accordance with the resolutions adopted in the 19th GECF Ministerial Meeting in Moscow, the Russian Federation. It aims to support the long-term priority objectives of the GECF Long-Term Strategy.

The present document is based on proprietary assessments of the evolution of energy and gas market fundamentals through to 2050. This Outlook was developed within the framework of the Technical and Economic Council (TEC) created within the Forum, to guide and monitor extensive research on global gas markets.

The GECF Global Gas Outlook is unique, as it is the only energy outlook worldwide to focus solely on natural gas. It aims to be a global reference for insights into gas markets. The document also represents an impartial view on gas market evolution by highlighting the most likely developments in the medium- and long-term.

The GECF Secretariat believes that it is impossible to cover all future uncertainties with a single scenario; multiple scenarios are needed in order to have a broader mapping of the uncertainties shaping the development of gas markets. In this regard, the Secretariat addresses future uncertainties and their possible impact with alternative scenarios through its annual publication of the GECF Global Gas Outlook and its Synopsis.

This document is divided into six main chapters. Chapters I and II introduce key global gas demand assumptions, including economic, energy price and policy assumptions, as well as environmental policy development. Chapter III highlights energy and gas demand trends, followed by supply assumptions in Chapter IV, which include global gas resources, upstream and unconventional production. Chapter V is dedicated to global gas trade and investment outcomes resulting from the equilibrium between supply and demand. It takes into consideration gas market constraints, in terms of supply infrastructure, international supply contracts and gas supply policies (e.g. the satisfaction of domestic gas demand as a priority for some countries). The final chapter features two alternative scenarios devised by the GECF Secretariat: the Carbon Mitigation Scenario and the Technology Advancement Scenario.

The results are quantified through the use of the GECF Global Gas Model (GGM), which is a unique energy model developed in-house at the GECF Secretariat, and which includes different sub-models with each one focused on one segment of the gas value chain (production, pipelines, LNG, shipping, regasification, contracts and demand).

The GGM is characterized by its uniquely high granularity, encompassing:

- 134 Country level forecasts (113 detailed break downs, 21 simplified) with over 60 regional aggregates and a global projection
- Complete energy balance estimates, covering 33 sectors and 35 fuels annually, from 1990 to 2050

- about 4545 gas supply entities representing gas supply potential at the global scale, divided into:
    - 632 existing and operational production facilities (including aggregates)
    - 1854 new projects based on existing reserves
    - 1696 yet-to-find (YTF) entities
    - 363 unconventional resources (existing and YTF), generating the most comprehensive database available of global shale, tight gas and coalbed methane

The infrastructure database contains:
- 586 liquefaction plants
- 775 regasification plants
- more than 5000 gas pipeline and shipping routes

The gas contracts database contains:
- Annual contracted and delivered volumes, including more than 700 contracts (country-to-country and non-dedicated), based on more than 1000 company-to-company contracts

Another important characteristic of the GECF model is that it endogenously calculates gas demand curves and gas production profiles country by country based on corresponding assumptions and inputs. All of the sub-models have been calibrated and based on 2018 as the last available year of historical data, and 2050 is considered to be a part of the GECF forecast, unless otherwise stated.

Energy and natural gas demand forecasts are derived based on a set of primary and secondary assumptions fed with macro and energy price data, utilizing econometric modelling techniques using time-series back to 1990. Policy measures are taken into consideration at each stage of this process.

In terms of data sources and historical data, we mainly reference the United Nations (UN) for demographic data, the International Monetary Fund (IMF) for economic data, and the International Energy Agency (IEA) for energy and gas demand data. These are cross-checked with other international and regional statistical sources, especially for the GECF Countries. For data on gas supply we use an in-house database updated by the GECF Countries and secondary sources, which also plays an important role in the GECF GGM calculations.

The core engine of the GECF GGM is the Global Gas Trade Model, which matches gas supply with gas demand for all the countries under consideration. The global gas trade projections in the GECF modelling exercise are derived from three fundamental inputs. The first input is the gas demand curve for each country/region.

Econometric time-series and stock models are based on Eviews 10 software that links

with other modelling outputs and a global gas trade model to produce a comprehensive global energy outlook.
The second key input is the available/potential domestic gas supply in each country/region that will define either the call for imports in any specific region or its export capacity, depending on whether the country is an importer or an exporter.

The third, most technical, input is the configuration of the trade network, either in terms of pipelines or shipping routes. Virtually all potential shipping routes are considered, while for the pipeline routes we consider only the main trans-border pipelines between the different trading regions and hubs. Our modelled gas pipeline network is a simplification of the actual physical network, which cannot be reproduced with the same level of detail and granularity as the shipping routes.

These three elements together -demand, supply and infrastructure- shape the projections for global gas trade. The consistency of the trade is always ensured in terms of total traded volumes between each source of supply and the corresponding source of demand.

01

Global Economic and Energy Price Prospects

Key findings:

- As global population growth in the next 30 years will be two-thirds of the 2000-2018 rate, and 500 million fewer workers will join the labour force, labour productivity will need to increase at over 2.5% rate to sustain a GDP growth rate of 3.2%.

- The expanding urban population is expected to account for all additional population growth, and is expected to be a primary energy demand driver.

- For the developed economies, growth prospects are supported by the knowledge-intensive growth model while for developing economies closing the labour productivity gap would be the main growth driver.

- Risks to the economic forecast are tilted to the downside. Growing tensions between the US and China go beyond trade and are the main risk for the global forecast, as there are signs that the global financial system could be fractured by the geopolitical standoff.

- The global car parc is forecast to grow by 716 million vehicles, including 545 million in developing Asia, and 440 million EVs by 2050. With growth constrained by pro-EV policies, NGVs will expand from 0.7% to 2.2% of the car parc.

- Long-term oil prices will reflect the falling cost of extraction for new tight oil projects, which are expected to decrease to USD 70/bbl.

- After the recent declines in natural gas prices as a consequence of the supply glut, the market is expected to rebalance in the mid-2020s, leading longer term to generally rising prices globally. Henry Hub prices reach some USD 4/mmBtu by 2030 and almost USD 6/mmBtu by 2050.

- Carbon pricing schemes in various regions and countries are expected to develop, which would provide significant support to the competitiveness of natural gas versus coal in the long- term. In the EU the ETS price is expected to reach USD 40/tCO_2 in the early 2030s and over USD 80/tCO_2 by 2050. Prices in other regions, however, would be significantly lower.

1.1 Medium-term economic outlook: is recession around the corner?

The global economy started to slow down in 2019, reflecting the impact of cyclical drivers as well as an increase in global trade barriers. The countercyclical policy response so far has been limited, and growth uncertainties in major economies remain tilted to the downside.

The ongoing momentum in the global trade is vulnerable to US–China tension, and the impact of recent tariff hikes dents global value chains. According to WTO, global trade turnover will increase by just 1.2% in 2019, which is the slowest since 2009, and 2.7% in 2020. IMF projects that trade growth to 2025 will remain sluggish, and GDP growth in 2019 will decelerate to the slowest rate in a decade, in line with the growth in the economies representing about 90% of global GDP.

This trade deceleration is broad-based both geographically and in terms of the markets but is likely centred on Asian import weakness largely caused by trade war expectations. Some recent US official statements also indicate investment banks might accompany tariff hikes. While it is too early to assess if the trade tensions will do any long-term damage to global economic prospects, there is certainly a solid medium-term impact. In 2020-2025, trade tensions and policy decisions will lead to cyclical deceleration of the global economy to annual 3.0-3.2%, and financial shocks accompanying growth deceleration are highly likely.

While the trade war is just one aspect of the unfolding broad-based standoff, it is the most important one for medium-term economic growth.

Given these drivers, deceleration in the global economy in the medium-term is imminent, and the uncertainty only pertains to the scope of the slowdown. The trend for long-term deceleration of China growth will persist, making India the fastest-growing large emerging economy of the next decade. We expect the medium-term deceleration of global GDP growth to the range of 3.0-3.2% in 2020-2025, on the back of the trade war and cyclical deceleration of the global economy, while policy space to address the slowdown will be very limited.

The monetary policy response is limited by zero interest rate bounds and accumulated government debt burdens, and not much fiscal space available

There is already a growing concern among policymakers about which way is the best to address cyclical slowdowns in the aftermath of the quantitative easing policy, as the global economy has grown accustomed to the low-rate environment.

This places the responsibility to react to macroeconomic shocks squarely on the shoulders of central banks. However, is there ample monetary policy space? In the economies producing more than 40% global GDP, the real rate is already below 0.5%, and for the economies producing more than 25% of global GDP (including euro area economies, Japan and the UK) the real rate remains negative.

So far as possible, central bankers are already managing the risks. ECB went further into negative rate territory and relaunched an asset purchase program of 20 bn EUR per month from November 2019. Japan is continuing with its QE program, and the Fed is reducing rates again. Many emerging countries' central banks follow suit, including China, which has already unleashed monetary stimulus earlier this year. However, these actions aim mainly to mitigate systemic bank risks and deal with the increased global uncertainty in financial markets rather than to prevent an economic slowdown. Without sound fiscal policy support, monetary easing on this scale is unlikely to prop up growth.

1.2 Long-term global economic and social projections

This sub-chapter is divided into sections describing the long-term projections for the following energy demand drivers: population, urbanization, economic development, car parc, housing stock, and reference energy prices to 2050.

1.2.1 Population growth and urbanisation

Population growth is the main driver of future energy trends. This Outlook is based on the projections outlined in the 2019 Revision of UN World Population Prospects, medium fertility scenario, which sees the global population rising from 7.6 billion in 2018 to 9.8 billion by 2050.

Out of 2.2 billion increase, Sub-Saharan Africa is expected to provide 1.2 billion, while Asia Pacific would add 0.6 billion, and India alone over 300 million. It is important to note that population in the areas with well-developed energy infrastructure would be almost unchanged by 2050: while the North American population grows by 100 million, and the population of China is expected to decrease by 50 million, Japan by 18 million, and the EU by 7 million. The Eurasian population is expected to remain stable. Thus, all the population increase would be in regions that need energy access the most, those regions with underdeveloped infrastructure. As there are no energy mix preferences defined by existing energy infrastructure, promotion of natural gas networks for those regions could tap a significant market potential.

The GECF comprises ten Members from the Middle East and Africa, and the combined population of GECF countries is expected to grow strongly at a rate of 1.4% per year, increasing its population by over 400 million by 2050.

Urbanization prospects used by this Outlook are based on the 2018 Revision of UN World Urbanization Prospects. Global urbanization is increasing, as measured by the share of the urban population, from 55% in 2018 to 69% by 2050, and almost all the 2.2 billion population increase is expected to add to the urban population, with rural populations globally staying flat. The rapid pace of urbanization is expected to transform rural societies in Sub-Saharan Africa (40% urban population in 2018) and developing Asia (with China still at 59% and India at just 34% urban population in 2018).

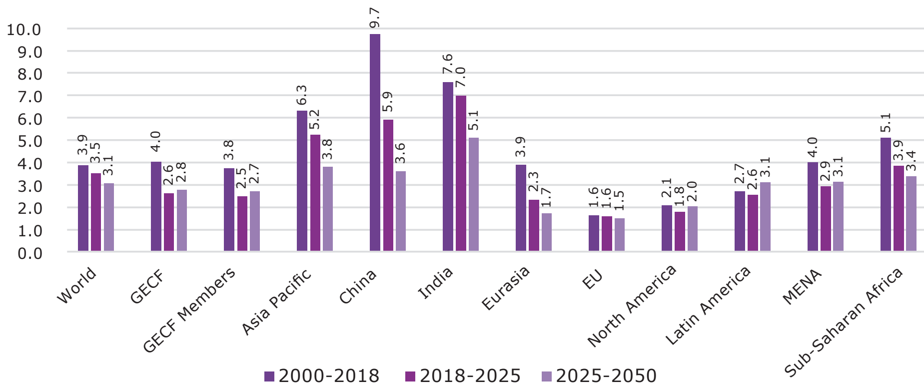
1.2.2 Long-term macroeconomic projections

Growth of the global economy is expected to average 3.2% p.a. in GDP in purchasing power parity terms for 2018-2050. This growth will be largely concentrated in Asia despite long term deceleration, with China growing by 4.1% p.a. on average and India at an average of 4.9% p.a. over the Outlook horizon.

With developed economies on a stable growth path of 1.7% p.a., and developing economies poised to grow by 4.0% p.a., long-term global economic growth is expected to be stable, with certain economic cycle dynamics in the medium-term growth path.

The GECF economies are expected to grow strongly in the long-term based on strong labour force and employment growth, provided that enough investment is devoted to human capital. Average annual growth of GECF GDP combined at PPP is expected to be at 2.7% for 2018-2050, as compared to 2.4% in 1990-2018 and 3.9% in 2000-2018.

Figure 1.1. Projected GDP growth rates, (%)



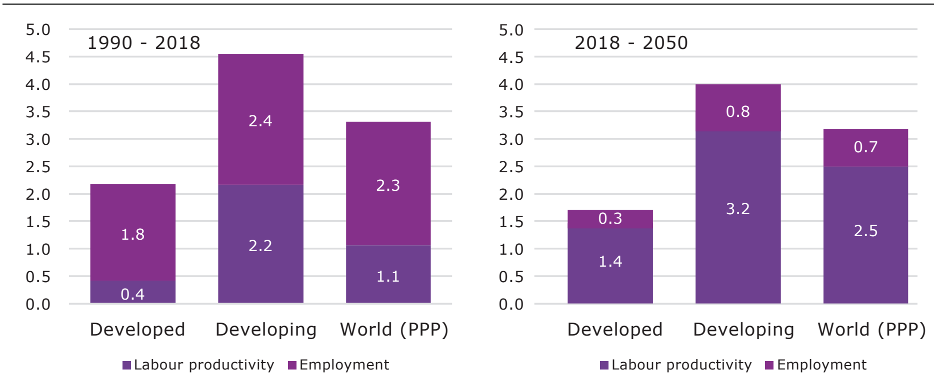
Source: GECF Secretariat based on data from the GECF GGM

Labour force, labour inputs and labour productivity outlook

Over the next 32 years, population growth will only reach two-thirds of the rate seen in 2001-2018. The corresponding employment growth will be half as much: only 780 million employees are expected to join the global workforce by 2050 against the global inflow of one billion employees in 1990-2018, mostly in the regions with low productivity.

The projected decrease in labour input is considered to be detrimental for growth. To some extent this is remedied by the extensive use of the labour force well above the present pension age in most European labour markets, with the situation being particularly pronounced for Spain, Portugal and Italy. For developing economies, the labour force is significantly (up to 50%) extended by the strongly growing inclusion of

Figure 1.2. Labour force and labour productivity contributions to GDP growth (p.p.)



Source: GECF Secretariat based on data from the GECF GGM

women and minorities. However, even these labour market changes pose a tremendous challenge for labour productivity to keep up the growth.
Labour productivity will have to increase by 2.5% per year to compensate for this deceleration, amounting to a 117% increase over 2018-2050 (triple the 34% growth achieved in 1990-2018). Such a growth in productivity has never been observed before. For developed countries, the transition to productivity-based growth is sizeable, with 1.4 percentage points of 1.7% of expected growth. However, most global growth is expected to come from the developing economies. Out of 3.2% of expected GDP growth over 2018-2050, over three quarters come in the developing economies. And out of 4.0% of expected growth in developing economies, 3.2 percentage points are expected to be from productivity improvements as the employment contribution decelerates to just 0.8 percentage points of growth.

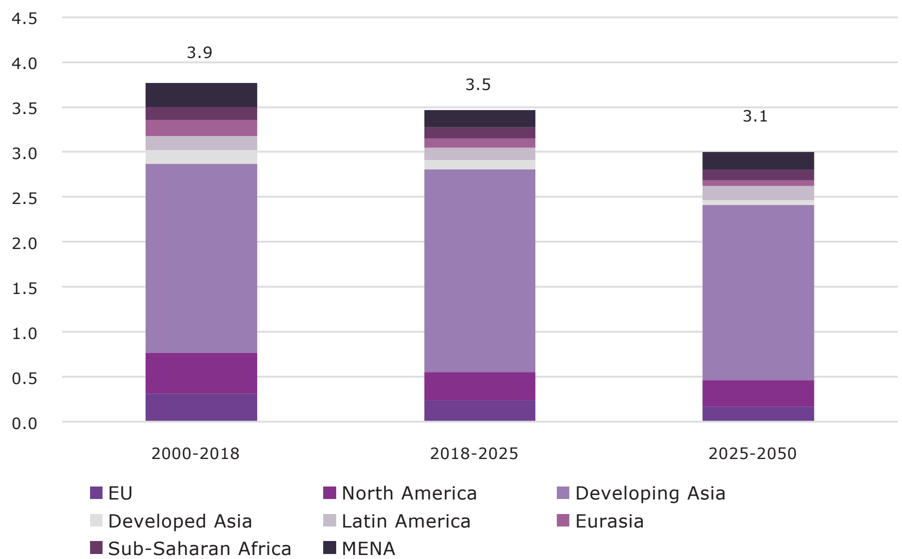
The regional productivity growth structure is also expected to shift, with developing and emerging economies gaining a significant boost in Asia, Latin America, Middle East and Africa.

The structure of global economic growth

The global economy is expected to deliver relatively strong economic growth in the long-term, anchored by strong labour productivity growth. The global GDP at PPP rates, according to the Reference case assumptions, will grow at 3.2% p.a. over the forecast period, assuming no major financial market bubbles. This growth rate will largely be provided by the expanding developing economies, especially in Asia, with a growing role of an expanding middle class.

Consequently, there will be a much larger contribution to global economic growth from developing economies (see) as their share grows and the productivity gap closes.

Figure 1.3. Projected GDP growth composition to 2050 (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

In Asia, developing economies will add over 2.0 p.p. to global growth over 2018-2050, while the MENA region will contribute 0.3 p.p. as a whole, and Sub-Saharan Africa will contribute around 0.1 p.p. The contribution of all the developed economies will be less than 1.0 p.p. over the same period.

For GGO projections, while the overall effect related to sea level rise and extreme weather effect is significant for some small economies, even for those it is contained to 5% of GDP by 2050 (0.15% p.a.), while for the largest economies the effect is well within 1% by 2050, meaning less than 0.05% growth p.a.

However, we understand that the climate change effects will not be distributed evenly within the economy, and less technologically advanced and less developed economies with more inequality and more poverty will be prone to more severe impact. This implies that climate change would have a much stronger social and political impact as compared to the macroeconomic effect. This could generate non-linear effects such as those outlined in Burke et al. (2015), which could measure much larger effects. However, as with most non-linear models, the greatest compounding effect would take place after 2050.

With all the methodological issues set aside, it is clear that global warming implies very significant damage to the economy by 2100, estimated at well over 10-15% of GDP levels (Burke et al. 2018).

1.3 Vehicle markets outlook

The road transport sector accounted for a little under 1.5% of global natural gas consumption in 2018 and this is projected to increase to just 4.4% by 2050. Nonetheless, road transport is a sector with considerable energy demand growth potential, as it accounts for 14.8% of global energy consumption, a share that is expected to increase to 17.6% by 2050.

The structure of the car parc will be profoundly changed over the Outlook period, as a policy push and technological advancement shapes the car market towards new powertrains and new forms of mobility. We expect electric vehicles to make good progress, while CNG and LNG would be less successful because of EV policy bias and relatively high gas prices.

During 2017-2019, 10 countries announced a definite ban on new sales of various forms of traditional powertrains between 2025 and 2040. Similar measures were also introduced for 10 large cities where no national sales ban is considered (including the US). India and China are still considering introducing an ICE ban, with various official announcements indicating they favour transition to electric vehicles in new sales between 2030 and 2040. Those policy decisions could have the most global impact on the car fleet structure.

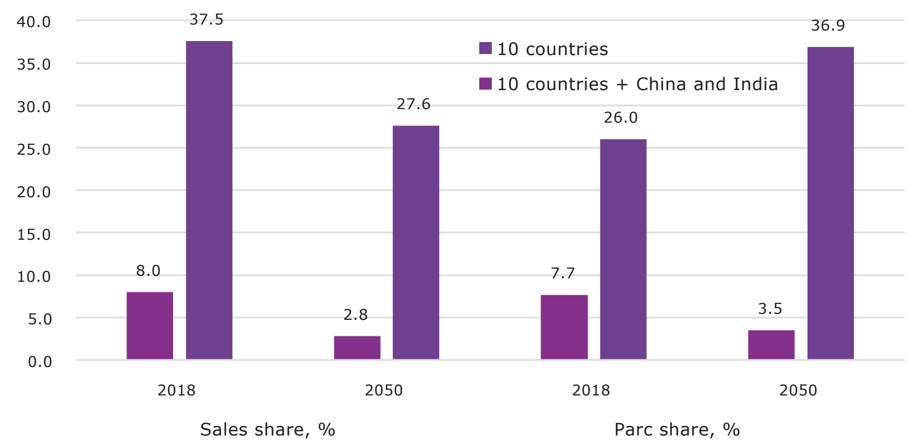
There is a differing rationale between developed countries like France or the UK and developing countries like India or China in introducing the vehicle bans. There are therefore different ways in which natural gas could benefit during the transformation of the mobility industry.

For developed countries the primary reason for EV policy push is the emissions that ICE vehicles produce, and the difference between a carbon footprint for a petrol car and electric car powered by largely low-emission energy systems in developed countries could be significant. While natural gas vehicle (NGVs) substitution for petrol cars is expected to reduce emissions significantly in the heavy goods vehicle sector, there is a smaller emissions benefit (estimated at around 10%, see OIES (2019)) for petrol to natural gas switching in the passenger car sector.

The increase in EV fleets benefits natural gas through a growing demand from the power sector. As the global EV car fleets adds 440 million vehicles by 2050 road transportation is expected to require an extra 1700 TWh or 4.1% of final electricity consumption per year. On average, power generation will still be about 25% gas-powered (about 36% in developed, and 20% in developing countries).

In contrast to climate-driven car policies in developed countries, developing countries have a dual priority of air quality and climate concerns in their car policy objectives. There are valid reasons to make air quality a priority, as confirmed by the WHO annual report: while 91% of the world population lives in areas where air pollution exceeds WHO guideline limits, the share is almost 100% for the population in developing countries.

Figure 1.4. Share of car sales and car parc of countries that announced petrol car sales bans as compared to share of China and India markets (%)



Source: GECF Secretariat based on data from the GECF GGM

The other reason for dual priority for developing countries is that using EVs is unlikely to reduce emissions, as energy systems in those countries are largely coal-powered. To make EV penetration work towards climate goals, a policy push in EVs in developing countries should be synchronized with a switch to a low-emission energy system. It is widely argued (see Copenhagen Institute (2019)) that the pile-up of energy costs in this case will jeopardize affordability of EV use on a mass-scale.

These features of developing countries' car markets present an opportunity for NGVs to make the case both for improved air quality and emissions reduction in road transportation.

On one hand, the case for air quality is very clear. CNG emits 95% less PM-2.5, and 70% fewer nitrate oxides compared to the strict Euro V vehicle fuel standards. This means ten times fewer polluting emissions as compared to the vehicle fuel standards (Euro IV or less strict) used in most developing countries.

On the other hand, for coal-powered energy systems, a 1% switch from oil to EVs is estimated to produce twice as many CO_2 emissions as switching into NGVs, as technological advances are expected to properly address pump-to-wheels methane leak control. Thus, for most developing countries that rely on coal, a switch to NGVs would reduce the emission pathway as compared to a switch to the EVs.

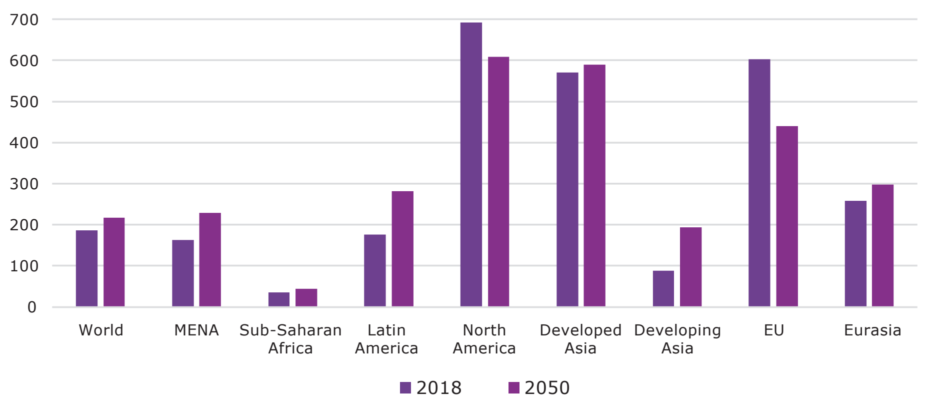
Because NGVs are more affordable than EVs and presently ready for mass-scale penetration as well, developing countries would largely benefit from expanding the NGV car parc instead of singlehandedly prioritizing EVs.

1.3.1 Car parc outlook

The global passenger car and light commercial vehicle (LCV) fleets are projected to grow by 711 million by 2050, at an annual rate of 1.2%. 547 million vehicles will be added in Asia, and 82 million in Latin America. We assume most additional mobility demand in developed countries will be increasingly satisfied via ride-sharing, ride-hailing and other forms of mobility than car ownership. After 2030 penetration of autonomous cars will further decrease developed country motorization levels.

In contrast, developing Asia motorization levels will more than double by 2050, from less than 0.09 cars per capita in 2018 to almost 0.2 cars per capita. This will still compare to more than 0.5 cars per capita in developed countries by 2050, despite the decrease from 0.6 cars per capita in 2018.

Figure 1.5. Cars per ‘000 population



Source: GECF Secretariat based on data from the GECF GGM

1.3.2 Parc structure outlook

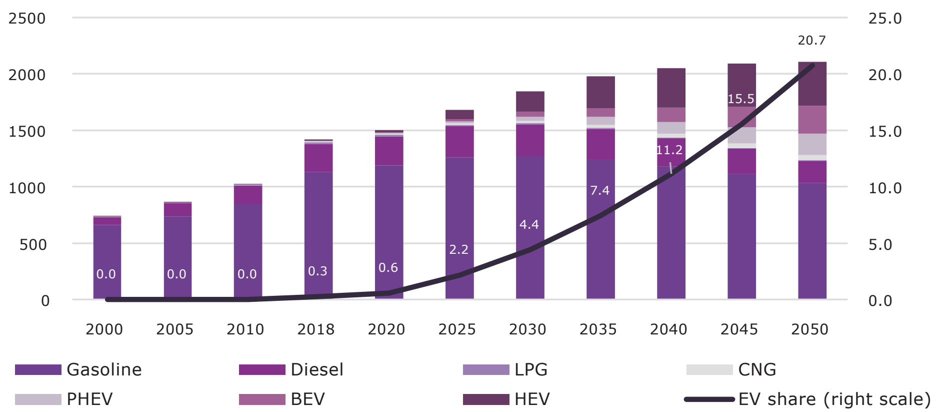
The passenger car and light commercial vehicle (LCV) parc structure outlook, as already mentioned, will be shaped both by policy decisions and technological advancement of the industry.

Under pressure from the expected sales bans and increasing competitiveness of EVs supported by a strong policy push, the share of gasoline and diesel vehicles is expected to decrease from 96.3% in 2018 to 56.9% of car sales by 2050. If gasoline and diesel hybrids are included in the sales figure, the share goes up to 65.8%, which still remains a significant drop.

While the speed and extent of penetration of new powertrain technologies is impressive, the power systems themselves might be a barrier to electrification. As the carbon footprint becomes a concern on a par with air quality in the developing countries towards 2050, the switch to EVs in high-emission power systems in those countries will not be an optimal solution to climate challenges. For this reason, we changed our projection from last year's Outlook towards a less optimistic view of the penetration of electric vehicles in developing countries. One of the major reductions to the projections is for China. While the national objective of reaching 5 million EVs by 2020 is feasible, the reaction of consumers to the gradual reduction of subsidies from 2017 and their elimination by 2021 was stronger than anticipated, and the reduced affordability of EVs is expected to significantly hamper their penetration.

Universal hybridization of ICE powertrains is another trend shaping parc structure that is important but often overlooked in forecasts. Hybrids are now supplied by most car manufacturers and as battery densities increase, the costs go down. Several important features make hybrids an essential component of the parc structure by 2050.

Figure 1.6. Global car fleet structure (million)



Source: GECF Secretariat based on data from the GECF GGM

First, hybrid powertrains are a tested technology for mass-scale production, constituting 0.9% of the total parc, more than ten times the combined share of EVs. Second, hybrid efficiency allows for a significant fuel saving and corresponding reduction in emissions. As battery technology advances, the savings might reach 50%. Third, there is the advantage that hybrids are independent of electric charging.

Moreover the competitiveness of hybrids vs ICE is unrelated to the readiness of the charging infrastructure; and the growth in the hybrid powertrain parc reduces emissions regardless of the carbon footprint of the power system. This means that hybrids are especially competitive in markets with underdeveloped infrastructure and a high-emission power mix.

The hybrid powertrain parc is projected to increase by almost 380 million by 2050, encompassing 18.4% of the total passenger and LCV car parc. This means hybridization substitutes about a half of gasoline and diesel vehicles phased out by 2050. We project only a modest car parc of hydrogen vehicles, 2.8 million by 2050, less than the present EV parc.

So far, most initiatives towards the development of hydrogen cars are a far cry from entering even long-term energy and car policy targets, with hydrogen mobility unlikely to be a commercial option by 2050.

Based on the assumed sales structure trends, the parc share of gasoline and diesel cars will fall from 97.2% in 2018 to 58.1% by 2050, excluding hybrids. NGVs will account for just 2.2% of the passenger and LCV parc (mostly CNG vehicles) by 2050, compared to 20.9% for EVs and 18.4% for hybrids.

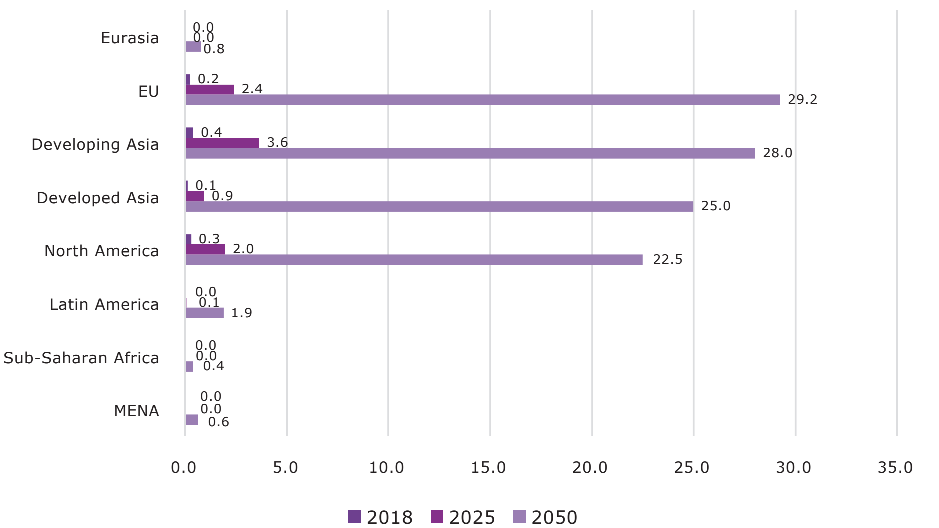
1.3.3 Electric vehicle prospects

There will be a projected 440 million electric passenger cars and LCVs globally, out of a total parc of 2.1 billion by 2050, compared to 3.6 million in 2018, an annual growth rate of 61.9% for 2018 to 2050. EVs are expected to have 36.1% of the global passenger fleet by 2050 and LCVs 20.9%. This is in line with projections from other energy forecasters.

In 2018 through 2019 more countries have introduced policies to promote electric mobility, and measures have remained quite aggressive. They include reducing non-electric mobility, non-electric car sales (via registration lotteries) or providing tariff and duty exemptions for electric cars owners. However, EV sales have slumped dramatically in countries that reduced subsidies, raising the question whether the policy will encourage EV switching in the future.

Beyond passenger and LCV parc, EV switching is strongly supported for public

Figure 1.7 . EV fleet shares by region (%)



Source: GECF Secretariat based on data from the GECF GGM

transportation in developing countries. In China, for instance, city-level programs for switching to EVs in public transport have been particularly successful, with the largest cities planning to use only electric and natural gas public transport by 2025. There are also programs for switching to EV taxis.

Over 2018-2019 the largest car manufacturers have announced that electric mobility will be a priority for R&D and will become a primary powertrain for models produced from 2025 alongside ICE options. Also, most car manufacturers have announced a release of new technological platforms (one or two are generally used for a whole range of a single manufacturer's models) specifically designed to run on electricity by 2022.

New electric vehicles are expected to expand strongly in the developing Asia region, with EVs taking 28.3% of the market. Due to the market size, though, developed countries will remain the primary market for EVs, with North America and Europe expected to achieve the EV transition by 2040 for a range of regulatory and economic reasons including emission standards, fuel excise duties, and household wealth. It is worth noting that outside Asia and the developed world, there is little or no optimism about long-term EV prospects at the moment, indicating that the strong policy needs of the industry are in contrast with the lifecycle cost competitiveness that drives consumer choice for ICE cars at present.

The developing Asian countries are actively engaged in subsidizing electrification, with that not being the only (or the most affordable) mobility option to provide for cleaner air in the cities, with climate rhetoric not directly applicable to the largely coal-powered EVs. While the EV push thus might seem puzzling at first, it is important to understand that global electric vehicle penetration is a superposition of three factors from different areas, with climate being at best the secondary factor.

1.4 Energy and carbon price projections

We expect that higher energy prices in the long-term, ceteris paribus, will encourage a decrease in energy intensity (in terms of energy use per unit of GDP) as well as stronger energy efficiency investment. So, as the market signal goes, the risks of demand slowdown at the moment outweigh supply disruption risks.

The size of the cushions provided by tight oil and gas is sufficient to offset most medium-term demand shocks. Concerning oil, flexible unconventional (mostly tight oil) production makes up 5-6% of global supply now, as compared to virtually zero in 2008. For natural gas, the relationship is even more complicated. Firstly, the share of unconventional gas is 15% today vs less than 2% in 2008, and secondly, natural gas markets are more influenced by inter-fuel competition than oil. Thus, despite stronger seasonal price swings in the gas market, over time as the timely volume adjustment to oil and gas demand shocks becomes more feasible, we are less likely to see fast and dramatic changes in prices.

