



GECF

Gas Exporting
Countries Forum

Global Gas Outlook 2050

8th Edition
March 2024

Disclaimer

The data, forecasts, analysis, and/or any other information contained within this document and any attachments thereto ('Documents') are for information purposes only and are provided on a non-reliance basis and any obligation and responsibility is hereby disclaimed with respect to such content.

Neither the GECF, any of the GECF Members and Observer Countries, nor any of their officials, representatives, agents or employees (the 'Parties'), while fully reserving their rights with respect thereto, shall assume any liability or responsibility for the content of the Documents and any data, analysis, or any other information incorporated therein.

None of the Parties, including any individual involved in the preparation of the Documents, provides any representation or warranty, express or implied, nor assumes any liability or responsibility as to the accuracy, adequacy, completeness, or reasonableness of any material, information, data or analysis contained in the Documents or represents in any way that its use would not infringe any rights owned by a Party or any third party. The Parties shall not be liable for any errors in, or omissions from, such information and materials.

The Document is not intended nor shall it be deemed as a substitute for your own independent judgment or professional advice for your business, investment, finance, or other commercial or non-commercial activity or clients. Subject to the above reservation, the analysis, information and views presented in this Document are those of the GECF Secretariat and do not necessarily reflect the views of GECF Members and/or Observer Countries.

Except where otherwise stated expressly, the copyright and all other intellectual property rights in the contents of this Document (including, but not limited to, designs, texts, and layout) shall be the property of GECF. As such, they may not be reproduced, transmitted, or altered, in any way whatsoever, without the express prior written permission of the GECF. Where the Documents contain references to materials from third parties, the GECF Secretariat shall not be responsible for any unauthorised use of third party materials and/or the consequences of such use.

Report citation: Gas Exporting Countries Forum. 8th edition of the GECF Global Gas Outlook 2050. March 2024.

Comments and questions regarding the 8th edition of the GECF Global Gas Outlook 2050 should be addressed to:

Gas Exporting Countries Forum

Tornado Tower, 47th-48th Floors, West Bay, Doha-Qatar

P.O. Box 23753

Tel: **+97444048400**

Email: **Oulook@gecf.org**

More information is available at **www.gecf.org**

About the GECF

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

As of December 2023, the GECF comprises twelve Members and seven Observer Members (hereafter referred to as the GECF Countries) from four continents. The Member Countries of the Forum are Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela (hereafter referred to as Members). Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal have the status of Observer Members (hereafter referred to as Observers).

Cooperation has been extended to technology with the establishment of the Gas Research Institute in 2019, headquartered in Algiers, the People's Democratic Republic of Algeria.

In accordance with the GECF Statute, the organisation aims to support the sovereign rights of its Member Countries over their natural gas resources and their abilities to develop, preserve and use such resources for the benefit of their peoples, through the exchange of experience, views, information and coordination in gas-related matters.

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

Acknowledgements

The publication of the 8th edition of GECF Global Gas Outlook 2050 recognises the assistance of a number of experts. It benefitted from the comments and suggestions by the GECF Executive Board Members, Technical and Economic Council Members, and the Secretary General, Eng. Mohamed Hamel.

PROJECT LEADER

Mohammad Amin Naderian, Head, Energy Economics and Forecasting Department, EEFD

LEAD AUTHORS AND THE GECF GGM MODELLING TEAM (alphabetical order)

Abubakar Jibrin Abbas, Senior Energy Forecast Analyst, EEFD

Alexander Ermakov, Energy Econometrician, EEFD

Galia Fazeliyanova, Energy Economics Analyst, EEFD

Masoumeh Moradzadeh, Energy Environment and Policy Analyst, EEFD

Mustafa Adel Amer, Energy Technology Analyst, EEFD

Sabna Ali, Research Assistant, EEFD

ADMINISTRATIVE AND DESIGN SUPPORT

Nargiz Amirova, Secretary, EEFD

ONGOING DATA AND SERVICE SUPPORT FOR THE GECF GGM

S&P Global

PEER REVIEW SUPPORT

Natural Gas World

Natural Gas World provided an extensive review of the report, checking for consistency and factual accuracy. The views and conclusions expressed are those of the GECF Secretariat and do not necessarily coincide with the opinions of Natural Gas World or its staff.

COVER AND DESIGN

Strategy to Execution (S2E) Agency

GECF TECHNICAL AND ECONOMIC COUNCIL (As of March 2024)

Sofiane Dakiche | Sergio A. Guzmán Ríos | Yaseen Mohamed Yaseen | Antimo Asumu Obama Asangono | Afshin Javan | Naima Suwani | Oluremi A.Komolafe | Jabor Yaser Al-Mesalam | Denis Leonov | Selwyn Lashley | Amal Al-Ali | José Agustín Ruiz



Table of Contents

Foreword	1
Executive Summary	2
Chapter 1 Global Economic and Price Assumptions	
1.1 Population and demographics	8
1.1.1 Accelerated urbanisation rate	10
1.1.2 Ageing population	11
1.1.3 Enhanced migration	12
1.1.4 Transformation of the average household size	12
1.2 Economic growth outlook	13
1.2.1 Current developments and short-term outlook	13
1.2.2 Long-term economic growth prospects and major drivers	13
1.2.3 Long-term economic growth outlook by region	15
1.3 Energy and carbon prices	20
1.3.1 Crude oil prices	20
1.3.2 Natural gas prices	21
1.3.3 Carbon prices	21
Chapter 2 Energy Policy Developments	
2.1 Global developments and trends	26
2.1.1 Short-term strategies for tackling the energy crisis amid geopolitical challenges	26
2.1.2 Global strategies under reassessment	26
2.1.3 The need for diverse paths of just, equitable and orderly transitions	28
2.1.4 Natural gas: policy support, and the challenges of market volatility	29
2.1.5 Natural gas as a key enabler in low-carbon hydrogen production	30
2.1.6 Natural gas as the primary low-carbon energy source and renewable energy partner	31
2.1.7 The resurgence of nuclear power	32
2.1.8 Steady growth for natural gas market	32
2.2 Policy drivers and developments in the key markets	32
2.2.1 India	32
2.2.2 China	36
2.2.3 The United States	37
2.2.4 The EU	39
Chapter 3 Energy Demand Outlook	
3.1 Global primary energy demand outlook	44
3.2 Primary energy demand outlook by fuel	46
3.2.1 Oil	46
3.2.2 Coal	47
3.2.3 Nuclear	47
3.2.4 Hydro	48
3.2.5 Renewables	49
3.2.6 Bioenergy	50
3.3 The outlook for global electricity demand and generation	51
3.4 The outlook for hydrogen demand, generation and trade	54
3.5 The outlook for energy-related CO₂ emissions	58
3.6 Energy intensity and consumption per capita prospects	61
Chapter 4 Natural Gas Demand Outlook	
4.1 Natural gas demand outlook: global overview and sectoral trends	68
4.1.1 Recent developments and global outlook overview	68
4.1.2 Sectoral trends	69
4.2 Regional trends in natural gas demand	71
4.2.1 Africa	71
4.2.2 Asia Pacific	74
4.2.3 Eurasia	80
4.2.4 Europe	81
4.2.5 Latin America	82
4.2.6 Middle East	84
4.2.7 North America	87

Chapter 5 Natural Gas Supply Outlook	
5.1 Global natural gas production	92
5.2 Global natural gas proven reserves current status	92
5.3 Natural gas production outlook	93
5.4 Regional natural gas production outlook	96
5.4.1 Africa	96
5.4.2 Asia Pacific	98
5.4.3 Eurasia	101
5.4.4 Europe	102
5.4.5 Latin America	103
5.4.6 Middle East	105
5.4.7 North America	107
Chapter 6 Natural Gas Trade Outlook	
6.1 Current natural gas market trends	112
6.2 Natural gas trade outlook	112
6.2.1 Pipeline natural gas trade outlook	113
6.2.2 LNG import outlook	114
6.2.3 LNG export outlook	115
6.3 Natural gas trade balance outlook	116
6.4 Natural gas trade infrastructure prospects	117
6.4.1 LNG liquefaction	117
6.4.2 LNG regasification	117
6.5 Natural gas trade outlook by region	118
6.5.1 Africa	118
6.5.2 Asia Pacific	120
6.5.3 Eurasia	123
6.5.4 Europe	125
6.5.5 Latin America	127
6.5.6 Middle East	129
6.5.7 North America	130
Chapter 7 Natural Gas Investment Outlook	
7.1 Upstream oil and gas investment	136
7.1.1 Current development in upstream natural gas investment	138
7.1.2 Global upstream gas investment requirement	140
7.1.3 Regional upstream gas investment requirement	141
7.2 Midstream natural gas investment	143
7.2.1 Historical background and current trends	143
7.2.2 Midstream natural gas investment by region	145
Chapter 8 Sustainable Energy Scenario	
8.1 Introduction	152
8.2 SES Assumptions	152
8.2.1 Per capita GDP assumptions	153
8.2.2 Power sector assumptions	153
8.2.3 Rapid low-carbon hydrogen adoption assumptions	153
8.2.4 Residential segment assumptions	153
8.2.5 Accelerated CCUS upscaling assumptions	153
8.3 SES results	154
8.3.1 Primary energy demand	154
8.3.2 Natural gas demand	157
8.3.3 Hydrogen demand and generation	160
8.3.4 Energy-related emissions	161
8.4 Implications	162
Annex A Abbreviations	165
Annex B Geographical coverage	168
Annex C Conversion table	173
Annex D Definitions	175

Table of Figures

Figure 1.1.	Global population growth outlook in 1950-2050 (million people)	8
Figure 1.2.	Global population outlook by region, 2022-2050 (million people)	9
Figure 1.3.	Population change outlook by region, 2022-2050 (million people)	10
Figure 1.4.	Urban population outlook, 2022-2050 (million people)	10
Figure 1.5.	Working age population share trends, 1990-2050 (%)	11
Figure 1.6.	Old-age dependency ratio outlook, 2022-2050 (%)	11
Figure 1.7.	Number of households' outlook, 2022 - 2050 (millions of households)	12
Figure 1.8.	GDP outlook, 2022-2050 (real trillion USD, base year = 2022)	14
Figure 1.9.	Per capita GDP outlook, 2022-2050 (real 1,000 USD, base year = 2022)	14
Figure 1.10.	Regional GDP incremental growth outlook, 2022-2050 (real trillion USD, base year = 2022)	15
Figure 1.11.	Long-term GDP growth outlook, 2022-2050 (real trillion USD, base year = 2022)	16
Figure 1.12.	Long-term per capita GDP growth outlook, 2022-2050 (real 1000 USD, base year = 2022)	16
Figure 2.1.	Factors incentivising natural gas policy	31
Figure 3.1.	Primary energy demand outlook, 2022-2050 (Mtoe)	44
Figure 3.2.	Global primary energy mix outlook, 2022 and 2050 (%)	45
Figure 3.3.	Global primary energy demand outlook, 2022-2050 (Mtoe)	46
Figure 3.4.	Global oil demand outlook, 2022-2050 (Mtoe)	46
Figure 3.5.	Global coal demand outlook, 2022-2050 (Mtoe)	47
Figure 3.6.	Global nuclear energy demand outlook, 2022-2050 (Mtoe)	48
Figure 3.7.	Global hydro demand outlook, 2022-2050 (Mtoe)	49
Figure 3.8.	Global renewables energy demand outlook, 2022-2050 (Mtoe)	50
Figure 3.9.	Global bioenergy demand outlook, 2022-2050 (Mtoe)	51
Figure 3.10.	Global electricity demand outlook by end-use sector, 2022-2050 (TWh)	51
Figure 3.11.	Global power generation outlook, 2022-2050 (TWh)	52
Figure 3.12.	Global power generation capacity outlook, 2022-2050 (GW)	53
Figure 3.13.	Hydrogen demand outlook, 2022-2050 (MtH ₂)	55
Figure 3.14.	Hydrogen demand outlook, 2022-2050 (MtH ₂)	55
Figure 3.15.	Hydrogen generation outlook, 2022-2050 (MtH ₂)	56
Figure 3.16.	Hydrogen fuel input outlook, 2022-2050 (Mtoe)	57
Figure 3.17.	Hydrogen import outlook, 2022-2050 (MtH ₂)	58
Figure 3.18.	Energy-related emission outlook, 2022-2050 (GtCO ₂ e)	58
Figure 3.19.	Contribution of regions in global energy-related emission, 2022 and 2050 (%)	59
Figure 3.20.	Energy-related CO ₂ emission per capita, 2022 and 2050 (tCO ₂ /person)	59
Figure 3.21.	Decomposition of CO ₂ emissions by its constituents (1990-2021 and 2022-2050)	60
Figure 3.22.	Global CO ₂ emission outlook, 2022-2050 (GtCO ₂ e)	61
Figure 3.23.	Energy intensity improvement outlook (%)	62
Figure 3.24.	Primary energy consumption growth decomposition (1990-2021 and 2022-2050)	63
Figure 3.25.	Regional primary energy consumption per capita outlook, 2022 and 2050 (toe/person)	63
Figure 4.1.	Global natural gas demand, 2010-2022 (bcm)	68
Figure 4.2.	Global natural gas demand outlook by region, 2022-2050 (bcm)	69
Figure 4.3.	Natural gas demand outlook by sector, 2022-2050 (bcm)	70
Figure 4.4.	Africa power generation outlook, 2022-2050 (TWh)	71
Figure 4.5.	Africa natural gas demand outlook, 2022-2050 (bcm)	72
Figure 4.6.	Asia Pacific power generation outlook, 2022-2050 (TWh)	74
Figure 4.7.	Asia Pacific natural gas demand outlook, 2022-2050 (bcm)	75
Figure 4.8.	China natural gas demand outlook, 2022-2050 (bcm)	75
Figure 4.9.	China power generation outlook, 2022-2050 (TWh)	76
Figure 4.10.	India natural gas demand outlook, 2022-2050 (bcm)	77
Figure 4.11.	India power generation outlook, 2022-2050 (TWh)	77
Figure 4.12.	Southeast Asia power generation outlook, 2022-2050 (TWh)	79
Figure 4.13.	Eurasia natural gas demand outlook, 2022-2050 (bcm)	80
Figure 4.14.	Europe natural gas demand outlook, 2022-2050 (bcm)	81
Figure 4.15.	Latin America power generation outlook, 2022-2050 (TWh)	83
Figure 4.16.	Latin America natural gas demand outlook, 2022-2050 (bcm)	83
Figure 4.17.	Middle East power generation outlook, 2022-2050 (TWh)	85
Figure 4.18.	Middle East natural gas demand outlook, 2022-2050 (bcm)	85
Figure 4.19.	North America natural gas demand outlook, 2022-2050 (bcm)	87
Figure 4.20.	The United States power generation outlook, 2022-2050 (TWh)	88
Figure 5.1.	Natural gas reserves by region, 2000-2022 (tcm)	92
Figure 5.2.	Natural gas production outlook by region, 2022-2050 (bcm)	93
Figure 5.3.	Natural gas supply growth outlook by region, 2022-2050 (bcm)	93

Figure 5.4.	Natural gas production contribution forecast by region (2022 and 2050)	94
Figure 5.5.	Natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	94
Figure 5.6.	Global natural gas production outlook by share of project types, 2022-2050 (%)	95
Figure 5.7.	Global natural gas production outlook by field type, 2000-2050 (bcm)	95
Figure 5.8.	Natural gas production growth outlook, 2022-2050 (bcm)	95
Figure 5.9.	Natural gas production outlook by field location, 2022-2050 (bcm)	96
Figure 5.10.	Africa natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	96
Figure 5.11.	Africa natural gas production outlook by project type, 2022-2050 (bcm)	97
Figure 5.12.	Africa natural gas production share outlook by field location, 2022-2050 (%)	97
Figure 5.13.	Asia Pacific natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	99
Figure 5.14.	Asia Pacific natural gas production outlook by project type, 2022-2050 (bcm)	99
Figure 5.15.	Asia Pacific natural gas production share outlook by field location, 2022-2050 (%)	99
Figure 5.16.	Eurasia natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	101
Figure 5.17.	Eurasia natural gas production share outlook by field location, 2022-2050 (%)	101
Figure 5.18.	Eurasia natural gas production outlook by project type, 2022-2050 (bcm)	101
Figure 5.19.	Europe natural gas production outlook by project type, 2022-2050 (bcm)	102
Figure 5.20.	Europe natural gas production outlook by field location, 2022-2050 (%)	103
Figure 5.21.	Latin America natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	104
Figure 5.22.	Latin America natural gas production outlook by project type, 2022-2050 (bcm)	104
Figure 5.23.	Latin America natural gas production outlook by field location, 2022-2050 (%)	104
Figure 5.24.	Middle East natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	105
Figure 5.25.	Middle East natural gas production outlook by project type, 2022-2050 (bcm)	106
Figure 5.26.	Middle East natural gas production outlook by field location, 2022-2050 (%)	106
Figure 5.27.	North America natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)	107
Figure 5.28.	North America natural gas production outlook by project type (bcm) and unconventional share (% , RHS), 2022-2050	108
Figure 5.29.	North America natural gas production outlook by field location, 2022-2050 (%)	108
Figure 6.1.	Global natural gas trade by flow type (bcm) and share of LNG trade (RHS,%) outlook, 2022-2050	113
Figure 6.2.	LNG imports outlook by region, 2022-2050 (Mt LNG)	114
Figure 6.3.	LNG imports market share outlook by region, 2022 and 2050 (%)	115
Figure 6.4.	LNG exports outlook by region, 2022-2050 (Mt LNG)	115
Figure 6.5.	LNG exports market share outlook by region, 2022 and 2050 (%)	115
Figure 6.6.	LNG imports and exports in 2022 (Mt LNG)	116
Figure 6.7.	LNG imports and exports outlook in 2050 (Mt LNG)	116
Figure 6.8.	Natural gas balance (net imports) outlook by region, 2022-2050 (bcm)	116
Figure 6.9.	Global LNG liquefaction capacity outlook, 2022-2050 (Mtpa)	117
Figure 6.10.	Global LNG regasification capacity outlook, 2022-2050 (Mtpa)	117
Figure 6.11.	Africa natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)	118
Figure 6.12.	Africa LNG exports (+) by destination and imports (-) by origin outlook, 2022-2050 (Mt)	119
Figure 6.13.	Africa LNG liquefaction capacity outlook, 2022-2050 (Mtpa LNG)	119
Figure 6.14.	Asia Pacific natural gas demand and net imports outlook by flow type, 2022-2050 (bcm)	120
Figure 6.15.	Asia Pacific LNG imports (+) by origin and exports (-) by destination outlook, 2022-2050 (Mt)	121
Figure 6.16.	Asia Pacific LNG regasification capacity outlook, 2022-2050 (Mtpa)	121
Figure 6.17.	Asia Pacific LNG liquefaction capacity outlook, 2022-2050 (Mtpa)	122
Figure 6.18.	Eurasia natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)	124
Figure 6.19.	Eurasia LNG exports outlook by destination, 2022-2050 (Mt)	124
Figure 6.20.	Eurasia LNG liquefaction capacity outlook, 2022-2050 (Mtpa)	124
Figure 6.21.	Europe natural gas demand and net imports outlook by flow type, 2022-2050 (bcm)	125
Figure 6.22.	Europe LNG imports (+) by origin and exports (-) by destination outlook, 2022-2050 (Mt)	125
Figure 6.23.	Europe LNG regasification capacity outlook, 2022-2050 (Mtpa)	126
Figure 6.24.	Latin America natural gas demand and net exports outlook, 2022-2050 (bcm)	127
Figure 6.25.	Latin America LNG imports (-) by origin and exports (+) by destination outlook, 2022-2050 (Mt LNG)	127
Figure 6.26.	Latin America LNG regasification capacity outlook, 2022-2050 (Mtpa)	128
Figure 6.27.	Middle East natural gas demand and exports outlook by flow type, 2022-2050 (bcm)	129
Figure 6.28.	Middle East LNG exports (+) by destination and imports (-) outlook by origin, 2022-2050 (Mt)	129
Figure 6.29.	Middle East LNG liquefaction capacity outlook, 2022-2050 (Mtpa)	130
Figure 6.30.	North America natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)	131
Figure 6.31.	North America LNG exports (+) by destination and imports (-) outlook by origin, 2022-2050 (Mt)	131
Figure 6.32.	North America LNG liquefaction capacity outlook, 2022-2050 (Mtpa)	131
Figure 7.1.	Upstream investment (billion USD) and natural gas production (bcm, RHS), 2011-2022	136
Figure 7.2.	Upstream oil and natural gas investment (billion USD) and annual change (RHS, %), 2011-2022	137

Figure 7.3.	Natural gas upstream investment by type, 2014 and 2022 (%)	137
Figure 7.4.	Natural gas CAPEX by project type, 2030 and 2050 (USD/1,000 cf)	138
Figure 7.5.	Regional upstream natural gas investment incremental contribution (billion USD) and annual growth rate (RHS, %) in 2022	138
Figure 7.6.	Regional upstream gas investment share in 2021 and 2022	139
Figure 7.7.	Natural gas upstream investment in 2021 and 2022 (billion USD)	139
Figure 7.8.	Natural gas upstream investment in 2021 and 2022 (billion USD)	140
Figure 7.9.	Natural gas global cumulative upstream capital expenditure required by reservoir type, 2022-2050 (real billion USD, base year = 2022)	140
Figure 7.10.	Upstream natural gas expenditure required, 2022- 2050, (real billion USD, base year = 2022)	141
Figure 7.11.	Historical and future global outlook of midstream investment (real billion USD, base year = 2022)	144
Figure 7.12.	Global midstream CAPEX outlook by region, 2022-2050 (real billion USD, base year = 2022)	144
Figure 7.13.	Global LNG liquefaction CAPEX outlook by region, 2022-2050 (real billion USD, base year = 2022)	145
Figure 7.14.	Midstream natural gas investment outlook by region, 2022-2050 (real billion USD, base year = 2022)	146
Figure 8.1.	Global primary energy demand outlook in SES and RCS (Mtoe)	154
Figure 8.2.	Global primary energy demand outlook in SES and RCS (Mtoe)	156
Figure 8.3.	Natural gas demand outlook in SES and RCS by sector (bcm)	157
Figure 8.4.	Natural gas demand outlook in SES and RCS by region (bcm)	159
Figure 8.5.	Hydrogen generation outlook in SES and RCS (MtH ₂)	160
Figure 8.6.	Energy-related emission outlook in SES and RCS (GtCO ₂ e)	161
Figure 8.7.	CCUS savings projection in SES and RCS (MtCO ₂ e)	162

List of Boxes

Box 2.1	Taking stock of SDGs progress at the mid-point	27
Box 2.2	COP28 outcomes	28
Box 3.1	Hidden costs of renewable power generation	53
Box 4.1	Transitioning from traditional biomass to LPG, a by-product of natural gas	73
Box 4.2	LNG-to-power developments in Southeast Asia	78

Foreword

I am delighted to introduce the 8th edition of the GECF Global Gas Outlook (GGO), which was unveiled on the sidelines of the 7th Summit of Heads of State and Government, held on March 2nd in Algiers, the People's Democratic Republic of Algeria.

If I had to encapsulate the essence of the GGO in a single statement, it would be this: For socio-economic development, environmental protection, and to ensure that no one is left behind, the world requires consuming more natural gas, not less. Allow me to elaborate.

The year 2023 marked a significant turning point, serving as a stark reminder that energy transitions are precisely that—gradual changes, not instantaneous transformations. It is particularly ironic that, despite the COP26 call in Glasgow in 2021 to reduce coal consumption, the subsequent years saw coal use soar to record levels. COP28 Global Stocktake outcome recognises that energy transitions need to be pursued in a just, orderly, equitable and nationally-determined manner, taking into account the different national circumstances, capabilities, pathways, and approaches.

The year 2023 marked also the midpoint of the United Nations 2030 Agenda for Sustainable Development. The publication of the United Nations Sustainable Development Goals (SDGs) Report shed a revealing light on the world collective progress—or lack thereof—towards the 2030 targets. Alarming, it was found that progress on more than half of the 140 targets set in 2015 is “weak and insufficient”. Even more concerning is that one third of these targets are significantly off track, with critical areas such as poverty alleviation, hunger eradication, and ensuring access to modern energy lagging far behind.

The insights gained in recent years have solidified our methodology for evaluating energy systems, advocating a perspective grounded in sustainable development. This approach emphasises the interconnection and mutual reinforcement of three fundamental pillars: economic development, social progress, and environmental protection. Additionally, our analysis incorporates the critical framework of the energy trilemma, which demands a concurrent focus on energy security, affordability, and sustainability. I would also add the dimension of acceptability: it recognises that public support is crucial. People are likely to oppose changes that significantly increase living costs or erode their quality of life, as epitomised by recent strikes in many European countries.

The first key takeaway from the GGO is the projected continuous rise in global energy consumption over the coming decades, underpinned by population growth and economic expansion, despite improvements in energy efficiency.

The second key message is that the world will need more natural gas in the next three decades, not less. The findings of the GGO clearly show that natural gas demand will continue to increase until 2050, reaching a level 34% above that of 2022 and constituting 26% of the global energy mix. This increase occurs alongside the remarkable expansion of renewable energy sources, particularly in the power sector, as electrification accelerates.

As the cleanest burning hydrocarbon, natural gas, notably LPG, offers a sustainable switch from traditional biomass, thus ensuring universal access to clean cooking, mitigating indoor pollution, reducing premature deaths, and curbing

deforestation. Moreover, the shift from coal to natural gas usage enhances air quality and reduces greenhouse gas and pollutant emissions. As a flexible energy source, natural gas supports renewable power systems and compensates for hydropower shortage in droughts. Crucially, it underpins fertiliser production, essential for feeding the world's population of 8 billion people.

The third key message is that the majority of natural gas production by 2050 will originate from new projects, along with discovered and yet-to-be-discovered resources. By 2050, the cumulative investment required in upstream and midstream sectors to meet global natural gas demand is projected to exceed USD 9 trillion. Therefore, calls to halt investing in natural gas are misguided and detached from reality.

Another critical insight from the GGO indicates a significant surge in global natural gas trade, projected to account for just over one-third of the global natural gas demand by 2050. Concurrently, LNG trade is anticipated to more than double by 2050, surpassing long-distance pipeline trade in the next few years. This trend is poised to elevate the integration, flexibility, and efficiency of natural gas markets in the foreseeable future.

While natural gas is clean, it could be made even cleaner. The Sustainable Energy Scenario underscores that achieving simultaneously sustainable development and climate change objectives requires increased demand for natural gas and the accelerated expansion of cleaner energy sources and technologies. This includes wind and solar power, a rapid shift from coal to natural gas, the deployment at scale of carbon removal technologies such as carbon capture, utilisation, and storage, and the expansion of blue and green hydrogen production capacity. Over the longer term, direct air capture is another key technology that needs to be progressively developed and deployed. However, the low hanging fruit is certainly to improve energy efficiency in the natural gas industry, eliminate routine gas flaring, and drastically reduce methane emissions.

Natural gas, along with renewables and cleaner hydrocarbon technologies, provides a realistic pathway to limit global temperature increases to below 2 degrees Celsius, concurrently supporting poverty eradication and socio-economic development, which are the overriding priorities of developing country Parties under the UNFCCC.

I extend my heartfelt appreciation to the dedicated GECF team for their unwavering commitment to producing this insightful report. I also wish to express my thanks to the GECF Technical and Economic Council, experts from Member Countries and all others who contributed to the comprehensive review of this edition of the GECF Global Gas Outlook.

Eng. Mohamed Hamel
Secretary General

Executive Summary

1.7 billion additional inhabitants on the planet by 2050, the majority in Africa

The global population is projected to increase from 8.0 billion in 2022 to 9.7 billion in 2050, with Africa and the Asia Pacific region contributing to 90% of this increase. Urbanisation rate reaches 65%. While the share of ageing population increases globally, Africa holds the world's youngest and most rapidly expanding population, which reaches 2.5 billion people by 2050. The working-age population is anticipated to peak between 2023 and 2026, constituting 68% of the total population. Remarkably, Africa's working-age population is expected to surpass that of Europe by around 2040 and North America by 2050. Simultaneously, the number of households worldwide is set to surge by 34%, accompanied by a decrease in the average number of people per household from 3.5 to 3.2 by 2050.

Global real GDP is set to more than double, with non-OECD economy exceeding the OECD by the early 2040s

Over the upcoming three decades, the expected average annual economic growth rate is of 2.6%, meaning that the size of the global economy more than doubles. Together, non-OECD economies are poised to surpass the combined economic output of OECD countries by the early 2040s. The Gini index, a measure of global income inequality, is expected to exhibit a modest improvement, reaching 59% by 2050, compared to 62% in 2022. Tackling income disparities continues to pose a serious challenge. The ageing population introduces intricate policy dilemma, necessitating the management of high-level debt while ensuring adequate support for the elderly in the medium to long term. Asia Pacific and Africa are the fastest-growing regions, with annual growth rates averaging 3.5% and 3.4%, respectively.

Primary energy demand is expected to increase by 20% by 2050

The global primary energy demand is expected to increase from 14,960 Mtoe in 2022 to 17,925 Mtoe in 2050, corresponding to a 20% increase and an average annual growth rate of 0.6%. The Asia Pacific and Africa regions are projected to account for approximately half and quarter of this increase, respectively.

Despite a forecasted 2.5% annual improvement in energy efficiency from 2022 to 2050, there is no indication of decoupling between energy use and economic activity globally. The Asia Pacific region is expected to outpace the global average, achieving a substantial 3.3% enhancement in energy efficiency by 2050.

Global energy-related emissions are anticipated to peak in 2025, subsequently undergoing an 18% reduction, reaching 32.1 GtCO₂e by 2050, down from the current 39.3 GtCO₂e. This reduction is particularly notable in the power generation sector and across the Asia Pacific region, emphasising the impact of heightened policy support for decarbonisation initiatives, especially through coal to gas switching.

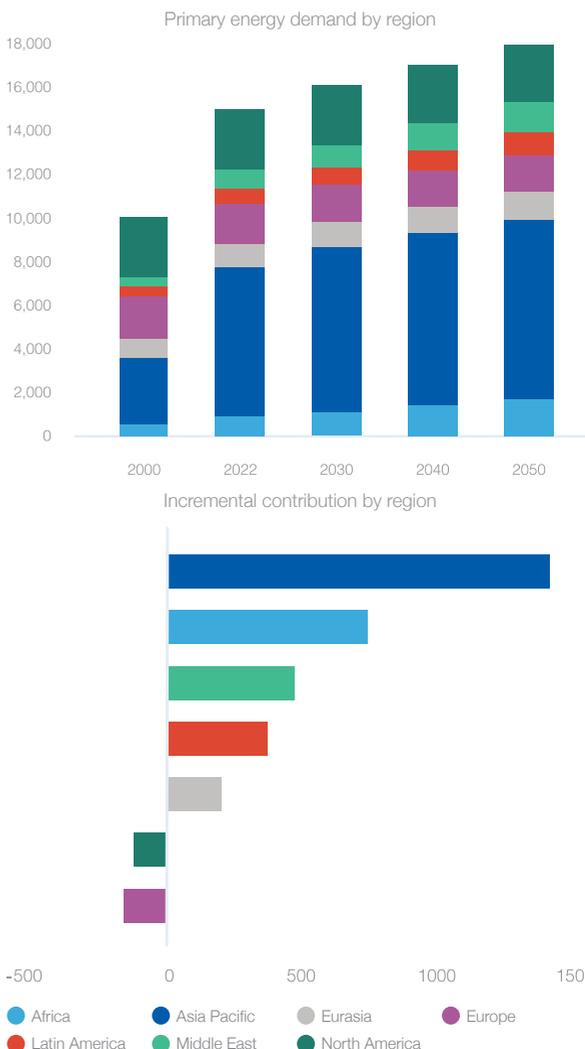
Fossil fuels share in the global energy mix is expected to decrease from 80% in 2022 to 63% in 2050. Throughout

ongoing energy transitions, renewables are anticipated to experience the highest growth rate, with their share projected to rapidly increase from 3% in 2022 to 17% in 2050.

Natural gas is poised for an average annual growth rate of 1% over the forecast period, ultimately surpassing coal as the second-largest energy source by the latter half of the 2020s. Due to the rapid expansion of electrification, a combination of natural gas and renewables is expected to account for around 68% of the total electricity supply by 2050. Carbon capture, utilisation, and storage (CCUS) is expected to gain momentum, significantly contributing to lowering electricity generation greenhouse emissions.

The demand for hydrogen triples from around 100 Mth₂ in 2022 to almost 300 Mth₂ by 2050. The Asia Pacific and Europe are poised to emerge as the leading demand centres, representing just above 70% of the expanded market. Hydrogen generated from natural gas is projected to contribute 43% of total hydrogen generation by 2050, with over 85% of hydrogen generation sourced from natural gas and renewables over the forecast period.

Primary energy demand outlook, 2000-2050 (Mtoe)



Source: GECF Secretariat based on data from GGM 2023

Global natural gas demand is projected to rise from 4,015 bcm in 2022 to 5,360 bcm in 2050, or 34%, with no peaking

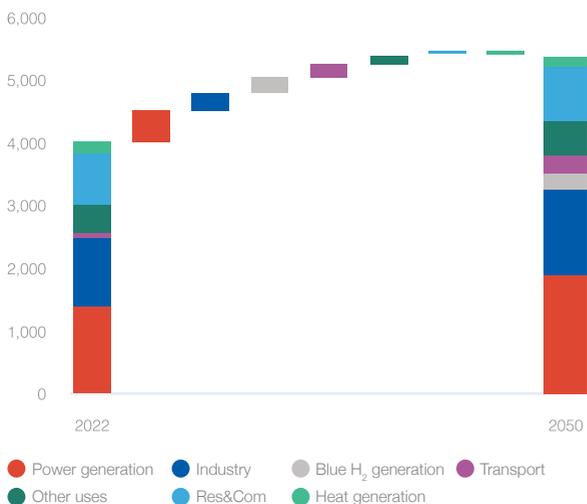
The increase in population and economic output, and policies aimed at air quality enhancement, GHG emission reduction, stability of renewable power systems, universal access to clean cooking, and the switch from coal and oil to gas are pivotal factors influencing the forecast. Natural gas, coupled with CCUS, is poised to underpin long-term demand, while the utilisation of blue hydrogen offers an additional pathway for decarbonising hard-to-abate sectors.

Natural gas demand expansion is primarily in the power generation sector, contributing 500 bcm to, and constituting 37% of the total growth. This growth is attributed to the accelerated electrification and to policies aimed at phasing down coal-fired power generation capacity. As the share of renewables expands, natural gas-fired power generation is projected to play an increasingly vital role, offering essential flexibility and backup support to solar and wind power, and to hydropower during periods of drought.

The industrial sector contributes an additional 275 bcm to natural gas demand increase, or 20% between 2022 and 2050. Natural gas retains its prominence as a primary fuel for medium and high-temperature industrial processes. Furthermore, its use in the industry is on the rise as a feedstock, driven by the growing demand for petrochemicals and fertilisers, with the latter contributing to agricultural sector productivity and food security.

The rise of blue hydrogen generation is positioned as a substantial pathway for enhanced utilisation of natural gas. The growth potential is conditioned by the development of an international hydrogen market. Additionally, the transport sector emerges as a pivotal demand center, spurred by stringent environmental regulations and supportive policies. The use of natural gas in road and marine transport is projected to surge by approximately 220 bcm over the forecast period, primarily propelled by the adoption of LNG as bunker fuel and its application in heavy goods vehicles.

Natural gas demand outlook by sector, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

From a regional standpoint, the majority of future natural gas demand growth is anticipated to emanate from the rapidly growing Asia Pacific markets and gas-rich Middle Eastern and African countries. Asia Pacific alone is forecasted to add almost 700 bcm, constituting 52% of the global net demand growth during the outlook period, with China, India, and Southeast Asian countries leading the way.

Meeting demand requires investments in exploration and development, as only 20% of the production in 2050 comes from legacy fields

Total global natural gas production is forecasted to grow by 33% from 2022, adding 1.3 tcm to reach 5.3 tcm by 2050. The Middle East adds 465 bcm, while Africa is expected to see the fastest average annual growth at 2.8%.

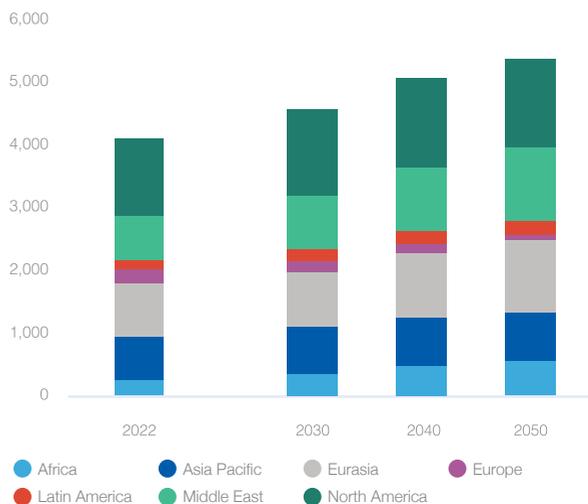
Natural gas production is set for major regional shifts, with Africa, Eurasia, and the Middle East expected to gain market share accounting for 10, 22, and 22% of global natural gas production by 2050, respectively. Consequently, North America's contribution is set to decline to 26%.

Offshore natural gas production grows at a faster growth rate than onshore gas production. It is projected to grow at an average annual rate of 1.6% over the outlook period, reaching 1.8 tcm in 2050. Conversely, onshore natural gas production is anticipated to experience a more modest average growth rate of just 0.8% annually.

Unconventional gas production is forecasted to sustain its upward trend, potentially reaching 1.4 tcm, or 27% of global gas production. However, despite this significant rise, its overall share of global natural gas production is expected to decrease by 1.3 p.p. Meanwhile, production from conventional resources is anticipated to grow faster than unconventional production reaching 3.9 tcm in 2050.

New conventional and unconventional gas developments make up 55% of global gas production by 2050, compensating for declines in existing fields. Together with yet-to-find (YTF) resources, these sources should provide 80% of global natural gas production by mid-century.

Natural gas production outlook by region, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

Realising projected large supply increases requires massive capital investment. New developments globally, especially in Africa, the Middle East, and Eurasia, are essential to meet rising natural gas demand.

LNG will dominate natural gas trade

LNG trade is on track to surpass long-distance pipeline trade by 2026, more than doubling by 2050 to reach 805 Mt (1,110 bcm), constituting 64% of traded gas.

The Asia-Pacific region remains the leading long-term LNG import market. China is expected to be the largest growth market in the current decade, and India to assume that role after 2030. South and Southeast Asia are poised for the highest incremental LNG import growth, albeit from a lower starting point.

The LNG share of EU gas imports rises from 24% in 2022 to 46% by 2030. The EU is set to expand and add regasification capacity, particularly utilising floating storage and regasification units (FSRUs).

Global liquefaction capacity exceeds 1,000 Mtpa by 2050, compared to 476 Mtpa in 2022, maintaining a utilisation rate of around 80% throughout the forecast horizon. Regasification capacity is expected to reach 1,800 Mtpa by the end of the outlook period, with a utilisation rate just under 50%.

The Asia-Pacific region is home to the most significant growth in LNG regasification capacity by 2050, more than doubling its 2022 level and adding 580 Mtpa. Russia continues to be a dominant force in Eurasian regional exports, with ongoing pipeline development projects, such as the Far Eastern project targeting 10 bcma, and the 50 bcma Power of Siberia 2, alongside Turkmenistan's Line D expansion with an additional 30 bcm, aiming to enhance natural gas transportation to Asian markets, particularly China.

The Middle East could potentially add over 130 Mtpa in liquefaction capacity by 2050, primarily driven by Qatari expansion projects. LNG continues dominating Latin America's natural gas trade, supporting renewables use and displacing oil. In Africa, LNG accounts for 70% of natural gas exports by 2050, with Mozambique emerging as the largest player from the

Net imports (+) and net exports (-) outlook by region, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

early 2030s. North America is poised for substantial growth in LNG exports, with the United States solidifying its position as the leading global LNG exporter from 2023 until 2050, reaching a liquefaction capacity of 240 Mtpa.

Cumulative global investment required in the period to 2050 is projected to amount to USD 8.9 trillion, with the upstream accounting for the larger share

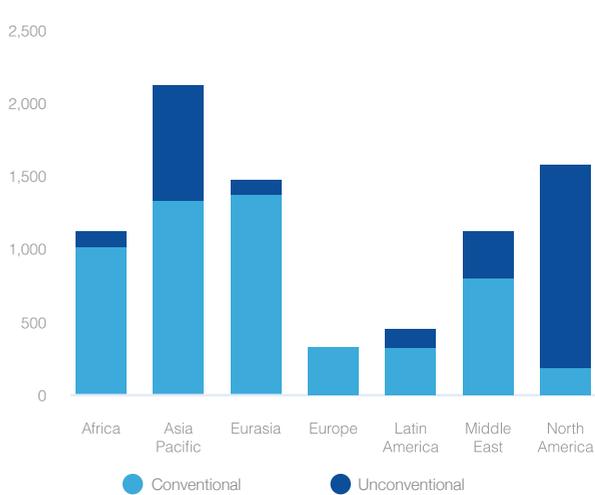
The recent energy crisis has spurred a global reconsideration of energy security, resulting in a significant 22% upswing in upstream oil and gas investment in 2022. This marks a pivotal shift after nearly a decade characterised by chronic underinvestment in the sector.

In response to the energy crisis, the oil and gas industry has undergone substantial structural changes. These include heightened price elasticity in both oil and gas demand and supply, an increased sense of risk aversion among investors, and a strategic shift towards resilience against low prices. The current global oil and gas supply landscape increasingly relies on short-cycle and brownfield production, exemplified by the ongoing prominence of the United States shale oil production. This trend, initiated before the COVID-19 pandemic, continues to shape the industry's response to evolving market conditions.

Upstream investment in conventional gas assets is anticipated to reach a substantial USD 5.3 trillion over the forecast period to 2050, while unconventional investments are projected to constitute USD 2.8 trillion. Natural gas production in Africa is estimated to reach 550 bcm by 2050, necessitating an upstream investment of USD 1.1 trillion to achieve this substantial production growth within the region. China is positioned to lead upstream investment requirements in the Asia Pacific region, accounting for a substantial USD 650 billion. In Eurasia, a formidable investment of USD 1.5 trillion in the gas upstream sector is envisioned to achieve a production forecast of 1,150 bcm by 2050, with a predominant focus on substantial investments in Russia.

Out of a significant USD 740 billion opportunity for natural gas midstream investments projected until 2050, LNG developers are expected to allocate approximately USD 438 billion towards liquefaction projects. Infrastructure entities are projected to

Upstream natural gas CAPEX required, 2022-2050 (USD billion)



Source: GECF Secretariat based on data from GGM 2023

invest around USD 230 billion in regasification. The Asia Pacific region is poised to lead in spending on natural gas infrastructure from 2022 to 2050, with an expected investment of nearly USD 203 billion, constituting 28% of the overall global midstream investment.

Energy future remains remarkably uncertain

The Sustainable Energy Scenario (SES) is a realistic energy pathway that assumes all countries exceeds the medium-income level by 2050 while ensuring a substantial reduction of greenhouse gas emissions of the energy sector.

The global primary energy demand in the SES increases by 23% between 2022 and 2050, ultimately reaching 18,478 Mtoe, surpassing the Reference Case Scenario (RCS) estimates by 555 Mtoe by 2050.

In the SES framework, natural gas assumes a crucial role, surpassing both oil and coal, constituting 29% of the global energy mix by 2050. Its demand is poised for robust expansion, surging to more than 6,200 bcm by 2050, a remarkable 55% increase over the forecast period.

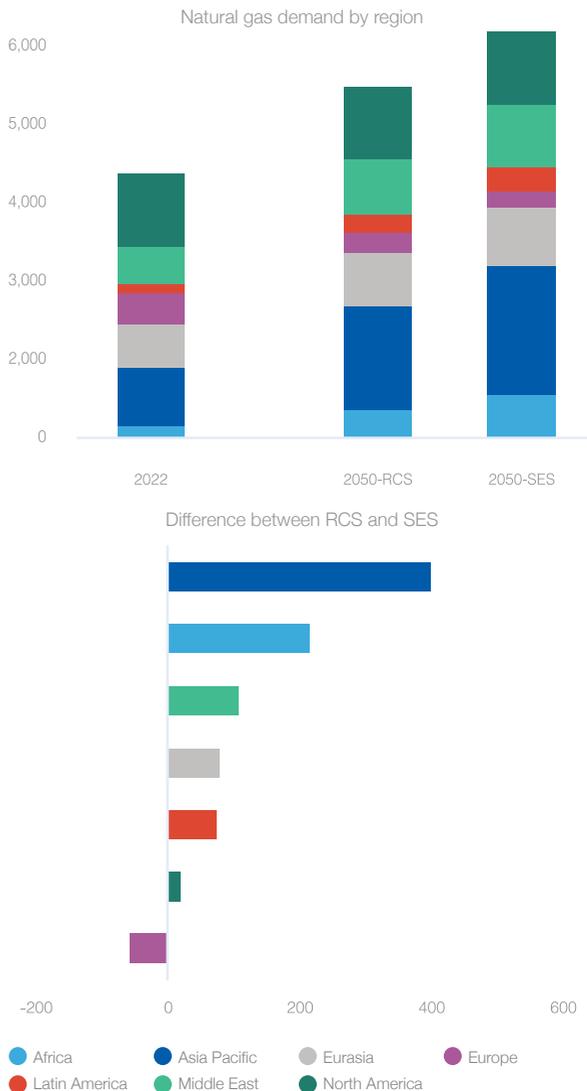
Natural gas significantly reshapes the global power generation mix in the SES, contributing approximately 26% by 2050. This transformation is underpinned by substantial demand growth, with estimates indicating an increase of 921 bcm, reaching 2,303 bcm by 2050—a substantial variation compared to the RCS forecasts.

The Asia Pacific region emerges as a primary driver of natural gas demand growth in the SES, propelled by a significant shift from coal to natural gas in the power generation sector, surpassing RCS estimates by a substantial 405 bcm. Blue hydrogen, derived from natural gas, increases from a negligible presence in 2022 to a substantial 147.5 Mth₂ by 2050, exceeding the RCS projections by approximately 90 Mth₂ and contributing nearly 40% to global hydrogen generation.

Despite the anticipated expansion of the energy system and significant strides towards sustainable development goals, especially in ensuring universal access to affordable, reliable, and sustainable modern energy, the SES forecasts energy-related emissions to decline to 22.6 GtCO₂e by 2050. This figure significantly undercuts the RCS scenario, denoting a 42% reduction from 2022 levels, while the RCS anticipates a more modest 18% decline in emissions.

The accelerated upscaling of CCUS emerges as the primary driver for emissions abatement within the SES. These technologies, designed to mitigate emissions arising from energy combustion, are set to make substantial contributions, with emissions savings projected to escalate from 12 MtCO₂e in 2022 to 7.5 GtCO₂e by 2050 in the SES—a significant contrast to the 1.7 GtCO₂e projected by the RCS.

Natural gas demand in SES and RCS (bcm)



Source: GECF Secretariat based on data from the GECF GGM



1

Global Economic and Price Assumptions



Highlights

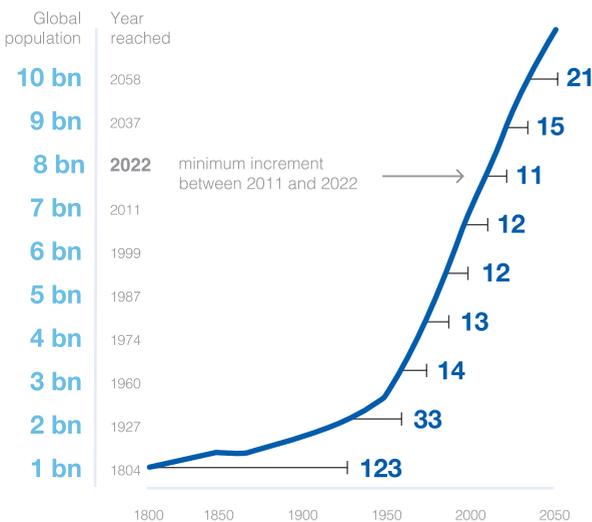
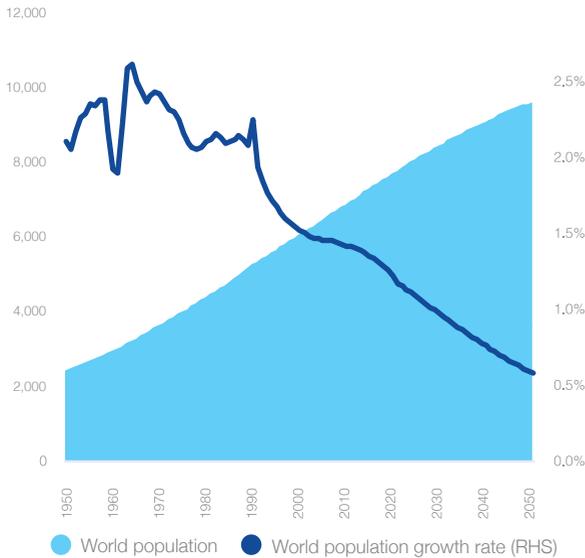
- ▶ The global population is expected to grow rapidly, reaching 9.7 billion by 2050, with Africa and the Asia Pacific region accounting for 90% of the increase.
- ▶ The global working-age population is projected to peak between 2023 and 2026, making up 68% of the total population. Africa's working-age population is on track to surpass that of Europe by 2039 and North America by 2050.
- ▶ Ageing population presents complex policy dilemma, such as managing high-level debt while providing adequate support for the elderly in the medium to long term.
- ▶ The number of households globally is set to increase by 34%, while the average number of people per household is expected to decrease from 3.5 to 3.2 by 2050. This shift will impact residential and commercial energy consumption.
- ▶ Estimated average global annual economic growth rate is 2.6% over almost the next three decades. Together, non-OECD economies are expected to surpass the combined economic output of OECD countries by the early 2040s.
- ▶ The Gini index, measuring global income inequality, is expected to show a slight improvement, reaching 59% by 2050, compared to 62% in 2022. Addressing income disparities remains a complex challenge.
- ▶ Asia Pacific and Africa are projected to be the fastest-growing regions, with annual GDP growth rates averaging 3.5% and 3.4%, respectively over the long term.
- ▶ Due to factors such as reliance on green fields, inflation in key materials, rising capital costs, and shifting investor risk preferences, it is assumed that the Brent crude oil price in real terms will hover around USD 70 per barrel in the long term.
- ▶ Average long term price for natural gas in Europe is assumed to stabilise at USD 9 per mmbtu, while in Asia the long term price is anticipated to settle at approximately USD 10 per mmbtu.
- ▶ Carbon markets are expected to remain fragmented, with a significant gap between carbon prices and the social costs of carbon needed to make a substantial impact on climate change mitigation.

1.1 Population and demographics

Population dynamics and demographic trends play a crucial role in driving and influencing progress in inclusive sustainable development and global economic growth, as well as in shaping future patterns and trajectories of global energy demand. Figure 1.1 highlights the trends in global population growth.

Figure 1.1.

Global population growth outlook, 1950-2050 (million people)



Source: 2022 Revisions of United Nations World Population Prospects, OECD
 Note: bn: billion people

The UN projections suggest that the world’s population is set to continue to grow but at a slower pace, with estimates indicating that the global population could stabilise or even begin to decline by the end of the 21st century.

The global population is anticipated to increase by 22%, from 8.0 billion in 2022 to 8.5 billion in 2030, 9.2 billion in 2040, and

9.7 billion in 2050. The medium variant of the UN projections serves as the basis for the current release of the Global Gas Outlook (GGO). There is a projected increase of only 3% in the population of children younger than 15 years old from 2022 to 2050, attributed to falling birth rates. Meanwhile, the population aged 65 and older is expected to double - growing from 0.8 billion people in 2022 to 1.6 billion people by 2050. This is set to represent a significant demographic shift on a global scale.

Population growth is projected to slow in all regions over the forecast period, decelerating from 1.3% p.a. between 1991 and 2022 to 0.7% p.a. from 2022 to 2050. The largest population additions are forecasted to be in Africa, the Asia Pacific and the Middle East, while Latin America and North America are expected to experience marginal population growth. According to the UN projections, Eurasia’s population is expected to remain almost unchanged. The population reduction is anticipated only in Europe over the forecast horizon (Figure 1.2). Together, two regions – Africa and the Asia Pacific – are anticipated to account for the majority of incremental growth, representing around 90% of the total increase in population from 2022 to 2050.

Africa boasts the world’s youngest and most rapidly expanding population. It is on track to increase at an average annual rate of 2.1% between 2022 and 2050, which is around three times the global average of 0.7%. The region is set to reach 2.5 billion people by 2050. A key feature of Africa’s demographic structure is the substantial presence of its youth population over the forecast period, where approximately half of the continent’s total population is projected to be under the age of 24.

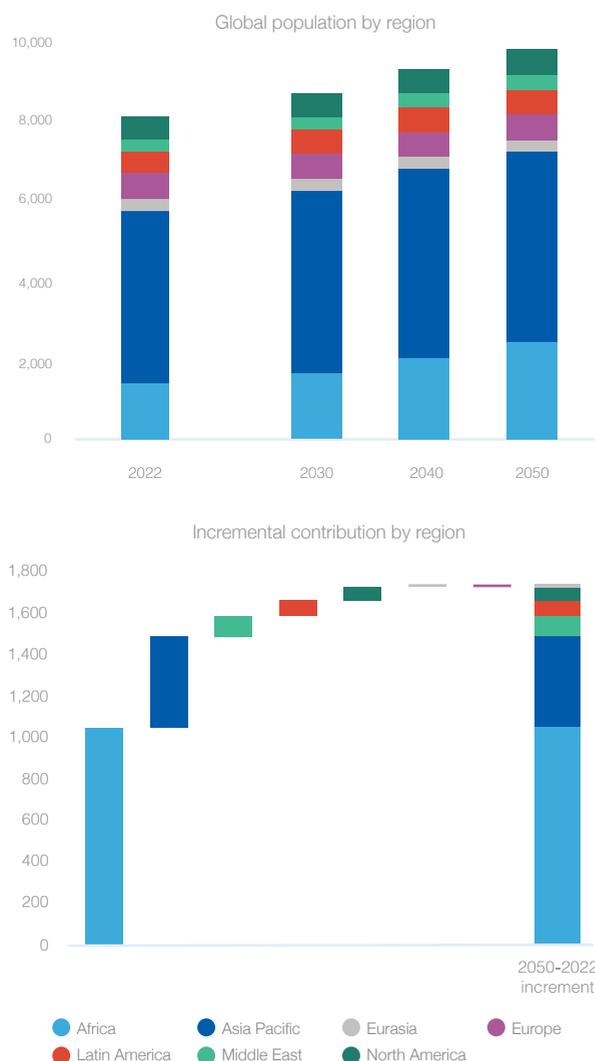
A remarkable 92% of Africa’s population growth is expected to occur in Sub-Saharan Africa between 2022 and 2050. The population of Nigeria – a GECF member country – which currently ranks sixth, is projected to reach 378 million by 2050. This would elevate it to the position of the world’s third-most-populous nation, surpassing the United States in terms of population in 2049.

The Asia Pacific currently hosts 54% of the global population, representing around 4.3 billion people. It is anticipated to be the home for almost half of the global population by 2050. It is forecast that the region’s population is anticipated to grow by 438 million people to reach 4,747 million people during the forecast period.

The Asia Pacific is very diverse in sub-region composition. According to the projections, South and Southeast Asia populations are expected to demonstrate a higher speed of growth compared to North East Asia, China, and the Pacific sub-regions, hence shifting the region’s structure in the long term. Meanwhile, the South Asian population is expected to grow by nearly a quarter, which is equivalent to an additional 425 million people. In contrast, the Chinese population is anticipated to decline by 8%, representing a reduction of 114 million people during the forecast horizon of 2022 to 2050. In 1990, China accounted for 40% of the Asia Pacific region’s population. However, by 2050, this proportion is projected to decrease to 29%. Conversely, during the same period, half of the region’s population is expected to reside in South Asia.

Simultaneously, all Asia Pacific sub-regions, spanning the entire spectrum of their variability, are anticipated to be characterised by similar shifting demographic patterns. These patterns are set to be marked by declining fertility and mortality rates, rapid urbanisation, and substantial migration flows within and beyond the region.

Figure 1.2. Global population outlook by region, 2022-2050 (million people)



Source: 2022 Revisions of United Nations World Population Prospects

The Asia Pacific region encompasses the world's most populous nations, including China and India, which together account for over one-third of the global population. China and India are heading in different demographic directions. In April 2023, India overtook China as the world's most populous country, reaching a population of 1,425 million people. India's population is expected to increase by 233 million by the year 2050. The population of 1.6 billion by 2050 in India is projected to be almost double the combined populations of the United States and the European Union (EU-27). This highlights the significant and distinctive demographic opportunity and challenge that India is set to harness and confront in the coming decades. In contrast, China's population recently reached its peak and experienced a decline in 2022. Projections suggest that China's population is set to decline by around 50 million people between 2022 and 2050.

The shares of the Middle East, North America, Latin America and Eurasia in the global population are expected to remain

relatively stable. From 2022 to 2050, the Middle East region is forecast to have the second fastest population growth rate in the world after Africa and its population is estimated to increase by 107 million people, rising from 279 million to 385 million. But similar to almost all other regions of the world, the Middle East is experiencing the same demographic transition to slower population growth. While urbanisation contributed to the reduction in fertility rates, the primary factor was women's empowerment. Over the past few decades, women in the Middle East have made significant strides in achieving greater educational equality and potentially increased workforce participation opportunities. The Middle East is transitioning from an era characterised by a population expansion to a new demographic phase where the significance of youth is diminishing, and the elderly population is becoming more prominent.

In the Latin American region, the population grew from 361 million in 1990 to 533 million in 2022 and is expected to grow by only 73 million people to reach 605 million by 2050. The global median age is anticipated to rise to 36 by 2050, a notable increase from the current age of 31. Surprisingly, the Latin American region, traditionally recognised for its youthful population, is projected to experience the most significant change, with its current median age of 31 expected to increase to 41. The demographic transition has brought about two significant outcomes for the region: population ageing and the conclusion of the demographic dividend. The region, as a whole, is undergoing a relatively swift process of ageing, and it is projected that, by 2046, individuals aged 65 and above will surpass those under the age of 15.

From 2022 to 2050, the North American population is set to expand from 500 million to 566 million, which represents a growth of 13% only. Mexico's population is projected to grow by 13%, while the United States is expected to grow by a similar 12% during the forecast period, primarily attributed to sustained high immigration rates. After 2030, it is anticipated that the population of the United States will grow slowly while ageing significantly and become increasingly racially and ethnically diverse. Consequently, net international migration is expected to overtake natural increase as the driver of population growth in the United States.

The long-term demographic trends in Eurasia are characterised by almost no incremental change in population growth between 2022 and 2050: an increase of only 7 million people to reach almost 300 million people. Russia's population is projected to decline from its current 145 million to 133 million in 2050, with a continued growing concentration of people in urban areas. Notably, there are distinct demographic trends between Eastern European CIS countries and Central Asia. In CIS countries such as Russia, Belarus, Ukraine, Moldova, Armenia, and Georgia, populations are both ageing and decreasing. Meanwhile, in Central Asia, including Kazakhstan, Kyrgyzstan, Uzbekistan, Tajikistan, and Turkmenistan, the total population is expected to increase from the current 77 to 104 million. During this period, Uzbekistan is predicted to remain the most populous country in Central Asia, with its population growing from 35 million at present to 46 million in 2050.

Between 2022 and 2050, Europe might be the sole global region where the population is set to decline – by 10 million people – reaching a total of 621 million. This decline is primarily due to decelerated population growth rates in Europe, leading to continued concerns about an ageing population. Europe is expected to have the highest median age in the world, at 47

years, by 2050, highlighting the demographic transformations taking place in the region. Over the projected period, Europe's contribution to the global population is anticipated to experience a slight decrease, marginally moving from 8 to 6%.