1.4.1 Crude oil

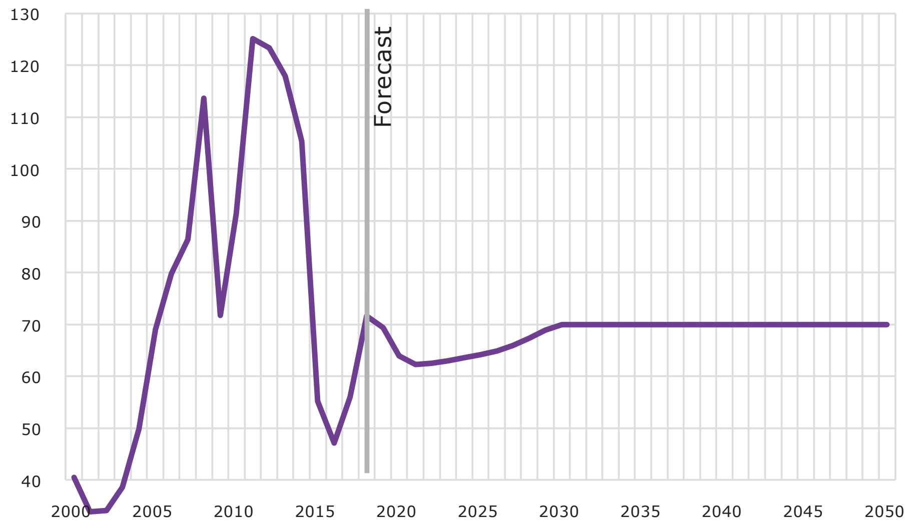
Market developments in 2018-2019

Throughout 2018-2019, the oil market remained stable, with volatility levels among the lowest for the decade. The coordinated OPEC+ (Organization of the Petroleum Exporting Countries and other members of non-OPEC cooperation) policy on one side and the stabilization of shale oil development in the US on the other side largely contributed to the oil market stability. While 2019 started with wide expectations of a build-up of US shale production and a corresponding price correction, the opposite happened. The breakeven price for shale projects was decreasing, but economic drivers resulted in a stable demand growth from developing countries until the second half of 2019, as well as a lack of abrupt price swings caused by breakdowns in expectations and demand-supply mismatches.

Medium-term drivers and outlook

In the medium-term, market stability will be preserved as the 2017-2019 cycle of stronger upstream investment in the oil industry will come to a halt due to three factors. First, demand worries intensify. Trade war with the US has already stymied growth in Asian oil demand, and it is set to slow down over the medium-term. With the economic growth slowdown spreading to the developing economies, developing country oil demand is set to decelerate to a decade minimum of around 2.2-2.3%. A period of sluggish growth in Latin American oil demand will probably continue as demand from both Argentina and Venezuela are unlikely to prop up growth.

Figure 1.8. Brent oil price (2018 USD per barrel)



Source: GECF Secretariat based on data from the GECF GGM

Second, the US shale oil industry is being restructured as it grows, and international oil majors have entered the playing field. Coupled with cost inflation that is in sight, this trend will lead to increased discipline in shale oil investment practices, as well as to prioritization of efficiency and infrastructure de-bottlenecking over the expansion-at-any-cost mood that dominated the early years of the industry. This change is expected to put a cap on fast-paced supply increases and investment in the US.

And last but not least, with US shale supply shifting into steady growth gear, the OPEC+ alliance has reclaimed the status of the swing producer, which has already contributed to market stability over the last three years. After several supply disruptions over 2018-2019 it is obvious that spare capacity behind OPEC+ is enough to guarantee oil market stability in the medium-term.

As the halt in investment drives out the oversupply, the oil price is expected to recover to USD 65/bbl in real terms by 2025, with the marginal cost increase period due to the new investment cycle stretching to 2030 as long-term drivers kick in.

Long-term drivers and outlook

We keep the long-term marginal cost approach for the benchmark oil price assumption. While we assume no major changes to the structure of the oil market, with the real price in the long-term tracking marginal costs. This means no medium-term supply-demand disagreements, as the oil supply adjusts in time to the changing demand trends.

Structurally, in the long-term OPEC keeps the role of the swing producer, and US tight oil supply stays firmly placed in the marginal cost curve as technological development (both in lateral drilling and hydraulic fracturing) offsets the decreasing quality of the wells drilled from the current USD 8 million as estimated by forecasters such as the EIA and Rystad Energy.

The marginal cost of US tight oil is estimated to have decreased to USD 40-50/bbl on average by 2019. It should be noted that the costs of extraction projects are expected to fall globally, despite the return of mild cost inflation.

Oil demand will change with technological and regulatory innovations. The kick-in of IMO emissions regulation from 2020 is not expected to impact the crude oil market, as it is pertinent for only a fraction of oil demand not covered by scrubbers (about 1.5% of total fuel oil demand or 0.5% of total oil demand). The major regulation change will take place around 2030 after the introduction of the first national bans on petrol cars. If rapidly developing electric powertrain technology is ready for global mass production by then, the market will be in for a significant demand adjustment that will later cause oil demand to flatten out and peak during 2030-2040.

We have kept our long-term oil price projections based on the market developments of 2018-2019, observing no significant changes to the existing regulation and technology trends. In the long-term, prices will reflect efficiency savings, as well as pressure from the mobility revolution, and are forecast to be around USD 70/bbl, corresponding to the level of marginal costs at the moment.

1.4.2 Natural gas

We project that the structure of the natural gas market over the outlook period will remain largely geographically segmented. As storage capacities grow and gas grids expand, LNG shipments will be increasingly used to eliminate the between-region intra-year price arbitrage. So far, a sizeable volume of Europe-Asia LNG deviations requires a price differential of over USD 4-5/mmBtu depending on transport costs at the moment.

Regional gas markets are expected to become strongly integrated post-2035, as the rapid development of LNG capacity, as well as transportation and trading networks, including large-scale export pipeline projects, stimulate market integration. Before that, it is more reasonable to consider several regional markets with weaker ties. Thus, we expect that until at least 2035 American and European markets, as well as the Asian and Latin American markets will remain integrated market regions with the most natural gas liquidity. Afterwards, it is projected that the global gas market will start emerging, with regional differences being less significant.

The projections for natural gas prices for each region are in two parts. The oil-indexed prices are exogenous and driven by oil prices (see the Oil price projections subsection), while spot natural gas prices are endogenous and are determined by the balance of supply and demand for a particular market.

This section only provides assumptions on natural gas price trends for the Reference Case. Being a crucial factors behind the natural gas, the pricing evolution and changing market structure is discussed in more detail in Chapter 5.

Market developments in 2018-2019

After a bullish 2018 that witnessed price growth of over 20% both in Europe and Asia, the price of natural gas has hit the bottom in 2019, with pipeline gas in Europe tumbling almost 40% from the peak levels, and expected to go down about 20% on an annual average basis. Asian LNG is wholesaling consistently at around USD 5/mmBtu after rising to above USD 11.5/mmBtu in October 2018. Weather anomalies, demand fears and the perceived LNG glut from rapidly-building overcapacity led to a significant price correction that is expected to persist for some time.

An oil and quasi-oil indexation (hybrid) pricing mechanism was used for a significant share of imported volumes of natural gas on the global markets, including 65.5% of LNG imports in 2018, according to an IGU survey. The effort to create hubs in European markets has had some success as of 2018-2019, with liquidity levels throughout the year allowing for placing small spot volumes. Asian markets have so far not accumulated enough liquidity for spot volumes to be placed reliably, though the trading amounts are increasing and JKM trading turnover bypassed 23% of global LNG trade in 2018. It is worth noting that GECF members for the last year have also successfully used gas trading platforms on a limited scale to market natural gas to potential customers.

The market structure is different for each region, though there is a clear evolution trend towards flexibility as the markets integrate. While all volumes traded within the US go through a gas-to-gas competition mechanism and are largely tied to the Henry Hub quotation, volumes exported to Asian and Latin American markets are largely oil-indexed. The share of oil indexation will decrease as more natural gas from the US enters the market. As of 2018, oil indexation was still used for at least 69.5% of Asian and 25% of Latin American LNG imports. It is important to acknowledge that hybrid pricing is often oil-dominated, though oil influence could change with oil price dynamics. A majority of volumes (estimated at over two thirds) imported to the European market are currently priced using a hybrid oil and benchmark gas indexation mechanism, and unless more regulation is enforced, this is expected to persist.

Medium-term drivers and outlook

The medium-term perspective for the gas market will be defined by the continuing LNG glut as demand adjusts to changing capacity schedules. Around 100 mtpa of LNG capacity and around 100 bcm of pipeline capacity are under construction globally and are scheduled for completion by 2025. Projects for another 300 mtpa of capacity have been announced for construction and some of them are highly likely to take FID in 2020.

While there is a rapidly growing demand for natural gas globally in the medium-term, it will not catch up to those plans, thus putting further pressure on prices. Some of the pre-FID projects will be shelved or rescheduled given the lower price environment. Given that no gas glut is expected by 2025 the gas price is expected to return to the delivery marginal cost levels within 5-7 years based on the previous cases of market reaction to natural gas affordability.

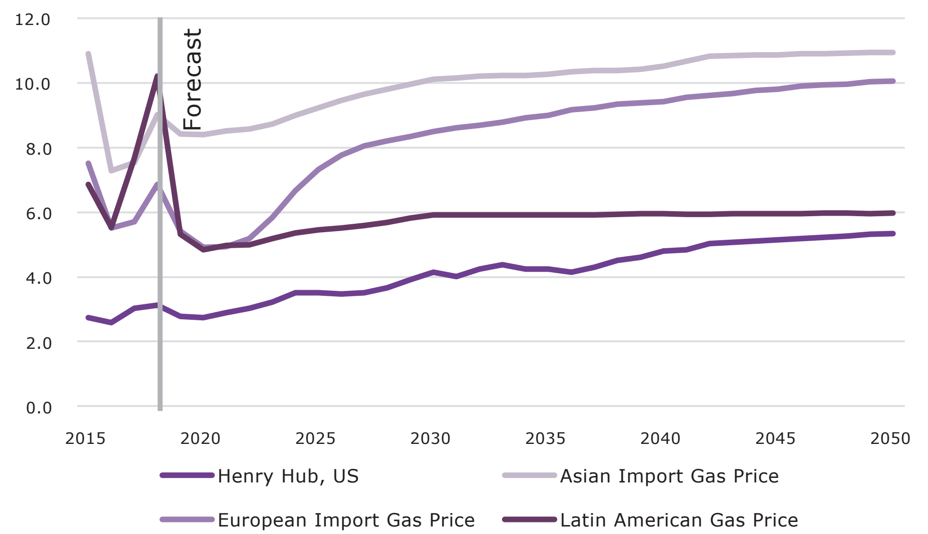
The market in Latin America will likely be the first to feel the pressure from US LNG as the voyage from the Gulf of Mexico to the east coast of South America (Brazil and Argentina) is the shortest and does not require to pass through Panama Canal.

For the Asian market, it is reasonable to expect that competition on the LNG market will put pressure on an "Asian premium" in the medium-term. Lower prices will intensify gas penetration in Asia, which is expected to be beneficial for natural gas consumption in the long-term. The Chinese market is expected to remain tariff-protected from US LNG and the size of the existing Asian market might not be sufficient to cover all Chinese demand growth by swaps.

The European market will remain the residual market for LNG, however, if pipeline suppliers choose to protect their market share, the ample pipeline capacity will render LNG supplies uncompetitive outside long-term contracts used for supply diversification. Global flexible LNG supplies to Europe will put a strong pressure on European gas prices in the medium-term. As Asian demand catches up, all this LNG pressure will gravitate towards premium markets.

Long-term drivers and outlook

Figure 1.9. Natural gas prices (2018 USD per mmBtu)



Source: GECF Secretariat based on data from the GECF GGM

The long-term trend in the natural gas prices will be driven up by the following:

First, despite technological advancement, gas production is expected to become increasingly capital intensive (see Chapter 5), with an increasing demand facing higher LRMC. Second, increasing carbon tax and methane abatement policies will put additional pressure on the cost of using natural gas after coal-switching benefits are exhausted.

Third, the LNG glut will lead to an investment pause, thus providing grounds for a demand-driven increase in natural gas prices after 2030.

The market structure in the long-term will likely gravitate towards many instruments traditionally present in the other commodity markets, such as the increased role of trading hubs, growth in the financialization of the natural gas trade and the greater role that settlement trades typically play. However, most commodities trade in hubs with the proper infrastructure. That is why futures such as JKM will need infrastructure support. So far in the longer-term, LNG indices based on the growing markets (such as China or the recently discarded Sling index) will be more suitable to use as a benchmark as those markets are striving to develop a gas trading infrastructure that can provide a backing for settlement (or "paper") trades.

Regional price divergences are expected to persist towards 2050. In Latin America, booming indigenous natural gas production and the short distance for US LNG shipments will keep prices basically tied to Henry Hub. For Europe, strong price pressure is expected following the introduction of a new phase of the ETS and planned coal and nuclear capacity phase-outs in the 2030s. The Asian market will face more flexible shipments from most LNG suppliers, as well as several new pipeline links. However, due to an investment pause in the mid-2020s, the Asian premium will still hold.

1.4.3 Thermal coal

The global consumption of coal is expected to decline from the present level of below 3.8 billion toe (6.4 billion tonnes of coal equivalent) to 3.3 billion toe (5.4 billion tonnes of coal equivalent) by 2050. Coal consumption phased out in the developed countries (and China, after 2025) is expected to be replaced by consumption growth in India and Southeast Asia. Global coal-generating capacity is also expected to increase from 2.1 TW in 2018 to 2.4 TW by 2050.

By 2050, we assume thermal (steam) coal will retain a key role in the global power mix and will still be an essential component in unlocking energy access in several power-hungry developing countries. At the same time, coal emissions will be a major target of environmental policies both in developed and developing countries. While developing countries will reduce coal focusing on air quality, developed countries see complete global coal phase-out as a prerequisite to staying within the carbon budget.

This raises an important challenge for technological advancement in energy, including coal, particularly developing commercial-scale carbon capture, use and storage (CCS) technologies and deploying them on the existing coal fleet. At present, the case for commercial deployment for this technology is absent, thus its deployment remains a long-term prospect. However, it is clear that along with all the policies, this will put pressure on coal competitiveness against other fuels in the energy mix.

Market developments in 2018-2019

In 2018-2019, coal prices have been through a peak and trough dynamic, with global market prices hitting a 7 year high in 2018 (surpassing USD 100/ for all internationally traded coal brands) and subsequently falling 40% over a year ago in the third quarter of 2019.

One important factor behind these dynamics has been a fall in natural gas prices, a competitor power sector fuel. Another is a recovery in Chinese coal production, as mines are re-opened on the back of completed renovations and industry restructuring, that started in 2016 after a stricter coal mining regulation was passed. The flattening demand expectations have also roiled the price outlook as the industry braces for fiercer inter-fuel competition.

Medium-term drivers and outlook

In the medium-term, the coal market is expected to be driven by limitations and phase-outs of coal-generating capacities in China, and coal phase-outs in the US and a number of European countries. The lower price of natural gas will also play an important role.

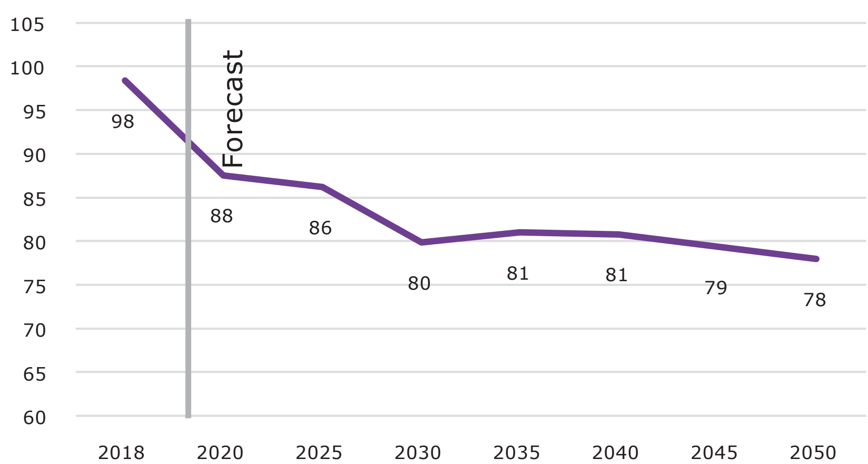
By 2025, developed economies are expected to use 27% or 400 mt less coal than in 2018. The decline in coal use due to capacity phase-outs for premium markets in the US and Europe would limit coal competitiveness.

While Indian and Southeast Asian demand is projected to grow, alone it will not provide enough volume to compensate for the flattening of the demand from the other developing markets. One important driver is that coal generation capacity in China will be capped from 2021 according to the energy sector 5-year plan. Along with the coal use regulations that limit domestic sector use of coal in China, this results in a practically flat consumption outlook. In total, developing countries' coal use will increase by 4.5% by 2025, or by 225 mt, almost the same volume as for the previous five years.

While this is an unfavourable outlook for the coal market, the current prices of USD 60/tonne are expected to correct in line with less competitive supply reductions, and the market is expected to balance at around USD 85/tonne by 2025.

Long-term drivers and outlook

Figure 1.10. Thermal coal price* (2018 USD per tonne)



**Average of Richards Bay, ARA and Newcastle prices*

Source: GECF Secretariat based on data from the GECF GGM

CHAPTER 1

The long-term outlook for thermal coal prices is to a lesser extent shaped by the supply-demand balance, as the capacity is expected to adjust to the accelerating decline in global demand. We do not assume the deployment of any commercial coal CCUS technology before 2050. The more important price driver is the competitiveness of coal vis-à-vis alternative fuels. This will be influenced by several factors.

First, is the capital requirements and marginal cost of non-coal power capacity in the developing countries, mainly gas and renewables. So far, coal remains the cheapest power sector energy source on a non-adjusted basis.

Second, is the global increase in carbon prices and proactive air quality policies in developing countries. These shift the basis for coal in inter-fuel competition. European carbon prices are expected to reach USD 85/tCO_2 by 2050, while the Chinese carbon price is expected to top USD 26/tCO_2.

Third, is strong electricity demand growth in capital-strapped developing Asia and Africa and the strategies for the energy sector those countries will take. While modern coal power is emitting more than any other modern source of energy, it is still widely viewed in those countries as a valid competitor to reduce emissions against traditional biomass and older technology. With power demand in developing countries growing by over 85% by 2050, and over 6 TW of capacity expected to be online by that time, it is an important factor for any power source including coal in the long-term.

We expect that in the long-term prices will be driven by these factors, and global prices for coal will go down to below USD 80/t on average.

1.4.4 Carbon

Climate change requires more effort - beyond energy efficiency - to meet international commitments and carbon markets remain one of the tools used to help move the world closer to its aspirations. Nevertheless, it is unlikely that the current targets will be met, but efforts to stop the increase in emissions will be made and gas has an important role to play.

An increasing number of global carbon trading systems are expected to be set up and functioning on a regular basis, and towards 2050 they will be integrated into a global carbon trading system. A balance between competitiveness and climate goals will strongly impact carbon regulation. While carbon price is expected to become the major force behind energy transition, its impact over the Outlook horizon will depend on the speed of development and integration of the national carbon frameworks that are so far largely finalized only for the European Union.

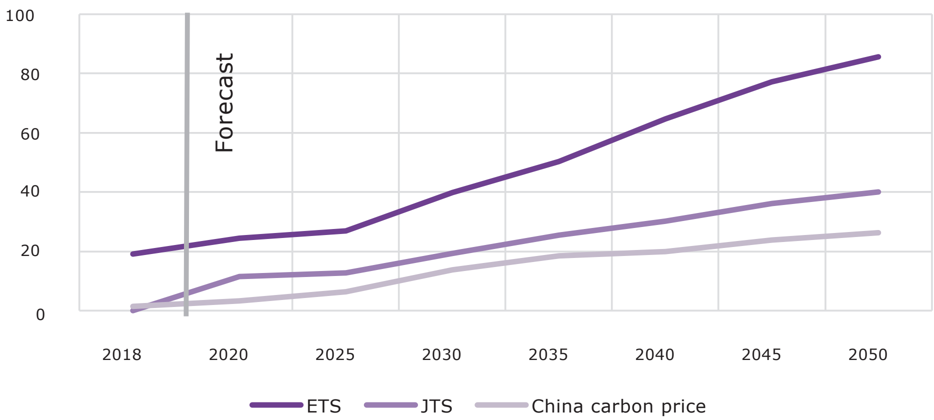
The assumptions in this sub-section include a projection of the carbon price dynamics within the main systems expected to be fully functioning by 2020, namely EU emissions trading system (ETS) stage IV, the Japanese Trading System (JTS), the Australian and New Zealand Trading System, and the expansion of the Chinese national cap-and-trade system. In the US, there are several state-level and local trading systems, however, pending the withdrawal from the Paris agreement, the national-level carbon price in the US is not expected to reach the levels significantly impacting competitiveness before 2030.

According to World Bank estimates, in 2019 there are about 40 national and 20 sub-national carbon pricing mechanisms that are implemented or will be implemented shortly, at a coverage equivalent to approximately 15% of global GHG emissions. They still cover about 11 Gt CO_2 (7.2 Gt CO_2 with regards only to implemented mechanisms), the same as one year ago, and about 95% of the emissions within the mechanisms are priced well below sensitivity levels (that impact competitiveness).

On a supranational level, the EU ETS so far remains the only initiative of regional integration within a unified framework. In 2018-2019, three new national-level As well as a number of sub-national mechanisms were introduced. This includes a South African carbon mechanism and the Argentinian carbon tax, as well as a new carbon tax in Singapore.
EU ETS carbon prices are reaching USD 25/tCO_2 during 2019 as stage IV draws near. However, several reasons lead us to assume that carbon prices will not move much from the present levels at least until 2030.

First is the national competitiveness dilemma. European industrialists have already expressed concerns that levels above USD 30 will impact energy prices, thus worsening industrial competitiveness and threatening European jobs. To tolerate even larger prices, there is a need for a transition period to let most stranded assets amortize. After 10

Figure 1.11. Carbon ETS reference price forecasts (2018 USD per tCO_2)



Source: GECF Secretariat based on data from the GECF GGM

years, the recently adopted preferences for low-emission investment projects will be reflected in physical capital, and no new stranded assets will be created.

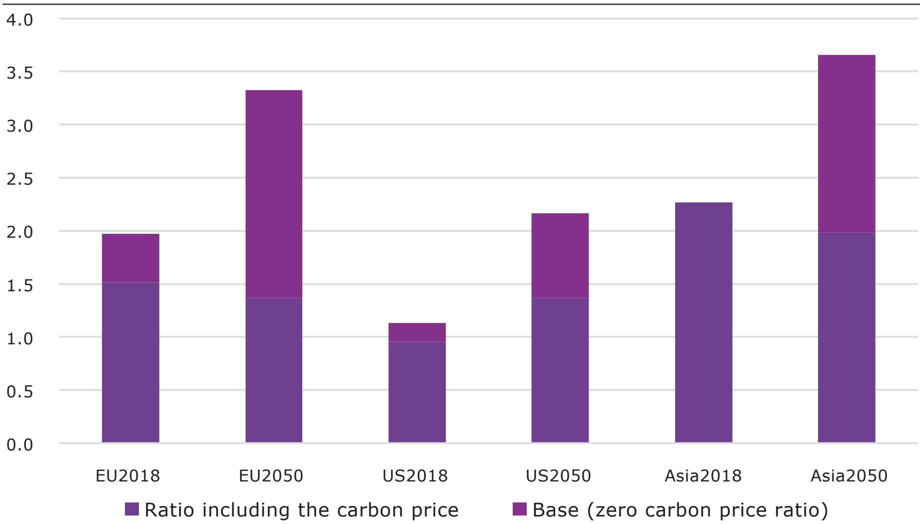
Second is a conflict between government social and climate goals. France, the first large European economy that moved to introduce an ecological tax on petrol, encountered strong public opposition and mass protests by the “gilets jaunes” in what was viewed as unfair redistribution of income and not a climate policy. There is a need for a large-scale public opinion shift in favour of climate policy priorities, and that may take quite a long time, as the French case illustrates.
Third, specifically regarding the EU ETS, the market started reacting to the approaching Stage IV of the mechanism only last year, even though the parameters were announced

in 2015. Apart from the real uncertainty connected to the setup period, policy uncertainty was very strong regarding the final parameters and the enforceability of the mechanism. Before the transition of the ETS to the next stage in 2030, uncertainty will likely remain high about what that stage will specifically entail, thus keeping prices stagnant.

After 2030, prices are expected to increase gradually under policy pressure as the larger scope of emissions is tackled by the carbon emission mechanisms. We assume by 2050, CO_2 will reach USD 85/tCO_2 in the ETS and USD 40/tCO_2 in the JTS respectively. The Chinese national carbon price is projected to be a material factor in national emissions policy at above USD 25/tCO_2 but much less restrictive than elsewhere, as industrial competitiveness challenges will hinder the introduction of stricter climate targets.

Carbon price assumptions affect inter-fuel competition, especially the process of coal-to-gas switching. As the carbon market is expected to support the competitiveness of natural gas, we assume it will make coal more expensive to use while keeping the coal-gas price ratio within the affordability range.

Figure 1.12. Natural gas to coal price ratio and the carbon price impact



Source: GECF Secretariat based on data from the GECF GGM

Energy Policy Developments and Emission Trends

Key assumptions and findings:

- Natural gas continues to receive positive policy support in several countries as an alternative to polluting and carbon-intensive fuels and a flexible option complementing intermittent renewables. However, this policy support is challenged, especially with governments setting more ambitious renewables targets and decisions by several lenders, including the World Bank to discontinue financing gas projects.

- For renewables, there is increasing reliance on market-based instruments such as auctions and renewable certificates trading, and fewer regulatory subsidies (such as feed in tariffs). The Outlook anticipates a short- to medium-term slowdown of solar PV and wind capacity additions, particularly due to feed-in tariffs reduction and shift of renewables support schemes, but sees expansion over the longer term driven by decreasing costs and ambitious renewables targets.

- Carbon pricing is emerging as a key carbon mitigation instrument with new initiatives recently announced, notably in Canada, Argentina, Singapore and South Africa. Despite the Trump administration position against a strengthened climate effort, several individual states (e.g. New Mexico, Oregon, California) are pursuing carbon pricing. It is estimated that one-third of the 2050 global energy-related emissions will be covered by carbon pricing of some sort.

- The Outlook expects that enhanced climate commitments by countries, supplemented by efforts of sub-national governments and business actors will drive further reduction of CO_2 emissions compared to the previous edition of the Global Gas Outlook forecasts. However, it anticipates that the implemented policies will not be sufficient to meet the ambitious Paris Agreement targets while satisfying the energy needs for a growing global population and economy.

- Energy-related CO_2 emissions are expected to increase by around 0.13% per year over the 2018-2050 period, a low growth rate reflecting a large anticipated deceleration of emissions. This deceleration will occur, specifically after 2030, where emissions are projected to stabilize and reach around 36 $GtCO_2$ by 2050.

- Natural gas is set to be responsible for the lowest share in global CO_2 emissions by 2050 (31%) despite its highest contribution to the primary energy mix (27%). Coal, however, is projected to be the largest contributor to 2050 global emissions with the lowest share in the primary energy mix. This carbon mitigation advantage puts gas in a good position to achieve further global emissions reductions by substitution for coal.

2.1 POLICY DEVELOPMENTS AND ASSUMPTIONS

This chapter aims to address the main policy developments that affect the energy and gas prospects which are highlighted in this Outlook. It considers recent policies and measures adopted or announced by major countries and regions, and makes an assessment of their potential effect, taking into account the various challenges for their implementation.

Different policy domains are analysed, including natural gas, coal, nuclear, renewables, energy efficiency as well as climate-related policies. The latter pays special attention to the ongoing climate commitments under the Paris Agreement process and the role of carbon pricing as a key instrument to support these commitments.

2.1.1 Natural gas policies

Natural gas continues to receive positive policy support in several countries, including major energy producers and consumers. This policy support, which has contributed to sustaining investment in gas supply chains despite the low gas price environment, and expanding gas demand and trade, materializes through various measures and initiatives on the supply and demand sides.

On the supply side, these measures comprise: i) advancing gas market reforms to attract investment and stimulate competition; ii) streamlining and accelerating administrative procedures to support building infrastructure along the gas value chain; iii) encouraging partnership to unlock the gas resource potential including unconventional resources; iii) promoting flexibility and security of gas supply through diversification of supply sources and routes. One indicator of this increased diversification is the increase of LNG regasification capacity by more than 22 million tonnes in 2018 (1), and the extension of LNG trade to new consuming markets such as Bangladesh and Panama.

On the demand side, natural gas has gained some policy push as an alternative to polluting and carbon-intensive fuels. Among the main policy initiatives and measures which are undertaken in this regard are: i) strengthening the emissions and energy performance standards; ii) mandating the switching from coal or oil, especially in heating and power generation; iii) implementing carbon pricing; iv) encouraging gas use in different transport modes through supporting the development of infrastructure and refuelling stations.

The above-mentioned positive policy drivers for natural gas are, however, opposed by various challenges and barriers impeding gas from playing its role in the transition to sustainable energy systems. These barriers mainly include restrictions on key gas producers that affect gas investments and trade; tightened financial resources, especially with several banks and institutions (e.g. the World Bank) deciding to discontinue financing oil and gas projects; uncertainties about gas revenues resulting from non-stable markets and the move away from traditional oil-indexed contracts; lack of long-term visibility of the role of gas in the energy transitions, particularly with the policy push towards renewables.

Despite all these challenges, natural gas remains a viable choice for sustainable development given its environmental, technical, economic and social advantages. Natural gas contributes to reducing carbon intensity and pollution effects resulting from energy-related activities; supports access to modern energy; improves availability and reliability of supply due to its abundance and flexibility underpinned by diversified supply routes; provides competitive and affordable energy compared to other alternatives. Natural gas can also be a vector of increased cooperation and transfer of technologies between countries (2).

This Outlook assumes that, over the long-term, gas will still benefit from policy support in many countries, where it is encouraged as a clean and affordable alternative to more polluting and carbon-intensive fuels, and also as a flexible option complementing intermittent renewables. Furthermore, the Outlook assumes that supply-side policy measures will contribute to improving long-term availability and the accessibility of natural gas. These measures, which might materialise through advanced gas market reforms and strengthened partnerships and cooperation, help to mitigate the observed technical and financial challenges, and therefore to support developing gas production and infrastructures, including specifically LNG infrastructure.

The Outlook assumes that natural gas is incentivized in the transportation sector with various measures supporting the development of gas-based transportation modes and vehicles and the extension of gas refilling systems. In the shipping sector, the implementation of IMO sulphur dioxide emissions standards after 2020 will drive increased demand for international shipping, and encourage seaports around the world to build bunkering stations. The Outlook estimates a potential for LNG demand in international bunkering to reach more than 5 times the current level of 9.3 Mtoe. The anticipated increase in LNG trade will lead to a substantial increase in the consumption of gas by LNG tankers.

2.1.2 Coal policies

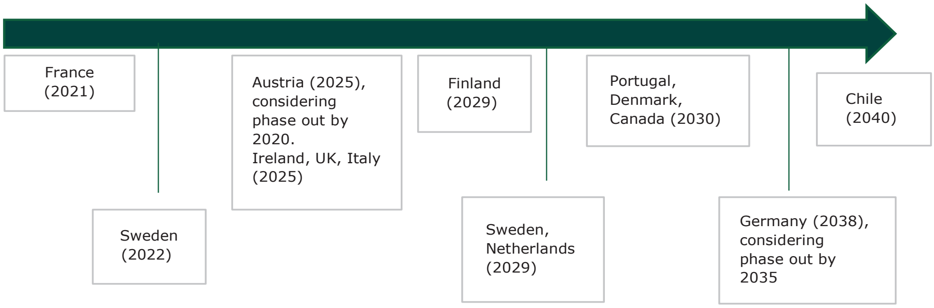
Since the publication of the last GGO, two main dynamics have been observed in coal policy orientation. On one side, several countries have announced strengthening their limitations on coal consumption to cope with their environmental and climate commitments. One indicator of this policy trend is the increasing number of countries which are part of the "Past Coal Power Alliance initiative", committing to accelerate coal phase-out in the power sector (3).

These countries add to other actors including sub-national governments, cities and companies that have announced bans on coal utilisation, as well as financial institutions that have reduced their commitment to financing coal projects.

On the other side, there are countries like the US and China which have relaxed some of their policy restrictions on coal, and others like Turkey, India, Indonesia and Vietnam which continue to support coal as a key source of energy, mainly because of security of supply and affordability concerns. Coal has also emerged as an option in the Middle East and North Africa for countries (e.g. UAE, Egypt) looking to diversify their energy mix and to have access to affordable fuel. This policy support adding to the competitiveness of coal has contributed to the observed increase in coal demand in 2018 after a period of relative stagnation (4).

Countries which still rely on coal strive to adopt clean coal technologies that reduce the environmental impact of coal utilisation, specifically, the high efficiency, low emissions technologies for power generation including the super-critical and Ultra-super critical power plants. It is estimated that more than 70% of the power plants which will be built over the next decade will use these two efficient technologies, which supplement other technologies and practices that aim to reduce the environmental footprint of coal, such as coal washing or desulphurization of flue gas after combustion.

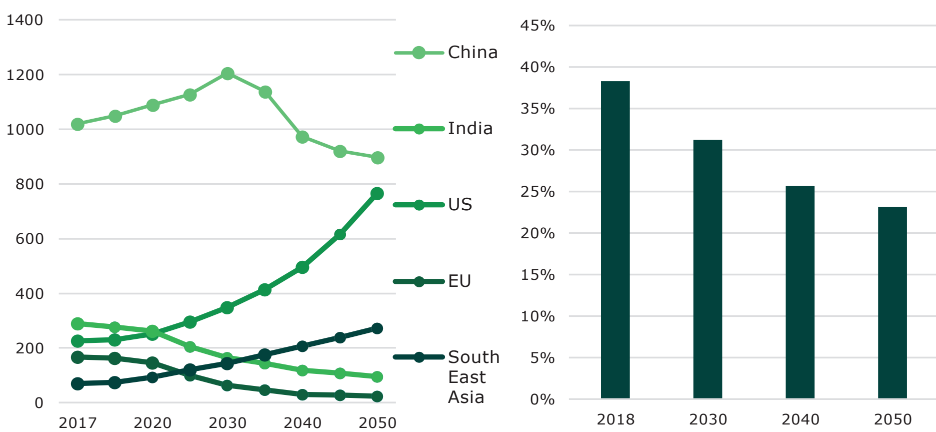
Figure 2.1. Main countries announcing phase-out date of coal-fired power plants



One trend which has been confirmed in 2018 is the tendency of the major coal consuming countries, especially those providing coal technologies, to support coal-based projects outside their own countries. Overseas coal-fired capacity is estimated at around 68 GW. Nearly 84% of this capacity is financed by three countries, China, Japan and South Korea, in various countries, especially in Asia and Africa (5).

The Outlook assumes that despite an anticipated decline in many countries, driven by policy and market fundamentals (e.g. competitiveness of gas), coal will still play a role in meeting growing electricity demand in various developing and emerging markets, as is highlighted in figure 2.2. However, the share of coal in the power mix is expected to decrease globally driven by coal phase-out in some markets, development of other alternatives including gas and renewables and efficiency improvements.

Figure 2.2. Coal-fired capacity prospects in major coal consuming regions (left) (GW), and coal share in power generation mix (right) (%)



Source: GECF Secretariat based on data from the GECF GGM

In the countries which are still expected to rely on coal, this Outlook assumes an increasing effort to limit the environmental impact of coal utilisation and to incentivize the large dissemination of clean coal technologies.

2.1.3 Nuclear policies

The global anti-nuclear policy stance which has dominated the energy scene after the Fukushima disaster continues to wane in a context of strengthening countries' commitment to lower their GHG emissions. Nuclear is seen by several countries, including the nuclear-advanced ones, as a carbon-free option that enables secure electricity supply, despite the growing average age of the nuclear power fleet and rising safety risks and concerns. Recent nuclear policy developments indicate that except Germany, whose commitment remains to phase out nuclear by 2022, countries which have announced severe nuclear reduction have shown clear hesitation in closing their old nuclear capacities: France has delayed the planned reduction of the nuclear share of its power generation mix. Other European countries including Finland, Belgium and the Czech Republic have extended operating licenses for their nuclear reactors (6). Japan has confirmed in its 2030 Strategic Energy Plan (7) the intention to restart a large part of its nuclear capacity stopped after Fukushima and the US strives to implement some policy support at federal and state levels to keep a role for nuclear despite the age of its old fleet. Emerging countries including China and India, also have large programs to expand nuclear power capacity. Nuclear production increased by 0.3% in 2018 over 2017, the first year-on-year global increase after the Fukushima disaster in 2011.

The main challenges faced by policymakers, especially in the nuclear-advanced countries (i.e. the US, Japan and European countries) is to enhance the security of operations of an old nuclear fleet whose maintenance incurs very expensive costs. The average age of the nuclear power fleet in these countries is around 35 years, and a large part of these capacities are close to the end of their lifetime (8). Lifetime extension of the old power plants or their replacement through new-build programs are the key policy uncertainties that will affect long-term prospects in the nuclear-advanced economies. For new construction, it is worth mentioning that several projects under construction (e.g. in France, Finland and the UK), specifically those using advanced technologies (EPR technology), face delays and cost overruns, increasing the risks and triggering investors' reluctance to engage in new nuclear ventures.

At global level, nuclear operations and the construction of new capacities face an increased complexity with strengthened safety regulations; public opposition to nuclear expansion; the issue of treatment and storage of nuclear wastes; the pressure on the availability of skilled labour; financing nuclear projects as well as the need to secure nuclear fuel supply. For the emerging and new nuclear countries, this complexity is exacerbated by the requirement to ensure technology transfer and building their capabilities in terms of expertise and regulatory design. The challenges and increased complexity faced by the nuclear industry make this option a costly way to mitigate GHG emissions.

This Outlook expects that the recent development of policy support and hesitation to close power plants will lead to life extension of several projects in nuclear-advanced economies. Nevertheless, the economic competitiveness of nuclear is assumed to have been substantially affected, especially by reinforced safety requirements and maintenance costs. The Outlook anticipates that the lifetime extension associated with a slow pace for developing new capacities in nuclear-advanced countries will not be sufficient to reverse the nuclear decline. The lack of competitiveness of nuclear projects against other clean alternatives such as combined cycle gas turbines (CCGT) and renewables contribute to this nuclear decline in the advanced economies.

In emerging and developing countries, the Outlook assumes that different technical, economic and regulatory challenges will make the pace of development of nuclear projects slower than expected by the announced policies and targets.

2.1.4 Renewables policies

Since the publication of the last edition of the Outlook, renewables policies have confirmed the increasing role of market-based mechanisms (e.g. auctioning, renewable obligations and renewable certificates trading) after a clear predominance and reliance, over the last decade, of regulatory subsidies, especially the Feed-in Tariffs (FITs). This market-based orientation is reflected in the move observed in many countries including China to improve the efficiency and effectiveness of renewables support schemes, particularly by reducing subsidies and creating instruments which are more responsive to the countries' electricity market conditions.

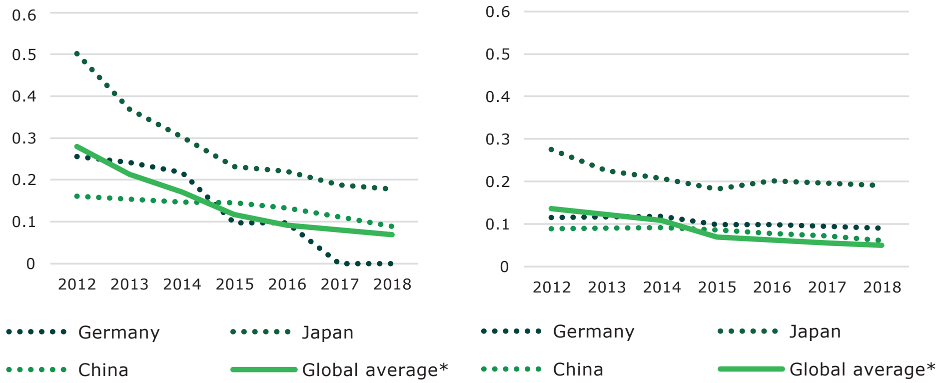
Auctioning continues to emerge as a key market-based instrument to support non-hydro renewables progress, especially in the power sector. The number of countries undertaking auction rounds for the development of renewable power capacity increased from 29 GW in 2017 to 48 GW in 2018 (9). It is estimated that 98 GW of the added renewable power capacity in 2017 and 2018 resulted from auctions (10), representing nearly one-third of the renewable capacity developed during this period. Auctions bring several advantages including increasing competition, driving renewables prices decrease and reducing the burdens on government budgets. However, they introduce larger risks for project developers and might lead to underestimated prices and delays in project implementation (11).

The increasing role of auctions as a support scheme is also associated with a tendency to reduce the level of subsidies, especially FITs for solar PV and wind. Figure 2.3 depicts the evolution of the mean FITs since 2012, based on an estimated average for 30 countries including China, Japan and Germany. It indicates a decreasing trajectory with a steeper decline for solar PV subsidies.
This shift of renewables support schemes is not without effect on solar and wind deployment, due to lower returns and larger risks for project developers. It has played a role in the recent slowdown of the global added capacity of solar PV and wind. This slowdown was confirmed in 2018 with reduced capacity addition compared to 2017.

For the future prospects, this Outlook factors in these recent evolutions and anticipates a short- to mid-term slowdown of solar PV and wind annual capacity additions, driven by markets which are observing substantial reductions in subsidies (China in particular). However, over the long-term, decreasing costs, government support and auctioning of capacities underpinned by ambitious renewable targets, will drive the expansion of these renewables. These drivers add to the increasing role of non-state actors including subnational governments, cities as well as companies that commit to increase their renewables uptake.

Despite the continuous progress of market-based support schemes, it is assumed that government intervention, even through regulated subsidies, still matter. Government intervention, especially for emerging and developing countries, remains a way to scale up capacity development, boost the less mature technologies and support the stated targets.

Figure 2.3. Mean Feed-in Tariffs for Solar PV (left) and Wind (right) (USD/Kwh)



Source: OECD (+ GECF estimation for 2018)

* Note: Average Feed-in tariffs of 30 countries: Australia, Austria, Canada, Czech Republic, Denmark, Estonia, France, Germany, Greece, Italy, Japan, Latvia, Luxembourg, Netherlands, Portugal, Slovak Republic, Slovenia, Spain, Switzerland, Turkey, United Kingdom, United States, Argentina, Bulgaria, China, India, Indonesia.

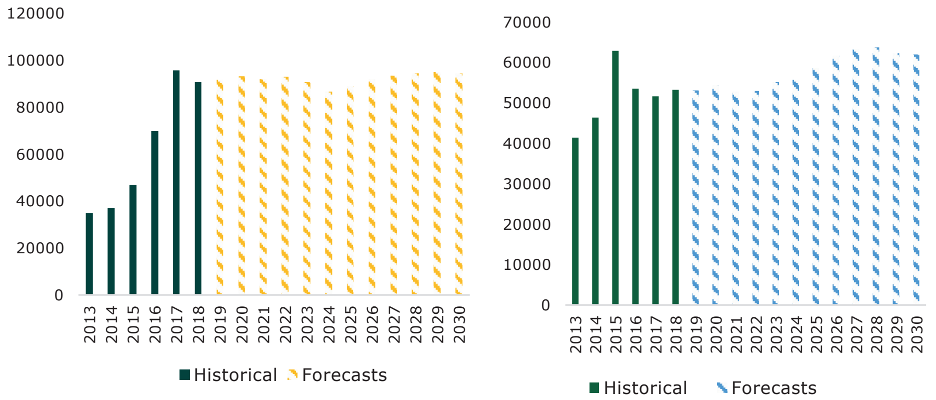
Integration of intermittent renewables will be a key challenge for future renewable energy expansion. Nevertheless, recent developments indicate a rising effort to deal with this issue by incentivizing the development of flexible power systems and adjusting electricity market design (9). Gas-fired power plants are encouraged in many markets as a tool to improve flexibility.

The Outlook anticipates that gas and renewables will continue to be key partners in dealing with integration challenges and ensuring the required flexibility for power systems with a large variable renewables share. Despite an expected progress of other options providing flexibility and balancing intermittency of renewables, such as demand side management and different forms of storage (e.g. batteries, hydropower..), flexible gas-fired power plants are set to remain a cost efficient way to deliver the right back-up for renewables, and reduce renewable electricity curtailments in major markets.

It is also assumed that distributed and off-grid renewables will receive increasing policy attention, specifically as an option for enhancing energy access in developing countries. The development of net-metering measures plays a key role in promoting distributed renewables, solar rooftop in particular since it enables distributed electricity consumers to sell their excess electricity on existing networks.

In addition to solar and wind expansion in the power sector, the Outlook anticipates increased policy support for other forms of renewables, especially geothermal and biogas in the heating sector. The Outlook continues to take a cautious view on biofuels in the transportation sector due to issues related to conversion process costs, pressure on lands for aliments production and competition from alternative products including Electric Vehicles and gas for transport.

Figure 2.4. Year-on-year global power capacity additions for solar PV (left) and wind (right) (MW)



Source: GECF Secretariat based on data from GECF GGM

2.1.5 Energy efficiency policies

The energy intensity of GDP (i.e. energy consumed per unit of produced GDP) continues to exhibit a declining trend at the global level, with a 0.7% decrease in 2018 over 2017. This intensity level, a more than 11% reduction compared to 2010 (figure 2.5), indicates an important global improvement in the efficiency of using energy in different economic sectors, as well as a shift in the global economic structure, with a lower role for energy-intensive industries and more penetration of services in global GDP.

Nevertheless, despite the continuous improvement in energy efficiency, its pace of progress slowed down in 2018. The slowdown confirms the decelerating trajectory of the energy efficiency improvement after the peak reached in 2015, which is mainly driven by the fall in oil prices as well as by the observed slackening of the energy efficiency policy effort. This reduced effort is particularly reflected in the slow progress of introducing new mandatory energy efficiency policies or reinforcing the existing ones (12) (13).

It is estimated that the energy use covered by mandatory policies (e.g. minimum energy efficiency performance standards) has stabilized at around one-third of the global energy use between 2016 and 2018. This progress has been much more important for the previous period where the coverage of efficiency policies increased from 22% in 2010 to 32% in 2016 (13).

Although the implementation of mandatory energy efficiency policies has seen a global slowdown over the last three years, there are emerging attempts to scale up the efforts again. These efforts are targeting the building and transportation sectors where reinforced energy performance standards and building codes have recently been enacted

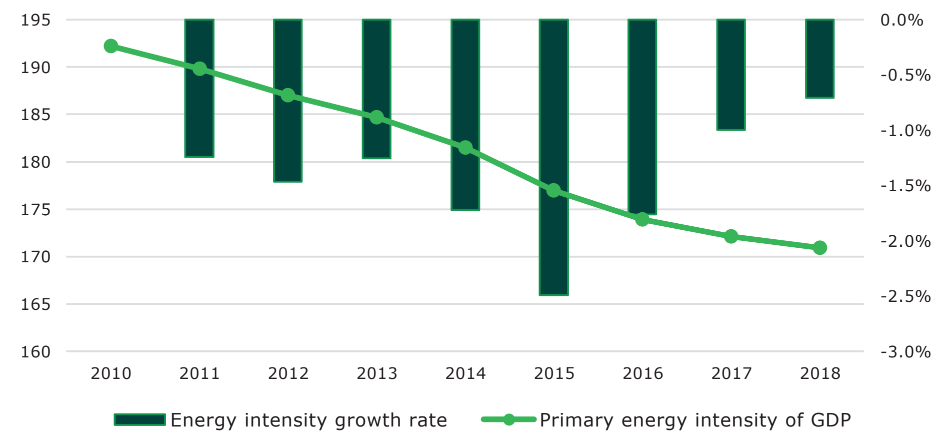
(e.g. amendment to the EU energy efficiency directive) or planned in various markets including China and India.

It is worth noting that a new global coalition - the "three percent initiative" - was launched at the Climate Summit in New York in September 2019 (14). This coalition involves 15 countries including India, Argentina, Italy and the UK and aims to reinforce policy actions in order to accelerate the progress of energy efficiency and achieve an energy demand trajectory aligned with a 3% annual efficiency improvement goal.

Another emerging trend relates to the policy support for developing appropriate financing mechanisms targeting energy efficiency projects, which often present a non-negligible risk profile. Policies play a role in providing specific funds for energy efficiency, promoting innovative financing instruments such as green bonds and developing public-private partnerships, especially with energy service companies (ESCOs). The ESCO business model is based on developing services and solutions for energy efficiency that are remunerated in line with energy saving achievements.

The Outlook assumes a continuous progress in energy efficiency, specifically in buildings, appliances and the transportation sector, spurred by implementation of measures including efficiency standards, price incentives underpinned by the deployment of smart technologies; financial and fiscal support and efficiency obligation schemes. Development of financing mechanisms and expansion of ESCOs will contribute to these improvements. Moreover, larger utilization of gas-based technologies (e.g. gas boilers, CCGT and cogeneration), especially for heating services and power generation is set to play a key role in improving energy efficiency.

Figure 2.5. Evolution of energy intensity of GDP (toe/real million USD) vs. Energy intensity growth rate (%)



Source: GECF Secretariat based on data from GECF GGM

Despite all this effort to scale up efficiency, the Outlook considers that significant potential remains untapped, particularly in the emerging and developing markets. Further improvements can be achieved in the industry and power sectors through better exploitation of synergies between heat and power generation, reducing waste in electricity networks and increasing material recycling.

2.1.6 Climate-related policies

In 2018, COP24 marked an important step in the adoption of the Paris Agreement Rulebook that sets out detailed guidelines and procedures for the implementation of the Agreement. The Rulebook provides, particularly, harmonized guidelines under a single transparency framework for collecting information, reporting countries' emissions and climate effort and tracking their progress (15).

The COP 24 was also an opportunity to make a first assessment of the progress of climate actions in the context of the Talanoa Dialogue. This assessment shows that, although countries have achieved progress in their emission mitigation and adaptation actions, driven by their National Determined Contributions (NDCs) commitments, they need to significantly scale up their efforts in order to meet the Paris Agreement's objectives.

The Paris Agreement stipulates that countries need to revise upward their ambitions by 2020. However, raising these ambitions remains a challenge, especially in a context characterized by the US announcing withdrawal from the Agreement, and the observed trends to scale back climate engagements in countries like Brazil and Australia. Other countries might resist making a substantial increase in their climate ambitions amid the lack of engagement of some wealthier countries, and their fear of losing economic competitiveness and welfare.

Nevertheless, there is a signal from several countries, including EU countries, Canada and Argentina which are part of the 'High Ambition Coalition' that they will enhance their climate ambitions and update their pledges in the context of the Paris Agreement process (16).

In addition to the climate-related effort of countries which are part of the United Nations Framework of Climate Change Convention-UNFCCC (Parties), there is an increasing involvement by Non-Party actors, including subnational governments, cities and businesses that commit to undertake strengthened climate actions. The Non-Party effort takes the form of individual actors' commitments or international cooperative initiatives (e.g. the global methane initiative that includes major oil and gas companies, the US "We are still in" initiative). The UNFCCC strives to support the Non-Party effort through improving partnership and coordination between Parties and Non-Parties and providing a platform that records the Non-Party initiatives and assesses their impact in dealing with climate change (17).

This Outlook assumes that several countries, including big GHG emitting countries in Europe and Asia, will enhance their emission pledges in the framework of the Paris Agreement process. These countries' commitments, supplemented by Non-Party stakeholders efforts will drive further reduction of CO_2 emissions compared to the 2018 GGO long-term forecasts. However, the Outlook anticipates that the implemented policies

and measures will not be sufficient to achieve an emission trajectory which is compatible with the very ambitious Paris Agreement targets while meeting the energy needs of the growing global population and economy.

Countries' efforts to reduce carbon emissions are underpinned by various measures and support schemes implemented in the framework of renewables, non-renewables and energy efficiency policies (see previous sections in the policy chapter). There are also other carbon mitigation measures that are set to play a role in the future, including carbon pricing, electrification of final energy usage, carbon capture, utilization and storage or promotion of carbon sinks.

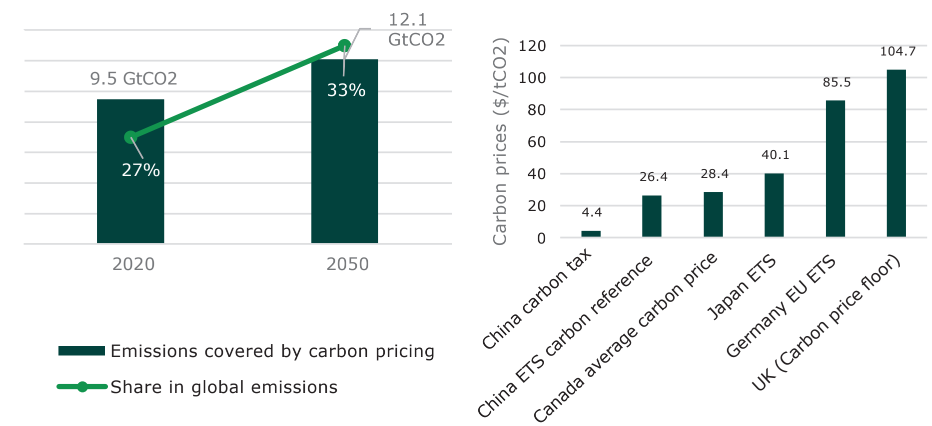
Carbon pricing emerges as a key mitigation instrument with recent evolutions indicating an increasing number of carbon pricing initiatives involving both emission trading systems and carbon taxes. Since the publication of the last GGO, ten new initiatives have been identified, including ETS and taxes in Canadian provinces; carbon taxes in Argentina and Singapore, as well as in South Africa, the first initiative in Africa (18). Moreover, recent trends indicate the increased effort by various jurisdictions to broaden and deepen carbon pricing instruments, through increasing their sectoral coverage and promoting more relevant price signals for carbon mitigation.

Taking into account the implemented and scheduled carbon pricing initiatives, it is estimated that around 27% of the 2020 global energy-related CO_2 emissions will be subject to carbon prices, either taxes or emission trading systems. The Outlook expects progress of carbon pricing in countries announcing or taking initiatives in this regard. By 2050, carbon prices are estimated to cover one-third of energy-related CO_2 emissions. Increasing emissions in countries which are not assumed to implement carbon pricing schemes (e.g. India), will affect the share of the emissions covered by carbon prices.

This Outlook predicts large disparities in carbon prices with a large part of emissions priced at low to moderate levels (less than USD 40/tCO_2) reflecting various challenges. These challenges include political acceptance of higher carbon prices (e.g. France scaled back on a policy to increase taxation), the effect on economic competitiveness, the risk of industrial migration from countries applying high carbon prices (i.e. carbon leakage)

and the design of carbon emission trading systems and their ability to respond to external shocks (e.g. Brexit or aggressive coal phasing out in the case of the EU ETS).

Figure 2.6. Evolution of energy-related CO_2 emissions covered by carbon pricing schemes (left), and anticipated carbon price levels by 2050 (USD/MtCO_2)



Source: GECF Secretariat based on data from GECF GGM

Despite efforts to link various carbon markets (e.g. Quebec and California, or EU ETS and the Chinese carbon market), the development of an integrated global market is not assumed to occur over the forecast period because of the huge heterogeneities in the design and nature of carbon markets as well as climate-related policies and ambitions. This adds to the current difficulties of implementing international carbon pricing mechanisms under Article 6 of the Paris Agreement, due to challenges related to double counting and the transition from the mechanisms applied under the Kyoto protocol.

This Outlook also does not consider that there will be large deployment of CCS projects and technologies, due to the technical difficulties and high investment costs that remain important barriers to CCS progress.

2.2 Energy-related CO_2 emissions developments and trends

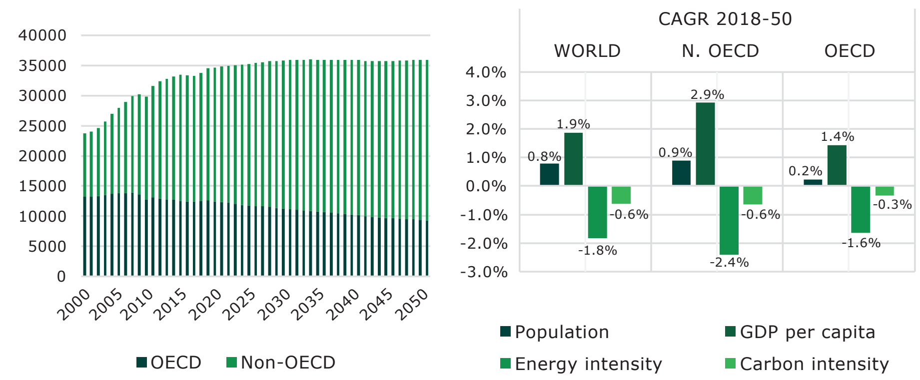
Global prospects

Energy-related CO_2 emissions are expected to increase by around 0.13% per year between 2018 and 2050, the low growth rate reflecting a large anticipated deceleration of emissions compared to recent years. This deceleration will occur, specifically after 2030, when emissions are projected to stabilize in the range of 35.7 – 36 $GtCO_2$ over the 2030-2050 period. Energy-related CO_2 emissions are forecast to reach nearly 36 $GtCO_2$ by 2050.

Although at a slower pace than observed in previous periods, emissions in non-OECD region will continue growing at 0.6% per year between 2018 and 2050; and this will largely compensate the expected decline in the OECD mature economies. The non-OECD share in global CO_2 emissions is projected to rise from 63% in 2018 to 74% in 2050.

The increase of non-OECD emissions is driven by population growth and GDP per capita, which offset the downside effect resulting from decreasing energy intensity and carbon intensity in the region (see figure 2.9). The expected reduction of non-OECD energy intensity reflects an anticipated energy efficiency improvement in various sectors, specific industry and power generation. The decrease of carbon intensity (the carbon content of the energy mix) reflects the larger role played by less carbon-intensive fuels, including natural gas, nuclear and renewables in the non-OECD energy mix.

Figure 2.7. CO_2 emissions forecasts, (left) ($MtCO_2$) and annual growth rates for main emissions drivers (right) (%)



Source: GECF Secretariat based on data from GECF GGM

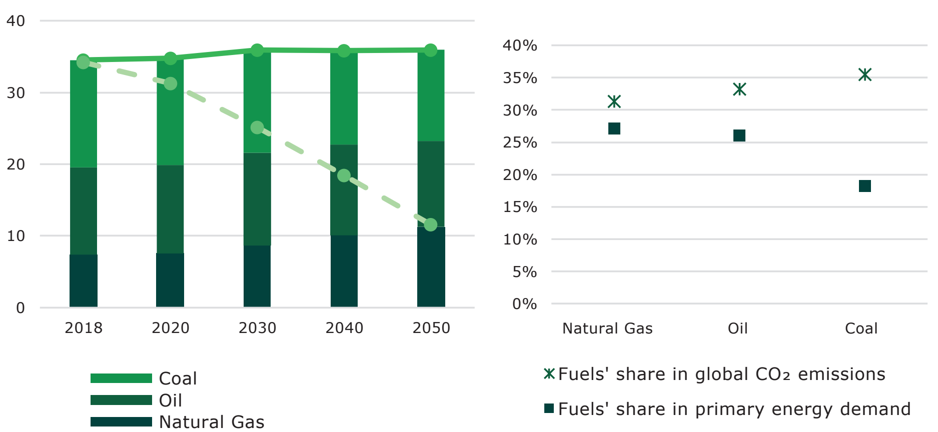
Note: the main emissions drivers are based on Kaya decomposition that considers four main components of energy-related CO_2 emissions: Population, Revenues (or GDP per capita); Energy intensity (Primary energy/GDP); and carbon intensity of the energy mix (CO_2 emissions / Primary energy).

Conversely, in the OECD region, the anticipated decrease of energy and carbon intensities will outweigh the growth of population and revenues, and drive emissions decline by around 1% per year over the forecast period. It is worth mentioning that energy efficiency improvements and structural change in the OECD economies, underpinned by a lower contribution from large energy-consuming industrial sectors, will lead to a substantial reduction of energy intensity (CAGR 2018-2050: -1.6%). This is a major driver of OECD emissions mitigation, adding to the effect of the progress of renewables and coal to gas switching.

Global trends by fuels

By 2050, the Outlook anticipates that coal and oil will remain the major contributors to global energy-related CO_2 emissions, representing respectively 35% and 33% of these emissions. The dominance of coal and oil will support the anticipated gap between forecast emissions in this Outlook, and the expected emissions trajectory under the 2° Celsius scenario (i.e. a scenario compatible with the Paris Agreement objective). The gap is estimated at around 17 $GtCO_2$ by 2040 and 24 $GtCO_2$ by 2050. One key option for closing this gap is to increase the penetration of natural gas, particularly at the expense of coal, the largest carbon-intensive fuel.

Figure 2.8. CO_2 emissions forecasts in the Reference Case vs. 2° Celsius scenario (left) ($MtCO_2$), and fuels' shares in 2050 global emissions vs. primary energy mix (right) (%)



Source: GECF Secretariat based on data from GECF GGM

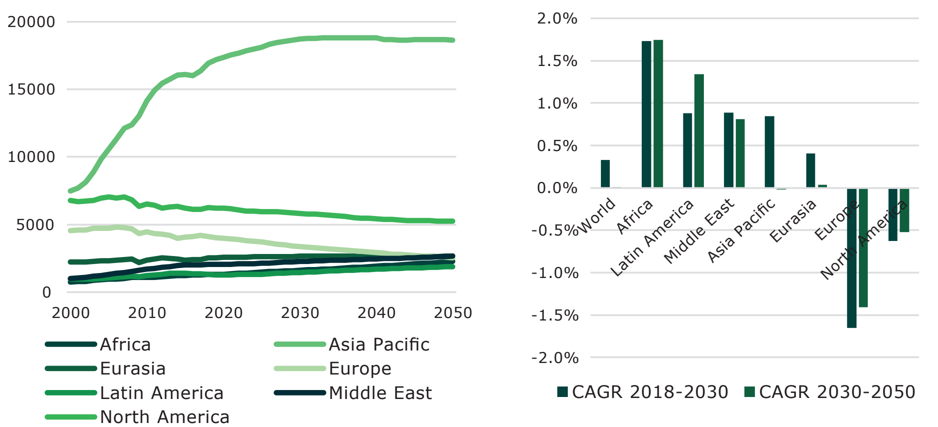
As depicted in figure 2.8 (left), natural gas is set to represent the lowest share in global CO_2 emissions by 2050 (31%) despite its highest contribution to the primary energy mix (27%). This is opposed to the forecast role of coal which is projected to be the largest contributor to 2050 global emissions with the lowest share in the primary energy mix. Natural gas is also projected to overpass oil as the largest consumed hydrocarbon energy source by 2050, though it will have a lower share of emissions than oil.

This carbon mitigation advantage of natural gas puts gas in a good position to achieve further reduction of global emissions, not only by increasing its penetration in the coal-consuming sectors (mainly power generation and industry) but also in the transport sector whose energy demand is set to remain dominated by oil products.

Regional prospects

The energy-related CO_2 emissions forecasts by region (figure 2.9) show that Asia Pacific will remain the major emitting region in the world but that it will observe a significant stabilization of its emissions after 2030, reaching almost 18.7 $GtCO_2$ by 2050.

Figure 2.9. Regional forecasts of CO_2 emissions (left) ($MtCO_2$) and CAGR (Right) (%)



Source: GECF Secretariat based on data from GECF GGM

This trajectory indicates an important decoupling between Asia Pacific economic growth (specifically in China) and emissions in the region. Figure 2.10 (left) highlights that coal-based emissions in Asia Pacific are expected to decrease by around 1.6 $GtCO_2$ between 2030 and 2050 due to significant reductions in coal utilisation in the power sector and in industrial and residential heating services. The reduction in coal demand is associated with important progress in gas demand that plays a role in stabilizing Asian Pacific emissions while providing an affordable source of energy after 2030.

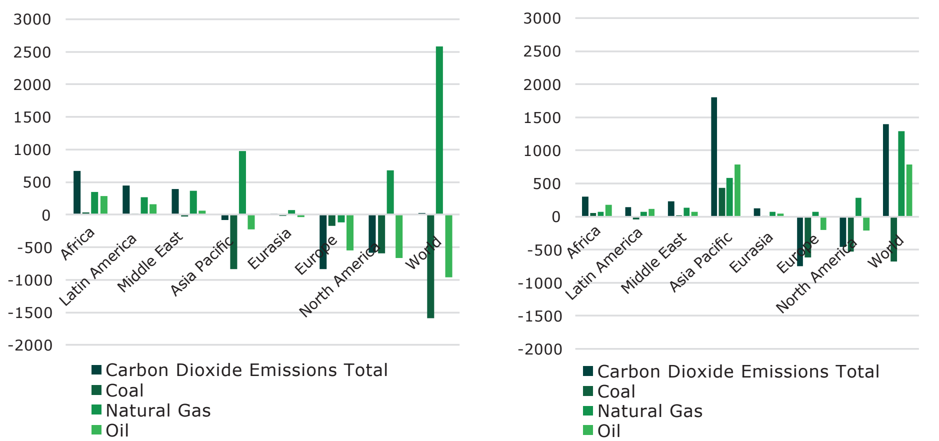
Africa and Latin America are expected to see the largest emissions growth rates (figure 2.9), driven by increasing economies and populations. Emissions growth will continue in the two regions even after 2030, underpinned by the increasing role of hydrocarbons at the expense of hydropower and biomass. Increased demand for oil in Africa and Latin America, essentially in the transport sector, is set to underpin the growth in emissions over the forecast period. Oil-based emissions will represent nearly 50% of incremental emissions in both two regions between 2018 and 2050. Total incremental emissions will reach around 970 $MtCO_2$ in Africa and almost 600 $MtCO_2$ in Latin America.

The Middle East is another region which is projected to observe a continuous growth in emissions, although a relative slowdown is anticipated due to energy efficiency improvement, progress of renewables and nuclear in countries such as the UAE, as well as greater penetration of gas at the expense of oil, especially after 2030. The average annual growth rate of the oil-based emissions in the Middle East is expected to fall from 0.6% over the 2018-2030 period to 0.3% over the 2030-2050 period.

Europe is expected to lead the decline in regional emissions with an average annual reduction estimated at 1.5% over the 2018-2050 period. As depicted in figure 2.10, natural gas is the only hydrocarbon which is anticipated to increase till 2030. After 2030, Europe will reduce substantially its demand for all hydrocarbon sources and their associated emissions due to strengthened effort to improve efficiency and increase the uptake of renewables.

North America will also reduce its global emissions by around 0.5% p.a. between 2018 and 2050, and the switching dynamic between gas and coal (figure 2.10) will support carbon mitigation in the region.

Figure 2.10. Incremental emissions for the period 2018-2030 (left) and for the period 2030-2050 (right) ($MtCO_2$)



Source: GECF Secretariat based on data from GECF GGM

It is worth mentioning that the reduction of coal-based-emissions is expected to weaken significantly after 2030 in Europe and to a lesser extent in North America. This is because the larger part of coal-based power plants is set to be retired between 2020 and 2030 following phase-out decisions in Canada and several European countries, as well as the lack of coal competitiveness in the US. As a result, the potential of coal to gas switching will be reduced after 2030, and relatively affect the emissions reduction momentum, especially in Europe (CAGR 2018-2030: -1.7 vs. CAGR 2030-2050: -1.4%).

03

Energy Demand Outlook

Key findings:

- Total global primary energy demand will rise by 0.8% per annum in the period 2018-2050, down from the historical average of 2.1% per annum since 2000 due to gains in energy efficiency.

- Fossil fuels will continue to dominate the global energy mix and will amount to 71% in 2050, against 81% in 2018. Oil will remain an important source of energy, but its share is expected to fall to 26%. Coal will drop sharply, providing only 18%. Natural gas will be the only hydrocarbon resource to increase its share, from 23% today to 27% in 2050.

- The share of renewables will more than quadruple to 9%, while nuclear and hydro will remain stable at 8% although the actual volumes will increase.

- Natural gas, the fastest growing fossil fuel, is projected to rise by 1.3% per annum from 3,924 bcm in 2018 to 5,966 bcm by 2050 driven by environmental concerns, air quality issues, coal-to-gas switching as well as economic and population growth.

- Asia Pacific, North America and the Middle East are projected to be where the bulk of future demand growth will take place, accounting for 39%, 24% and 13% respectively of the total gas increments to 2050. Europe demand is also expected to call for additional gas to 2030, but to go into gradual decline thereafter.

- The power generation (1.7% per annum) and industrial (1.2% per annum) sectors will be the biggest contributors, accounting for about 66% of additional gas demand volumes to 2050. Gas as a feedstock (1.4% per annum) is also expected to be an important source of demand growth, driven by an expanding population and its needs for fertilizers and other products of the chemical and petrochemical industries.

- The rise of gas demand in land and marine transport is projected to be particularly robust, surging by 5.4% per annum. Increasingly stringent air pollution restrictions will lead to switching from heavy fuel oil in the maritime industry. The use of LNG in heavy trucks and CNG in cars will have even more potential for growth, partially through policy initiatives aimed at offsetting transportation emissions.

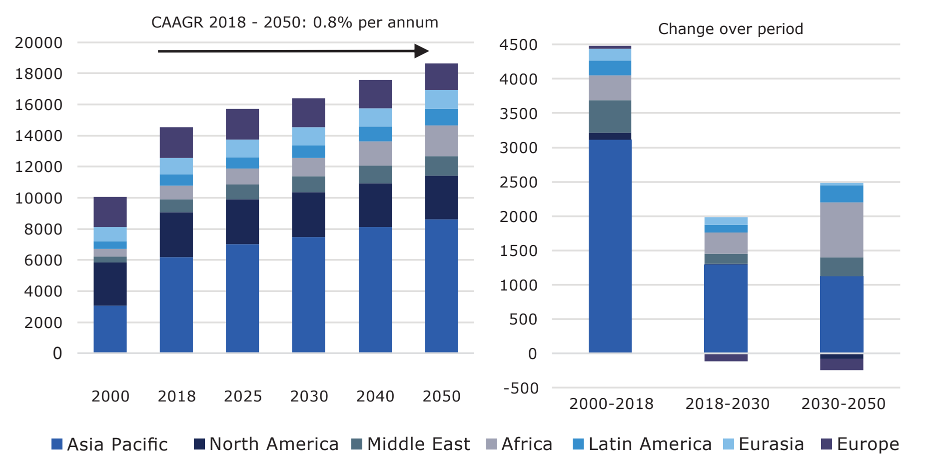
- In the power sector, gas usage will be propelled by a strong rise in electricity demand and policies to phase out coal-fired capacity. Assertive development of renewables will make gas a key fuel, providing flexible back-up. Natural gas is expected to supply 25% of the power generation mix in 2050, overtaking coal in the early 2040s.