A demographic imbalance exists, with the non-OECD countries characterised by lower income levels compared to higher income in OECD countries, representing different stages of the demographic transition (Figure 1.3). Many developing countries are still in the early stage of the demographic transition, characterised by high birth rates and decreasing death rates. Conversely, developed countries have largely transitioned to the later stage, with lower birth and death rates, resulting in more stable population growth or even population reduction in some cases.

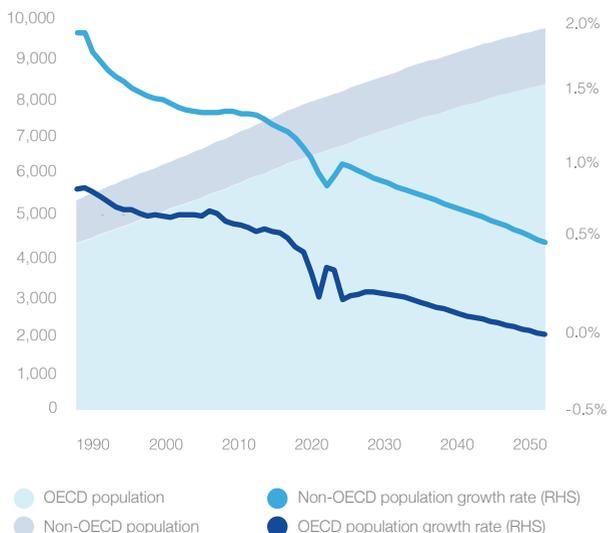
A significant portion of the world's population growth during the forecast period is expected to be concentrated in some of the globe's most economically disadvantaged countries. In less economically developed regions, particularly in Africa and developing Asia, there is a pronounced surge in population. This surge is expected to, in part, emanate from the 47 least developed countries, where the fertility rate averages 4.3 births per woman.

The population in these countries is projected to reach 1.9 billion people by 2050, marking a substantial increase from the current estimate of one billion. Conversely, Europe and North America, which represent the developed world, are expected to show sluggish population growth rates. Hence, by 2050, regions with well-established energy infrastructure are poised to witness minimal changes in population.

Collectively, the demographic landscape of the global population by 2050 is set to be shaped by four key factors: accelerated urbanisation rate, ageing populations, enhanced migration and transformation of the average household size.

Figure 1.3.

Population change outlook by region, 2022-2050 (million people)



Source: 2022 Revisions of United Nations World Population Prospects

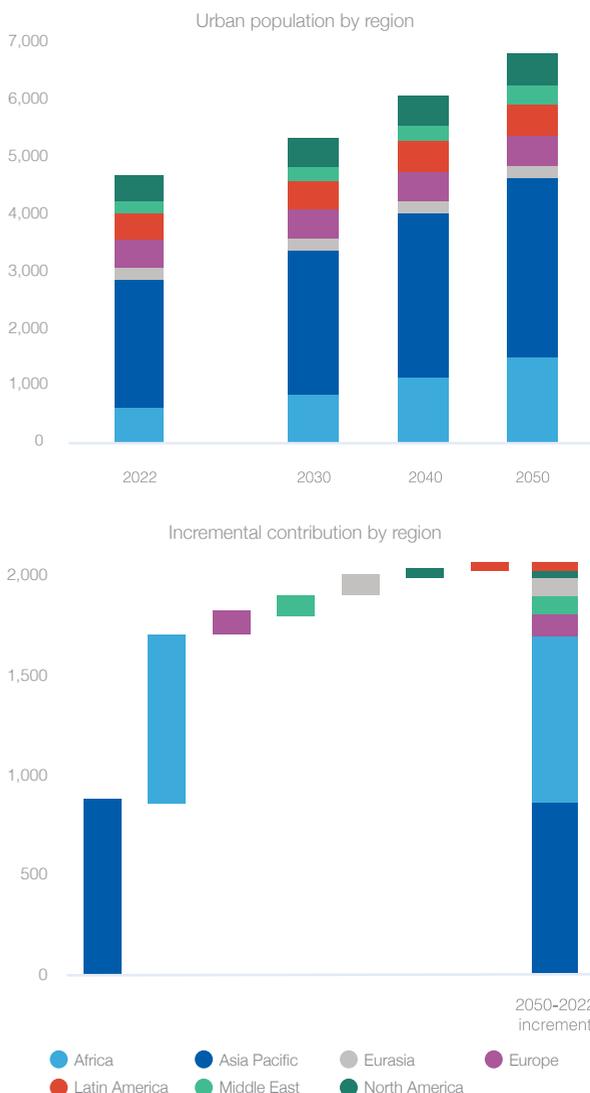
1.1.1 Accelerated urbanisation rate

The continuous process of urbanisation plays a key role in fostering global sustainable development and wealth generation. Urbanisation and income are closely intertwined, with wealthier countries typically exhibiting higher urbanisation rates and urban populations generally experiencing superior living standards in comparison to their rural counterparts. The world is currently experiencing rapid urbanisation, and this trend is expected to accommodate almost all of the additional population growth.

Globally, a larger percentage of the population resides in urban areas than in rural regions, with approximately 57% of the world's population, totalling 4.5 billion individuals, living in urban settings as of 2022. This represents a significant shift from 1950 when only 30% of the global population resided

Figure 1.4.

Urban population outlook, 2022-2050 (million people)



Source: The 2018 Revision of United Nations World Urbanization Prospects

in urban environments. Projections suggest that by 2050, over 65% of the world's population, representing 6.6 billion people might be residing in urban areas (Figure 1.4). On the contrary, the rural population peaked in 2020 at 3.4 billion people and is anticipated to drop to 3.1 billion by 2050. Several decades ago, the majority of the world's most extensive urban conglomerations were situated in the more advanced regions. However, in the present day, large cities are predominantly concentrated in the global South.

1.1.2 Ageing population

The social and economic consequences of an ageing population are becoming more evident: a reduction in the working-age population, rising healthcare expenses, challenging pension obligations, and shifting demand dynamics within the economy. These have far-reaching consequences on socioeconomic indices and energy consumption patterns.

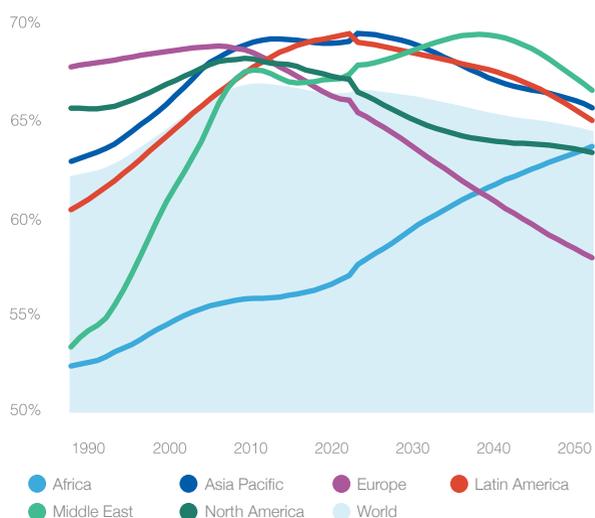
The population aged 65 and above is projected to more than double by 2050, with elderly people constituting 16% of the population, reaching 1.6 billion from 776 million in 2022. The ageing population is anticipated to be unevenly distributed across countries, with a partial balancing effect anticipated through implied migration in the longer term.

The working-age population typically refers to individuals aged 15 to 64, a range considered capable of participating in the labour force. The share of the global population that falls within the working age peaked at 65% in 2006 and is anticipated to begin declining from 2033, reaching 63% by 2050. The working-age population in the Asia Pacific has grown by 60%, from around 1.8 billion people in 1990 to 2.9 billion in 2022, representing 67% of the total population in the region. The working-age population is projected to peak between 2023 and 2026, representing 68% of the total population, after which it is anticipated to decline, as shown in Figure 1.5.

The population growth and age distribution trends in Africa have prompted projections indicating that Africa's working-age population could surpass that of Europe by 2039 and North America by 2050. The Middle East region has undergone

Figure 1.5.

Working-age population share trends, 1990-2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

a substantial demographic change in recent decades, encompassing shifts in population growth, fertility rates, and the age distribution of its residents. Projections indeed suggest that the working-age population in the Middle East is expected to peak around the period of 2035 to 2039, constituting 68% of the total population and ranking as the highest among all other regions of the world.

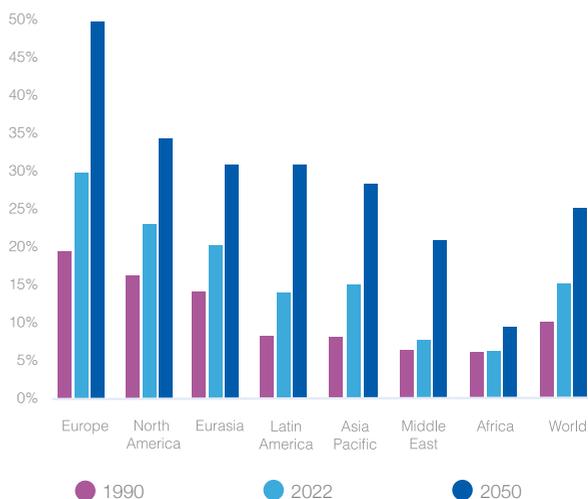
An accelerated ageing population leads to a decline in the number of individuals in the workforce, resulting in a shortage of skilled labour. The reduction in labour available for the economy is expected to result in a slowdown of GDP growth. As the working-age population diminishes, there will be increased financial contributions from this group to sustain elderly care, placing a greater strain on public budgets as a result of increased healthcare and retirement program expenses for the older population.

Across every region worldwide, the old-age dependency ratio has exhibited a consistent upward trend since 1990, albeit with varying rates of increase. As of 2022, there were 15 individuals aged 65 or older for every 100 individuals aged 15 to 64 globally. By 2050, this ratio is projected to increase to 25 per 100. In fact, the old-age dependency ratio is expected to rise in all regions between 2022 and 2050 (Figure 1.6).

Over the next nearly three decades, estimates indicate a substantial increase in old-age dependency ratios across multiple regions globally, including Europe, North America, Eurasia, Latin America, the Asia Pacific, and the Middle East. By 2050, Europe is expected to reach the highest ratio at 50%, signifying two working-age adults for each elderly person is expected. In North America, this ratio is projected to reach 34%. Eurasia, Latin America, and the Asia Pacific are anticipated to experience ratios within the range of 28-31%, with Latin America, and the Asia Pacific expected to exhibit the most considerable incremental growth from their initial percentages of only 14 and 15% in 2022, respectively. Notably, Africa is foreseen as the sole region to undergo minor changes in the old-age dependency ratio, increasing marginally from its current 6% to only 9% by the year 2050.

Figure 1.6.

Old-age dependency ratio outlook, 2022-2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

1.1.3 Enhanced migration

Migration is expected to continue gaining greater significance as a factor in the population growth of developing economies in the next few decades, favoured by the forecasted decreased fertility rates and increased life expectancy. Since the 1990s, migration has been the dominant factor driving population growth in developed regions, and this trend is expected to intensify after 2040 due to the projected population decline in these areas.

Notably, the proportion of immigrants in the overall population of advanced economies has increased from 7 to 12% between 1990 and 2022. In contrast, the share of immigrants in emerging markets and developing economies has remained relatively stable, hovering at around 2% during 1990-2022. Also, the influence of emigration on population growth in developing regions might have a limited impact.

The scale of international migration has expanded, albeit at a slower pace, due to the impact of COVID-19. In 2020, the estimated number of international migrants reached approximately 281 million worldwide, and nearly two-thirds of these migrants were classified as labour migrants.

It is worth noting that this figure represents a relatively small proportion of the global population, accounting for only 3.6%, indicating that the vast majority of people worldwide (96.4%) were estimated to be living in the country of their birth. The involvement of armed conflicts and economic downturns significantly drives migration, presenting substantial challenges in foreseeing the intensification or resolution of these conflicts and economic crises in the future. Migration generally improves economic growth and productivity in host countries, with immigrants in advanced economies increasing output and productivity both in the short and medium term.

1.1.4 Transformation of the average household size

Household projections play a significant role in influencing energy demand, especially in the residential and commercial sectors. The number of households globally is expected to grow more rapidly – by 34% – compared to the 22% growth of the world’s population in 2022-2050.

The projections for the number of global households show an increase of almost 770 million units, from 2,260 million in 2022 to 3,030 million in 2050 (Figure 1.7).

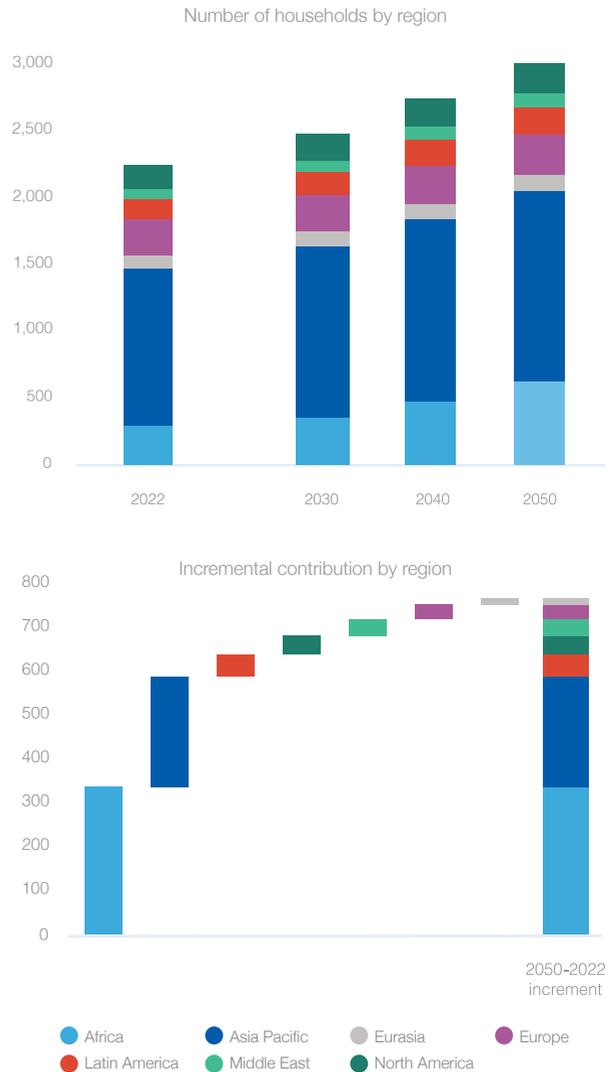
A substantial majority of new households built of almost 590 million, representing over three-quarters, is expected to take place in Africa and the Asia Pacific. Nearly 335 million new households are expected to emerge in Africa and 250 million in the Asia Pacific over the forecast period.

An intriguing demographic trend worth noting is that the number of people per household is projected to decrease from 3.5 to 3.2 globally by 2050. This reduction reflects a broader social trend of atomisation, where households become smaller on average, leading to a decrease in average family size.

These demographic changes have implications for housing space needs, energy-consuming amenities and energy consumption behaviours, including electricity and natural gas demand. Smaller households may adopt different heating, cooking, and energy usage patterns compared to larger, extended families, sharing building spaces and energy-consuming facilities.

Figure 1.7.

Number of households’ outlook, 2022-2050 (millions of households)



Source: GECF Secretariat based on data from the GECF GGM

The dynamics of household composition is undergoing significant changes worldwide. In 2022, couples with children represented more than 30% of all household types. However, global trends indicate that the average household size is expected to decrease.

Several factors are contributing to this shift, including the rapid expansion of households with one person, alongside the ageing of populations and a decrease in the average number of children per household, notably in regions such as the Asia Pacific, the Middle East and Africa.

Another contributing factor to the above trend is the growing interest among women in pursuing independent and self-sufficient lifestyles, often leading them to join the workforce. This results in a reduction in household size.

1.2 Economic growth outlook

At the heart of energy demand lies a critical catalyst: the dynamic interplay between economic growth and the value-added contributions emanating from various sectors within the economy. Within the structure of the GECF Global Gas Model (GGM), the trajectory of economic growth across diverse regions and sectors is exogenously determined. In this section, these foundational assumptions were reviewed, highlighting the rationale and substantiating arguments that underpin them.

1.2.1 Current developments and short-term outlook

The forecast for global economic growth indicates a stable pattern, with the growth rate expected to stay at 3.1% in 2024, mirroring the 2023 figure, and then experiencing a slight increase to 3.2% in 2025 based on annual averages. The advanced economies are expected to experience a modest slowdown, dropping from 1.6% in 2023 to 1.5% in 2024, and then rebounding to 1.8% in 2025. In contrast, emerging markets and developing economies are anticipated to maintain growth at 4.1% in 2024 and 4.2% in 2025, showcasing relative resilience amid evolving global economic conditions.

Despite the World Health Organization's announcement in May 2023 that it no longer considered COVID-19 a global health emergency, the global economy remains in a state of incomplete recovery. This prolonged recovery is attributed to a combination of structural and cyclical factors, culminating in a divergence in economic growth patterns across different regions of the world. Examining the structural factors contributing to this sustained economic fragility, consideration of the enduring repercussions of the pandemic itself is essential. Its far-reaching impact has ushered in an era of heightened geopolitical tensions and economic fragmentation. These lingering structural issues continue to cast a shadow on the global economic landscape.

Simultaneously, the cyclical drivers further complicate the path to full economic resurgence. Central banks, in response to mounting inflationary pressures, have embarked on the path of monetary policy tightening, a move that can induce economic headwinds. Additionally, governments grappling with elevated levels of debt have been compelled to adopt contractionary fiscal policies, further complicating the quest for a complete economic rebound.

In developed countries, the United States is anticipated to surpass its pre-pandemic economic trajectory, whereas the EU is still grappling with an incomplete recovery. This disparity can be attributed to the EU's heightened vulnerability to the consequences of the geopolitical tensions, which has resulted in adverse terms of trade shocks.

In China, the extensive output deficit, when compared to the pre-pandemic era, is mainly attributed to a combination of factors. The pandemic-induced slowdown in 2022, coupled with a crisis in the real estate sector, has significantly contributed to this decline.

This trend is even more pronounced in low-income countries, where economic recovery remains weak. These countries are grappling with the challenges of elevated global interest rates and the depreciation of their currencies, which further hinder their efforts to return to pre-pandemic levels of economic performance.

It is important to highlight that the current phase of recovery is predominantly powered by robust consumer spending, particularly in the United States, where tight labour markets have increased consumer confidence. Furthermore, economies that heavily rely on travel and tourism have also experienced a significant boost in consumer activity.

The global economic outlook, when compared to the previous year, exhibits a more balanced risk profile, with the likelihood of a severe economic downturn diminishing. Nevertheless, it is crucial to highlight that the overall risk landscape for global growth continues to lean towards the downside.

A potential catalyst for concern is the evolving crisis in China's property sector, which has the potential to deepen further and trigger global repercussions. Concurrently, there is an upswing in medium-term inflation expectations, prompting the need for higher interest rates as a means to address these emerging price pressures. Another notable source of risk arises from the increasing fragmentation of the global economy, which is disrupting global supply chains. This fragmentation limits the smooth flow of commodities across markets, consequently contributing to heightened price volatility and posing economic challenges.

Additionally, the rising levels of debt, particularly in low-income developing countries, represent a significant risk factor for the global economy. More than half of these countries either face or are at high risk of debt distress, which can have far-reaching economic implications for global financial stability.

1.2.2 Long-term economic growth prospects and major drivers

In 2022, the global economy reached a remarkable milestone, surging past the USD 100 trillion mark, signifying a doubling in size over a span of 25 years. This substantial expansion in economic activity has witnessed a noteworthy shift in the primary drivers of growth.

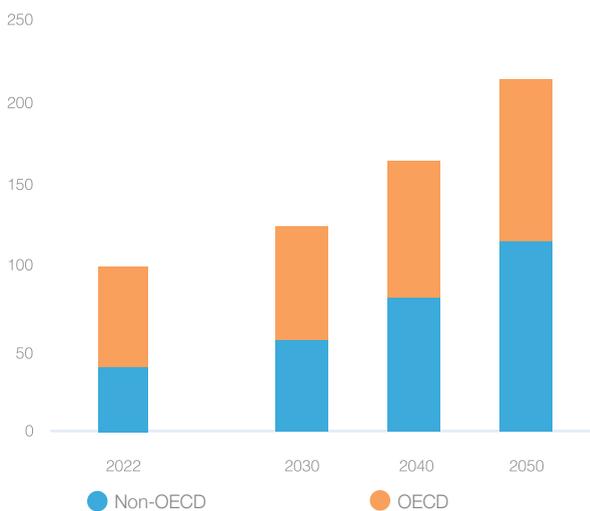
The centre of this transformation has transitioned from predominantly OECD economies to burgeoning non-OECD economies. This profound transformation is reflected in the annual real GDP growth rates of these two categories. OECD economies experienced a modest growth rate of 1.3%, whereas non-OECD economies exhibited an impressive annual growth rate of 3.4% in the last 25 years. As a result of these dynamic shifts, the contribution of non-OECD economies to the overall size of the global economy has surged from 25% to a substantial 40% over the past quarter-century. This remarkable transformation highlights the increasing economic prominence of emerging markets and developing countries, emphasising their pivotal role in shaping the world's economic landscape.

Projections for the long-term real GDP indicate a significant expansion in the global economy's size over the next almost three decades, poised to more than double, reaching an impressive USD 213 trillion. This corresponds to an estimated annual growth rate of 2.6% during this period.

In the long run, the pace of economic growth in non-OECD economies is anticipated to accelerate when compared to the preceding 25 years. Projections indicate a robust annual growth rate of 3.6% for these emerging economies. One of the standout features of this forecast is the eventual surpassing of OECD countries by non-OECD economies. As this transformation unfolds, it is expected that by the early 2040s,

Figure 1.8.

GDP outlook, 2022-2050 (real USD trillion, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

the combined economic output of non-OECD economies is set to overtake that of the OECD countries. As a result of this reconfiguration, the share of non-OECD countries in the global economic arena is poised to reach a substantial 54% (Figure 1.8). This highlights the growing influence of emerging markets on the international stage, reaffirming their role as pivotal drivers of global economic activity.

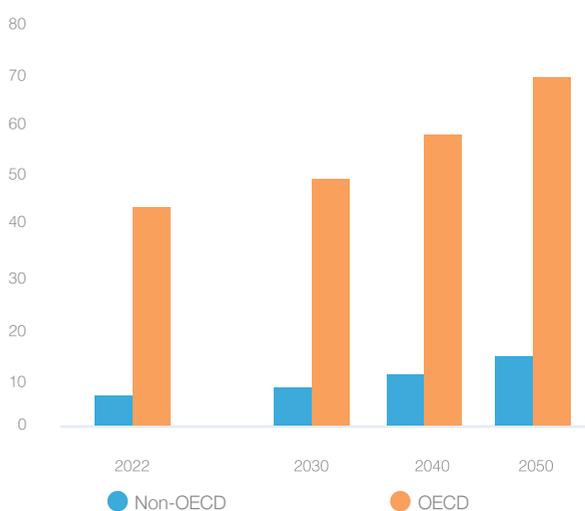
While there is an expectation that the size of non-OECD economies is set to eventually surpass that of OECD countries, a crucial factor to consider is the rapid population growth in non-OECD regions, as detailed in Section (1.1) of this chapter. This demographic difference is expected to result in a persisting gap in per capita GDP between the two regions throughout the forecast horizon until 2050. According to projections, the global per capita real GDP is set to experience a steady annual growth rate of 1.9% by 2050. Over the same period, non-OECD economies are anticipated to more than double their per capita real GDP. Nevertheless, it is important to emphasise that the projected per capita income is still only one-fifth of the anticipated per capita real GDP of OECD countries in 2050. The estimations reveal that in 2022, per capita real GDP in OECD countries is notably higher and nearly seven times greater than that of non-OECD countries (Figure 1.9). This data highlights that the accelerated economic growth in non-OECD regions over the next three decades is unlikely to coincide with significant reductions in global income inequality between countries.

According to our estimations, the Gini index, a measure of global income inequality between countries, stands at 62% in 2022. There is a modest projected improvement, with the index expected to decrease to 59% by 2050. This data underscores the complexity of addressing global income disparities, revealing that while there may be some progress, substantial inequality is likely to persist on a global scale between countries.

The Reference Case Scenario (RCS) considers a number of key influential factors that shape the contours of long-term economic growth:

Figure 1.9.

Per capita GDP outlook, 2022-2050 (real 1,000 USD, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

Rising global debt level. Global debt levels have indeed reached an alarming peak, and this challenge has been exacerbated by the extensive stimulus measures put in place during the COVID-19 pandemic, followed by the 2022 energy crisis. In a significant number of advanced economies, both private and public debt have surged to levels surpassing 400% of their respective GDP. This has raised substantial concerns over the sustainability of such indebtedness. Remarkably, even in the case of China, a powerhouse of economic growth, debt levels have surged past 300% of GDP. In 2022, the United States' total debt level reached 274% of the country's GDP. The implications of this debt burden are far-reaching. The increasing repayments are exerting immense pressure on economic growth. The resources that could otherwise be invested in productive activities, infrastructure, and innovation are diverted towards servicing debt. This can hinder the ability to foster sustainable economic development, as indicated by a recent UN report highlighting a significant implementation gap in UN SDGs and also to maintain a stable financial environment.

Ageing population and unfunded liabilities. The global debt problem is further complicated by the ageing demographics seen not only in advanced economies but also in some emerging markets such as China and South Korea. These ageing populations entail significant unfunded liabilities, especially in the form of pensions and healthcare obligations. With ageing populations becoming increasingly prevalent, the burden of servicing debt while ensuring adequate support for the elderly presents a complex policy dilemma. Governments worldwide are tasked with navigating this intricate challenge to prevent the exacerbation of the global debt crisis, requiring prudent and forward-thinking strategies in order to secure economic stability and the well-being of their citizens. While immigration can potentially improve the working-age population and alleviate the economic burden of caring for the elderly, it often sparks discontent and political resistance.

Higher long-term inflation and interest rate. Prolonged near-zero interest rates, implemented by central banks to stimulate economic growth, have inadvertently fuelled

speculative, exuberant investments and a significant build-up of private debt. The consequence of these accommodative monetary policies has been a twofold challenge. Firstly, it has inflated both credit and the prices of assets and goods, making it increasingly challenging to combat inflation through conventional measures such as interest rate hikes. The presence of substantial debt in the economy constrains the ability of central banks to take decisive actions to address rising prices. This challenge has given rise to a daunting economic scenario: stagflation. Stagflation represents a concerning combination of persistently high inflation and economic recession. This unusual convergence of issues defies the standard toolkit for economic policy, presenting central banks and governments with complex challenges in balancing the need to curb inflation while implementing policies that support the imperative of fostering economic growth and stability.

Artificial intelligence effects. The rise of digitalisation, artificial intelligence (AI), and robotics have the potential to significantly impact productivity growth. The widespread adoption of these general-purpose technologies across various industries holds the promise of significantly enhancing total factor productivity and operational efficiency. However, this landscape also presents a critical concern: the apprehension that contemporary doubts about AI's effect on employment may indeed be substantiated. The emergence of AI introduces a unique challenge, where the creation of new job opportunities may not sufficiently offset the displacement of traditional roles. The ramifications of this AI-driven transformation are profound, with one of the most pressing concerns being the widening of wealth inequalities. Proposed solutions, such as Universal Basic Income (UBI) and the taxation of AI-driven automation, though well-intentioned, may also trigger divisive political debates, underscoring the complexity of the issue.

Energy transition costs. The energy transitions present a substantial cost-push shock for both developed and developing countries, with implications for their economic landscapes. Transitioning to cleaner and more sustainable energy sources necessitates substantial upfront investments. Such investments can strain public financing in both developed and developing countries, diverting funds from other vital sectors and potentially leading to fiscal deficits. Furthermore, the transitions often result in increased production costs, especially during the initial phases when new technologies and infrastructure are being integrated. Rising energy prices can contribute to inflationary pressures, therefore eroding consumer purchasing power and disrupting economic stability, affecting the overall economic condition. The impact of energy transitions on labour markets is also a shared concern. Job displacement in traditional fossil fuel industries can lead to unemployment, adding to socioeconomic challenges and potential unrest.

Climate change impacts. Adding another layer of complexity is the pressing issue of climate change. Its ramifications could lead to the deterioration of social and economic conditions, especially in regions such as Africa and South America, where the adverse effects on agriculture are set to be deeply felt. The aftermath of climate change could trigger unprecedented migration patterns as individuals and communities seek refuge in cooler, agriculturally abundant regions or countries. This mass migration has the potential to reshape geopolitical dynamics and intensify global challenges related to displacement, resource allocation, and humanitarian crises.

The current global events unfolding are defined by their intricacy and the interconnected nature of the challenges they pose for

accurate prediction. One could argue that the world is in the midst of an unparalleled phase characterised by geopolitical dynamics and a transition towards a multipolar global landscape, where varying sets of values and belief systems coexist. Nevertheless, the precise outcomes and the full extent of this transition's implications remain highly uncertain and difficult to foresee.

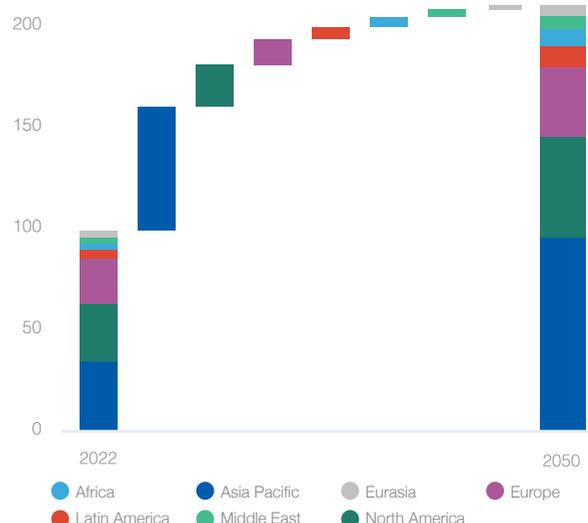
1.2.3 Long-term economic growth outlook by region

In 2022, the global economic landscape is characterised by the Asia Pacific region's dominant position, holding nearly 35% of the world's economy. Following closely behind are North America and Europe, contributing 29 and 22%, respectively, of the global GDP. In stark contrast, Africa and Eurasia represent the smallest contributors, accounting for a mere 2.9% each, ranking as the two regions with the smallest share in terms of global economic activity. Latin America and the Middle East account for 4.8 and 3.4% of the global economy in 2022.

Looking ahead to 2050, the projected changes in GDP distribution follow a similar pattern. Asia Pacific, Europe, and North America continue to maintain their top positions, while Eurasia, the Middle East, Africa, and Latin America are expected to experience the lowest incremental GDP changes by 2050 (Figure 1.10).

Asia Pacific, Africa, and Latin America are set to witness a significant expansion in their contributions, growing by 10.5, 0.7, and 0.4 p.p., respectively, reaching 45, 3.6, and 5.2% of the projected USD 213 trillion global economy in 2050. Notably, Europe, North America, Eurasia, and the Middle East are expected to witness a decline in their share of the global economic activity over the forecasted period. Europe and North America are set to experience substantial declines of 5.8 and 5.3 p.p., respectively, ultimately comprising 16 and 24% of the global GDP in 2050. In contrast, Eurasia and the Middle East, initially the smallest contributors to the global economy in 2050,

Figure 1.10. Regional GDP incremental growth outlook, 2022-2050 (real trillion USD, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

are projected to witness a decrease of 0.3 and 0.1 p.p. in their share, reaching 2.5 and 3.3% of the global economy in 2050, respectively.

Analysis of the global regions' long-term economic growth prospects highlights key trends to emerge. Among these regions, Asia Pacific and Africa stand out as the fastest-growing regions, with projected annual growth rates of 3.5 and 3.4%, respectively. However, it is important to note that these growth rates signify a deceleration compared to the historical trends observed during the years 2000 to 2019.

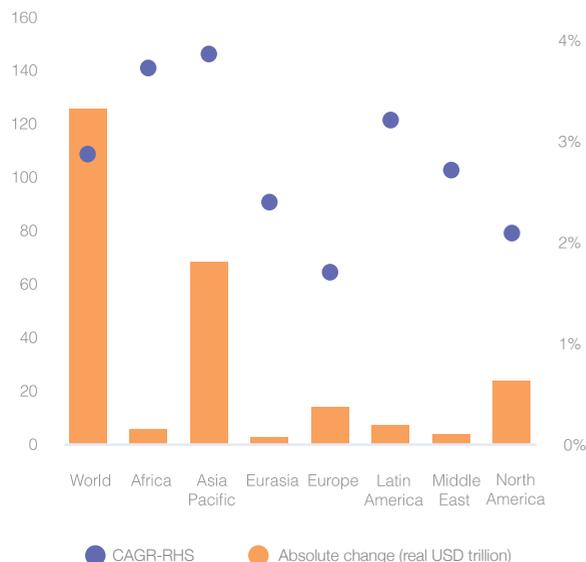
As illustrated in Figure 1.11, the region with the most conservative long-term annual growth rate forecast is Europe, which is expected to expand at a rate of 1.6% p.a. over the next nearly three decades. This forecast reflects a significant contrast to the long-term growth experienced in prior decades. In North America, the long-term annual growth rate is also projected at 1.9 % p.a., a level consistent with the potential output growth observed during the 2000-2019 period.

Latin America, on the other hand, is expected to experience a noteworthy increase in potential economic growth, forecasted at 2.9% p.a. This represents a significant acceleration compared to previous trends. In contrast, the regions of Eurasia and the Middle East are anticipated to encounter a considerable deceleration in their long-term economic growth rates, with forecasts of 2.2 and 2.5%, respectively, indicating a substantial slowdown compared to the historical trends observed during the 2000-2019 period. These regional variations in growth trajectories highlight the dynamic and evolving nature of the global economic landscape.

While global economic growth rates exhibit variations across regions, the overall economic landscape points to North America and Europe maintaining their leading positions in terms of per capita GDP by 2050. As depicted in Figure 1.12, the incremental change in per capita GDP is most pronounced in North America and Europe, with projections indicating

Figure 1.11.

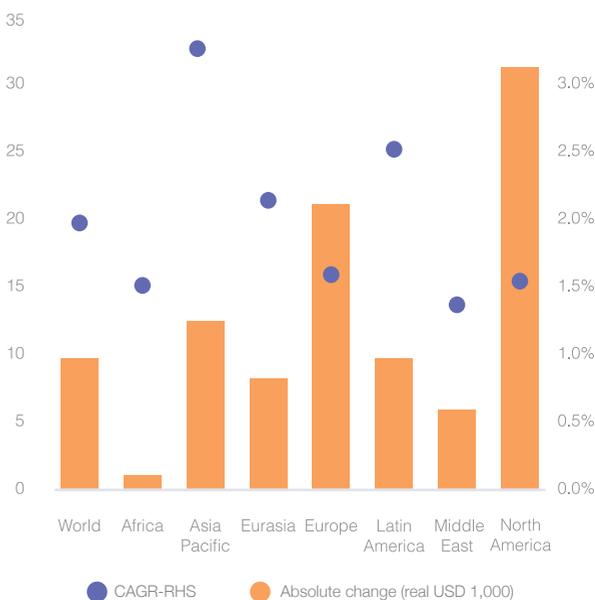
Long-term GDP growth outlook, 2022-2050 (real trillion USD, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

Figure 1.12.

Long-term per capita GDP growth outlook, 2022-2050 (real 1,000 USD, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

substantial growth, followed by the Asia Pacific region, where per capita GDP is anticipated to surge by nearly 150%. This underscores the robust economic expansion expected in these regions over the next 28 years.

Meanwhile, Africa is forecasted to experience an annual growth rate of 1.5% for GDP per capita, incrementally increasing by USD 1,080 over the forecast horizon. Despite this positive development, the continent is expected to retain its classification as a lower-middle-income region, according to the World Bank classification. It should be emphasised that some Sub-Saharan economies are expected to remain in the low-income countries classification by 2050. This highlights the enduring challenges Africa faces in its journey toward higher living standards, even as progress is evident. In Africa, there has been a rise in both real GDP per capita and labour productivity, nevertheless, sluggish growth overall has prompted a rethinking of economic and social policies to achieve the transformational objectives of the United Nations Sustainable Development Goals (SDGs), specifically Goal 8, which focuses on promoting sustained, inclusive, and sustainable economic growth. In the least-developed countries (LDCs), the SDG target strives for a minimum of 7% real GDP growth, a goal that our projections fall short of.

The next section of this chapter is dedicated to the economic growth prospects within each region, providing insights into their unique trajectories.

1.2.3.1 Africa

Africa, constituting approximately 3% of the global economy in 2022, is set for a second consecutive year of slowdown in 2023. Africa is expected to achieve a growth rate of 3.3% in 2023, following a 3.8% growth in the preceding year. The challenges facing African economies have been amplified by a confluence of factors, including last year's geopolitical tensions

in Eastern Europe and the subsequent global interest rate hikes. These developments have precipitated strong inflationary shocks, exchange rate depreciation, and increased debt levels, culminating in a widening divergence in economic growth across the region.

Although there is a glimmer of hope on the horizon, characterised by a reduction in inflationary pressures and macroeconomic rebalancing in 2023, formidable challenges continue to loom on the path forward. The repercussions of a slowdown in international demand, notably driven by anticipated China's slowdown, coupled with heightened debt vulnerabilities, substantial exchange rate pressures, and persistently high inflation, all pose significant threats to economic growth in the African region.

North Africa, representing just under 30% of the African economy in 2022, is poised to undergo significant economic transformation. The long-term projections indicate an annual economic growth rate of 3.3% by the year 2050, with the provision that medium-term growth in this region reaches 3.9% by 2030. This indicates that North Africa's economy is poised for robust growth in the medium term, setting the stage for a subsequent deceleration in the longer term.

Egypt, serving as the largest economy in the region, is expected to emerge as the fastest-growing economy in the long term. Projections indicate an annual long-term economic growth rate of 4%. Moreover, Egypt is projected to make substantial contributions to North Africa's GDP, reaching 60% by 2050.

Within Sub-Saharan Africa, the long-term annual economic growth rate is projected at 3.6% p.a., marking a notable comparison with the historical potential growth output of 4.3% during the period spanning from 2000 to 2019. Sub-Saharan Africa is set to exhibit a diverse range of economic growth rates, with certain countries demonstrating robust expansion while others grapple with unique challenges. In the long term, the region is forecasted to maintain its overall growth trajectory.

Two noteworthy standouts among the fastest-growing economies in the long term are Kenya and Mozambique, both anticipated to achieve impressive growth rates of 5.1% and 5%, respectively, by the year 2050. Meanwhile, the largest economies within the region, Nigeria and South Africa, collectively constituting 43% of Sub-Saharan Africa's economic landscape in 2022, are expected to undergo relatively modest growth over the forthcoming three decades.

It is crucial to emphasise that Sub-Saharan Africa holds a significant demographic advantage as the world's youngest and fastest-growing population. By 2050, the working-age population in this region is anticipated to surpass the working populations of China or India. These demographic strengths and the wealth of resources present a unique opportunity for the continent to substantially enhance its productivity and potentially reverse the pronounced economic deceleration that has been forecasted. Leveraging this potential could unlock new paths for growth and development, making the most of the youthful and dynamic population within Sub-Saharan Africa.

1.2.3.2 Asia Pacific

In 2022, the Asia Pacific region, holding two-thirds of global economic growth, exhibited a growth rate of 3.2%, representing a significant deceleration compared to the robust 6.4% economic growth it experienced in 2021. This noteworthy shift can largely be attributed to the rapid deceleration observed in

China, a key player in the Asia Pacific's economic landscape. Given that China accounts for more than half of the GDP of the Asia Pacific region, its economic performance significantly influences the entire region. In 2022, China recorded a growth rate of 2.9%, marking a notable slowdown compared to the 8.1% annual economic growth achieved in 2021.

The primary driver behind this trend has been the tightening of monetary policies and the concurrent global rise in interest rates, particularly in OECD countries, responding to the escalating concerns of inflation. Adding to this complex economic landscape is the deceleration in China's property sector, which looms as a significant force exerting downward pressure on demand across the entire region. Notably, any upswings in economic growth witnessed in the United States and Japan are unlikely to fully offset the adverse impact stemming from China's economic dynamics. This is primarily driven by the evolving global demand dynamics, marked by a shift from goods to services and a transition from reliance on foreign suppliers to a preference for domestic manufacturers. These shifting patterns in demand deliver a more muted impetus to the Asia and Pacific region in comparison to historical trends.

In the OECD Asia Pacific region, the projection for long-term economic growth stands at 1.5%, reflecting a consistent momentum of growth that surpasses historical potential output trends. However, an anticipated shift in the distribution of economic growth among countries within this region is on the horizon. According to projections, Australia is expected to take the lead in terms of growth, with an impressive annual rate of 2.5%. Conversely, Japan, a significant economic contributor representing over half of the region's GDP in 2022, is forecasted to experience a more modest annual long-term economic growth rate of 0.9%. Consequently, these dynamics are set to lead to a transition in the regional economic landscape, with Japan's contribution to the region's economic activity diminishing to 45%, while Australia's positive profile, marking a substantial seven p.p. increase in the OECD Asia Pacific's GDP share since 2022, elevating it to 28% of the region's collective GDP in 2050.

The non-OECD East Asia region, which currently accounts for a significant quarter of global GDP, is poised to undergo a notable deceleration in its economic growth over the coming three decades. According to the projections, the annual long-term growth rate for this region is forecasted to be 4.1% over the period leading up to 2050. This represents a substantial decline from the 7.6% long-term growth rate experienced during the period from 2000 to 2019.

China and India, two economic powerhouses within this region, collectively contribute to around 90% of its GDP and play pivotal roles in shaping its future. Despite a slight reduction in its growth pace, India is expected to maintain its status as the fastest-growing economy in non-OECD East Asia. India is projected to achieve an annual long-term economic growth rate of 5.4% by 2050. In sharp contrast, China's economic growth trajectory reflects a marked deceleration. The annual long-term growth rate for China is forecasted at 3.8%, significantly lower than the historical average growth rate recorded during the years 2000 to 2019, which stood at 7.6%.

South East Asia, constituting a substantial 10% of the GDP within the Asia Pacific region, is anticipated to maintain its growth momentum over the long term, albeit with a minor deceleration. The projections shed light on the region's economic trajectory, indicating an annual growth rate of

4.1% by 2050. Notably, Cambodia and Vietnam emerge as the standout performers in this region, with both economies expected to exhibit the fastest-growing economies. These projections suggest that these two countries are poised to achieve an impressive annual growth rate of 5.7 % in the long term.

Indonesia, as the largest economy in the Southeast Asia region, contributing to 37% of the regional GDP in 2022, is set for continued growth in the long term. The forecast anticipates a solid annual growth rate of 4.4% over the extended period. These dynamics highlight the region's resilience and potential for sustained economic expansion, with Cambodia and Vietnam emerging as key drivers of growth and Indonesia solidifying its role as an economic anchor within Southeast Asia.

1.2.3.3 Eurasia

Eurasia was the only region to witness an economic contraction in 2022, with its real GDP declining by an annual rate of 3.5%. This downturn caused the region's contribution to global real GDP to decrease from 3.1% in 2021 to 2.9% in 2022. However, there is optimism that Eurasia's economic growth is set to rebound in 2023, with an expected growth rate of 2.5%.

According to the latest edition of the Global Gas Outlook (GGO), the Russian economy, which constitutes just under three-quarters of Eurasia's GDP in 2022, experienced an annual decline in real GDP of 2.2%. This decline exceeded earlier expectations and underscored the country's economic resilience in the face of Eastern Europe's geopolitical tensions in the preceding year. Belarus and the Republic of Moldova, for instance, entered into economic contractions, while others experienced a notable slowdown.

In response to the escalating inflation, policymakers implemented a tightening of monetary policy measures, which temporarily intensified the economic deceleration in 2022. Nevertheless, the economic forecast indicates a resurgence in economic activity in 2023. It is worth noting that the only country in the region expected to continue experiencing an economic downturn in 2023 is Ukraine. The country is anticipated to undergo a further 3% annual decline in GDP following a significant contraction of approximately 45% in 2022.

In the long term, the average annual real GDP growth forecast for Eurasia is projected to reach 2.2% by 2050. This rate is lower than the global average annual growth rate, resulting in a reduced share of 0.4 p.p. in 2050 compared to the figures in 2022. Russia, being the largest economy in the region and expected to account for 64% of Eurasia's economic activity in 2050, is projected to experience an average annual economic growth of 1.7% over the forecast period.

1.2.3.4 Europe

In the aftermath of the COVID-19 pandemic and the energy crisis stemming from the geopolitical tensions in the region, Europe found itself facing an elevated risk of stagflation. The surge in inflation, primarily driven by soaring energy prices, eroded households' purchasing power and posed a significant challenge to economic growth.

In spite of these economic challenges, Europe responded by implementing supportive monetary and fiscal policies, along

with providing energy subsidies totalling EUR 390 billion in the year 2022 alone. As a result, while economic growth continued, it did so at a somewhat moderated pace throughout 2022, with estimates hovering around 1.9% annually.

Considering the future, the European economy is poised for recovery, with lower energy prices, and the easing of supply chain bottlenecks on the supply side expected to enhance cost structures and distribution efficiency. Simultaneously, improving household real income, on the demand side, is set to stimulate greater consumer spending, contributing to economic growth. The unwinding of tighter monetary policies is also a pivotal factor in shaping the demand side, potentially promoting increased lending and investment. The convergence of these factors from both the supply and demand sides is poised to play a vital role in bolstering Europe's economic resurgence.

In the long term, Europe's economic outlook points to a scenario characterised by prolonged sluggish growth and persistent inflation. Within OECD Europe, which constitutes nearly 97% of the continent's economic activity in 2022, a long-term average annual growth rate of 1.6% is projected until 2050. This rate closely mirrors the historical long-term GDP growth in the region. Notably, the significant economies of Europe, comprising Germany, France, the United Kingdom, and Italy, and contributing to over half of Europe's GDP, are expected to sustain a gradual growth trajectory over the next three decades. This broad alignment in lower economic growth rates among countries in this group is foreseen to cement the position of the Big Four countries as the largest economies on the continent by the year 2050.

In contrast to OECD Europe, non-OECD Europe, which makes a relatively smaller contribution to the continent's domestic production, is poised for a more robust economic performance. It is projected to achieve a higher average long-term annual growth rate of 2.4 % by 2050. Notably, the largest economy within this group, Romania, is expected to maintain a solid growth trajectory with a long-term annual rate of 2.2 % by 2050. This growth is expected to enable Romania to sustain its significant share, exceeding 45%, of the non-OECD Europe's GDP by the year 2050.

1.2.3.5 Latin America

In 2022 and the early months of 2023, Latin America experienced robust economic growth, primarily fuelled by two key factors. Firstly, the resurgence of economic activity in the United States, coupled with the post-COVID reopening of China, injected vitality into the Latin American economies. This recovery resulted in increased trade, investment, and business opportunities, stimulating growth across the region.

Furthermore, Latin America benefited from soaring commodity prices in the international market, creating a favourable external economic environment. This surge in commodity prices provided essential support for the region's economy. The export of commodities, such as oil, minerals, and agricultural products, played a pivotal role in shaping Latin American economies. Despite these positive trends, some challenges and headwinds have emerged to temper the momentum of growth. Notably, concerns in China's real estate sector have raised uncertainties in global financial markets and external demand for Latin America. In addition, there has been a notable shift in the composition of economic growth in the United States,

with a greater emphasis on non-tradeable and service sectors negatively influencing the region's balance of trade.

To address rising inflation, many Latin American countries have adopted a strategy of tightening monetary policy, which, in turn, has affected overall economic activity.

The forecast for Latin America's economic growth indicates a positive trajectory, with an estimated expansion of 4.1% in 2022. However, in 2023, the region is expected to experience a slowdown in growth, with a forecasted rate of 2.3%. Adopting a more extended outlook, the prospect for economic growth lean distinctively towards the downside. Several factors contribute to this perspective.

Firstly, the prospect of lower growth in major trading partners has become a cause for concern. This could potentially impact export-driven economies and hinder their growth trajectories. Another significant variable in the equation is the volatility of commodity prices, which poses both challenges and opportunities for economies heavily reliant on commodities. Moreover, the intensification of geopolitical tensions on the global stage adds another layer of complexity to the economic landscape. These tensions can disrupt trade, investment, and cooperation, potentially impeding economic growth. Also, climate-related risks have moved to the forefront as a critical consideration for long-term economic planning. The increasing frequency and severity of climate-related events can have adverse economic consequences,

According to the GGO 2023 forecasts, Brazil and Argentina, being the largest economies in the Latin American region and representing more than half of the total Latin American economic output in 2022, are poised for an increasingly robust economic expansion. Projections indicate that both Brazil and Argentina are expected to achieve significant annual long-term economic growth rates of 2.6 and 3.1% p.a., respectively. As these economic powerhouses in the region continue to accelerate their growth, it is noteworthy that their relative contribution to the overall GDP of the Latin American region remains relatively stable.

1.2.3.6 Middle East

The Middle East exhibited remarkable resilience in its domestic demand following the dual challenges of the COVID-19 pandemic and the energy crisis. However, the region faced headwinds due to substantial oil production cuts by oil-exporting countries, and the implementation of contractionary monetary and fiscal policies to address rising inflation in the past year. In 2022, the Middle East achieved an annual economic growth rate of 6.6%, but this is expected to decelerate to 4.4% in 2023.

When evaluating the prospects for economic growth in the region, various factors can be considered. The expected alleviation of inflationary pressures and a more gradual pace of interest rate hikes by central banks provide favourable conditions for the region's economic outlook. Nevertheless, it is crucial to acknowledge that the considerable slowdown in economic growth in China and selected developed economies could have adverse effects on external demand, potentially dampening economic prospects. Moreover, the escalating debt levels and the looming risk of debt distress in some non-GCC (Gulf Cooperation Countries) countries within the region due to prolonged elevated global interest rates pose a significant threat to the region's financial stability.

The forecast for the Middle East's long-term average annual growth rate until 2050 is set to stand at 2.6%. This projection signifies a notable slowdown compared to the historical output growth of the region. Notably, the primary contributors to domestic production in the Middle East are expected to be the oil- and gas-exporting countries, including Qatar, Saudi Arabia, and the UAE, collectively accounting for more than 55% of the region's economy throughout the years leading up to 2050. It is worth noting that these economies are projected to experience a mild slowdown in their economic growth potential over the coming decades. However, efforts toward economic diversification and the promotion of non-oil and non-gas GDP, particularly within the manufacturing sectors, have the potential to mitigate the pace of this deceleration in the years to come.

1.2.3.7 North America

North American economic growth is markedly influenced by the economic development of the United States, which contributes to just under 90% of the region's GDP. A combination of factors has been propelling this growth, with the United States playing a central role. Resilient consumption growth and a robust business environment, which have persisted following the COVID-19 pandemic, are the primary drivers of economic expansion in the region. These trends are indicative of a tight labour market and consumer confidence that supports sustained growth.

Furthermore, fiscal expansionary policies have continued to improve the economy, injecting stimulus into various sectors. However, on the flip side, the economy faces the challenge of monetary tightening aimed at curbing rising inflation. This presents a headwind to the overall economic climate. It is worth noting that a slowdown in wage growth, coupled with the gradual depletion of savings accumulated during the pandemic, is expected to amplify the impact of the Federal Reserve's contractionary monetary policy. This adjustment could have implications for overall economic performance.

Taking these dynamics into consideration, the economic growth of North America was estimated to be around 2.2% in 2022, and the forecast for 2023 suggests that the region's growth is set to remain relatively stable at 2.3%.

Taking a long-term perspective, it becomes evident that the very forces that have been instrumental in driving growth and prosperity in the region since the 1990s are now displaying signs of weakening. Several key indicators and trends underscore this shift.

The growth rate of investment and total factor productivity, which played a pivotal role in the region's economic success, has been on the decline. This reduction in investment and productivity growth poses a challenge to sustained economic expansion. Moreover, the labour force is grappling with the challenges of ageing and slower expansion. A slower-growing workforce can hinder the potential for economic growth and innovation. Income inequality is anticipated to persist, and the middle class is facing a significant contraction.

A shrinking middle class could have socio-economic implications and impact overall economic stability. Finally, there are growing concerns about the prospects of higher inflation rates and the likelihood of "higher for longer" interest rates. These factors, combined with the burden of unsustainable debt levels, introduce additional complexities to the future of economic growth in North America.

It is anticipated that the United States is set to undergo a noticeable change in its global economic share by 2050, with a projected decline of 5 p.p., reducing its contribution to the global economy to 20%. However, within the North American context, the United States maintains a remarkably stable share, contributing around 87% to the regional economic output.

When examining long-term economic growth projections for the United States through 2050, the pace of growth is expected to settle at 1.6%. This rate closely mirrors the historical potential output growth experienced from 2000 to 2019, signifying a degree of continuity in the United States economic trajectory.

In contrast, Canada and Mexico show signs of acceleration in their long-term economic growth rates, with forecasts projecting growth at 2 and 2.3% p.a., respectively. These rates represent an uptick compared to their historical trends, suggesting increased economic dynamism in these North American neighbours.

1.3 Energy and carbon prices

Within the structure of the GGM, the prices of crude oil, natural gas, and carbon emissions are determined exogenously. In this section of the chapter, a review of the assumptions underpinning these price determinants was made while presenting a concise justification for the assumptions made.

1.3.1 Crude oil prices

The strong oil demand rebound in 2023 can be attributed primarily to the post-pandemic reopening of China, and this growth, driven by rising consumption in non-OECD countries, is expected to continue. However, there are notable negative risk factors, including China's higher debts and a property market crisis, which have increased uncertainty about short-term oil demand. Furthermore, persistently high inflation and tighter monetary policies are contributing to uncertainty regarding future economic conditions, which ultimately impact oil demand.

On the supply side, OPEC+ has voluntarily decreased production in response to the highly uncertain market environment, leading to the market balance and reduction of stock levels in OECD countries. Meanwhile, although United States oil production has returned to pre-pandemic levels, drilling activity has declined, leading to a forecasted slowdown in United States oil supply in the near future. As the market moves towards a global oil deficit and reductions in stocks, price risks appear to be relatively balanced, with speculation in the market expected to have a minimal impact due to OPEC+'s strategic approach.

It is expected that prices could stay below USD 80 per barrel by 2024-2025 as additional supply enters the market and the pace of demand expansion decelerates. Forecasts suggest a stabilisation of the crude oil market in the medium term.

Post-2027, specifically within the 2028-2050 timeframe, the average long-term price of Brent crude oil is assumed to gradually decline toward an average of USD 70 per barrel in real terms.

When the future of oil prices is considered, it is crucial to recognise that long-term oil prices are marked by significant uncertainty and are primarily shaped by the marginal cost of

supply to end users. Therefore, the path of long-term oil prices is influenced by a range of critical factors that have an impact on the marginal cost of production, including:

Reliance on green fields to meet oil demand. This factor underscores that the existing oil fields are inadequate to satisfy the expanding demand. A substantial portion of the anticipated supply is set to be derived from fields or projects not presently in production, including newly discovered reserves. Looking further into the future, it is expected that higher-cost United States unconventional onshore operations are poised to play a pivotal role in balancing demand. These regions are set to be in competition with yet-to-find (YTF) in mature Latin America offshore basins and North Sea wells. This development entails an escalation in the average and marginal production costs.

Inflation for key materials. Long-term economic indicators point towards a sustained period of elevated inflation, with a notable emphasis on critical minerals vital to the oil sector, such as steel and copper. The surge in demand for these crucial materials is anticipated to be driven by the rapid expansion of renewable energy infrastructure, notably in the solar and wind energy sectors. These metals are integral components across various facets of the oil industry, and as a result, there is a robust cost-push factor contributing to heightened inflation within the realm of oil production. Moreover, it should be emphasised that carbon pricing policies in various countries can potentially lead to an increase in the cost of oil production. In essence, higher steel, offshore and land rigs, equipment and labour costs are expected to remain critical throughout the forecasted period.

Rising cost of capital. The oil industry's capital-intensive nature necessitates substantial investments in upcoming decades to boost oil production from new projects and fields. However, sustained rises in interest rates and heightened perceived risks within the oil market have the potential to escalate the cost of capital, thereby making project financing more expensive for oil companies that rely on increased debt. Moreover, the heightened demand for higher returns on equity investments due to increased perceived risks among investors further contributes to the upward trajectory of the cost of capital.

Consequently, this upward trend in capital costs inevitably leads to an escalation in the overall cost of oil production.

Shift in investor risk preferences due to heightened uncertainty. Another pivotal factor is the uncertainties linked to the energy transitions, which have already begun to reshape the risk preferences of investors in oil projects. Investors now demand a significantly higher hurdle rate to invest in long-cycle oil projects. It is projected that these changes in risk preferences are projected to carry substantial implications for the cost of oil production going forward.

Considering these long-term drivers for the oil price within an environment marked by uncertainty and assuming the requisite investments are secured and efficiency gains are stable, the long-term Brent oil price, as the key benchmark oil price in the global market, is estimated to hover around USD 70 per barrel. This projection appears adequate to incentivise sufficient long-term supply. Moreover, it mirrors the evolving dynamics of the oil market as it adapts to shifting demands, technological advancements, and the pursuit of more sustainable energy sources.

1.3.2 Natural gas prices

Following a period of heightened volatility and a series of record-breaking price surges in 2022, global natural gas prices have predominantly been trending downward. The outlook for gas and LNG market sentiment is expected to stay 'bearish' through 2024.

Natural gas prices at the United States Henry Hub (HH) in 2023 reached their lowest point since mid-2020. In 2023, the average annual HH price was USD 2.57/mmbtu, marking a substantial 62% decrease from the average price of USD 6.43/mmbtu in 2022. The notable factors behind this decline included record-high natural gas production, stable consumption rates, and an increase in natural gas inventories, all contributing to lower prices compared to the preceding year.

In 2023, the average front-month Title Transfer Facility (TTF) price, serving as the benchmark for Europe, stood at USD 12.90/mmbtu, reflecting a remarkable decrease of 66% compared to an average USD 37.57/mmbtu TTF price observed in 2022. An improved balance between European gas demand and supply has facilitated the decrease of EU hub prices. The combination of reduced demand and the rise in liquefied natural gas (LNG) imports to the EU has largely offset the decrease in Russian pipeline supply. Despite these adjustments, the overall availability of gas supply options in the EU remains restricted, leading to volatility in prices and making them susceptible to increases in the event of unforeseen circumstances.

As for the Asian market, the annual average NEA spot LNG price in 2023 dropped 60% compared to 2022 and reached USD 13.47/mmbtu as demand for cargoes eased after a surge in 2022 led by Europe's efforts to replace Russian pipeline natural gas. The Asia Pacific region saw a recovery in gas demand in 2023, marked by China's consistent 20% rise in LNG imports since March 2023. Additionally, India, Thailand, and the Philippines collectively increased their LNG purchases by 30% in 2022. LNG demand in the region is expected to experience sustained growth in 2024, driven by a combination of moderated LNG spot prices and ongoing economic expansion.

Elevated gas prices are expected to persist until the mid-2020s. As the global gas markets undergo ongoing adjustments in response to the absence of Russian pipeline gas supply to Europe, the dynamics and structure of the industry are being reshaped. Tight global gas market conditions are anticipated to persist until a significant influx of new liquefaction capacity becomes operational in the mid-2020s. However, volatility will remain high in the face of large uncertainties in both the demand and supply sides.

The global LNG market is anticipated to rebalance around 2026-27, coinciding with the commissioning of a significant wave of new liquefaction capacity that is currently under construction. At this juncture, it is expected that the full-cycle cost of new United States LNG exports is set to establish European hub prices and Asian spot LNG prices as well.