3.1 Global primary energy demand outlook

According to the reference case scenario, the Outlook expects that energy markets will undergo a significant transformation over the next three decades, as energy accessibility unlocks an additional 28% of demand. Climbing from 14,538 Mtoe in 2018, global primary energy demand will reach 18,645 Mtoe by 2050 which corresponds to an annual average growth rate of 0.8%. Nevertheless, this indicates a slower pace than the historical average of 2.1% between 2000 and 2018, when total energy consumption expanded by 45%.

In fact despite ongoing economic and population growth, especially in developing countries, this forecast projects pervasive electrification and progress in energy efficiency in all the energy-consuming sectors, supported by energy policies oriented to diminish emissions of GHGs. It will lead to a faster rate of decline in global primary energy-intensity of GDP (set to decrease by 2.3% per annum over the 2018-2050 period, compared to the historical reduction of 1.5% per annum on a PPP basis), limiting the strong rise in energy demand. Additionally, the shift in global GDP towards the less energy-intensive service sector in developed and developing countries also favours this trend.

Figure 3.1. Global primary energy demand trends by region (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

A look at the regional breakdown of primary energy demand demonstrates that almost all of the future increase will stem from fast-growing developing countries, led by China, India as well as other emerging Asian and African economies. Thanks to rapid economic development, huge population, living standard improvements and access to domestic energy resources the Asia Pacific share of total energy demand will rise from 43% in 2018 to about 46% by 2050. Africa will represent nearly 11%.

No other region comes close to matching Asia Pacific and Africa in terms of incremental consumption, with the Middle East and Latin America being the next largest sources, with demand increases in response to sufficient energy supply and economic expansion.

Showing a robust growth over the outlook period, the Middle East and Latin America will account for 7% and 6% of global primary energy demand respectively by 2050.

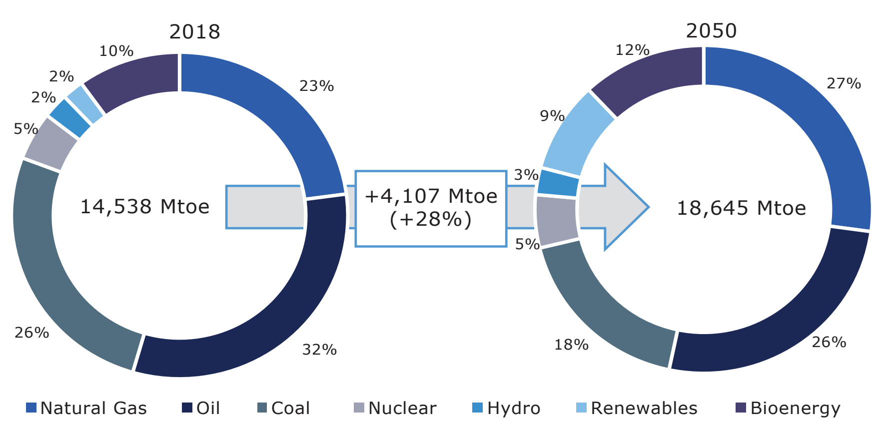
North America energy consumption is projected to remain relatively flat and account for 15% of total energy demand by 2050. Eurasia region will have the smallest incremental demand and will account for 6% of total energy consumption by 2050. Modest growth is attributed to the significant potential in energy efficiency.

Conversely, energy demand in Europe will decrease over the outlook period. Advancements in energy intensity, switching to more efficient technologies, gains in vehicle fleet fuel economy as well as the impact of energy policies targeting lower-carbon energy mix, all contribute to the drop of demand in a context where population is more-or-less static. Consequently, Europe energy demand will constitute 9% of global volumes by 2050, compared to 14% at present.

In terms of inter-fuel competition, the Outlook projects that fossil fuels will continue to dominate the global primary energy demand and will amount to 71% (13,249 Mtoe) in 2050, against 81% (11,798 Mtoe) in 2018. Oil will remain an important source of energy, but its share is expected to fall to 26%. Coal will drop much more sharply, providing only 18% of the future energy mix.

Natural gas, as the cleanest of fossil fuels, will be the only hydrocarbon resource to increase its share, from 23% in 2018 to 27% by 2050. Favoured by policymakers as well as benefiting from the low-price environment, abundant reserves and continuing expansion of suppliers globally, natural gas will make significant in-roads in the transition towards low emission energy systems.

Figure 3.2. Global primary energy demand in 2018 and in 2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

Note: Bioenergy includes traditional and modern biomass. Renewables include solar, wind, tidal and geothermal energy

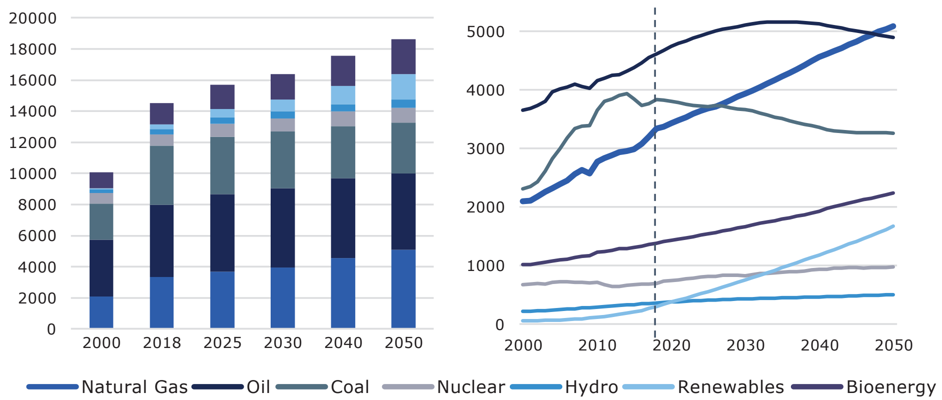
As for non-fossil fuels, the rapid growth of renewable energy, propelled by consumption for power generation, will contribute to a more diversified structure of the energy mix, with its share to increase from 2% to 9% by 2050. Nuclear and hydro will capture

CHAPTER 3

8%, approximately the same share as in 2018, but their output will continue to grow. Given that bioenergy is also projected to expand and to stay high (particularly traditional biomass in the residential sector of developing Asia and Africa), natural gas has additional potential for fuel substitution while meeting energy needs and achieving SDG 7. Overall, according to the reference case scenario, non-fossil fuels are set to increase by 2.1% per annum over the outlook horizon, at a much faster pace than fossil fuels with a growth rate of 0.4% per annum.

Natural gas demand growth is spread over many sectors. Supported by a number of factors – increasing availability of supplies, strong policy efforts to improve air quality, continued coal-to-gas switching, accompanied by traditional drivers such as rising levels of population, industrial development and surging electricity demand – natural gas is expected to be the fastest growing fossil fuel. Increasing by 1.3% per annum, it will expand from 3,346 Mtoe in 2018 to 5,091 Mtoe by 2050. In the latter half of the 2020s, natural gas will replace coal as the second-largest energy source. Taking into account that oil demand is forecast to plateau in the late 2030s and then decrease, natural gas will converge on oil by the end of the projection period and come out on top in the global primary energy mix.

Figure 3.3. Global primary energy demand trends by fuel type (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

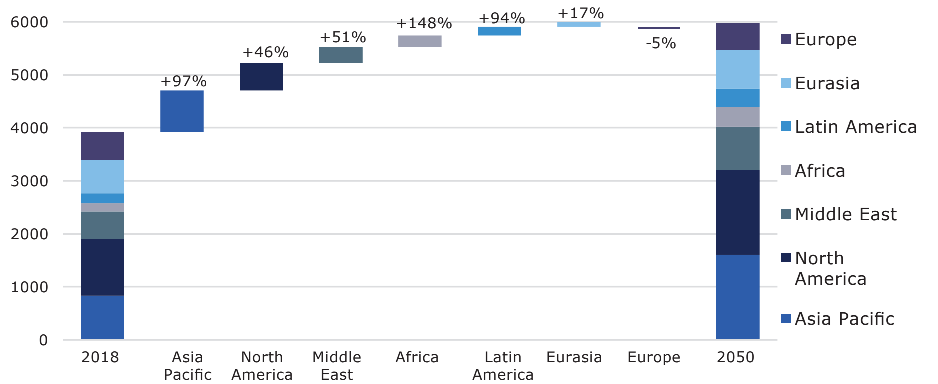
Note: Bioenergy includes traditional and modern biomass. Renewables include solar, wind, tidal and geothermal energy

3.2 Natural gas demand outlook

Global overview

Global natural gas demand is forecast to increase at an annual average growth rate of 1.3%, from 3,924 bcm in 2018 to about 5,966 bcm by 2050. It will correspond to an overall rise of 52%, an additional 2,042 bcm over the outlook period. Asia Pacific, North America and the Middle East markets are projected to be where the bulk of future demand growth will take place, accounting for 39%, 24% and 13% respectively of the total gas increments to 2050.

Figure 3.4. Trends in global natural gas demand by region (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The potential for gas demand growth in Asia Pacific is enormous. Gas consumption is expected to rise by 2.1% per annum from 828 bcm in 2018 to 1,633 bcm by 2050. Growing levels of population and industrial development, surging electricity demand as well as continued coal-to-gas switching will support this trend, allowing Asia-Pacific to catch-up with North America and become the largest gas consumer in the world, constituting 27% of the total gas demand in 2050.

In North America, demand increase will continue to be driven by the surge in shale production, particularly in the US, helping to sustain a regional growth of 1.2% per annum. Gas consumption is projected to reach 1,558 bcm by 2050, compared to 1,070 bcm in 2018, and natural gas will be a very attractive fuel for power generation. North America will account for 26% of global demand in 2050.

Gas demand in the Middle East is forecast to grow by 1.3% per annum, peaking at 795 bcm by 2050 (from 528 bcm in 2018), and to be concentrated in the industry and the power sectors, which will be the frontrunners as many countries switch away from oil to gas in order to maintain and grow oil exports while using domestic gas more efficiently. This region will represent 13% of global gas demand in 2050.

Africa is expected to have the fastest growth of 2.9% per annum, albeit from a low base, with overall demand more than doubling to 380 bcm by 2050, responsible for 6% of world total consumption. The key drivers will be the development of indigenous resources in a number of countries and increasing electricity demand.

The increase in Latina America will be supported by domestic gas resources and the desire of policy-makers to encourage the diversification of the energy mix, although infrastructure bottlenecks could be a limiting factor. At the same time, LNG imports will represent a relevant option to satisfy countries' needs. Gas demand is projected to rise by 2.1% per annum from 179 bcm in 2018 to 347 bcm by 2050, corresponding to 6% of global gas volumes. Nevertheless, gas consumption will continue to be weather dependent, taking into account the critical role that hydro plays in the region.

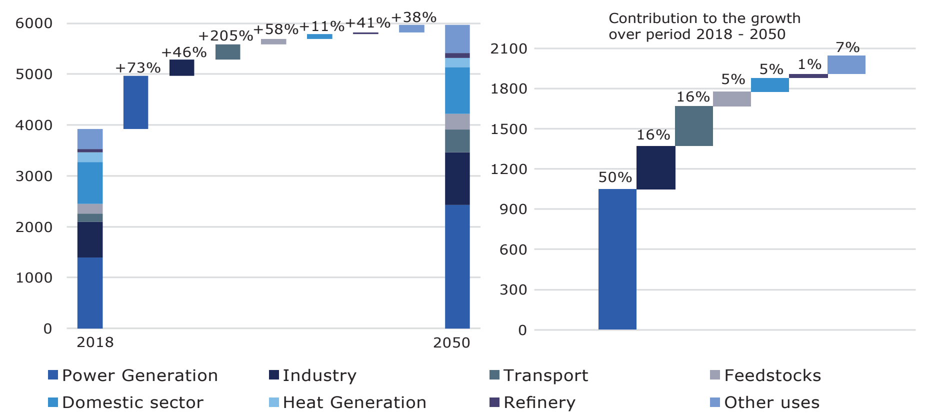
Demand growth in the Eurasia region is expected to be relatively slow, developing by 0.5% per annum from 638 bcm in 2018 to 748 bcm by 2050, due to the huge potential for efficiency gains in the power and heat generation sectors. However, expansion of gas-to-chemicals, petrochemicals and non-metallic minerals production will balance gas savings, entailing incremental rise in the region. By 2050, Eurasia will consume around 13% of global gas demand.

Europe gas consumption in the mid-term is forecast to call for additional volumes, but after the 2030s will experience a slow decline due to renewables' advancement and increased energy efficiency measures that offset the benefits of coal-to-gas switching. As a result, overall gas demand growth will be relatively stagnant (-0.1% per annum), achieving 504 bcm by 2050, with the most interesting growth prospects coming from the transport sector. Europe will account for around 8% of the global gas consumption in 2050.

Sectoral trends

From a sectoral perspective, the power generation and industrial sectors will be the biggest contributors to global natural gas demand growth, accounting for about 66% of additional volumes between 2018 and 2050. Transport will emerge as a significant new area, responsible for almost 16% of the demand growth over the projection period. Nevertheless three sectors – the power generation, industrial and domestic – will continue to be the main consumers, constituting 40%, 17% and 15% respectively of the total natural gas demand in 2050.

Figure 3.5. Global natural gas demand trends by sector (bcm)

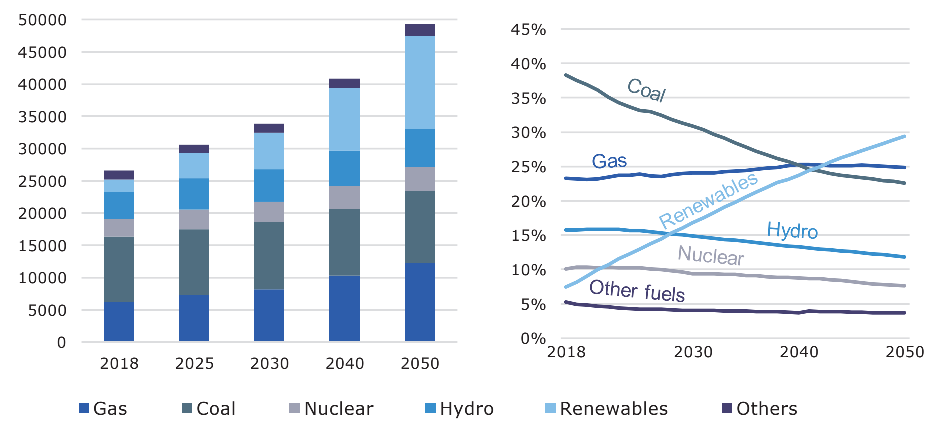


Source: GECF Secretariat based on data from the GECF GGM
Note: Other use includes natural gas demand for hydrogen production and energy industry own use
Gas demand in the heat generation sector is expected to remain flat

Power generation sector

The power generation sector will represent the largest growth engine of natural gas demand, providing half of the global gas increments through to 2050. Totalling 1,394 bcm in 2018, this sector will see an increase of 73% (or 1.7% per annum), reaching 2,405 bcm by 2050. Over the projection period, its share in the global natural gas consumption will rise in parallel, from 36% to 40%. Asia Pacific and North America will be the main drivers of additional natural gas in the power generation sector (amounting to above 64% of the growth through to 2050), although the Middle East and Africa will also demonstrate a considerable increase.

Figure 3.6. Global growth of the power generation (TWh) and fuel shares (%)



Source: GECF Secretariat based on data from the GECF GGM
Note: Other fuels (others) include oil and bioenergy

The strong rise in electricity demand, supported by policies to phase out coal-fired capacity and nuclear power plants in some regions, will open significant prospects for the development of gas-fired generation. As well as its critical role in reducing emissions compared to oil and coal generation, gas-burning power plants are characterised by a high flexibility and short start-up times. It will make natural gas a key balancing fuel suited to complement and facilitate the deployment of solar-based and wind renewable energy sources, even taking into account an anticipated progress in currently limited electricity storage.

This Outlook forecasts that global electricity demand will surge almost two-fold from 26,594 TWh in 2018 to about 49,308 TWh by 2050 (annual growth of 1.9% per annum), driven by increasing requirements in all the countries. At the same time, the power generation mix is expected to change impressively. Assertive development of renewables (predominantly, in Asia Pacific, North America and Europe) will push their share up from the current 7% to 29% by 2050, while the share of coal will fall from over 38% to under 23%. The shares of nuclear and hydro will also decrease, although much less sharply, leaving gas as the natural back-up in the light of the substantial growth in renewable energy in power systems.

We expect that the share of natural gas in the global power generation mix will reach 25% by the end of the forecast period, overtaking coal in the early 2040s. Overall, natural gas and renewables will provide 54% of 2050's electricity supply. However, coal-fired generation is projected to remain dominant in a range of countries of developing Asia, such as India, Indonesia, and Vietnam, where indigenous coal is relatively cheap. In terms of gas-fired capacity additions, this Outlook assumes an expansion by over 1,700 GW worldwide, given all the commissioning and retirements within the forecast period.

Industrial sector

The industrial sector is projected to become the second-largest source of the total natural gas increments, contributing 16% to the growth through to 2050. Industrial consumption will rise by 46%, from 705 bcm in 2018 to 1,031 bcm by 2050, corresponding to an annual rate of 1.2%. Its share in the total gas demand will remain stable at around 17%. Natural gas will continue to be widely used in energy-intensive industries where high heating temperature is required. Alongside the usage of natural gas to provide process heat in the iron and steel, and non-ferrous metals production, it will be more concentrated in the chemical and petrochemical, non-metallic minerals and, especially, in light industries (e.g. textiles, manufacturing, food and beverages), as policies to reduce emissions will be the main driver. Besides overall economic development and population growth, switching from coal- to gas-fired boilers in developing economies will also help to create the catalyst for broad-based natural gas demand in industry. Among all the regions, Asia Pacific and the Middle East will represent almost 80% of additional consumption volumes in this sector.

Domestic sector

In 2018, the domestic sector accounted for 21% of the global gas demand, reaching 821 bcm. About 69% (567 bcm) of these volumes was absorbed in the residential, followed by 30% (244 bcm) in the commercial and only 1% (10 bcm) in the agricultural segments. The majority of gas used is dedicated to space heating with typical seasonal variations due to weather-related demand. Cooking and water heating consumption is also increasing, especially in developing Asia-Pacific countries, propelled by the expansion of distributed gas grids and the overall increase in prosperity.

Driven by global urban population growth, natural gas consumption in the domestic sector is forecast to rise by 0.3% per annum (growth of 11%) to 915 bcm over the outlook period, constituting 15% of the total gas demand in 2050. However, this increase will be much less dynamic than in other sectors, reflecting that the bulk of additional total energy demand within the domestic sector will be provided by electricity thanks to greater use of electrical appliances. Another factor is declining trends in a range of European countries and the US, associated with increasing end-use energy efficiency, but these declines will be largely offset by the potential for growth in other regions.

Feedstock sector

The non-combusted use of natural gas as a feedstock is an increasingly important component for petrochemicals, agricultural chemicals (fertilizers) and pharmaceutical products. Natural gas consists almost entirely of methane that is used in methanol, ammonia and urea production, however, it also contains a small amount of other hydrocarbon gases such as butane, ethane, propane, pentane, making this fuel a base ingredient for many industrial applications. Growing global supplies of LNG will support the availability of natural gas as a feedstock.

In the feedstock sector, a variety of trends will shape future demand. A key driver is population growth, reinforced by the process of urbanization. According to the projections, the global urban population will reach almost 6.7 billion by 2050 (around 70% of the global population) that is about 2.5 billion higher than in 2018. Another factor is the increase of living standards and the movement of people from the lower to the middle economic class. As the production of almost all consumer products is linked to the petrochemical industry, growth in durable and non-durable goods will catalyze per-capita consumption. Natural gas demand in gas-to-chemicals, petrochemicals and fertilizer feedstocks sector is expected to increase by 1.4% per annum, from 190 bcm in 2018 to about 300 bcm in 2050 (overall growth of 58%).

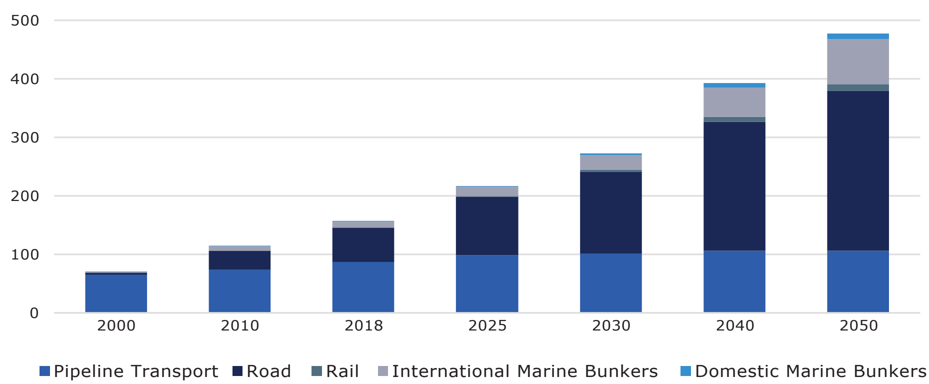
3.3 Natural gas prospects in the transport sector

The growth of the natural gas share in the global energy mix is partly thanks to the demand prospects for gas in the transport sector. Despite that a large portion of the energy consumed in global transportation networks comes mostly from petroleum-based products, natural gas represents the most versatile, affordable and the cleanest burning convention alternative. It could gradually substitute gasoline, diesel and other oil-based fuels in the land (road and rail) and marine transport segments.

In 2018, natural gas demand in the transport sector totalled 157 bcm, constituting 4% of global gas consumption. Nearly 56% (87 bcm) was related to the usage in pipeline transport, 44% to the road (58 bcm) and marine (11 bcm) segments. This report forecasts that gas demand in the transport sector will rise at an annual pace of 3.5% over the outlook period, much faster than in other sectors, achieving about 478 bcm in 2050. It will account for 8% of global gas consumption.

Our forecasts show that this robust gas demand growth rate will be encouraged by important progress in natural gas vehicles (NGVs), partially through policy initiatives aimed at offsetting transportation emissions, which account for more than 24% of global GHG emissions. The International Maritime Organization regulations are also forecast to have an impact on gas demand in transport, as the maritime industry begins to switch to LNG.

Figure 3.7. Global natural gas demand trends in the transport sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

In spite of the growing interest of gas applications in the railway industry, demand volumes in this segment are forecast to develop at a moderate pace, while road transport will drive consumption. About 214 bcm of incremental gas volumes to 2050 are expected to stem from the development of the global NGV market. The use of LNG as a marine bunkering will be another promising area with additional consumption of 76 bcm within the forecast horizon. Overall, global gas demand in the land and marine transport segments (excluding gas used in pipeline transport) is projected to rise by about 300 bcm, from 70 bcm in 2018 to over 370 bcm by 2050. It will correspond to a growth rate of 5.4% per annum.

The prospects of natural gas usage as a fuel for vehicles

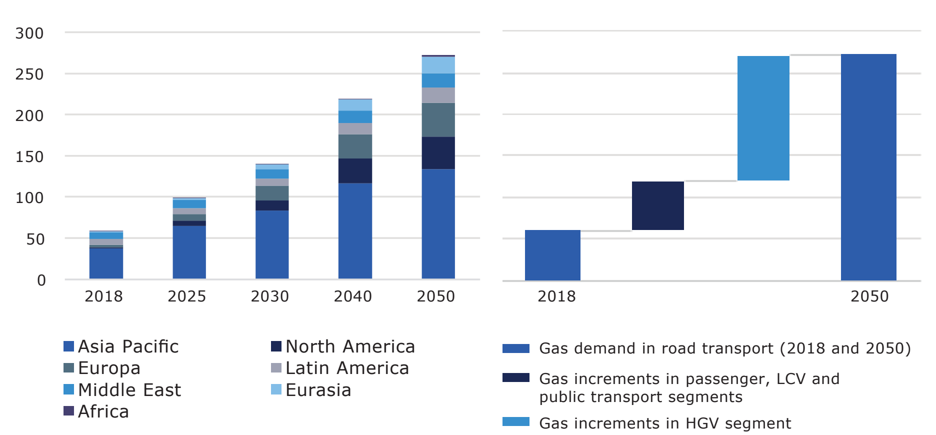
The increasing availability of natural gas, together with its economic and environmental advantages, make NGVs a very prominent alternative to diesel and gasoline-based engines in road transport. Liquefied petroleum gas (LPG) is also widely used across the world. However, being a mixture of propane and butane it is not as clean as natural gas, whose main chemical component is methane.

Over the last decades natural gas, predominantly in the form of compressed natural gas (CNG), has made remarkable progress in various sub-markets – passenger, buses, light commercial vehicles (LCVs) as well as heavy-good vehicles (HGVs) and special mining and haulage company trucks. Surging by almost 17% per annum, natural gas demand in the road transport segment increased from 4 bcm in 2000 to about 58 bcm in 2018. Major contributions to this growth came from Asia Pacific (China, India, Pakistan) and the Middle East (particularly, Iran), while Latin America countries (mainly, Argentina and Brazil) experienced moderate rise, staying around the same volumes from 2005 to 2018.

In spite of the impressive growth rate, natural gas represents less than 2.5% of the total energy consumed in the global road transport market, which is currently dominated by oil-based products – gasoline and diesel – with a 96% share. As many countries are adjusting legislation to reduce the environmental impact of transportation modes and setting targets to mitigate air pollution, we anticipate that the role of methane in this segment will grow over the forecast period, assuming a higher uptake of NGVs and a corresponding level of gas demand. Favourable government policies and regulatory frameworks are expected to be the forces driving increasing penetration of natural gas in road transport.

This Outlook expects that gas demand in road transport will increase by about 214 bcm, from 58 bcm in 2018 to 272 bcm by 2050, corresponding to an average increase of 4.9% per annum. More than 80% of gas increments will originate in Asia Pacific (mostly, China and India), North America (the US) and Europe (led by Italy, France, Germany and Spain).

Figure 3.8. Natural gas demand in road transport by region and by segment (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The natural gas share of energy demand in the global road transport market (estimated to grow from 2,154 Mtoe in 2018 to 2,420 Mtoe by 2050), is forecast to rise from 2.5% in 2018 to 10% by 2050, while petrol and diesel will go down from 96% to 83%. Over the same period, electricity use is projected to increase from 0.3% to 6%, a much more impressive growth. Given that EV penetration into all vehicle classes is underway, they are considered to be a more realistic option for the passenger, public transport and LCV segments, while the potential of NGVs could be much higher in the HGV segment, where transport costs are more vital. Moreover, environmental regulations are set to be stricter, propelling fuel replacement in oil-based products.

In this context, the future prospects of natural gas will be mostly concentrated in HGVs, driven by anticipated restrictions on the use of diesel trucks in a range of countries. The majority of gas demand is expected to come from LNG-powered trucks thanks to their high annual mileage. It is worth mentioning that governments of more than 10 countries in 2017-2019 introduced forward-looking sales bans on new diesel or petrol vehicles for 2025-2040, which represents an additional push for gas usage.

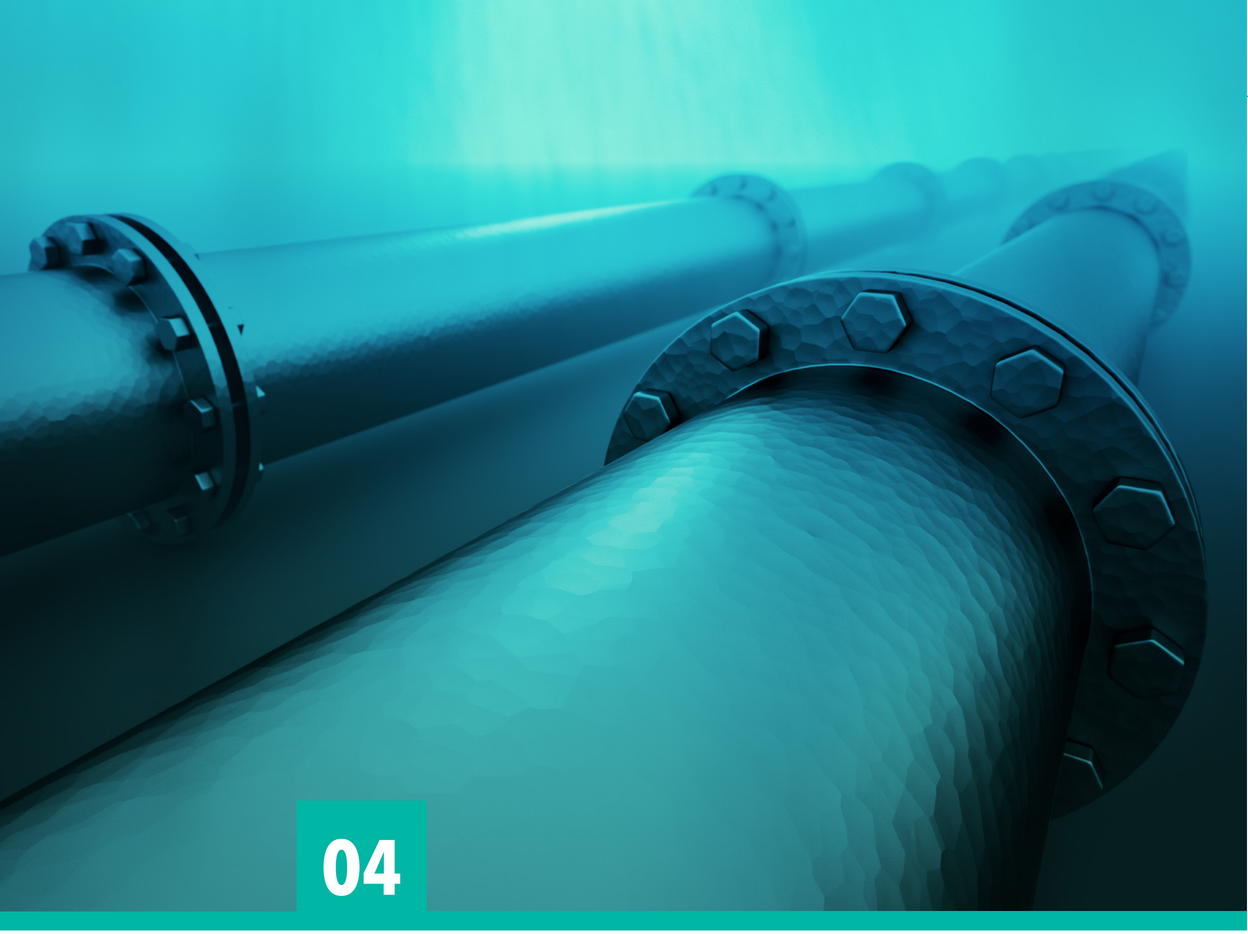
Natural gas demand in marine transport

The use of LNG as a shipping fuel is expected to become an important alternative to heavy fuel oil, foremostly thanks to its compliance with the future requirements for the major types of emissions. LNG does not produce particulate matters and, compared to oil-based fuels, can reduce substantially carbon dioxide (CO_2) and nitrogen oxide (NOx) emissions. Simultaneously, LNG contains virtually no sulphur oxides (SOx). In this context, the implementation by the IMO of a new emission standard of a 0.5% cap on the amount of sulphur in marine fuel (replacing the current limit of 3.5%) coming into effect from 2020, will give fresh impetus to LNG bunker demand as a fuel of choice for new build vessels or retrofitting existing ones. Such a move will contribute to the IMO initial strategy to reduce GHG by at least 50% by 2050, compared to 2008.

According to our projections, marine LNG demand will accelerate post-2025, although LNG propulsion will face strong competition from low-sulphur oil products as well as the installation of scrubbers. The economics of retro-fitting and LNG-fueled engines are not great compared with scrubbers, but it is expected that new ships will increasingly be constructed with LNG engines. As a result, the move to LNG will be quite gradual.

In the long-term, stricter environmental regulations, such as the existing 0.1% limit on sulphur content within the mandated emission control areas (ECAs), as well as local restrictions applying for open-loop scrubbers (particularly due to concerns about the disposal of sulphur-rich wash water and other waste products) will lead to more conversions and new builds, utilizing LNG engines.

Overall, in 2050, the total consumption of bunker fuels is projected to be around 258 Mtoe. Thanks to the combination of environmental advantages, availability and price competitiveness, the LNG share of the global bunker fuel market will reach 29% (compared to 3% in 2018). Accordingly, this Outlook predict LNG demand in the marine transport segment to reach 87 bcm by 2050 from the level of 11 bcm in 2018, increasing by 6.7% per annum.



04

Natural Gas Supply Outlook

Key findings:

- Gas production will rise by 1.3% per annum to 2050, with North America accounting for the largest share of this growth, followed by Eurasia, Africa and the Middle East. Total gas supply is estimated to reach almost 6 tcm by the end of the period.

- Global gas production will become more diversified, with 13 countries producing more than 100 bcm per annum by 2050, compared to 9 countries at present.

- Europe is the only region where gas production is expected to fall. All the major producers (Norway, the UK, the Netherlands) will see sharp declines, with Cyprus being the only country where production is set to rise over the long-term.

- Latin America has significant gas production potential, despite being a small supplier at present. By 2050 it is expected to have overtaken Europe as a gas producer, with output of 280 bcm being 56% higher than in 2018.

- Recent discoveries of large gas fields in Africa mean that the region has huge production growth potential, with overall output from the continent expected to rise from below 250 bcm to over 660 bcm by 2050, accounting for 20% of the global gas production increase during the period.

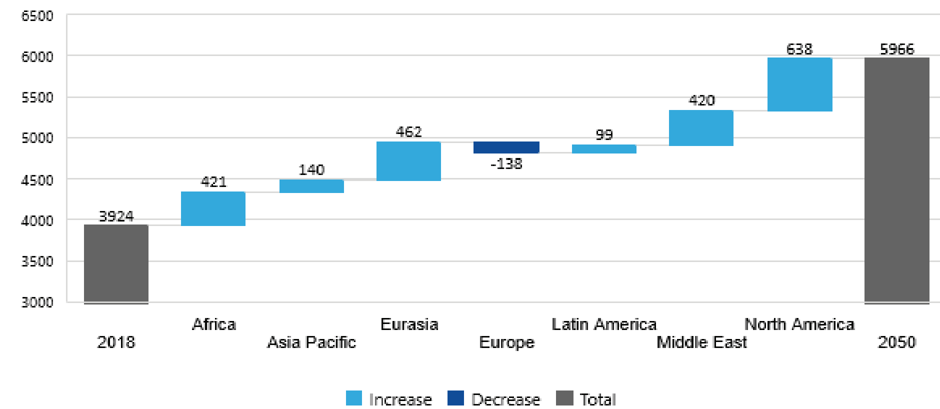
- Production from unconventional resources will become increasingly important, and their share of overall output is expected to rise from 25% to 38% by 2050. In addition, yet-to-find production will also be vital, highlighting the need for increased exploration for new gas reserves.