Additionally, competition among gas suppliers has eased in the short to medium term, resulting in lower spot gas prices. Markets are displaying a tendency toward quicker convergence due to the accelerated prominence of LNG in the natural gas trade.

In a long-term equilibrium market, differences in prices between basins are poised to be influenced by transportation costs from the marginal supplier. With flexible destination volumes, United States LNG is expected to serve as the marginal supplier, with the ability to adapt volumes to global price differentials. The variations in prices between Northwest Europe and Northeast Asia are anticipated to be determined by netback equivalent costs for the United States Gulf Coast suppliers.

On the other hand, in the long run, expectations point towards a sustained elevation and increased volatility in the natural gas prices. This is due to the simultaneous competition for LNG between two pivotal gas markets - Asia and Europe. The reduced market flexibility in Europe further intensifies the competitive landscape.

In essence, natural gas prices act as a dynamic mechanism for coordinating the interactions between supply and demand in the energy market. The pricing system ensures that resources are allocated efficiently, encourages investment in natural gas production and infrastructure, and helps maintain equilibrium in the energy system. To some extent, factors defining the long-term trend of natural prices is resembling those impacting the crude oil prices.

The trajectory in natural gas prices over the long term would be influenced by the following factors:

Inflation for upstream capital costs. Higher steel, offshore and land rigs, equipment and labour costs will remain critical throughout the forecast period.

Growing capital intensity. Despite advancements in technology, the capital intensity of gas production is projected to rise. Increasing demand will face a higher long-run marginal cost of supply (LRMC), also influenced by the restructuring of the natural gas market and the elimination of natural gas with marginal costs within the lower cost range.

LNG investment wave. A surge in investment is being driven by undersupply in the LNG market. This trend is expected to continue, balancing the LNG market post-2026 and returning spot prices to a more normal level.

Carbon taxation and methane abatement policies. Climate concerns are anticipated to exert additional cost pressure on natural gas as a result of carbon taxation and policies addressing methane abatement. This pressure becomes more pronounced after the benefits of switching from coal have been maximised.

Accordingly, it is expected that the average long-term price for natural gas in Europe is set to stabilise at around USD 9/mmbtu, while in Asia, the long-term price is anticipated to settle at approximately USD 10/mmbtu. Meanwhile, the Henry Hub, which serves as a benchmark, is forecasted to maintain an average long-term natural gas price of about USD 4/mmbtu throughout the projected period.

1.3.3 Carbon prices

As of August 2023, there has been a remarkable global proliferation of carbon taxes and Emission Trading Systems (ETs), with a total of 73 such mechanisms currently in operation. According to the IMF, 49 countries have already implemented carbon-pricing schemes, and an additional 23 countries are actively considering their adoption. Notably,

among the recent entrants to the carbon markets' landscape are Indonesia, Japan, and Vietnam, all of which have initiated their carbon pricing initiatives.

Revenues stemming from carbon taxes and Emissions Trading Systems (ETS) have achieved an all-time high, totalling approximately USD 95 billion in 2022, according to the World Bank. A significant 23% of global emissions, equivalent to a staggering 11.7 GtCO₂ equivalent, are now subject to existing carbon taxes or emission trading schemes.

It is important to note that the vast majority of these carbon pricing mechanisms are concentrated in high-income countries, primarily in Europe and North America. Indeed, each country within the European Economic Area has some level of its emissions regulated through one of these mechanisms at the national level. In North America, the United States presently lacks a nationwide carbon pricing initiative, but permits individual states, such as California, to implement their own ETS.

However, when viewed beyond these regions, the landscape changes. In Latin America, the Caribbean, and South Asia, while some countries have implemented carbon taxes, China and Mexico stand out as countries with operational ETS. In Africa and the Middle East, there are scarce examples of these carbon pricing instruments being utilised.

The expansion of carbon prices is happening in three key ways. First, governments are creating new markets and levies, with Indonesia as an example. Japan introduced a voluntary national market for carbon offsets in April 2023, which is poised to work alongside an existing regional cap-and-trade policy in Tokyo. Vietnam is also in the process of establishing an emissions-trading scheme to begin in 2028, where firms exceeding emissions thresholds will need to offset them by purchasing credits.

Second, countries with established markets are strengthening their policies. China's National Climate Strategy Centre announced in September 2023 that its emissions-trading scheme, the world's largest, is set to expand its focus from just the carbon intensity of coal power plants to include total emissions. This scheme is also expected to link with a carbon-credit market, allowing power plants to meet obligations by purchasing credits for renewable power, afforestation, or mangrove restoration. In Australia, which had scrapped its original carbon price in 2014, the previously ineffectual "safeguard mechanism" has been reformed. Since July 2022, industrial facilities responsible for 28% of the country's emissions must reduce them by 4.9% annually against a baseline. Those failing to do so must purchase offsets, which trade at a price of around USD 20 per tonne.

The third method of spreading carbon markets is through cross-border schemes, with the EU's program being the most advanced. In the pilot phase of the Carbon Border Adjustment Mechanism (CBAM), importers of various goods need to report "embodied emissions" generated through production and transport. Starting in 2026, importers will be required to pay a levy based on the difference between the carbon cost of these emissions in the EU's scheme and any carbon price paid by the exporter in their domestic market. Free permits for certain sectors are set to be phased out, and the housing and transport industries are poised to be integrated into the market. On another note, there is growing concern about the violation of the World Trade Organization (WTO) in implementing such schemes.

Given these developments, it is anticipated that carbon markets are set to remain fragmented over the forecast horizon, with a significant disparity between carbon prices. The benchmark carbon price in the EU ETS is expected to rise gradually from USD 85 in 2022 to USD 100 by 2040 before experiencing a rapid increase to USD 166 in 2050.



2

Energy Policy Developments



Highlights

- ▶ The past four years underscore the critical importance of finding a harmonious balance among reliability, sustainability, and affordability goals in energy policy-making. This multifaceted challenge takes centre stage on the policy agenda.
- ▶ Acknowledging that there is no one-size-fits-all energy source or technology is paramount in the pursuit of just, equitable, and orderly energy transitions. Developing climate and energy policies based on the unique national circumstances, capabilities, and priorities is key to success.
- ▶ In developing countries, just energy transitions prioritise economic development and poverty alleviation. As a matter of fact, the UNFCCC underscores that “socio-economic development and poverty eradication are the overriding priorities of developing country Parties”.
- ▶ Significant policy support and investment have been directed toward natural gas as a strategic response to potential energy shortages, driven by energy security concerns and rising energy costs impacting households and businesses.
- ▶ Natural gas has gained prominence as a pragmatic approach to reducing energy-related emissions, given the challenges associated with scaling up renewable energies, including limited access to critical minerals and the need for extensive power grids.
- ▶ While still in its infancy, there has been a rapid increase in the number of countries incorporating hydrogen into their energy sector strategies, reflecting its potential as a clean energy carrier.
- ▶ Market volatility, exacerbated by recent energy crises, has posed challenges to the expansion of natural gas use, particularly in price-sensitive sectors such as power generation in South and Southeast Asia.
- ▶ Significant policy support has emerged for nuclear energy, with countries revisiting and amending their energy policies to reintroduce and promote nuclear power as a crucial component in the global energy mix.
- ▶ In 2023, China introduced a new approach to liberalise natural gas prices, aiming to bridge the gap between higher-tariff industrial users and residential consumers, promoting equitable distribution of fuel costs and encouraging global market participation.
- ▶ In 2023, the EU initiated the preliminary stage of its carbon border tax plan, requiring importers to disclose CO₂ emissions associated with products entering Europe. This move, including potential financial penalties, aims to address carbon emissions associated with imported goods, such as steel and cement, contributing to global climate objectives.

The significance of energy policy development is profound, as it holds sway over numerous facets of society, the economy, and the environment. Furthermore, it stands as a fundamental pillar within the realm of energy modelling, wielding substantial influence in shaping and guiding decisions pertaining to energy systems, sustainability objectives, and the allocation of resources. In the following chapter, our aim is to explore an examination of the intricate web of global and regional energy policies and their profound impact on the natural gas market and industry. This exploration seeks to shed light on the interplay between policy dynamics and the evolving landscape of the natural gas sector.

2.1 Global developments and trends

2.1.1 Short-term strategies for tackling the energy crisis amid geopolitical challenges

The turbulent events of 2022 triggered substantial global turmoil, challenging established norms and reconfiguring the global energy system's paradigms. Efforts focused on energy transitions since 2015, following the Paris Agreement, were overshadowed by the imperative to address the repercussions of the energy crisis. This predicament, which arose from the very same efforts, has been labelled by some as the "first energy crisis of the energy transitions." It resulted from a mismatch between strong demand growth and underinvestment in conventional supplies. The disruption in energy markets was further exacerbated by geopolitical tensions in Eastern Europe.

Against this backdrop, the natural gas markets underwent a substantial transformation, with Europe emerging as the preferred destination for LNG cargoes, a departure from its previous role as a last-resort market. The sharp increase in LNG spot prices due to robust demand in Europe has redirected supply from cost-sensitive markets in various Asian countries, leading to significant and enduring impacts on energy accessibility for billions of people. Meanwhile, natural gas lost its competitive edge against coal, leading to a resurgence in coal demand, especially in developing economies. However, this trend revealed a paradox: the increased use of coal had adverse environmental impacts, undermining global efforts to reduce greenhouse gases (GHGs) and improve air quality.

The crisis has reminded policymakers and energy consumers of the immediate importance of reliable and affordable natural gas supplies. This period underscored the incontestable reality that in the absence of secure and affordable energy, the aspirations for sustainability would be relegated to mere rhetoric.

Moreover, the increasing emphasis on energy security and affordability in policy discussions subsequent to the energy crisis has brought to the forefront the ongoing debate over the roles of governments and markets. One significant implication of the shifting priorities in energy policy is the noticeable trend away from market-driven mechanisms toward an expanded role for the state within energy markets. Governments have proactively implemented measures to mitigate the adverse effects of energy-related shocks on consumers and businesses, often resorting to the introduction of substantial support packages, which inevitably impact fiscal balances. To fund these support and subsidy initiatives, several countries have resorted to implementing windfall taxes and levies. For instance, in 2022, the EU's total subsidies in the energy sector, aimed at addressing high prices, exceeded €390 billion. Additionally,

in certain instances, governments have opted to nationalise specific energy assets.

In response to these challenges and emerging trends, several distinct policy trends have become evident. Firstly, there has been a notable increase in government-backed policies supporting domestic energy production to enhance energy security. This has translated into greater policy backing for renewables in Europe, a combination of coal and renewables in countries such as India and China, and the development of domestic oil and gas production in numerous countries. Secondly, many countries have implemented policies and measures to manage natural gas supply by requesting gas storage capacities to be filled at a certain minimum requirement, diversifying supply sources, and establishing reliable partnerships with various gas suppliers.

As countries adapt to these evolving energy dynamics, the focus shifts beyond immediate measures to a more systematic and future-oriented approach.

2.1.2 Global strategies under reassessment

In late 2022 and 2023, with tensions subsiding, the global community grew more accustomed to the evolving landscape, and a more favourable window of opportunity emerged for critical review and reevaluation of prior policies. Furthermore, in 2023, reports from the 6th cycle of the IPCC assessment, the first Global Stocktake (GST) at COP28 (Conference of Parties 28), and the UN SDG 2023 Progress Report were released. These reports collectively underscored that the world is deviating from its intended trajectory in achieving collective goals.

The SDGs Progress Report 2023 indicates that billions still remain far from achieving modern living conditions, highlighting a significant global challenge. A preliminary assessment of the roughly 140 targets with data shows that only about 12% are on track, while close to half are moderately or severely off track. Affordable and reliable energy is essential for improving key aspects of human development, including living standards, life expectancy, education, and per capita income. Additionally, as global economic empowerment grows, so does the energy demand of billions worldwide (refer to Box 2.1).

Concurrently, the outcomes of the first GST alongside COP28 (refer to Box 2.2) reveal that the current pace of emissions is rapidly diminishing the global carbon budget, necessary to stay within the 1.5°C pathway by this decade's end, highlighting the urgent need to intensify emission reduction efforts. Failing to curb temperature increases could detrimentally impact economies, with the most vulnerable populations facing the greatest risks due to climate change. However, recent events have also demonstrated that a disorderly net-zero transition can lead to challenges in affordability. If such a transition is perceived as hindering the prospects for improved living conditions, public support for these initiatives may falter. This trend is observable in Europe, which has set some of the world's most ambitious emission reduction targets. Despite vigorous efforts towards energy transitions, Europe is experiencing increasing resistance to its climate policies. As a result, it is becoming evident that the energy transitions are more intricate than previously thought, and reevaluating past policies is imperative. This complexity underscores the necessity of reassessing past policies and approaches to better balance the urgent need for climate action with socio-economic realities.

The experience of the COVID-19 pandemic and energy crisis over the last few years showed that the balance between the reliability, sustainability and affordability goals, without focusing specifically on every single element, is the most significant issue on the policy-making agenda. Therefore, more holistic models, frameworks and instruments, which consider the full range of

socio-economic impacts of energy and climate policies, would help policymakers understand the broader implications. Multi-dimensional frameworks and instruments are needed to fully understand multi-dimensional energy transitions, and in this endeavour, it should be noticed that there is no one-size-fits-all climate change policy that fits all countries.

Box 2.1 Taking stock of SDGs progress at the midpoint

In 2023, representing the midpoint of the 2030 Agenda timeline, the Special Edition of the SDG Progress Report delivers a stark message: we are failing over half the global population. The report reveals that progress on over 50% of the Sustainable Development Goals (SDGs) targets is either weak or insufficient. Alarming, for 30% of the targets, progress has either stalled or regressed. This includes critical areas such as poverty reduction, hunger alleviation, and climate action. The report serves as a dire warning that, without immediate and decisive action, the 2030 Agenda risks becoming a memorial for missed opportunities and unfulfilled potential.

A reality check of the progress made on the SDGs shows that:

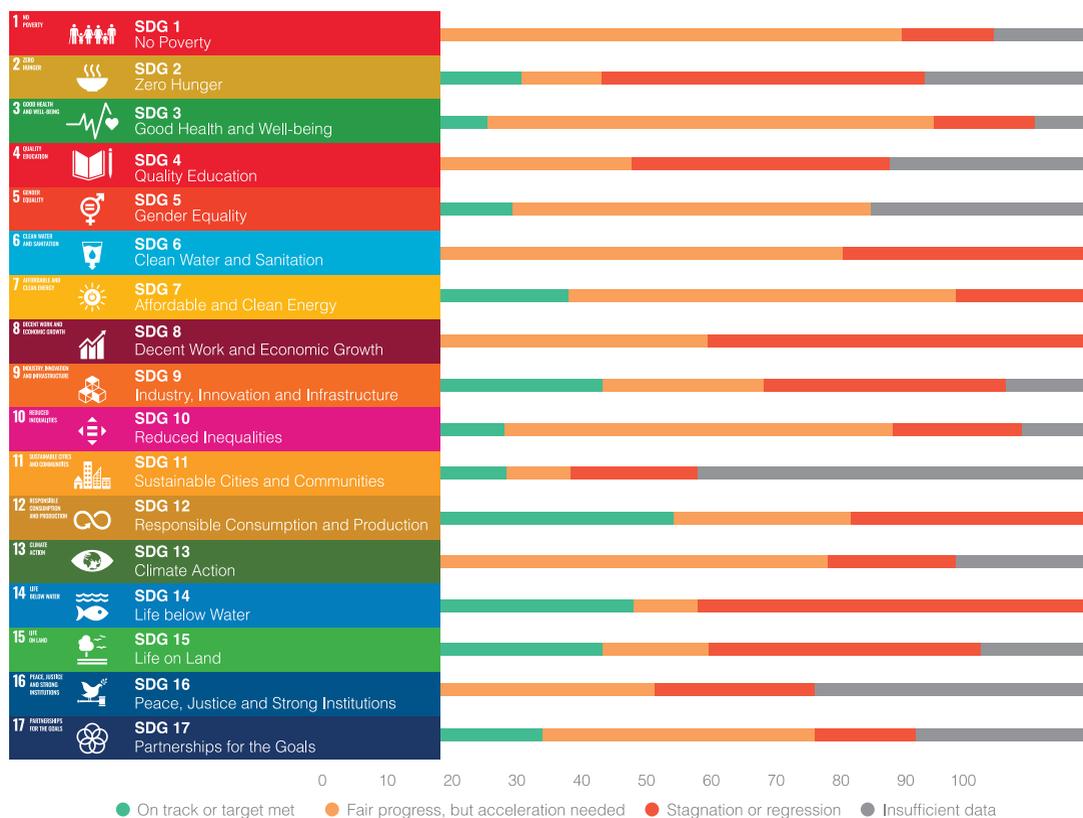
In 2021, approximately 675 million people, mainly in low-income countries, lacked access to electricity. If current trends

continue, around 660 million are expected to still be without electricity by 2030. In Sub-Saharan Africa, despite population growth, the number of people without access to electricity has remained largely unchanged since 2010, with 567 million still without access in 2021.

As of 2021, 2.3 billion people, 29% of the world's population, still used polluting cooking methods. Global access to clean cooking fuels and technologies increased only slightly since 2015. South-Eastern Asia made significant progress, but Sub-Saharan Africa lagged, with 0.9 billion people still lacking access. If trends continue, by 2030, only 77% of the global population is anticipated to have clean cooking solutions, leaving about 1.9 billion people, including 1.1 billion in Sub-Saharan Africa, without access.

Figure 2.1.1

SDGs Progress Report 2023



2.1.3 The need for diverse paths of just, equitable and orderly transitions

A string of shocks, crises, and tensions in the global energy system during the past four years underpin the necessity of developing transitions that accommodate varying conditions worldwide, encompass a range of policy approaches and promote equity.

In 2023, there was a notable increase in concerns voiced during global dialogues. These concerns highlighted that an exclusive focus on a single pathway to achieving net-zero emissions by 2050 might imperil the attainment of other sustainable development goals, limit funding for vital energy projects and threaten the essential public support for climate policies. In 2023, while holding the presidency of the G20, India made substantial efforts to incorporate the idea of multiple energy pathways into the group's summit communique, receiving support from countries such as China and South Africa. The same language was also adopted at the BRICS and Africa Climate summits.

The term “just transition” is increasingly finding its way into policy documents, but its interpretation varies across regions. The concept of a just transition appears quite distinct in Africa,

developing countries of Asia, and Latin America compared to Europe or the United States, where per capita incomes can be as much as 40 times higher. In the developing world, a just transition seeks to ensure that energy policies and investment decisions prioritise economic development and poverty alleviation. For example, in many Global South countries, the energy transitions involve shifting from traditional sources such as wood and waste to LPG, which not only offers improved functionality and convenience but also addresses indoor air pollution, effectively marking a transition from a lack of energy to accessing reliable energy sources.

In recognition of the need for just, orderly and equitable energy transitions, there is a suggestion to substitute the term “energy transition” with “energy transformation.” This shift emphasises making energy sources cleaner and highlights the goal of decarbonising emissions from fossil fuel use rather than advocating for a complete halt in investment in all fossil fuels. Prioritising emission outcomes over specific fuels could promote a more well-rounded approach that takes into account all facets of the energy trilemma. This approach may also enhance the potential for securing funding for critical technologies such as CCUS and DAC.

Box 2.2 COP28 outcomes

COP28, the 28th session of the Conference of Parties to the UN Framework Convention on Climate Change (UNFCCC), held from November 30 to December 13, 2023, in Dubai, United Arab Emirates, culminated in the UAE Consensus. This consensus was significant for its incorporation of the first GST, a comprehensive assessment aimed at defining the necessary measures to maintain the goal of limiting global warming to 1.5°C. The reaction to the outcomes differed significantly between developed and developing countries. Developed countries generally viewed the outcomes positively, appreciating progress towards transitioning away from fossil fuels and the loss-and-damage fund. However, developing countries expressed concerns that the resolutions did not sufficiently address the greater historical responsibility of wealthier nations for climate change. They emphasised the need for more financial support, highlighting the uneven impact of climate change on their economies. The key highlights from COP28 encompass:

The first GST

A key component of the ‘UAE Consensus is the decision on the GST to assess progress post-Paris Agreement and propose measures to address gaps by 2030. The outcomes of the GST include several key directives:

Energy transitions:

It calls for transitioning away from fossil fuels, a tripling of renewable energy and a doubling of energy efficiency globally by 2030. The decision acknowledges the necessity to peak global emissions by 2025 and encourages economy-wide Nationally Determined Contributions (NDCs) submissions from countries.

Role of transitional fuels:

While natural gas is not explicitly mentioned, the decision acknowledges the role transitional fuels might play in facilitating energy transitions and maintaining energy security.

Adaptation finance:

The decision also stresses the critical need for significantly scaling up adaptation finance, going beyond just doubling, to meet evolving needs effectively.

National adaptation plans:

It calls for the submission and implementation of National Adaptation Plans by 2025 and 2030, respectively, as a key component in managing climate impacts.

Climate finance architecture:

The decision underscores the importance of finance in realising these ambitions, laying the groundwork for a new global climate finance architecture to support post-2025 goals, which is expected to advance further at COP29.

Global Goal for Adaptation

In alignment with the mandate to establish a Global Goal for Adaptation, COP28 presented the Emirates Framework for Global Climate Resilience. This framework aims to protect food and water security, health, nature, livelihoods, infrastructure and cultural heritage. These targets will be further refined over a two-year negotiation, culminating in COP30 in Brazil. On the financial aspect, while initial drafts of the agreement suggested a definitive commitment by governments to close the adaptation finance gap, the final version of the agreement softened this stance, merely expressing an intention or aspiration to “seek” to close this gap.

Loss and damage

The fund for loss and damage, pledged during COP27, has been formally ratified on the opening day of COP28. This newly established fund, initially hosted by the World Bank for a four-year term, is designed to allocate resources judiciously,

leveraging available evidence to address the impacts of climate-related losses and damages. Notably, a minimum percentage of the fund is earmarked for allocation to countries aligned with the UAE consensus and the vulnerable Small Island Developing States (SIDS). A remarkable commitment by 19 countries, totalling USD 792 million, has been pledged toward this fund. Among these commitments, the UAE has taken a significant step by contributing USD 100 million to support funding arrangements addressing loss and damage.

Trade-related unilateral measures

During the discussions, developing countries strongly advocated for the incorporation of debates concerning carbon taxes, exemplified by the European Union's CBAM, into the purview of the Just Transition Pathways' (JTP) work program and the Forum on the Impacts of the Implementation of Response Measures. They underscored the necessity to confront "trade-related unilateral measures aimed at combating climate change that have transboundary implications." Regrettably, this proposition faced staunch opposition from developed countries.

Despite concerted efforts, the issue of 'unilateral trade measures' did not receive direct attention in the conclusive resolutions of either the JTP or the Forum. However, it did secure acknowledgement within the decision of the Global Stocktake (GST). Positioned within the "International cooperation" segment of the GST, there is a clear emphasis on the principle that "measures taken to combat climate change, even if unilateral, must not be a means of arbitrary or unjustifiable discrimination or a veiled impediment to international trade."

Cooperative implementation (market and non-market approaches)

Countries at the conference were unable to finalise the framework for trading carbon offsets bilaterally or to launch a global carbon market under UN auspices. Despite extensive work over a year by a technical body to establish rules on project methodologies and the inclusion of carbon removal activities, these proposed guidelines were not accepted. The failure to reach an agreement was largely due to two opposing views: the urgency to activate the carbon trading system quickly and the necessity to ensure its integrity and transparency. These divergent goals ultimately remained unresolved.

2.1.4 Natural gas: policy support and the challenges of market volatility

In 2023, significant policy support and investment have been channelled towards natural gas as a strategic response to potential shortages exacerbated by persisting geopolitical tensions and the ramifications of escalating energy costs and inflation on both households and businesses. Notably, the G7 countries, in their May 2023 communique, reaffirmed their support for increased investments in natural gas. Japan, on the other hand, positions LNG as a pivotal transitional resource, fostering the evolution towards a more environmentally sustainable economy. In the wake of the the geopolitical tensions, which inflicted notable supply disruptions, Germany is proactively directing efforts towards bolstering its investments in LNG infrastructure.

Additionally, little headway was made in developing non-market approaches for international cooperation on climate change, which do not involve the exchange of carbon credits. The conference concluded with a procedural decision, merely encouraging further exploration of such non-market strategies.

New partnerships and initiatives

COP28 saw the launch of several new partnerships and initiatives aimed at addressing climate change:

The Summit on Methane and Other Non-CO₂ Gases: This summit mobilised USD 1.2 billion to reduce methane and other non-CO₂ GHG emissions across various sectors. The World Bank committed support to 15 countries for national programs aiming to cut methane emissions from rice production, livestock, and waste.

Oil & Gas Decarbonisation Charter: This charter, endorsed by 52 companies responsible for 40% of global oil and gas production, focuses on supporting the goal of net zero emissions by 2050 or earlier.

Industrial Transition Accelerator: With the backing of 38 companies and six industry associations, this initiative targets the decarbonisation of the construction sector by 2030, including specific breakthroughs in buildings and cement.

Global Renewables and Energy Efficiency Pledge: Endorsed by 132 countries, this pledge commits to tripling renewable energy and doubling annual energy efficiency improvements by 2030. To support this commitment, USD 5 billion has been mobilised, particularly for renewable energy deployment in the Global South.

Utilities for Zero Alliance: Comprising 31 partners, including 25 global utilities and power companies, this alliance is dedicated to promoting electrification, renewables-ready grids, and clean energy deployment in line with the 2030 Breakthroughs.

In addition to these key initiatives, significant progress was made in areas such as renewable hydrogen trade, reducing cooling-related emissions, promoting the electrification of cooking, and developing carbon management strategies. These diverse efforts represent a comprehensive approach to tackling climate change on multiple fronts.

In an effort to enhance energy security, certain countries have undertaken initiatives to create a more favourable environment for upstream investment with the aim of boosting their domestic gas production. Take Indonesia, for instance, which has set forth an ambitious objective to significantly increase its domestic gas production, targeting a leap from 58 bcm in 2022 to 124 bcm by 2030. This aligns with Indonesia's broader goal of augmenting the contribution of natural gas in its primary energy mix, which stood at 17.8% in 2013. According to its National Energy Plan (RUEN), Indonesia seeks to raise this share to 22.4% by 2025 and further to 25% by 2050.

Furthermore, several Southeast Asian economies have strategically opted to develop LNG-receiving terminals, a decision shaped by a convergence of compelling factors. These factors encompass an upsurge in natural gas demand, a decline in domestic gas production due to the maturation of

oil and gas fields, the necessity to broaden the sources of gas supply, geographical disparities between supply and demand hubs, and the transformation of transit pipeline business models following geo political conflicts.

A discernible shift observed in the power sector involves a notable trend of transitioning from coal to gas, primarily driven by the allure of cost-effective natural gas and the imposition of substantial carbon prices. This shift has been evident in the past and is anticipated to persist in these countries, albeit at a more gradual pace.

Vietnam released its National Power Development Plan 8 (PDP8) in May 2023. This key document outlines the country's future energy mix and includes proposals for new LNG receiving terminals and gas-fired power plant projects. Similarly, the Philippines had multiplied LNG projects in 2023 and is charting a progressive course in this arena, with plans underway to develop seven LNG regasification projects nationwide. In a recent development as of September 2023, India has also unveiled plans to provide 7.5 million complimentary cooking gas connections to households over the next three years.

China has seen substantial growth in LNG import terminals, driven by rising demand and efforts to involve non-state entities in gas imports. This expansion is expected to continue due to a recent policy change in June 2023 aimed at liberalising natural gas prices, which could encourage increased LNG imports by distributors. In its 14th Five-Year Plan (FYP), China explicitly outlines the integration of natural gas into the power sector as a strategic approach to effectively address the challenges associated with the intermittent generation of electricity from renewable energy sources.

However, the market volatility, spurred by the recent energy crisis, has posed some challenges to the expansion of natural gas, particularly in cost-sensitive sectors such as power generation in South and Southeast Asia. In these regions, energy pricing is a key factor influencing policy decisions, with high gas prices potentially weakening the earlier strong momentum towards increasing the share of gas in power generation. Although the expansion of domestic gas distribution networks in countries such as China and India is expected to proceed, their earlier ambitious plans to substantially increase the use of gas in electricity generation are being reassessed and moderated.

Pakistan provides a notable example in this regard. In an effort to reduce power generation costs and enhance energy security, Pakistan has announced its decision to postpone the construction of new gas-fired power plants in the near future. Instead, the country plans to significantly expand its domestic coal-fired capacity, with the goal of quadrupling it from the current 2.3 to 10 GW. This strategic shift is in response to a gas shortage, which accounts for 33% of the country's total power output. This shortage led to extended power outages in 2022, aggravated LNG being rerouted away from Pakistan to Europe that could afford to pay a premium.

Although Pakistan has set ambitious emissions reduction targets, aiming to achieve a 50% reduction compared to its 2015 baseline, achieving this goal may pose challenges given the planned expansion of coal capacity.

Meanwhile, several major gas producing countries have pursued emission reduction policies that have had adverse implications for the natural gas sector. Australia, a significant global LNG exporter, has recently passed new legislation

amending the Safeguard Mechanism, which is set to take effect in July 2023. This policy adjustment represents a critical step in Australia's commitment to achieving its net-zero emissions target by 2050. Under this revised policy, facilities falling under the scope of the mechanism are obligated to reduce their emissions intensity by 4.9% annually. This requirement applies to a wide range of sectors, including oil, natural gas, waste management, and transportation companies.

The implementation of this legislation carries potentially significant implications for Australia's gas and LNG sector, which plays a pivotal role in the country's economy and contributes to both domestic and international energy security.

2.1.5 Natural gas as a key enabler in low-carbon hydrogen production

Hydrogen, mainly blue hydrogen, is another catalyst for the growth and evolution of the natural gas market. The United States included billions of dollars of green hydrogen tax credits in its Inflation Reduction Act (IRA), the European Union approved EUR 5.2 billion (USD 5 billion) in subsidies for green hydrogen projects in 2022 and India announced a USD 2.1 billion incentive plan in 2023. While many countries are adopting hydrogen strategies and targets for technology deployment, China has surged ahead in actual deployment, leading the world in electrolyser capacity additions.

According to the Hydrogen Council, more than 1,040 large-scale hydrogen projects have been announced globally as of January 2023, an increase of 350 new proposals since May 2022. While Europe leads with the most announced projects, North America has the highest percentage of committed investments. In North America, nearly 75% of announced projects include blue hydrogen, which is produced from natural gas, while the CO₂ emitted is captured and stored using CCUS technologies. According to the US's Inflationary Reduction Act of 2022, 6 to 10 clean or low-carbon regional hydrogen hubs across the United States should be established, with at least two hubs in regions with abundant natural gas resources and infrastructure. Similarly, the UAE's updated energy strategy, unveiled in July 2023, outlines ambitious hydrogen objectives, including the development of five hydrogen hubs by 2050, aims to produce 1.4 MtH₂ annually by 2031, with 0.4 MtH₂ expected to be blue hydrogen, generated from natural gas.

In recent years, there has been a rapid increase in the number of countries incorporating hydrogen into their energy sector strategies. As of September 2022, four governments have revised their hydrogen strategies, and an additional 15, predominantly from developing economies, have newly unveiled national hydrogen strategies aligned with government objectives for low-emission hydrogen production. This collective effort underscores the growing commitment of 41 governments worldwide to leverage hydrogen as a pivotal element of their energy agendas, highlighting the global momentum behind the adoption and development of hydrogen technologies.

While green and blue hydrogen stand as the main sources of low-carbon hydrogen, blue hydrogen currently holds a significant cost advantage over green hydrogen. Presently, green hydrogen is considerably more expensive than an equivalent of natural gas, and its production remains limited. This combination of limited availability and high cost poses a challenge for potential end users in evaluating the feasibility of using hydrogen as a power or heat source in place of existing fuels.

Additionally, concerns have been prompted about whether there would be enough emission-free electricity for planned green hydrogen production since this kind of hydrogen requires massive power for production and associated losses. Renewables are most effective in decarbonising the power sector directly, where their impact surpasses that of converting them into green hydrogen. Consequently, the development of blue hydrogen becomes essential, as green hydrogen is unlikely to be available in significant quantity until the power sector is thoroughly decarbonised with renewable electricity. Additionally, establishing a market shift towards hydrogen is crucial for swiftly decarbonising the non-electric sector. In this context, blue hydrogen, derived from natural gas, is poised to lead the way in the upcoming decades, setting the stage for the eventual adoption of green hydrogen.

Nevertheless, it is crucial to recognise that despite the widespread attention and enthusiasm surrounding low-carbon hydrogen's potential as a clean industrial feedstock and energy carrier, its adoption is still in its infancy. As at September 2023, only a mere 4% of potential production projects had progressed to the point of taking a Final Investment Decision (FID), underscoring the early stage of development in the hydrogen industry. This nascent stage gives rise to a wide range of possible long-term outcomes for hydrogen's role in the global energy landscape, making it a subject of significant interest and debate among policymakers, industry leaders, and environmental advocates.

2.1.6 Natural gas as the primary low-carbon energy source and renewable energy partner

Recent years have witnessed a notable acceleration in adopting renewable energy globally. Growth in renewables in 2022 was driven mainly by the United States, China, and India implementing policies and market reforms to support renewable deployment more quickly than previously planned. The momentum of embracing renewables carried into 2023, with

countries worldwide enhancing their policy frameworks to fortify energy security and realise ambitious climate targets.

In recent years, a combination of reduced costs, accessible capital, and political endorsement has significantly accelerated the global shift towards renewable power. However, the surge in renewable energy is meeting unexpected challenges. Disrupted supply chains and escalating interest rates are inflating costs and testing the resolve of consumers and governments.

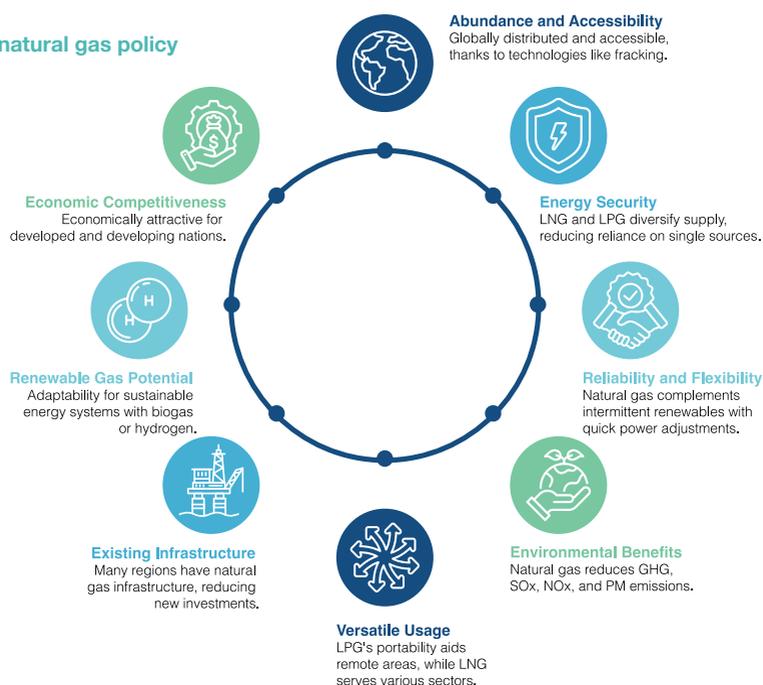
With the growth of renewables, and as electricity begins to power more extensive sectors of economies, enhancing grid capacity and storage infrastructure is becoming increasingly critical. The existing transmission lines are proving inadequate to accommodate the proliferation of new and decentralised renewable energy projects. Building more transmission lines is expensive and complicated, particularly in areas with high population density. Additionally, there is often a mismatch between regions rich in renewable energy sources and those with the highest electricity needs. Without enhancements to the electrical grid, the safe and efficient distribution of the growing generated electricity could be at risk, potentially destabilising the entire network.

On the flip side, there is a growing concern regarding the limited access to critical minerals and metals, such as copper, lithium, cobalt, nickel, and aluminium, which are essential for solar and wind power generation. The production of these metals is facing challenges to keep up with the rapidly increasing demand and is concentrated a handful of countries. Due to the capital-intensive nature of these industries and the long lead time required for production, it takes a significant amount of time to establish new capacities that can respond to this rising demand. Even when new sources of these metals are discovered, legal and financial obstacles can take years to overcome.

Moreover, mining critical minerals for renewable energy is often tagged as a 'dirty' activity, leading to its exclusion from

Figure 2.1.

Factors incentivising natural gas policy



sustainable finance options and facing resistance at the local level, not to mention prolonged approval processes. This situation poses a paradox for the renewable sector, initially burgeoning due to its sustainability credentials. Policymakers and investors are now confronted with the challenge of reconciling the sustainable nature of renewable energy with the less environmentally friendly aspects of mineral extraction essential for them. Addressing this contradiction is vital to sustain the momentum of renewable energy adoption globally.

Another paradox emerges from the substantial concentration of critical minerals supply chains in a handful of countries. While many countries have embraced policies favouring renewables to augment energy security, this concentration poses a contradiction, eroding the foundational objectives of such policies. It prompts a renewed form of dependency and vulnerability. For instance, over 80% of polysilicon for solar panels and 70% of finished modules are produced in China. The country is also responsible for up to 90% of the refining capacity for rare earth elements essential in electric motors, wind turbines, and other renewable energy products. This level of control in production and refining capacity intensifies concerns about the security of critical mineral supply chains amidst geopolitical competition. Achieving diversified and resilient supply chains is a complex task that demands substantial investment, time, and expertise.

In the face of these challenges, natural gas stands out as a compelling solution, providing practical avenues for curbing energy related emissions. As depicted in Figure 2.1, the rationale behind global natural gas policy support is multifaceted.

2.1.7 The resurgence of nuclear power

In meeting the world's energy demand with low-carbon sources, the resurgence of nuclear power is particularly noteworthy. Previously abandoned due to safety and environmental concerns, nuclear energy is now receiving renewed support as its potential to address climate change and energy security is being re-evaluated and acknowledged. In the past two years, significant policy support has emerged, with countries revisiting and amending their energy policies to reintroduce and promote nuclear power as a crucial component in the global energy mix, aiming for a sustainable, low-carbon future.

In a major move, China approved ten new nuclear projects in 2022 and greenlight expansions at three existing nuclear plants in 2023. The UAE has engaged in nuclear energy cooperation agreements with Chinese entities, and India is rethinking its stance on foreign investment in nuclear power and contemplating greater domestic private sector involvement.

Japan, in a notable turnaround, announced the reactivation of the 780 MW Unit 1 of the Takahama nuclear power plant in August 2023, which had been inactive since the Fukushima disaster in 2011. Furthermore, Japan has entered into a nuclear partnership with France focused on research and development of advanced nuclear technologies, such as sodium-cooled fast reactors.

In 2022, the EU decided to list nuclear power plants as investments eligible for green labelling, aiming to direct investments towards climate-friendly technologies.

In the United States, nuclear plants have been offered three channels of financial support: the IRA credit, which provides

a base value of USD 3/MWh and can go up to USD 15/MWh under certain conditions, funds allocated through the Infrastructure Investment and Jobs Act (IIJA), and state zero-emission credit programs. These initiatives reflect a global re-evaluation and renewed commitment to nuclear energy as a pivotal component in the pursuit of a low-carbon future.

2.1.8 Steady growth for natural gas market

The intricate interplay of global energy dynamics is underscored by the advancements in renewable energy sources, the resurgence of nuclear power and coal, and the persistent role of natural gas. The urgent need for reliable, affordable and clean energy supplies toward inclusive and sustainable development has reaffirmed natural gas's pivotal role. As a result, with policy support, natural gas remains a significant player.

2.2 Policy drivers and developments in the key markets

As we explore the intricate landscape of global energy policies, it is imperative to focus on the key markets that are shaping the future of this sector. In this analysis, we turn our attention to India, China, the United States, and the EU, each representing a unique and influential player in the global energy arena. As we examine each of these markets, we will explore the recent general energy policy trends and look deeper into the specific policies related to natural gas, including the latest regulations and policy-making developments that have emerged in 2023. Table 2.1. provides a brief overview of primary government objectives across regions, offering a glimpse of the diverse approaches taken by governments worldwide to address energy challenges. This sets the stage for our in-depth exploration of each country's energy policies in the following sections.

2.2.1 India

Since 2001, India has been actively implementing climate actions. In 2008, India introduced the National Action Plan for Climate Change, which featured a range of initiatives, including relatively modest solar energy targets aimed at achieving 20 GW capacity by 2022. India's push for renewable energy has led to more investments due to its clear and steadily rising ambitious targets shared with local and international private investors. By 2022, India had already surpassed the milestone of 156 GW in renewable energy capacity, and it has now set its sights on an even more ambitious target of reaching 500 GW by 2030.

Its updated NDC underscores an unconditional commitment to reduce the emissions intensity of India's GDP to 45% below 2005 levels by 2030, representing a notable advancement from the earlier target of 33-35% set in the previous NDC submitted in 2015. Furthermore, the updated NDC includes a conditional commitment to achieve approximately 50% of its installed energy-generating capacity through non-fossil fuel sources by the same year, provided that financial support and technology transfer are furnished by other countries.

And yet, India has planned to increase its coal capacity for the second half of the decade. At the beginning of 2023, India requested utilities to postpone the retirement of coal-fired power plants until 2030, citing a rise in electricity demand. Its latest National Electricity Plan (NEP,2022) includes an additional 25.5 GW of coal capacity for the second half of the decade

on top of the 25.6 GW already under construction. While they indicated their intention to amend the NEP 2022 in May 2023, aiming to cease new coal-fired capacity development except for ongoing projects, coal remains the primary energy source in their mix.

2.2.1.1 Policy support for natural gas

According to the Indian vision for the future of the country's energy system, supported by their leaders, hydrocarbons are set to remain a crucial energy source for the foreseeable future, playing a significant role in India's ongoing growth trajectory. Emphasising the importance of a gas-based economy, Indian policymakers have underscored the need for concerted efforts to enhance natural gas production and establish import infrastructure. This vision has been translated, quantified, and put into action through various policy documents, plans, and initiatives.

India set the ambition to increase the share of gas in its primary energy mix to 15% by 2030. Since 2016, the country has introduced diverse policies to support the penetration of natural gas, ranging from market liberalisation for selected upstream producers, formula-based gas prices, and improved business environment through initiatives like the Hydrocarbon Exploration and Licensing Policy (HELP) with Open Acreage Licensing Policy (OALP), and attraction of infrastructure investments such as city gas distribution. Many of these advancements address long-standing demands from the gas sector.

On the Demand side, India is promoting gas to improve energy access, reduce air pollution, especially in highly populated cities and ensure diversification from oil products. A strong emphasis has been laid on the expansion of the City Gas Distribution (CGD) network across the country.

India has set its sights on expanding its pipeline network to provide free gas connections to the most economically disadvantaged families. Following several city gas licensing rounds, the government announced in 2022 that nearly 98% of the country's population and 88% of its land area would have access to natural gas. In a recent development as of September 2023, India plans to offer 7.5 million complimentary cooking gas connections to households led by women over the next three years, with an estimated financial commitment of approximately \$200 million.

For transportation, the National Auto Fuel Policy, Auto Fuel Vision, and Policy 2025 acknowledge LNG/CNG as the prime alternative to liquid fuels. In 2020, the government unveiled plans to construct 50 LNG fuelling stations along national highways, with a subsequent expansion to 1,000 such stations within three years. Additionally, the transition from Bharat Stage IV emissions standards directly to Bharat Stage VI standards is expected to further incentivise the switch to CNG.

Within CGD, the industrial sector is poised to influence demand significantly. The expansion of micro, small, and medium enterprises, coupled with enhanced accessibility to natural gas, regulatory measures against heavily polluting fuels, and the limited penetration of renewables and electrification, collectively contribute to propelling momentum.

While the expansion of the CGD network is set to persist, the government has abandoned its intentions to incorporate gas power further into its electricity generation. Among all sectors, the power industry is particularly sensitive to price fluctuations.

Consequently, the recent temporary surge in gas prices is currently jeopardising the momentum for coal to gas switching and reinforcing the ongoing reliance on coal.

On the supply side, the government has focused on increasing domestic gas production. To achieve this goal, they actively encourage greater involvement of private sector players in upstream activities. This strategic move has set momentum towards reforming the gas sector, making it more attractive for private sector participation, with key advancements seen in areas such as liberalisation, gas pricing, and marketing reforms. These critical changes have been making notable progress in the past few years.

2.2.1.2 Recent policy developments

During 2023, a significant emphasis of India's energy policy initiatives revolved around the decarbonisation of the energy system and advancing low-carbon fuels.

Hydrogen: In January 2023, India introduced the National Green Hydrogen Mission, a strategic initiative designed to establish India as a global hub for the production, utilisation, and export of green hydrogen and its associated products. The mission sets its sights on achieving a yearly production capacity of 5 Mt of green hydrogen by 2030, coupled with the expansion of renewable energy capacity to approximately 125 GW within the country.

In line with the National Green Hydrogen Mission, the Strategic Interventions for Green Hydrogen Transition Programme (SIGHT) establishes two distinctive financial incentive mechanisms. These mechanisms are set to target the domestic manufacturing of electrolysers and the production of Green Hydrogen. With a 174.9 billion rupee (USD 2.13 billion) incentive approved in 2023, India aims to reduce the production cost of green hydrogen by a fifth over the next five years. The government expects to support 3.6 Mt H₂ production capacity in the next three years under the scheme and to support about 3 GW of annual electrolyser capacity for five years through the scheme.

Coal gasification: India plans to launch a program to bolster coal and lignite gasification projects in the country. This programme is set to use 100 Mt of domestic coal and lignite in gasification projects. The resulting syngas from coal gasification can be processed to produce energy fuel, methanol, and products such as ammonia and urea.

Nuclear: India is exploring a significantly greater role for nuclear power. India targets a three-fold rise in nuclear-installed capacity by 2032 and has 7000 MW plants under construction. However, India is looking forward to the knowledge to establish small modular nuclear reactors (SMRs), which depends on sharing and transferring relevant technologies. For this, India is considering overturning a ban on foreign investment in its nuclear power industry and allowing greater participation by domestic private firms. The emphasis is on private participation through small modular reactors to fast-track nuclear energy generation. The government panel has also recommended replacing old coal-based plants with SMRs.

Carbon trading market: India is establishing domestic regulations and procedures to operate a carbon market. Planning envisages the market becoming fully operational in 2026, covering 37% of the country's emissions. India already has a market for trading certificates in above-target energy

Table 2.1.

Primary government aims in the energy sector

	Global	India
Main policies	<ul style="list-style-type: none"> Achieving universal access to affordable, reliable, and modern energy services by 2030 Increasing the proportion of renewable energy sources by 2030 Promoting access to clean energy research and technology by 2030 	<ul style="list-style-type: none"> Boosting energy efficiency Increasing domestic production Reducing dependence on imports Transitioning towards cleaner energy alternatives
Natural Gas	Transitioning away from fossil fuels in energy systems, in a just, orderly and equitable manner, with recognising the role of transitional fuels in facilitating energy transitions and maintaining energy security	<ul style="list-style-type: none"> Achieving a 15% share of gas in the primary energy mix by 2030. Expanding city gas distribution. Increase domestic gas production. Enhancing regasification capacity to 70 Mtpa by 2030 and 100 Mtpa by 2040
Other fossil fuels	Transitioning away from fossil fuels in energy systems, in a just, orderly and equitable manner	An additional 25.5 GW of coal capacity for the second half of the decade
Renewables	Tripling capacity globally by 2030	500 GW by 2030
Nuclear	Accelerating nuclear	A three-fold rise in nuclear-installed capacity by 2032
Hydrogen	Accelerating low-carbon hydrogen production	Achieving a yearly production capacity of 5 Mt of green hydrogen by 2030.
Emission reduction	43% by 2030, 60% by 2035/2019; net zero by 2050	The emissions intensity reduction to 45% by 2030/2005, carbon neutrality by 2070
Energy efficiency	Doubling the global average annual rate of energy efficiency improvements by 2030	Setting new regulations for the energy consumption of equipment, appliances, buildings, and industries

China	Europe	United States
<ul style="list-style-type: none"> • Prioritising renewables and coal with trading mechanisms to cut energy use and CO₂ emissions • Targeting 84% domestic self-sufficiency by 2025 • Seeking a 20% increase in non-fossil energy in total energy consumption by 2025 	<p>Enhancing energy transition efforts to achieve dual goals: reducing dependence on Russian energy sources and advancing emissions reduction initiatives</p>	<ul style="list-style-type: none"> • Directing significant funding to advance clean energy • Catalysing growth in decarbonization technologies
<ul style="list-style-type: none"> • 230 bcm of domestic gas production by 2025 • Aiming for gas storage capacity of 55-60 bcm by 2025 • Expanding natural gas imports through pipelines and enhance domestic pipeline infrastructure 	<ul style="list-style-type: none"> • Expanding LNG imports from multiple sources • LNG to provide +50 bcma of added gas supply • Pipeline gas demand of at least +10 bcma • EUR 10 billion investment in LNG infrastructure by 2030 to diversify suppliers 	<ul style="list-style-type: none"> • Expansion of LNG exports facilitated • Streamlining of project permitting process • Allocation of funding for CCUS • Implementation of levies on methane emissions"
<p>4.2 billion tonnes of raw coal production by 2025</p>	<p>Strengthened environmental restrictions on coal-based activities</p>	<p>Allocation of funding for CCUS</p>
<ul style="list-style-type: none"> • Aiming for 25% of energy derived from non-fossil sources by 2030 • Ensuring renewables account for at least half of increased electricity demand 	<p>Targeting to 42.5% by 2030</p>	<ul style="list-style-type: none"> • Backed by production and investment tax credits • Establishment of technology-neutral credits • Aim for 100% carbon-free electricity by 2035
<p>Nuclear capacity to 70 GW by 2025</p>	<p>Including nuclear power plants as eligible investments for green labeling</p>	<ul style="list-style-type: none"> • Financial assistance up to USD 15/MWh • Implementation of state zero-emission credit programs
<p>100-200 Kt tonnes of hydrogen annually from renewable sources by 2025</p>	<p>Aiming for 20 Mt of renewable hydrogen production and imports by 2030</p>	<p>10 MtH₂ annually by 2030, 20 Mt by 2040, and 50 Mt by 2050</p>
<p>18% CO₂ intensity reduction by 2025</p>	<ul style="list-style-type: none"> • Aiming for reducing emissions to 55% of 1990 levels by 2030 • Achieving carbon neutrality by 2050 • Implementation of Methane Emissions Reduction regulation, CBAM, and EU ETS revision 	<p>GHG emissions reduction by 26%-28% compared to 2005 by 2025 and by 40% by 2030</p>
<p>13.5% energy intensity reduction by 2025</p>	<p>Targeting an 11.7% reduction in final energy consumption by 2030, capping final consumption at 763 Mtoe and primary consumption at 993 Mtoe in the EU</p>	<ul style="list-style-type: none"> • Tax incentives • Adoption of Energy Efficiency Resource Standards

savings and another for renewables (Renewable Purchase Obligation- or RPO). India's carbon market is being set up in two phases. In the first phase, between 2023 and 2025, the existing tradeable certificates for energy efficiency and renewable energy generation is set to be converted to carbon credits.

2.2.2 China

The core policies shaping the future of energy in China are covered in the 14th FYP for 2021-25, along with its subsequent policy documents published in 2022, including the 14th FYPs for a modern energy system, the 14th FYPs for renewable energy, the first Medium-Term Plan for Hydrogen, and a roadmap for energy storage. These collective documents steer the course for China's energy landscape. However, it is worth noting that adjustments were made in 2023 in response to heightening energy security concerns.

The 14th FYP for a Modern Energy System was the first energy-focused plan to be announced after China's dual carbon goals (the 2030 carbon peaking and 2060 carbon neutrality commitments). The policy shifts the focus of China's energy sector toward long-term transition goals and the construction of a modern energy system to solve both sustainability and supply security concerns. However, the plan is not expected to slow down the development of coal-fired power plants. Instead, it focuses on the "clean and efficient use of coal," implementing trading mechanisms to reduce energy consumption and CO₂ emissions and providing tax credits to support low-carbon development.

Nonetheless, the discourse on energy security has intensified since then, driven by a combination of international pressures and domestic energy supply challenges. The country has adopted a policy strategy of "first, set up the new, then remove the old." In the Party's Work Report released in October 2022, China outlined an all-of-the-above energy strategy for the near term, briefly emphasising and giving equal importance to all of the country's main energy sources in the order of their current size and significance. Subsequently, in the Work Reports delivered by the National Development and Reform Commission (NDRC) and the government in March 2023, the focus on energy security was highlighted, emphasising the need to continue boosting domestic coal supplies, investing in coal power, and increasing domestic production of oil and gas, while limiting energy imports. The recent government Work Report calls for China to "give full play to coal's role as the main energy source," omitting previous calls to "orderly reduce and replace coal."

Additionally, the National Energy Administration (NEA) Guidance for 2023 calls for expediting the commissioning and production of coal mines currently under construction to enhance the capacity to increase coal production and ensure a stable supply. This shift in stance is reflected in the surge of new coal plant approvals observed during 2022-2023, making China the only major economy opens to fresh requests to add significant new coal-fired capacity.

Therefore, fossil fuels continue to play a significant role in China's energy landscape. As the world's largest emitter of CO₂ and with a substantial dependence on coal for energy, China is actively seeking solutions to mitigate its carbon footprint while still utilising its coal resources.

However, renewable energy sources are expected to continue

their growth trajectory, keeping pace with the expansion witnessed in recent years. While the recent government and NDRC Work Reports emphasise coal, they also note the need to advance wind and solar capacity and develop energy storage industries. Renewables continued to be indicated prominently in both reports. Thus, while hydrocarbons appear to have priority, renewable capacity additions high pace will continue unabated.

2.2.2.1 Policy support for natural gas

Over the past decade, China's natural gas consumption has surged due to intensified efforts against air pollution. These actions led to a reduction in the use of low-grade coal and a robust promotion of electricity and natural gas.

For the 2016-2020 period, the government aimed for natural gas to account for 10% of the energy mix, but this was later revised down to 8%, a goal that has been met. At the same time, the government's outlook for domestic production in the 13th FYP – seeking to reach 200 bcm of domestic output, including 30 bcm of shale – has not been met.

The prominence of natural gas as a clean and low-carbon fuel remained steadfast within China's energy policy during subsequent years, as evidenced in the "Action Plan for Carbon Dioxide Peaking Before 2030" (October 2021), where significant emphasis is placed on natural gas' transitional role in carbon emission mitigation.

Aligning with many policy goals, natural gas has upheld its role as a catalyst for energy supply during the 14th FYP period. Contrary to the focus in the 13th FYP on air pollution control, the 14th FYP emphasises climate commitment and energy transitions. The policy focus on managing carbon emissions and enhancing gas infrastructure underscores ongoing support for a higher gas presence within the growing energy mix. This commitment is highlighted by a target for domestic production to reach 230 bcm, as well as a heightened focus on bolstering domestic reserves and output from both conventional and unconventional gas sources. Additionally, the plan sets its sights on achieving gas storage of 55-60 bcm.

China has witnessed a substantial rise in LNG import terminals driven by robust demand growth and complemented by market liberalisation initiatives to facilitate greater participation of non-state entities in gas imports. In response to surging demand, China's strategy remains committed to market reforms, fostering third-party engagement across both upstream and downstream gas activities.

Additionally, China aims to amplify natural gas imports via pipelines. The Power of Siberia pipeline originating from Russia, designed to transmit 38 bcma to China, is anticipated to achieve full operational capacity in 2024-2025. In February 2022, China reached an agreement to import gas from Russia's Far East island of Sakhalin through a novel pipeline, poised to deliver up to 10 bcm annually by around 2026. Furthermore, Russia and China have been engaged in discussions regarding the construction of a second pipeline, the Power of Siberia 2, featuring an annual capacity of 50 bcm.

China also continues to add domestic pipeline capacity. The 14th FYP discusses the need to develop the pipeline infrastructure as well as the digitisation and technological upgrade of the energy sector, including the oil and gas sector. However, with the imperative to concentrate on rural advancement, China's "No.1 document" for 2021 underscores

the inclusion of “promoting rural natural gas utilisation” as a component of the clean energy infrastructure initiative.

Nonetheless, the 14th FYP does not explicitly address the role of natural gas within the energy mix or its contribution to the dual carbon targets. Notably, it lacks a specific goal for the gas share in the energy matrix and omits a target for the gas share in installed power capacity. However, it does distinctly envision a role for natural gas in the power sector to mitigate intermittency. The emphasis on supply security and cost reduction through market reforms, on the other hand, indicates an anticipation of tempered growth in gas demand during the 14th FYP period compared to the previous five years.

On the other hand, China introduced a fresh approach to liberalising natural gas prices in June 2023, a move that could incentivise distributors to explore LNG imports. This new market-based pricing system is anticipated to narrow the price gap between higher-tariff industrial users and residential consumers, fostering a more equitable distribution of fuel costs and potentially stimulating greater participation in the global market. Predictions indicate that this policy shift will ultimately result in more reasonable downstream gas prices, thereby motivating city gas utilities to increase purchases from upstream importers.

However, it is important to acknowledge that this mechanism could also increase residential natural gas prices, as distributors may pass on costs to consumers. After implementing the reform, more than 30 cities and provinces gradually raised residential tariffs by 6 to 20% within a month. Despite these increases, the impact on household demand is expected to be minimal, as subsidies are set to be provided to low-income households to alleviate any resulting difficulties.

Developing a carbon market in China has another potential impact on the natural gas market. China’s national carbon market has been trading for two years. The market only covers China’s power sector, but the plan aims to expand steadily, embracing other emissions-intensive industries, such as steel, non-ferrous metals and building materials. In a carbon-constrained environment, natural gas could become more economically competitive, particularly against coal, a major contributor to carbon emissions.

Examining both the discouraging and encouraging factors for natural gas in China’s energy landscape, it becomes evident that the latter carries more weight and promise for the future. While there have been considerations around supply security and controlled expansions in coal-to-gas projects, the encouraging factors overshadow these concerns. The drive to align with climate goals, secure a robust supply, diversify energy sources, and establish fair pricing mechanisms position natural gas as a central and promising element in China’s energy strategy. The encouraging factors undoubtedly outweigh the potential challenges, emphasising natural gas as a pivotal player in China’s sustainable energy future.

2.2.3 The United States

The United States energy transition has gained momentum under the current presidential administration. Key legislation such as the IIJA and the IRA drive the country toward its climate goals.

The convergence of market forces, regulations, and technological advancements has spurred both public and

private sectors to commit to a net-zero future. The IIJA focuses on upgrading infrastructure to integrate more renewable energy, expand electric vehicle charging networks, and reduce CO₂ emissions in power generation. Meanwhile, the IRA represents a major investment in clean energy projects and provides support for energy efficiency, electric vehicles, low-carbon hydrogen, carbon capture and methane emissions reduction. In the coming decade, the IRA is set to direct a considerable amount of funding towards initiatives that advance clean energy and have the potential to catalyse significant growth in decarbonisation technologies. Notably, it is anticipated that renewables could be the primary beneficiaries of the IRA’s provisions, positioning them for substantial gains.

The IRA introduces tax incentives to drive electrification in buildings, maritime ports, and heavy-duty vehicle fleets, resulting in a faster and larger shift toward electrification than previously anticipated. Subsequently, the United States administration in May 2023 launched a USD 4 billion effort to electrify United States ports and cut heavy-duty truck emissions. Concurrently, the federal government is targeting achieving 100% carbon-free electricity by 2035, pursuing this objective by leveraging renewables, carbon capture technologies, and existing nuclear power facilities.

The legislation also doubles tax incentives, for many home energy efficiency improvements. Expanding tax incentives for home energy efficiency improvements and establishing Corporate Average Fuel Economy (CAFE) vehicle standards advance the transition. CAFE requires the average fuel economy of new light vehicles sold in the United States to reach 5.9 litres/100 km and increase by 8% and 10% in 2025 and 2026 to contribute to the overall transition.