4.1 Global natural gas production outlook

Global natural gas production will continue to rise by an average annual growth rate of 1.3% from 3924 bcm in 2018 to 5966 bcm in 2050. North America will contribute the largest share of the growth, accounting for almost 31% of the total change, and is followed by the Eurasia, Africa and Middle East. Europe is the only region that sees its gas production declining over the outlook period.

Figure 4.1 illustrates how regions contribute to the total expansion in global natural gas production.

Figure 4.1. Outlook on global natural gas production expansion by region (bcm)



Source: GECF Secretariat based on data from the GECF GGM

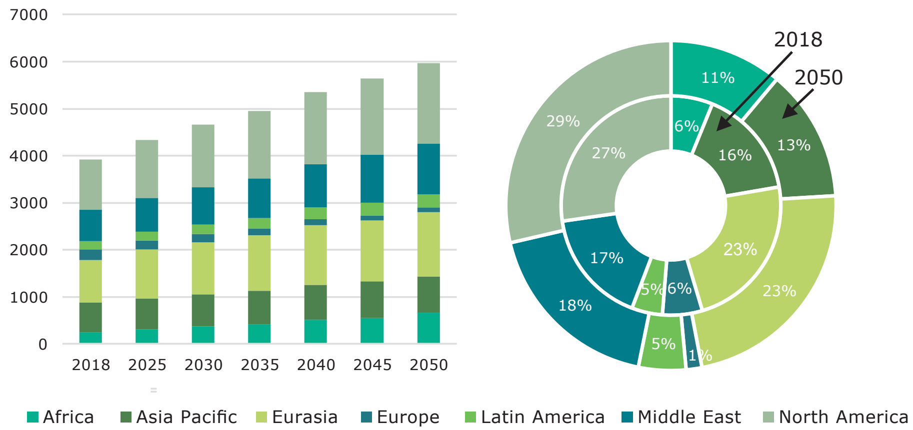
The Medium-term forecast for natural gas production is also promising. Global gas production will increase by around 400 bcm to slightly more than 4330 bcm by 2025, an average annual growth rate of 1.4% that is marginally above the average annual growth rate for the period till 2050. North America is also set to be the largest contributor to medium-term natural gas production escalation with a share of almost 50% and is again followed by Eurasia.

Besides the rise in natural gas demand as the main driver for natural gas production other policy measures, the economic advantages of natural gas, technological improvements and resource availability will stimulate the rise in natural gas production. Just to name a few, they include coal-to-gas switching policies, technology advancement in unconventional production as well as deep-water production, and infrastructure development in the mid-stream and down-stream.

Technology innovation in offshore production, especially in stranded deep-water fields, will stimulate unlocking a huge volume of gas resources and increase natural gas production. The recent advancement in FLNG technology can be mentioned as an example of cost reduction from commercialising this technology has led to it being deployed in small-scale units such as Petronas FLNG1 and Golar's Hilli Episeyo facilities.

Natural gas production will be more diversified geographically in the future. According to the latest modelling results, the number of countries with natural gas production above the level of 100 bcm per annum will rise to thirteen, compared with nine in 2018. In addition, more than twenty countries are set to produce above the level of 50 bcm per annum by 2050. As a result, a more competitive situation and the diversified location of the production nodes will shape future gas markets and stimulate different forms of natural gas trading together with price changing mechanisms. Figure 4.2 illustrates the global natural gas outlook over the period between 2018 and 2050, and the share of each region at beginning and end of the forecast period.

Figure 4.2. Global natural gas production by region (bcm), and the share of regions in global production (%)



Source: GECF Secretariat based on data from the GECF GGM

Figure 4.2 highlights the share of European gas production to reach 1% in global gas production, while the share of Africa is forecast to increase and reach 11% by 2050. This means that development in established African gas producers in addition to the new significant potential of production in countries such as Mozambique will promote the position of the region in global gas supply, and Africa will produce more natural gas than the current production level of Europe and Latin America combined. Currently African gas production is half of the aggregated production from these regions.

Historical data shows that during recent years (from 2010 to 2018), with the exception of Europe, all regions have enhanced their gas production. The Middle East marked an annual growth rate of 4.7%, followed by North America with 3.6% and Asia Pacific with 3.5%. Expansion in the Middle East has been driven by Iran and Qatar and, to a lesser extent, Saudi Arabia, adding 97 bcm, 70 bcm, and 34 bcm, respectively, to the annual global gas production. In the Asia Pacific region, China and Australia were responsible for most of the increase, adding more than 60 and 80 bcm respectively to the annual production.

The US, Russia, and Iran are currently the top three natural gas producers in the world, and it is expected that this ranking will remain unchanged by 2050, similar to our previous forecast. These significant gas producers will keep expanding their exploration and will in aggregate increase their annual production by more than 1 tcm, which will account for 42% of the total global incremental volume expected by 2050.

4.2 Regional natural gas production outlook

ASIA PACIFIC

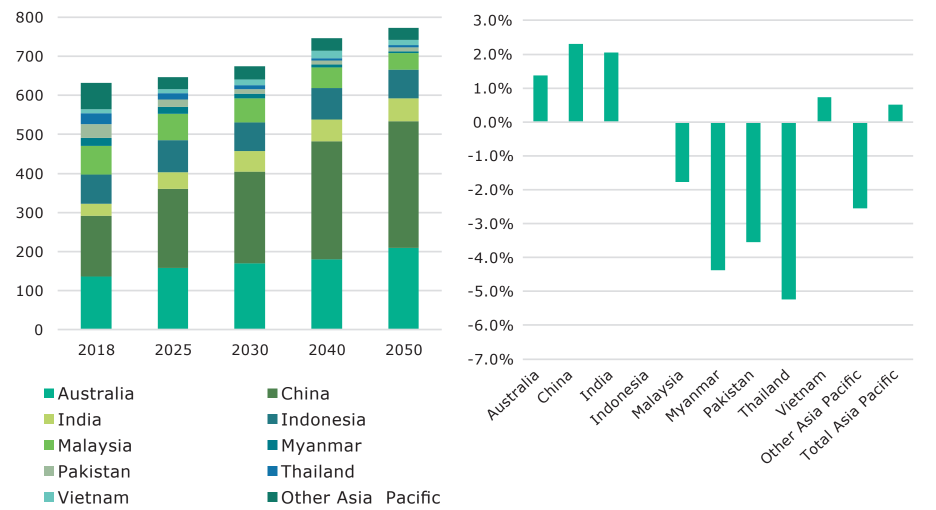
Currently, the Asia Pacific region is a source of more than 16% of global gas production with established gas producers such as China, Australia, Indonesia, and Malaysia. There are also countries with plans to increase gas production, such as Myanmar, Thailand.

Recent discoveries in Indonesia, Malaysia, and Vietnam support the projection of a steady supply over the next 10 years. With new supplies from the established gas producers, the overall outlook for Asia Pacific is optimistic up to 2040, when more than 150 bcm per annum of additional supply is forecast to be sourced from the region. However, after 2040 we see a reduction in the production of almost all the region's producers except China and Asutralia. It is expected that Indonesia and Malaysia will reduce the annual production of natual gas over the period between 2040 and 2050 by around 19 bcm, mostly due to field depletion and lack of new resouces. Vietnam, Thailand, and Myanmar are expected to have slight negative growth in that period.

Figure 4.3 illustrates the outlook for the Asia Pacific as well as the average growth rate of the main gas producers of the region over the outlook period.

As mentioned, almost all producers in the region except China and Australia will not be able to maintain their gas production growth after 2040 and the share of the region in global gas production is forecast to be only 13% in 2050. China will maintain positive growth after 2040 thanks to shale gas development and, to a lesser extent, coal-bed methane. This Outlook sees an overall annual average growth rate of 0.5% for the region with the highest contribution from China accounting for around 170 bcm per annum, which is around 60% of the total incremental value of gas production in the region.

Figure 4.3. Asia Pacific natural gas production (bcm), and associated CAAGR (2018-2050, %)



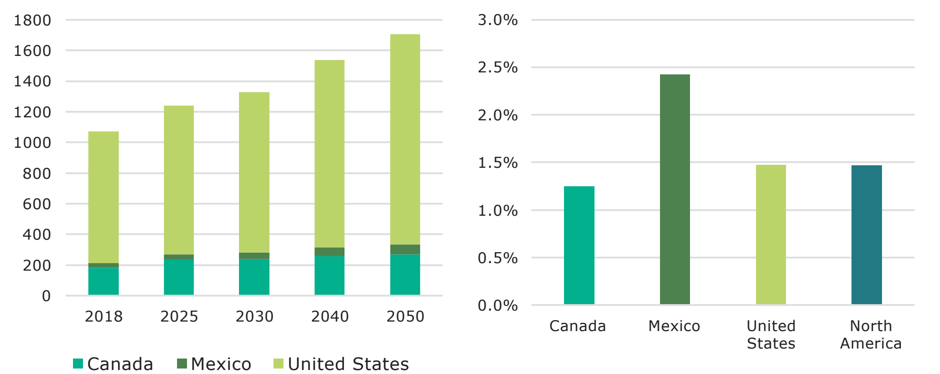
Source: GECF Secretariat based on data from the GECF GGM

North America

North America is the largest gas producing region with a share of more than 27%. In 2018, North America added approximately 100 bcm to its total marketed gas production, almost all sourced from the US production backed up the commissioning new export facilities and pipeline expansion from several production points to consumption centres. Historically, excess production of shale gas in the US, plus huge associated natural gas production in the Permian basin encouraged ambitious export plans. Planned liquefaction facilities have been coming on stream one after another during recent years and, as a result of the expanded capacity of the natural gas supply chain there has been an increase in US gas production.

Except for Mexico, which experienced a slight reduction in its gas production due to the depletion of oil fields and consequently a reduction in associated gas production, the other two countries displayed an increase in production that was mostly due to the development of export facilities.

Figure 4.4. North America natural gas production (bcm), and associated CAAGR (2018-2050, %)



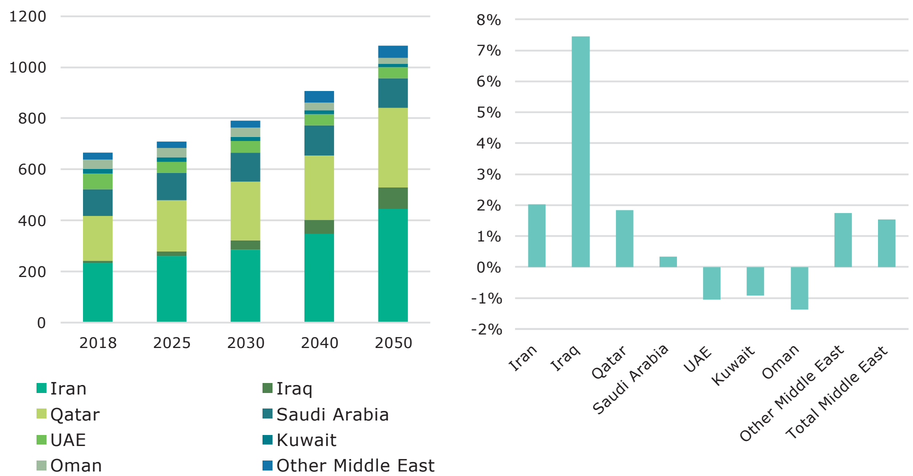
Source: GECF Secretariat based on data from the GECF GGM

The region is expected to display the largest increase in the value of natural gas production, compared to other regions, over the Outlook period. The Outlook expects that more than 638 bcm of natural gas will be added to the region's annual production, which will reach more than 1,708 bcm by 2050. All three countries in the region, US, Canada, and Mexico, are expected to enhance their production capacity and consequently maintain their shares of global production over the forecast period. The US is expected to contribute almost one quarter of the global gas supply, and Mexico increases its share of global gas supply from the current 0.8% to 1.1%. The region is foreseen to achieve an annual average growth of 1.5%, a total growth of 60% by 2050.

MIDDLE EAST

With almost 17% of global gas production, the Middle East is the third-largest gas exporter worldwide after North America and Eurasia. The region produced around 660 bcm in 2018, a growth of more than 5% year-on-year. Iran, Saudi Arabia, and Qatar are the main source of the growth. These three countries, in addition to Oman and UAE, are the largest gas producers in the region and provide more than 90% of gas output in the Middle East. Iran alone is the source of more than one-third of Middle East gas output and more than 6% of global marketed gas production.

Figure 4.5. Middle East natural gas production (bcm), and associated CAAGR (2018-2050, %)



Source: GECF Secretariat based on data from the GECF GGM

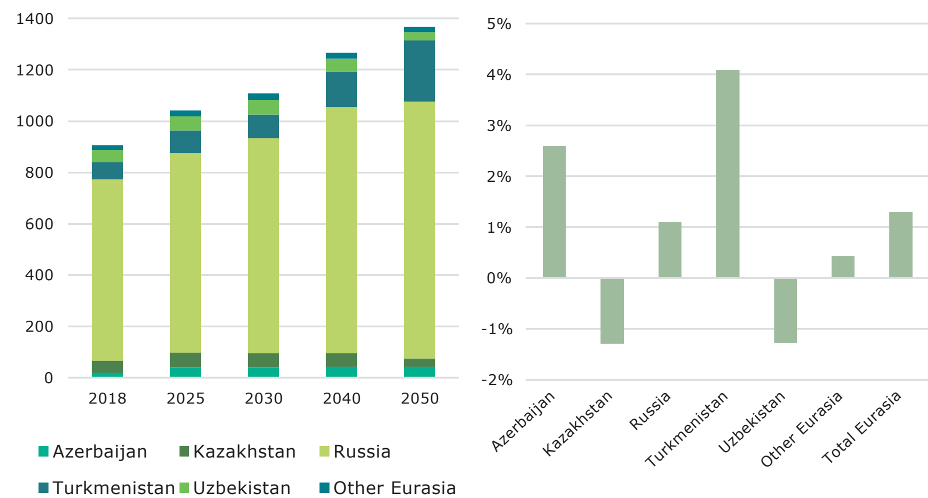
Based on a very significant resource base and the feasibility of gas exports and progressing increasing demand, the outlook for this region has always been promising, and the latest modelling results were no exception.

This Outlook expects that natural gas production in the region will continue to rise to more than 1.1 tcm by 2050 when the share of the region in global marketed gas production is up to almost 18%. The Middle East will be responsible for more than 20% of changes in world natural gas production by 2050 by adding almost 420 bcm to its current annual production.

EURASIA

Eurasia produced more than 900 bcm of natural gas in 2018, almost 23% of global production. More than 78% of the region's gas production was sourced by Russia. Other countries, including Turkmenistan, Uzbekistan, Kazakhstan, and Azerbaijan contributed to 7%, 5%, 5%, and 2%, respectively. Russia, Turkmenistan, and Azerbaijan are forecast to increase their level of gas production over the Outlook period while gas production in Kazakhstan and Uzbekistan is expected to fall after 2040. The region is expected to add more than 460 bcm to its current annual production, of which Russia contributes more than 65%, around 300 bcm by 2050. Eurasia gas production is expected to increase at an annual average growth rate of 1.3% between 2018 and 2050.

Figure 4.6. Eurasia natural gas production (bcm), and associated CAAGR (2018-2050, %)

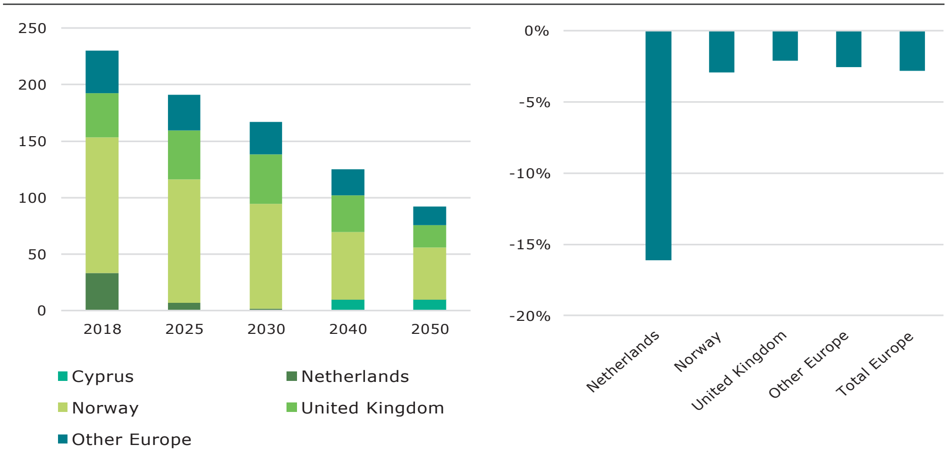


Source: GECF Secretariat based on data from the GECF GGM

EUROPE

As in our previous Outlook, this Outlook sees Europe as the only region in which natural gas production will fall over the next decades. Except for Cyprus, all other gas producers in Europe will reduce their level of gas production by 2050. In some cases, such as Romania and Poland, a modest increase is expected in the short-term but overall the level of production at the end of the outlook period is lower than at present.

Figure 4.7. Europe natural gas production (bcm), and associated CAAGR (2018-2050, %)



Source: GECF Secretariat based on data from the GECF GGM

The most significant fall in natural gas production will be marked by Norway whose annual production will fall by more than 75 bcm to 46 bcm by 2050 followed by the Netherlands and UK, which are expected to decline by 33 and 20 bcm respectively over the same period. In spite of these huge reductions in gas production, Norway and UK will maintain their positions as the first and second largest gas producers in Europe. However, the third-largest gas producer in Europe in 2050 will not be the Netherlands but Cyprus.

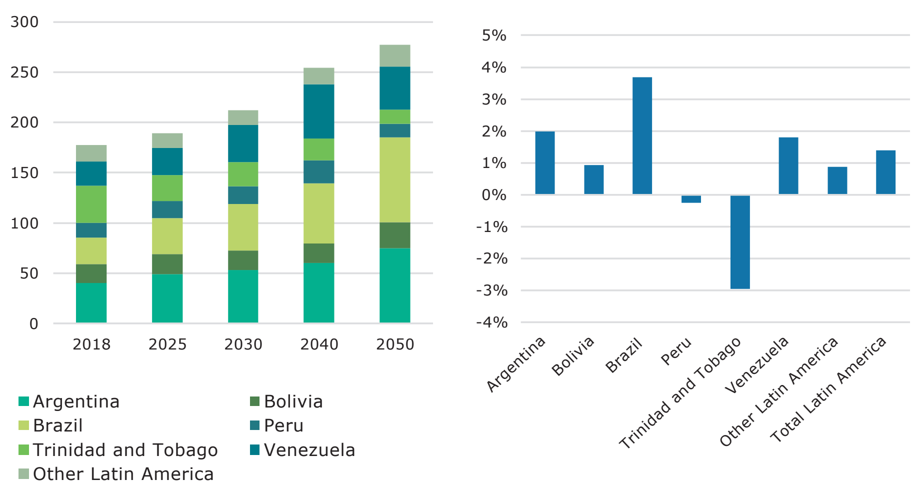
Total European gas production is expected to reach about 88 bcm per annum by 2050, almost one-third of the current volume. Europe is expected to contribute only 1.5% of global gas production compared with the current 5.9%.

LATIN AMERICA

Various untapped gas resources in Latin America position this region as one in which natural gas will have a bright future. Within the region, almost all types of natural gas resources can be found, such as shale gas, tight gas, CBM, and conventional resources. Latin America, including the Caribbean countries, is currently the smallest producer globally, with more than 180 bcm of natural gas production.

Latin American production is mostly sourced from Argentina, Trinidad and Tobago, Brazil, Venezuela, Bolivia, Peru, and Colombia in order of significance. Almost all of them, except for Trinidad and Tobago, are expected to increase their gas production over the forecast period. As a result, the region is expected to boost its gas production by around 100 bcm to around 280 bcm by 2050 which will enable it to overtake Europe's gas production by then. According to the latest results of the GECF GGM, Latin America will expand its gas production by 56% over the forecast period and will account for 4.6% of global annual gas production in 2050 (see Figure 4.8).

Figure 4.8. Latin America natural gas production (bcm), and associated CAAGR (2018-2050, %)



Source: GECF Secretariat based on data from the GECF GGM

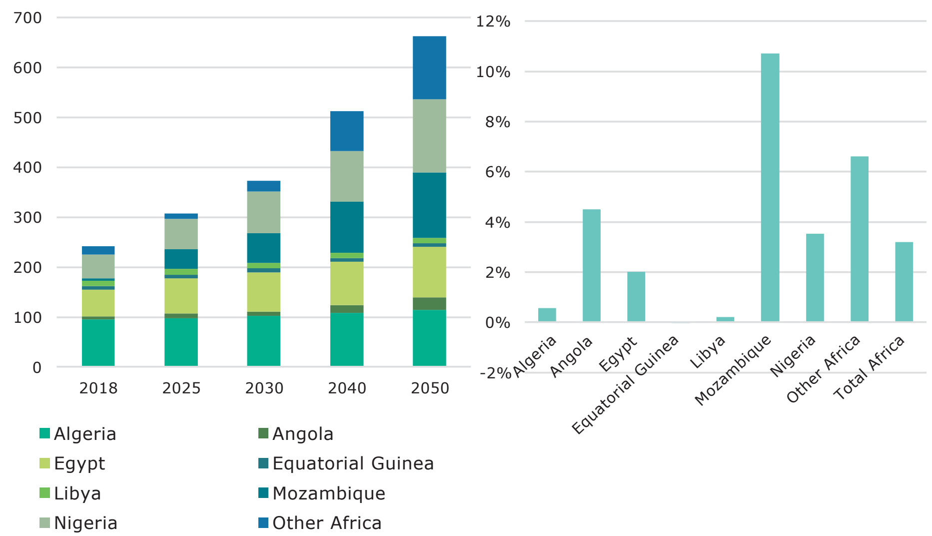
AFRICA

Thanks to a set of very significant discoveries all over the continent and extensive resources, the region has gained attention in the oil and gas industry as having a great potential. Although a huge share of most of these resources has not yet been developed for various reasons, including lack of investment, a very promising outlook is expected in the future, and almost all reserves holders are expected to contribute positively.

Currently, Africa holds a share of around 6% in global marketed gas production; however, this Outlook foresees that it will rise to 11% by 2050. The Outlook expects that Africa's annual gas production will increase by more than 420 bcm over the forecast horizon.

Marketed gas production in Africa is forecast to increase from around 240 bcm in 2018 to more than 660 bcm by 2050, a 182% increase at an annual average growth rate of 3.3%. Almost one-fifth of the increase in global natural gas production is set to be sourced from Africa. Approximately half of the African expansion will come from Mozambique and Nigeria. All other established gas producers in Africa, such as Algeria, Egypt, Libya, Angola, and Equatorial Guinea will contribute positively to the region's development. Other emerging producers such as Tanzania, Cameroon, Mauritania, and Senegal will also show positive contributions (See Figure 4.9).

Figure 4.9. Africa natural gas production (bcm), and associated CAAGR (2018-2050, %)

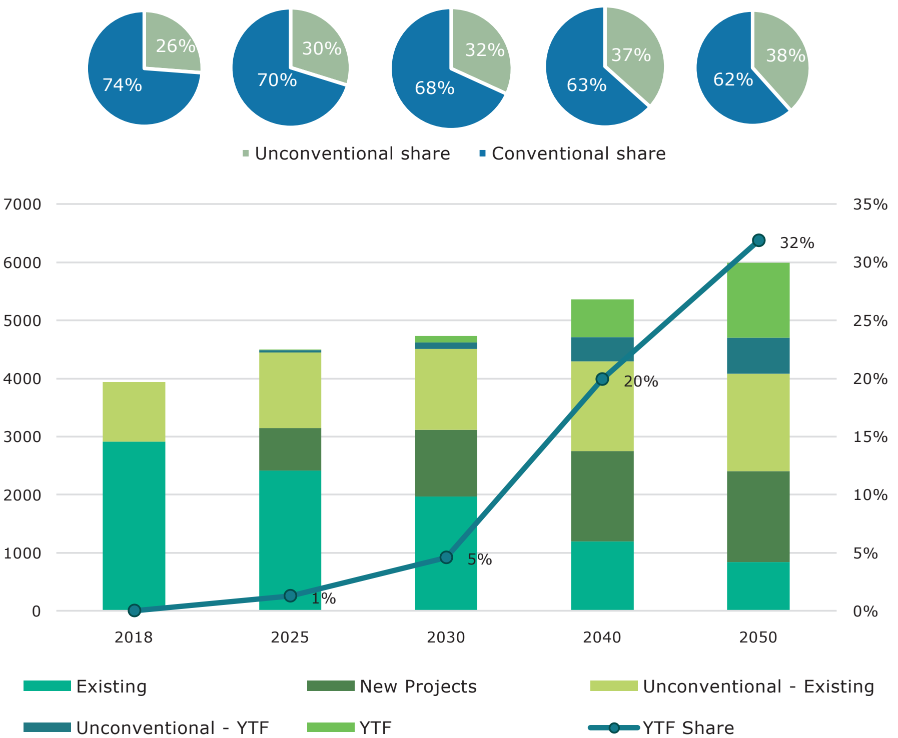


Source: GECF Secretariat based on data from the GECF GGM

4.3 Unconventional and YTF gas production outlook

Technology advancement in up- and mid-stream gas production sector has been enhancing the competitiveness of unconventional production over the decade. Advancement and cost reduction in directional and horizontal drilling as well as fracturing technologies besides other technologies to control the negative climate impacts across the entire production chain, has already signed a bright future for almost all types of unconventional resource and in particular shale gas production.

Figure 4.10. Global conventional and unconventional gas production outlook (bcm, %)



Source: GECF Secretariat based on data from the GECF GGM

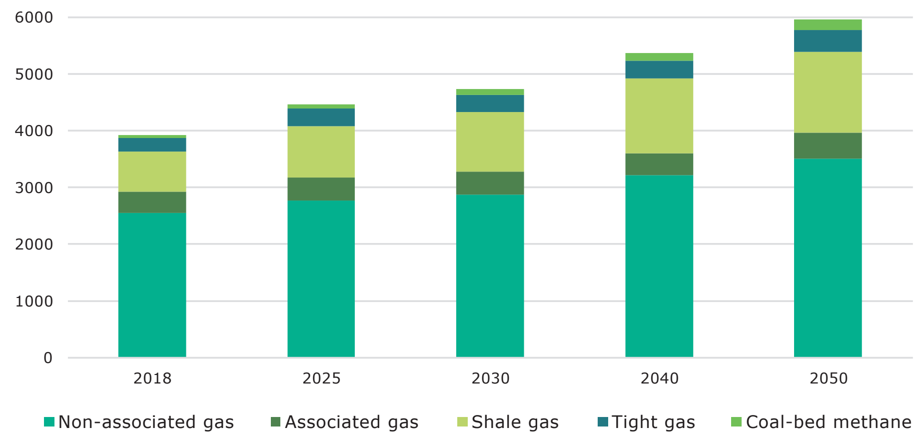
Currently, more than a quarter of global natural gas production is sourced from unconventional resources. This is mostly due to the significant production in the US and to a lesser extent in Canada, Australia, and China.

According to the latest modeling results, the share of unconventional production in global gas production will continue to increase and reach 38% by 2050. This significant expansion is mostly from the US followed by China, Canada, and Argentina and to a lesser extent Algeria, and Australia. The Outlook expects that total unconventional production will reach an annual value of more than 2,300 bcm by 2050, a growth of 220% compared to the current value. This is mostly sourced from shale gas production, followed by tight gas and coal-bed methane.

The role of YTF resources in the natural gas production outlook is very significant. It is forecast that around one third of total annual production by 2050 will be sourced from gas resources that have not yet been categorized as proven reserves. This means that the world needs to lead exploration projects to discover reserves to avoid facing a volume of reserves insufficient to meet the global gas demand.YTF unconventional resources are set to play an important role in developing production in some countries such as China. It is forecast that China will produce more than 200 bcm per annum from YTF unconventional resources in 2050, which will account for more than half of its total forecast production. Therefore, we can see that the discovery and exploration of unconventional plays is a vital issue in expanding production in certain countries. It is forecast that more than 1,680 bcm of natural gas will be produced annually by 2050 from existing proven unconventional plays located in the US, Canada, China, Australia, Argentina, Oman, and other producing countries. Also, around 620 bcm per year of production will be sourced from YTF unconventional resources by 2050 (around 10% of total production).

Shale gas development is the main factor behind unconventional expansion over the outlook period. Production from shale plays has been developing in the last decade, especially in North America and advancements in extraction technologies from shale such as hydraulic fracturing have resulted in reduced costs that enable economic production even with lower oil and gas prices. Figure 4.11 presents the outlook for gas production by type of hydrocarbon, including associated and non-associated gas, to show how each type of hydrocarbon is forecast to contribute to the total natural gas production over the forecast period.

Figure 4.11. Global gas production outlook by type of hydrocarbon (bcm)



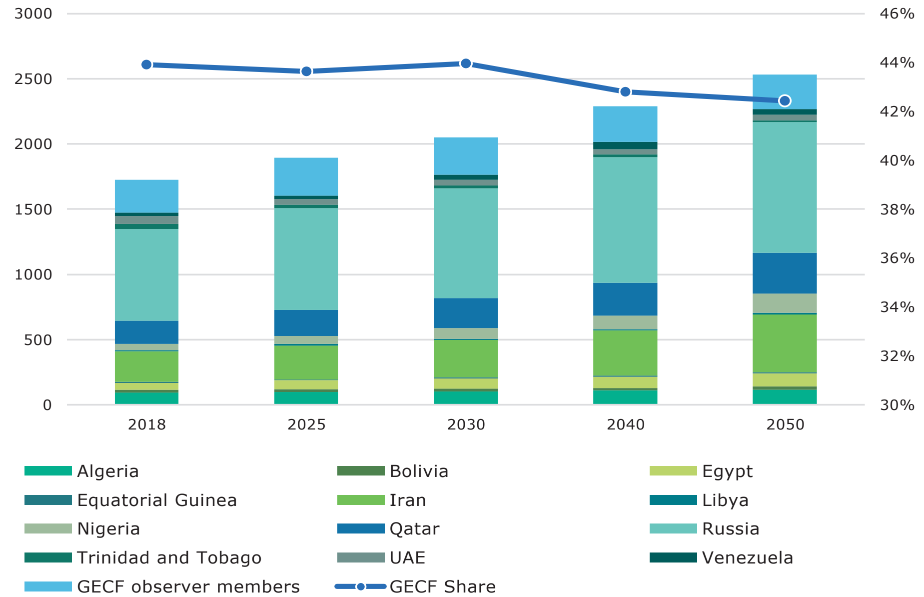
Source: GECF Secretariat based on data from the GECF GGM

4.4 GECF countries' gas production outlook

Most GECF countries will enhance or maintain their level of gas production capacity over the outlook period. Russia, Iran, Qatar, and Nigeria will make the largest contribution to the total GECF gas production expansion accounting for around 78% of total GECF incremental value over the outlook period.

Total gas production from the current combination of GECF members will rise by 47%, reaching approximately 2,530 bcm by 2050. This translates to a 1.2% average annual growth rate over the period between 2018 and 2050. GECF share in global gas production will slightly reduce till 2025 due to the rise in non-GECF producers including the US and Australia. Maintaining the production capacity in GECF countries in longer-term will enable the GECF to keep its share in global gas production at more than 42.4% by 2050.

Figure 4.12. GECF countries’ natural gas production outlook (bcm)



Source: GECF Secretariat based on data from the GECF GGM

05

Gas Trade and Investment

Key findings:

- The wave of natural gas export capacity additions that started in 2016 will shape the market in the next decade, with rapid expansion outpacing demand growth, before slowing down, enabling demand growth to catch up. The global gas trade is expected to have grown by 84.6% by 2050, at 1.9% per annum, and reached 2,141 bcm, sourcing 35.9% of global gas demand in 2050.

- Growth in LNG trade is the main driving force and will exceed total pipeline trade by 2050, whereas in 2018 it was only just over half pipeline trade. The LNG sector is expected to grow at 2.9% to 1,077 bcm by 2050, while pipeline trade will expand more slowly at a rate of 1.2% per annum to reach 1,063 bcm by 2050.

- By 2050, most additional import demand for natural gas is expected to come from Asia Pacific, Latin America and Europe, with total increases of over 600 bcm, 140 bcm and 100 bcm, respectively. This will be met in the medium-term by supply increases from Eurasia and North America, and in the longer-term also by new supply from Africa and the Middle East.

- GECF countries will see growth in their exports, but their market share will decline from just under 60% in 2018 to around 50% in 2050, as new gas exporters emerge, especially in Africa.

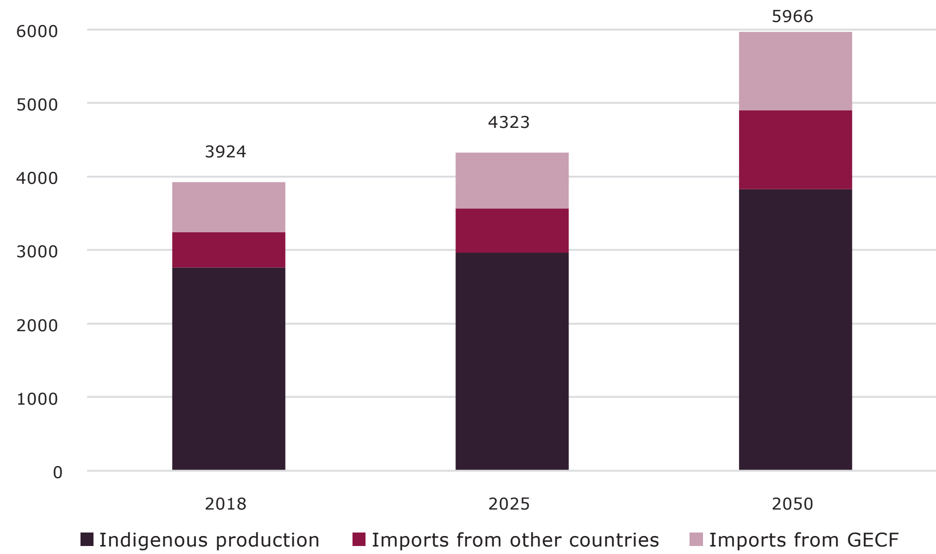
- As of 2018, 63 countries were net importers of natural gas, and that number will grow to 81 by 2050. The number of net exporters of natural gas could grow from 28 to 32 countries by 2030 and stay the same through to 2050.

- Through to 2050, USD 9.7 trillion is earmarked for investment in the gas sector. Most of this is upstream, but trade infrastructure will still require some USD 400 billion, with over half in liquefaction. Most of the USD 400 billion will be invested in Africa, Asia Pacific and Eurasia.

5.1 Global gas trade

In 2018, out of 3,924 bcm consumed to satisfy global natural gas demand, 1,160 bcm was imported (including 685 bcm from GECF Members). Total imports, comprising 29.5% of total natural gas consumption, are projected to gradually increase to 35.9% of consumption through to 2050 as gas exploration and production advancements and expansion of LNG trade makes natural gas imports more widely available (see figure 5.1).