Notably, the IRA also supports other fuels. It supports the oil and gas industry through CCUS incentives while imposing taxes and fees on emissions and extraction. Clean hydrogen production also receives significant attention with a considerable subsidy in IRA, accelerating development timelines for hydrogen projects. Additionally, nuclear energy gains recognition as a crucial element in emissions reduction efforts, with financial support channels from both the IRA and the IIJA ensuring the survival of nuclear plants.

Overall, these legislative measures drive a comprehensive energy transition strategy with quantifiable targets and incentives across various sectors. As a result, the United States is expected to remain on course to achieve its NDC target of reducing GHG emissions by 26%-28% below 2005 levels by 2025 and by 40% from 2005 levels by 2030.

In the year since the law’s passage, the IRA, in tandem with the IIJA, has underpinned a stunning clean energy boom powering United States manufacturing revitalisation. Anchored by an ambitious suite of incentives to build and deploy climate solutions in the United States, the package has unlocked a more considerable surge in private investment across the country. During the period of August 2022 until the end of July 2023, companies have announced more than USD 270 billion in planned clean energy projects.

2.2.3.1 Recent policies influencing the natural gas sector

Boosting LNG exports: The United States is expanding its LNG exports to rival energy-exporting countries such as Russia. Recently, the administration approved LNG exports from Alaska

in April 2023, with expectations of opening the project by 2030. These proposed exports primarily target Asian markets. The IRA supports the oil and gas sector by streamlining project permitting and expediting the acquisition of federal leases for both onshore and offshore endeavours.

Furthermore, the administration is engaging in discussions with global energy firms and foreign officials to establish standards for certified natural gas, positioned as an environmentally friendly fuel. This endeavour aligns with the United States intent to boost LNG exports to Europe, reducing reliance on Russian energy while promoting climate change mitigation. The creation of a credible certified natural gas market could effectively address both objectives. Producers can gain low- or no-carbon certification by demonstrating emission reductions during production and transportation or by purchasing carbon offsets to mitigate their net climate impact.

Prior to this initiative, the United States had extended CCUS funding through the IIJA and the IRA further propelled this encouragement. Moreover, the legislation levies a price on methane emissions for both offshore and onshore producers, natural gas processing, transmission, and compression, along with underground gas storage, LNG facilities, and gas gathering and boosting stations. This fee starts at USD 900 per tonne in 2024 and increases to USD 1,500 per tonne in 2026.

Moreover, the inaugural United States Methane Emissions Reduction Action Plan, initially presented at COP26 and updated in 2022, highlights augmented ambition and strides towards achieving substantial methane reductions within the country. This strategy encompasses more than USD 20 billion in new investments to curb methane emissions, sourced from the IIJA, IRA and annual appropriations. The enhanced plan outlines a comprehensive strategy, elaborating on over 50 initiatives the administration is undertaking to address methane emissions domestically.

Transformation for the power sector: In May 2023, the Biden administration unveiled a pivotal plan to cut GHG emissions from the United States power sector. This proposal sets technology-based standards for individual power plants and pushes power companies to adopt CCUS or low-emission hydrogen as fuel sources.

According to the proposal, new and existing large natural gas plants are expected to install CCUS that removes 90% of their

carbon emissions by 2035 or co-fire with 30% hydrogen by 2032 and 96% hydrogen by 2038. New gas-fired plants, used as the backup generation, would face less stringent standards. For existing coal plants, the Environmental Protection Agency (EPA) is set to consider their planned lifespan. For example, coal plants that run past 2040 will be required to install CCUS technology starting in 2030, while those shutting between 2035 and 2040 will be required to co-fire with 40% gas by 2030.

This proposal is subject to regulatory processes, and public input before finalisation, with proponents highlighting environmental benefits and opponents expressing concerns over grid stability and costs. The EPA justifies the standards through the upcoming IRA Act, which provides financial incentives for CCUS and green hydrogen adoption.

The United States government power plant proposal presents a huge test for CCUS. This plan envisions an unprecedented large-scale application of CCUS and green hydrogen within the next decade, prompting inquiries into the capabilities of these climate-mitigating technologies to meet the demands. A successful implementation could propel the United States toward achieving net-zero emissions from the power sector.

New emission standards for heavy-duty trucks: In

June 2023, significant updates to clean air standards were sanctioned for heavy-duty trucks, marking the first substantial revision in over two decades. These standards, which are 80% more stringent than current standards, significantly curb emissions that contribute to smog and soot formation. They focus on heavy-duty vehicles (HDV) and are set to take effect in the model year 2027.

In April 2023, the EPA introduced new GHG emissions standards for HDV, labelled as Phase 3. These proposed standards, targeted at HDVs for the upcoming model years 2028-2032, represent the EPA's strictest regulations ever. If approved, the phase 3 standards would achieve a substantial 29% reduction in GHG emissions from HDVs below 2021 levels by 2032. These proposed standards encompass a wide range of HDVs, spanning trucks, buses, and trailers. They would be gradually introduced over time, with the most demanding requirements applicable to vehicles from the model year 2032 onwards.

Clean hydrogen: Recent legislation and incentives have laid the groundwork for hydrogen project investments. The IIJA allocates up to USD 8 billion in funding to establish six to ten regional hydrogen hubs in the United States. Additionally, there is a dedicated USD 1 billion earmarked for enhancing the efficiency and cost-effectiveness of electrolysis technology. The IIJA also mandates that the Department of Energy (DOE) explore and support opportunities for hydrogen production from various energy sources, including fossil fuels, with CCUS. These opportunities encompass regions in the United States abundant in natural gas, suitable CO₂ storage reservoirs, or existing natural gas supply infrastructure.

The IRA introduces a clean hydrogen production tax credit, offering up to USD 3 per kg of hydrogen, along with a USD 85 credit for every metric tonne of CO₂ sequestered. This legislation has spurred the gas section to invest in large-scale clean hydrogen facilities, prioritising production incentives, fostering market expansion, and affording the private sector the necessary flexibility for substantial investments.

As of January 2023, North America boasts 135 projects, as reported by the Hydrogen Council, with ambitions for either full or partial commissioning by 2030. Collectively, these projects represent a substantial investment, totalling USD 46 billion in direct funding through 2030, a notable increase from the USD 29 billion reported in the previous year. Of particular interest is that nearly 75% of these announced projects are focused on producing blue hydrogen, a variant derived from natural gas but featuring a process that captures and stores the CO₂ emissions generated in its production.

The United States National Clean Hydrogen Strategy and Roadmap, introduced on June 5, 2023, bolsters existing legislation by presenting a comprehensive plan to accelerate clean hydrogen production, processing, delivery, storage, and utilisation across the United States. It charts a path to reach substantial clean hydrogen production goals: 10 Mt H₂ annually by 2030, 20 Mt by 2040, and 50 Mt by 2050. The strategy focuses on three key objectives:

- a. Target high-impact uses: Prioritise clean hydrogen in sectors like industry, heavy-duty transportation, and energy storage for maximum impact.
- b. Reduce cost: The Hydrogen Shot (USD 1 per 1kg H₂ in one decade) aims to lower clean hydrogen production costs through innovation and infrastructure development.
- c. Regional networks: Invest in Regional Clean Hydrogen Hubs to promote large-scale production near major users, driving growth, sustainability, job creation, and domestic investment.

However, the Hydrogen Council foresees that beyond 2032, once the incentives from the IRA expire, renewable hydrogen, despite all the innovation, scaling up, and manufacturing and supply chain developments, is expected to remain costlier than grey hydrogen.

2.2.4 The EU

In response to geopolitical developments in 2022, the EU intensified its energy transition efforts and revised targets established in the Green Deal (2019) and the Fit for 55 package (2021). It also acknowledged the urgent need for immediate measures to diversify its natural gas supply sources. The May 2022 REPowerEU plan provides a blueprint that outlines the steps and resources necessary to no longer import Russian gas by 2027, including measures to enhance energy efficiency, increase supply diversification (with a focus on LNG), and accelerate the deployment of renewable energy sources.

According to this plan, the EU is poised to increase its import of LNG from more suppliers in the coming years. LNG is expected to contribute the most incremental gas (+50 bcm/a), offering significant supply diversity, while pipeline gas (+10 bcm/a or more) is expected to also be required. Investing €10 billion in constructing LNG infrastructure through 2030, which is a part of this plan, is anticipated to also augment the opportunity for gas supply to originate from a growing number of sellers.

The EU External Energy Strategy is another part of the REPowerEU Plan that sets out how the EU will work with its neighbours. It plans to negotiate with different countries for additional gas and hydrogen supplies, including the United States, Canada, Norway, Egypt, Qatar, Algeria, Azerbaijan, Nigeria, Senegal, and Angola.

Before 2022 and as part of the Fit for 55 package, the EU Commission proposed the Gas and Hydrogen package to update the existing market design for natural gas while also introducing a similar framework for hydrogen and bio-methane. However, following geopolitical developments and natural gas supply deficits in 2022, the EU had to implement emergency measures, which challenged the liberalisation of the gas market. They included the Gas Storage Regulation in June 2022, the Market Correction Mechanism (wholesale gas price cap), and the Gas Demand Aggregation and joint purchasing platform in October 2022.

2.2.4.1 Recent policy developments

The Green Deal aims to put the EU on a path to climate neutrality by 2050 through the decarbonisation of all economic sectors. Under the Fit for 55 packages, each proposal (notably revisions of the Renewable Energy Directive, the Energy Efficiency Directive, the Emission Trading System, the CBAM, the Tax Directive, and the Methane Emissions Reduction regulation) was drafted, taking into account the vision and overarching target to reduce GHG emissions by 55% by 2030.

Several proposals, such as the EU ETS revision and the introduction of the CBAM, were initially adopted by the EU co-legislators before 2023. However, numerous revisions and additional measures have been introduced during 2023. The most significant of these are outlined below:

Transport section: in March 2023, EU countries agreed on new rules on decarbonising EU maritime transport. It requires gradually cutting CO₂ emissions of large ships below the 2020

level (91.16 gCO₂/MJ of energy used) by 2% as of 2025, 6% as of 2030, 14.5% as of 2035, 31% as of 2040, 62% as of 2045 and 80% as of 2050. The emission cap would apply to big ships (above a gross tonnage of 5,000), which account for 90% of maritime emissions, and to all energy used on board in or between EU ports, as well as to 50% of energy used on voyages where the departure or arrival port is outside of the EU or in EU outermost regions. They also approved a law in March to end sales of new CO₂-emitting cars by 2035, with an exemption for e-fuel vehicles. This law sets zero CO₂ emission targets for new cars by 2035 and a 55% reduction by 2030 compared to 2021. In February, the European Commission proposed a 2040 target for reducing CO₂ emissions from new trucks by 90%, with discussions in June considering a 100% cut. Negotiations with EU member governments will follow an upcoming EU lawmaker vote. The EU also aims to end free allocations for aviation by 2026 and foster sustainable aviation fuels. An agreement reached in April 2023 between the Parliament and the Council promotes the adoption of alternative aviation fuels such as used cooking oil, synthetic fuel, and hydrogen, aiming to achieve a goal of 70% sustainable aviation fuel usage at EU airports by 2050. Moreover, there are outlined specific escalating quotas for synthetic fuels, particularly e-kerosene, which are expected to increase, reaching a target of 35% by the year 2050.

Energy efficiency: In July 2023, the Council adopted the new Energy Efficiency Directive. The previous 2018 directive aimed to cut EU energy consumption by 32.5% by 2030, based on 2007 forecasts. The new regulations mandate an 11.7% reduction in final energy consumption by 2030, compared to 2020 forecasts, capping the EU's final consumption at 763 Mtoe and primary consumption at 993 Mtoe.

Renewables: In September 2023, EU legislators raised the target to 42.5% by 2030, up from the previous 32% target. The revised targets aim to boost renewable use in transport and industry, spurring more investments in wind and solar.

Furthermore, the EU has updated its TEN-E policy, effective in June 2022, focusing on connecting European energy infrastructure through eleven priority corridors and three thematic areas. This updated policy emphasises renewable energy integration, streamlined permitting, and enhanced cooperation, including offshore grid development and regional agreements for offshore renewable expansion by 2050.

Priority corridors include electricity, offshore grids, and hydrogen infrastructure, while thematic areas encompass smart grids, smart gas grids, and cross-border CO₂ transport networks. Concerning the CO₂ network section, TEN-E addresses the transport and storage of CO₂ within the EU and with neighbouring countries, primarily emphasising pipelines, CO₂ storage facilities, and associated surface and injection facilities.

Regarding hydrogen and natural gas, the TEN-E policy introduces enhanced regulatory measures to promote low-carbon hydrogen. It offers increased support for decarbonising gas networks, establishing a legal and regulatory framework for repurposing existing gas infrastructure to accommodate hydrogen transport. Under TEN-E, existing gas networks can be repurposed to transport hydrogen with EU financial support available until the end of 2027.

Additionally, projects linked to repurposing can transport hydrogen-methane blends until the end of 2029. Notably, a substantial portion of the European Hydrogen Backbone (EHB)

is expected to utilise repurposed gas networks. Moreover, the Complementary Climate Delegated Act, published in July 2022, includes gas energy activities in the list of economic activities covered by the EU Taxonomy. This green classification system identifies environmentally sustainable economic activities, leading to more confident investment and financing.

Green technology: To support green technology, the European Commission took two significant steps. On March 10, they adopted new state aid rules known as the Temporary Crisis and Transition Framework (TCTF), which streamline the approval process for national support measures under state aid rules, with a focus on sectors essential for the transition to a net-zero economy, such as battery manufacturing, solar panels, wind turbines, heat pumps, electrolysers, and CCUS. Additionally, on March 16, the Commission proposed the Net-Zero Industry Act to boost the production of strategic net-zero technologies. The act targets at least 40% of the annual deployment needs for these technologies to be manufactured in the EU by 2030. It encourages countries to employ various policies, including permitting, subsidies, and procurement, to achieve this goal. The Net-Zero Industry Act also designates CCS as a "strategic net-zero technology," streamlining permitting and funding processes for CCS projects. It includes an ambitious EU injection-capacity target of 50 Mt per year by 2030, aligning with European climate targets and incentivising large-scale CCS development.

European Emissions Trading System (ETS): The EU revised the ETS in April 2023 to better align it with its emission reduction goals. Previously, the ETS governed approximately 40% of the European Union's total GHG emissions. The revised ETS aimed to achieve a 62% reduction in emissions from the covered sectors by 2030 compared to 2005. It also includes the phasing out of free allowances and the establishment of a new ETS II for road transport and building fuels. Furthermore, The EU will squeeze the carbon market cap in 2024 by accelerating the reduction in the supply of permits. With these stricter reforms in place and carbon-emitting companies competing for a reduced number of permits, carbon prices are expected to increase in the coming years.

CBAM: In October 2023, the EU initiated the initial stage of its carbon border tax mechanism, compelling importers to disclose the CO₂ emissions associated with products entering Europe, including items such as steel and cement, under the threat of potential financial penalties. The primary objective of this new system is to shield domestic EU industries from unfair competition by foreign counterparts with higher pollution levels while these EU industries make efforts to decrease emissions. Upon full implementation in 2026, imports to the EU are poised to be subjected to a CO₂ fee equivalent to the fees already paid by European companies in the EU's carbon market.

EU Methane Regulation: In November 2023, the European Union finalised its first major methane regulation. This regulation mandates new protocols for measuring, reporting, and verifying methane emissions in the oil, gas, and coal sectors within the EU. Under these rules, companies are required to conduct regular inspections of above-ground infrastructure and promptly repair any detected methane leaks. Additionally, the regulation restricts most practices of flaring and venting, where companies deliberately burn off or release methane into the atmosphere. By 2030, these regulations will also apply to imported fossil fuels, requiring importers to ensure that their foreign suppliers comply with the same standards.



3

Energy Demand Outlook

Highlights

- ▶ Global primary energy demand is projected to increase from 14,960 Mtoe in 2022 to 17,925 Mtoe in 2050, corresponding to a 20% increase and an average annual growth rate of 0.6%. The Asia Pacific region is expected to represent about half of this increase.
- ▶ Africa is positioned to become the second-largest contributor to incremental primary energy demand, accounting for 25% of the total increase and adding 750 Mtoe over the forecast period.
- ▶ While fossil fuels are expected to maintain their dominant position in the global primary energy mix, their share is forecast to decrease from 80% in 2022 to 63% in 2050.
- ▶ Natural gas is anticipated to experience an average annual growth rate of 1% over the forecast period, ultimately surpassing coal as the second-largest energy source by the latter half of the 2020s and converging oil's position by 2050.
- ▶ During the ongoing energy transitions, renewables are expected to grow at the highest rate, contributing to a more diversified structure of the global energy mix, with their share projected to increase from 3% in 2022 to 17% in 2050.
- ▶ Due to the rapid expansion of electrification, a combination of natural gas and renewables is forecast to account for around 68% of the total electricity supply by 2050. CCUS technologies are set to gain momentum and significantly contribute to low-emission electricity generation.
- ▶ The demand for hydrogen is set to experience a substantial surge, rising from 101 MtH₂ in 2022 to around 298 MtH₂ by 2050. Asia Pacific and Europe are anticipated to emerge as the leading demand centres, representing just above 70% of the expanded market.
- ▶ Hydrogen generated from natural gas is projected to contribute 43% to the total hydrogen generation by 2050, with over 85% of hydrogen generation sourced from renewables and natural gas over the forecast period.
- ▶ Global energy-related emissions are poised to peak in 2025, subsequently undergoing an 18% reduction, culminating in 32.1 GtCO₂e by 2050, a decrease from the current 39.3 GtCO₂e. This reduction is particularly noteworthy in the power generation sector and across the Asia Pacific region. It underscores the influence of heightened policy backing for decarbonisation initiatives, particularly in the forthcoming decade.
- ▶ Despite a forecasted 2.5% annual improvement in energy efficiency from 2022 to 2050, there is no sign of decoupling between energy use and economic activity on a global scale. The Asia Pacific region is expected to outperform the global average, achieving a 3.3% enhancement in energy efficiency by 2050.

3.1. Global primary energy demand outlook

In 2022, the global energy crisis brought back energy security to the top of the priority list. This has spurred greater focus on deploying renewable energy sources and other cleaner technologies as key solutions to address the challenges posed by the crisis. Simultaneously, these measures align with broader energy transition goals harmonising with climate change policies.

Nevertheless, even as there is a concerted push for the accelerated development of low-carbon energy sources, it remains imperative to strike a delicate balance between meeting economic and societal needs and adhering to environmental considerations. Hence, it becomes evident that a multidimensional approach is the most prudent course of action when navigating the complex terrain of long-term energy and climate objectives.

While climate change policies are poised to retain their pivotal role in shaping the energy landscape, it is essential to underscore that energy security, affordability, and sustainability are set to continue to hold equal importance. Within this overarching context, the oil and gas industry is positioned to serve as a foundational element of the solution. In this light, the Reference Case Scenario (RCS) adopts a pragmatic and realistic perspective, recognising the indispensable role of natural gas and oil. These hydrocarbons are underscored for their substantial contributions to the current global energy mix and their capacity to significantly achieve long-term objectives, particularly in tackling energy poverty and delivering reliable and affordable modern energy sources to consumers. Natural gas, renowned for being the cleanest burning hydrocarbon, holds a pivotal role in facilitating just, equitable and orderly transitions, while ensuring energy security.

The RCS anticipates a significant transformation in the energy sector over the next three decades. Global primary energy demand is projected to increase from 14,960 Mtoe in 2022 to 17,925 Mtoe in 2050, corresponding to a 20% increase (Figure 3.1). The average annual growth rate is 0.6%, notably slower compared to the historical average of 1.8% observed between 2000 and 2022, a period which witnessed a 50% expansion in global energy demand.

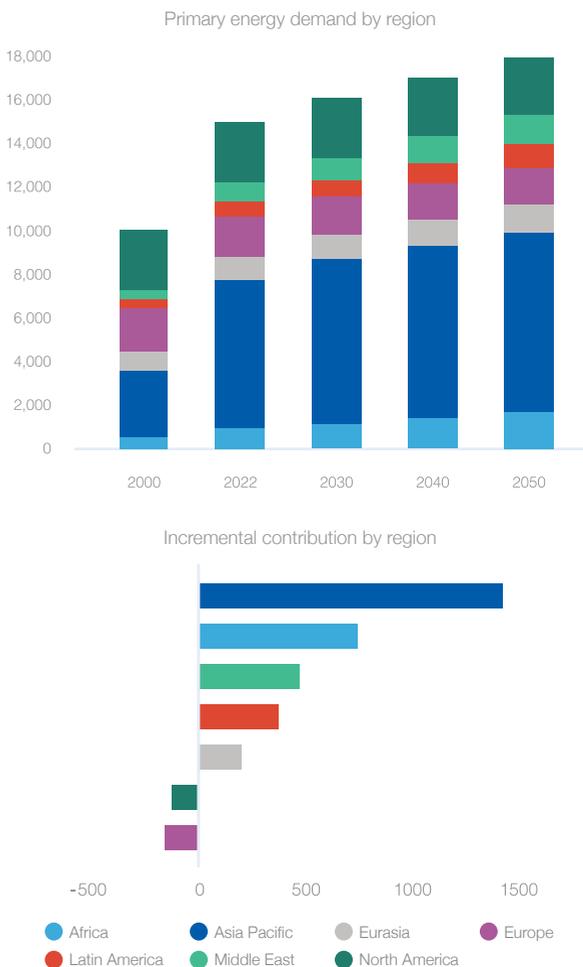
The deceleration in energy demand growth can be attributed to the more rapid improvement in primary energy intensity relative to GDP. Over the 2022-2050 period, the primary energy intensity of GDP (on a Purchasing Power Parity basis) is expected to decrease by 2.5% p.a., in contrast to the historical reduction rate of 1.5% p.a. during 2000-2022 period. Consequently, despite the ongoing expansion of the global economy, population growth, and urbanisation trends, the future surge in energy demand is expected to be reduced by substantial advancements in energy efficiency.

These efficiency gains are improved by market and non-market based policies and measures aimed at fostering a low-emission transitions, coupled with technological advancements, notably in the realms of digitalisation and artificial intelligence. Furthermore, the greater electrification of end-use activities (the RCS projects electricity to meet over 29% of the total final energy demand in 2050, compared to 21% in 2022) plays a pivotal role in supporting this trend. Additionally, the shifting composition of global GDP towards the less energy-intensive

service sector, observed in both developed and developing countries, further reinforces this trajectory.

Figure 3.1.

Primary energy demand outlook, 2000-2050 (Mtoe)



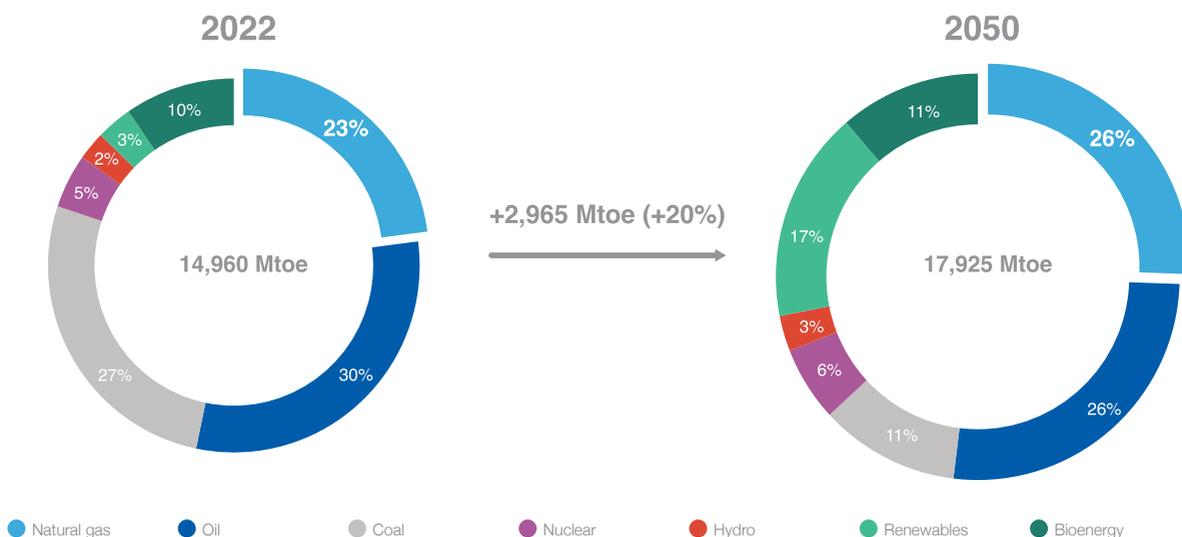
Source: GECF Secretariat based on data from the GECF GGM

An examination of the regional breakdown of primary energy demand growth reveals that approximately 1,450 Mtoe, accounting for nearly 50% of the global increase between 2022 and 2050, is anticipated to originate from the Asia Pacific region. This surge is set to be propelled by the rapidly expanding economies of China, India, and Southeast Asia, which boast substantial and growing populations. Furthermore, Africa is poised to become the next significant contributor to incremental energy demand, accounting for 25% of the total increase and adding 750 Mtoe over the forecast period. This growth is expected to be bolstered by increased access to domestic energy resources.

The Middle East and Latin America are also poised to witness robust growth, with their energy demand projected to rise by nearly 470 Mtoe and 375 Mtoe, respectively. This growth is in response to ample energy supply and economic expansion in these regions. Conversely, Eurasia is expected to exhibit the smallest additional demand, totalling around 200 Mtoe between

Figure 3.2.

Global primary energy mix outlook (%)



Source: GECF Secretariat based on data from the GECF GGM

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

2022 and 2050. This modest level of growth can be attributed to the region’s significant potential for energy efficiency improvements, achieved through the replacement of older energy-intensive capital equipment.

In North America, energy demand is projected to decline by 125 Mtoe over the forecast period. Most of this reduction is expected to occur in the US, influenced by factors such as slow population growth, notable improvements in energy efficiency (especially in road transport). In Europe, a more pronounced decline in energy demand is forecast, estimated at 160 Mtoe by 2050. Several factors contribute to this decline, including moderate economic development, a declining population, the adoption of more efficient technologies and the impact of energy policies targeting carbon neutrality.

In the realm of inter-fuel competition, fossil fuels are poised to maintain their dominance in the global primary energy mix, albeit at a reduced share. They are projected to comprise 63% of the mix in 2050, down from 80% in 2022 (Figure 3.2). Oil will continue to play a significant role but is expected to see a decline in its share, slipping from 30 to 26%. Meanwhile, coal’s share is anticipated to plummet steeply from 27 to 11% over the forecast period, driven by countries’ commitments to reduce coal consumption in line with environmental goals.

On the other hand, natural gas, currently satisfying 23% of the world’s primary energy demand, is projected to increase its share to nearly 26% by 2050. It is poised to play a pivotal role in meeting the growing demand for clean and affordable energy.

Furthermore, the increasing emphasis on decarbonisation initiatives and commitments to achieve zero-carbon goals are anticipated to lead to a substantial contribution from non-fossil fuels, resulting in a more diversified global energy mix. Renewables, in particular, are expected to play a central role, with their share rising from 3% in 2022 to 17% in 2050. Additionally, the growing output of nuclear and hydro energy sources is forecast to capture a 9% share by 2050, slightly

higher than in 2022. Moreover, there is an expected increase in global bioenergy demand driven by the expanding use of modern forms of biomass.

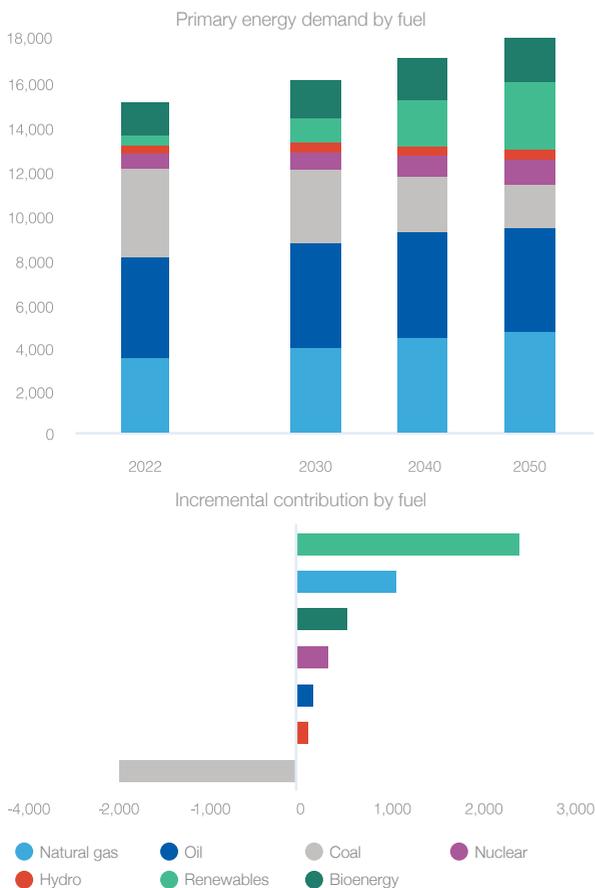
As a result, ongoing energy transitions are in progress, with both natural gas and renewables poised to gain in significance. They are expected to be the primary contributors to the incremental growth in global energy demand, as illustrated in Figure 3.3. Natural gas, in particular, holds a pivotal role as a global enabler for continuous and substantial emissions reduction by substituting carbon-intensive fuels, such as coal, and providing backup and stability support to variable and intermittent renewables. Simultaneously, the emission mitigation potential of natural gas is expected to increase with the greater deployment of decarbonisation options. These options include natural gas coupled with carbon capture, utilisation, and storage (CCUS), as well as the production of blue hydrogen and blue ammonia. These advancements are assumed to establish a leading role for natural gas in the long-term energy landscape.

As detailed in Chapter 4, Section 4.2, the demand for natural gas is on the rise across various sectors, including power generation, industry, the transport sector, and as a source for blue hydrogen generation. This increasing consumption is expected to bolster natural gas’s position globally. Several factors contribute to this growth, including robust policy initiatives aimed at improving air quality, continued shifts from oil and coal to natural gas, its role as a backup for intermittent renewable energy sources like wind and solar, as well as hydroelectric power during periods of drought. Additionally, factors such as population growth, rising needs for petrochemicals and fertilisers, industrial development, and a surge in electricity demand further drive the demand for natural gas. The projection anticipates a steady annual growth rate of 1.0%, resulting in an increase in natural gas demand from 3,432 Mtoe in 2022 to approximately 4,585 Mtoe by 2050, marking a 34% increase. By the latter half of the 2020s, natural gas is anticipated to surpass coal as the second-largest energy

source. Considering that oil demand is expected to plateau in the early 2040s, natural gas is projected to come close to oil in terms of consumption by the end of the projection period. The following section will provide a more comprehensive examination of various energy sources.

Figure 3.3.

Global primary energy demand outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

3.2. Primary energy demand outlook by fuel

3.2.1 Oil

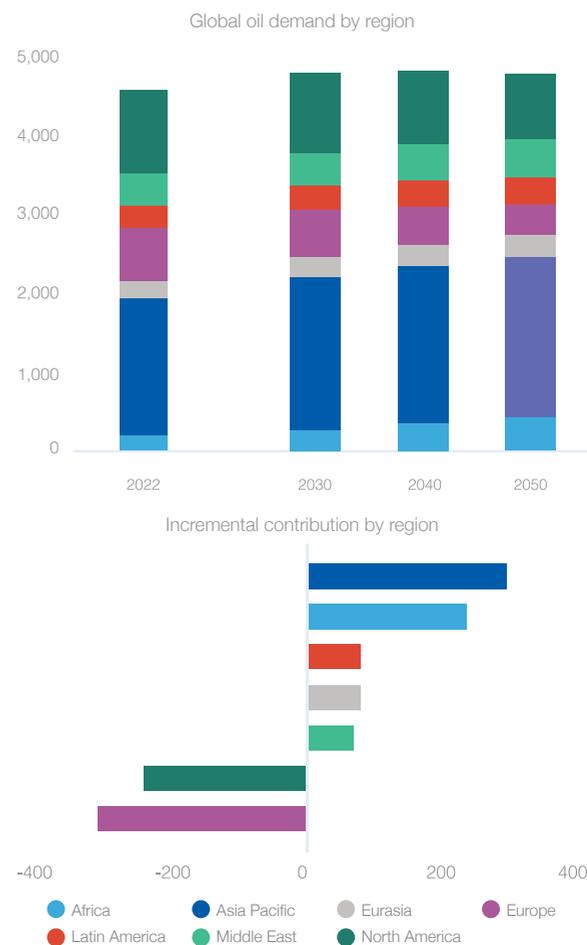
The global oil market has witnessed significant fluctuations in recent years, marked by the largest recorded decline in oil demand in 2020 and a subsequent partial recovery in 2021. In 2022, despite considerable geopolitical instability and resulting spikes in energy prices, the recovery of global oil demand persisted. Oil demand is expected to continue growing in the coming years as it realigns with economic activity during the post-COVID-19 recovery. However, it is worth noting that this growth faces significant challenges, including the potential slowdown of economic growth as a result of inflationary pressures and high interest rates as well as energy policies leading to progressive electrification of road transport.

Global oil demand is projected to experience a modest increase of 0.1% p.a., rising from 4,535 Mtoe in 2022 to 4,725 Mtoe in

2050, representing a 4% overall growth. However, this growth trajectory is characterised by distinct phases. Oil demand is expected to continue its upward trend in the coming decades, ultimately reaching a plateau in the early 2040s, stabilising at approximately 4,775 Mtoe (Figure 3.4). This deceleration in demand growth can be attributed to several factors, including the substitution of oil with biofuels, natural gas, and electricity, the increasing adoption of electric vehicles (EVs), natural gas vehicles (NGVs), and hydrogen fuel cell vehicles in the transport sector, as well as efficiency improvements across various industries. Additionally, the power generation sector is expected to reduce its reliance on oil. These developments are anticipated to counterbalance the growing use of oil as a feedstock in the petrochemical manufacturing sector.

Figure 3.4.

Global oil demand outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

The global oil demand outlook reflects divergent trends between developed and developing countries. The overall projected growth in global oil demand masks a gradual decline in demand in Europe, North America, as well as certain Asian countries like Japan and South Korea. These declines are primarily driven by the substitution of oil and the electrification of road transport, along with policies aimed at displacing oil in industrial and residential sectors. Europe leads this trend, with oil demand in the region expected to decrease by 290 Mtoe, equivalent to a 43% reduction between 2022 and 2050.

Conversely, all the growth in oil demand is expected to originate from developing countries, with India, China, Southeast Asia, and Sub-Saharan Africa at the forefront of this expansion. It is important to note that the oil demand forecast indicates significant incremental growth in major oil-consuming countries, particularly China, from 2022 to 2030. However, this growth is expected to slow down for the remainder of the forecast period and eventually experience a small decline during the 2040s.

3.2.2 Coal

In 2022, there was a notable increase in coal demand, primarily driven by concerns related to energy security. Growth in coal consumption was particularly evident in India and Europe, where power plants shifted away from natural gas and filled the supply gap created by reduced production from other sources, including nuclear and hydro power. Meanwhile, in China, coal consumption experienced a modest uptick as the economy continued to struggle with sluggish growth attributed to COVID-19 restrictions.

In response to the recent energy crisis, some Asian countries, especially China and Pakistan have announced the construction of new coal-fired power plants that rely on their domestic coal supplies. China, in particular, approved 106 GW of new coal-fired projects in 2022 and greenlit an additional 50 GW in the first half of 2023. However, it is important to recognise that this renewed interest in coal is expected to be short-lived. As energy markets stabilise, the structural decline in global coal demand is anticipated to return, while efforts to reduce emissions, improve energy efficiency and enhance air quality are set to intensify.

According to the RCS, global coal demand is projected to decline by 2.5% p.a., falling from 4,020 Mtoe in 2022 to 2,005 Mtoe in 2050, representing a 50% decrease. This outlook underscores the global commitment to enhance energy efficiency and address climate change. Over the forecast period, coal demand is expected to decrease across various sectors, with the most significant reduction anticipated in power generation, responsible for more than 75% of the overall decline. This decline is driven by environmental concerns, carbon pricing, supportive policies favouring natural gas as a fuel switch, and the expansion of renewables. Additionally, coal consumption is set to continue its gradual decline in the residential and industrial sectors, driven by policies aimed at improving air quality. However, coal is likely to retain importance in certain industrial processes, particularly in the production of iron, steel, and cement, where substitution options are limited. The incorporation of CCUS facilities in some coal plants may extend their operational life while aligning them with environmental goals.

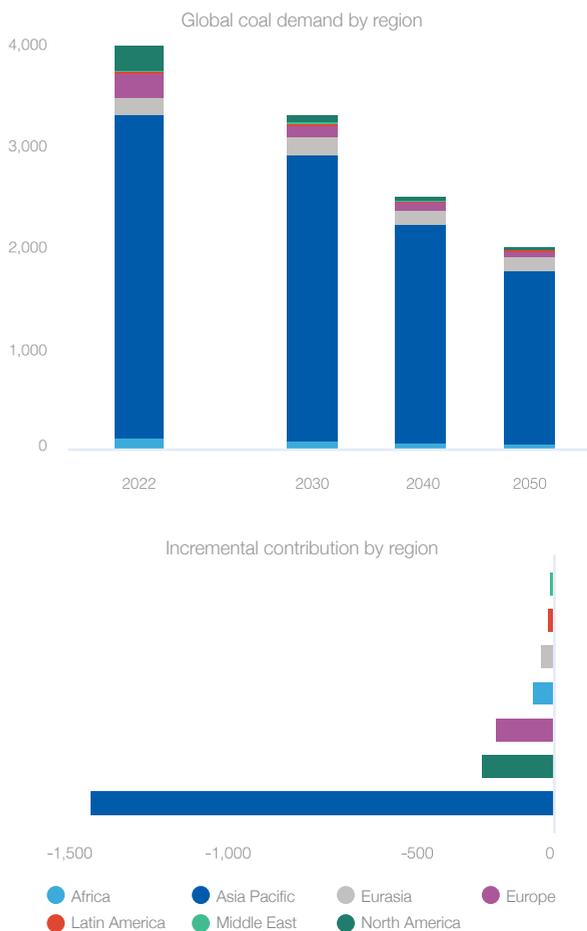
Regionally, North America and Europe are expected to witness the most significant declines in coal demand, particularly before 2040, as many countries in these regions accelerate their coal phase-down efforts in power generation. The US, in particular, benefits from access to cheap natural gas and is projected to rapidly adopt renewable energy sources driven by policies like the IRA.

As depicted in Figure 3.5, the Asia Pacific region is anticipated to account for the largest share of the global decline in coal demand, representing approximately 74% of the total reduction between 2022 and 2050. However, the outlook for coal in the Asia Pacific region varies. China is expected to lead the decline in coal consumption, with significant reductions also seen in Japan, South Korea, and Australia. In contrast, India is poised

to experience a substantial increase in coal usage, with growth only beginning to slow after 2040. Factors such as rapidly rising electricity demand, energy security considerations and the availability of domestic coal reserves are expected to drive this trend.

Overall, despite global commitments to reduce coal usage for environmental reasons, coal is likely to remain a critical energy source in many countries across South and Southeast Asia due to considerations related to energy security and affordability.

Figure 3.5. Global coal demand outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

3.2.3 Nuclear

After a decade of slow deployment, primarily in response to the Fukushima disaster, many countries are now reconsidering nuclear power as a viable option to support their climate targets. Nuclear power offers the advantage of providing a reliable and carbon-free baseload power supply with low variable costs. The recent energy crisis has further accelerated interest in nuclear power as a means to enhance energy security.

Several countries with historical nuclear programmes, including France, Japan, South Korea, and the US, are extending the operational lifetimes of existing plants and reversing previous phase-out plans. Additionally, support for new nuclear reactors

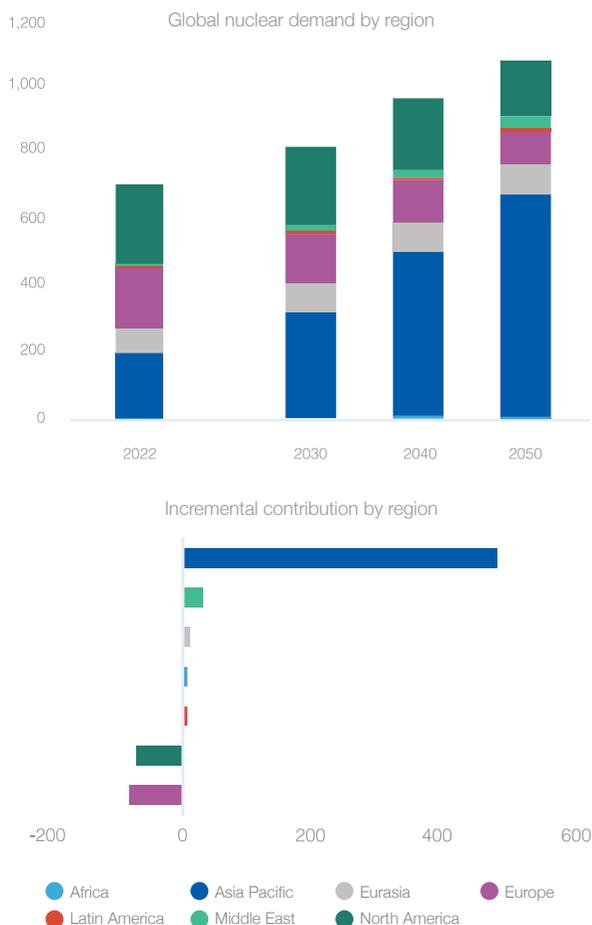
has been announced or expedited in countries such as China, India, Iran, Russia, the UK, and various EU member states. Several countries, including Egypt, Bangladesh, Poland, Saudi Arabia, and Türkiye, are also considering a shift toward nuclear power.

However, it is important to note that while new nuclear capacity is being added, this is offset to some extent by the permanent shutdown of ageing nuclear plants. A significant portion of the existing nuclear capacity is now between 30 and 40 years old, posing a challenge to the expansion of nuclear power in the coming years.

Assuming the strong policy push outlined in the RCS, nuclear energy demand is projected to grow by 1.5% p.a., increasing from approximately 700 Mtoe in 2022 to nearly 1,070 Mtoe in 2050, marking a 53% rise. Figure 3.6 illustrates the expected evolution of nuclear energy demand and its regional distribution.

Figure 3.6.

Global nuclear energy demand outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

In North America and Europe, demand for nuclear energy is anticipated to decline due to the decommissioning of ageing capacities. Conversely, the Asia Pacific region is poised to become the focal point for nuclear energy demand, primarily driven by China's and India's nuclear programmes. China, in

particular, is expected to assume a progressively significant role in nuclear power as part of its long-term decarbonisation strategy, with the country on track to become the global leader in nuclear power by the early 2030s. India has also outlined plans to triple its installed nuclear capacity in this decade, targeting 22.5 GW by 2031.

While nuclear power offers a valuable source of carbon-free baseload energy, several factors can impede its substantial growth. These challenges encompass stricter safety regulations, the complexities of nuclear waste management and storage, and uncertainties surrounding decommissioning expenses. These factors can result in elevated capital costs and protracted construction timelines, diminishing the competitiveness of nuclear generation compared to natural gas-fired and renewable power generation. Simultaneously, there is an interest in small modular reactors (SMRs) that offer abbreviated construction and approval periods. Additionally, the production of "yellow hydrogen" (generated using nuclear power in the electrolysis process) presents another avenue to enhance the long-term potential of nuclear energy. However, any serious nuclear accident would likely halt the renewed interest in nuclear energy.

3.2.4 Hydro

Hydropower currently stands as the leading source of carbon-free electricity, contributing to 15% of global power generation. In light of the continued growth in electricity demand, it is expected that hydropower projects will retain their attractiveness. According to the International Hydropower Association, there are about 600 GW of hydropower projects in the pipeline, which includes around 130 GW currently under construction and an additional 160 GW that have already been approved.

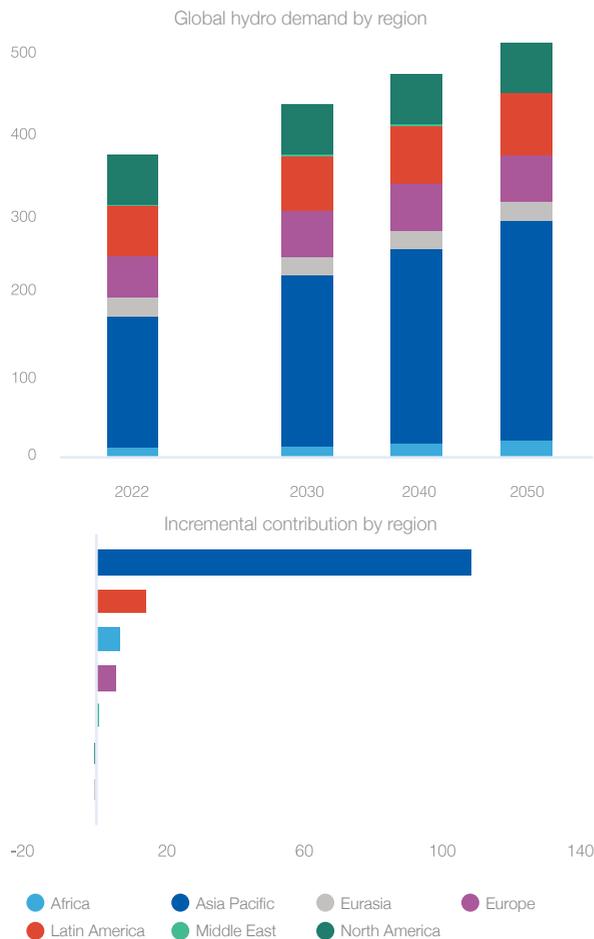
In the context of developing economies, particularly in Asia Pacific, Africa and Latin America, there is a strong emphasis on prioritising and supporting large-scale hydropower plants to meet the strong growth in electricity demand. Furthermore, pumped hydro facilities are poised to play an increasingly significant role in balancing variable solar and wind capacities, enhancing their importance in the energy landscape.

The RCS anticipates a gradual increase in demand for hydroelectric power, growing at a rate of 1.1% annually. This projected growth will take hydroelectric energy consumption from approximately 370 Mtoe in 2022 to nearly 510 Mtoe in 2050, equivalent to a 37% increase. However, this growth trajectory is less robust than the global potential due to several factors. One prominent factor is the relatively high construction and installation costs associated with hydroelectric projects. Additionally, concerns related to the protection of biodiversity and the impact on climate change are likely to slow down decision making. Climate-related events, such as increasingly severe and recurring heatwaves and droughts, have adversely affected hydropower generation in many regions in recent years. These events have raised questions about the resilience of hydropower infrastructure and represent a potential barrier to its more substantial development.

In terms of regional contributions, Asia Pacific, with a particular focus on China, India, Pakistan, and Indonesia, is expected to lead the growth in hydropower demand (Figure 3.7). China, a major investor in hydropower capacity, is on track to maintain its position as the world's leading producer of hydroelectricity. India is also projected to experience an increase in hydropower output throughout the forecast period.

Figure 3.7.

Global hydro demand outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

Latin America is anticipated to witness incremental growth in hydropower, driven by new developments in countries such as Brazil, Venezuela, and Paraguay. Moreover, Africa, namely Sub-Saharan African countries, is expected to experience an increase in hydropower demand, thanks to untapped resources in the region, provided there is accelerated access to financing.

In contrast, other regions are likely to see slower growth in hydropower demand due to the saturation of available resources, with more emphasis placed on the deployment of solar and wind energy projects.

3.2.5 Renewables

The demand for renewables has witnessed remarkable growth in recent years. Wind and solar energy installed capacity has exceeded 290 GW in 2022, with a notable concentration in China. This surge in renewable energy deployment has been accompanied by a decline in the levelised cost of renewable power generation, making it economically more attractive and leading to increased investment in this sector.

Nonetheless, it is crucial to acknowledge that employing the levelised cost of electricity (LCOE) generation as a metric for intermittent energy sources like wind and solar does not provide

an accurate assessment of the competitiveness of renewables compared to other technologies (refer to Box 3.1).

Furthermore, as the market share of renewables is expected to surge in the future, the demand for critical minerals commonly used in renewable energy technologies, including rare earth elements (e.g., neodymium, dysprosium), lithium, cobalt, and tellurium, is projected to rise rapidly. These minerals are indispensable for the manufacturing of magnets, batteries, and photovoltaic cells. However, the availability of critical minerals can be vulnerable to supply chain disruptions, given that a significant portion of their production is concentrated in a few countries. This concentration can lead to geopolitical risks and price fluctuations, which, in turn, can impact the overall cost of renewable energy technologies. For instance, fluctuations in the price of rare earth elements can have a direct effect on the cost of wind turbines and electric vehicle motors. Therefore, it is imperative to recognise that achieving the decarbonisation of energy systems cannot rely solely on a single energy source or technology, such as solar and wind power.

The RCS projects a remarkable surge in global renewable energy demand, encompassing solar, wind, geothermal and tidal power sources. This demand is expected to grow at a rapid rate of 6.9% p.a., escalating from 465 Mtoe in 2022 to a substantial 3,010 Mtoe by 2050, marking a remarkable increase of 547%. The driving force behind this rapid growth is expected to be the rapid deployment of solar photovoltaic (PV) technology, coupled with the widespread adoption of onshore and offshore wind installations. These developments are aimed at meeting the escalating electricity demand and achieving the decarbonisation of power systems. Moreover, the acceleration in renewable energy demand is set to be further fuelled by the increasing utilisation of green hydrogen, which necessitates dedicated renewable power sources for its production.

The anticipated growth in renewables energy demand is underpinned by a confluence of factors, including supportive policies aimed at achieving carbon neutrality, sustained reductions in production costs, the establishment of robust supply chains for critical minerals, ongoing technological advancements, and initiatives to expand and modernise power grids. These driving forces collectively propel the rapid expansion of renewable energy sources.

However, as the share of renewables in the power generation mix continues to rise, the challenge of intermittency becomes increasingly pronounced. To address this challenge effectively, additional backup generation capacity is required. Over the forecast period, this challenge is expected to intensify, given the higher proportion of renewables in the energy mix.

In this context, as a complementary partner to renewables, natural gas emerges as a cost-effective solution for supplying backup and providing stability to power grids that are dependent on variable and intermittent renewables. Natural gas offers the advantage of low fixed costs coupled with relatively higher variable costs, making it a flexible and economically efficient choice. On the other hand, nuclear power, characterised by high fixed costs and low variable costs, becomes significantly more expensive and less practical, especially when considering the need to construct nuclear power plants solely to cover periods when renewables are unable to generate electricity due to adverse weather conditions, such as windless hours. Furthermore, natural gas plants are generally more flexible and can ramp up or down quickly to adjust to the fluctuating supply from renewables like wind and solar. This quick response time makes natural gas

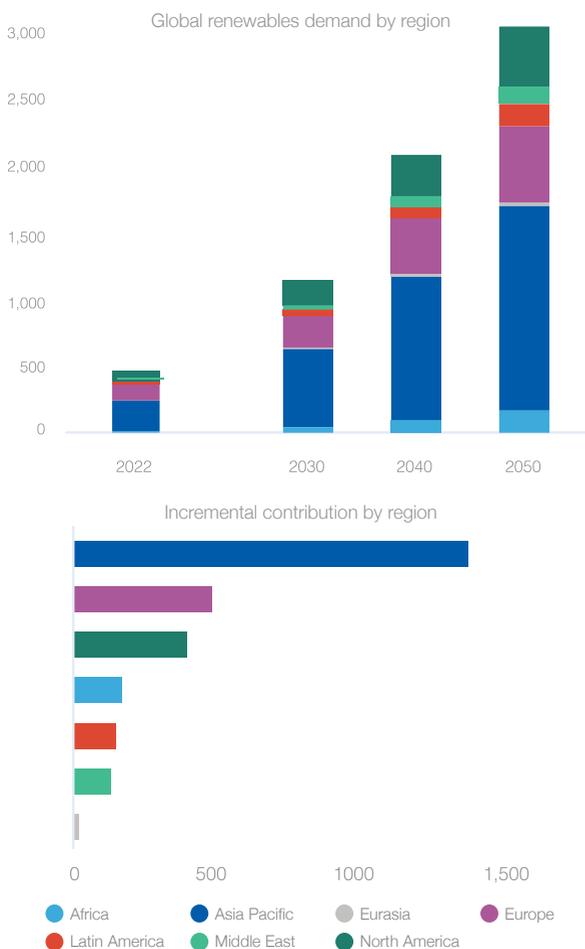
a suitable choice for balancing the intermittency of renewable sources. In contrast, nuclear power plants are designed for steady, continuous operation and do not ramp up or down as quickly.

As illustrated in Figure 3.8, the expansion of renewable energy demand is expected to encompass all regions worldwide. The Asia Pacific region, in particular, is positioned as the global leader in renewable energy adoption, constituting 50% of the total incremental demand between 2022 and 2050. This substantial growth is primarily attributed to China and India, which are committed to achieving carbon neutrality by 2060 and 2070, respectively.

Europe is anticipated to contribute significantly to the overall demand increase, accounting for 18% of the total. This growth is driven by the implementation of the REPowerEU programme and the ambitious decarbonisation goals outlined in the EU's Green Deal. In North America, robust investments in renewables are expected to take place, supported by generous tax credits and long-term incentives offered through the IRA. These incentives are set to facilitate the deployment of wind and solar power across the continent.

Figure 3.8.

Global renewables energy demand outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

3.2.6 Bioenergy

Bioenergy, encompassing both modern and traditional biomass, accounts for 10% of the global energy mix in 2022. Within this, traditional biomass represents nearly 45% of the total bioenergy demand, with its primary usage concentrated in the residential sectors of Asia Pacific and Sub-Saharan Africa, where it is employed for heating and cooking purposes.

Consumption of traditional biomass serves as an indicator of inadequate access to modern energy sources. Dependence on these seemingly free but environmentally harmful energy resources has adverse effects on the environment, public health, and the broader economy. This reliance often results in unsustainable practices, contributes to deforestation, and emits harmful pollutants, thereby exacerbating environmental degradation. Furthermore, the health risks associated with indoor air pollution from biomass burning disproportionately affect vulnerable populations, leading to serious public health concerns. Economically, the inefficiency and productivity loss associated with traditional biomass use hinder economic development and perpetuate energy poverty. Addressing this issue is vital for achieving sustainable energy access and improving the quality of life in affected regions.

Modern biomass is considered as a viable solution to achieve climate change mitigation objectives. Governments are actively supporting the production of biofuels and modern biomass for heating in residential and industrial settings, power generation and production of Sustainable Aviation Fuel (SAF).

Bioenergy demand is expected to grow steadily at a rate of 1.2% p.a., increasing from 1,437 Mtoe in 2022 to approximately 2,025 Mtoe by 2050, representing a 41% rise. Figure 3.9 illustrates that the global bioenergy landscape is poised for significant transformation. This shift entails a move away from the traditional use of biomass, such as wood and dung, primarily for off-grid residential lighting, heating, and cooking, towards a greater reliance on advanced forms of biomass, including modern solid bioenergy, biofuels, and biogases.

The traditional use of biomass is anticipated to decline by approximately 17% to reach around 530 Mtoe by 2050, although regional variations persist (Figure 3.9, right graph). In Asia Pacific, demand is projected to decrease significantly, mainly driven by national initiatives in China and India aimed at improving indoor and outdoor air quality by phasing out polluting cooking and heating sources. Conversely, in Sub-Saharan Africa, the demand for traditional biomass is expected to experience marginal growth. This modest increase reflects some progress in adopting cleaner cooking methods, given the rapidly growing population and the corresponding rise in household energy demand. Nevertheless, traditional biomass is likely to remain a significant energy source in the region.

The RCS highlights an opportunity for modern and clean energy sources, including liquefied petroleum gas (LPG), a by-product of natural gas, to fulfil the access to clean cooking needs of these communities. By doing so, these sources can help tackle energy poverty and contribute to the achievement of the United Nations' Sustainable Development Goals, particularly Goal 7, which focuses on ensuring access to affordable, reliable, sustainable, and modern energy for all.

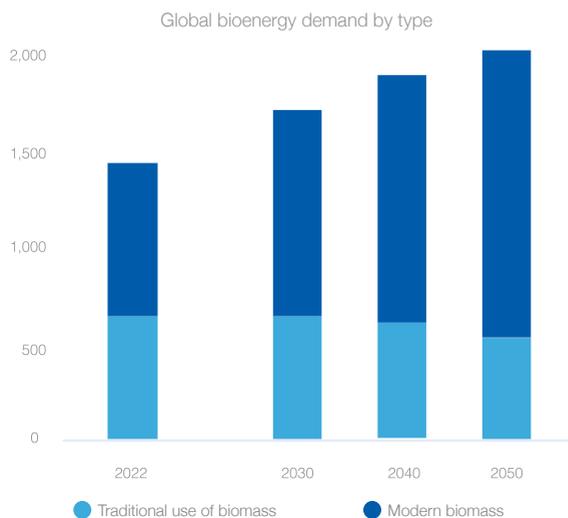
The demand for modern biomass is projected to nearly double, reaching approximately 1,495 Mtoe. Power generation, including the practice of biomass co-firing in thermal power plants, is expected to be the primary driver of this growth.

Additionally, residential and transport sectors are poised to demonstrate significant increases in demand for modern biomass. Several factors are contributing to this expansion, including decarbonisation policies, the substitution of traditional biomass use, and, to some extent, energy security objectives.

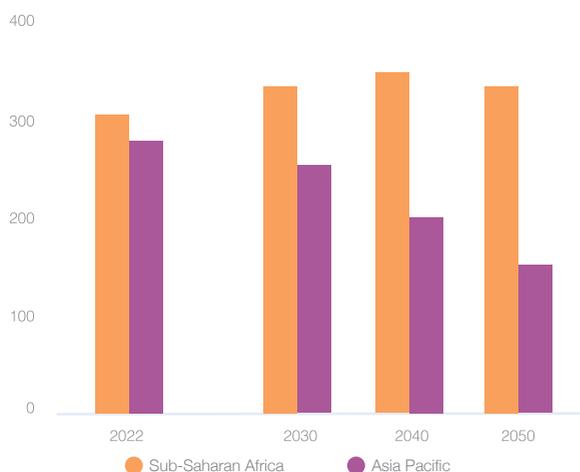
In particular, the adoption of biofuels in road transport is expected to increase due to wider adoption of blending requirements. Furthermore, biofuels are considered a promising option for aviation, given the limited availability of alternative fuels. Biogas and biomethane, while currently representing a smaller portion of bioenergy demand, are gaining attention. There are ambitious production targets for biomethane, especially in Europe, where it is viewed as a source of low-emission domestic gas supply.

Overall, the demand for modern biomass is anticipated to grow across all regions and countries, with China, India, the United States, European countries, and various markets in Sub-Saharan Africa leading the way in this expansion.

Figure 3.9. Global bioenergy demand outlook, 2022-2050 (Mtoe)



Traditional use of biomass in Sub-Saharan Africa and Asia Pacific



Source: GECF Secretariat based on data from the GECF GGM

3.3. The outlook for global electricity demand and generation

The electrification of the global energy system is poised to become a prominent trend in the ongoing energy transitions. Projections indicate that global electricity demand across end-use sectors will experience a nearly 80% increase, reaching approximately 44,350 TWh by 2050. This growth represents an additional demand of about 19,700 TWh compared to the present levels.