Figure 5.1. Sources for global gas import (bcm)



Source: GECF Secretariat based on data from the GECF GGM

According to the projection, out of 5,966 bcm global natural gas demand in 2050, 2,141 bcm would be imported (including 1,067 bcm from GECF Members).

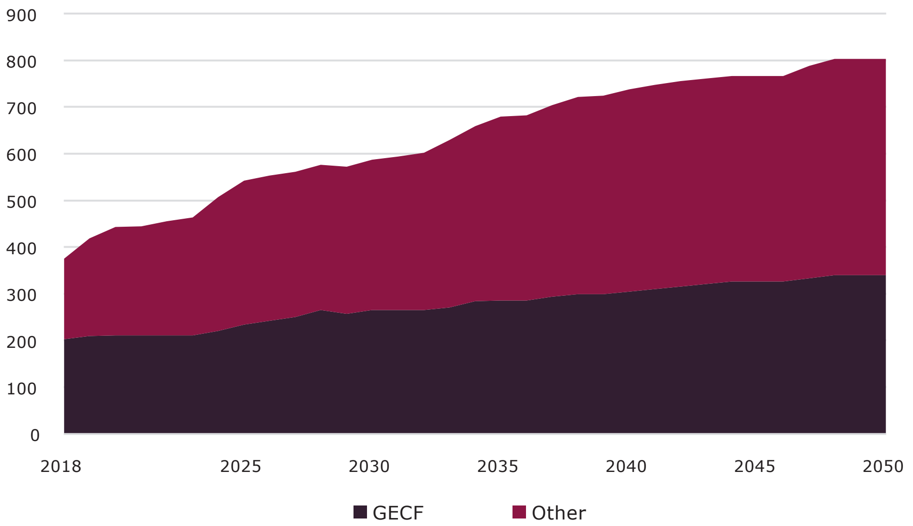
International volume of trade in natural gas including re-exports reached 1,255 bcm in 2018, up from 1,204 bcm in 2017. It represents the physical volumes of gas traded. Unlike the gas series indicator in this Outlook, however, it includes gas exports that come from the intermediary countries that chiefly import gas for consumption and store gas imported previously.

Gas trade infrastructure prospects

The global gas trade infrastructure will see significant capacity increases in both pipeline and LNG by 2050. The biggest regas capacity additions to 2050 are expected in Asia-Pacific, while the biggest liquefaction capacity additions are expected in North America, Africa, Eurasia and Asia-Pacific.

LNG infrastructure will see a much faster build-up than pipelines, as it requires far fewer intergovernmental negotiations and is much less affected by geopolitical tensions, and will have over 800 mtpa capacity by 2050 as compared to 380 mtpa capacity in 2018. As of end-2019, there is 129 mtpa of liquefaction capacity under construction, which will significantly ramp up the global LNG supply within the next five years. Another 253 mtpa of liquefaction projects are likely due over the next two decades.

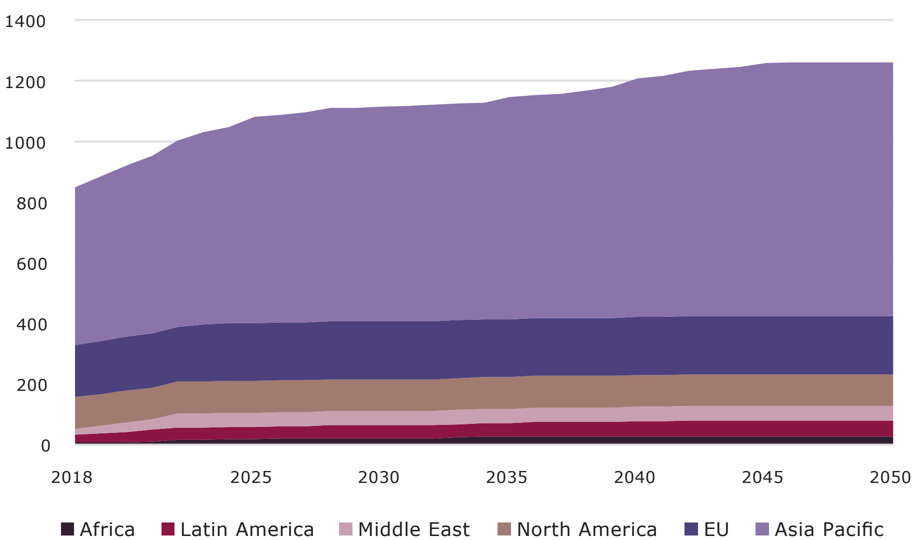
Figure 5.2. LNG capacity outlook (mtpa)



Source: GECF Secretariat based on data from the GECF GGM

Global regas capacity is estimated at 850 mtpa (1,170 bcm) as of 2018, as compared to 380 mtpa liquefaction capacity. By 2050, as evidenced by Figure 5.3, regas capacity is projected to grow to 1,270 mtpa (1,750 bcm), more than double liquefaction capacity in 2018. Place utility of natural gas will still keep most regasification capacity used for flexibility needs only.

Figure 5.3. Regasification capacity outlook (mtpa)



Source: GECF Secretariat based on data from the GECF GGM

The global pipeline export network is expected to add over 600 bcm of capacity by 2050. This only refers to the capacity of export pipeline projects across country borders, and not to the supporting pipeline networks. The larger part of the capacity, totalling 300 bcm, is expected to run from Eurasia to the markets both in Europe and Asia with over half of that directed to the Asian market. There are also export pipelines expected to be constructed within the Middle East and Central Asia regions leading to the Asia Pacific market, with combined capacity over 250 bcm. The largest pipeline capacity additions are expected to be from Iran, Russia and Turkmenistan.

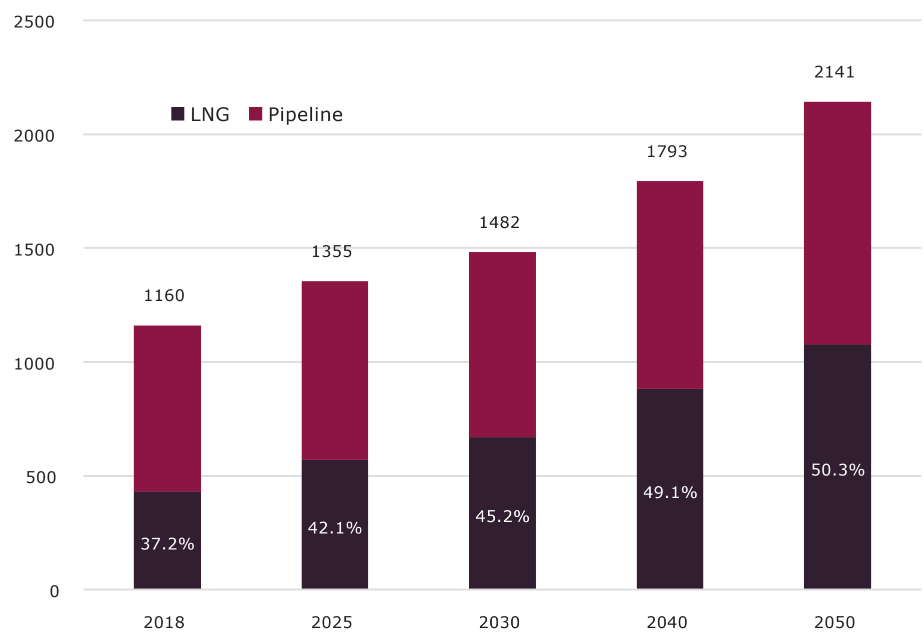
Project plans have already been announced that run at least up to 2030. This includes completions of Central Asia-China gas pipeline D, the Iran-Pakistan pipeline, and both routes for the Power of Siberia pipelines.

In the same timeframe, pipeline capacity for supplies to the European market is expected to be expanded with the completion of the Southern Gas Corridor (via the Transadriatic pipeline or TAP), Nord Stream 2 and 3 pipelines, and Turkish Stream. In Europe, the gas market will emerge significantly more integrated after several intra-EU gas pipeline interconnectors are finished.

Global gas trade trends

The global gas trade volume is projected to grow at an average annual rate of 1.9% for 2018-2050 (from 1,160 bcm to 2,141 bcm), with LNG trade (2.9% per year) growing 2.5 times as fast as pipeline trade (1.2% per year).

Figure 5.4. Global gas trade via pipeline and LNG (bcm) and share of LNG trade (%)



Source: GECF Secretariat based on data from the GECF GGM

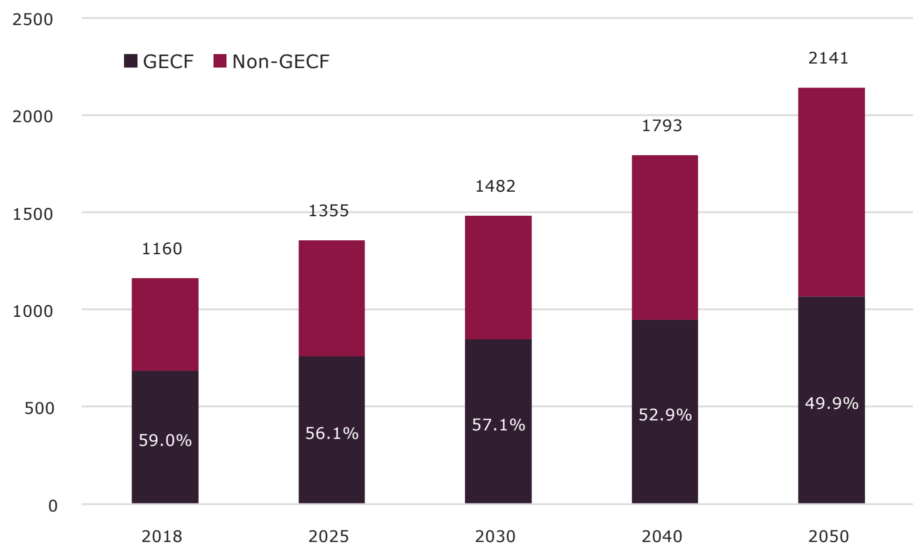
The liquefaction capacity expansion in "waves" which started from 2016 is expected to continue on an unprecedented scale. This will lead to an increase of LNG share of gas exports to 42% in 2025 and 45% by 2030, despite significant pipeline capacity expansions taking place at the same time. By 2050, LNG will secure a 50.3% share of global gas trade.

The result is expected to be much stronger integration of the global gas market than in 2018, with a different market structure, and increased natural gas affordability for local markets.

Due to the build-up of LNG capacity, there are concerns among market participants as to how this additional capacity would affect the market, with oversupply concerns most widely cited.

The average annual growth in global LNG demand from 2009 to 2018 was 6.8%; the total increase was 140 Mt, with half of that from China. According to the reference case scenario, in 2018-2030 global LNG consumption will continue to grow at a slower rate of 3.7%, adding only 173 Mt to reach 485 Mt, while total natural gas trade will add 322 bcm to reach 1,482 bcm. With 129 mtpa of LNG capacity and over 100 bcm of export pipeline capacity under construction globally, there is limited room for announced projects in LNG alone of nearly 250 mtpa capacity.

Figure 5.5. Global gas exports (bcm) and GECF share in global exports (%)



Source: GECF Secretariat based on data from the GECF GGM

Regional gas trade trends

By 2050, we expect most additional import demand for natural gas to come from Asia Pacific, Latin America and Europe, with total increases of over 600 bcm, 140 bcm and 100 bcm, respectively (see Table 5.1). This will be met in the medium-term by supply increases from Eurasia and North America, and also in the longer-term by new supply from Africa and the Middle East.

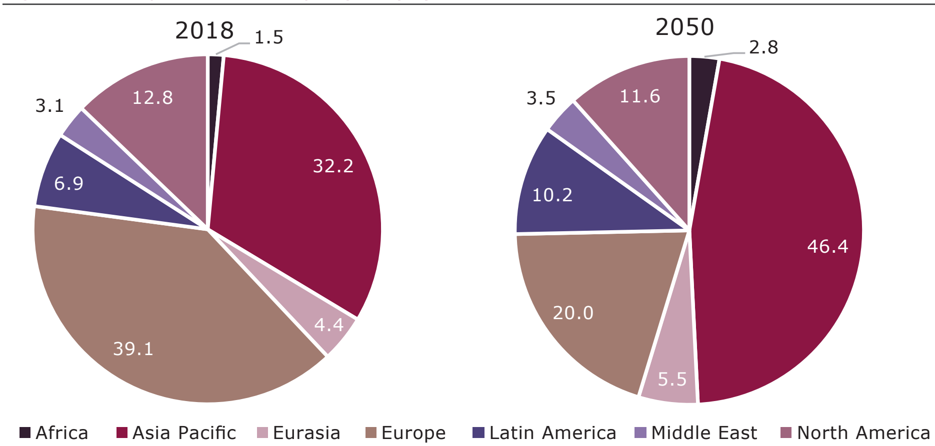
Table 5.1. Global gas balances ([+] surplus, [-] deficit) (bcm)

Region	2018	2025	2050
Africa	91	129	266
Asia Pacific	-183	-309	-787
Eurasia	267	360	622
Europe	-279	-352	-386
Latin America	-44	-63	-183
Middle East	122	136	292
North America	26	98	175

Source: GECF Secretariat based on data from the GECF GGM

Asia Pacific will account for the highest share of global imports by 2050, while the share held by the European market will gradually diminish as import volumes increase slowly.

Figure 5.6. Import volumes by region (%)

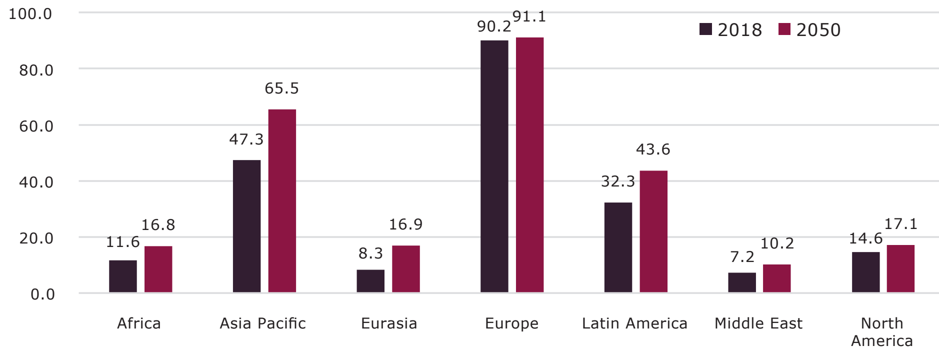


Source: GECF Secretariat based on data from the GECF GGM

By 2050, Europe's share of global imports will almost halve, while Asia's will rise by more than 14 percentage points. Imports by Latin American countries will grow three percentage points, while Middle Eastern and Eurasian imports will practically keep the same share in 2050 as in 2018.

Overall, import dependence is expected to increase in all the regional markets. The share of regional consumption supplied by imports is expected to be highest in Europe, however, after a decline in indigenous production this share is not expected to change significantly, hovering above 90% of consumption. The growth in Asia Pacific gas demand will significantly increase its import dependence, despite growth projected for indigenous production (see Figure 5.7).

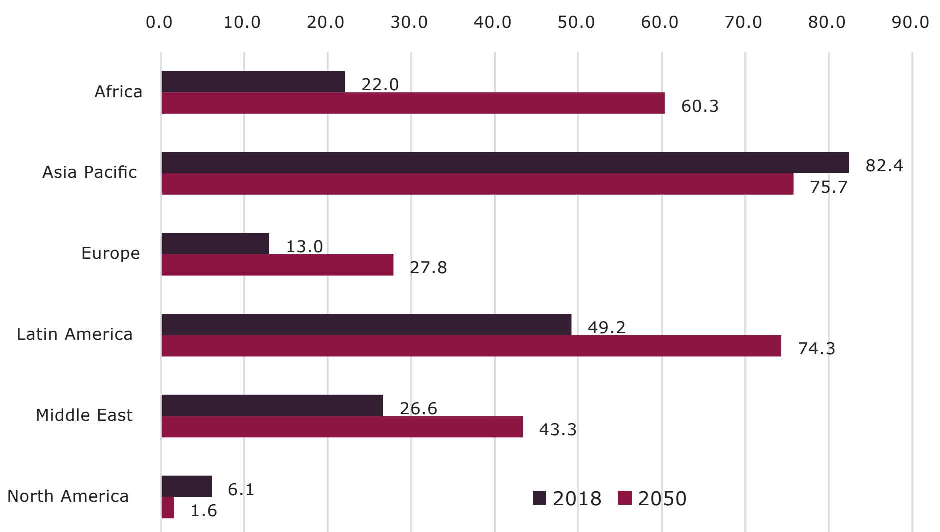
Figure 5.7. Imported volumes as a share of regional gas consumption (%)



Source: GECF Secretariat based on data from the GECF GGM

After the trends in developing gas trade infrastructure, the main increase in LNG imports as a share of total gas imports will come from the Asian market, where pipeline infrastructure is just starting to be developed and will largely lag regasification growth.

Figure 5.8. LNG's share of natural gas imports by region (%)

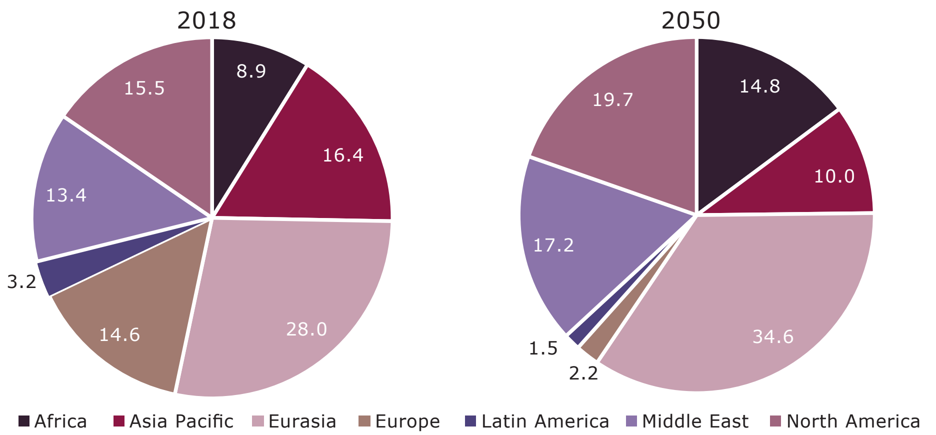


Source: GECF Secretariat based on data from the GECF GGM

The increase in LNG supplies to Europe will be the consequence of the diversification policy advocated by many European countries, as well as the result of increasing affordability of LNG in the medium-term. We project that existing exporters will choose to keep their share of additional natural gas demand whenever possible. The diversification of gas imports will increase, however, with the growth in the number of exporters.

As of 2018, 28 countries were net exporters of natural gas, but 32 countries could become net exporters by 2030 and hold that status through to 2050, including several African countries. 17 countries exported more than 10 bcm in 2018, and by 2050, 18 more countries are expected to do the same. As of 2018, 63 countries were net importers of natural gas, and that number will grow to 81 by 2050. 21 countries import 10 bcm or more on a net basis in 2018, and by 2050 there will be 37 countries that import on that scale. The number of importers is projected to grow fast, with many countries forming so-called "niche markets", typically with LNG imports well below 3 mtpa. However, some of them are expected to develop into new significant LNG markets not to be missed by the suppliers.

Figure 5.9. Share of natural gas exports by region (%)



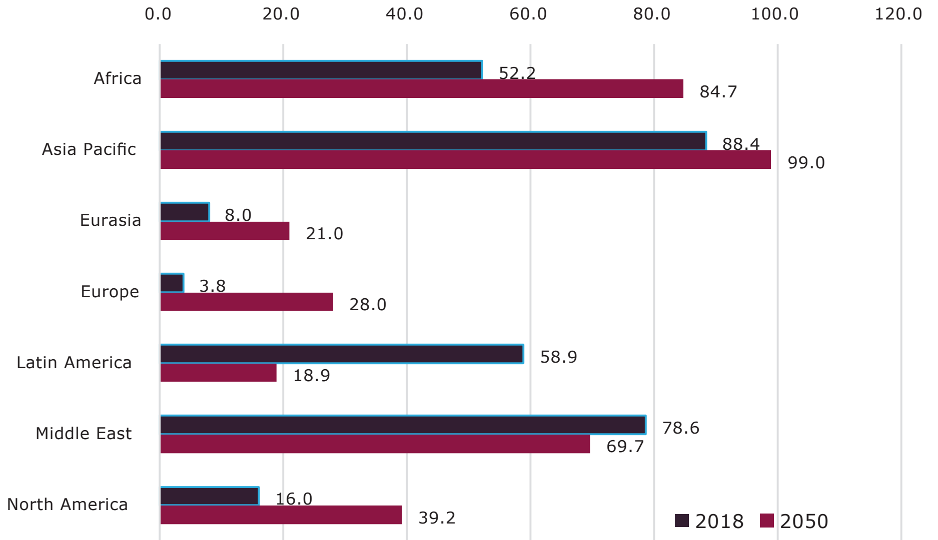
Source: GECF Secretariat based on data from the GECF GGM

In terms of regions, the biggest increase in the global share of exports is spread between three regions: Africa, which will increase its share of global exports from 8.9% to 14.8%, Eurasia, which will increase from 28.0% to 34.6%, and North America, that will increase from 15.5% to 19.7%. Eurasia is expected to increase its share by almost seven percentage points, while Europe's share of global exports is expected to drop from 14.6% to 2.2% over the next 32 years as The Netherlands leaves the market and Norway decreases its exports by almost 60%.

The role of LNG in exports is projected to increase with the share rising from 37.2% in 2018 to 50.3% in 2050, as most new export capacity constructed will be in the liquefaction segment.

More exporters are turning to LNG technology to speed up capacity build-up. There will be significant structural changes as new capacity opens in Eurasia and its share of exports increases to 21%, and in North America, where it rises to almost 40%. In Africa all new capacity is projected to be LNG.

Figure 5.10. The share of gas exports supplied via LNG by region (%)



Source: GECF Secretariat based on data from the GECF GGM

Natural gas trade and pricing mechanisms

The environment for natural gas pricing and contracting is rapidly changing, and the change accelerated in recent years as the market shifts into the structural oversupply stage and new business models emerge.

The most important change that has happened since a new wave of LNG capacity started is the decline in the use of destination clauses and the rise in portfolio purchases. With natural gas being no longer bound for a specific destination, demand security disappears.

Absence of demand security is of particular relevance to the new LNG and pipeline projects, as no confirmed (via take-or-pay) demand means there is no option of project financing for upstream and transport infrastructure investment. The alternative option that we see on the market is equity financing, largely employed by international oil and gas companies for portfolio gas offtake. However, as there is no final consumer, the equity offtake shifts the demand risk from the final consumer onto the portfolio offtaker. How does this transform the international gas market? In short, this will likely introduce cyclical dynamics, while making demand grow faster and also making gas industry projects a riskier investment.

First, the risk of regular market imbalances becomes imminent, as the take-or-pay confirmation of demand is replaced by marketing estimates that are prone to err on the upside. As supply-demand ties are weaker, dynamic in the cycles or "waves" emerges, and we have already seen two such boom-bust waves on the LNG market.

Second, with an increase in risky gas investment, natural gas exporters face increased risk as gas consumers get much stronger support from their governments and regulators. Removal of destination clauses was one such interference that has already transformed the market.

Third, the market is entering into the previously unexplored territory in which gas from new projects cannot be placed. This introduces a "capacity competition" market development model, in which investment should take in the risk of persistently underutilized capacity. cargo cancellation and other "take-or-pay" or "liquefy-or-pay" type clauses are likely to become the next line of attack from both consumers and their national regulators.

Fourth, in the aftermath of quantitative easing and along with the decrease in entry barriers into the gas export industry mandated by the new technologies (such as module LNG and FLNG), there is a surge of gas value chain investment from outside the traditional gas industry. This typically follows the high-risk approach typical for venture capitalists that is bound to disrupt traditional gas market practices even further.

Development of gas hubs has been a clear trend but the dynamics are still uneven, with European spot price benchmarks being clearly established in TTF, NBP, and probably a German gas benchmark post the merger of Gaspool and NCG volumes. In Asia, there is still no large buyer prepared to commit to JKM for its long-term contract – so far, there is just one 15-year portfolio commitment for 1.5 mtpa of Driftwood LNG that has not taken FID yet. However, the use of the benchmark of OTC spot and short-term trades has surged over the last three years, and there are no developing alternatives at the moment, after the closure of the Singaporean hub project.

GECF country companies are currently in the process of testing an integrated gas export marketplace, specifically designed to answer this question. The case in point is GazpromESP, developed by the Russian national pipeline gas exporter monopoly. Volumes are offered for the specific virtual points including Gaspool and NCG and for physical delivery only. For 2018-2019, the turnover has been 12 bcm and is growing rapidly, to over 2.5 bcm per month by November 2019. Such direct sales have a great potential to increase flexibility for consumers while simultaneously competing with short-term LNG markets, as the delivery time for spot LNG cargoes ranges from 30 to 90 days from the transaction. However, they still represent less than 5% of Gazprom's exports (on a company-reporting basis).

What does this mean in the age of structural oversupply that is expected in the medium-term and, probably, in the longer-term? We expect that in the long-term, the increase in LNG exports and gas market reforms will precipitate a rise in uncontracted volumes: in 2018 about 86% of gas exports were estimated to be supplied on the basis of existing contracts, though most portfolio trades went to the spot market. The share of supplies under existing gas contracts (obligated trade) will decline to two-thirds by 2050. This, along with the growth in trading volumes, means a significant increase in short-term and spot trades.

International trade prospects for the main regional natural gas markets

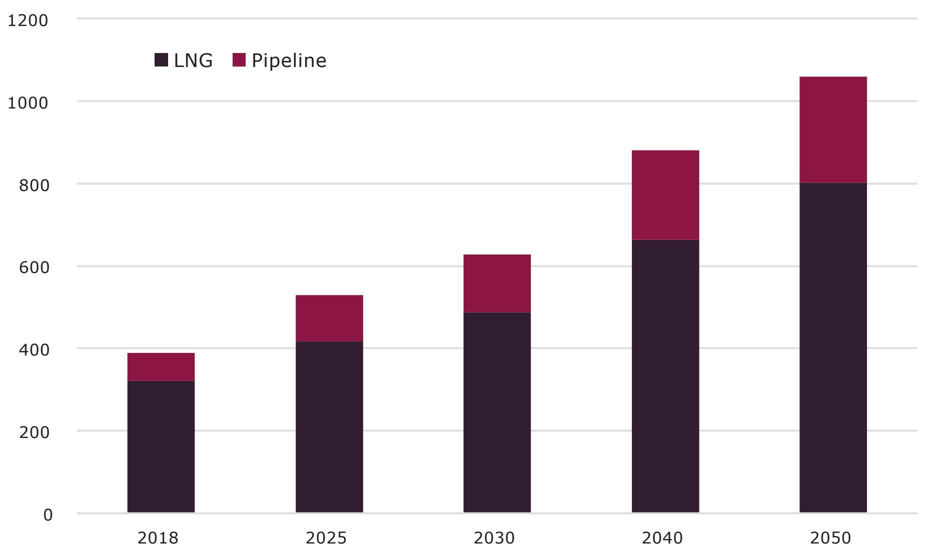
Out of 1,160 bcm of global gas trade in 2018, 389 bcm was imported into Asian markets and 470 bcm was imported into Europe, with those two markets together comprising almost 75% of global gas imports. By 2050, these volumes are projected to increase to 1,060 bcm and decrease to 458 bcm respectively, together still comprising over 70% of global gas imports. Latin American countries imported 30 bcm in 2018, and the market is expected to more than triple with 100 bcm by 2050.

Another 160 bcm was imported by North American countries in 2018 (10% of total imports), almost entirely traded within the region, and are projected to grow to 260 bcm (12% of total imports) by 2050. However, the North American market is largely isolated, connected by local pipeline systems and offtakes practically no LNG. Thus, it is no longer a feasible market for GECF exporters.

Asian natural gas market

Asian natural gas market is expected to stay the largest regional market over the Outlook period, as more countries start importing natural gas and some existing importers greatly ramp up purchases. Of the increase in Asian imports, 240 bcm will be taken by China, 75 bcm by India, 30 bcm by South Korea, with the balance taken by new importers and Chinese Taipei, Japan will slowly decrease gas imports.

Figure 5.11. Asian gas trade via pipeline and LNG (bcm)



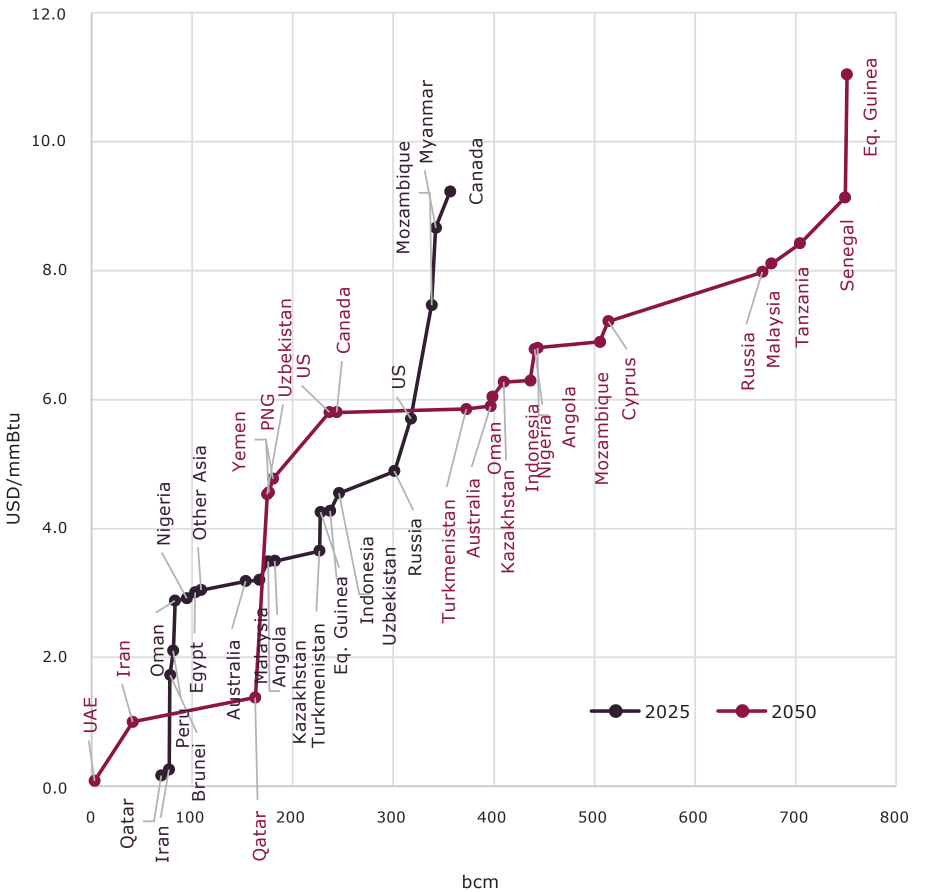
Source: GECF Secretariat based on data from the GECF GGM

The emergence of the new players and significant new infrastructure will transform gas trade in Asia. As the market grows, suppliers from both within and outside the region vie for dominance in the market. New players well-placed on the cost curve to compete, such as the US, Mozambique and Russia are set to enter the Asian market. On the pipeline front, new routes from Russia, Turkmenistan and Iran will be completed by 2050.

For the medium-term, China will be the only rapidly growing market in Asia for gas exports, and as such, it will be a primary destination for any new pipeline and LNG projects initiated in the next decade. In this context, it is important to consider the impact that Chinese trade tariffs will have over the development of new LNG projects, especially in the US.

Over the Outlook period, Asian natural gas imports are expected to be concentrated in several markets. Up to 2025, those will be Japan, South Korea, China, India, and Chinese Taipei.

Figure 5.12. The marginal cost curve for the Asian market



Source: GECF Secretariat based on data from the GECF GGM

Note: the cost curve is calculated on a country basis, with the marginal cost of the country being a volume-weighted average of the total cost of all the projected pipeline and LNG deliveries into the concerned market. A liquids credit is taken out of the cost, which might lead to certain associated gas supplies being delivered at a negative cost.

In the long-term, there is likely to be significant growth in ASEAN countries (Vietnam, Philippines, Indonesia etc.) and Pakistan – possibly as much as China and India together. Those countries are not importing much gas now (less than 3 bcm in 2018), but they are expected to add 257 bcm of imports by 2050.

European natural gas market

The European natural gas market is expected to remain the second-largest, but imports of natural gas are expected to grow only incrementally in the medium-term due to declining indigenous production, and in the longer-term to decline with falling demand. Compared to 471 bcm in 2018, imports are projected to be 458 bcm by 2050, which is still over 20% of global gas imports by that time.

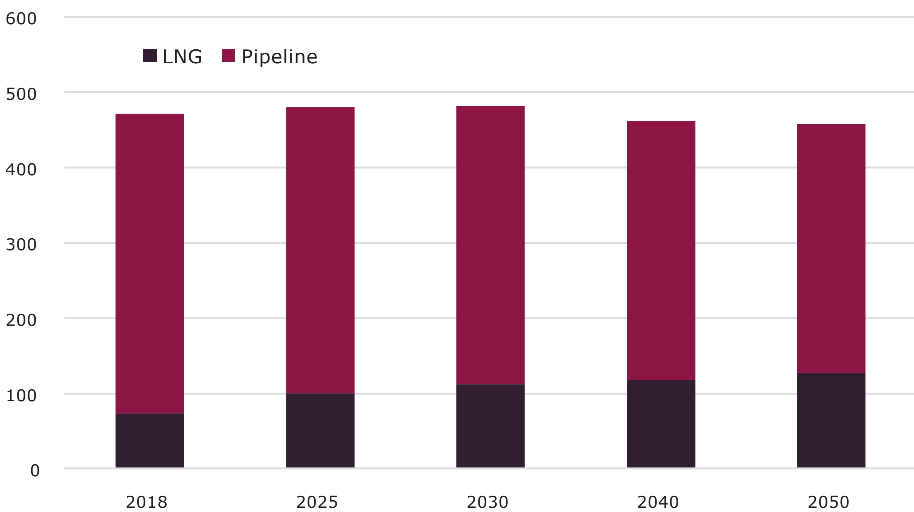
In terms of infrastructure, the plans to connect European gas markets with a number of two-way flow pipelines is expected to be completed in the medium-term, enabling consumers to access gas hubs far more easily in line with the new regulation. Also, more export pipelines are expected to be connected to the European market in the next decade, bringing more natural gas from Russia, Azerbaijan and possibly new Mediterranean sources in Israel, Cyprus and Egypt.

Between the gas source diversification policy and more available infrastructure, an increasing share of those imports will be from LNG. This is also due to the fact that Europe is the residual market for LNG shipments, absorbing the results of structural oversupply.

There are certain suppliers that would view the European market as easier to keep, primarily due to the position on the cost curve. The pipeline gas exports from Russia, North Africa and Norway are expected to persist because they have the lowest marginal costs.

LNG imports, on the other hand, are well above the cost curve and thus are expected to be driven mainly by non-economic factors or imported outside the needs of natural gas demand (i.e. to replace petroleum products). The differing sources of supply are expected to add to a greater price flexibility on the European market, as is the further decrease in oil-linked contracting. On the downside, that will diminish the consumer options to withdraw more oil-linked gas in case of international gas price swings, and, in the case of smaller long-term supplier obligations, will significantly increase volume risks. For the suppliers, the lack of take-off guarantees in the declining European market will stimulate the shift of infrastructure investment activity to other regions that provide for more growth opportunities and more equitable risk-sharing.

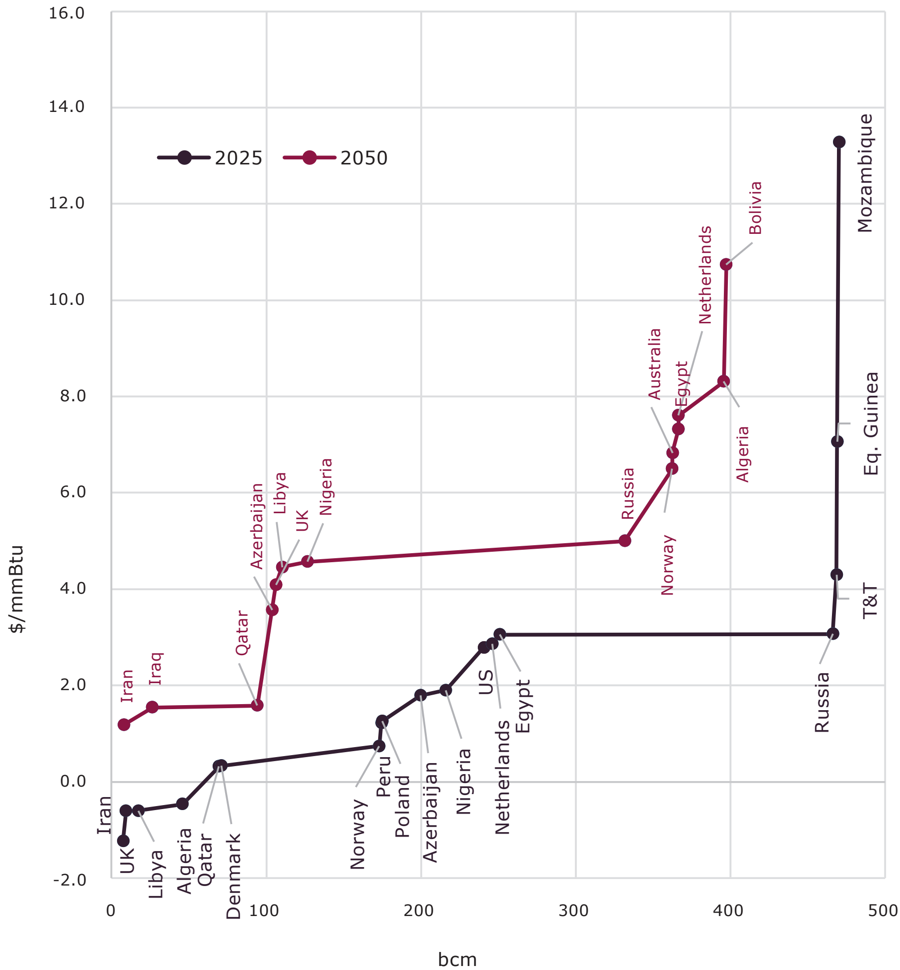
Figure 5.13. European gas trade via pipeline and LNG (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The five largest European gas import markets in 2018 were Germany, Italy, France, Spain and the UK, and those markets are expected to stay the Europe's largest for the long-term as well.

Figure 5.14. The marginal cost curve for the European market



Source: GECF Secretariat based on data from the GECF GGM

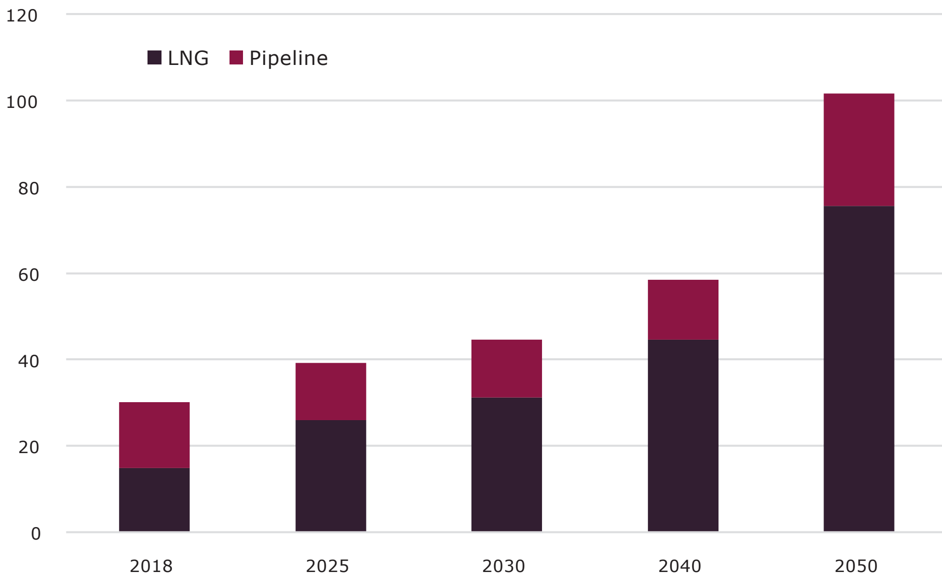
Note: the cost curve is calculated on a country basis, with the marginal cost of the country being a volume-weighted average of total cost of all the projected pipeline and LNG deliveries into the concerned market. A liquids credit is taken out of the cost, which might lead to certain associated gas supplies being delivered at a negative cost.

Latin American natural gas market

A Latin American gas market is emerging as the affordability of gas increases and more LNG capacity is being built in the Americas, primarily in the US. During the Outlook period, the market will be largely transformed by the emergence of US LNG as the strong player on the market, as well as by the growth in indigenous production. The overall imports into Latin American market are estimated at 102 bcm by 2050, as compared to 30 bcm in 2018, and the share of LNG imports is expected to rise from 50% to 75%. The market is expected to grow as natural gas will be more affordable and ample space for gas switching in the energy mix will be tapped, however, so do the domestic suppliers. This specifically concerns the long-term projections, as import demand in the medium-term looks contained.

The top three Latin American importers within the Outlook period are Chile, Brazil and Argentina.

Figure 5.15. Latin American gas trade via pipeline and LNG (bcm)



Source: GECF Secretariat based on data from the GECF GGM

5.2 Gas investment

To meet growing demand for natural gas by 2050, the GECF calculates that 9.7 trillion USD in 2018 prices is needed to invest in additional natural gas production capacity and the aforementioned gas trade infrastructure, as compared to 4.3 trillion USD in 1990-2018.

Global gas investment trends

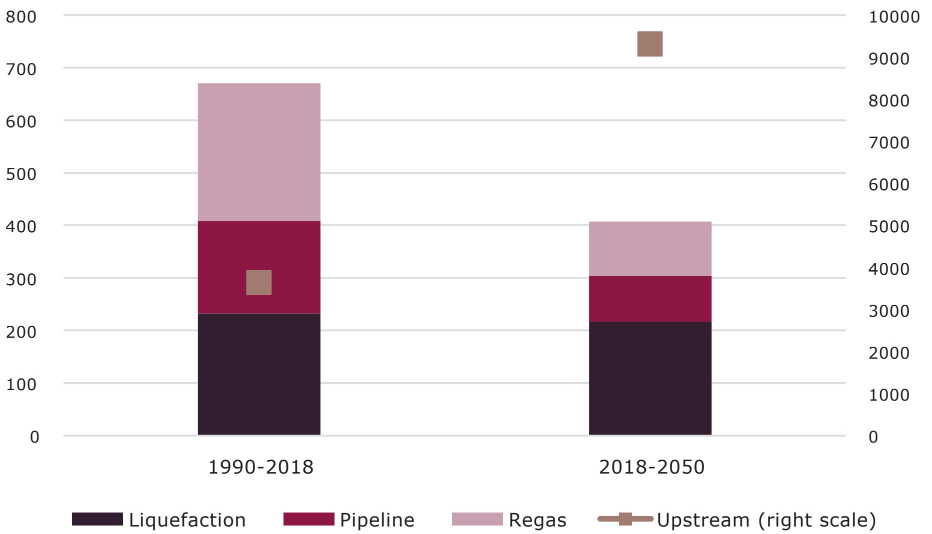
Although most of this projected 9.7 trillion USD earmarked for gas investment is required in the natural gas exploration and production sectors, the trade infrastructure still requires over USD 400 bn of capital in 2018 prices by 2050. The gas industry investment outlook is thus shaped both by trade infrastructure and upstream investment needs.

The upstream is expected to increase its share from a historical 84% to nearly 96% while already being the main driver for gas industry investment, as production shifts to capital-intensive unconventional sources both in and outside the GECF. This is connected to two factors.

First, unconventional projects will play a much larger role in upstream gas development. They have much higher capital requirements than conventional projects (see the next subsection for details) despite the learning curve and the new technologies that are being introduced into gas production. Second, there is a decrease in projected investment in pipeline and regas as compared to the historical levels as there is already enough capacity and capital costs are trending down because of technological advancement.

CHAPTER 5

Figure 5.16. Global gas industry investment by purpose (2018 USD bn, not discounted)

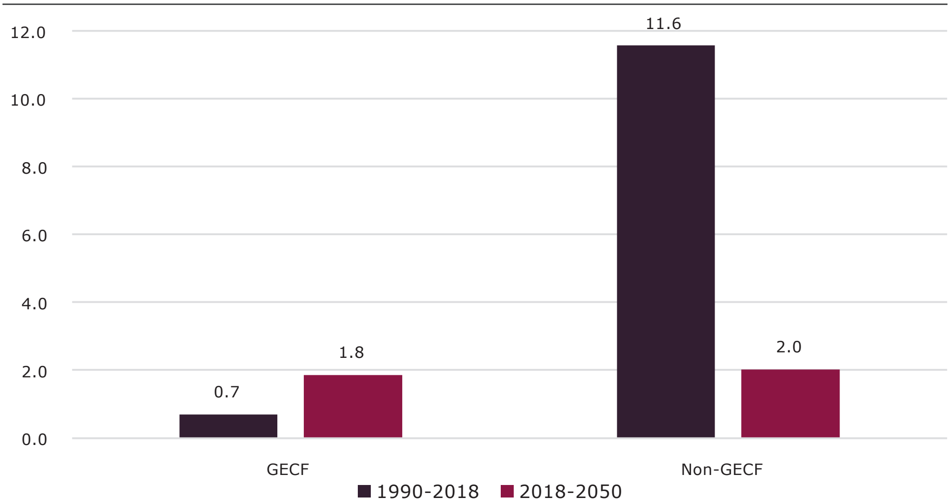


Source: GECF Secretariat based on data from the GECF GGM

Capital intensity outlook

Figure 5.18 displays average capital intensity (or capital costs) of gas upstream projects for different types of source gas, calculated as a ratio of total capital requirement (not discounted) in constant prices over the respective amount of production over 2019-2050. It does not reflect production operating costs but only the capital required to put the respective gas industry projects online.

Figure 5.17. Capital intensity of gas production, (2018 USD/mmBtu, not discounted)



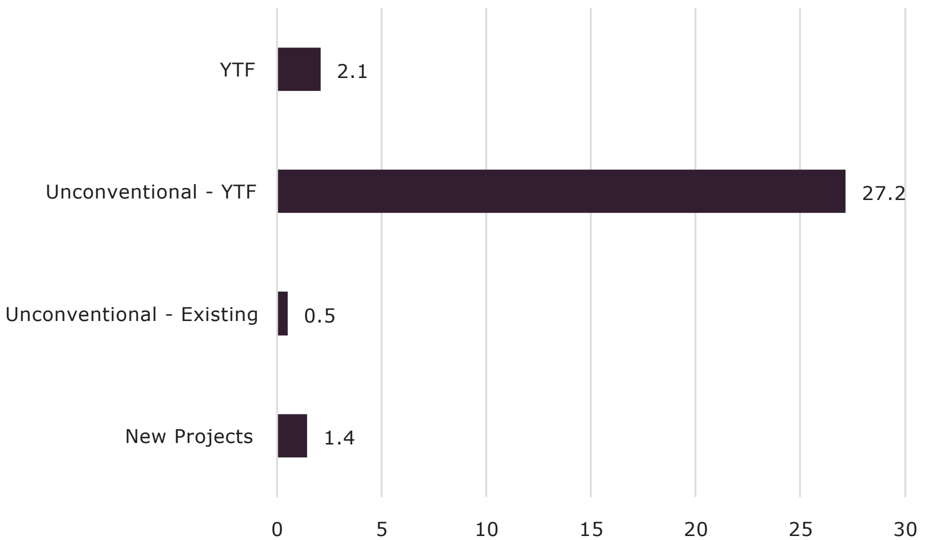
Source: GECF Secretariat based on data from the GECF GGM

Gas production projects in the future are expected to have higher capital intensity as production shifts from onshore conventional to offshore and unconventional sources. However, technological advancement and respective learning curves have strongly reduced the capital costs of gas upstream in recent years. The interaction between better technologies applied in more challenging geological conditions is reflected in the assumption of a reduction in average capital intensity for gas projects for 2019-2050 to USD 1.9 per mmBtu (both in 2018 dollars, not discounted), as compared to the USD 5.5/ mmBtu global average observed for 1990-2018.

As the leading gas producers, GECF countries are expected to retain cost leadership even as supply shifts to unconventional and offshore sources. However, in the past ten years, upstream developments in the gas industry have seen much lower capital costs for both traditional and unconventional upstream projects. This provides a competitive advantage to entrant projects in gas production as compared to the historical period, as it reduces the respective investment requirements. One important advantage of projects in the GECF countries, however, is that they already have gas infrastructure in place. Thus, the upstream development in the same GECF gas deposits requires much less investment, as most producers outside the GECF which have to develop a costly gas infrastructure first. Moreover, it should be noted that the GECF export cost advantage is not limited to the upstream but encompasses total costs across the gas value chain.

While a current capital intensity estimate for unconventional YTF resources for 2019-2050 of USD 27.2 per mmBtu (in 2018 dollars, not discounted) might seem prohibitive, the earlier projects will be developed on a non-commercial basis, such as Chinese experimental tight gas projects. The drive down the learning curve and technology advancement will allow this type of resources to be developed much more cheaply,

Figure 5.18. Capital intensity estimates of gas production projects by type of field, 2019-2050, (2018 USD/mmBtu, not discounted)



Source: GECF Secretariat based on data from the GECF GGM

especially after the key project infrastructure is put in place. Consequently, this estimate includes the larger part of unconventional YTF development that will occur later and thus face much lower capital costs.

The learning curve for existing unconventional shale projects is assumed to perform a deep dive, ultimately bringing the capital costs below current traditional gas projects (estimated at USD 1 per mmBtu global average). This is expected to happen as more and more associated gas from unconventional oil and gas deposits is produced, adding to the production side of the ratio, and the upstream capital costs for present unconventional gas and traditional gas get closer.

Regional gas investment prospects by segment of the gas value chain

The developments in upstream that are planned in Algerian unconventional projects after 2030, and new projects both in Mozambique and Tanzania (to a lesser extent, Nigeria, Egypt and Senegal) will drive African investment, while some new LNG capacity investment is also expected to take place.

Eurasia investment past-2035 is also expected to be driven by the rise in capital intensity, while pipeline investment, as compared to 2013-2018 investment, will be significantly less after 2030, as the connection of large-scale pipeline projects linking gas output from Azerbaijan, Kazakhstan, Russia, Turkmenistan, and Uzbekistan to European and Chinese consumers is established.

Investment in Asia-Pacific will mostly be driven by upstream in China and Australia, as well as India, with required capital intensity increase profoundly impacting the investment outlays.

06

Alternative Scenarios

Key findings:

- The Global Gas Outlook 2050 builds on the 2018 edition, which defined two accelerated energy transition scenarios: The Carbon Mitigation Scenario (CMS) and the Technology Advancement Scenario (TAS). The combined effect of mitigation policy and technology drivers under these scenarios is captured in the Energy Transition Scenario (ETS), which results from applying the CMS assumptions to the Reference Case (RCS) and the TAS assumptions to the CMS.

- In the CMS, natural gas demand is expected to rise marginally compared to the RCS, due to larger penetration of intermittent renewables (i.e. solar and wind) that reduces the average utilisation rates of the gas-fired power plants and then puts pressure on gas demand in power generation. The incremental gas demand in the CMS compared to the RCS is mainly driven by the penetration of NGVs that compensates the downside effect of gas in the power sector. In the ETS, gas demand increases significantly compared to the CMS due particularly to larger deployment of blue hydrogen in various sectors.

- The share of natural gas in total primary consumption reaches 28.7% and 29.2% respectively in the CMS and ETS by 2050 (compared with 26.8% in the RCS).

- The share of renewables in 2050 will rise from 9% in the RCS to 12.19% in the CMS and 12.22% in the ETS. The relative stability of the renewables share in the ETS compared to the CMS is due to no large renewables capacities additions being imposed when considering the technology-related assumptions in the ETS, and also to the decrease of primary energy demand mainly because of global efficiency improvements.

- Coal is projected to decline by 1.6% and 1.7% p.a. in the CMS and ETS respectively (0.5% p.a reduction in the RCS over the forecast period). This is largely driven by the phase out of coal and reduction of its demand, specifically in the large coal consuming countries including India and China. The 2050 share of coal is expected to reach 12.8% in the CMS and 12.3% in the ETS dropping from 17.5% in the RCS.

- Oil demand, which is seen in the RCS to grow at 0.2% p. a. between 2018 and 2050, is flat in the CMS because of larger penetration of NGVs and EVs, while the ETS oil demand growth lies between the CMS and RCS on account of improved internal combustion engine efficiency and use of oil in hydrogen production.

- Overall energy related CO_2 emissions, which are anticipated to reach 36.0 $GtCO_2$ by 2050 in the RCS, are projected to be 31.3 $GtCO_2$ in the CMS and 26.6 $GtCO_2$ in the ETS.

- In CMS, 4.2 the $GtCO_2$ amid the total 4.6 $GtCO_2$ reduction forecast for 2050 comes from a changing power generation mix, driven by renewables and natural gas penetration against coal and oil. The transport sector will be responsible for around 280 $MtCO_2$ reduction in the CMS compared to the RCS in 2050, due to the penetration of NGVs and EVs.

- In the ETS, power generation continues to play a key role and enables further reductions of emissions by 3 $GtCO_2$ compared to the CMS. This reduction is underpinned by improved thermal efficiency of power plants and the larger deployment of CCS technologies.

6.1 Background and methodology

This Outlook investigates, through the development of alternative scenarios, the potential effect of an accelerated energy transition towards less-carbon intensive energy systems. The GECF alternative scenarios are based on a forward-looking approach that aims to assess the energy transition drivers, their potential and possible developments over the long-term, their impact on global energy configuration and carbon emissions as well as the future role of natural gas.

In the 2018 GGO, the GECF defined two accelerated energy transition scenarios: i) The Carbon Mitigation Scenario (CMS), which aims to assess the effects that strengthened CO_2 mitigation policies have on energy configurations; ii) The Technology Advancement Scenario (TAS) that takes into account expected progress in energy technologies across the energy supply chain. The two scenarios reflect a deviation compared to the reference case when considering the implementation of reinforced carbon mitigation policies for the first and achievement of further progress in technologies for the second.

In the CMS, technology progress is assumed to be in line with the reference case development with no significant breakthrough occurring over the forecast period, while in TAS, the focus is more on technology development. The TAS takes into account policies which support technical progress and innovation in energy-efficient and environmentally friendly technologies (the CMS and TAS are built by applying their assumptions on the reference case scenario) (see figure 6.1).

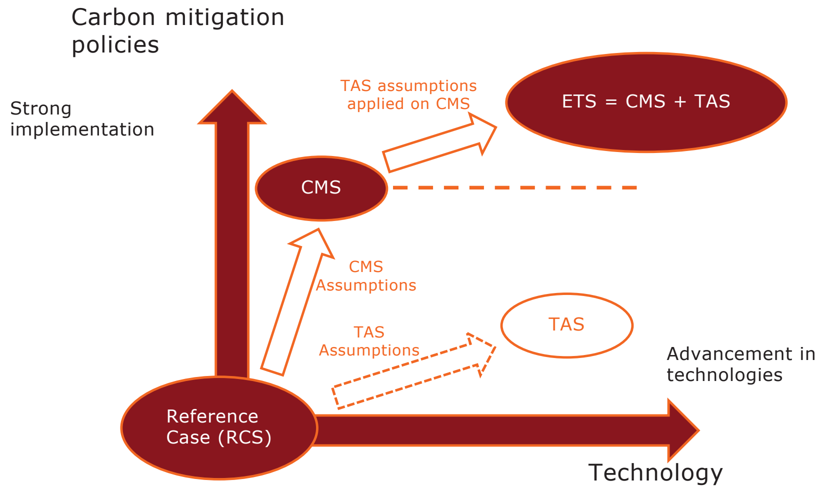
This Outlook builds on these two previously elaborated scenarios and investigates the main energy transition drivers on both policy and technology dimensions. For the CMS, it is focused on two major shifts resulting from the implementation of strengthened carbon mitigation policies: first, an accelerated penetration of clean energy sources in the power generation sector, which is a key contributor to the decarbonisation of the energy systems; and second, a more aggressive development of clean sources in the road transport sector, including EVs and NGVs. The CMS pays special attention to the NGVs, which is a marked addition compared to the previous GGO.

In the case of TAS, this Outlook introduces several revisions of the developments considered in the previous 2018 TAS edition, including technology-related efficiency improvements, and development of batteries and digitalization (see table 6.1). In addition, TAS has, this year, a special focus on hydrogen-related technologies and the penetration of these technologies across the whole energy system. Blue hydrogen production technologies (i.e. technologies producing hydrogen from natural gas) have also been taken into account, and these technologies are also supposed to be associated with Carbon Capture and Storage.

The development of alternative scenarios keeps the principle used in the previous 2018 GGO, which aims to primarily focus on the critical parameters featuring in each scenario. It is proposed to investigate and analyse the combined effects that carbon mitigation policies and technology advancement have on the energy mix and natural gas prospects in particular. This combined effect is captured by considering the Energy Transition Scenario (ETS), which results from applying CMS assumptions to the RCS, and applying TAS assumptions to the CMS as highlighted in figure 6.1.

Therefore, the ETS, which applies the TAS assumptions on the CMS, will prospect further carbon mitigation potential that can be captured, assuming larger availability of some decarbonizing technologies such as hydrogen. This adds to the potential for deploying strengthened policies targeting the existing carbon mitigation technologies and options

Figure 6.1. Illustrative representation of the CMS, TAS and ETS compared to the GECF RCS



Source: GECF Secretariat based on data from the GECF GGM

6.2 Main CMS and TAS assumptions

This section highlights some details on the main CMS and TAS assumptions affecting specifically the power and transport sectors, which are the main focus of this scenario analysis.

6.2.1 Power generation sector

CMS assumptions

The CMS factors in an accelerated penetration of clean energy sources, including renewables and natural gas, at the expense of coal and oil in power generation. This development is incentivized by reinforced policy measures compared to the RCS in different policy domains including:

Natural gas: The CMS assumes that gas-fired power plants will be significantly promoted as a flexible and viable option to reduce both carbon and pollutant emissions. These power plants will benefit from their great ability to run cost-efficiently both in baseload, intermediate load and peak load regimes. The complementarity between gas and intermittent renewables will play a prominent role in this scenario.

In addition, policy support for gas infrastructure development along the natural gas value chain is extended by the CMS through investment incentives and application of frameworks for strengthening cooperation. Particularly, infrastructures that improve pipeline interconnections and storage to manage the seasonality of gas demand, receive larger support in this scenario.

Renewables: The CMS scenario assumes a substantial reinforcement of renewables support schemes, intensification of auctioning for capacity development, improvement of electricity market design to accommodate the intermittent specificity of solar and wind, and the deployment of several options (e.g. demand-side management, battery storage and flexible power plants) that support the balancing of renewables and their integration in the electricity networks.

Coal and oil: The CMS considers more aggressive phasing out of coal compared to the RCS driven mainly by reinforced regulations (e.g. emission standards, carbon and coal taxation). For the Oil-fired capacities, the CMS assumes larger policy push towards substitution of oil by other alternatives, specifically by natural gas in power generation.

Nuclear: Since the aim of the CMS is to investigate the potential effect of further renewables and gas penetration at the expense of coal and oil, it supposes no additional policy support for nuclear energy compared to the RCS. This assumption is underpinned by high investment cost of nuclear energy due to increased safety requirements, lack of skilled labour, waste treatment requirements and some other factors, which build a barrier against the larger development of nuclear, compared to the RCS.

TAS assumptions

In TAS, wind turbine technologies, including on-shore and off-shore turbines, have been quantified by improving the related unit size, efficiency, and utilization rates. Reduction of the levelized cost of supply is also considered by 30% by 2050 that is assumed as a result of advancement in these technologies (compared with the CMS).

Advancement in solar PV systems has also been quantified as equal to wind turbines. Batteries are implemented in the power sector, which can shift peak demand and compensate for intermittency.

Other technical advancements that result in a reduction of cost and improving efficiency are considered in other types of power plants, including fossil fuel-fired power plants. Employment of more advanced fossil fuel plant technologies such as IGCC and CCGT is also assumed.

Digitization in the power sector is another advancement that is taken into account in TAS development. Digitization is assumed to result in the introduction of smart grids, which one of the advantages is improving demand peak-shaving.

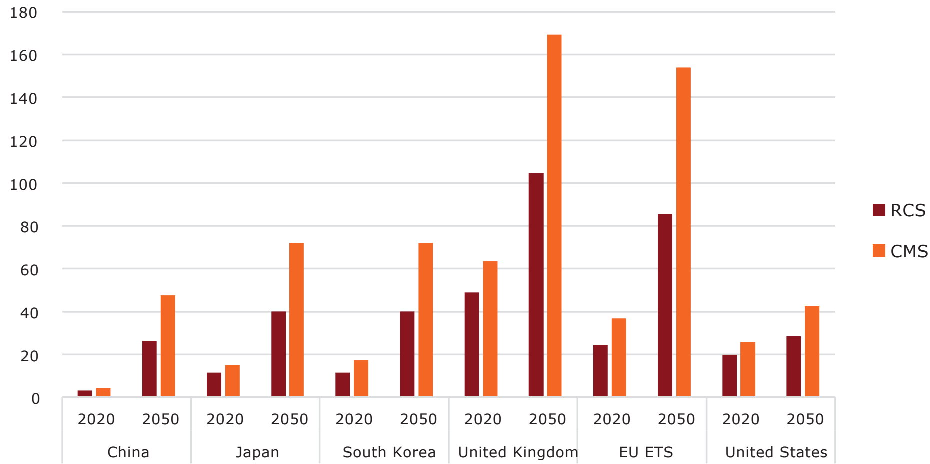
6.2.2 Carbon pricing

Carbon prices, either in the form of carbon taxes or carbon market prices, are assumed to increase in the key markets. Particularly, the CO_2 price references that result from the implementation of carbon markets, including the emissions trading systems, are assumed to increase, over the long-term, compared to the RCS. This reflects extended efforts to improve the functioning of these markets and also to increase their role in reducing emissions.

In the European Union, CO_2 prices will increase significantly over the long-term driven by EU ETS Phase IV reforms. The reforms will support increasing carbon prices and address the imbalances in CO_2 emission allowances in supply and demand.

As highlighted in Figure 6.2, under the CMS, carbon prices in Europe, China, South Korea and Japan in 2050 are assumed to be double the RCS levels. The US average price is expected to be around 50% higher in 2050, which is less than the increase assumed in the other benchmarked countries, to reflect the federal policy orientation to weaken its climate commitment and withdraw from the Paris Agreement. For the UK, the CMS assumes that carbon prices remain linked to the EU ETS system and that the UK government continues to apply a carbon support price in addition to this EU reference. Carbon prices in the UK are assumed to significantly increase in the CMS, driven by the UK commitment to achieve a carbon-neutral economy by 2050. The UK carbon price will reach around USD 170/tCO_2 by 2050, which is 15% higher than the EU ETS reference price and 60% higher than the projected level in the RCS.

Figure 6.2. Carbon prices in the RCS vs. the CMS (USD/tCO2)



Source: GECF Secretariat based on data from the GECF GGM

6.2.3 The transport sector

CMS Assumption

The CMS assumes more aggressive penetration of clean-energy vehicles in the road transport sector compared to the RCS, with a primary focus on NGVs, EVs (i.e. Battery EVs and Plug-in Hybrid EVs). Hybrid Electric Vehicles are also considered, but not under the EV category. The CMS does not factor in an increase of hydrogen fuel cell vehicles, but this is investigated as a result of technology improvement in the TAS.

The recent observed policy orientation in major energy-consuming countries aims to strongly support electric mobility, particularly for passenger cars and light commercial vehicles (LCVs). This has driven a substantial progress of EVs at the expense of other alternatives. These trends have been captured in the RCS where the 2050 share of EVs (Battery EVs and Plug-in Hybrid EVs) in the global passenger and LCV fleet is projected to reach around 20.7% compared to only 2.3% share for the NGVs. (EVs and NGVs count respectively 1.2% and 0.6% in 2018).

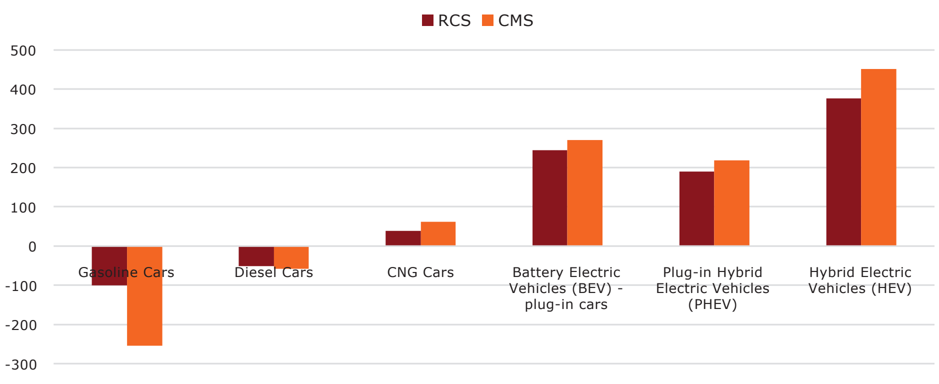
Nevertheless, there is still a non-negligible potential to increase the number of NGVs due to its various environmental and economic advantages. These advantages are particularly relevant in the case of Heavy Goods Vehicles (HGVs), especially with the emergence of LNG-based engine technologies and the potential synergies with small-scale LNG supply chains.

Clean vehicles prospects in the CMS

Figure 6.3 highlights the variation in passenger and light commercial vehicle numbers between 2018 and 2050 in the RCS and CMS. It is expected that CNG vehicles in this segment will increase by around 62 million in the CMS between 2018 and 2050, compared to 23 million in the RCS. As a result, the CNG share in the global passengers and LCV vehicles will rise from 2.3% in the RMS to around 3.4% in the CMS.

The CMS also anticipates significant expansion of EVs and Hybrid Electric Vehicles, with 55 million additional EVs and 75 million hybrids in 2050 compared with 2018. This expansion increases the 2050 share of these vehicles in the passenger and LCV segment to respectively 23.4% and 22% (respectively 20.7% and 18.5% in the RCS).

Figure 6.3. Passengers and LCVs variations between 2018 and 2050 in the RCS and CMS (millions of vehicles)



Source: GECF Secretariat based on data from the GECF GGM

TAS assumption

In TAS, we have implemented adjustment factors that resulted in an increased number of hydrogen vehicles in the passenger and light commercial sector (LCVs). The total number of passengers and LCVs remained constant, as we have not imposed any assumption on the passenger and LCV transportation demand drivers, such as population. For all scenarios, slightly over 2,100 million vehicles is assumed for the year 2050. Imposing scenario adjustment factors in the TAS resulted in 20 million hydrogen cars in the passenger sector by 2050 and slightly less than 3 million hydrogen vehicles in the LCV fleet, making a total of 23 million hydrogen cars by 2050, equivalent to 1% of total passenger and LCVs.

We assumed that 5% of freight in the heavy goods vehicles (HGV) market will be carried by hydrogen-fuelled heavy vehicles by 2050. The share is currently zero in the Reference Case Scenario and the CMS. The GGM model of the HGV and train market employs methodology using the tons of freight transported per kilometre per year, which is determined by overall economic activities driven by GDP, fuel cost, and industrial output.

In the passenger sector model results are based on a stock model driven by the number of cars. The HGV sector needs to be adjusted for the penetration of hydrogen into the entire freight transportation market. Obviously, as the other income drivers are not subject to change, total freight in the other scenarios is the same. However, the total energy consumed might change. As for our scenario, hydrogen vehicles were substituted for other types to consume 5% of the total energy demand in freight.

In rail, as well as marine bunkers and aviation, hydrogen is assumed to penetrate. Hydrogen can be used to produce synthetic fuels to drive commercial aviation and marine bunkers, but the amount of penetration in our scenario is not as great as for LCVs and passenger vehicles.

6.3 Main results of the alternative scenarios

Although the previous sections refer to the CMS and TAS assumptions that feature the main factors and uncertainties related to carbon mitigation policies and potential technology progress, the following sections highlight the scenarios' assessment results for the CMS and Energy Transition Scenario (ETS), which assesses the combined effect of the CMS and TAS.

Energy demand prospects

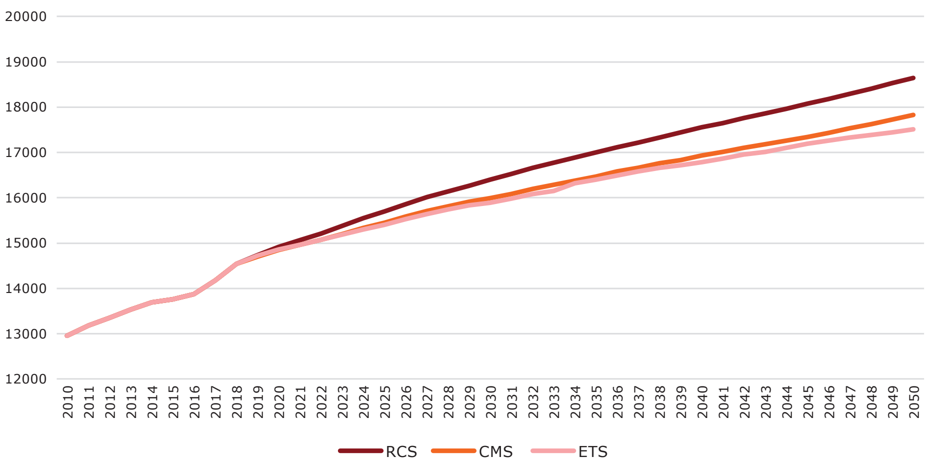
The CMS anticipates a significant slowdown of the progress of primary energy demand compared to the RCS, with an average annual growth rate, over the 2018-2050 period, expected to drop from 0.78% in the RCS to around 0.64% in CMS. This decelerated growth momentum will lead to a reduction of primary energy demand in the CMS by around 820 Mtoe in 2050, equivalent to more than 4% energy savings at this horizon in comparison with the RCS level.