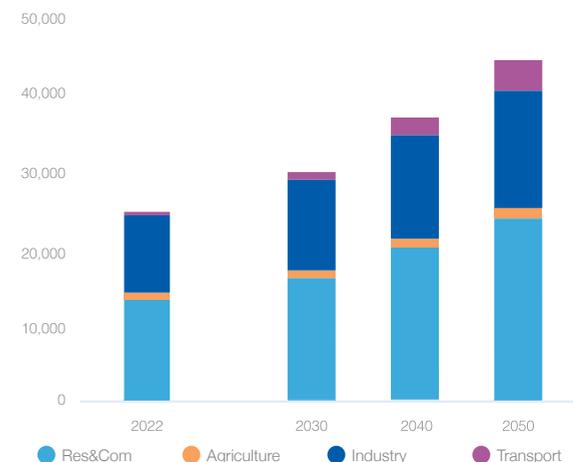
This surge in electricity demand is anticipated to be a global phenomenon affecting all countries. The majority, roughly 80%, of this increase is expected to emanate from developing economies, notably led by the Asia Pacific region. Several factors contribute to this trend, including endeavors to decarbonise energy systems, rising living standards, increased prosperity, expansion of the service sector, heightened industrial output and improved energy access in various regions.

As illustrated in Figure 3.10, the residential and commercial sector currently represents the largest consumer of electricity and is expected to maintain this position until 2050, accounting for approximately 55% of the incremental growth in final electricity demand. This growth can be attributed to increased requirements for space cooling and heating, as well as the rising ownership of household appliances, particularly due to expected growth in the number of households. Moreover, a shift toward the electrification of household heating is anticipated through the adoption of heat pumps, aligning with net-zero strategies. However, it is worth noting that challenges persist, particularly the high upfront and switching costs associated with this transition, as well as the substantial expenses associated with building or updating an extensive electricity grid to cater to end-users.

The industrial sector contributes to 25% to the total growth in electricity demand, which primarily reflects the increased adoption of electric motors for low-heat industrial processes, driven by policies aimed at reducing emissions. Among the end-use sectors, the transport sector currently consumes the least amount of electricity, constituting approximately 2% of the total. However, it is expected to experience rapid growth as the global electric vehicle (EV) fleet expands

Figure 3.10.

Global electricity demand outlook by end-use sector, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM

In line with the growth of the final electricity demand, global electricity generation¹ is projected to increase almost 1.8-fold from 28,890 TWh in 2022 to over 50,600 TWh (excluding electricity for green hydrogen). Concurrently, the global power generation landscape is on the cusp of a profound transformation as it shifts towards low-carbon energy sources (Figure 3.11). Coal, which currently stands as the world's primary source of electricity, is anticipated to undergo the most substantial decline. Despite a temporary resurgence in coal-fired power generation driven by soaring natural gas prices in 2021-2022 and the ongoing global energy crisis, many countries remain steadfast in their commitment to phase down coal to meet their climate obligations. The share of coal in the global power generation mix is projected to plummet from 36% in 2022 to a mere 8% by 2050.

Shares of hydropower and nuclear, though they are expected to witness an increase in absolute output, are also expected to decline, albeit less steeply. They are projected to contribute approximately 12% and 8%, respectively, to the global power generation mix in 2050, down from 15% and 9% in 2022. In contrast, the rapid deployment of renewables, driven by policy support and cost reductions, is set to significantly boost their share from 12% in 2022 to 49% by 2050. As discussed in Chapter 2, recent policy developments in major markets such as China, India, the EU and the US are expected to provide a substantial impetus to renewables deployment. Nevertheless, the rapid expansion of renewables poses challenges related to managing intermittency and the need for backup generation, including natural gas-fired power plants and electricity storage.

Natural gas-fired generation is projected to maintain its current share of around 22% in the global power generation mix over the next decade, surpassing coal in the early 2030s. In the long term, natural gas-fired power generation is poised to continue to rise in absolute terms to meet the growing demand for electricity, but its share is set to gradually decline, reaching approximately 19% by 2050 as the shares of solar PV and wind power surge. As shown in Figure 3.11, by 2050, natural gas and renewables combined are expected to constitute nearly 68% of the total electricity supply. Furthermore, CCUS technologies are poised to gain momentum, with natural gas-fired power plants expected to be equipped with CCUS, primarily after 2030, contributing to low-emission electricity.

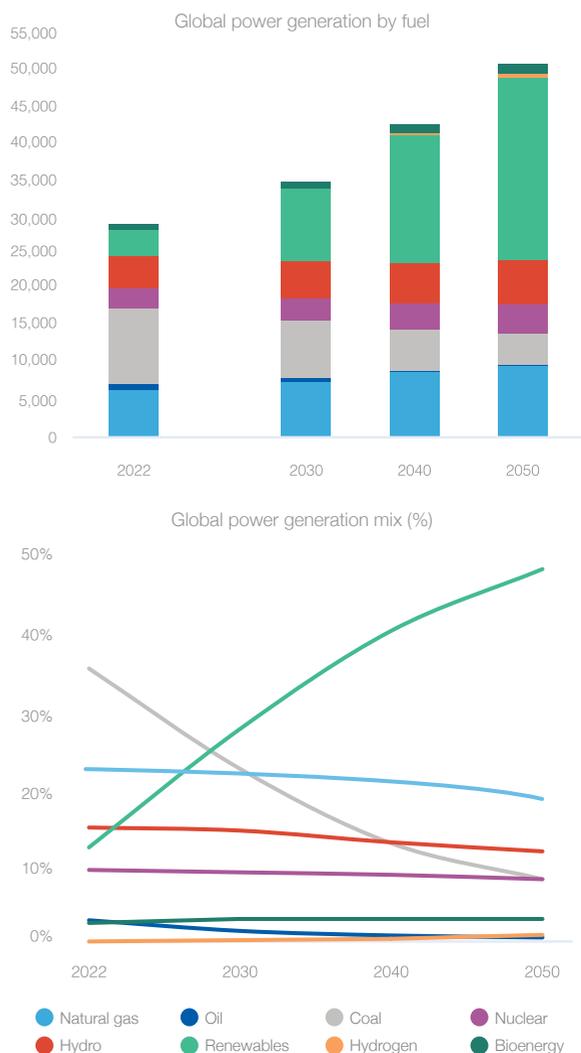
Additionally, co-firing with hydrogen or ammonia in natural gas- or coal-fired power plants may present a viable option for further decarbonisation. Although this technology is still maturing, its development is limited in the RCS over the outlook period. Similarly, hydrogen-based generation (using hydrogen fuel cells) is not expected to be deployed on a significant scale in the RCS, accounting for less than 1% of the global power generation mix in 2050, primarily to provide flexible operations. Some progress in hydrogen-based generation (using hydrogen cell fuels) is projected to be made in South Korea, Japan, China, the US, the UK and several EU markets.

In terms of global installed capacity, a substantial increase from 8,550 GW in 2022 to 19,300 GW by 2050 is forecast. Solar and wind energy are expected to constitute approximately 79% of the total net capacity additions, with significant growth anticipated in key countries, including China, the US, India, Brazil, Germany, Spain, Saudi Arabia, Japan, South Korea, and Indonesia. As depicted in Figure 3.12, solar energy is projected to surpass all other sources and become the largest contributor

to installed capacity by 2027, maintaining steady growth thereafter.

Figure 3.11.

Global power generation outlook, 2022-2050 (TWh)



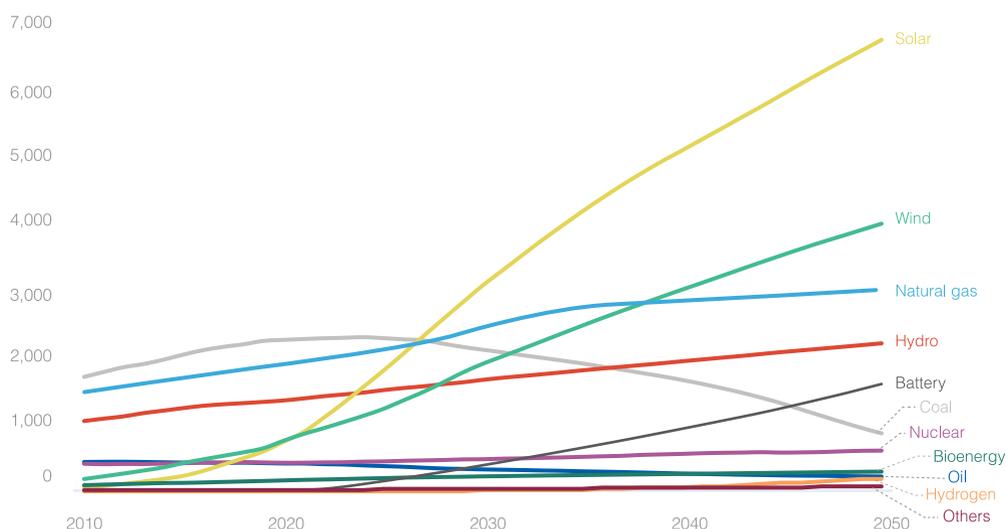
Source: GECF Secretariat based on data from the GECF GGM

Global coal-fired capacities are expected to reach a plateau in the coming years. The projected retirements of coal-fired plants in the US and European markets are expected to be balanced by new additions in Asian countries. However, beyond 2026, the development of coal-fired power plants worldwide is poised to decelerate significantly, with total capacities projected to decline due to an increasing number of decommissioned plants exceeding new constructions.

In contrast, natural gas-fired power capacities are anticipated to experience growth, increasing from 1,940 GW in 2022 to 2,975 GW by 2050. Natural gas is projected to account for 15% of

¹Electricity generation is defined as final electricity demand plus other electricity use, including power sector own use as well as transmission and distribution losses. Electricity for green hydrogen production is excluded and defined separately in order to provide a more accurate estimation of the power generation mix.

Figure 3.12.

Global power generation capacity outlook, 2022-2050 (GW)

Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include geothermal and tidal.

the global installed capacity by 2050. The largest contributions to the rise in natural gas-fired capacity additions are expected to come from the power systems of China, Iran, Mexico, the US, Vietnam, Indonesia, Iraq, Saudi Arabia, Brazil, and Nigeria. This growth reflects the ongoing importance of natural gas as a reliable and flexible energy source, particularly as it complements the increasing share of intermittent renewables in the power generation mix.

With the increasing integration of intermittent wind and solar energy sources, the importance of flexibility has grown significantly in ensuring the security of electricity supply. This flexibility can be sourced from various options, including conventional power plants, enhanced grid infrastructure and cross-border connections between countries and regions,

advanced energy storage technologies and demand-side response measures. While battery capacities are expected to experience substantial growth and can contribute to flexibility to some extent, they are less suitable for addressing seasonal and long-duration storage requirements.

Given these considerations, dispatchable, low-emission generating capacities are anticipated to play a central role in providing the necessary system flexibility. Among these options, natural gas-fired generation is expected to maintain its position as the primary choice. It is poised to serve as a vital partner to renewables, ensuring the stability of power supply in many countries. For a more detailed analysis of natural gas's role in the power generation mix, please refer to Chapter 4, where regional and country-specific sections provide further insights.

Box 3.1. Hidden costs of renewable power generation

Proponents of a rapid transition to renewable energy often emphasise the attractive Levelized Cost of Electricity (LCOE) associated with wind and solar photovoltaic (PV) technologies, highlighting them as the most cost-effective options for electricity generation.

While LCOE is a widely used metric for guiding investment decisions, it has limitations when comparing intermittent energy sources such as wind and solar with dispatchable ones such as natural gas, coal, and nuclear power. It does not account for the nuanced complexities of electricity supply, where not only the generation but also the precise delivery of electricity to specific locations at specific times is paramount.

Renewables often incur additional costs due to their limited flexibility in terms of geographical placement compared to fossil fuel plants. This limitation necessitates the development

of extensive grid infrastructure to transport electricity from remote solar or wind sites to urban centers where the demand is highest. For instance, in Germany, many offshore wind farms are situated in the North, while the majority of consumption centers are located in the central and southern parts of the country.

According to a recent report by the Energy Transition Commission, the cost split for a reliable supply of clean electricity to the final consumers is approximately 55% for new generating capacity and 45% for the construction and maintenance of distribution, transmission, and energy storage systems. This translates to an estimated annual cost of approximately USD 1.1 trillion between 2022 and 2050 for grids and storage infrastructure alone. However, current global spending on electric grids, as estimated by the IEA, falls far short of these requirements. Furthermore, the IEA predicts that meeting climate and energy targets is anticipated to demand the addition or replacement of 80 million kilometers of power lines globally by 2040, equivalent to the entire existing global

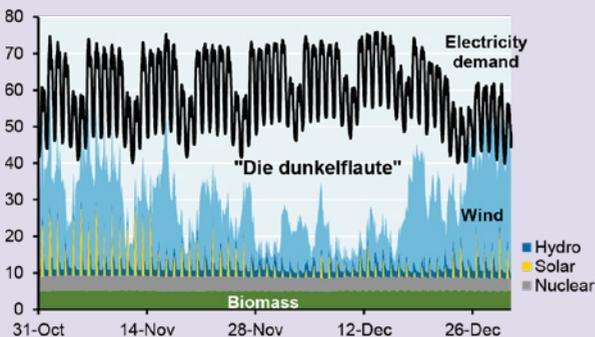
grid. This is one of the key components not included in LCOE measurement of wind and solar electricity supply to the end consumers.

The timing aspect of electricity supply has become increasingly crucial, particularly in light of the intermittent and non-dispatchable nature of many renewable energy sources. Ensuring a constant balance between supply and demand on the electrical grid is paramount. In situations where the proportion of intermittent generation is limited, dispatchable capacity plays a vital role in compensating for the fluctuations in intermittent generation, thereby upholding grid stability. Essentially, dispatchable generators indirectly subsidise renewable sources by offering essential support in real-time grid balancing.

Take, for example, Germany, where extended periods of low wind conditions, known as “dunkelflaute,” can persist for weeks (Fig 3.1.1). During such periods, when electricity demand surges, the gap in electricity demand is filled mainly by increased coal generation and imported LNG. The ongoing decommissioning of nuclear power plants in Germany may exacerbate this challenge in the years ahead. The LCOE metric proves inadequate in addressing this issue since it overlooks the necessity for backup power. It is not coincidental that electricity costs tend to rise in Europe with greater adoption of renewable energy sources.

Figure 3.1.1.

Germany power generation by source during Nov-Dec 2022 (GW per 15 min)



Source: Fraunhofer ISE (2022)

Another illustrative case is Texas, where wind capacity factors averaged 32% in December 2022. However, this does not imply that wind power consistently operated at 32% of installed capacity. In fact, Texas' wind generation ranged from a low of 5% of capacity to a peak of 70% during that month. LCOE remains indifferent to whether Texas wind capacity factors consistently sit at 32% for every hour in December or if they average 32% but exhibit a wide range from 5 to 70%. When temperatures plummeted significantly on December 23, 2022, leading to a surge in electricity demand, renewable output collapsed. The increased electricity demand was met by a significant increase in natural gas fired power generation. Even if the wind and solar capacity in Texas were five times larger, the need for gas-fired power on that day would not have been 20% lower. In essence, there was a substantial gap that could only be filled by backup power, a factor not accounted for in LCOE calculations.

Looking ahead, as the proportion of intermittent energy sources surpasses a certain threshold and dispatchable capacity diminishes, concerns arise about the allocation of costs related to ensuring ongoing energy system reliability. How should the expenses tied to integrating renewables into the energy system be factored into the overall cost assessment?

The LCOE metric, typically used for cost comparisons, falls short in capturing the differences in production profiles between intermittent and dispatchable energy sources, as well as the market value fluctuations of the electricity they supply. Consequently, LCOE tends to overstate the economic competitiveness of intermittent energy sources when compared to dispatchable base-load generating technologies.

Indeed, solar panels and wind turbines, while being promising sources of clean energy, possess limitations that can diminish their overall value. When they cannot consistently generate electricity on demand, their capacity to meet power needs becomes less reliable compared to traditional power plants. In this context, natural gas, characterized by its low fixed costs and relatively high operational flexibility, emerges as the optimal backup solution for integrating renewable-based power systems in the future.

Consequently, it is reasonable to assert that natural gas and renewable energies should be regarded as complementary partners rather than direct substitutes moving forward. Their synergy and collaborative utilisation offer a more robust and resilient approach to meeting the diverse and fluctuating energy demands over the just, equitable and orderly energy transitions.

3.4. The outlook for hydrogen demand, generation and trade

Hydrogen has historically found extensive use as a chemical feedstock, particularly in refineries and fertiliser production. However, its role as an energy carrier has remained marginal. Hydrogen faces significant challenges, including cost, complexity, efficiency and safety issues, especially when compared to the direct use of electricity. Nonetheless, there are sectors where direct electrification is not a practical option, making hydrogen and its derivatives, such as ammonia, methanol and e-kerosene, attractive low-carbon alternatives. As a result, there is growing consensus that low-carbon and renewable hydrogen will likely play a significant role in future

decarbonised energy systems, although the extent of its prominence remains uncertain.

In the RCS, hydrogen demand is projected to increase from 101 Mth₂ in 2022 to around 298 Mth₂ by 2050. This forecast indicates a remarkable acceleration in hydrogen demand over the forthcoming three decades, albeit from a very low base. As a proportion of the energy sector, hydrogen's share is expected to climb to 4.5% by 2050, up from just over 1.7% in 2022.

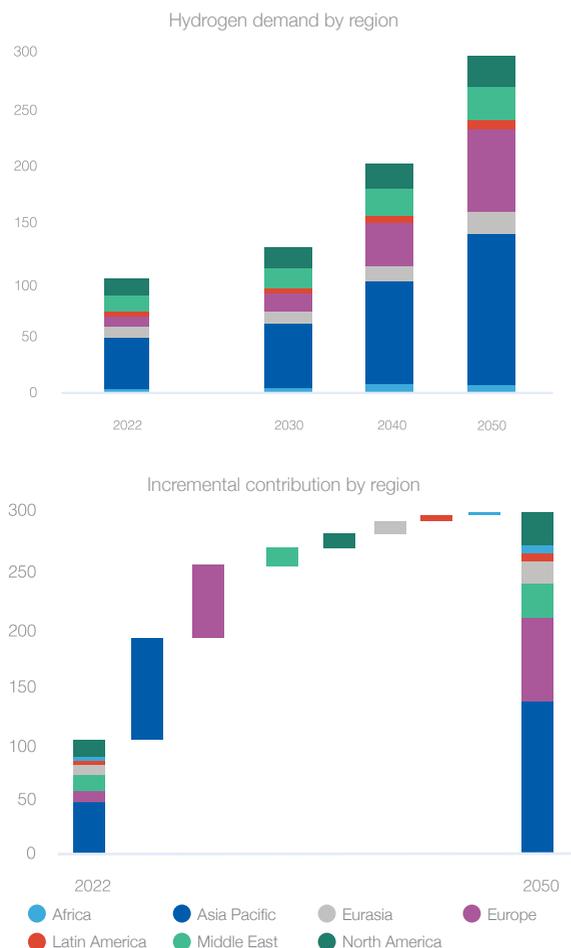
In 2022, Asia Pacific, North America, and the Middle East were the primary contributors to hydrogen production, representing shares of 44, 16, and 14%, respectively. However, the 2050 outlook anticipates a shift in market dominance, with Asia Pacific and Europe set to emerge as the leading players, jointly comprising nearly 70% of the expanded hydrogen

production (Asia Pacific: 45%, Europe: 25%). This production is projected to be more than three times the size of the 2022. It should be remembered that the current developments in the hydrogen, are strongly supported by government incentives and measures.

As illustrated in Figure 3.13, these two regions are expected to undergo substantial growth in hydrogen demand by 2050, with Asia Pacific increasing by 91 Mth₂ and Europe by 63 Mth₂. These figures correspond to 45% and 25% of the total expected global hydrogen demand over the forecast horizon. Conversely, Africa and Latin America are expected to contribute the least to the hydrogen market, with their increased demand reaching 2.6 and 4.6 Mth₂ by 2050, making up just 1.3 and 2.3% of global hydrogen growth over the projection horizon.

Figure 3.13.

Hydrogen demand outlook 2022-2050 (Mth₂)



Source: GECF Secretariat based on data from the GECF GGM

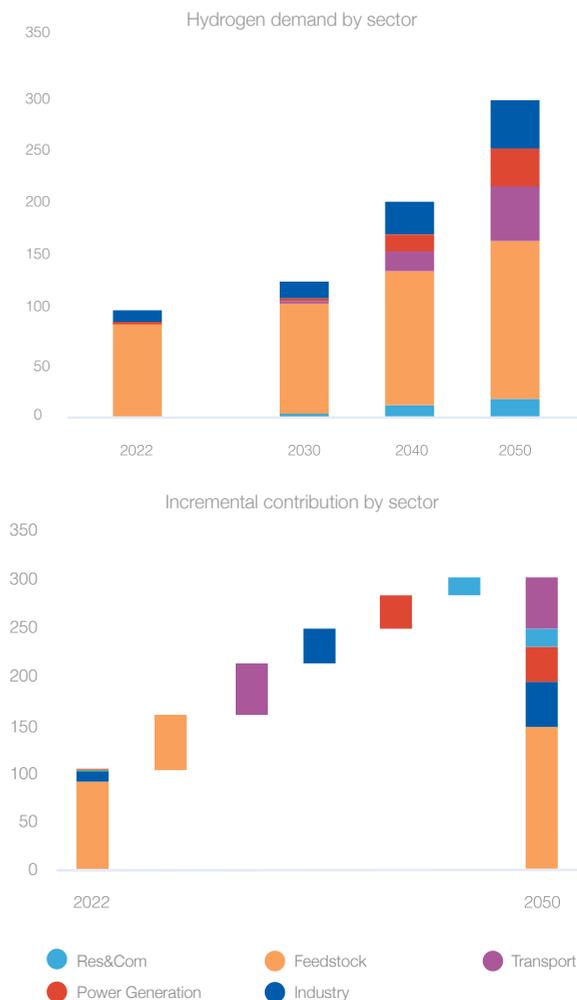
In the year 2022, hydrogen predominantly served as a feedstock for petrochemicals and refineries, constituting roughly 90% of the total hydrogen demand. A smaller portion used in the industrial sector, notably within the iron and steel industries. However, the landscape for hydrogen applications is on the path of a significant transformation. In RCS, hydrogen is expected to take on new roles as an energy carrier, especially in sectors such as transport, power generation, residential, and

commercial use. Nonetheless, hydrogen's role as a feedstock is expected to remain substantial.

As illustrated in Figure 3.14, hydrogen's role as a feedstock for petrochemical and refinery operations is projected to account for around 50% of global hydrogen demand, reaching 146 Mth₂ by 2050. This represents a significant increase from the 90 Mth₂ recorded in 2022, indicating that hydrogen's application as a feedstock is expected to be on par with its use as an energy carrier by 2050.

Figure 3.14.

Hydrogen demand outlook 2022-2050 (Mth₂)



Source: GECF Secretariat based on data from the GECF GGM

On the other hand, the transport sector, particularly maritime and road transportation, is expected to selectively embrace hydrogen derivatives such as ammonia, methanol, and e-fuels. Hydrogen demand in this sector is projected to surge to 52 Mth₂ by 2050, constituting 18% of the global hydrogen demand. The application of hydrogen in shipping holds significant promise, especially since this sector operates independently of the grid and requires substantial energy. This makes electrification and pure hydrogen less viable alternatives to the fossil-based fuels they currently rely on. In road transport,

hydrogen demand is anticipated to be limited to heavy-duty transportation, particularly long-haul trucking, where fuel consumption is naturally higher.

The power generation sector presents a more nuanced landscape for hydrogen in its pure form. Hydrogen consumption in power generation is predicted to increase to 34 MtH₂ by 2050, up from a mere 0.4 MtH₂ in 2022, constituting 15% of global hydrogen demand in 2050. Hydrogen is expected to be gradually integrated into power generation starting around 2030, initially in small quantities, primarily through hydrogen injection into natural gas grids. As the need for peak balancing grows, its share is expected to increase. Indeed, reliance on renewables in power generation is expected to enhance the competitiveness of hydrogen in electricity production, particularly with grid-connected electrolysis.

The industrial sector is projected for rapid growth in hydrogen use, with hydrogen demand in this sector projected to reach 34 MtH₂ by 2050. This reflects a significant increase of 22 MtH₂, with the industrial sector's share of overall hydrogen demand in 2050 expected to expand to 15%. This marks a significant increase from its 11% share in 2022. This growth is expected to primarily occur in pioneering regions such as China and Europe, particularly within the context of iron and steel manufacturing. The substitution of hydrogen for coal in iron ore reduction is expected to increase, along with its utilisation as a fuel in steelmaking. Additionally, hydrogen blended with natural gas is expected to gain momentum in blast furnaces in the steel industry, particularly as the energy efficiency of hydrogen generation improves.

The adoption of hydrogen in the residential and commercial sectors is expected to contribute the least to hydrogen demand in the coming decades. These sectors are projected to make up only 3% of the total hydrogen demand in 2050. The limited projected use of hydrogen in buildings for space and/or water heating is attributed to considerations of safety, efficiency, costs and infrastructure availability compared to competing technologies, mainly electric district heating and efficient natural gas systems. However, hydrogen's application in blended forms with natural gas, as fuel cells, and in combination with ammonia is likely to experience substantial growth, increasing from 0.44 MtH₂ in 2022 to 10 MtH₂ by 2050, constituting 3% of the overall growth in global hydrogen demand.

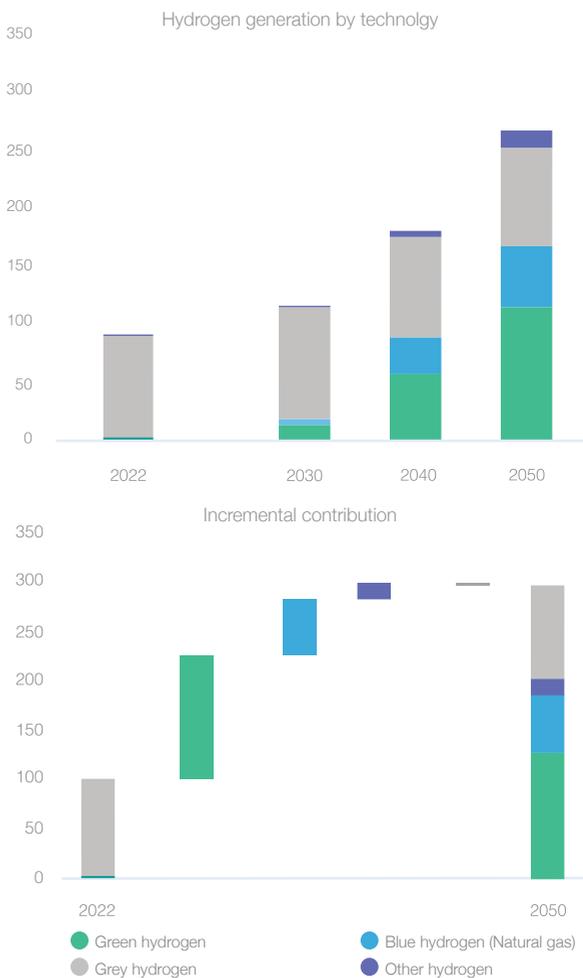
In 2022, the predominant method of hydrogen production fell into the category of grey hydrogen, which primarily originated from natural gas, oil, and coal and was mainly used for feedstock applications. Natural gas, coal, and oil contributed 63, 25.4, and 11.2%, respectively, to grey hydrogen production in 2022. Conversely, green hydrogen generated through the process of electrolysis amounted to an estimated 3.5 MtH₂ in 2022, representing only about 3% of the global hydrogen demand. Grey hydrogen production accounted for an estimated 98 MtH₂, constituting approximately 97% of the total hydrogen output.

As it is shown in Figure 3.15, the RCS predicts that green hydrogen production is expected to witness rapid expansion, reaching 129 MtH₂ by 2050, indicating a significant increase of 126 MtH₂ over the following 28-year period. Green hydrogen, which is produced through the electrolysis of water using renewable energy sources, is projected to capture a significant share of the overall hydrogen market by 2050, accounting for approximately 43%. This represents a rise of more than 40 p.p. compared to its 2022 share.

Blue hydrogen, particularly derived from natural gas through methane reforming, is also anticipated to gain substantial traction during the forecast period, reaching significant production levels by 2050. Blue hydrogen, which is produced from natural gas, oil, and coal combined with CCUS technologies, is forecasted to contribute to one-fourth of the total hydrogen production in 2050. The share of natural gas-based blue hydrogen within the overall blue hydrogen generation is expected to exceed 80%, primarily due to its cost-effectiveness and reduced environmental impact.

Figure 3.15.

Hydrogen generation outlook 2022-2050 (MtH₂)



Source: GECF Secretariat based on data from the GECF GGM

While hydrogen produced from oil and coal (grey hydrogen) is expected to decline significantly by 2050, grey hydrogen derived from natural gas is projected to reach 72 MtH₂, representing a 10 MtH₂ incremental increase. Natural gas-based grey hydrogen is anticipated to constitute approximately 24% of the global hydrogen mix in 2050, making it the second-largest share in the overall hydrogen production mix.

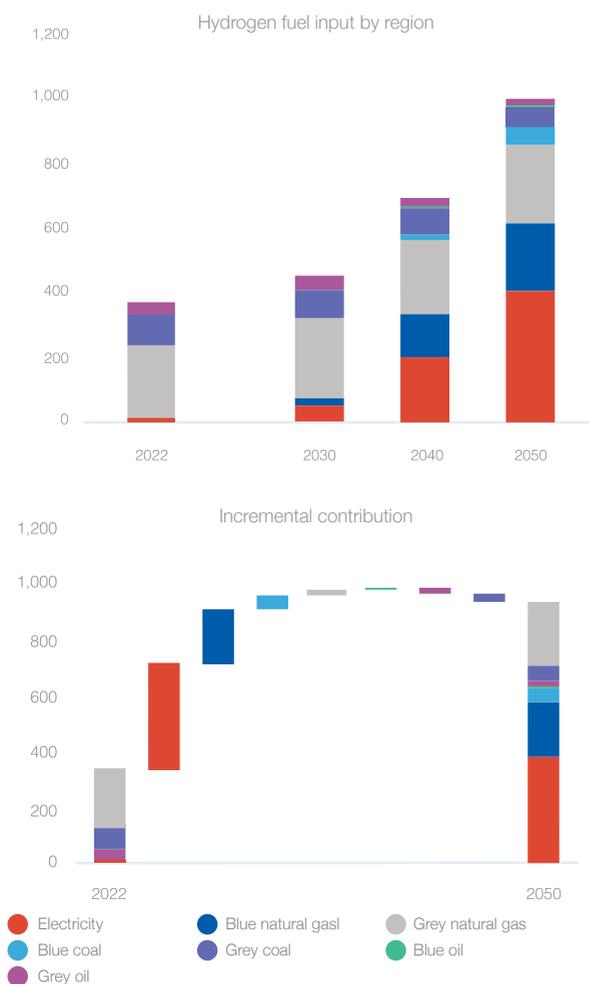
It is important to note that hydrogen generated from natural gas, whether in the form of grey or blue hydrogen, is expected to contribute to 43% of the total hydrogen production in 2050, a share equivalent to that of green hydrogen. This highlights

that more than 85% of hydrogen production in the upcoming three decades is expected to be sourced either from renewable energy or natural gas.

The landscape of fuel input for hydrogen generation is evolving, primarily driven by two major sources: dedicated green electricity for green hydrogen and natural gas for blue hydrogen. In the year 2022, the fuel input for hydrogen generation was estimated at 371 Mtoe, with natural gas emerging as the predominant source, contributing slightly over 60% of the total fuel supply for the production of grey hydrogen, primarily used as feedstock in petrochemical and refinery plants. Additionally, in 2022, electricity accounted for approximately 15 Mtoe, equivalent to 4% of the total fuel input for green hydrogen production.

Figure 3.16.

Hydrogen fuel input outlook, 2022-2050 (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Electricity dedicated to the production of green hydrogen is not included in global power generation described in section (3.3)

As depicted in Figure 3.16, the demand for fuel in the hydrogen generation process is projected to increase significantly, reaching 1,002 Mtoe in 2050, reflecting a growth of 631 Mtoe from the 2022 level. With the expected surge in green hydrogen production, the demand for electricity associated with hydrogen production is projected to constitute a substantial share, amounting to 63% of the overall incremental change during the period from 2022 to 2050.

The contribution of natural gas to the fuel input mix for hydrogen generation is expected to decrease to 45% by 2050. However, the absolute change is anticipated to witness a notable increase, reaching 454 Mtoe by 2050. The amount of natural gas allocated to the production of blue hydrogen in 2050 is projected at 209 Mtoe, constituting more than 90% of the total natural gas demand for hydrogen generation by 2050. On the other hand, the natural gas utilised for the production of grey hydrogen is expected to experience a modest change, increasing by 18 Mtoe compared to the 2022 level.

However, amid this substantial expected growth, a critical challenge emerges – the efficiency of hydrogen production. The process incurs losses, with almost 38% losses in fuel input to generate an equivalent amount of hydrogen. This raises significant apprehensions about the efficiency of energy transformation when compared to the direct utilisation of electricity or natural gas. The debate on the optimal pathway for hydrogen production intensifies as stakeholder’s grapple with the trade-offs between scale and efficiency.

Addressing the efficiency concerns becomes paramount to ensure the sustainability and effectiveness of hydrogen as a key player in the global energy transitions. Striking the right balance between scaling up production and mitigating losses in fuel input is essential for maximising the benefits of hydrogen across diverse applications and sectors.

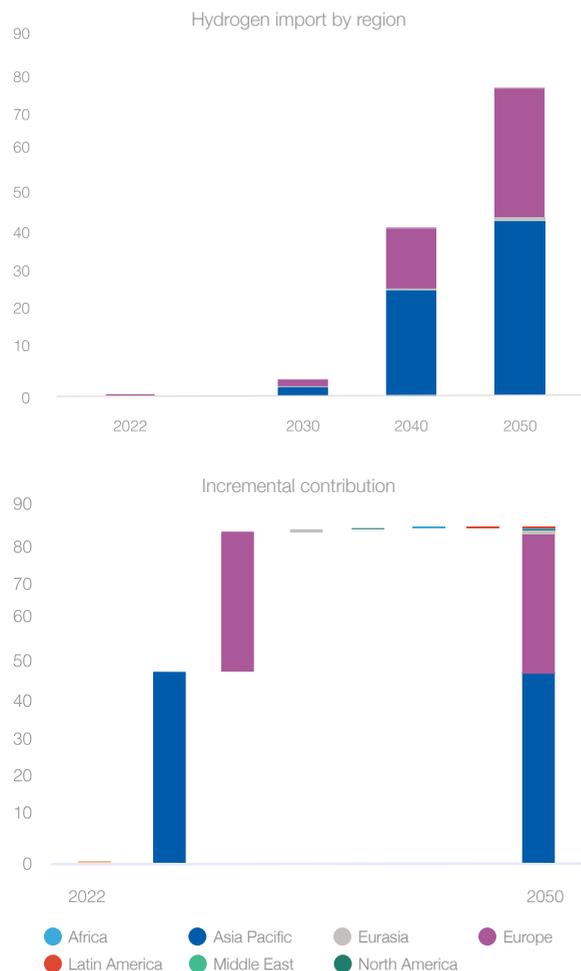
The anticipated growth in hydrogen trade is indeed remarkable, progressing from minimal levels to reach 78 MtH₂ by 2050, which represents a 26% of global hydrogen demand. It is noteworthy that the majority of this growth is expected to occur after 2030. One formidable challenge that remains is the liquefaction of hydrogen at an exceptionally low temperature of -253 degrees Celsius, a mere 20 degrees Celsius above the lowest possible temperature and nearly 100 degrees Celsius lower than natural gas liquefaction temperature for LNG production, which poses a significant hurdle to this development.

The long-term import of hydrogen is foreseen to be mainly concentrated in the Asia Pacific and Europe. As it is depicted in Figure 3.17, these two regions are poised to witness substantial hydrogen import growth, reaching 44 MtH₂ and 32 MtH₂, respectively, by 2050. Together, they are anticipated to account for 57% and 41% of the total hydrogen imports during that period. The contribution of other regions is expected to be negligible.

It should be noted that the future landscape of hydrogen trade is expected to primarily span medium distances between countries, driven largely by challenges related to material degradation, such as embrittlement, and the flow properties associated with high-velocity transport, which causes erosion and pipeline failure. When it comes to trade by sea, the utilisation of ammonia as a carrier, aiming to mitigate these complex challenges, is likely to become a prevalent practice.

Figure 3.17.

Hydrogen import outlook, 2022-2050 (Mth₂)



Source: GECF Secretariat based on data from the GECF GGM

3.5. The outlook for energy-related CO₂ emissions

Recent years have witnessed increased policy support globally for renewable energy, nuclear power, and carbon removal technologies. This trend is driven primarily by the goals of enhancing energy security and meeting ambitious climate targets. Post-COP27, an additional 9 countries have submitted new or revised NDCs, raising the total to 149 updates since the original submissions around the time of the Paris Agreement. The UNEP projects that if all new and updated unconditional and conditional NDCs, along with all net-zero pledges, are fully implemented, global GHG emissions are expected to decrease to 21 GtCO₂e (with a range of 6-33 GtCO₂e) by 2050, down from the current 57.4 GtCO₂e. This signifies a reduction of over 50%.

As per the RCS, adopting a pragmatic and realistic approach that places a strong emphasis on energy-related emissions reduction, it is projected that these emissions will decline by 18%. By 2050, they are expected to decrease to 32.1 GtCO₂e from the current level of 39.3 GtCO₂e (Figure 3.18).

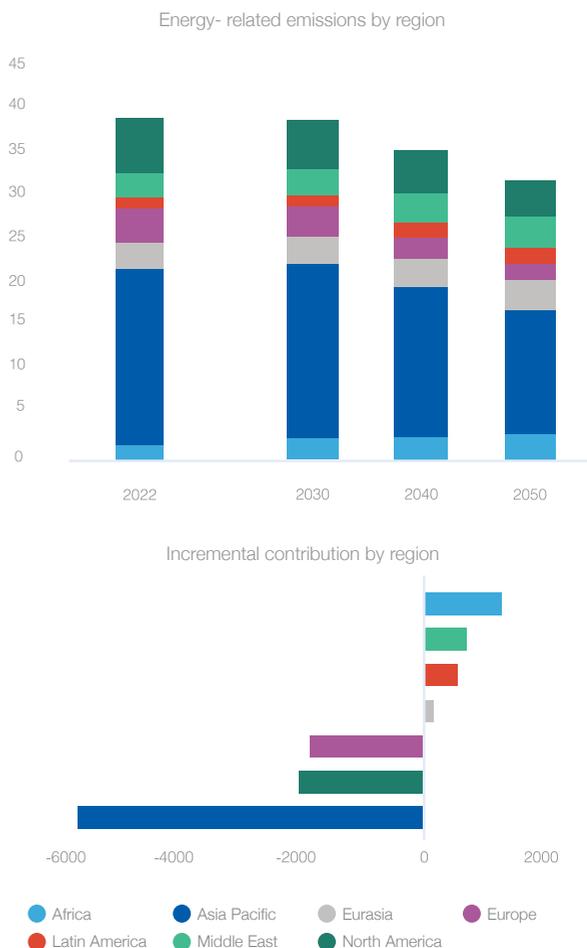
In 2022, GHG emissions and global average temperatures reached unprecedented levels. According to the RCS projections, this upward trend in emissions is expected to continue until 2025, after which a gradual decline in emissions is anticipated.

The energy-related emissions forecast highlights that the current decade is considered critical in curbing the rise of global average temperatures and as a result, a marked rise in policy support for decarbonisation initiatives is anticipated. This policy support is expected to significantly reduce emissions by 2030. Post-2030, this reduction rate may decrease as initial, simpler decarbonisation steps, the low hanging fruits, are anticipated to have been implemented by then.

Starting in 2040, the task of reducing emissions is projected to become increasingly intricate, with the focus shifting towards sectors that pose greater challenges for decarbonisation. Industries like heavy manufacturing, aviation and shipping present particularly formidable obstacles since they currently have limited low-carbon alternatives available, and the transition to such technologies can be both costly and technologically

Figure 3.18.

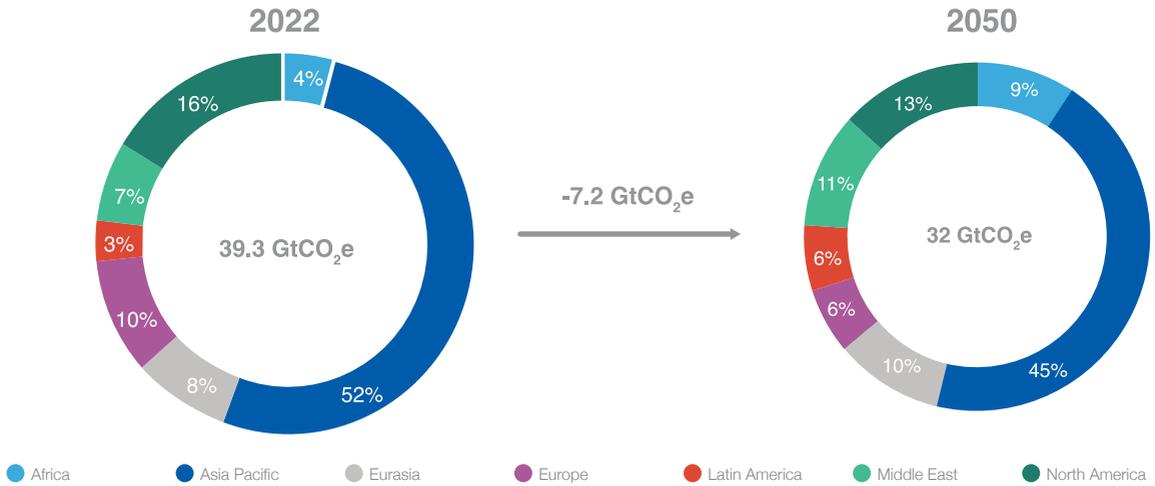
Energy-related emission outlook, 2022-2050 (GtCO₂e)



Source: GECF Secretariat based on data from the GECF GGM

Figure 3.19.

Contribution of regions in global energy-related emission, 2022 and 2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

demanding. Additionally, the inertia associated with altering existing infrastructure and transitioning energy systems across various regions is set to significantly contribute to the slower pace of emissions reduction.

The global peak in energy-related emissions is primarily attributed to the expected peak in the Asia Pacific region, forecasted to occur in 2025. As the region with the highest annual contribution to energy-related emissions, it is projected to have a significant influence on future global emission trends.

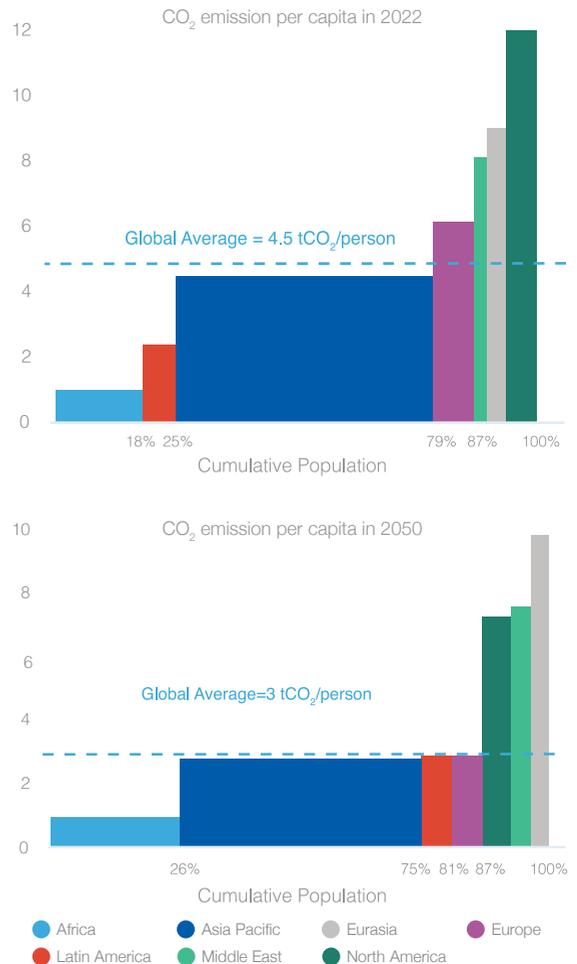
Figure 3.19 shows the contributions of various regions to global energy-related emissions and tracks their evolution from 2022 to 2050. The largest share of global energy-related emissions in 2022 is attributed to Asia Pacific, North America, and Europe, accounting for 52, 16, and 10%, respectively. In contrast, Latin America, Africa, Eurasia, and the Middle East contribute the smallest shares, representing 3, 4, 8, and 7% of the overall emissions, respectively.

When we consider the long-term outlook, regions with the lowest contribution to global emissions and those in the developing stages of their economies are expected to witness an increase in energy-related emissions. Africa, for instance, is projected to experience a growth of 1.3 GtCO₂e in energy-related emissions by 2050 due to its rapid population growth and industrialisation prospects. Meanwhile, Asia Pacific is anticipated to reduce its energy-related emissions by just under 6 GtCO₂ throughout the forecast period. Consequently, Africa's share of energy-related emissions is expected to reach 9%, while Asia Pacific is forecasted to contribute 45% of the total energy-related emissions by 2050, representing a nearly 7 p.p. reduction compared to the 2022 figures.

When we examine emissions on a per capita basis, a different perspective comes into view (Figure 3.20). The global average of emissions per capita in 2022 is estimated to be 4.5 tCO₂/person. What is particularly noteworthy is that Africa, Latin America, and Asia Pacific, which together account for roughly 80% of the global population in 2022, demonstrate emissions per capita that are below the global average. To be more specific, Africa, home to nearly 18% of the global population in

Figure 3.20.

Energy-related CO₂ emission per capita, 2022 and 2050 (tCO₂/person)



Source: GECF Secretariat based on data from the GECF GGM

Figure 3.21.

Decomposition of CO₂ emissions by its constituents (1990-2021 and 2022-2050)

Source: GECF Secretariat based on data from the GECF GGM

2022, is estimated to have emissions of just under 1 tCO₂ per person per year. This figure is approximately 12 times lower than the CO₂ emissions per capita in North America and 9 times smaller than that of Europe in 2022.

According to the RCS projections, CO₂ emissions per capita are expected to decline to 3 tCO₂ per person, primarily due to emission reduction efforts in Asia Pacific, North America, and Europe over the next three decades. Consequently, it is anticipated that CO₂ emissions in Europe will drop below the global average, while the Middle East and Eurasia are likely to become regions with the highest CO₂ emissions per capita levels in 2050.

It is important to emphasise that historical energy-related emissions by region present a distinct narrative. According to IPCC (2023) report, cumulative CO₂ emissions from North America and Europe from 1850 to 2020 are estimated to account for 28% and 24% of the total historical CO₂ emissions released into the atmosphere, respectively. In contrast, Africa and Latin America shares during the same period amounts to around 3 and 4%, respectively. Moreover, Eurasia and the Middle East are responsible for 8% and 7% of historical CO₂ emissions released into the atmosphere since 1850. Consequently, the historical responsibility of developed countries cannot be understated. It is even clearer when deforestation since two centuries is factored in.

Figure 3.21 visually decomposes CO₂ emissions into multiple components, including population, per capita GDP, energy intensity, and carbon intensity of energy consumption. Over the period from 1990 to 2021, the average annual growth of CO₂ emissions stood at 1.5%. However, in the forecasted period, it is expected to decline by 0.8% p.a. This reduction in global CO₂ emissions is primarily credited to prospective advancements in energy efficiency and a decrease in carbon intensity compared to historical patterns.

Between 1990 and 2021, the increase in emissions in regions such as Africa primarily resulted from population growth, while in contrast, the Asia Pacific region experienced increased emissions primarily due to economic growth. Globally, it becomes evident that the drivers of emission growth, including economic expansion and consumption patterns, have outweighed the impact of emission-reduction factors such as the adoption of cleaner energy, improvements in energy efficiency, and the implementation of various decarbonisation measures.

As we look ahead to the forecast period from 2022 to 2050, the projections indicate that while population and economic development will continue to be significant drivers of CO₂ emissions in regions like Africa, there is also an anticipated improvement in energy and carbon intensity, particularly in the Asia Pacific. This suggests ongoing efforts to enhance energy efficiency and reduce CO₂ emissions per unit of energy consumption. Such changes could stem from technological advancements, regulatory policies, or transitions to less carbon-intensive energy sources.

In terms of emissions across different sectors, the power generation sector is poised to achieve a significant reduction in its CO₂ emissions, decreasing from 13 GtCO₂ in 2022 to approximately 6.6 GtCO₂ by 2050. This represents a noteworthy reduction of approximately 50% (Figure 3.22). This decline can be attributed to various factors, including the increased adoption of renewable energy sources, particularly solar and wind power, a decrease in coal usage due to phase-out policies and environmental regulations, a transition to natural gas, and improvements in the thermal efficiency of power plants. These measures are expected to largely offset any potential emission increases resulting from the global growth in electricity demand.

Despite the expected reduction, the power generation sector

is foreseen to continue as a substantial contributor to global energy-related emissions until 2040. Beyond this juncture, the transport, power generation, and industry sectors are projected to emerge as the primary sources of emissions, with transport, power generation, and industry accounting for 27, 22, and 20% of global energy-related emissions, respectively. The accelerated decarbonisation of the power generation sector after 2025 stands out as a pivotal factor propelling the projected global emissions peak by 2025.

While the global shift towards renewable energy, carbon removal technologies, and nuclear power, as outlined by RCS, represents a crucial phase in addressing climate change, the role of natural gas remains distinct in this context.

Natural gas is poised to play a critical role in diminishing the emissions gap through larger penetration against coal and oil. The carbon intensity of natural gas is nearly half that of coal and 20% less than that of oil. This lower carbon intensity positions natural gas as a viable option for immediate and cost-effective emission reductions, especially through direct substitution in sectors such as power generation, industry,

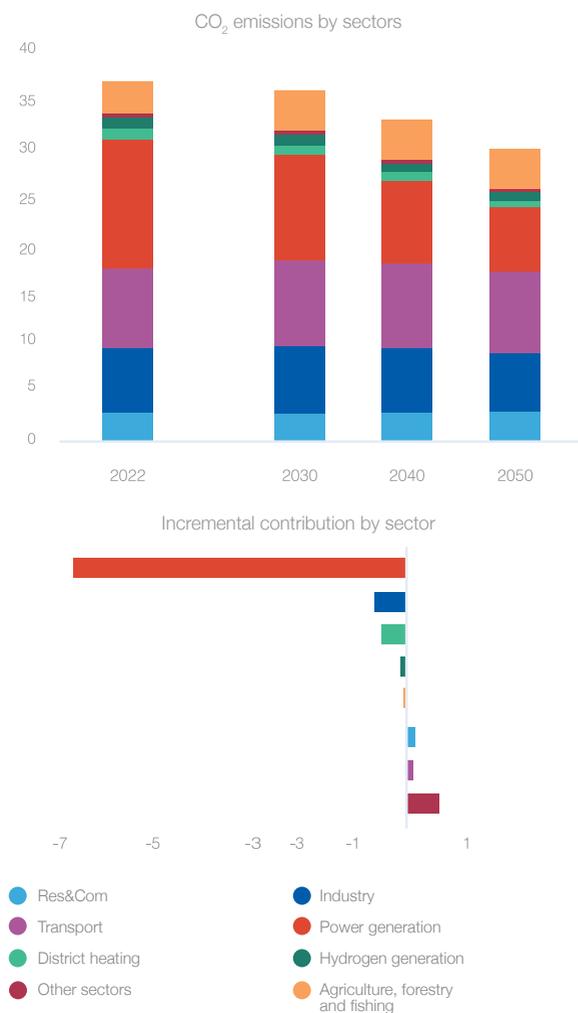
and transport. As an example, there is presently an estimated global coal-fired generation capacity of 2000 GW, contributing to over 10 GtCO₂e emissions. Replacing this capacity with gas-fired thermal power plants would result in a reduction of approximately more than 5.5 GtCO₂ emissions. Furthermore, due to the superior energy efficiency of gas-fired power plants compared to coal-fired ones, this policy would lead to improved energy efficiency and better control over primary energy demand.

The potential of natural gas in this regard is further reinforced by the advancement of CCUS and other carbon removal technologies. By 2050, the annual global savings from CCUS are projected to reach 1.67 GtCO₂ per year, with a substantial portion (over one-third) expected to be associated with the natural gas. This enhancement in reducing its carbon intensity strengthens the role of natural gas as a crucial element in mitigating climate change.

Furthermore, natural gas plays a pivotal role in decarbonising hard-to-abate sectors where direct electrification is impractical, either directly or indirectly through blue hydrogen. This is particularly critical in the current decade as we work to develop the hydrogen market for decarbonisation goals. Green hydrogen, while promising, is not yet cost-effective, and we require renewable electricity for other more efficient applications. In this context, natural gas is poised to support the growth of this market effectively.

Figure 3.22.

Global CO₂ emission outlook, 2022-2050 (GtCO₂)



Source: GECF Secretariat based on data from the GECF GGM

3.6. Energy intensity and consumption per capita prospects

Energy efficiency improvement is widely recognised as one of the key factor that aligns with the goals of ensuring reliable, affordable, and sustainable energy supplies. This improvement is measured by a crucial indicator known as energy intensity reduction, which quantifies the percentage decrease in the ratio of primary energy demand per unit of GDP on a PPP basis. Notably, global energy intensity has exhibited a consistent reduction over the past decade (2010-2020) at an annual rate of 1.8%, surpassing the rates observed in the previous two decades. However, it has declined over the last five years.

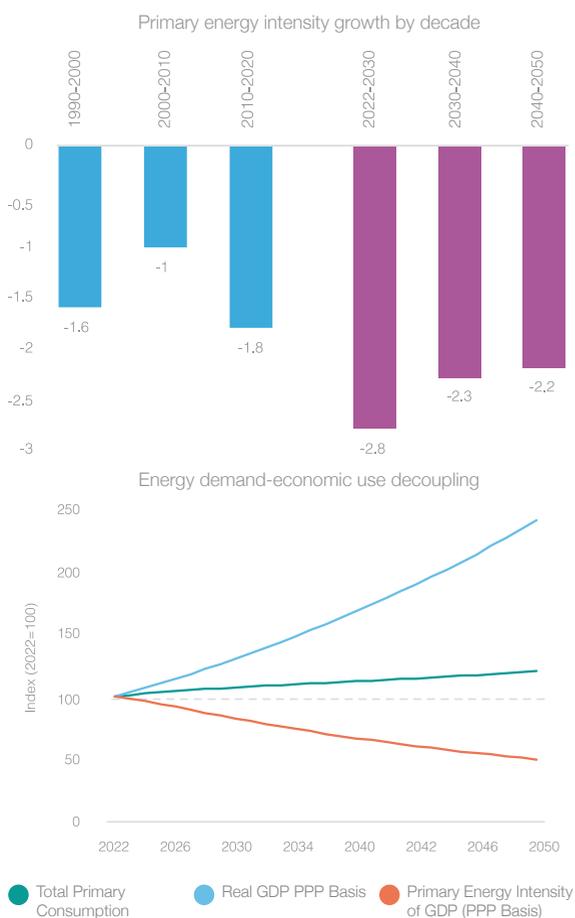
Several primary measures have contributed to this enhanced energy efficiency over the past decade. These include the phase-out of older, inefficient industrial capacities, advancements in energy efficiency within the building and industrial sectors, a shift towards industries that are inherently less energy-intensive, and the expansion of the services sector in the global economy.

However, it is essential to emphasise that energy efficiency improvement experienced a decline in 2022, dropping to 0.6%. This decline can largely be attributed to the effects of the COVID-19 pandemic, including lockdowns and travel restrictions, which disrupted normal economic activities. Consequently, drawing firm conclusions about the ongoing global structural energy efficiency improvement is challenging at this juncture. Nevertheless, it is important to view this dip as a temporary shock to the broader trend, as considered in the RCS.

According to the RCS, there is an expected improvement in energy efficiency of 2.5% p.a. during the period from 2022 to 2050. However, as depicted in Figure 3.23, despite the anticipated rapid acceleration of energy efficiency improvement to 2.8% annually during the 2022-2030 period, this momentum

Figure 3.23.

Energy intensity improvement outlook (%)



Source: GECF Secretariat based on data from the GECF GGM

is projected to gradually slow down to 2.3% and 2.2% p.a. during the following two decades, specifically in the 2040s and 2050s.

It is important to emphasise that while this significant reduction in energy intensity is expected, it may not necessarily lead to a complete decoupling of economic activity and energy use on a global scale. Nevertheless, the relationship between these two variables is expected to weaken over time.

Due to varying economic structures, levels of economic development, demographics, climate conditions and urbanisation rates, energy intensity trends exhibit differences across regions and countries. Thus, gaining a comprehensive understanding of the energy efficiency landscape necessitates an exploration of energy intensity trends at regional levels.

Energy intensity has improved worldwide since 1990, but significant variations in these trends can be observed across regions, as depicted in Figure 3.24. The Asia Pacific region stands out, experiencing the highest level of energy efficiency improvement at 2.5% p.a. during the 2010-2020 period. This progress aligns with the region's rapid economic growth and the associated increase in primary energy consumption. Notably,

one of the key factors driving energy efficiency improvement in the Asia Pacific has been the enhancement of electricity supply efficiency through the modernisation of electricity supply infrastructure and improvements in fossil fuel-based electricity generation. In particular, the efficiency improvements in natural gas-based electricity generation have offset the slower progress in the efficiency of coal and oil-based electricity generation. A similar trend can be observed in North America, where energy intensity has reduced by 1.6% annually over the last decade, almost in line with the global average.

During the last decade, Europe experienced a slight decrease in primary energy consumption, reflecting slower economic growth and the decoupling of the economy from energy usage — a trend not observed in other regions during the same period. Key factors contributing to energy efficiency improvement in Europe included a shift toward industrial activities that consume less energy and greater energy efficiency in buildings.

The smallest average improvements in energy intensity were observed in Africa and Latin America during the 2010-2020 period. In Latin America, primary energy demand remained relatively stagnant, and the region experienced some of the slowest GDP growth globally, resulting in an annual energy intensity improvement of only 1%. In contrast, Africa witnessed an annual energy efficiency improvement rate of 1% during the same period, albeit with different dynamics compared to Latin America. Energy consumption and GDP growth in Africa outpaced the global average, albeit with relatively low initial levels. Notably, in Sub-Saharan Africa, which is a focal point for energy poverty, the energy intensity in absolute terms is more than 1.5 times that of Latin America. This underscores the strong correlation between achieving universal access to energy and enhancing energy efficiency. Improving energy efficiency is considered a key factor in addressing energy poverty in Sub-Saharan Africa and can be realized through various measures. For example, transitioning from traditional biomass to LPG, a by-product of natural gas, not only enhances universal access to affordable, reliable, and sustainable modern energy but also contributes to improving the overall energy efficiency of the global energy system.

Various energy efficiency policies are currently in effect worldwide, encompassing standards, financial incentives, market-based mechanisms, capacity-building initiatives, and regulatory measures. These policies are further complemented by the integration of pertinent technologies such as digitalisation and artificial intelligence. As a result of these concerted efforts, it is anticipated that the acceleration of energy efficiency improvements will gain momentum over the coming decades across all regions. This collective progress is expected to lead to a greater convergence of energy intensity levels across the globe.

According to the RCS, the Asia Pacific region, the only one expected to surpass the global annual energy intensity improvement rate by 2050, is projected to experience a substantial 3.3% enhancement in energy efficiency throughout the forecast period. In contrast, in Europe and North America, energy efficiency improvements are anticipated to lead to the decoupling of economic growth and energy usage. In these two regions, energy efficiency is expected to grow annually by 2 and 2.2%.

As per the RCS forecast, the Middle East and Africa, despite experiencing the largest annual growth in primary energy consumption during the period from 2022 to 2050, are

Figure 3.24.

Primary energy consumption growth decomposition (1990-2021 and 2022-2050)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Per capita GDP in PPP (base year = 2022)

expected to have the lowest energy efficiency improvements during that same period. Energy intensity improvement in the Middle East and Africa is projected to be at 1.1 and 1.3% p.a., which is nearly less than half of the forecasted global average.

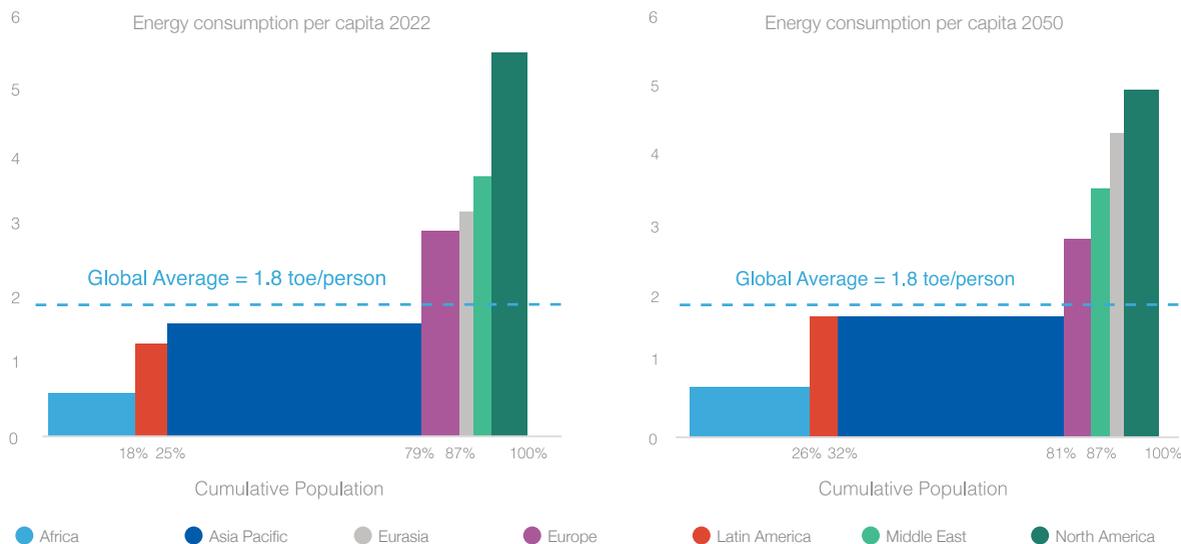
It is worth noting that cost savings resulting from energy efficiency improvements can lead to increased usage of energy-efficient technologies or services, as well as heightened spending in other areas that consume additional energy. These direct and indirect rebound effects of energy efficiency

improvements may result in an incomplete realization of the expected energy efficiency gains, particularly in low-income countries with limited access to energy.

In the global pursuit of sustainable development, securing access to affordable, reliable, and sustainable energy for all stands as an overarching imperative. The United Nations Sustainable Development Goals (SDGs) progress report underscores the gravity of the situation, revealing that in 2021, an estimated 675 million people still lack access to electricity, while a staggering 2.3 billion lack access to clean cooking facilities. It is worth noting that the majority is in Sub-Saharan

Figure 3.25.

Regional primary energy consumption per capita outlook, 2022 and 2050 (toe/person)



Source: GECF Secretariat based on data from the GECF GGM

Africa, a region poised to be a focal point of future population growth. This underscores the urgent need to address these energy access disparities, as they are pivotal to creating a more equitable and sustainable future for the global community.

The global average primary energy consumption per capita, a commonly utilised metric for assessing energy access, is estimated to be 1.8 toe per person in 2022. Remarkably, this figure closely resembles the levels observed for this indicator during the 2010-2020 period. The trends in energy consumption per capita vary across different regions due to distinct populations and energy consumption patterns inherent to each specific region (Figure 3.25).

In 2022, energy consumption per capita exhibited distinct patterns across different regions. Africa, Latin America, and the Asia Pacific region recorded levels below the global average, while Europe, the Middle East, Eurasia, and North America displayed higher-than-global-average energy consumption per capita. Africa, which is home to 18% of the global population, exhibited the lowest level of primary energy consumption, standing at 0.6 toe per person. This figure is approximately 9 times smaller than the energy consumption per capita in North America, where the figure is 5.5 toe per person, despite North America having only 6% of the global population.

It is worth emphasising that Africa, Latin America, and the Asia Pacific region collectively account for a substantial 80% of the global population in 2022. Despite this demographic dominance, there exists a significant disparity in energy consumption per capita between these regions and those surpassing the global average.

This divergence underscores the profound inequality in energy consumption per capita among regions, highlighting the pressing need to address these disparities and strive for a more equitable distribution of energy resources and access on a global scale.

The projected energy consumption per capita in the RCS offers insights into the prospective global energy landscape. It is noteworthy that the global average energy consumption per capita is expected to remain relatively stable over the forecast

horizon. This stability is primarily attributed to the expected parallel growth in energy consumption and population levels on a global scale.

Nonetheless, certain regional disparities in energy consumption per capita are anticipated. Notably, Europe and North America are expected to experience a slight reduction in energy consumption per capita. This decline is primarily attributable to the expected faster primary energy consumption decline rather than population in this region. However, it is important to underscore that developed regions such as North America and Europe are poised to maintain their status as hosts to energy-intensive industries, extensive transportation systems and lifestyles characterised by higher energy usage over the long term.

In contrast, Eurasia, the Middle East, Asia Pacific, and Latin America are expected to see higher energy consumption per capita, largely due to a growing population, urbanisation and industrialisation leading to increased energy demand. Moreover, the types of industries predominant in this region can also influence energy consumption. Energy-intensive industries, such as the oil and gas industry, manufacturing and heavy industry, are expected to contribute to higher energy use in these regions. An important projection emphasises that Africa, despite experiencing rapid population and energy consumption growth, is expected to see a modest increase in energy consumption per capita.

As illustrated in Figure 3.25, energy consumption per capita in Africa, Latin America, and the Asia Pacific region — comprising just under 80% of the global population by 2050 — is projected to remain below the global average. This underscores the enduring and fundamental challenge of ensuring access to affordable, reliable, and sustainable modern energy for all, particularly in the RCS scenario. Addressing this challenge, particularly in Africa, remains a critical priority for achieving global sustainability goals over the forecast horizon.

Natural Gas Demand Outlook



Highlights

- ▶ Global natural gas demand is projected to rise by 34% from 4,015 bcm in 2022 to 5,360 bcm in 2050, with no anticipated peak.
- ▶ Rising population, economic activity and policies, aimed at air quality improvements, reducing GHG emissions, renewable power system stability, universal clean cooking access, and coal- and oil-to-gas switching are the key determinants behind the forecast. Natural gas paired with CCUS, both in power generation and industry, is expected to support long-term natural gas demand, while the use of blue hydrogen represents an additional pathway toward decarbonisation of hard-to-abate sectors.
- ▶ The power generation sector is poised to be the main area of natural gas demand expansion, adding 500 bcm and accounting for 37% of the total growth. This is due to the strong rise in electricity needs and policies to phase down coal-fired power generation capacity. Moreover, as the share of renewables increases, natural gas-fired power generation is projected to become increasingly instrumental. It will provide essential flexibility and backup support to solar and wind power, and to hydropower during periods of drought.
- ▶ The industrial sector is forecast to provide additional 275 bcm, equivalent to 20% of incremental volumes between 2022 and 2050. Natural gas retains its place as a primary fuel suited for medium and high temperature industrial processes. Moreover, natural gas use in industry rises as a feedstock, underpinned by growing need for petrochemicals and fertilisers, with the latter contributing to agricultural sector productivity and food security.
- ▶ Blue hydrogen generation is expected to become another major avenue for increased natural gas use. Growth potential lies in the development of an internationally traded hydrogen market, while substituting grey hydrogen with blue hydrogen in existing industrial applications is also anticipated.
- ▶ The transport sector emerges as an important demand centre on the back of stricter environmental regulations and supportive policies. The use of natural gas in road and marine transport is forecast to rise by around 220 bcm over the forecast period, mainly driven by LNG as bunker fuel and in heavy goods vehicles.
- ▶ From a regional perspective, the bulk of future natural gas demand growth is expected to come from fast-growing Asia Pacific markets and gas-rich Middle Eastern and African countries. Asia Pacific alone is forecast to add almost 700 bcm and account for 52% of the global net demand growth during the outlook period, with China, India and Southeast Asia countries in the lead.
- ▶ China is set to retain its role as the greatest demand contributor, accounting for 45% of Asia Pacific's incremental natural gas use, and providing 23% of additional global volumes over the forecast horizon.
- ▶ Natural gas demand in North America is expected to remain resilient through to 2050. Europe is anticipated to be the only region to experience an evident declining trend in natural gas demand due to increased policy support for renewables and alternative decarbonisation options.

4.1 Natural gas demand outlook: global overview and sectoral trends

4.1.1 Recent developments and global outlook overview

For the second consecutive year, global natural gas demand has surpassed the 4,000 bcm threshold. Following an exceptional post-COVID rebound in 2021 (+5%), attributed to the lifting of lockdown measures and economic recovery, global demand experienced a slight decline of about 1%, reaching 4,015 bcm in 2022 (Figure 4.1). The impact of mild winter temperatures on demand was felt in the residential and commercial sector across many Northern Hemisphere countries. Additionally, the decrease in demand was significantly influenced by elevated gas prices in Europe and Asia amid tight market conditions. Responding to LNG price spikes, countries shifted to alternative fuels, primarily turning to coal for power generation, or curtailed natural gas use in energy-intensive industries. The reduction in renewable output further contributed to an overall reduction in natural gas demand.

Despite the global slowdown in demand, the year 2022 witnessed contrasting regional trends, with year-on-year variations ranging from +5% in North America to -11% in Europe. European natural gas demand in particular experienced its steepest decline in absolute terms in history, accounted for about 61 bcm in 2022. Exceptionally mild weather conditions in Q4 weighted on space heating requirements. Furthermore, demand in the region was impacted by industrial production curtailments due to record high gas prices as well as energy conservation efforts, and fuel switching. This occurred in the context of implementing EU regulation 2022/1369 of 5 August 2022, focusing on coordinated demand-reduction measures for gas.

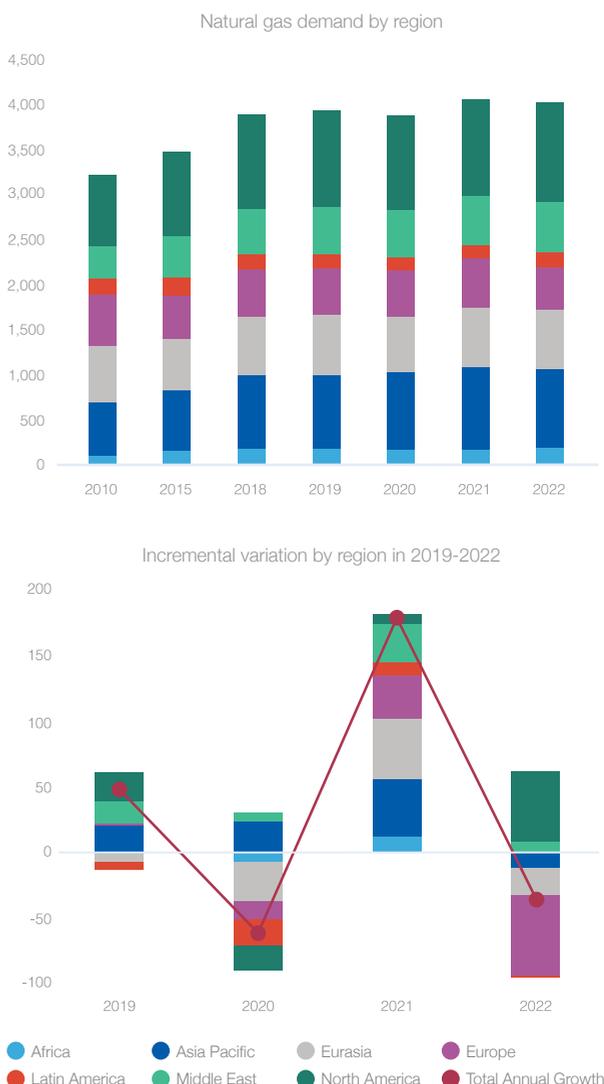
Asia Pacific natural gas demand also came under pressure in 2022. The high LNG prices, driven by a surge in LNG imports in Europe to replace Russian piped gas supplies, triggered LNG demand destruction in many Asian markets. The largest declines were observed in China and India influenced by the switch to coal use, and a slowdown in industrial activity in China due to widespread lockdowns within the country's zero-COVID policy. Natural gas consumption was also severely curtailed in Pakistan and Bangladesh as unaffordable spot LNG prices led to power shortages and blackouts, prompting attempts to switch to highly emitting energy sources like fuel oil and coal.

On the contrary, North America's natural gas demand showed a solid growth, accounting for around 53 bcm year-on-year in 2022, fully recovering from the 2020 COVID-induced losses. The increase was primarily attributed to substantial consumption growth in the United States power generation sector, as a consequence of coal-fired plants retirement and tightening coal supplies. The United States also experienced several heatwaves during the summer, which boosted additional gas-fired power for cooling needs. The Middle East was the second region to make a positive contribution with natural gas consumption increasing modestly, mainly due to higher electricity generation from gas-fired power plants.

In spite of the unfolding global energy crisis and gas market developments observed in 2022, the future for global natural gas demand remains bullish. The 2023 year has already indicated a return towards a growth trajectory, driven by demand gains in Asia Pacific. During 2023, gas prices have softened, while an anticipated surge in LNG supply in the

Figure 4.1.

Global natural gas demand, 2010-2022 (bcm)



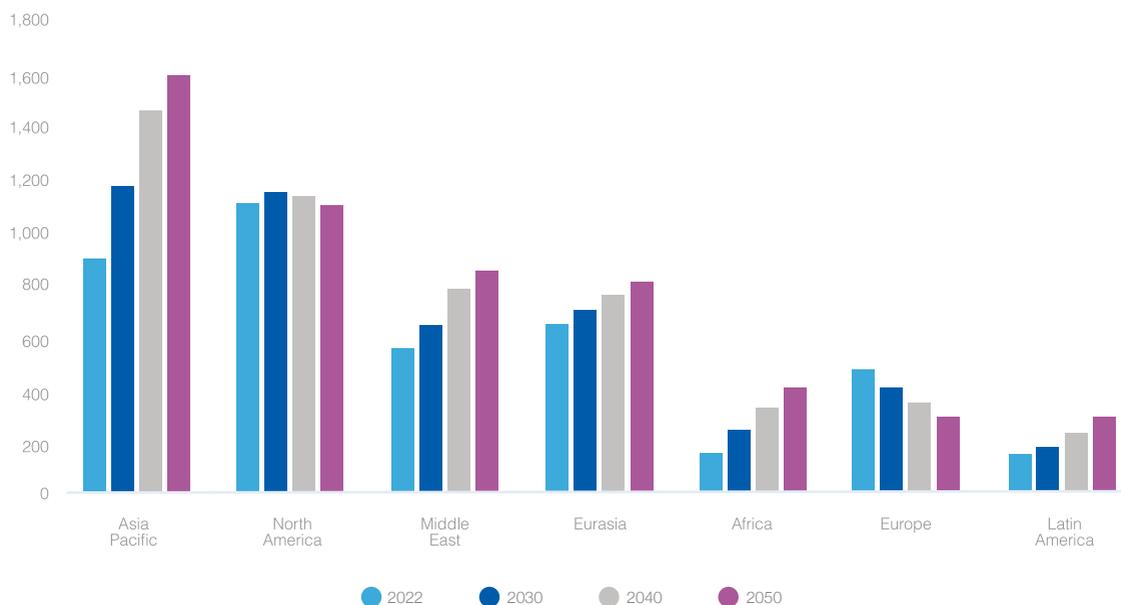
Source: GECF Secretariat based on data from the GECF GGM

coming years is set to further bring down prices, and ease gas supply security concerns. Meanwhile, policy efforts aimed at air quality improvements, reducing GHG emissions and coal- and oil-to-gas switching are assumed to be the key determinants, ensuring a sustained long-term outlook for natural gas.

This energy source is expected to be favoured by the move away from coal in power generation, higher consumption from the industrial sector, and greater use as a transport fuel. As decarbonisation activity gains additional traction, the deployment of low-carbon technologies, such as CCUS and blue hydrogen generation, is projected to play a crucial role and support long-term natural gas use. Natural gas paired with CCUS, both in power generation and industry, is set to become an important carbon mitigation option, while the use of blue hydrogen represents an additional pathway toward decarbonisation of hard-to-abate sectors.

Figure 4.2.

Global natural gas demand outlook by region, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Based on economic and population drivers, as well as an assessment of current energy policy settings, as discussed in detail in Chapters 1 and 2, global natural gas demand is forecast to rise by 34% from 4,015 bcm in 2022 to 5,360 bcm in 2050, with no peaking expected. This abundant, flexible and the cleanest burning hydrocarbon is set to expand specifically across Asia Pacific, Middle Eastern, and African markets, with Asia Pacific alone contributing to 52% of the global net demand increase during the forecast period.

Overall, the long-term trend shows that natural gas demand is anticipated to be strong in all regions, except Europe, and resilient in North America (Figure 4.2). In Europe, natural gas use is expected to have an orderly decline due to increased policy support for renewables and alternative decarbonisation options, such as pervasive electrification and energy efficiency, along with biomethane and green hydrogen deployment, provided they become competitive. This Chapter features a detailed view of the natural gas demand dynamics in each region (Section 4.2), presented after demand trends from the sectoral perspective.

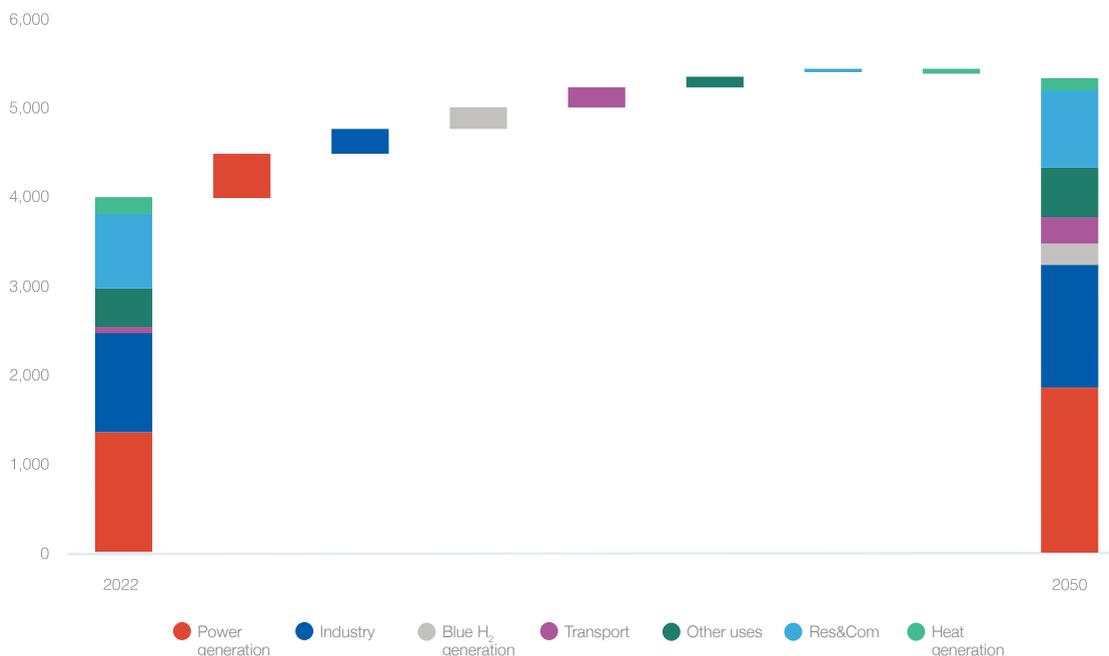
4.1.2 Sectoral trends

Looking towards 2050, the power generation sector is set to be the driving force behind natural gas demand growth, accounting for 37% of incremental volumes over the outlook period. The industrial sector comes in second, providing 20% of the total increase. Other major avenues for natural gas demand expansion include its growing use as a source for blue hydrogen generation, as well as greater penetration in the transport sector. The increase in residential and commercial sector is projected to be much less dynamic, contributing to just 3% of additional demand between 2022 and 2050. Figure 4.3 provides an overview of natural gas demand trends by sector.

The **power generation** sector is forecast to remain the largest consuming area, comprising 35% of the global natural gas demand in 2050. Natural gas use in this sector is set to rise by around 500 bcm to over 1,880 bcm by 2050, mainly underpinned by the strong growth in electricity needs, and policies to phase down coal-fired power capacity. At the regional level, the biggest contribution to the demand increase is expected to come from Asia Pacific where coal-fired power generation currently dominates, and Africa where energy poverty is still high. In addition, with the assertive deployment of solar and wind capacity, the need for flexibility as a pillar of electricity security mounts, and natural gas-fired power generation is expected to play a growing role in helping to balance variable renewables, and ensuring stability of power grid systems. It provides a backup when hydropower supply faces drought-induced shortages. The demand for natural gas as a flexible and dispatchable source is expected to persist across all regions, even considering anticipated progress in storage technologies. The potential synergy with CCUS provides additional opportunities for gas-in-power, ensuring a significant reduction in carbon emissions.

In the **industrial** sector (industry), natural gas demand is anticipated to grow by nearly 275 bcm over the outlook period, reaching around 1,380 bcm by 2050, with Asia Pacific and Middle Eastern markets taking the lead. This includes the rise of natural gas use as a feedstock for the production of petrochemicals and fertilisers, with the latter contributing to agricultural sector productivity and food security. Overall, in addition to traditional drivers such as on-going industrialisation in developing countries and population growth, policy-driven initiatives to reduce emissions act as a significant catalyst, favouring coal- and oil-to-gas switching. Natural gas is set to witness an increasing role in providing heat and steam across energy-intensive industries, particularly in chemical and

Figure 4.3.

Natural gas demand outlook by sector, 2022-2050 (bcm)

Source: GECF Secretariat based on data from the GECF GGM

Note: 1) Industry includes gas used as energy fuel and feedstock as well as for grey hydrogen generation and the production of liquid fuels; 2) Transport includes road transport and marine bunkers; 3) Other uses include gas demand for energy industry own use, for rail and pipeline transport.

petrochemical production, non-metallic minerals, iron and steel as well as a broad range of light manufacturing, and retain its position as a primary fuel suited for medium and high-temperature processes. Many industries using natural gas are expected to initiate the deployment of CCUS, influenced by carbon market developments. This evolving trend enhances environmental credentials of natural gas and facilitates the decarbonisation of assets on a cost-competitive basis.

Blue hydrogen generation is set to emerge as an additional avenue for increased natural gas demand, aligning with countries' efforts to scale up the deployment of low-carbon hydrogen in various sectors. The attractiveness of blue hydrogen is projected due to the maturity of its technology, lower cost compared to green hydrogen, and synergy with the existing natural gas infrastructure. Growth potential lies in the development of an internationally traded hydrogen market, akin to the current LNG market, in the anticipation of the evolution in hydrogen liquefaction and storage technologies. Substituting grey hydrogen with blue hydrogen in existing industrial applications is set to materialise responding to climate targets efforts. Overall, natural gas demand for blue hydrogen generation is forecast to reach 240 bcm by 2050. North America is expected to contribute most, accounting for around 27% of the total natural gas demand increase in this sector, followed by the Middle East, Eurasia and Europe.

In the **transport** sector (both road and marine transport), natural gas demand is forecast to grow by around 220 bcm, reaching over 290 bcm by 2050. **Marine transport** is set to account for 36% of this incremental growth, implying

that natural gas demand in this segment reaches nearly 90 bcm by 2050. The introduction of the International Maritime Organization's (IMO) global cap of 0.5% sulphur content has favoured LNG to gain traction, while anticipated stricter regional regulations, such as Emission Control Area requirements (with 0.1% sulphur limit), as well as rising orders for LNG-powered vessels maintain high expectations for fuel use at a global level. The shipping industry is focused on meeting long-term decarbonisation targets, set by the 2023 IMO GHG Strategy, however many of alternative fuels, such as hydrogen and ammonia, are in a nascent stage of development, and face commercial and technical limitations. In its turn, LNG is well-positioned to offer enhanced competitiveness due to its extensive LNG infrastructure and supply chains. It also provides significant advantages by complying with future requirements for major types of emissions, contributing to an improvement in overall air quality.

Natural gas demand in **road transport** holds even greater growth potential, estimated at an additional 140 bcm between 2022 and 2050. This accounts for 64% of the total demand increase in the transport sector. Many countries are adopting stricter environmental requirements for vehicles due to pollution linked to the use of traditional liquid fuels. In this context, mature CNG and LNG technologies may represent a bridge to sustainable and decarbonised mobility in the future. Favourable government policies and the expansion of refuelling infrastructure will drive the demand with Asia Pacific in the lead, followed by Eurasia, North America and African countries. The increase is expected to concentrate in the heavy goods vehicle (HGV) segment, particularly due to the prospects of using LNG-

powered trucks, as a competitive and more environmentally friendly alternative to diesel. Implementation of forward-looking national or regional sales restrictions on new diesel or petrol vehicles, is also expected to implicitly support natural gas mobility, despite the rapid penetration of EVs.

In the **residential and commercial** sector, natural gas demand is forecast to rise by 35 bcm over the outlook period, exceeding 860 bcm in 2050. Increased demand is set to be much less significant compared to other sectors, as electrification, energy efficiency improvements, building retrofits and alternative heating options (such as biomethane, heat pumps, low-carbon hydrogen or renewables) may limit the scope for natural gas. A decline is projected in Europe and North America, given policy interventions targeting to decarbonise buildings through leveraging energy conservation measures, and transitioning towards low-carbon gases and electricity. However, this is expected to be largely offset by potential growth in other regions, primarily in Asia Pacific and Eurasia, amid switching from coal to gas, gas grid expansion, and growing household connections. Programmes to improving access to clean cooking, particularly in Sub-Saharan Africa, are expected to represent additional area for natural gas, notably LPG, enabling the move away from traditional biomass use in the residential segment.

4.2 Regional trends in natural gas demand

4.2.1 Africa

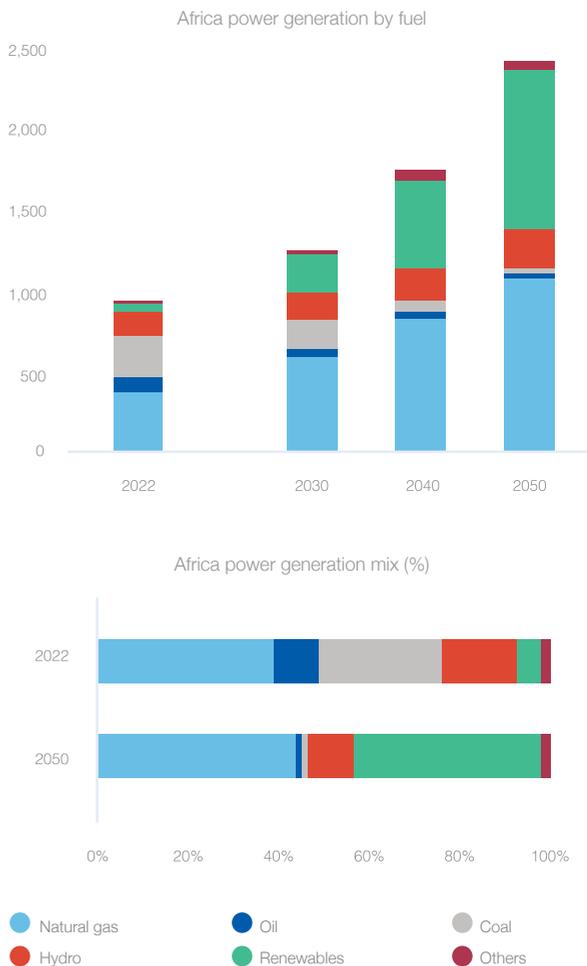
Natural gas demand in Africa is forecast to grow by 3.3% per annum, from 165 bcm in 2022 to 410 bcm by 2050. Strong economic expansion, continued industrialisation and rapidly rising urban population, accompanied by an accelerated increase in electricity needs, are the main drivers. The forecast for natural gas demand growth is largely underpinned by the availability of abundant gas reserves and significant prospects for the continent's own production. A number of countries, both established natural gas producers and emerging ones, with considerable gas resources (Mozambique, Tanzania, Senegal, Mauritania to name a few), have plans for gas network expansion to stimulate local natural gas use, despite significant export orientation of the projects. Regional gas infrastructure is expected to enlarge, and become more diverse with potential impetus coming from long-distance pipeline developments. Many projects are under consideration, including Trans-Saharan Gas Pipeline and recently announced the Central African Pipeline System, which are poised to intensify intra-regional integration.

With targets to ensure universal access to electricity, and the need to meet the substantial power deficit, especially in Sub-Saharan countries, the power generation sector is set to provide the major share of natural gas demand increase, accounting for incremental 140 bcm or around 57% of additional volumes in the region between 2022 and 2050. From an economic and environmental view, there is significant scope for natural gas to displace oil-fired generation, to constrain the expansion of coal-fired capacity in South Africa and its neighbours (where coal is a dominant source), and to enable accelerated electrification in partnership with variable renewables. Simultaneously, options such as gas-by-wire within the same regional power pool and the development of LNG-to-power projects will create additional sources of demand,

allowing African nations to monetise locally produced gas.

According to estimations, electricity generation in Africa is poised to surge from 950 TWh in 2022 to around 2,450 TWh in 2050 (Figure 4.4). Natural gas is forecast to cover more than 45% of the total growth of Africa electricity requirements, while its share in the regional power generation mix is forecast to rise from 40% in 2022 to 44% in 2050. Egypt, Nigeria as well as countries in Western and Southern Africa are to be the largest contributors of this trend, given intentions to expand their gas-fired fleet. This takes into account South Africa's shift away from coal, along with declining oil-fired generation across Sub-Saharan Africa. In this context, natural gas, in tandem with renewables (which is set to grow rapidly, underpinned by countries' plans and supporting programmes and initiatives), become essential in improving electricity access. Natural gas is also expected to play an increasingly important role in sub-Saharan countries that continue to depend on hydropower, ensuring a back-up during dry spells.

Figure 4.4. Africa power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include bioenergy, nuclear and hydrogen

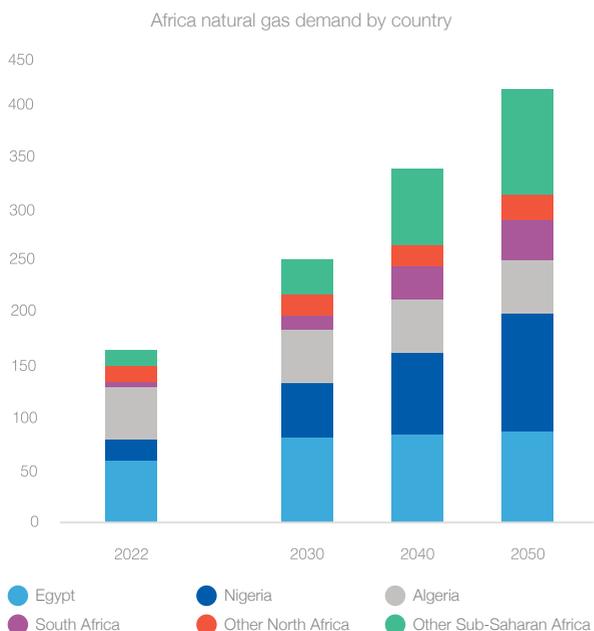
The industrial sector is projected to represent the second largest area of natural gas demand increase, adding around 35 bcm over the outlook period. The development of petrochemical, fertiliser and methanol plants in Egypt and Nigeria largely underpin this growth. Moreover, many industrial projects have been proposed in a number of sub-Saharan countries that is projected to provide ample commercial cases for the development of their domestic gas markets. Natural gas as a key fertiliser input will contribute to agricultural sector productivity, and play a role in ensuring food security in Africa.

In the residential and commercial sector, demand is expected to increase by 25 bcm between 2022 and 2050. There is a strong potential for natural gas to penetrate the residential segment, especially for clean cooking in Sub-Saharan Africa, where households rely heavily on the use of traditional biomass (refer to Box 4.1). The growth is also set to come from North African countries amid the development of transmission and distributions systems, and an increasing number of citizens connected to the grid. Additionally, the transport sector emerges as a significantly new area with major opportunities arising from the development of NGV markets. Natural gas demand in road transport in Africa is forecast to reach almost 18 bcm by 2050 from less than 1 bcm in 2022.

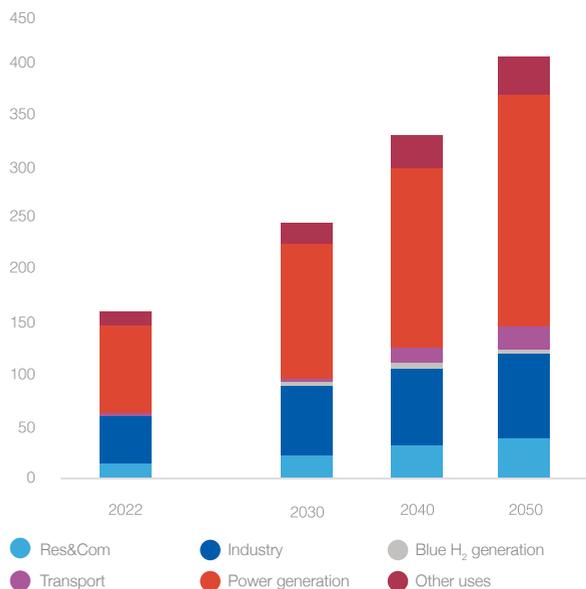
Figure 4.5 shows an expected development of natural gas demand in Africa and its sectoral distribution. On a country level, the largest incremental demand over the forecast period is projected for Nigeria, Egypt and South Africa. Meanwhile, it is important to note that the position of natural gas varies significantly across the continent. In North Africa, natural gas currently meets around 48% of the sub-region's energy mix, and is expected to remain a dominant energy source over the outlook period. Conversely, in sub-Saharan Africa, natural gas accounts for just 5% today, but it is set to make remarkable progress due to the push for industrial and social development.

Figure 4.5.

Africa natural gas demand outlook, 2022-2050 (bcm)



Africa natural gas demand by sector



Source: GECF Secretariat based on data from the GECF GGM

North Africa currently accounts for about three-quarters of the continent's natural gas demand, which remains concentrated in Egypt and Algeria. Consumption in this sub-region is expected to rise from 124 bcm in 2022 to 163 bcm by 2050 with relatively balanced sectoral contributions. In **Algeria**, the second largest and already mature gas market in Africa, demand is forecast to increase only modestly. The intensified development of renewables, particularly solar PV capacity, and integration of efficient CCGTs will put gas-in-power demand on a declining trajectory, offsetting growing natural gas use in the residential segment, road transport and for blue hydrogen generation. In **Morocco**, demand is projected to rise by 5 bcm between 2022 and 2050, mostly for industrial needs and replacement of coal-fired generation, as coal currently generates over 70% of the country's electricity.

Egypt will lead demand growth in North Africa, adding over 28 bcm through to 2050. This increase is projected to emerge from surging electricity needs and the associated expansion of the gas-fired power fleet as well as rising demand in industry, residential segment and road transport. The country's energy policy prioritises natural gas use as a substitute for oil products, while the ramp-up of production from existing fields, new discoveries and the development of transmission and distribution systems will underpin this direction. The pace of natural gas demand growth is set to slow down in the 2030s as the government boosts renewables, which could limit output from gas-fired power plants. Furthermore, Russia's Rosatom started construction of the 4.8 GW El Dabaa nuclear power plant and gradual commissioning of its four units will put additional pressure on gas-in-power demand in the long-term.

Sub-Saharan African natural gas demand is forecast to rise from 41 bcm in 2022 to 247 bcm in 2050, amounting to 84% of the total continental gas demand growth. This trend is set to be overwhelmingly driven by the ramp-up in gas-fired generation, growing industrial activity, and rising demand for energy sector-related needs amid the development of LNG export facilities.

Box 4.1 Transitioning from traditional biomass to LPG, a by-product of natural gas

The residential segment holds a significant role in Africa's energy landscape, serving as the largest energy consumer across the continent. In the year 2022, this segment accounted for a substantial 364 Mtoe of energy consumption, constituting over 56% of the total final energy consumption within the region. A noteworthy observation is that traditional biomass served as the predominant energy source for African households, supplying over 300 Mtoe of energy during that year. It is crucial to emphasise that this substantial contribution of the residential segment to final energy consumption, as well as the prevalence of traditional biomass as the primary energy source for households, is particularly prominent in the Sub-Saharan region. In contrast, North Africa's residential energy demand in 2022 featured a consumption of approximately 3 Mtoe of traditional biomass, with household demand accounting for an estimated 26% of final energy consumption during this period, in line with the global average.

The primary reason behind the significantly higher consumption of biomass in African households compared to other regions worldwide is the lack of access to reliable, affordable, and sustainable modern energy sources. Consequently, households are left without energy alternative but to rely on wood, dung, and charcoal, which, due to their low efficiency, require more fuel for daily needs. This situation places a heavy burden on households, particularly women and children, who are typically responsible for gathering biomass.

In Sub-Saharan Africa, households without access to clean cooking facilities typically spend an average of 2 hours each day collecting fuels. Additionally, they allocate 3 hours to cooking and food preparation, which includes managing the fire. The health consequences of using traditional stoves and open fires for cooking are extremely severe. According to the World Health Organization (WHO), household air pollution resulting from the lack of clean cooking methods is the second leading cause of premature death in Sub-Saharan Africa, contributing to approximately 700 thousand fatalities annually in the region. Alarmingly, women and children account for 60% of these tragic deaths. It is essential to emphasise that transitioning from traditional biomass to LPG can help mitigate the dire health risks associated with particulate matter generated from incomplete combustion and gaseous reactions of traditional biomass. This transition can potentially save around 400 thousand lives annually in Africa by reducing exposure to ambient particulate matter.

According to the United Nations, from 2015 to 2021, the percentage of individuals who gained access to clean cooking fuels and technologies increased by just 7 p.p. However, in South and Southeast Asia, specifically in countries such as India and Indonesia, substantial and consistent progress was observed. By 2021, approximately three-quarters of their populations had gained access, marking a 14 p.p. increase since 2015. Conversely, the region with the lowest rates of access was Sub-Saharan Africa, where advancements in clean cooking solutions have failed to keep up with the growing population. This left a total of 0.9 billion people without access in 2021. If present trends persist, it is projected that only 77% of the global population will have access to clean cooking solutions by 2030, leaving nearly 1.9 billion people without access, including 1.1 billion in Sub-Saharan Africa.

Substantial advancements in providing clean cooking solutions have primarily been propelled by the adoption of LPG (liquefied petroleum gas). In India, the number of people primarily using LPG for cooking surged by nearly 300 million from 2015 to 2022, thanks to robust measures and initiatives such as the Pratyaksh Hanstantrit Labh, which has been subsidising LPG refills since 2015, and the Pradhan Mantri Ujjwala Yajona, which has provided over 80 million deposit-free connections to women in impoverished households since 2016. Similarly, in Indonesia, the government's LPG subsidy program significantly contributed to a 60 million increase in the population primarily using LPG for cooking during the same period, representing more than 20% of the population. In sub-Saharan Africa, a series of efforts in different countries have established LPG as the most prevalent clean cooking technology available today.

LPG, with over 60% of its production originating from natural gas, possesses a multitude of advantages in addressing the clean cooking accessibility challenge in Sub-Saharan Africa:

Clean and efficient combustion: LPG burns with exceptional cleanliness and efficiency, emitting fewer harmful pollutants in comparison to traditional biomass fuels.

Enhanced indoor air quality: The clean combustion of LPG reduces indoor air pollution, thereby mitigating health risks linked to household air pollution.

Accessibility and safety: LPG is readily available, and can be safely distributed and stored in cylinders, even in remote rural areas.

Stable and easily controllable flame: LPG provides a stable and easily adjustable flame, thereby reducing cooking time and effort.

Time and effort conservation: LPG significantly decreases the necessity of gathering firewood or biomass fuels, resulting in time and effort savings. This benefit is especially meaningful for women and children who often bear the responsibility of fuel collection.

Environmental advantages: LPG's clean-burning characteristics contribute to a reduction in deforestation and environmental degradation.

Versatility: LPG can be used for a variety of cooking methods, from stovetop cooking to baking and grilling, making it a versatile choice for different cooking needs.

Energy efficiency: LPG stoves are often more energy-efficient compared to traditional cook stoves, leading to less fuel for the same cooking needs, resulting in cost savings over time.

Alignment with sustainable development goals: LPG aligns with various UN SDGs, encompassing improvements in health, gender equality, clean energy adoption, and environmental sustainability.

As a result, LPG presents Sub-Saharan Africa with a cleaner, safer, more efficient, and modern cooking solution, elevating household well-being and furthering progress towards SDGs.

The power generation sector is anticipated to lead the increase, contributing to around 135 bcm, equivalent to 65% of additional volumes in this sub-region through to 2050, due to growing access to electricity. The size of the gas-fired power fleet in the sub-region will scale up massively, rising from 22 GW in 2022 to about 145 GW in 2050, led predominantly by the expansion in capacity in Western and Southern Africa countries. In South Africa in particular, gas-fired power projects may significantly contribute to the future power generation mix, helping to shift away from extensive coal use (in 2022, coal accounted for 86% of country's total electricity generated), while LNG-to-power projects are assumed to be an attractive option.

From country perspective in Sub-Saharan Africa, **Nigeria** is projected to add the most – around 90 bcm between 2022 and 2050. A recently adopted policy and initiatives, such as the “Decade of Gas” launched in 2021, directed at expanding the local use of significant gas resources, are to be the pillar for the gas-based transition for the Nigerian economy. The country is expanding its gas pipeline network, including the Abuja-Kaduna-Kano gas pipelines anticipated to be commissioned in 2024, as well as encourage the monetisation of gas that is currently flared. Natural gas demand is forecast to be primarily driven by its higher use in the power generation sector, accompanied by striking electricity demand growth. Consumption in the industrial sector will be also considerable, principally due to the development of petrochemicals and fertiliser production.

4.2.2 Asia Pacific

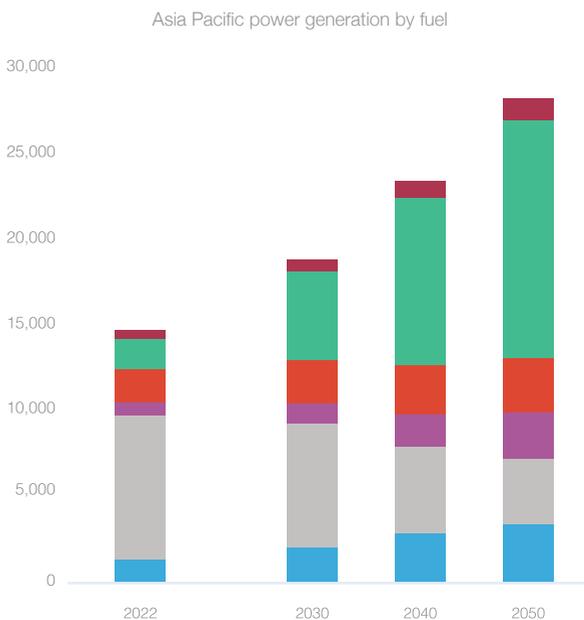
The central theme that unifies countries in Asia Pacific is a robust policy initiative to improve air quality and reduce greenhouse emissions. The primary focus revolves around cutting coal dependence, which presently accounts for around 47% of the regional energy mix. These priorities set the stage for a substantial increase in the use of natural gas. The region's demand for natural gas is projected to grow at the rate of 2.1% per annum, climbing from 895 bcm in 2022 to 1,590 bcm by 2050. The share of this fuel in regional energy mix is set to surge from 11% in 2022 to over 16% by 2050. Key drivers of this shift are electrification, policy measures encouraging coal- and oil-to-gas switching, and significant investments in gas infrastructure. This encompasses the development of new regasification capacity, the expansion of transmission and distribution networks, and other initiatives.

Power generation is set to take a prominent position, constituting 47% of the total increase in natural gas demand. Gas-fired generation is expected to be favoured across all markets in Asia Pacific in the context of continued diversification from coal and as a part of the long-term decarbonisation strategy. Gas-based power generation is also projected to be in demand to facilitate the integration of variable solar and wind capacities, addressing the need for enhanced flexibility in the face of intermittency issues. With robust electricity requirements in Asia Pacific and significant potential for displacing coal, the share of natural gas-fired generation is set to increase to 13% in 2050, up from 10% in 2022 (Figure 4.6).

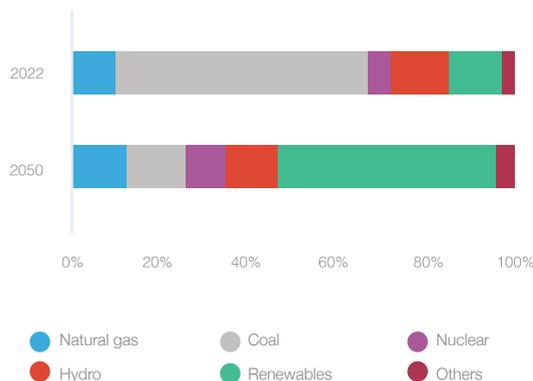
Demand for natural gas in the industry is projected to rise considerably, accounting for 21% of total growth, driven by strong economic development and policy shift away from polluting fuels. The residential and commercial sectors contributes 12% to the incremental increase in demand in the region through to 2050. Moreover, Asia Pacific is expected to

Figure 4.6.

Asia Pacific power generation outlook, 2022-2050 (TWh)



Asia Pacific power generation mix (%)



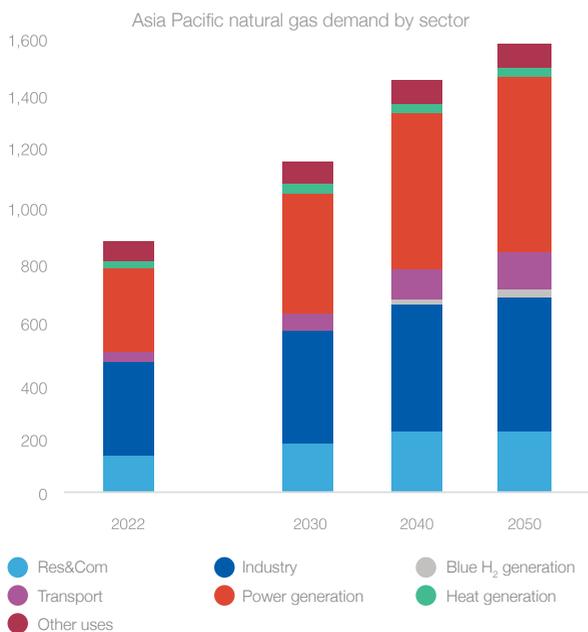
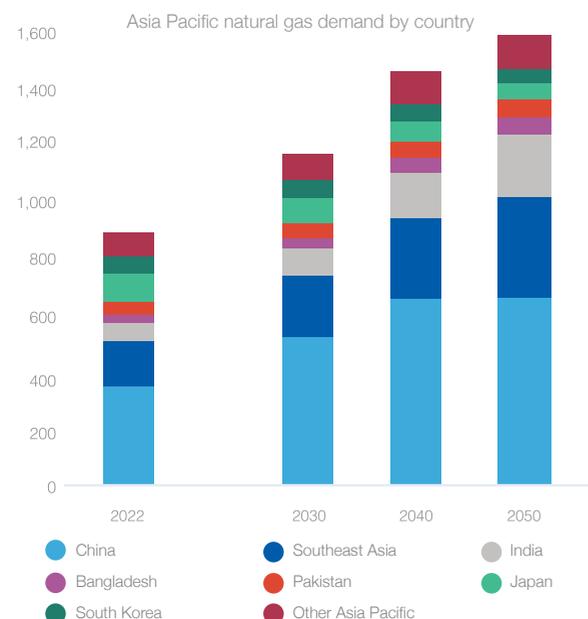
Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include oil, bioenergy and hydrogen

be a very promising region for natural gas use in the transport sector. Much of the increase will stem from efforts to promote CNG- and LNG-fuelled vehicles amid strengthening emission standards and strategies to expand refuelling stations.

On a country level, China, India and Southeast Asia are set to be the primary growth centres in Asia Pacific (Figure 4.7). Meanwhile, Japan and South Korea are projected to be the only countries to witness declines in natural gas demand due to nuclear restarts, growing renewable capacity and integration of imported hydrogen in the energy system, however the reliance on LNG will continue to be a key component of their decarbonisation strategy and energy security.

Figure 4.7.

Asia Pacific natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

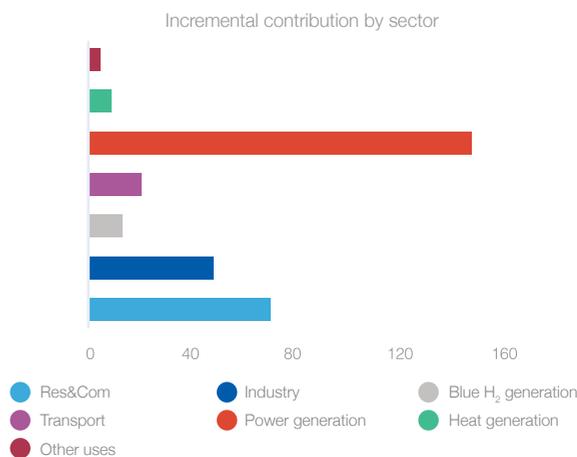
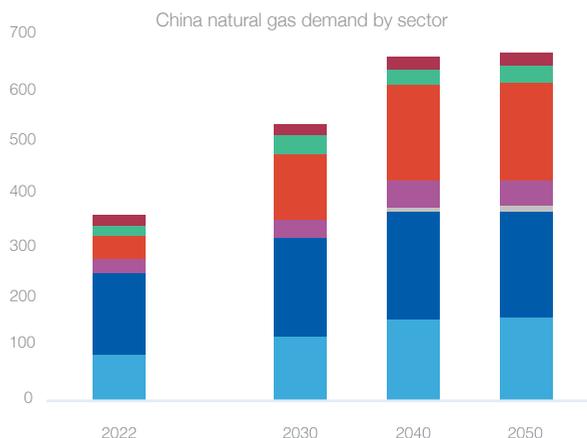
In **China**, growing use of natural gas aligns with the main priorities to diversifying the coal-dominated energy mix and improving air quality. Gas market reforms aimed at domestic production growth, market liberalisation, boosting investments and facilitating third-party access to infrastructure, including LNG terminals, are progressing. Crucial step was the launch of the midstream operator PipeChina, which has been accelerating the realisation of its “one network across the country” strategy, consolidating provincial pipeline assets, and

building new transmission capacities. As the country continues with its transition to lower-carbon energy system, coal-to-gas switching is expected to play a key role during the 14th Five-Year Plan. Eventually, the country’s pledge to become a carbon-neutral economy by 2060, while achieving peak emissions before 2030, could provide an upside potential for natural gas to expand across consuming sectors.

Demand for natural gas is estimated to rise to almost 670 bcm by 2050, up from 355 bcm in 2022. Economic expansion, urbanisation, wealthier households, coal-to-gas conversions, infrastructure buildout, and ongoing market reforms are the main factors behind this robust increase. Power generation is set to be the primary driver, accounting for 47% of the total demand growth. Residential and commercial sector as well as industry are anticipated to represent remarkable components, contributing 23% and 15% respectively of the rise in demand. The transport sector is responsible for 6% of the growth, entirely driven by LNG, both in marine and road transport. LNG-fuelled heavy vehicles are expected to be the key segment, supported by increased availability of LNG refuelling infrastructure, stringent emission standards, and restrictions on diesel trucks movements to improve air quality. Figure 4.8 shows the dynamics of natural gas demand in China by sector over the forecast period.

Figure 4.8.

China natural gas demand outlook, 2022-2050 (bcm)



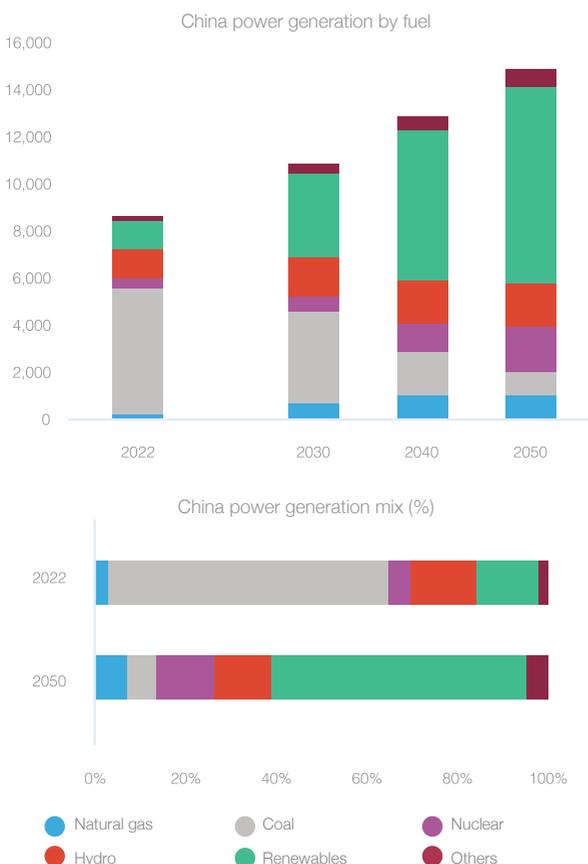
Source: GECF Secretariat based on data from the GECF GGM

In the residential and commercial sector, natural gas is projected to benefit from urbanisation, investments in city gas projects, and new grid connections. Additionally, the draft policy on sectoral gas use, published by China’s National Energy Administration in September 2023, reaffirms the prioritisation of gas supply to the residential segment. Nevertheless, demand in this sector stabilises after 2040 due to greater electrification. Industrial gas demand increase is expected to level off in the 2040s. Coal-to-gas switching mandates for energy-intensive industries are to be the key drivers, with the most significant potential for growth in the coastal regions. In the long-term, the peaking of the total industrial energy demand presents a major downside risk for natural gas, while the penetration of alternative clean energy options is expected to have an additional effect.

In the Chinese power sector, policy-driven expansion and the need for a flexible power source to provide dispatchable capacity amid increasing renewables keep demand for natural gas on an upwards trend. Electricity supply from gas-fired power plants is expected to more than quadruple reaching 1,090 TWh. However, it is expected to account for only 7% of the total generation mix in 2050. During the same period, renewables are projected to increase their share from 14 to 56% between 2022 and 2050, while coal-fired generation is set to drop from 62 to 7% (Figure 4.9).

Figure 4.9.

China power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include oil, bioenergy and hydrogen

Despite this shift, coal-fired power plants are likely to receive approval to expand over the next decade due to energy security concerns. As a result, this outlook anticipates coal-fired capacity to peak at about 1,248 GW in 2026.

In **India**, demand for natural gas is expected to benefit from drivers similar to China, and air quality has become a top priority in the list of policymakers. Promotion of gas through fuel switching is seen as an important part of the Long-Term Low Emission Development Strategy, announced in November 2022. The government’s vision to raise gas’s share in the primary energy mix to 15% by 2030 (up from 5% in 2022) also remains in place. To increase utilisation of this fuel, India has been pressing forward with a myriad of supportive policy measures, including extensive gas infrastructure build and changes in regulation. One of the latest regulatory steps has been the introduction of a unified pipeline (transmission) tariff, designed to provide an affordability boost for regions located far from supply sources, while helping to achieve the “One Nation, One Grid, and One Tariff” model.

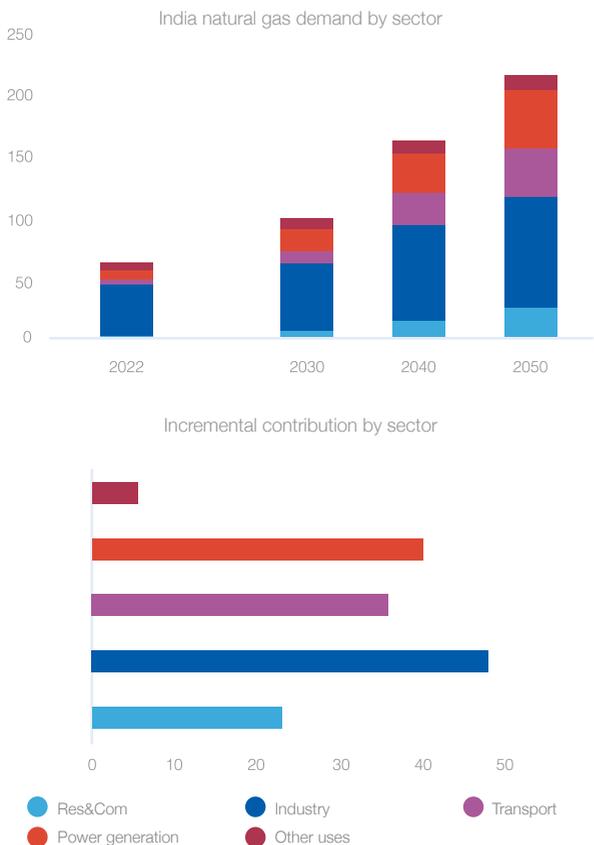
Development of the National Gas Grid is a crucial enabler to increase gas accessibility across the country. In this regard, a significant investment program to add around 12,000 km to the existing pipeline grid (currently stands at over 23,000 km) is underway. These could remove infrastructure bottlenecks, spur regasification at LNG terminals, and facilitate the deployment of planned LNG regasification facilities, bringing additional natural gas to industrial consumers, power plants and city gas distribution (CDG) networks. Moreover, LNG supplies are forecast to dominate the country’s gas demand, as domestic gas production growth is projected to be insufficient. Following the commissioning of the Dhamra LNG terminal in April 2023, India has seven LNG facilities with a combined capacity of about 47.5 mtpa, while the policy envisages an increase in import capacity to 70 Mtpa by 2030 and 100 Mtpa by 2040.

Expansion of CGD network is also set to continue, and the uptake of natural gas for road transport, residential cooking, as well as for a wide range of commercial and small-scale industrial users are poised to largely depend on the pace of these developments. After the completion of the 11 A bidding round, the coverage has expanded to 630 districts, and potentially 98% of India’s population and 88% of its geographical area are assumed to have access to gas. These CGD networks target to connect more than 120 million households and commercial consumers by 2030, implying that the number of piped gas connections could rise by over 10 times. Additionally, around 5,100 CNG stations were built as of January 2023, and the government aims to more than triple this number to 17,700 units by 2030. Within road transport segment, there are concrete plans to promote LNG as a fuel for trucks, and establish a refuelling network along major highways, with the goal of adding up to 1,000 LNG stations.

Thus, broad policy support, accompanied by the overall forecast for India’s economy and urban population, translates into rapid growth of natural gas demand. It is set to more than triple from 61 bcm in 2022 to around 215 bcm by 2050, while the rise accelerates after 2027 as natural gas accessibility and affordability improve (Figure 4.10). A clear trend of increased demand is expected in industry and road transport amid gas infrastructure enhancement and policy-driven fuel switching. Industrial sector in particular is expected to lead rising use of natural gas, supported by the development of fertilisers, petrochemical plants and light manufacturing. Natural gas demand for power generation is also forecast to increase,

Figure 4.10.

India natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

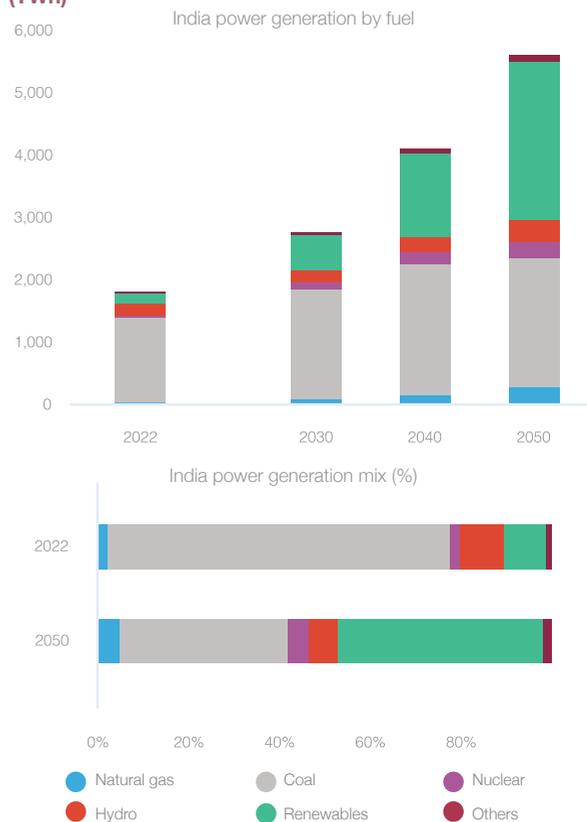
although dynamics of this rise is set to be restrained due to competition mainly from low-priced domestic coal and renewables.