The ETS expects energy demand to grow by around 0.58% p.a. leading to further demand reduction in 2050, estimated at almost 320 Mtoe compared to the RCS. The ETS, which combines both the mitigation policy and technology progress effects will lead to around 6% energy demand savings over the RCS.

As the CMS mainly focuses on power generation and road transport sectors, the energy demand reduction in this scenario is driven by the reduction of fuel consumption in these two sectors. The power sector is responsible for more than 690 Mtoe, or 85% of the energy conserved by 2050 compared to the RCS. This demand saving is due to the implementation of higher carbon prices which affects electricity demand and to the accelerated phasing out of less efficient coal-fired power plants. The expansion of gas-fired power plants and renewables will significantly improve the average efficiency of generating power in the CMS.

In the transport sector, the progress of clean vehicles (i.e. NGVs, EVs and Hybrid vehicles) will drive a primary energy demand reduction in the CMS compared to the RCS of around 60 Mtoe in 2050, representing 7% of the total savings. This reduction results from the combination of several opposing effects. First, a downside effect due to the penetration of more energy-efficient cars (especially hybrid cars), and to the reduction of the average distance driven by passenger and LCV vehicles, because of higher fuel costs applied in the CMS compared to the RCS. The higher fuel costs are particularly underpinned by the implementation of carbon taxes in the transport sector and by larger utilisation of electricity, priced at higher levels than other hydrocarbon fuels. Conversely, there is an upside effect on primary energy demand in the CMS which is due to the penetration of EVs. This increases the consumption of electricity and primary energy demand, which integrates the power plant conversion efficiency and waste in the power systems.

Figure 6.4. Primary energy demand prospects in the RCS, CMS and ETS (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

On the other side, it is worth mentioning that the progress of clean vehicles in the CMS will lead to a substantial reduction of oil product demand in the transport sector, estimated at almost 90 Mtoe by 2050.

For the ETS, the integration of technology progress in various sectors including industry, buildings and power generation specifically materializes through an improved efficiency of both the transformation and final utilization of energy. This technology-related efficiency improvement will drive the global demand reduction compared to the CMS, although various factors resulting from this technology progress such as increased electrification and penetration of hydrogen have an upside effect on primary energy demand. This is due to the transformation efficiency factor that enables generation of electricity or hydrogen.

Primary energy demand by fuel

Figure 6.5 depicts the average growth rates, over the 2018-2050 period, of the primary energy sources in the RCS, the CMS and the ETS. In the CMS, the average growth rate for natural gas demand is expected to rise marginally compared to the RCS, despite the significant policy support for gas in power generation and transport sectors assumed in this scenario. The key reason for this marginal increase is larger penetration of intermittent renewables (i.e. solar and wind) that reduces the average utilisation rates of gas-fired power plant capacities, and then puts a pressure on gas consumption in this sector. The global average growth rate of gas demand in the power generation, over the forecast period, is set to drop from 1.7% in the RCS to 1.5% in the CMS, which leads to almost 200 Mtoe gas demand reduction by 2050. Conversely, gas-fired capacities are anticipated to grow by around 3% per annum in the CMS compared to 2.5% per annum in the RCS. A large proportion of gas power plant operates in intermediate and peak-load regimes to achieve a cost-efficient balancing for renewables.

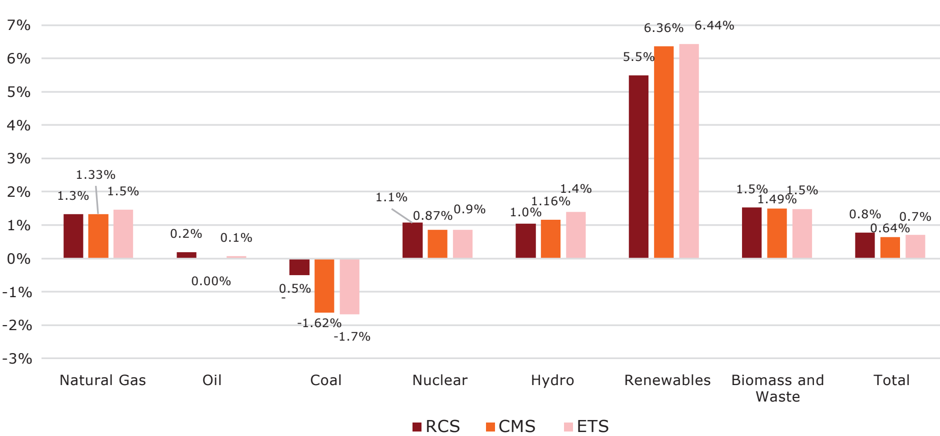
The reduction of demand growth in the power sector is, however, compensated by larger momentum in the road transport sector, benefitting from a policy push for NGV deployment. The additional NGV gas demand in the CMS over the RCS is estimated at around 210 Mtoe, thereby overpassing the reduction of this demand in the power sector. Overall, global gas demand in the CMS is anticipated to reach 5,110 Mtoe around 20 Mtoe more than the RCS.

For the ETS, the gas demand growth is pointing at around 1.5% per annum over the Outlook forecast period, which is markedly higher than the pace of growth in the RCS and CMS, This higher growth compared to the CMS is particularly supported by the deployment of blue hydrogen in various sectors. As depicted in figure 6.5, this ETS gas demand growth is estimated to add almost 210 Mtoe of natural gas to the CMS by 2050.

Coal is projected to decline by around 1.6% and 1.7% per annum in the CMS and the ETS, respectively. The decline of coal in the CMS is driven by more aggressive phasing out of coal and by measures supporting the adoption of more energy-efficient clean coal technologies that lead to less coal consumption for the amount of electricity produced, specifically in the Asia-Pacific, Europe and North America. China and India will lead the coal demand reduction in the CMS; these countries represent respectively 50% and 13% of the 980 Mtoe demand contraction in the CMS compared to the RCS.

The ETS estimates further coal shrinkage in comparison with the CMS, which is supported by higher efficiency and lower costs implemented for other alternatives to coal, especially the gas-based alternatives. Moreover, the ETS considers a level of efficiency improvements for coal-fired power plants, which also contributes to reducing coal demand in this sector.

Figure 6.5. Primary energy consumption CAAGR (2018-2050) in the RCS, CMS and ETS



Source: GECF Secretariat based on data from the GECF GGM

The fastest-growing source of energy in the RCS, renewables (excl. hydropower and biomass), is set to accelerate its development in the CMS, due to larger deployment of solar and wind. The CMS projects 6.4% annual growth for renewables adding around 0.9 percentage points to the RCS. Asia Pacific, particularly China and India, will drive the acceleration of renewables, especially solar. In the CMS, demand for renewables will increase by more than 800 Mtoe between 2018 and 2050 in China and India, which is 260 Mtoe higher than incremental demand in the RCS. This increase is driven by continuous policy support and cost reductions that will be seen in these two countries.

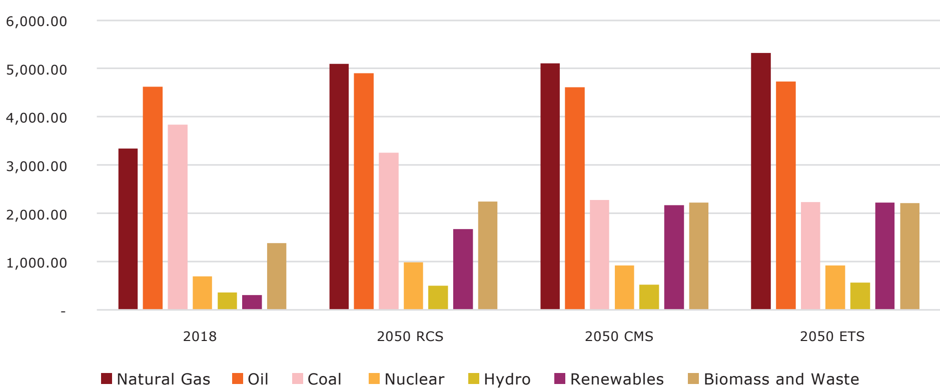
The ETS anticipates a relative increase of renewables at a global level compared to the CMS, which captures the bulk of the renewables incremental addition when comparing to the RCS. The ETS has a potential to add more than 50 Mtoe to the CMS renewables demand, estimated at around 2,175 Mtoe by 2050. This addition is particularly driven by the progress in batteries and digitalization that improves renewables integration in the power system.

Hydropower is also expected to achieve higher growth in the CMS and ETS as a result of further policy push for clean sources of power generation and technology progress. Particularly, hydropower including pump storage is expected to play a role in managing renewables intermittency in the two scenarios.

The long-term momentum of oil demand is expected to change from a very moderate growth (CAGR 2018-2050: 0.2%) in the RCS to a flat evolution in the CMS. This reflects larger penetration of EVs at the expense of oil-based vehicles, as well as a reduction of oil-fired power plants. The ETS, however, factors in larger efficiency progress in Internal Combustion Engines and some utilisation of oil in hydrogen production that allows some additional demand compared to the CMS.

The CMS does not expect further policy support for nuclear energy and additional nuclear capacities are not imposed on the RCS. As a result, the progress of other alternatives to nuclear in producing power, especially renewable energies and gas, contribute to decreasing the average annual growth rate of nuclear from 1.1% to around 0.9% over the forecast period.

Figure 6.6. Global primary energy demand trends by fuel type in all scenarios (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

The growth prospects of renewables, natural gas, coal and oil in the CMS and ETS will lead to significant changes in the primary energy mix by 2050.

In the CMS, demand for natural gas and renewables in 2050 is expected to be respectively 18 Mtoe and 500 Mtoe higher than in the RCS. Conversely, demand for coal and oil is expected to be 980 Mtoe and 280 Mtoe respectively lower. The substitution momentum in the power sector, coupled with the progress of EVs and NGVs, is anticipated to be favourable for natural gas and renewables in the global energy configuration by 2050.

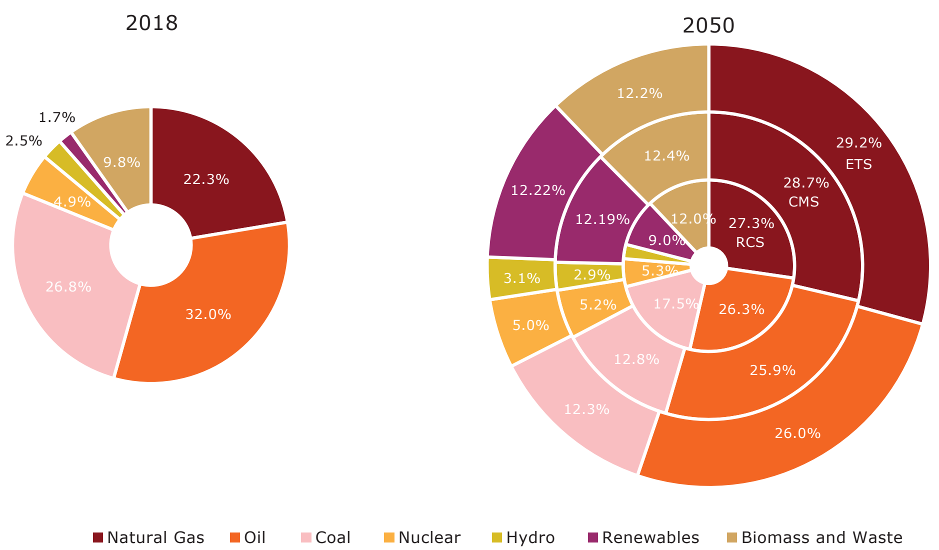
For the ETS, adding the technology advancement assumptions, specifically the blue hydrogen technologies and efficiency improvements will increase natural gas demand in 2050 by 210 Mtoe and renewables by 50 Mtoe, when comparing to the CMS.

The share of natural gas in total primary consumption will reach 28.7% and 29.2% respectively in the CMS and ETS by 2050 (compared with 26.8% in the RCS). The increase of the gas share in the two scenarios compared to the RCS results from both an increase of gas demand as well as a decrease of the primary energy demand.

The share of renewables will rise from 9% in the RCS to 12.19% in the CMS and 12.22 in the ETS. Two factors explain the marginal increase of the renewables share in the ETS compared to the CMS: First, low incremental increase of renewables since no large capacity additions are imposed in the renewables technology-related assumptions, applied to the CMS. Second, the decrease of primary energy demand mainly underpinned by global efficiency improvements.

If we include hydro and biomass/waste, renewables' contribution will reach 21.3% in the CMS and 22.6% in the ETS, significantly surpassing the share of coal. The role of coal in primary energy is, therefore, anticipated to decline significantly and reach 12.8% in the CMS and 12.3% in the ETS by 2050 compared to 17.5% in the RCS.

Figure 6.7. Global primary energy mix in 2018 and 2050 by fuel type in all scenarios (%)

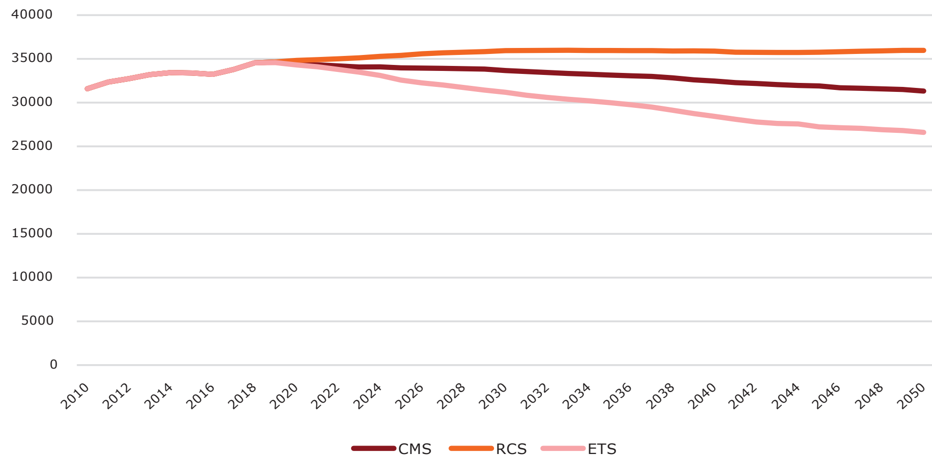


Source: GECF Secretariat based on data from the GECF GGM

Global energy-related CO2 emissions

Energy-related CO_2 emissions are expected to reach 31.3.$GtCO_2$ in the CMS by 2050. This will drop to around 26.6 $GtCO_2$ in the ETS, which captures further carbon mitigation potential due to technology advancements and larger deployment of hydrogen. These emissions forecasts reflect substantial reductions compared to the RCS, estimated at 4.6 $GtCO_2$ in the CMS and nearly 9.4 $GtCO_2$ in the ETS. The total CO_2 emission trajectory shows that emissions are expected to peak by 2022 in the CMS and by 2020 in the the ETS.

Figure 6.8. Prospect of global energy-related CO2 emissions in all scenarios (MtCO2)



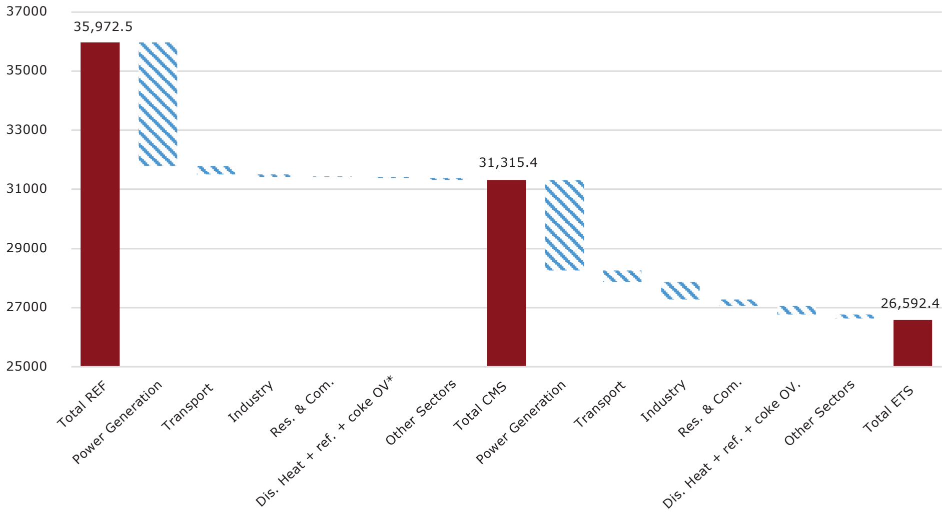
Source: GECF Secretariat based on data from the GECF GGM

It is worth remembering that the objective of analysing these alternative scenarios is not to reach energy-related CO_2 emissions pathways, which are compatible with the Paris Agreement objectives. Rather, the purpose is to investigate the potential of some feasible options that can be deployed by increasing the policy effort targeting mainly the existing technologies and allowing them to be more largely disseminated, and the technology advancement that adds progress of some key technologies including hydrogen deployement.

In the CMS, the bulk of emissions reductions comes from a changing power generation mix with renewables and natural gas penetration against coal and oil. This sector is expected to reduce its emissions by around 4.2 $GtCO_2$ of the total 4.6 $GtCO_2$ reduction forecast for 2050 in this scenario (figure 6.9). In the ETS, power generation continues to play a key role and enables further reductions of emissions by 3 $GtCO_2$ compared to the CMS. This reduction is underpinned by improved thermal efficiency of power plants and the larger deployment of CCS technologies.

The transport sector will be responsible for around 280 $MtCO_2$ reduction in the CMS compared to the RCS in 2050, due to the penetration of NGVs and EVs. Additional emissions mitigation of around 390 $MtCO_2$ is permitted with further progress of EVs and development of hydrogen-based vehicles as highlighted in figure 6.9. Although EVs reduce emissions in the transport sector, they contribute to displacing them towards the power generation sector, because the incremental electricity demand required by

Figure 6.9. Energy-related CO2 emissions reduction in 2050 by sectors (MtCO2)



Source: GECF Secretariat based on data from the GECF GGM

EVs needs to be met by increasing electricity generation and thereby will drive the rise of power-related emissions. Nevertheless, the shift of the power generation mix with aggressive penetration of clean options (i.e renewables and gas), particularly in the CMS, plays a role in mitigating this emissions displacement effect.

The mitigation potential in other sectors including residential and industrial sectors is limited in the CMS which has a focus on power generation and transport. The ETS enables, however, non-negligible mitigation in the industry and residential and commercial sectors, with respectively 595 $MtCO_2$ and 222 $MtCO_2$ emission savings. This reduction potential mainly results from the increased electrification of these sectors as well as the uptake of hydrogen, especially in the energy-intensive industries. Hydrogen technology penetration also plays a role in the district heating sector with an expected saving of around 288 $MtCO_2$.

As was previously mentioned for EVs, increased electrification in the industrial, residential and commercial sectors, contributes to displacing the emissions form these sectors to the power generation sector. This displacement effect is, however, offset by the progress of more efficient power plants and CCS. Furthermore, hydrogen penetration has an upside effect on emissions in the hydrogen conversion sector, but this effect is largely offset by the deployment of CCS, implemented for blue hydrogen conversion.

ANNEX I: REGIONAL GROUPINGS

Advanced economies: OECD regional grouping, plus Bulgaria, Croatia, Cyprus, Latvia, Lithuania, Malta and Romania

Africa: North Africa and Sub-Saharan Africa regional groupings

Asia Pacific: Afghanistan, Australia, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Chinese Taipei, Cook Islands, Democratic People's Republic of Korea, Fiji, French Polynesia, Hong Kong (China), India, Indonesia, Japan, Kiribati, Korea, Lao People's Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Timor-Leste, Tonga, Vanuatu, and Viet Nam

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, and Uzbekistan

Developed Asia: Australia, Japan, South Korea, New Zealand

Developing Asia: Afghanistan, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Chinese Taipei, Cook Islands, Democratic People's Republic of Korea, Fiji, French Polynesia, Hong Kong, India, Indonesia, Kiribati, Lao People's Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Timor-Leste, Tonga, Vanuatu, and Viet Nam

Developing economies: All other countries not included in the "advanced economies" regional grouping

Eurasia: Caspian region and Belarus, Moldova, Russia, and Ukraine

Europe: European Union and Albania, Bosnia and Herzegovina, Gibraltar, Iceland, Montenegro, Norway, Serbia, Switzerland, the Former Yugoslav Republic of Macedonia, the Republic of Moldova, and Turkey

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom

GECF Members (As of December 2019): Algeria, Bolivia, Egypt, Equatorial Guinea, Libya, Iran, Nigeria, Qatar, Russia, Trinidad and Tobago, the United Arab Emirates, and Venezuela

GECF Observer Members (As of December 2019): Angola, Azerbaijan, Iraq, Kazakhstan, Norway, Oman, and Peru

Latin America: Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay, and Venezuela

Middle East: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, and Yemen

Middle East and North Africa (MENA): Middle East and North Africa regional groupings

North Africa: Algeria, Egypt, Libya, Morocco, and Tunisia

North America: Canada, Mexico, and the United States of America

OECD: Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom and the United States.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Viet Nam

Sub-Saharan Africa: Angola, Benin, Botswana, Burkina Faso, Burundi, Cabo Verde, Cameroon, Central African Republic, Chad, Comoros, Côte d'Ivoire, Democratic Republic of the Congo, Djibouti, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea Bissau, Kenya, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Mozambique, Namibia, Niger, Nigeria, Republic of the Congo, Réunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan,

ANNEX II: ABBREVIATIONS

ACE	Affordable Clean Energy rule
AEMO	Australian Energy Market Operator
BEV	Battery Electric Vehicles
BN	Billion
CAAGR	Compound Annual Average Growth Rate
CBM	Coalbed Methane
CCGT	Combined-cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CMS	Carbon Mitigation Scenario
CNG	Compressed Natural Gas
CNPC	Chinese National Petroleum Company
CO2	Carbon Dioxide
CPP	Clean Power Plan (US)
CPS	Carbon Price Support
DOI	United States Department of the Interior
EB	Executive Board (GECF)
EC	European Commission
ECB	European Central Bank
EIA	Energy Information Administration (US)
EOR	Enhanced Oil Recovery
EPA	US Environmental Protection Agency
ETS	Energy Transition Scenario
EU	European Union
EV	Electric Vehicle
FBC	Fluidised Bed Combustion
FID	Final Investment Decision
FSRU	Floating Storage Regasification Unit
FYP	Five-Year Plan
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum

GGM	Global Gas Model
GGO	Global Gas Outlook
GHG	Greenhouse Gas
GIIGNL	International Group of Liquefied Natural Gas Importers
GTL	Gas to Liquids
ICE	Internal Combustion Engine
IEA	International Energy Agency
IED	Industrial Emissions Directive
IMF	International Monetary Fund
IMO	International Maritime Organization
INDC	Intended Nationally Determined Contribution
JCPOA	Joint Comprehensive Plan of Action
JFTC	Japan Fair Trade Commission
JKM	Japan Korea Marker
JOGMEC	Japan Oil, Gas and Metals National Corporation
JPY	Japanese Yen
LCV	Light Commercial Vehicle
LFPR	Labour Force Participation Rate
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MER	Market Exchange Rates
NAFTA	North American Free Trade Agreement
NBP	National Balancing Point (UK gas hub)
NDCs	Nationally Determined Contributions
NEXI	Nippon Export and Investment Insurance
NGO	Non-Governmental Organisation
NGV	Natural Gas Vehicles
NOX	Nitrogen Oxides
OCS	Outer Continental Shelf
OPEC	Organization of the Petroleum Exporting Countries
PHEV	Plug-in Hybrid Electric Vehicles
PPP	Purchasing Power Parity
PSPP	Public Sector Purchase Programme
PV	Photovoltaic
R&D	Research and Development
RBI	Reserve Bank of India
RCS	Reference Case
RES	Reference Energy System
RPS	Renewable Portfolio Standards (US)
SCP	Southern Caucasus Pipeline
SDGs	Sustainable Development Goals
SOX	Sulfur Oxides
TANAP	Trans-Anatolian Gas Pipeline
TAP	Trans Adriatic Pipeline
TAPI	Turkmenistan-Afghanistan-Pakistan-India pipeline
TAS	Technology Advancement Scenario
TEC	Technical and Economic Council
TENP	The Trans Europa Naturgas Pipeline
TPES	Total primary energy supply

TTF	Title Transfer Facility (Dutch gas hub)
UAE	United Arab Emirates
UK	United Kingdom
UN	United Nations
US	United States
USD	United States Dollar
VAT	Value-Added Tax
WEF	World Economic Forum
WHO	World Health Organization
WTI	West Texas Intermediate
WTO	World Trade Organization
YTF	Yet-to-find

ANNEX III: CONVERSION FACTORS AND DEFINITIONS

From\To	CM	mmBtu	toe	GJ	Therms	CF	T LNG	CM LNG	MWh	BOE	TC
CM (S)	1	0.034	0.0009	0.035797	0.34	35.31	0.0007252	0.001639	0.009944	0.0066	0.0014
mmBtu	29.47	1	0.02519	1.0548	10.00	1040.59	0.021	0.048	0.293	0.1940	0.0420
toe	1169.59	39.69	1	41.868	396.93	41303.70	0.8481	1.917	11.63	7.700	1.667
GJ	27.94	0.9480	0.0239	1	9.48	986.52	0.0203	0.0458	0.2778	0.1839	0.03981
Therms	2.947	0.1000	0.0025	0.1055	1	104.06	0.0021	0.0048	0.0293001	0.019	0.0042
CF	0.02832	0.000961	0.00002421	0.0010	0.009610	1	0.000021	0.000046	0.00028	0.00019	0.0000
T LNG	1379	46.80	1.1791	49.36	468.00	48699	1	2.26	13.71	9.08	1.97
CM LNG	610.0	20.70	0.5216	21.84	207.02	21542	0.4423	1	6.066	4.02	0.87
MWh	100.57	3.413	0.0860	3.600	34.13	3551	0.073	0.16	1	0.66	0.14
BOE	151.9	5.155	0.1299	5.438	51.55	5364	0.1101	0.2490	1.5104	1	0.22
TC	701.8	23.82	0.6000	25.12	238.16	24782	0.5089	1.1504	6.9780	4.6199	1

NATURAL GAS									LNG	
MJ/Nm3 (GCV)	kCal/Nm3 (GCV)	kWh/Nm3	(N)bcm /mtoe	(S)bcm /mtoe	MJ/Sm3 (GCV)	kCal/Sm3 (GCV)	kWh/Sm3	Btu/Scf GCV	mmBtu /Tonnes LNG	47
41.959	10,022	11.66	1.1087	1.1696	39.775	9500	11.049	1068	CM/Cubic meters LNG	610

[1]Each of the gas production entities has its own calorific value so the specific value is used for these flows to convert into the energy content. For this reason values that appear in the production entity tables and in the supply data tables that aggregate the volumes may be different from the production values using standard conversion factors

Agriculture
Includes all energy used on farms, in forestry, and for fishing [ISIC Divisions 01 – 03].

Associated Gas
Natural gas found in contact with or dissolved in crude oil in the reservoir.

Barrel of Oil Equivalent (BOE)
The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.

Biofuels
Liquid fuels derived from biomass or waste feedstocks, including ethanol and biodiesel.

Biomass and Waste
Renewable organic materials, such as wood, agricultural crops or wastes, and municipal wastes, especially when used as a source of fuel or energy. Biomass can be burned directly or processed into biofuels such as ethanol and methane.

Bunkers
Includes both international marine bunkers and international aviation bunkers.

Coal
Includes primary coal (hard coal, lignite, coking, and steam coal) and derived fuels (including patent fuel, brown coal briquettes, coke oven coke, gas coke, gas-works gas, coke-oven gas, blast-furnace gas, and oxygen steel furnace gas). Peat is also included.

Coalbed Methane
Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas or natural gas from coal.]

Condensate
A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.

Contracts for Difference
A mechanism of hedging the price of electricity for renewables between renewable generators and counter parties (for instance Low Carbon Contracts Company in the UK). It allows the generators to receive a pre-agreed level for the duration of contracts (the strike price). Under this mechanism, when the market price for electricity generated (the reference price) is below the strike price agreed in the contract, compensation is paid by the counter party. On the other side, when the reference price is above the strike price, the renewable generator pays the counterpart.

Conventional Resources
Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The petroleum initially in place is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer, and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.

Cost Tranche
A set of production entities grouped according to a defined cost range.

Curtailment
According to National Renewable Energy Laboratory, curtailment is a reduction in the output of a generator of variable renewable energy from what it could otherwise produce given available resources like wind or sunlight. Variable renewable energy curtailment is usually used as a way to reduce the production of energy that cannot be delivered due to lack of power system flexibility.

Distributed Energy System
Include systems which generate and deliver energy services (Power, cooking, or heating services) independent of centralised systems. For renewable power, they include particularly off grid renewable generators such as home solar panels.

Domestic
The domestic sector includes energy used in the residential, commercial and agricultural sectors. Domestic energy use includes space heating and cooling, water heating, lighting, appliances, and cooking equipment.

Dry Gas
Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behaviour definition. (Also called lean gas.)

Electricity Generation
Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own-use. This is also referred to as gross generation.

Energy Sector
Covers the use of energy by non-energy sector and the energy losses in converting primary energy into a form that can be used in the final consumption sectors. It includes losses by gas works, petroleum refineries, blast furnaces, coke ovens, coal and gas transformation, and liquefaction. It also includes energy used in the distribution network. Transfers and statistical differences are also included in this category.

Enhanced Oil Recovery (EOR)
The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called improved recovery.)

Existing Gas Production Facilities
Those that are in production as of 2019.

Feed-in Premium
A renewable policy support mechanism which offers compensation based on markets conditions. In this mechanism, electricity from renewable energy sources is sold on the electricity spot market and renewable producers receive a premium on top of the market price of their electricity production. No premium is paid if market prices are higher than the reference tariff level.

Feed-in Tariff
A renewable policy support mechanism which offers a fixed compensation to renewable energy producers, providing price certainty and long-term contracts that help finance renewable energy investments. The level of compensation is based on the cost of generation of each technology.

Feedstock
Includes refinery feedstocks and petrochemical feedstocks.

Final Investment Decision (FID)
Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.

Flare Gas
The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).

Gas Exports (Upstream Volumes)
Gas volumes shipped by a gas exporting country to an importing country including all the losses (pipelines, liquefaction, shipping, and regasification).

Gas Hydrates

Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.

Gas Imports (End Use Volumes)
Net gas volumes delivered by an exporting country to an importing country, not including the losses during the shipment.

Heat Energy
Obtained from the combustion of fuels, nuclear reactors, geothermal reservoirs, the capture of sunlight, exothermic chemical processes, and heat pumps which can extract it from ambient air and liquids. It may be used for heating or cooling, or converted into mechanical energy for transport vehicles or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Heat Generation
Refers to fuel use in heat plants and combined heat and power (CHP) plants.

Heat Plants
Refers to plants (including heat pumps and electric boilers) designed to produce heat.

Hydropower
The energy content of the electricity produced in hydropower plants.

Industry
Includes fuel used within the manufacturing and construction industries. Key industry sectors include iron and steel, chemical and petrochemical, nonferrous metals, non-metallic minerals, and other manufacturing.

International Aviation Bunkers
Includes the deliveries of aviation fuels to aircraft for international aviation. The domestic/international split is determined based on departure and landing locations and not by the nationality of the airline.

International Marine Bunkers
Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined by the port of departure and port of arrival, and not by the flag or nationality of the ship.

Nationally Determined Contributions (NDCs)
Intended Nationally Determined Contributions (INDCs) after their ratification by individual governments. They include the countries' GHG mitigation and adaptation pledges submitted to the UNFCCC in the framework of the Paris Agreement.

Natural Gas Liquids (NGLs)
A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.

Natural Gas Production Capacity
The potential volumes of natural gas ready to be produced by developed wells and processing units associated with a production entity.

Natural Gas Production
Marketed production including domestic sales and exports

Natural Gas Proven Reserves
Refers to existing reserves, new projects, and unconventional (existing) gas resources.

Natural Gas
Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non-hydrocarbons.

New Project Gas Production
Fields that have been discovered but have yet to be developed or are in development.

Non-Energy Use
Fuels used for non-energy products excluding use as feedstock in petrochemical plants. Examples of non-energy products include gas works, cooking ovens, lubricants, paraffin waxes, asphalt, bitumen, coal tars, and oils as timber preservatives.

Nuclear
Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

Oil
includes demand for crude oil both conventional and unconventional and petroleum products include refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil naphtha, and other oil products (white spirit, lubricants, bitumen, paraffin, waxes, and petroleum coke) and natural gas liquids but excludes biofuels and synthetic oil based products.

Oil Sands
Sand deposits highly saturated with natural bitumen. Also called "tar sands." Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.

Petrochemical Feedstocks
The petrochemical industry includes cracking and reforming processes for the purpose of producing ethylene, propylene, butylene, synthesis gas, aromatics, butadiene and other hydrocarbon-based raw materials in processes such as steam cracking, aromatics plants, and steam reforming.

Power Generation
Refers to fuel use in electricity plants and combined heat and power (CHP) plants.

Probable Reserves
An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Production Entity
A gas field, or group of gas fields located in the same zone, or gas geological prospects from which marketed natural gas production is expected to be available and economically viable.

Production Signature
A curve that models the rate at which the remaining recoverable gas reserves will be produced, without damaging the corresponding reservoir.

Proved Reserves
Those quantities that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations

Refinery Feedstocks
Processed oil destined for further processing (e.g. straight run fuel oil or vacuum gas oil) other than blending in the refining industry. It is transformed into one or more components and/or finished products. This definition covers those finished products

imported for refinery intake and those returned from the petrochemical industry to the refining industry.

Renewables
Geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Reserves
Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.

Residential
Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices, and cooking equipment.

Shale Gas
Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production.

Tight Gas
Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.

Total Final Consumption
The sum of consumption by the different end-use sectors. TFC is broken down into energy demand in the following sectors: industry, transport, domestic (including residential, commercial and agriculture), and feedstock uses.

Total Primary Energy Demand
Represents domestic demand only and is broken down into power generation, heat generation, refinery, energy sector, non-energy sector, and total final consumption.

Transport
Fuels and electricity used in the transport of goods or persons within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the global level and is excluded from the transport sector at a domestic level

Unconventional Gas Production
Fields that are associated with gas resources that are from either coal bed methane, tight shale, or other resources that require special development techniques.

Unconventional Resources
Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined oil/water contact (OWC) or gas/water contact (GWC) (also called "continuous-type deposits"). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

Yet-to-Find (YTF)
Refers to the theoretical volume of undiscovered gas reserves, calculated based on the probability of finding reserves in certain geological areas. YTF also assumes that technological advancements will make it economically feasible to extract the gas in the future.

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