In the power generation sector, over the coming decade, the rise in gas demand is assumed to be subdued, as there is no specific measures to promote gas-based generation. India plans to achieve 500 GW of installed electricity capacity from non-fossil-fuel sources by 2030. Moreover, there is no clear commitment to phase out coal, and the country's draft electricity plan anticipates an additional 26 GW of coal-fired power capacity to be developed by 2026-27. Consequently, the use of natural gas is more promising after 2030, driven by its ability to provide flexible balancing power, as significant supplies come from renewables, but natural gas's role is anticipated to remain limited to 4% on average of the power generation mix through the whole outlook period (Figure 4.11).

In general, with coal currently accounting for 75% of electricity supply, natural gas could offer a strong opportunity to accelerate India's energy transition, and reduce carbon emissions in this sector. However, for this to happen, in parallel with ongoing gas market reforms, there is a need to address the issues of affordability relative to domestic coal, if the most optimistic demand estimates are to be achieved. In this context, restrictions on coal use will be inevitable to drive substantial natural gas demand growth in the power generation sector.

Figure 4.11.

Figure 4.11. India power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM

Note: Others include oil, bioenergy and hydrogen

Natural gas demand in **Bangladesh** is projected to double, reaching 60 bcm by 2050. Power generation is set to lead the increase amid sharp rise in electricity needs, and the development of new CCGTs capacities, although the overall trend is also underpinned by higher gas use in industry and residential segment. LNG imports are forecast to come at the forefront to meet demand growth due to dwindling domestic gas reserves. Stagnation of indigenous gas production has already forced the government to turn to imports, with two FSRUs at Moheshkhali Island commissioned in 2018 and 2019. The third terminal, located at Matarbari in the Cox's Bazar district, is expected to become operational in early 2026. Other regasification terminals are planned for Payra Seaport in Patuakhali and an additional facility at Moheshkhali. Growing LNG import supplies are set to cover more than 70% of the countries' total gas demand by 2030 and this share could gradually increase later on.

Bangladesh generates a large share of electricity from natural gas, averaging 57% in 2021-2022, and is expected to remain the backbone of the power system. There is still an opportunity to replace fuel oil through switching to natural gas. As LNG imports increase and more gas-fired capacity comes online, the need for oil-fired generation, which reached over a quarter of electricity supply last year, is set to diminish. To enhance energy security, Bangladesh is introducing a diverse set of generation options, including nuclear, renewables and the

increase of power imports (based on hydropower from nearby regions in India, Nepal and Bhutan). Particularly, the first unit of the Rooppur nuclear plant (a combined capacity of 2.4 GW), developed by Russia's Rosatom, is set to start commercial operation in 2024, while the country aims to reach 7 GW of nuclear capacity by 2041. The scale-up of alternative energy sources may lower natural gas demand growth in power generation, although without its displacement, as electricity requirements are strong.

In **Pakistan**, natural gas demand is forecast to grow by 19 bcm, exceeding 61 bcm by 2050, driven by its higher use in industry, power generation as well as in residential segment, and road transport. To offset the long-term decline in domestic gas production, Pakistan is projected to rely more on imports. There are interstate pipeline plans (e.g. Iran-Pakistan and Turkmenistan-Afghanistan-Pakistan-India), however LNG supplies are forecast to take the bulk of the strain, catering for rising demand. Regasification expansion in Port Qasim, Karachi is underway: in addition to the existing two FSRUs (commissioned in 2015 and 2017), two new facilities – Tabeer and Energas terminals – are planned to be integrated in the near future. Carrying extra LNG volumes to demand centres will require the development of transmission infrastructure. In this context, the 1,100 km-long Pakistan Stream Gas Pipeline between Karachi and Lahore, which is being built in partnership with Russia, is a key project, designed to facilitate the deployment of new receiving terminals, and support the country's reliance on natural gas.

Stronger growth in natural gas demand is expected to be constrained by the developments in the power generation sector. Natural gas plays an important role in electricity supply, accounting for around 30%, although the expected increase in coal, nuclear, hydro and renewables capacities (including funded under the China-Pakistan Economic Corridor) is poised to slow the growth of gas-fired generation. For example, the government targets doubling hydropower capacity by 2030, adding 10 GW of hydro currently under construction, while the country has around 36 GW under the planning stage. On the nuclear side, the long-term goal envisages an elevation of nuclear capacity to 8.8 GW, compared to 3.5 GW at present. To that end, the construction of the fifth unit (1.2 GW) at the Chashma nuclear power plant began in July 2023. Coal also may pose a threat to natural gas. In February 2023, two coal-fired power plants, 1.32 GW Thar and 330 MW ThalNova, were inaugurated. Moreover, the government announced that more coal-fired power capacity are to be built in the coming years due to higher LNG prices. Nevertheless, setting up new coal-based projects is expected to face difficulties in securing finance amid increasing environmental pressure.

In **Southeast Asia**, demand for natural gas is projected to more than double, rising from around 160 bcm in 2022 to above 355 bcm by 2050, with over 80% of incremental demand concentrated in Indonesia, Viet Nam, Thailand, the Philippines and Malaysia. This growth is set to take place favoured by substantial economic expansion, urbanisation, and associated surge in electricity needs. In the meantime, countries in the region show strong emission-reduction commitments, aiming for net-zero between 2050 and 2065. Hence, the role of natural gas, currently making up 18% of Southeast Asia's primary energy mix and 30% of its power generation mix, is forecast to become more prominent, complementing increasing variable renewables, and cutting the use of coal. Domestic natural gas infrastructure favours the continued consumption of natural gas, and financial institutions in the region are expected to ramp

up investments to enhance interconnectivity and enable LNG access.

Southeast Asia is projected to transform into a net gas importer by around 2028-2029, given that indigenous gas production in countries is either declining, or unable to meet the rising demand. This will bring LNG imports to the forefront, leading to a significant rise in regasification capacity. The crucial factor is the growing number of LNG-to-power projects, including the development of small-scale LNG solutions, across Southeast Asia (refer to Box 4.2). In addition, Singapore is considering to become a leading natural gas hub in the region, and actively developing other related activities, including LNG bunkering services. There is an alternative project of gas hub creation in Thailand. In 2022, the country commissioned its second LNG import terminal, Map Ta Phut 2, to maintain its reliance on natural gas and support rising electricity demand.

Box 4.2. LNG-to-power developments in Southeast Asia

The development of electricity markets in Southeast Asia is at a dynamic stage, both for demand and supply. Countries are continuing their path towards increasing levels of electrification, while the region's power industry and policymakers intend to improve the environmental sustainability of the sector. In recent years, a number of LNG-to-power projects have been proposed in the region and this push is backed by a clear policy priority to mitigate reliance on coal. In its turn, the combination of depleting domestic natural gas resources and strong growth in electricity demand is set to further drive the deployment of LNG-based power generation, thereby promoting LNG demand across Southeast Asia. Indonesia, the Philippines and Viet Nam present currently the most vibrant examples in this sphere.

A strong impetus for LNG is expected to come from the advancement of intra-country LNG trade in Indonesia, given the plan to make natural gas supply accessible to the entirety of its archipelago, allocating small-scale LNG terminals coupled with generators. As a part of the energy transition program, the government is targeting to convert some of the country's existing 5,200 diesel power plants to gas firing (the first stage envisages 33 larger diesel generators in eastern Indonesia). Moreover, Indonesia plans to fully commission the 1.76 GW Jawa-1 plant integrated with a floating storage and regasification unit (FSRU), the country's first conventional-sized LNG-to-power project and the largest combined cycle power plant in Southeast Asia. The power plant itself started commissioning one of its units in February 2022, but the full operation is facing delays.

In Viet Nam, country's eight Power Development Plan (PDP8), released in May 2023, sees much of the increase in gas-fired power capacity to be LNG-based (13 new LNG-fired power plants, comprising 22.4 GW, are proposed by 2030, and two additional plants with 3 GW by 2035). In July 2023, the Thi Vai terminal became the country's first commercial regasification facility, while an additional six LNG regasification units are under different stages of development. The Thi Vai terminal will primarily supply the Nhon Trach 3&4 power plants (total capacity of 1.6 GW), scheduled to come online in 2024-2025. Some of the 13 LNG-to-power projects, specified in PDP8, have also made significant progress, namely the Hiep Phuoc Phase 1 (1.2 GW), Bac Lieu (3.2 GW), Hai Lang Phase 1 (1.5 GW) and Son My 2 (2.2 GW), which are expected to become operational before 2027.

The Philippines, which imposed a moratorium on the construction of coal-fired power plants, the dominant power generation source in the country, also plans to focus on LNG-fired power generation as part of decarbonisation efforts. Currently, all of the existing natural gas-fired generation (around 3.5 GW, providing 14% of the power generation mix) is supplied from the Malampaya gas field. With gas production projected to decline due to field depletion, the country aims to replace Malampaya output with LNG. To meet long-term incremental electricity demand growth, the government approved the integration of seven LNG terminals. Two facilities in Batangas were completed, and the country received its first LNG delivery in April 2023.

or planned gas-fired power projects, including LNG-to-power schemes. Industrial natural gas demand is set to make up the bulk of the remaining growth. More gas is expected to be required for chemical, fertiliser production and light manufacturing, while there are opportunities for displacement of oil, coal and biomass as a source of process heat. Indonesia, Thailand and Malaysia are anticipated to realise the most sizeable increase in the industrial sector. Finally, in the transport sector, marine transport is poised to contribute most, underpinned by growing sales of LNG for international bunkering, particularly in Singapore and Thailand.

Based on policy goals, Southeast Asia's power sector is slated to undergo a profound transformation. High degree of coal dependence makes natural gas a viable option to balance strong power demand growth and sustainability commitments. Amid ambitious plans towards renewables, natural gas is set to play a critical role regionally, substituting coal and stabilising ever-more complex grids. Considering projects under construction and an assessment of long-term capacity additions, gas-fired generation, based on indigenous gas production and LNG imports, is expected to become the largest generation source by around 2030, helping to accommodate a higher share of share of renewables. By 2050, natural gas is projected to reach a 37% share of Southeast Asia's power generation mix (Figure 4.12).

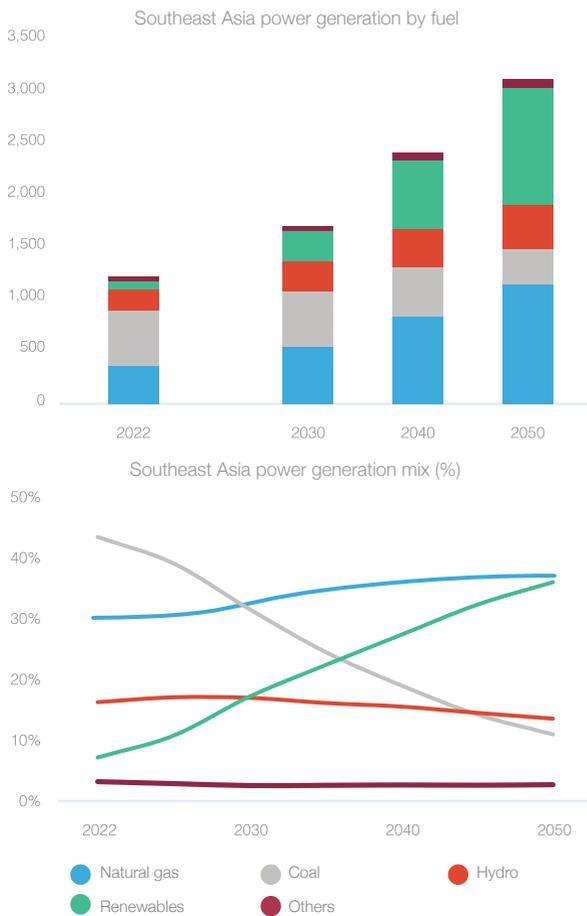
In **Japan**, natural gas demand is forecast to decrease from 103 bcm in 2022 to less than 60 bcm in 2050. The declining demand is expected in industry, residential and commercial sector, as a result of the shrinking population, slow GDP growth, and efficiency improvement. However, over 80% of the total reduction is expected to emerge from the power generation sector. Reinstated nuclear power capacity could lead to a sizable decrease in natural gas use. In 2030-2035, demand is likely to be stabilised, given the government plans to build new LNG-fired power capacity by 2030. This step is poised to support the phase-out of aging and inefficient coal-fired power plants. In the long-term, lower natural gas utilisation could persist amid accelerated deployment of renewables (primarily offshore wind, along with solar), and hydrogen-based generation. Moreover, the country is working to develop a blended combustion with hydrogen or ammonia in gas-fired power plants.

The progress in resuming operations at existing nuclear power plants is a major determinant, weighing on natural gas demand, specifically in the coming decade, although the timing of restart of idle reactors is still uncertain. There are 33 reactors (representing over 33 GW), designated for commercial use, while three projects (around 4 GW) are under construction. In September 2023, the Takahama-2 became the 12th unit to receive regulatory clearance to restart, raising total operating nuclear capacity to 11.6 GW. This number is projected to gradually increase, as the Japan's 6th Strategic Energy Plan sets a goal for nuclear to increase to 20-22% of power generation mix by 2030, up from 5% in 2022. Additionally, in May 2023, within Japan's Green Transformation (GX) policy, the parliament enacted a law, allowing the country's nuclear reactors to operate beyond the current limit of 60 years. The policy also stipulates building "next-generation innovative reactors" to replace units, scheduled for decommissioning.

In **South Korea**, natural gas demand is projected to fall from 63 bcm in 2022 to below 55 bcm by 2050. Nevertheless, volumes may vary, reaching a peak at 65-66 bcm in the early 2030s. Demand is expected to depend on power sector trends, particularly due to the policy shift towards increased nuclear

Figure 4.12.

Southeast Asia power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include oil, bioenergy, nuclear and hydrogen

Overall, from a sectoral perspective, the power generation sector is projected to drive Southeast Asia's natural gas demand, accounting for over 130 bcm, equivalent to around 67% of the total growth between 2022 and 2050. Electrification with substantial scope for coal-to-gas switching are behind strong gas-to-power demand increase. This is expected to be primarily led by developments in Viet Nam, Indonesia, the Philippines, Myanmar and Malaysia with numerous approved

power generation, envisaged in the 10th Basic Plan for Long-Term Electricity Demand and Supply. Following the start of the APR-1400 Shin Hanul-1 in December 2022, there are currently 25 reactors in operation, totalling 24.65 GW of installed capacity, and three 1.4 GW reactors (Shin Hanul-2, Saeul 3&4) are set to come online in the mid-term. The development of two paused projects (Shin Hanul 3&4, 1.4 GW capacity each) were resumed, while the government also extends support for existing reactors, targeting to raise nuclear share in the power generation mix to 32.4% by 2030 and 34.6% by 2036 (up from 28% in 2022).

In this context, pro-nuclear stance is set to provide competition for LNG-based generation, which supplied 27% of electricity needs in 2022. Although the share of natural gas in the power supply is forecast to shrink over the forecast period, coal-to-gas switching opportunities are projected to support LNG demand, specifically in the next 10-15 years, as the policy assumes to convert 28 aging coal-fired power plants (with a combined capacity of 15.1 GW) to LNG. Natural gas use is also poised to be required in order to maintain scheduled reactor outages. Nevertheless, in the long-term, in addition to nuclear revival plans, demand for natural gas in the power sector could be restrained by accelerated deployment of renewables, and plans to integrate hydrogen-based generation. In other sectors, natural gas demand in the industry as well as in residential and commercial sector is anticipated to decline amid efficiency gains, electrification, and the adoption of low-carbon hydrogen. The transport sector is forecast to demonstrate limited growth potential, emanating from LNG bunkering services.

4.2.3 Eurasia

In Eurasia, natural gas accounted for a significant 52% share in the regional energy mix in 2022, and it is poised to retain a dominant position over the outlook period. Its demand is set to grow by 0.8% per annum from 650 bcm in 2022 to 810 bcm by 2050. Incremental volumes are projected to originate in many sectors amid low gas prices, economic growth and active promotion of this fuel. To a greater extent, this trend is supported by rising household gas connections, the development of NGV markets and higher natural gas use in industry owing to the expansion of gas-to-chemicals, petrochemicals and non-metallic minerals production. Blue hydrogen generation is an additional important natural gas demand area, driven by Russia's strategic initiatives to export and consume low-carbon hydrogen in various spheres of the economy.

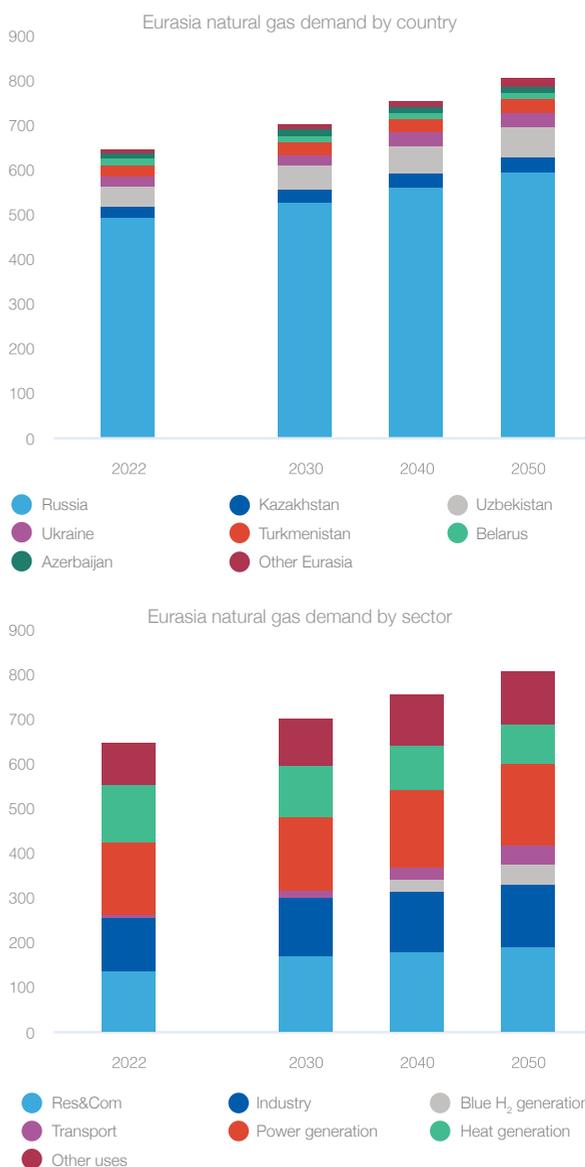
Stronger growth in natural gas demand in the region is set to be limited due to high potential for energy savings, particularly in the power and heat generation sectors. Favoured by the improvements in heating supply modes and refurbishment of the CHP fleet, primarily in Russia, demand in the heat generation sector is set to fall by 42 bcm over the forecast horizon. In its turn, natural gas use for power generation is poised to rise, although moderately, by just 23 bcm between 2022 and 2050. Given that power and heat generation sectors are interrelated, the large-scale modernisation of thermal power plants impacts natural gas demand growth for electricity supply. Construction of new, efficient CCGTs as well as commissioning of nuclear capacities and renewables' deployment are also expected to have an effect.

Regarding countries' shares to incremental natural gas demand, Russia will account for around 64% of the total regional growth (Figure 4.13). Significant increase is also set

to be witnessed in Kazakhstan, Turkmenistan and Uzbekistan, together responsible for over 24%, as economic development and energy policy priorities support the expansion of natural gas in end-use sectors and for electricity generation. The forecast anticipates an increase in gas requirements linked to energy industry own needs and use in the pipeline transport systems, where the bulk of extra volumes comes from Russia amid the growth of domestic gas production and the ramp-up of export pipeline and LNG supplies.

Figure 4.13.

Eurasia natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

In **Russia**, the largest gas market in the region, demand is forecast to rise by more than 100 bcm over the outlook period. Maximising the contribution of the domestic hydrocarbon industry and growing natural gas use are strategic objectives, which are expected to be stipulated in the updated Russian Energy Strategy to 2050. Increase in demand is set to be

primarily driven by blue hydrogen generation, an ongoing gasification program, the development of gas-intensive industries, notably gas-to-chemical projects, and plans to advance the use of natural gas as a fuel for vehicles. These vectors will largely offset an expected demand decline in the heat generation sector, which is forecast to occur amid switching to efficient gas-fired boilers, modernisation of district heating systems and technological renovation of existing CHP plants.

Almost 45% of net natural gas demand increase is forecast to come from blue hydrogen generation. The development of hydrogen technologies is one of the highest priority areas. Besides export opportunities, there are plans to consume low-carbon hydrogen on a mass scale in various sectors. Substitution of grey hydrogen with blue hydrogen in existing industrial applications could take place in response to climate measures. This, together with vast CCUS potential in depleted oil and gas fields, will contribute to Russia's pledge for carbon neutrality by 2060. Despite the strong prospect in Russia for yellow hydrogen, produced at electrolyzers using nuclear power, blue hydrogen is set to be the most viable option, serving as an important driver for natural gas demand growth.

Meanwhile, the residential and commercial sector, road transport as well as industry are forecast to add around 75 bcm between 2022 and 2050. The major portion of this growth is driven by the progress in gasification program: the gasification level is expected to reach 74.7% in 2024, while the target envisages achieving 83% by 2030. Demand potential is set to also materialise from new consumers in Eastern Siberia and the Far East of the country. Additionally, the use of natural gas as a fuel for vehicles is expected to continue to rise due to government support, broadening the line-up of NGVs and building refuelling infrastructure. In industry, the development of gas-to-chemicals projects, such as methanol, ammonia and urea production, is set to play the leading role. Particularly, at least eleven new projects for methanol production are in different stages of implementation. Most are export-oriented, while six projects with a total capacity of over 9 mtpa are under advanced development and could potentially come online in the coming decade.

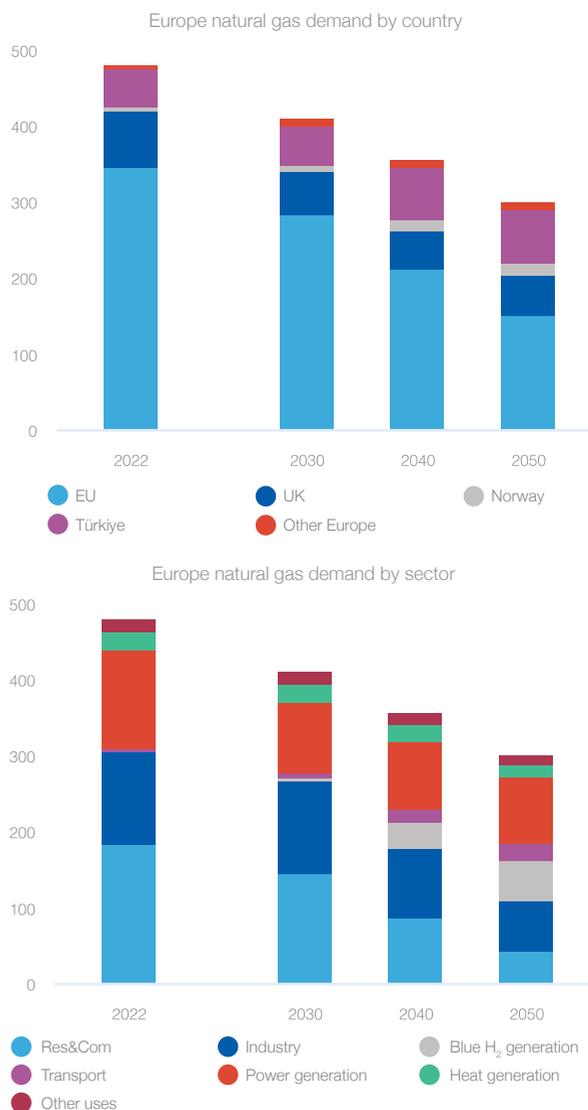
4.2.4 Europe

The European energy system is forecast to undergo a significant energy transformation, affecting each sector of the region's economy. Natural gas accounted for 22% of the continent's energy mix in 2022, and is set to encounter a severe downward pressure. Its share in the regional energy mix is forecast to drop to 15% by 2050, while its demand declines by 1.7% per annum, from 480 bcm in 2022 to 300 bcm by 2050. This trend will be shaped by decarbonisation policies, set out in the EU's Green Deal and the Fit for 55 package (see the EU energy policy section in Chapter 2 for details). The implementation of the REPower EU plan is assumed to give additional impetus to accelerate decarbonisation measures through energy efficiency gains, electrification, heat pumps, renewables advancement and the scaling up of biomethane and green hydrogen, resulting in considerable natural gas demand contraction over the long-term.

The EU as a whole is forecast to drive the drop in demand. The bloc's natural gas use reduction is estimated at more than 190 bcm between 2022 and 2050, led by Germany, Italy, France, and Spain. A structural decline will be observed in almost all consuming sectors, except for road and marine

transport, and as a source for blue hydrogen generation, offering the best growth potential. Outside the EU, UK natural gas demand is projected to decrease by 23 bcm through 2050, as this fuel could be displaced in power generation and in residential segment, however the development of nascent clean technologies, such as blue hydrogen and CCUS, which is in line with objectives of the British Energy Security Strategy, supports long-term natural gas use in the country. Blue hydrogen generation will advance also in Norway, mainly for export supplies, leading to natural gas demand increase, particularly post-2030. At the same time, Türkiye is forecast to be the only market in the region to experience strong rise in demand with the growth originating mostly in power generation and industry, underpinned by bright economic prospects, the expansion of domestic gas network, new discoveries and opportunities for rising imported supplies. Figure 4.14 illustrates natural gas demand trends in Europe, including at the sectoral level.

Figure 4.14. Europe natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

From sectoral perspective, residential and commercial sector is projected to encounter a significant natural gas demand decline, accounted for around 140 bcm between 2022 and 2050. Energy efficiency measures are the key driver, while high gas prices have already triggered energy conservation behaviour. Electrification of space heating, particularly accelerated heat pump installations, as well as alternative heating options such as biomethane or low-carbon hydrogen, could further reduce natural gas demand. Germany and the UK are set to lead decline in this sector. For example, in the UK, intentions to ban sales of new gas boilers from 2035 and switching to heat pumps could affect natural gas demand strongly, given that natural gas currently accounts for around 62% of the total needs in UK's residential segment. In Germany, in September 2023, the parliament approved a legislation on phasing out fossil-fuel heating systems, and amendment to the Building Energy Act requires newly installed heating systems in old and new buildings to run on at least 65% renewable energy. The installation of gas heaters is still permitted, provided they are hydrogen-compatible and can be retrofitted for using blends or pure hydrogen at a later date. Partial blending in particular is expected to be promising in Europe, as it can leverage existing gas infrastructure and reduce the carbon intensity of energy consumption in buildings.

In the power generation sector, short-term energy security leads to a temporary delay in the scheduled closure of some coal-fired and nuclear power plants, while long-term pressure on natural gas is set to intensify from renewables. There could be benefits of coal-to-gas switching after 2030, especially in Central and Eastern European countries with a relatively high coal share in their power generation mixes. For example, in Poland, coal accounted for 72% of country's total electricity generated in 2022, in Czech Republic – 45%, in Bulgaria – 45%, in Germany – 33%. Nevertheless, looking ahead, waning opportunities of fuel switching as well as an assertive build-up of renewables and integration of hydrogen-based generation will weigh on natural gas demand. In this regard, natural gas-fired generation is forecast to lose its current 20% share in the regional power generation mix in the long-term, but it will continue to be essential, contributing to long-term electricity growth and to the stability and security of power supply on the back of increased reliance on variable solar and wind generation.

In the industrial sector, natural gas is forecast to be squeezed by ongoing electrification of low-heating industrial processes, and movement toward direct low-carbon hydrogen use. Green hydrogen in particular is gathering political support in Europe as a way to decarbonise hard-to-abate industrial sub-sectors, such as steel and chemicals, and to displace natural gas. In this context, natural gas paired with CCUS is expected to become an important solution, enhancing the long-term resilience of natural gas, while this technology is already central to decarbonisation strategies in Northwest Europe (e.g. Denmark, Germany, the Netherlands, Norway, the UK).

Norway's Longship/Northern Lights and Netherlands' Porthos projects are important early steps, where CO₂ from industrial sources is planned to be transported and stored beneath the North Sea. The Longship project, which is scheduled to start operation in 2024, includes capturing emissions from cement factory and waste-to-energy plants in the Oslo-fjord region. FID for Porthos has been taken in October 2023 and the system, aimed at transporting CO₂ captured by several companies in the port of Rotterdam to depleted gas fields, is expected to be operational from 2026. In its turn, the UK is working on

decarbonising industrial clusters through the deployment of CCUS. For example, within the Humber, H₂H Saltend project is an important stepping stone, which includes a 600 MW low-carbon hydrogen production facility, targeting to switch the power generation and industrial customers in the Saltend Chemicals Park from natural gas to blue hydrogen. At Teesside, the driving force is the 860 MW Net Zero Teesside Power, an integrated gas-fired power and carbon capture project.

Commercialisation of CCUS and the development of a corresponding full-scale value chain will support the ramp-up of blue hydrogen generation both for export and domestic consumption in end-use sectors, including grey hydrogen displacement in industry. Blue hydrogen is expected to be an attractive option in Europe, given its long-term competitiveness with green hydrogen and synergies with the existing natural gas infrastructure. Natural gas demand for blue hydrogen generation is set to rise by 53 bcm over the forecast period, but is assumed to advance only in a limited number of countries, namely those which have access to offshore storage. The UK, Norway and the Netherlands will drive natural gas demand in this sector.

The transport sector is forecast to represent an additional area for natural gas demand expansion. Consumption is projected to rise by 18 bcm between 2022 and 2050, driven by LNG usage as a bunker fuel and in heavy goods vehicles. In marine transport, the inclusion of shipping in the EU's ETS is forecast to provide a strong regulatory incentive for more shipowners who might be considering LNG as a fuel of choice. Moreover, the establishment of a Mediterranean ECA (coming into force from 1 May 2025) could have major consequences for LNG, accelerating the expansion of refuelling infrastructure in this area. In road transport, the increase in demand is forecast to be concentrated in the HGV sub-segment due to the scope for displacing diesel. The penetration of CNG in the passenger car market will conversely be limited in the region given policy focus on EVs and plug-in hybrid cars, although blending natural gas with biomethane can provide reasonable opportunity.

4.2.5 Latin America

Natural gas demand in Latin America is forecast to increase by 2.3% per annum, from 155 bcm in 2022 to 295 bcm in 2050. Sustained economic and population growth, along with government policies to promote natural gas usage, mainly in power generation, industrial and road transport sectors, are the key factors. Growth in domestic gas production, particularly in Argentina, Brazil and Venezuela, will boost availability, although a full-fledged gas integration in the region is set to be challenging due to lack of pipeline interconnections. Therefore, LNG imports are anticipated to become a relevant option to satisfy country's energy needs, being an important component in providing energy security, and building more sustainable energy systems. Overall, the position of natural gas in Latin America is set to strengthen with its share in the regional energy mix rising to 24% by 2050, up from 20% in 2022.

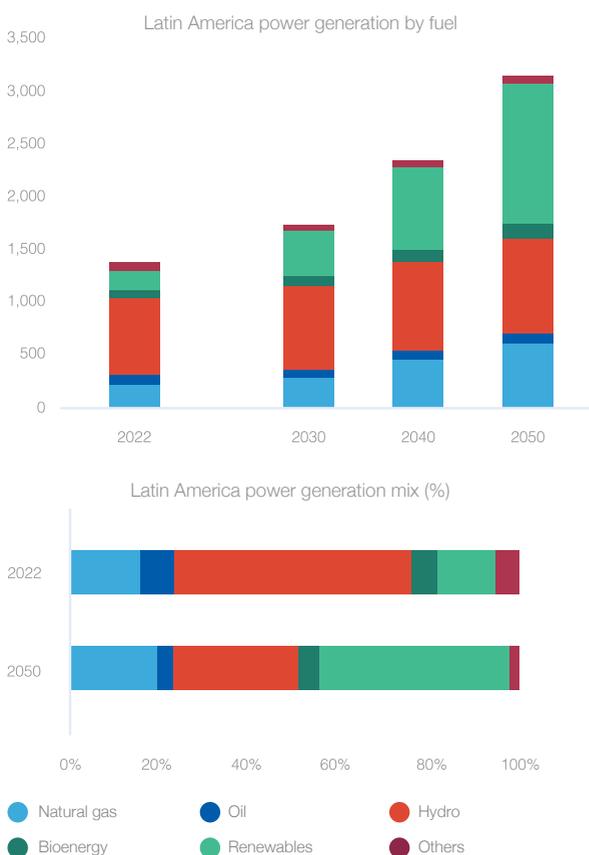
Natural gas demand growth is projected to be mainly driven by the needs of the power generation sector, accounting for around 80 bcm or almost 58% of additional gas use in the region. Gas-fired generation development, including based on LNG, will gain momentum in the region as a way to accelerate coal phase-out (e.g. Chile), displace oil-fired generation, which is used extensively in many countries (e.g. Argentina, Ecuador, the Caribbean), as well as reduce dependence on hydropower,

offsetting its fluctuations. Moreover, the region is forecast to see impressive growth in renewable generation amid countries' expansion plans and supportive policies. In this context, gas-fired power generation is projected to be in demand to provide a flexible back up.

Owing to these developments, and while hydropower generation is set to rise slightly, natural gas-fired power generation is forecast to meet 22% of increasing electricity requirements over the forecast horizon. Hydro could lose its present ranking, while the share of natural gas in the regional power generation mix is expected to grow from 15% in 2022 to 19% by 2050 (Figure 4.15). Nevertheless, natural gas use in power generation sector will continue to be characterised by some volatility, rising in dry seasons and declining during months with greater rainfall, taking into account the critical role that hydro is playing. Among countries, Brazil, Venezuela, along with Argentina, the Caribbean, Peru and Chile are forecast to drive gas-in-power demand growth.

Figure 4.15.

Latin America power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include coal, nuclear and hydrogen

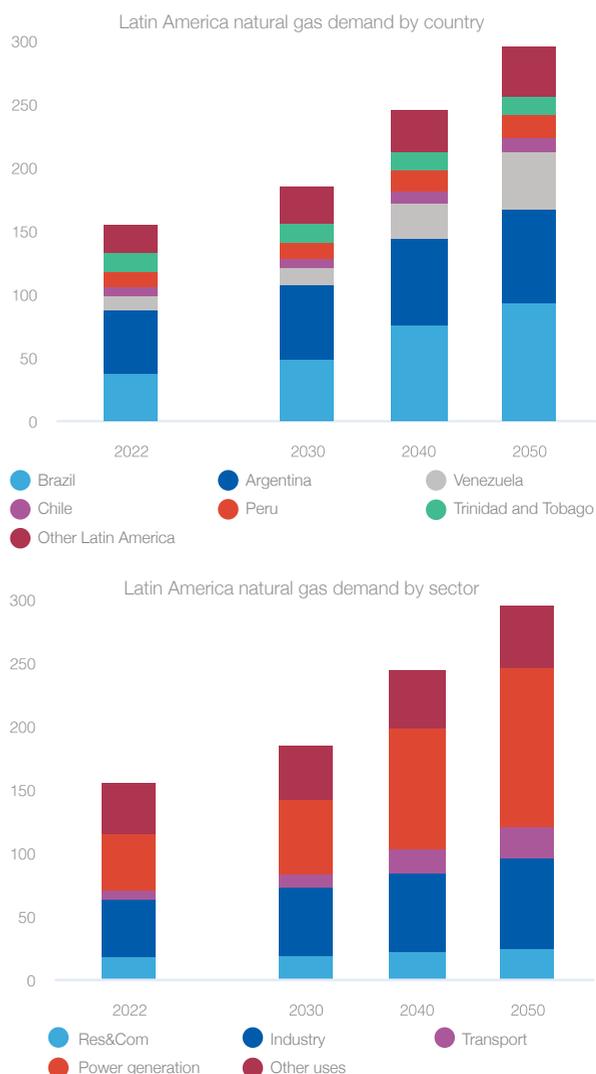
The industrial sector is another area that holds a great potential. Demand is projected to rise by more than 25 bcm between 2022 and 2050. Argentina, Brazil, Colombia and Peru lead this trend due to bright economic prospects, easing bottlenecks in pipeline infrastructure, market reforms, displacement of polluting fuels, and investments in new industrial facilities. In addition, natural gas availability is set to raise domestic

production of fertilisers, thereby reducing countries' dependence on the import.

In the transport sector, diesel-to-gas switching in HGV segment is forecast to be the main driver for natural gas demand growth. Argentina and Brazil will remain the biggest NGV markets due to a tradition for natural gas usage in road transport, the development of refuelling infrastructure and policy support. Moreover, growth in demand is expected to arise from deploying LNG for bunkering. The strategic role of the Panama Canal and rising regasification infrastructure in the region could stand as a viable pathway. As for the residential and commercial sector, demand is projected to grow predominantly in Argentina, given firm plans to expand transmission and distribution grids, but it could remain highly seasonal, ensuring heating requirements during the southern hemisphere winter. In addition, Colombia focuses on expanding gas coverage in order to substitute the use of firewood for cooking within its Just Energy Transition roadmap.

Figure 4.16.

Latin America natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 4.16 summarizes sectoral natural gas demand trends in Latin America and provides demand prospects on a country level. Almost all countries in the region are forecast to demonstrate growth in demand with Argentina, Brazil and Venezuela in the lead, together contributing around 80% to the total regional increase between 2022 and 2050. Brazil is set to become the largest natural gas market, surpassing Argentina's demand after 2035.

For **Argentina**, natural gas is a fundamental fuel. It currently makes up around 52% of the energy mix, and is a primary source for electricity supply. Meanwhile its importance for the national economy is expected to remain significant. Demand is forecast to rise by around 24 bcm, growing in all sectors and reaching almost 75 bcm by 2050. This increase is set to be supported by the development of huge reserves from the Vaca Muerta shale formation, located in the Neuquén Basin. To ramp up the production volumes, the government has extended 2020-24 gas production incentives program (known as Gas Plan.Ar) to 2028. In parallel, a strong priority is given to the expansion of gas transportation capacity that would enable to substantially increase gas flows to demand centres.

Argentina is moving forward in debottlenecking Vaca Muerta supplies. The core component is the Presidente Néstor Kirchner gas pipeline project (a total capacity of around 16 bcm per year) which is planned to transport natural gas from Neuquén to Santa Fe provinces, crossing the provinces of Río Negro, La Pampa and Buenos Aires. The first phase, a 570-km section, was commissioned in July 2023, linking the shale play with Buenos Aires. In August 2023, Argentina launched a tender for works to complete Northern Gas Pipeline reversal that will allow Vaca Muerta-sourced gas to be sent to the north of the country. The construction on the Mercedes-Cardales gas pipeline, designed to connect the southern and northern gas transport systems, is also progressing. These projects, along with operating pipelines extensions, are the part of Transport.Ar program, aimed at ensuring increased gas production, replacing liquid fuels consumption in the power system (in 2022, oil-fired generation accounted for 15% of electricity) as well as promoting regional gas integration.

Natural gas demand in **Brazil** is projected to rise strongly by 55 bcm, reaching 93 bcm by 2050. This growth is driven by the power generation sector with an extra 30 bcm of demand, while industry, currently the largest consumer, is forecast to increase demand by 12 bcm through to 2050. The share of natural gas in the energy mix rises to 17% by 2050, up from 10% in 2022. Regulatory changes and viable economic growth support greater natural gas use. Brazil liberalised its gas sector in April 2021, aiming to promote competition, vertical unbundling and lower prices for domestic customers. The new regulatory framework and accompanying market design are expected to encourage investments in gas production and transportation infrastructure, leading to the expansion of supply, including monetisation of the country's vast pre-salt gas reserves.

On the back of reform and rising indigenous production, gas-fired generation is set to gain momentum, while regasification infrastructure development is poised to create a favourable landscape for the commissioning of LNG-to-power projects, supporting the need to address ongoing problems in the hydro industry, as rainfall patterns become unpredictable. Overall, rising electricity demand, reduced reliance on hydropower, and the need to provide flexible back-up for growing renewables are central to the forecast.

Venezuela is expected to contribute strongly to Latin America long-term increase in natural gas demand, adding around 35 bcm between 2022 and 2050. Given vast natural gas resources, growth potential emanates from positive economic development, the strategy to revitalise gas sector, particularly in the light of the recent easing of the United States' energy sanctions, and the planned expansion of gas pipeline grid. Most of demand growth is expected to come from the power generation sector due to rising electricity requirements and the associated expansion of the gas-fired power fleet. In addition, oil-fired power displacement and reduced dependence on hydropower (in 2022, hydro accounted for 86% of country's total electricity generated) are among the key drivers.

4.2.6 Middle East

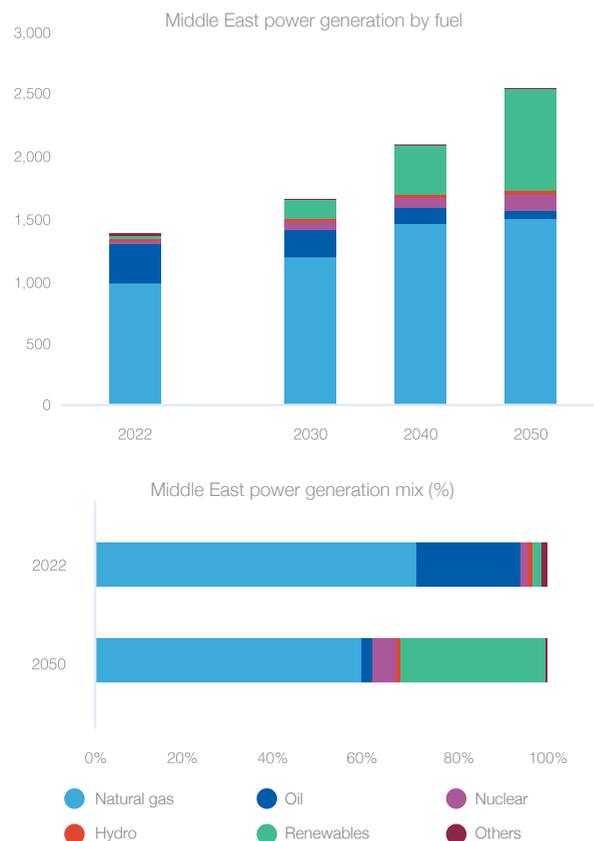
In the Middle East, natural gas, which contributed 53% to the regional energy mix in 2022, is forecast to persist as the most utilised energy source. Demand is expected to rise by 1.5% per annum from 560 bcm in 2022 to 855 bcm by 2050, attributed to significant economic growth and demographic trends, increased living standards as well as the scope to displace oil products, primarily in power generation. Countries' strategies to exploit its large natural gas reserves are set to raise natural gas availability and drive demand in all sectors. Meanwhile, recently unveiled national hydrogen strategies could push blue hydrogen generation and CCUS development. These capabilities are set to support a sustained natural gas demand trend, simultaneously ensuring the long-term viability of oil and gas industry in the region.

Over 60% of incremental natural gas demand in the Middle East between 2022 and 2050 are forecast to emanate from industry, power generation and water desalination. Industrial gas demand (both as an energy fuel and a feedstock) is expected to become central, adding around 115 bcm through to 2050, driven by expansion of gas-to-chemicals, petrochemicals, fertiliser production and light manufacturing. Given rising gas production, countries will place more emphasis on value-added industries as a route towards economic diversification. Gas-to-power demand is projected to continue to increase, supported by surging electricity needs, and oil-to-gas switching policies, although could plateau in 2040s due to the integration of more efficient CCGT plants and accelerated deployment of renewables and nuclear capacities. In its turn, growing alternative generation sources free up additional gas volumes for industrial applications and the production of blue hydrogen and its derivatives.

Rapid adoption of renewables is anticipated, given the premium conditions the region offers. With the lowest PV tariffs worldwide, countries, especially Saudi Arabia and the UAE, are taking proactive steps to realise their vast renewables potential, implementing public tenders/auctions within ambitious programmes. While nearly absent from the mix in 2022, renewables are set to contribute 32% to the region's electricity supply by 2050, with solar alone providing 24%. The share of oil-fired power generation is expected to fall from 23% to less than 3% over the outlook period. Countries that rely heavily on oil for electricity supply (e.g. Iraq with oil as 47% of its power generation mix, Kuwait with 43% or Saudi Arabia with 38% in 2022) are projected to demonstrate continued switching to natural gas to achieve a less carbon-intensive power system. The role of natural gas in the regional power generation mix is forecast to remain dominant, although squeezing from 71% in 2022 to about 60% in 2050 (Figure 4.17).

Figure 4.17.

Middle East power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include coal, bioenergy and hydrogen

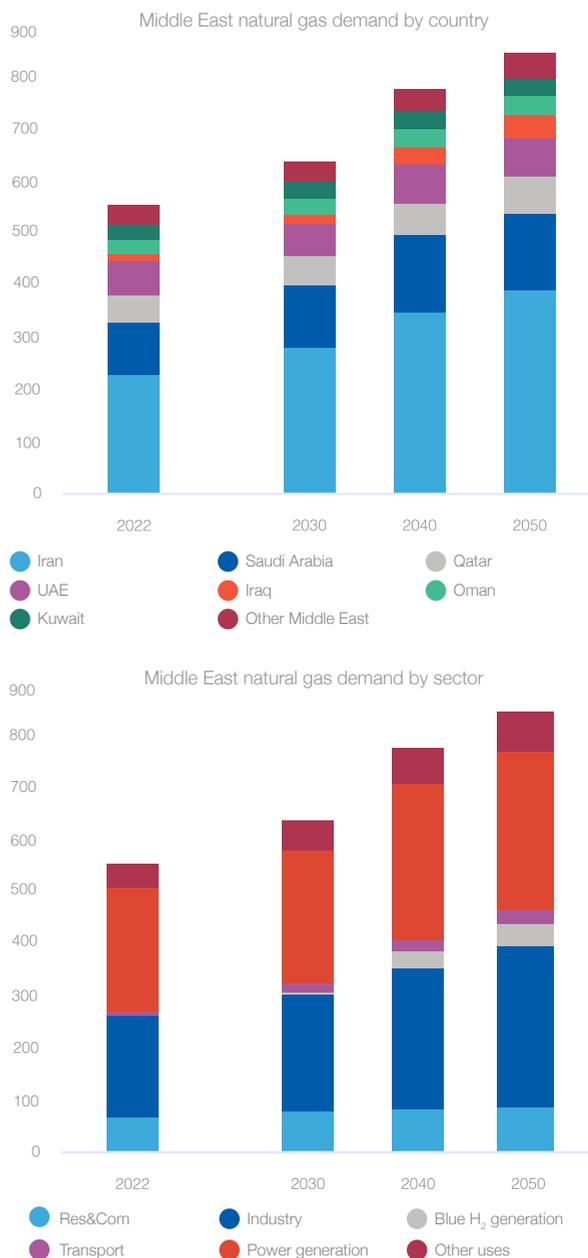
Blue hydrogen generation is expected to become another promising natural gas demand centre, making up 15% of the total additional natural gas use, underpinned by countries' plans to adopt low-carbon hydrogen use in major sectors, as well as to develop export markets. State funding and state-owned companies are already engaged in hydrogen projects built on natural gas capacity. For example, Saudi Aramco seeks to gain a large market share in global blue hydrogen demand in the coming decade, particularly in the form of blue ammonia, and has already dispatched the world's first shipment of blue ammonia to Japan in 2020 and to South Korea in 2022. In 2022, QatarEnergy announced the world's largest blue ammonia plant (the Ammonia-7 project with a capacity to produce 1.2 Mt per year), which is set to come online in 2026. In July 2023, the UAE within its National Hydrogen Strategy set an intermediate target to produce 0.4 Mt per year of blue hydrogen by 2031 (of the total 1.4 Mt per year of low-carbon hydrogen) and ADNOC is set to significantly contribute to blue hydrogen target.

About 6% of natural gas demand growth is projected to be attributed to the residential and commercial sector, entirely led by Iran amid growing population and expanding natural gas access to new rural areas. Equal contribution is expected from the transport sector. Road transport demand is projected to continue developing in Iran, due to policy support and low CNG prices. An increase is expected also in Saudi Arabia, primarily in

the HGV segment, as the country aims to curb oil demand. In addition, LNG as a bunker fuel is forecast to rise in the region, providing a great opportunity to service LNG-powered vessels on Europe-Asia shipping routes.

Figure 4.18.

Middle East natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 4.18 illustrates natural gas demand growth in the Middle East at the country and sectoral levels. With the region as a whole is set to add 295 bcm of demand between 2022 and 2050, the biggest increase is forecast in Iran, accounting for over 55% of additional gas use. This is followed by Saudi Arabia with 16%. Iraq also sees strong demand growth, mainly driven

by gas-in-power developments. The UAE is set to remain the third largest gas market in the region, after Iran and Saudi Arabia, although long-term demand rise may flatten due to the introduction of large-scale, non-gas power generation, while blue hydrogen generation could provide upside potential.

In **Iran**, natural gas demand is projected to increase by around 165 bcm between 2022 and 2050, driven by positive expectations for GDP growth, and large gas reserves. In addition, Iran's high level of energy intensity and low fuel prices, among the lowest in the world, will stimulate demand. Industry and power generation are set to lead the growth, together accounting for 73% of additional gas use. Industrial needs in particular are expected to add almost 65 bcm through to 2050 in light of the development of gas-to-chemicals, petrochemicals complexes as well as light manufacturing, which will significantly contribute to the Iranian economy. The rise in demand is also forecast in residential and commercial sector. Although around 95% of the population is connected to gas grids, the government aims to further enhance gas availability for the growing population.

In the Iranian power system, in 2022, natural gas-fired plants accounted for 70% of the total installed capacity, and provided 84% of the power generation mix. Over 30 GW of gas-fired capacity is in various stages of completion with a high probability of being commissioned within the coming decade, while the capacity build out is set to persist thereafter amid continuous electricity demand growth. Over the outlook period, gas-fired generation is expected to remain the backbone of electricity supply, maintained in part by ongoing oil-to-gas switching policy, however currently untapped solar and wind could also start to penetrate the mix, given government support, and huge potential of Iran's non hydropower renewables resources. Additionally, nuclear power development is likely to put a pressure on a stronger gas-in-power demand growth. Iran is expanding the Bushehr plant with two units (1 GW each) under construction by Russia's Rosatom. The building of the 300 MW Karun nuclear power plant started in October 2023. Earlier, in July 2023, it was announced that the country plans to develop five new nuclear power plants by 2041, totalling 20 GW.

In **Qatar**, natural gas demand is set to grow by 18 bcm over the outlook period. Most of additional demand comes from rising gas use linked to energy sector-related needs amid the expansion of LNG export production capacity. Moreover, the country is exploring ways to diversify the economy and investments in low-carbon gas-based solutions are key to this diversification. In this context, blue hydrogen generation and its derivatives are poised to present additional natural gas demand growth opportunities. For example, Qatar recently unveiled plans to build the world's largest blue ammonia plant: scheduled to be operational in 2026, the facility is expected to generate sales of 1.2 MT per year. In its turn, the power generation sector is forecast to provide a slight increase in natural gas use due to rising renewables capacity. The country targets 5 GW of solar by 2035. The 800-MW Al Kharsaah solar PV plant was commissioned in 2022. Two additional solar power projects in industrial cities, Mesaieed and Ras Laffan, with a combined capacity of about 880 MW are planned within the next two years.

Demand for natural gas in **Saudi Arabia** is forecast to grow by almost 50 bcm, stabilising in early 2040s at around 150 bcm and then levelling off. High economic growth, low gas prices and policy focus on increased use of natural gas, including as

a means to substitute oil products in power generation, are the main factors behind the forecast. Country's demand is set to grow in tandem with the expansion of the domestic production, supported by plans to invest in new unconventional shale gas production and to develop the Ghawar area, specifically the Jafurah Basin. Natural gas output growth will advance long-term goals to provide more gas for power generation and for industry, particularly in the growing petrochemicals sector given country's strong export-oriented intentions. At the same time, Saudi Arabia is targeting to allocate considerable gas volumes for blue hydrogen and blue ammonia generation to supply both domestic and international markets.

Within the power generation sector, natural gas demand is forecast to have a contrasting trend. It rises until the later half of 2030s amid commissioning of new gas-fired capacity and then declines below 2022 levels, as oil-to-gas switching potential is set to be largely played, while the deployment of renewables and nuclear are also expected to accelerate. Having pledged to meet carbon neutrality by 2060, non-fossil fuel expansion in the power system is an essential part of country's ambitious. Saudi Arabia plans initially to build two 1.4 GW nuclear reactors with a goal of increasing nuclear capacity to over 17 GW by 2040. Moreover, the country envisages 58.7 GW of renewable capacity by 2030, outlined in the Saudi Vision 2030 roadmap.

The forecast anticipates strong intent to pursue renewables projects, although 2030 renewable target is projected to be delayed, as that amount of capacity would require a substantial effort at the network level to adapt to the new power generation mix, given such a short lead time period. Overall, Saudi Arabia is set to witness a significant transformation of its fossil fuel-based power system. The share of oil in the country's power generation mix is forecast to drop from 38% in 2022 to 3% by 2050. Natural gas, which holds a 62% share, is expected to decline to 39% by 2050, however gas-fired generation continues to be crucial to meet rising electricity demand and provide required flexibility. Nuclear (assuming the partial implementation of the program) and renewables, having huge opportunities to ramp up, could supply around 58% of electricity needs in 2050.

In the **UAE**, natural gas demand is forecast to rise by 7 bcm between 2022 and 2050, however this increase masks contrasting trends in consuming sectors. Particularly, natural gas use for power generation is set to decline amid the deployment of nuclear and renewables as part of efforts to achieve carbon neutrality by mid-century. In the power system, in accordance with the updated Energy Strategy 2050, the country targets a 30% share of CO₂-free installed generation capacity by 2030, implying that clean sources reaches 32% of the power generation mix by that date (compared to 16% in 2022).

On nuclear side, the fourth reactor at the Barakah nuclear station is under testing for anticipated start up in 2024, which will raise the total operation capacity of the power plant to 5.6 GW. The nuclear facilities are the second phase of a long-term clean energy program that began with the 1.2 GW Noor Abu Dhabi solar PV power plant in late 2019. The UAE plans to invest massively in solar energy to meet objectives regarding the development of renewables (the updated Strategy calls for renewables capacity to more than triple, reaching 14.2 GW by 2030). For example, the 2 GW Al Dhafra Solar PV plant in the Emirate of Abu Dhabi was inaugurated in November 2023. Important project under development is a 5 GW Mohammed bin Rashid Al Maktoum Solar Park, located in the Emirate of

Dubai. The country's very low PV cost supports the promising outlook for this technology. According to estimations, solar accounts for almost 50% of the power generation mix in 2050, up from 6% in 2022. In its turn, natural gas share is forecast to drop strongly from 79% in 2022 to around 35% in 2050.

Gas-in-power demand decline is expected to be largely offset by growing natural gas volumes, allocated for blue hydrogen generation and its derivatives. The UAE, alongside with Saudi Arabia, is striving to become one of the leading producers and exporters of low-carbon hydrogen. The country aims to produce 1.4 Mt per year by 2031 and 15 Mt per year by 2050. Blue hydrogen is seen as a steppingstone to increase domestic hydrogen use and support export targets, while expected to play a significant role in the balance of UAE's low-carbon hydrogen production in the long-term.

4.2.7 North America

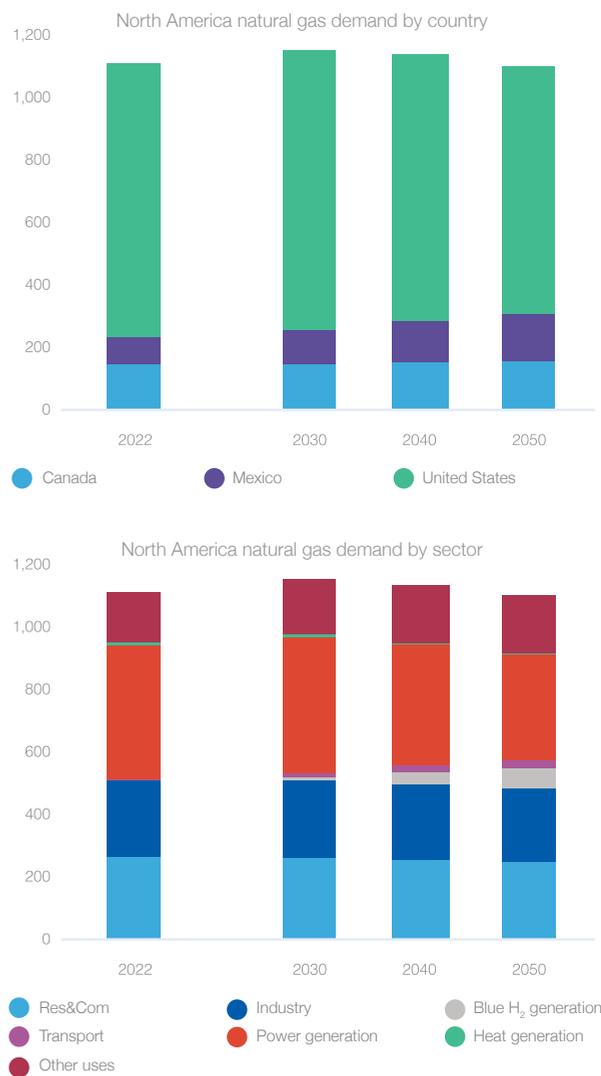
Natural gas is forecast to remain a strategically important fuel in North America, with its share in the regional energy mix enhanced from 35% in 2022 to 36% in 2050. Energy transition plans in the region is projected to continue, mainly driven by the United States Inflation Reduction Act (IRA), although emission-reduction measures are expected to impact coal and oil within the power generation and transport sectors, while natural gas is set to retain a considerable role due to affordability, ample supplies and environmental advantages. The gas industry in North America, specifically the United States, is responding to the climate challenge through scaling up options that support deep decarbonisation of natural gas, including the deployment of CCUS and methane abatement technologies. CCUS in particular has a huge potential given significant CO₂ storage capacity in mature fields. Both the United States and Canada are aiming to spur CCUS projects with direct government spending and tax credits.

In absolute volumes, natural gas demand in the region is expected to remain relatively unchanged over the forecast period. It is set to rise moderately this decade and reach a prolonged plateau at around 1,150 bcm. After 2030, demand is expected to gradually decline to 1,100 bcm by 2050 that is slightly below 2022 level (Figure 4.19). At the same time, this trend conceals noticeable changes in countries' consumption trajectories. While Canada is expected to witness a slow increase, gas use in Mexico is anticipated to expand significantly, driven by gas-based power generation and industrial needs. In the United States, accelerated coal plant retirements provide growth opportunities, although its gas market could enter perpetual contraction after 2026-2027 due to the focus on decarbonisation technologies, and assertive renewables drive. Overall, the push for natural gas use in the region is expected to originate mainly in blue hydrogen generation and the transport sector. LNG export facility ramp-up and growing gas production are set to provide additional consumption for energy industry own use. These areas largely offset demand reductions in other sectors over the forecast period.

The increase of natural gas demand for blue hydrogen generation is set to be substantial, with an estimated increase of around 65 bcm between 2022 and 2050. The United States and Canada are well positioned to increase blue hydrogen utilisation as a tool to decarbonise the non-power sectors, given the low-cost nature of gas production, availability of infrastructure, and policy support to scale up CCUS developments. There is strong potential for conversion of

Figure 4.19.

North America natural gas demand outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

existing on-site grey hydrogen generation, particularly within methanol, ammonia and refining facilities. Additional impulse for natural gas demand growth will materialise from blue hydrogen export potential.

Road and marine transport are expected to grow significantly accounting for incremental 24 bcm over the outlook period. This trend is forecast to be overwhelmingly driven by the United States, with NGV market development being the largest contributor. Rising natural gas use gains from strengthened emissions standards and policy initiatives. The HGV segment is the primary target of continued gas engine conversion, having economic and environmental benefits. Future demand is also buoyed by the expansion of requisite infrastructure through private sector investments.

In the power generation sector, more coal plants in the United States are set to be retired in the coming decade, while significant expansion of gas-fired power capacity is forecast in Mexico during the whole forecast period. Even in Canada, where the power system benefits from an abundance of hydroelectricity, natural gas has the opportunity to replace existing coal-fired power plants, and provide flexibility to renewables. Demand in this sector is projected to decline after 2030 due to strong renewables build-out, and improvements in battery storage technology, primarily in the United States. Despite the drop, the power generation sector remains the largest consumer of natural gas in the region, accounting for around 30% of total or 335 bcm in 2050.

In the industrial sector, natural gas is expected to remain resilient. Mexico is set to raise demand driven by economic development. Industrial gas use in the United States and Canada is set to be relatively flat at least until the mid-2030s, but decline thereafter. Particularly, in the United States, rising GDP and new methanol and petrochemical plants, could even stimulate some demand increase this decade, although energy efficiency improvements and natural gas displacement from low-carbon hydrogen offset, dragging sectoral demand in the country slightly down in the second half of the outlook period. Industrial gas use in combination with CCUS will be crucial to address further GHG mitigation. For the residential and commercial sectors, upside demand potential is limited due to efficiency gains and increasing electrification of heating systems.

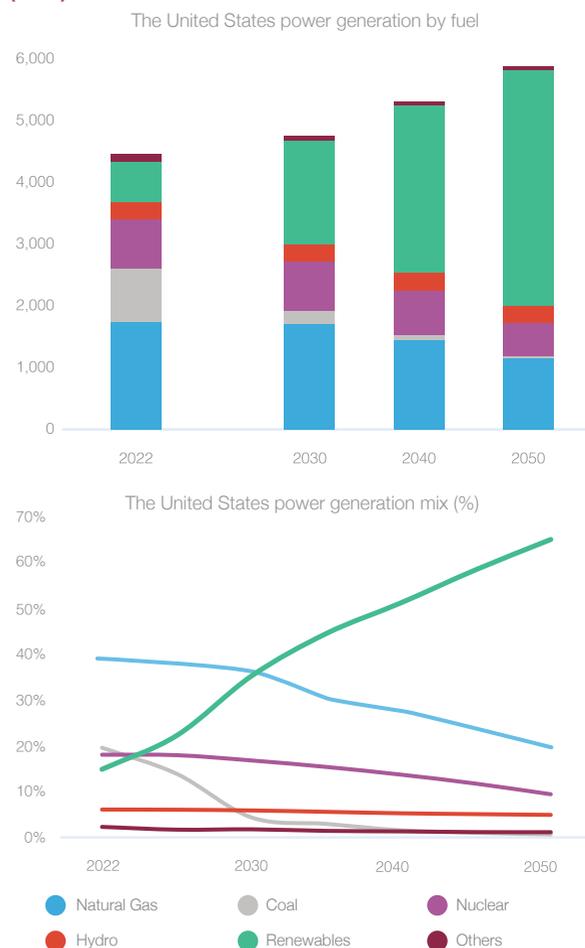
In **Mexico**, natural gas demand is forecast to grow by around 65 bcm to more than 150 bcm by 2050. Rising demand in the power generation and industrial sectors is set to be the main drivers, with gas-to-power needs accounting for 68% of the total increase. Natural gas share in the energy mix is set to rise from 39% in 2022 to 46% by 2050. Affordable piped supplies from the United States, cross-border pipeline capacity additions, increased domestic exploration-production activities and expanding country's gas transmission network support demand growth. In the Mexican power system, natural gas is projected to maintain its dominant role, favoured by the ongoing strategy to add numerous CCGTs to the grid. Replacing the remaining polluting coal- and oil-fired power plants, and providing a base load for increasing electricity demand, natural gas-fired generation is forecast to supply around 60% of the power generation mix in 2050, slightly declining its share from 64% in 2022 as solar and wind generation rises.

In the **United States**, natural gas demand is expected to continue rising in the coming years, driven primarily by large-scale coal-to-gas switching in power generation, but could peak at around 910 bcm in 2026-2027. From there, demand is projected to decline to around 790 bcm by 2050, as decarbonisation technologies mature, and adoption of clean energy sources increases. Still, natural gas retains a significant share in the country's energy mix, hovering around 34% over the outlook period. The transport sector and blue hydrogen generation are set to provide upside potential for natural gas. Blue hydrogen in particular becomes more significant given IRA tax incentives, and its use is set to accelerate.

The overall drop in natural gas demand is projected to be triggered by power generation sector dynamics, reflecting a 100% carbon-free electricity supply target by 2035. In this regard, the IRA, through the establishment of new technology-neutral credits, is intended to incentivise investment in renewable projects, and support nuclear power, including plants that are at high risk of early retirement. Nevertheless, achieving a net-zero power sector by 2035 is forecast to be challenging, and 67% of carbon-free power generation by that date seems realistic. Natural gas-fired power generation is projected to support the transition away from coal, and provide 36% of the total by 2030. However, its share drops to 30% in 2035 and 20% by 2050 amid aggressive renewables buildout (Figure 4.20). The integration of CCGTs fitted with carbon capture will be crucial to contribute to reducing carbon emissions in the power system.

Figure 4.20.

The United States power generation outlook, 2022-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
 Note: Others include oil, bioenergy and hydrogen



5

Natural Gas Supply Outlook

Highlights

- ▶ Driven by projected increase in natural gas demand, global natural gas production is forecast to rise by 1.3 tcm between 2022 and 2050, reaching 5.3 tcm by 2050.
 - ▶ The annual growth rate is forecast at 1% over the entire period. More specifically, production is expected to expand at 1.4% per year during this decade, followed by 1.1% per year during the 2030s and 0.5% per year in 2040s. This compares to robust growth of 2% per year from 2012 to 2022.
 - ▶ Conventional gas is set to continue to make up the larger share of global natural gas production going forward compared to unconventional gas, despite higher growth rate from unconventional sources over the past 20 years. Conventional natural gas production is projected to reach 3.9 tcm by 2050, while unconventional gas output is forecast to reach 1.4 tcm.
 - ▶ Non-associated natural gas from conventional fields is the largest component of global gas production and is projected to continue dominating production through 2050. This type of fields is forecast to reach 3,440 bcm in 2050, accounting for 64% of total gas production by that time.
 - ▶ Offshore natural gas production is forecast to grow at a faster rate than onshore gas production. Specifically, offshore gas output is projected to expand at an average annual rate of 1.6%, reaching 1.8 tcm by 2050. This compares to current offshore production of 1.16 tcm.
 - ▶ In terms of regional growth outlooks, the Middle East is forecast to see the largest absolute increase in natural gas production through 2050, with output projected to grow by 480 bcm. Meanwhile, Africa is expected to record the fastest average annual growth rate of 2.8% during the forecast period to 2050.
 - ▶ Unconventional gas production in North America is expected to peak at 1,125 bcm in 2030s and then decline to 1,080 bcm in 2050 due to decreasing output from existing assets .
 - ▶ By 2050, Africa, Eurasia, and the Middle East will gain market share, accounting for 10, 22, and 22% of global gas production, respectively, while North America is anticipated to witness a reduction in its share to 26%.
- Looking ahead to 2050, the vast majority of global natural gas production is expected to come from new project developments and exploration/production of yet-to-find (YTF) resources.
- ▶ Specifically, 80% of natural gas production by 2050 is projected to be sourced from new projects and YTF resources.

5.1. Global natural gas production

While global natural gas production for 2022 held steady at approximately 4,025 bcm, akin to the 2021 level of 4,030 bcm, regional gas production exhibited noteworthy fluctuations. The year 2022 marked a recovery from the production levels witnessed in 2020, and notably, it exceeded the pre-COVID gas production levels of 2019.

Significant shifts were observed in regional gas production. The Middle East and North America expanded their gas production capacities, while the Asia Pacific and Europe experienced relatively modest incremental growth. Latin America's production remained stable. Conversely, Africa saw a slight decline in gas production, and Eurasia marked a substantial decrease in gas production levels.

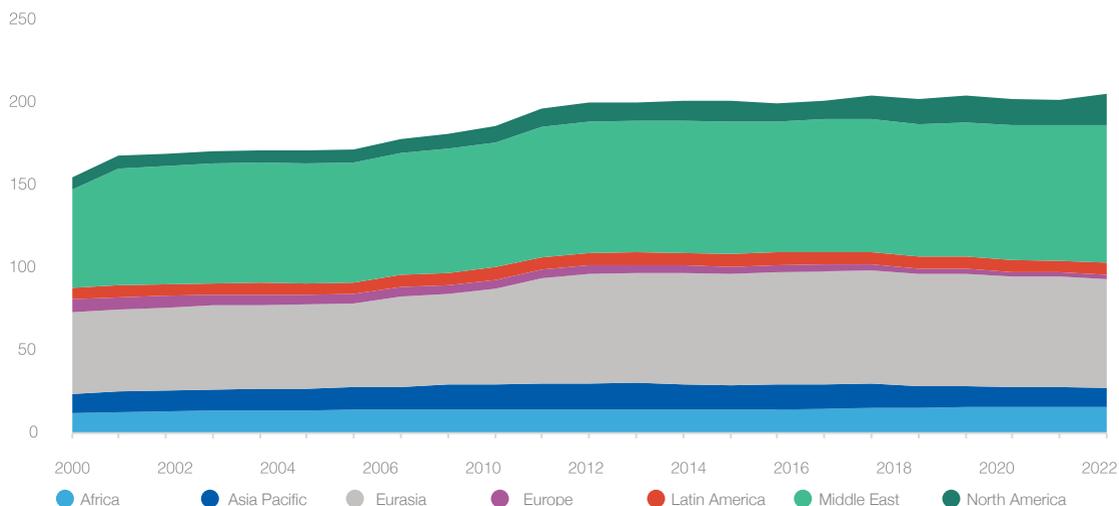
Gas production in the Middle East witnessed a 2.2% increase, rising from 670 bcm in 2021 to 685 bcm in 2022, with Iran and Saudi Arabia driving this growth. In 2022, the Middle East contributed to 17% of global natural gas production. Similarly, North America experienced a 6% growth in gas production, surging from 1,160 to 1,230 bcm. This growth was primarily driven by the United States, specifically by associated gas from the Permian Basin and shale gas extracted from the Haynesville and Eagle Ford plays. North America has the largest share of global gas production at 30.6%.

In the Asia Pacific region, gas production rose by approximately 12 bcm, reaching 650 bcm in 2022, reflecting annual growth of 1.8%. This increase was primarily spearheaded by China, contributing an additional 11 bcm. However, Thailand experienced the most notable reduction in the region, with a decrease of 5 bcm. In 2022, the Asia Pacific accounted for 16.1% of global gas production. Surprisingly, Europe saw a 3.8% upswing in production, reaching 213 bcm, equivalent to 5.3% of the world's gas production. This production boost in Europe was attributed to production expansion in Norway and the UK, which more than compensated for the substantial decline observed in the Netherlands.

Natural gas production in Latin America remained stable at 158 bcm, with increases in Argentina, Peru, and Trinidad and

Figure 5.1.

Natural gas reserves by region, 2000-2022 (tcm)



Source: GECF Secretariat based on data from Cedigaz and the GECF Annual Statistical Bulletin

Tobago balancing out declines in Brazil, Bolivia, and Venezuela. Latin America contributed 4% to the global gas production in 2022. In contrast, Africa experienced a slight production decrease of 4 bcm, reaching 254 bcm in 2022, marking a decline of 1.5%, and accounting for 6.3% of global production. Algeria spearheaded the growth in gas production in the region, with Equatorial Guinea and Libya following suit. However, production declines, especially in mature fields in Egypt and Nigeria, resulted in an overall reduction in the region's natural gas production.

Eurasia recorded the largest decline in gas production, with a decrease of 90 bcm, representing 9.7%, resulting in a total production of 835 bcm in 2022. This decline was predominantly attributed to a decrease in Russian gas production, influenced by the geopolitical factors surrounding pipeline gas imports from Europe. Eurasia constituted 20.7% of the global natural gas production market in 2022.

5.2. Global natural gas proven reserves current status

As of 2022, global natural gas proven reserves total 205 tcm based on the aggregation of Cedigaz data and the GECF Annual Statistical Bulletin on the GECF Member Countries, with the Middle East being the largest holder, boasting 83 tcm, followed by Eurasia with 66 tcm. Together, these two regions collectively represent 73% of the world's gas reserves (Figure 5.1).

According to Cedigaz, natural gas reserves exhibited a consistent upward trend from 1980 until 2011, followed by a period of relative stability until 2022. The surge in reserves during this period can be attributed to heightened investments in exploration and production, coupled with technological advancements that facilitated the exploitation of previously inaccessible gas fields, particularly in challenging environments like deep-water areas. Additionally, the development of more precise exploration technologies significantly contributed to the accurate delineation of gas fields. Over the span from 1980 to 2014, there was a remarkable escalation in upstream expenditure for natural gas, surging from USD 21 billion in 1980 to an impressive USD 285 billion in 2014.

As per RystadEnergy’s analysis, approximately 750 tcf (21 tcm) of conventional gas volumes were discovered between 2010 and the end of August 2023. Expanding this analysis to encompass unconventional resources reveals that the total volume discovered from 2010 to 2022 amounts to 36 tcm, surpassing the cumulative global natural gas production from 2010 to 2019. Nonetheless, only 18 tcm of these natural gas volumes have been developed and put into production, as a significant portion of capital expenditure was directed toward brownfield expansion.

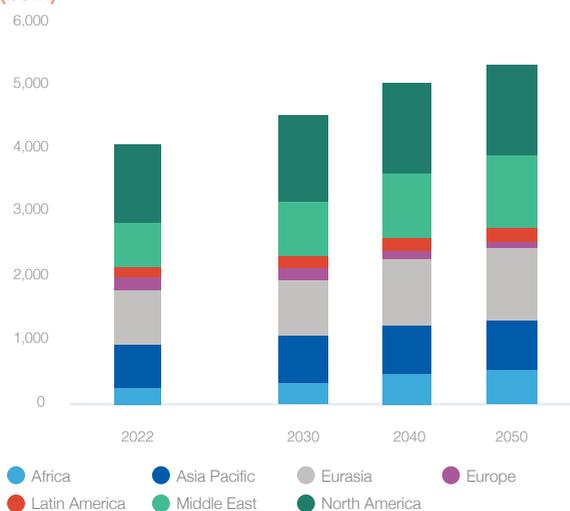
The protracted development of greenfield areas over the past decade has led to a decline in the global reserve-to-production ratio. This ratio, which stood at 61 years in 2011, dwindled to 50 years by 2022. In practical terms, this implies that at the current production rate, all existing reserves could be depleted within 50 years. However, by striking a balance between the development of brownfield and greenfield areas, the ratio can be restored to the 60-year benchmark. In general, the abundance of substantial natural gas reserves enhances consumer confidence in the long-term security and reliability of natural gas supply.

5.3. Natural gas production outlook

To satisfy the growing natural gas demand, global natural gas production is expected to increase and reach 5.3 tcm by the year 2050. This represents an estimated increase of 1.3 tcm from the 2022 level, marking a substantial 32% growth in gas production. This translates to a compound annual growth rate of slightly above 1% in natural gas production in the period 2023-2050. Driven by projected natural gas demand, the forecast indicates that natural gas supply set to witness more rapid growth in the current decade compared to the subsequent two decades. Until 2030, natural gas production is projected to experience the highest annual growth rate of 1.4% over the forecast period. However, this growth is anticipated to slow down in the 2030s, averaging 1.1% annually, and further decrease to 0.5% annually by 2040s.

Figure 5.2.

Natural gas production outlook by region, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

This growth pattern is anticipated to be a global phenomenon, with the majority of regions undergoing expansion. However, Europe is an exception to this trend. North America, maintaining its position as the world’s largest natural gas producer, is expected to retain this status in 2050, with output reaching 1,400 bcm. This is closely followed by the Middle East and Eurasia, each producing 1,165 bcm (Figure 5.2).

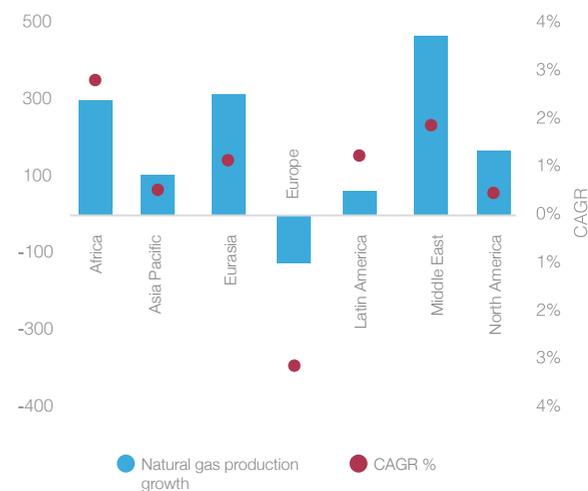
Profound shifts are anticipated in country-level gas production dynamics, with the roster of the top five producing countries set to undergo a transformation by 2050. As of 2022, the leading producers, namely the United States, Russia, Iran, China, and Canada, jointly contribute to 57% of global gas production. However, by 2050, Canada is set to be displaced by Qatar in this list, with the top five producers collectively representing 59% of global gas production. The United States is projected to maintain its position as the largest global natural gas producer throughout the forecast period. However, Russia is anticipated to witness the most substantial incremental production growth, driven by its efforts to address current geopolitical challenges and expand its gas trade infrastructure. The country is projected to return to the 700 bcm production level in the late 2030s through the projected expansion of trade infrastructure towards the Asia Pacific region and through LNG exports.

In terms of regional forecasts, the Middle East is anticipated to lead the way in absolute natural gas production growth, while Africa is projected to exhibit the fastest average annual growth rate over the period to 2050. The Middle East is poised for the most substantial gas production expansion, with an expected contribution of 480 bcm, followed by Eurasia and Africa adding 310 and 300 bcm, respectively (Figure 5.3). However, North America is expected to maintain its position as the largest gas producer, with an additional 170 bcm of production by 2050. Asia Pacific and Latin America are projected to exhibit the lowest growth in gas production volume, adding 105 and 65 bcm, respectively.

When analysing compound annual growth rates, Africa emerges as the frontrunner with the highest annual growth rate of 2.8%, followed by the Middle East at 1.9%. In contrast,

Figure 5.3.

Natural gas supply growth outlook by region, 2022-2050 (bcm)



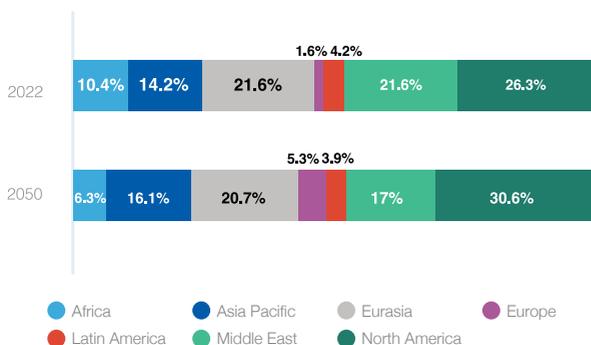
Source: GECF Secretariat based on data from GGM 2023

Europe is poised for a decline of approximately 3.1% per year. This decline can be attributed to a combination of factors such as the maturation of legacy fields in countries like Norway, the UK, and the Netherlands, along with inadequate investment levels in exploration and production activities, as the European region pursues policies aimed at transitioning away from natural gas. Latin America is forecast to experience growth at an annual rate of 1.2%, while the Asia Pacific and North America are expected to achieve more moderate growth at 0.5% by the year 2050.

In terms of market share, the Middle East and Africa are set for significant gains, increasing by 4 p.p. each in 2050 compared to their 2022 shares, reaching 22 and 10% respectively. Eurasia is expected to also witness a growth in its production share, reaching 22% of global gas production by 2050. Likewise, Latin America is projected to contribute 4% of global gas production, representing a modest increase of 0.3 p.p. compared to its 2022 share. On the contrary, North America is anticipated to witness a reduction in its global gas production share, declining from 31% in 2022 to 26%. Likewise, Asia Pacific is expected to experience about 2 p.p. reduction in its share (Figure 5.4). However, Europe's share is forecasted to diminish to only 1% by 2050, a notable decrease from its 5% share in 2022.

Figure 5.4.

Natural gas production contribution forecast by region (2022 and 2050)



Source: GECF Secretariat based on data from GGM 2023

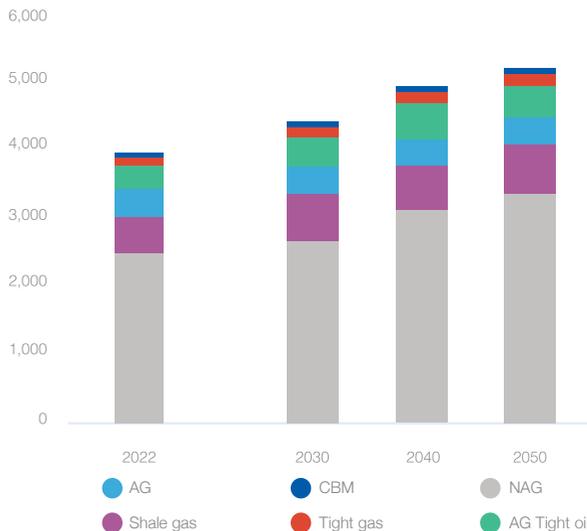
In terms of the type of hydrocarbons, non-associated gas (NAG) from conventional fields has been the dominant source of natural gas historically, and is anticipated to maintain its position for the future. The NAG extracted from conventional reservoirs is projected to contribute 3,440 bcm to the production level by 2050, marking an incremental growth of 950 bcm from the 2022 level, translating into a commendable 1.2% annual growth rate. The NAG production is set to be prominent in Iran, Mozambique, Nigeria, Qatar, and Russia. Conversely, the outlook for associated conventional gas (AG) is expected to remain relatively unchanged (Figure 5.5).

Regarding natural gas production from unconventional sources, we foresee a gradual upturn in production from unconventional reservoirs, primarily propelled by shale and tight gas, as well as associated gas from tight oil reservoirs. These combined sources are projected to grow by 340 bcm. Nevertheless, it is worth noting that coal bed methane (CBM) is not expected to witness significant development and is likely to remain below

the 100 bcm throughout the forecast period. This situation is due to production increases in China and Indonesia, expected to be counterbalanced by declines in Australia and the United States.

Figure 5.5.

Natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

Over the forecast period to 2050, there is necessity for new projects, including from yet-to-find (YTF) resources. This is essential to compensate for the decline in production from existing assets, and to contribute to meeting growth in demand. In 2050, production from new projects, both conventional and unconventional, is anticipated to account for 55% of global gas production. Alongside YTF resources, these sources are expected to constitute a substantial 80% of the global future gas production by 2050 (Figure 5.6). Therefore, it is crucial to invest in exploration and development activities.

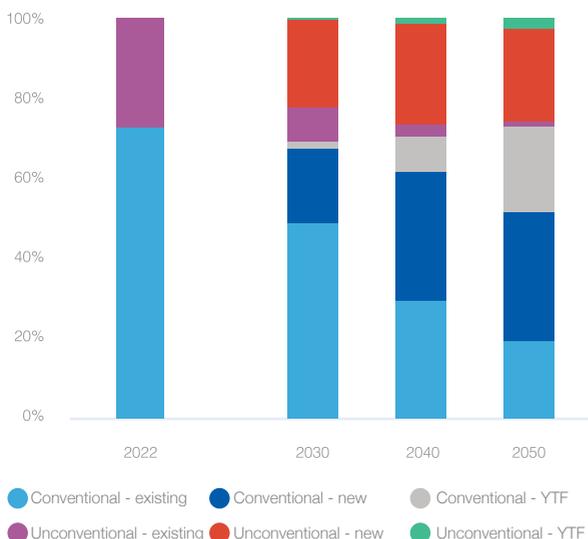
Existing fields, those in production prior to or at the base year of 2022, experience varying rates of decline. On a global scale, it is projected that production from existing conventional assets are set to decrease by an average annual rate of 3.6%, from their current level of 2,860 bcm, while unconventional assets are expected to globally decline by a rate of 8.8% from their present level of 955 bcm. Regionally, Eurasia and the Middle East demonstrate the lowest average decline rates in existing assets, at 3.3 and 1.6%, respectively, owing to the extensive size of their gas fields.

To offset the production loss resulting from the decline in existing assets, new conventional and unconventional gas production is poised for a growth of 1,675 and 1,050 bcm respectively. Furthermore, to meet the demand, alongside the required development of natural gas production from new assets, YTF resources will be necessary to contribute to natural gas production growth, particularly from 2040 onwards, in order to satisfy demand. Conventional and unconventional YTF are anticipated to contribute 1,100 and 140 bcm, respectively, by 2050.

Over the past two decades, unconventional natural gas production has stood out as a driving force behind the growth

Figure 5.6.

Global natural gas production outlook by share of project types, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

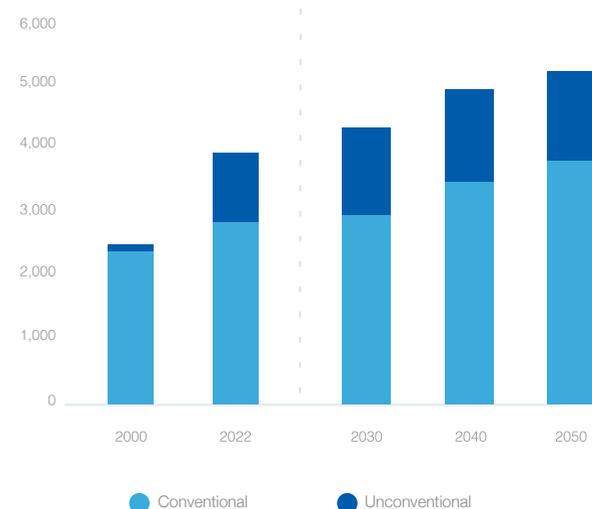
in global production. According to the RystadEnergy data, unconventional gas production has witnessed an extraordinary tenfold surge, rising from 108 bcm in 2000, to a substantial 1,125 bcm in 2022. During this period, the breakeven cost of unconventional assets experienced a significant decline, mainly attributed to the decreasing drilling and hydraulic fracturing costs, driven by technological advancements. Furthermore, access to low-cost financial resources played a pivotal role in propelling this rapid growth.

Unconventional natural gas production is poised for considerable expansion in the future, with an additional 300 bcm projected to be added to its output by 2050. However, this growth is expected to remain moderate compared to its historical trend. The momentum of unconventional natural gas production is forecast to diminish, declining to an annual growth rate of 0.8% from 2022 to 2050. The forecasted slowdown in growth of unconventional gas production is primarily attributed to the rapid decline of existing unconventional gas assets. These existing unconventional gas assets are expected to witness a substantial average annual decline of 8.8% over the forecast period on global basis. This decline is set to counter the additions of new unconventional production, which are expected to continue growing and contribute 1,350 bcm by 2050. The decline of existing unconventional fields, and the growth of new unconventional production additions combine to result in a slowdown of unconventional growth. This is reflected in an annual growth rate of 2.7% in the present decade, decreasing to 0.6% in the 2030s, and eventually experiencing a decline of -0.3% annually in the 2040s.

By the year 2050, unconventional gas production is projected to maintain its upward trajectory, reaching an estimated 1.43 tcm, making up approximately 27% of global gas production. However, despite this significant increase, its share of global natural gas production is anticipated to experience a slight decline of approximately 1.3 p.p. Production from conventional resources is expected to expand from 2.95 tcm in 2022 to 3.9 tcm in 2050 (Figure 5.7), accounting for a growth of 980

Figure 5.7.

Global natural gas production outlook by field type, 2000-2050 (bcm)



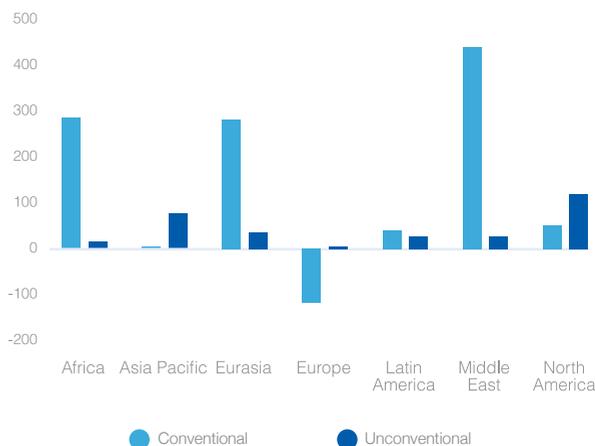
Source: GECF Secretariat based on data from GGM and Rystad Energy

bcm, which is more than three times the growth observed in unconventional gas production.

North America is expected to remain the primary driving force behind the growth in unconventional gas production. In this region, unconventional gas production is projected to surge from 960 bcm in 2022, to approximately 1,080 bcm by 2050 (Figure 5.8). After North America, the Asia Pacific region is poised to experience significant growth, with unconventional gas production increasing from 130 bcm in 2022 to approximately 210 bcm by 2050. Furthermore, conventional natural gas-producing countries such as Oman, Saudi Arabia, and the UAE, are actively developing unconventional gas assets, a context that has been explored further in the Middle East section of the Outlook.

Figure 5.8.

Natural gas production growth outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

Offshore natural gas production is poised to outpace onshore production in terms of growth. Offshore natural gas production is projected to expand at an average rate of 1.6% p.a., reaching 1.8 tcm in 2050, up from the current 1.16 tcm. Onshore natural gas production, on the other hand, is anticipated to witness an annual average growth rate of 0.8% over the period to 2050, reaching 3.5 tcm (Figure 5.9). The share of offshore natural gas production is set to increase globally, rising from the present 29 to 34%. This surge in offshore gas production is primarily attributed to the growth in Africa, where offshore production is expected to increase from 28% in 2022 to 73% in 2050, and in Latin America, where offshore production is set to rise from the current 35 to 49% by 2050. Similarly, Eurasia is expected to experience an increase in its offshore production share, growing from 6% in 2022 to 14% in 2050. In contrast, Asia Pacific, the Middle East, and North America are anticipated to maintain nearly the same share of offshore production throughout the forecast period.

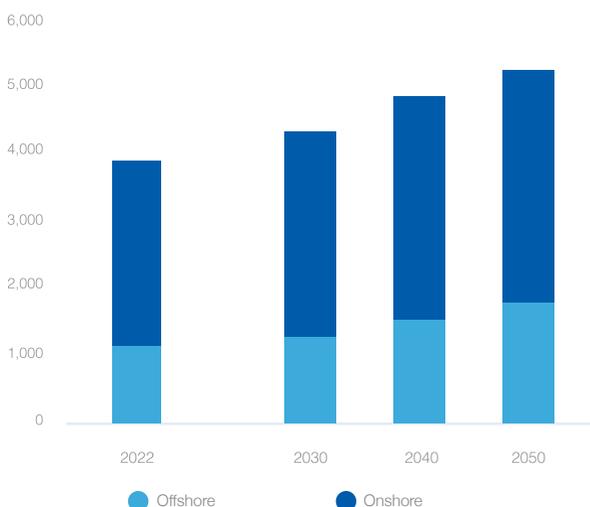
Regionally, natural gas offshore production is set to witness the most rapid growth in Africa at 6.2% annually, driven by key developments in Egypt, Nigeria, Mozambique, and other parts of West Africa, including offshore projects such as Akata, Nile Cone Delta, Rovuma LNG, and Yakkar Teranga LNG.

Securing a stable and abundant supply of natural gas is of paramount importance, and this entails substantial investments in the upstream gas sector to meet the expected 32% surge in natural gas production compared to 2022 levels. Given the natural production decline in existing conventional and unconventional assets, these are projected to contribute only 1,040 and 70 bcm, respectively, in 2050. As a result, existing conventional assets are set to make up just 20% of the required natural gas production in 2050. Beyond the projects that are set to shape the industry over the forecast period, the geographical distribution of fields is also expected to evolve, with greater emphasis on offshore fields contributing to heightened capital investment requirements.

Consequently, the majority of future natural gas requirements, accounting for 80%, is set to depend on the development of new projects, including from YTF resources. This emphasises the

Figure 5.9.

Natural gas production outlook by field location, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

critical importance of investment in greenfield and exploration activities, to ensure a resilient and adequate supply of natural gas, in order to satisfy growing demand in the years ahead. It should also be highlighted that the forecast trend implies an anticipated increase in the marginal cost of natural gas production compared to historical trends as production could be sourced from more challenging fields. However, the regional trends provide a nuance comparison between regions.

5.4. Regional natural gas production outlook

As regional gas production changed structurally in 2022, natural gas production is expected to experience several dynamic regional changes.

The major natural gas producing regions, Eurasia and the Middle East are projected to observe high growth leading to a staggering share of 43.2% of global gas production in 2050. Considering the expected high growth in Africa, driven mainly by offshore natural gas production, the three regions are set to hold the majority of natural gas production, accounting for 53.6% of global gas supply.

The North American region is expected to experience considerable growth driven by the United States and Canada, although the region's share of global gas production is anticipated to drop by 4.3 to 26.3%.

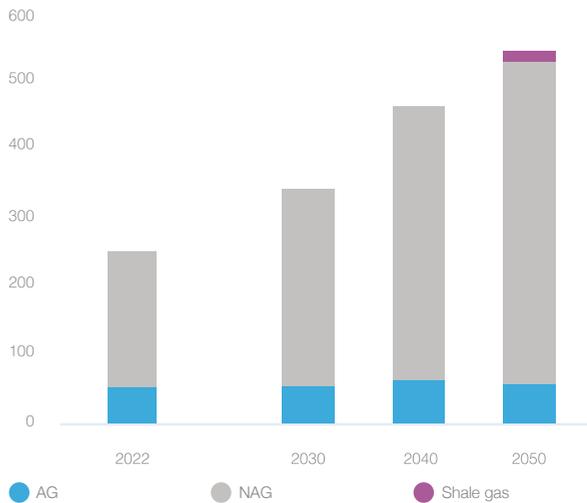
5.4.1 Africa

Africa witnessed a slight production decrease of 4 bcm in 2022, representing 1.5%, reaching 254 bcm, equivalent of 6.3% in global production (Figure 5.10). Algeria led natural gas production growth in the region, followed by Equatorial Guinea and Libya. However, production declines in mature fields, particularly in Egypt and Nigeria, resulted in an overall drop in the region's production.

Natural gas production in Africa is poised for remarkable growth, with the region projected to achieve the fastest annual

Figure 5.10.

Africa natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

gas production growth rate of 2.8% during the forecast horizon. By 2050, natural gas production is expected to reach 550 bcm, more than doubling as it did over the past two decades. This surge in production is anticipated to be driven by Mozambique, Nigeria, and other countries in West Africa.

The majority of gas production is set to come from non-associated gas, while associated gas production is expected to remain relatively stable, accounting for less than 60 bcm throughout the forecast period to 2050, with Nigeria emerging as the major associated gas producer, adding 18 bcm to this category.

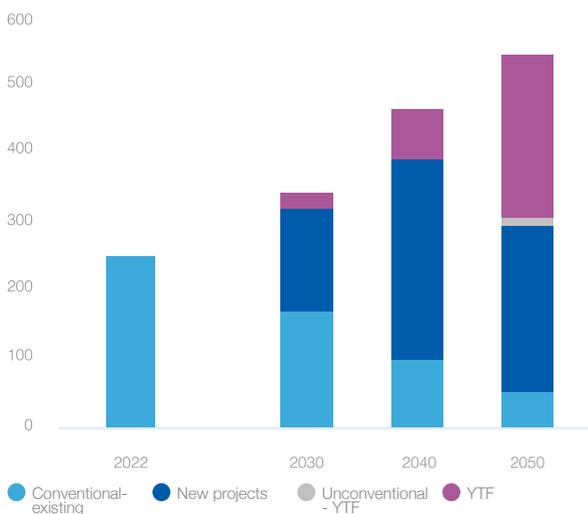
New projects in the region are expected to play a substantial role in boosting natural gas production, contributing to additional 260 bcm by 2040. However, their impact is projected to gradually decrease to 230 bcm by 2050 (Figure 5.11). After 2040, the growth of natural gas production is foreseen to heavily rely on new discoveries, emphasising the role of intensified exploration in realising the production forecast outlined in this outlook. Notably, the development of YTF resources in Algeria, Egypt, Mozambique, and Nigeria are set to play a pivotal role in driving gas production beyond 2040. Collectively, these resources constitute approximately 40% of the total production in the region, underscoring the critical importance of heightened investment in exploration, particularly given the region's current underexplored status.

The growth in natural gas production is set to primarily be fuelled by the expansion of offshore production. Accounting for 28% in 2022 (Figure 5.12), it is projected to reach 73% by 2050. Mozambique, Nigeria, and part of West Africa are poised to lead the change in driving offshore production growth in the long term. Notably, the region is currently experiencing a notable uptick in offshore projects, with potential developments such as BirAllah, Graff FLNG, Prosperidade LNG, Rovuma LNG, Tanzania LNG, and Yakaar Teranga LNG playing key roles in this expansion.

Algeria is increasing its natural gas supply through the development of mature fields, and expediting the exploitation of new discoveries in the short and medium term, reducing natural

Figure 5.11.

Africa natural gas production outlook by project type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

decline over the long term. Natural gas production witnessed a notable increase, rising from 85 bcm in 2019 to 101 bcm in 2022, primarily propelled by the expansion of Hassi R'Mel. It is anticipated that natural gas production is expected to maintain a level of 100 bcm by 2030.

Furthermore, Algeria has made new discoveries in proximity to its largest gas field, Hassi R'Mel, and is giving priority to their development, in order to add 3.5 bcm to its production. Additionally, Algeria is focusing on expediting the development of key projects set to commence operations in 2023, with an expected contribution of 10 bcm, notably LD2 in Hassi R'Mel, Ahnet, and In Amenas Periphery.

The increased investment from international oil and gas companies (IOCs) in Algeria is expected to accelerate gas production. An illustrative example is ENI's acquisition of BP's operations, which is set to expedite natural gas production. The Italian company is actively working to secure natural gas trade via the TransMed pipeline. This initiative is expected to result in enhanced gas production from the In Amenas and In Salah fields, which together contain approximately 850 bcm of recoverable gas resources.

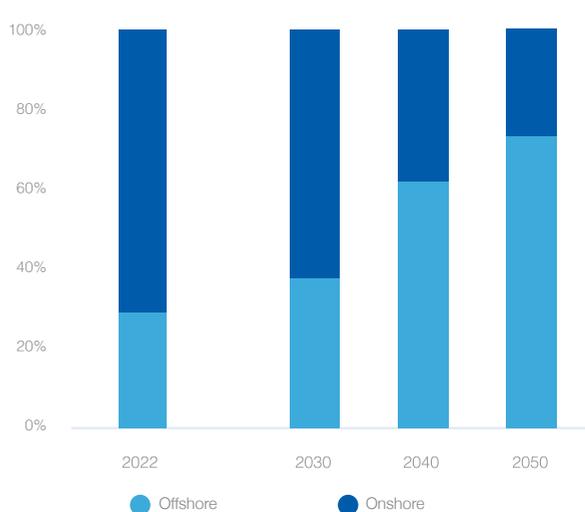
Furthermore, Algeria's state-owned oil company, Sonatrach, achieved multiple hydrocarbon discoveries in 2023. These discoveries encompassed resources located in various basins, including the Amguid Messaoud, Berkine, Illizi, and Oued Mya basins.

Finally, it is noteworthy to mention that Algeria has one of the largest unconventional gas resources.

Driven by heightened offshore exploration activities, **Egypt** has made significant strides in boosting its natural gas production in recent years. Investment in offshore upstream natural gas assets surged from USD 3.4 billion in 2014 to USD 6.1 billion in 2019, leading to a corresponding production increase of 18 bcm. Offshore exploration and discoveries played a pivotal role in Egypt's production growth, elevating it from 42 bcm in 2016 to 70 bcm in 2021. Egypt's natural gas production is projected to reach 80 bcm by 2030.

Figure 5.12.

Africa natural gas production share outlook by field location, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

Egypt has been intensifying its efforts in exploration and production, actively attracting investment from IOCs to expand its oil and gas resources. The recent discovery of Nargis in the offshore Nile Delta has piqued the interest of these companies in neighbouring blocks, such as East Port Said and South Nour. Over the next two years, Egypt is planning to invest USD 1.8 billion in drilling approximately 30 exploration wells in the Mediterranean Sea, and the Nile Delta. The potential gas discoveries from these endeavours, involving many major international oil and gas companies, have the potential to support Egypt's growing gas demand and exports. Additionally, Egypt is advancing the development of gas fields, including Nargis, Satis, and Nour in the Mediterranean, the East Damanhour field in the Nile Delta, and various fields in the Western Desert.

In addition to advancing exploration and the development of newly discovered assets, Egypt is actively pursuing measures to enhance production in its offshore fields, and is focused on production activities. One of such initiative involves a planned investment of USD 1.2 billion for maintenance and infill drilling in the Zohr field.

Mozambique is poised to become a significant natural gas exporter, with an expected natural gas production of 35 bcm in 2030, 80 bcm in 2040 and 110 bcm in 2050, harnessing its substantial gas reserves. The country is estimated to possess recoverable natural gas reserves totalling around 130 tcf, equivalent to 3.7 tcm.

Natural gas production commenced in Mozambique in 2004 with the Temane field, and five years later, production witnessed an increase upon the introduction of the Pande field. In 2023, Mozambique is projected to produce approximately 8 bcm of natural gas, marking a 75% increase from 2022. This growth has been supported by the expansion of production in the Coral Sul project within the Rovuma Basin.

The successful operation of the Coral Sul Floating Liquefied Natural Gas facility in 2021, may pave the way for more FLNG developments in the country, facilitating the transportation of the expected substantial gas production to international markets. The outlook takes into account a series of new project developments, including Prosperidade that is expected to start by mid 2030s, Mozambique LNG signed by TotalEnergies and the Mozambique authorities in 2020, that includes the development of Atum and Golfinho gas fields, as well as Rovuma LNG that are expected to start up by the end of this decade.

South Africa has the potential to establish itself as a significant gas supplier in Africa, contributing an additional 8 bcm to the continent's gas production by 2050. South Africa's gas production history reached a peak of 5 bcm in 2003, after which it experienced a substantial decline, falling to just 0.5 bcm, according to RystadEnergy data. This decline has been primarily attributed to the absence of new asset development, and the decline of legacy offshore fields.

The future trajectory of natural gas production in South Africa depends heavily on the successful development of deep-water natural gas resources found in the Luiperd and Brulpadda fields. The exploration and exploitation of these two fields, hold the key to South Africa's potential to achieve a substantial long-term gas production of 8 bcm by 2050.

In **Mauritania**, significant progress has been achieved in the energy domain, particularly with the Greater Tortue Ahmeyim

project, spanning the maritime boundaries of Mauritania and Senegal. The initial phase of this project is scheduled to start natural gas production by 2024.

This pivotal development is poised to position Mauritania among natural gas producing nations, forecasting an output of 3 bcm within the period spanning from 2024 to the mid-2030s. Subsequently, there is an anticipated gradual uptick in natural gas production, projected to increase to 15 bcm in preparation for the start-up of the BirAllah LNG project.

Over the forecast period, Mauritania's natural gas production trajectory is expected to experience a steady increase, eventually reaching 18 bcm by the year 2050.

Tanzania is poised to emerge as a significant player in the natural gas sector. Presently, the country's natural gas production stands at 2 bcm. Anticipated forecasts project a notable surge in investments specifically geared towards the Tanzania LNG project.

In May 2023, the Tanzanian government successfully concluded negotiations with Equinor, Shell, and other partners for the development of the Tanzania LNG project. The FID for this project is anticipated in the latter half of this decade. The gas feedstock for the project is to be sourced from Tanzania's Block 1, Block 2, and Block 4 located offshore in southern Tanzania, harboring an estimated gas in place of 45 tcf equivalent to 1.3 tcm. The Tanzania LNG project is slated to commence production by the early 2030s. The development of this project is expected to significantly boost Tanzania's gas production to 16 bcm by 2050.

5.4.2 Asia Pacific

In the Asia Pacific, gas production increased by approximately 12 bcm and reached 650 bcm in 2022, accounting for a growth rate of 1.8%. The growth was driven primarily by a notable 11 bcm increase attributed to China contribution. However, Thailand experienced the most reduction in the region, with a decrease of 5 bcm. Asia Pacific accounted for 16% of the global gas production.

Asia Pacific region is poised for substantial growth in its natural gas production over the coming decades. In the past ten years, from 2012 to 2022, the region witnessed an impressive 30% increase in natural gas production, surging from 500 to 650 bcm. Looking ahead, our outlook foresees a continued upward trajectory in natural gas production, with the region projected to reach 760 bcm by 2050. This marks an additional increase of 110 bcm from the 2022 levels.

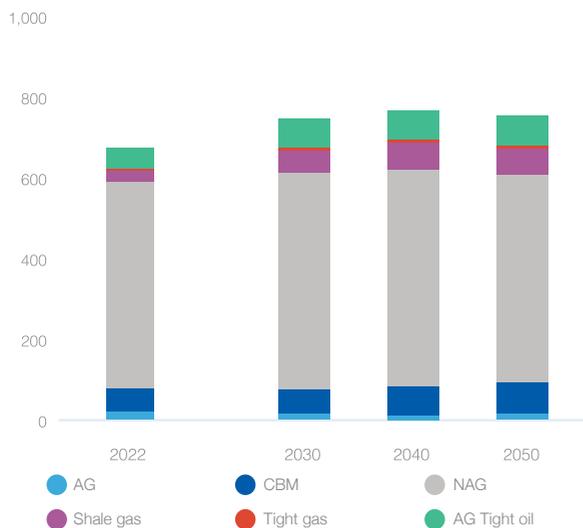
The growth in natural gas production within the region is expected to be primarily driven by China, with smaller but notable contributions from Indonesia and India. In contrast, Australia, a major natural gas exporter in the region, is anticipated to experience a decline in its natural gas production after 2040.

However, it is important to note that by 2050, the region is expected to have a slightly reduced market share in global natural gas production, declining to 14% from its 17% share in 2022. Despite the growth in natural gas production in the region, it is projected to remain the major natural gas importer by 2050.

Natural gas production growth in the region is forecast to be driven mainly by unconventional gas from China and Indonesia. Unconventional gas production is set to account for 78% of

Figure 5.13.

Asia Pacific natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

natural gas production growth by 2050. CBM production is projected to grow in the region from 55 bcm in 2022, to 78 bcm in 2050 (Figure 5.13), driven mainly by China. While, conventional production is expected to be driven primarily by China and Indonesia.

Exploration activities play a vital role in realising the projected outlook for the Asia Pacific region. YTF resources are poised to contribute significantly to the region’s production, accounting for a substantial 39% of the total production in the long term, primarily in countries such as Australia, China, India, Indonesia, and Malaysia. The region is actively promoting upstream exploration activities. According to RystadEnergy, the acreage awarded in gas basins has been on the rise in South East and South Asian countries such as Indonesia, Malaysia, Pakistan, and Thailand. In 2022, the acreage awarded in the region constituted approximately 50% of the global total.

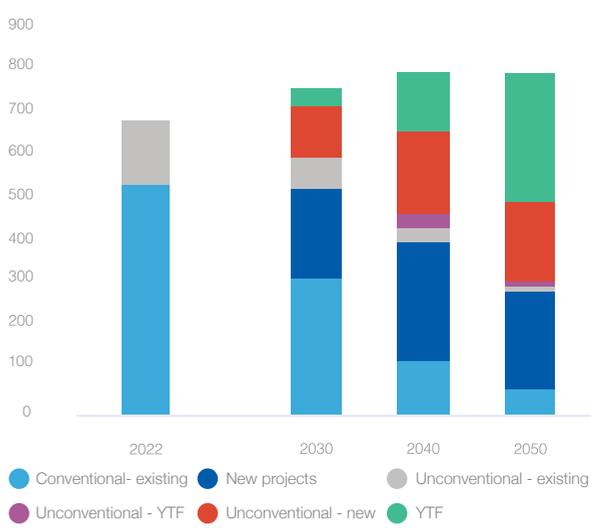
Offshore natural gas production in the region is projected to increase slightly from 39% in 2022 to 42% over the forecast period (Figure 5.15). Offshore production growth is set to take place mainly in Australia, India, Indonesia, and Malaysia.

Australia has witnessed a historic expansion in its natural gas production, with an impressive 240% increase from 2014 to 2019. In 2022, the country’s natural gas production stood at 145 bcm. In the short to medium term, it is anticipated that Australia is expected to reach a production level of 150 bcm by the end of the current decade, supported by the Gorgon Stage 2 development project, off the coast of Western Australia, which commenced production in June 2023. However, the outlook expects Australia natural gas production to decline after 2040, reaching 127 bcm in 2050.

Australia’s natural gas supply future is marked by uncertainty over the long term. Several factors contribute to this uncertainty. Firstly, there has been a noticeable decline in natural gas reserves, with a 31% decrease since their peak in 2013. This decline aligns with historically low levels of investment in the natural gas sector. Without increased investment in exploration

Figure 5.14.

Asia Pacific natural gas production outlook by project type, 2022-2050 (bcm)



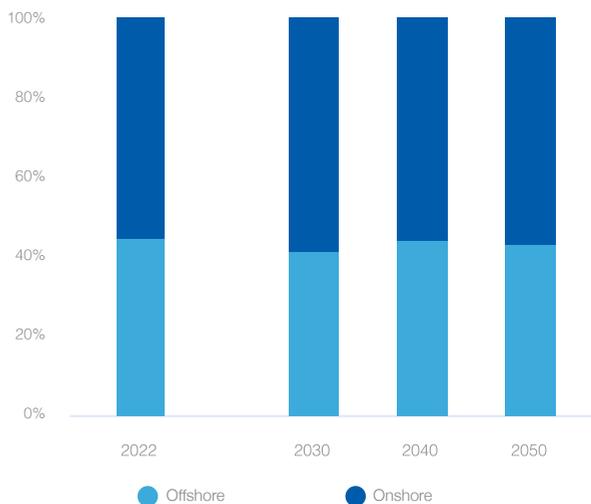
Source: GECF Secretariat based on data from GGM 2023

and gas upstream development, the declining reserves and investment trend is set to impact Australia’s gas production and exports. Secondly, an accelerated shift away from coal could lead to heightened domestic demand for renewables and natural gas. Lastly, changes in industrial carbon dioxide emissions reduction regulations, including the Safeguard Mechanism Amendment, may lead to further adverse implications for Australia’s natural gas industry. In combination, these factors contribute to uncertainties surrounding the country’s long-term natural gas supply.

The Safeguard Mechanism Amendment, approved by the

Figure 5.15.

Asia Pacific natural gas production share outlook by field location, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

Australian Parliament in July 2023, mandates facilities emitting over 0.1MtCO₂e p.a. to reduce their emissions intensity by 4.9% p.a. by 2030. Further, the Amendment requires new gas fields feeding existing LNG facilities to maintain net zero direct emissions, specifically reservoir CO₂ emissions, from production start-up. These regulations pose a financial risk for new projects. For instance, new gas fields with a CO₂ content ranging from 10 to 18%, such as Barossa, Crux, and Plover gas fields, necessitate substantial carbon credits, potentially complicating the economic viability of these projects. Implementing CCUS becomes essential to address and comply with these regulatory obligations.

Natural gas is a pivotal component of **China's** evolving energy landscape as the country diversifies its energy sources. China has witnessed remarkable growth in natural gas production, experiencing an eightfold increase over the past two decades. Production has surged from 25 bcm in 2002 to a substantial 200 bcm in 2022. This impressive growth has been fuelled by extensive development in key basins like Ordos, Sichuan, and Tarim. Due to proactive measures promoting upstream oil and gas investment and reforms, aimed at boosting domestic exploration and production, China is expected to achieve a natural gas production of 360 bcm by 2050. However, despite this substantial production increase, China is expected to remain one of the world's leading importers of natural gas.

In response to heightened energy demand and security concerns, China has initiated policy reforms and incentives to attract investors to the upstream oil and gas sector. Prior to 2017, subsidies were employed to promote unconventional resources like CBM and shale gas. Starting in 2017, structural reforms were implemented to enhance industry competitiveness, encouraging the participation of private companies and facilitating competitive mining rights transfers. Notably, in 2019, foreign companies were granted the ability to independently explore and produce oil and gas in China. These policies aim to diversify industry participation, which was previously dominated by state-owned enterprises. This year, China unveiled the 'Opinions on Deepening Mining Resource Management (Exposure Draft)', highlighting the necessity for mining rights transfers to be conducted through a competitive process. Nonetheless, China's upstream sector remains largely controlled by three state-owned companies.

We anticipate that development costs could rise, driven by the increased share of unconventional resources, expected to increase by 140 bcm over the forecast period, the need for exploration and new discoveries. Consequently, the average domestic supply cost is projected to increase by 55% in 2050.

Indonesia's natural gas production has experienced a downward trend since 2010, declining from 80 bcm in 2010 to approximately 58 bcm by 2022. This decline is primarily driven by the depletion of major fields at an annual rate of 10%. For instance, Peciko and Tunu, which collectively produced 16 bcm in 2010, currently contribute less than 2 bcm in 2022.

To revitalise natural gas production, the way forward is through new exploration and production development. The country faced reduced exploration investment following the 2014 oil price crash. However, the government is actively promoting investment in the upstream oil and gas sector by offering new acreage awarded through bid rounds and facilitating farm-ins for existing fields, while fostering alliances on idle wells.

In support of exploration efforts, the Indonesian government has conducted exploration surveys and regional studies, including the Spermonde, Northeast Java, and the South Makassar Basin. These initiatives have supported the identification of significant prospects, improved access to data, and provided more attractive fiscal incentives.

In addition to intensifying exploration endeavours, Indonesia is witnessing promising developments in its upstream sector. One noteworthy project is the Indonesia Deepwater Development (IDD), which aims to achieve peak production of 8.5 bcm, as reported by the Indonesian Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas). ENI has recently acquired this project and plans to leverage its operated Jangkrik infrastructure and the Bontang LNG facility to expedite project development, with production expected to commence by 2027.

Farm-in exploration activities include the giant Natuna D-Alpha, which was offered in the 2023 bid round. Natuna D-Alpha is a substantial gas condensate field discovered in 1973 and estimated to contain 46 tcf (1.3 tcm) of gas resources. The project has faced historical challenges due to the high CO₂ content of the natural gas, necessitating separation and reinjection back into the reservoir.

We anticipate that the successful development of discovered and under development projects in Indonesia could potentially boost the country's production to 80 bcm by 2050.

India is actively targeting a 15% increase in the share of natural gas in its energy mix by 2030. This goal is to be achieved through the expansion of pipeline networks, construction of LNG terminals, and support for domestic production. Natural gas production in India has been on an upward trajectory since 2020, surging from 24 bcm to 35 bcm in 2023. A significant portion of this increase is attributed to offshore production, accounting for over 70% of the overall production growth.

Introduced in 2016, the Hydrocarbon Exploration and Licensing Policy (HELP) sought to enhance India's upstream sector regulations, attract foreign investment, and expedite exploration activities. This initiative introduced revenue-sharing contracts (RSC) as a replacement for conventional Production Sharing Contracts (PSCs). The shift aimed to streamline operations, address challenges such as cost recovery and stimulate increased exploration opportunities, ultimately enhancing the country's upstream activities.

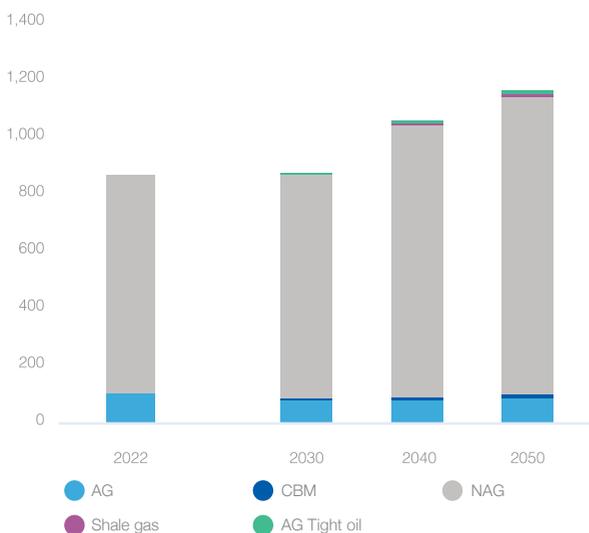
The Indian Oil and Natural Gas Corporation (ONGC) is planning to boost its natural gas production by 25% by 2025 from 2022 level through intensified exploration. In recent developments, ONGC announced the discovery of a gas field in the Mumbai basin and an onshore discovery in the *Krishna Godavari* basin.

These reforms have fostered greater international participation in India's upstream sector. For example, Reliance Industries Limited and BP, have brought three offshore fields into production since 2020. The R-series commenced production in 2020 followed by the Satellite Cluster in 2021 and most recently, the MJ field. BP estimates that, at their peak, these fields are to collectively produce 10 bcm to meet domestic demand in India.

We anticipate that India is expected to achieve a natural gas production level of 50 bcm by 2050, with 95% of this production originating from offshore projects.

Figure 5.16.

Eurasia natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

5.4.3 Eurasia

In 2022, Eurasia’s production reached 835 bcm. The region witnesses the most substantial annual gas production decline globally, experiencing a reduction of 90 bcm corresponding to 9.7%. This decline was primarily driven by a drop in Russian gas production. The geopolitical situation surrounding Europe imports from Russia, and the absence of infrastructure for redirecting Russian gas to Asian markets played significant roles in this decline. Consequently, Eurasia’s share in the global natural gas production market for 2022 stood at 20.7%.

Despite the decline in natural gas production in 2022, the Eurasian region boasts substantial natural gas reserves, and a promising potential for production expansion. The outlook anticipates an increase in production from the current 835 bcm in 2022. Projections indicate a significant upswing in natural gas production, particularly beyond the current decade, with the region expected to reach 1,150 bcm by 2050. This represents a substantial additional gain of 330 bcm (Figure 5.16).

The primary driver of natural gas production growth in the region is expected to be non-associated conventional gas projects, particularly in countries such as Russia, Turkmenistan, Kazakhstan, and Azerbaijan.

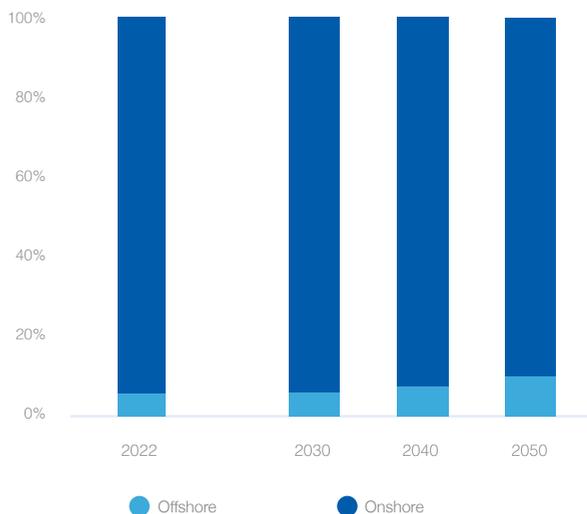
Importantly, the region is positioned to expand its portion of global natural gas production, rising from 20.7% in 2022 to 21.6% by 2050.

In the region, onshore natural gas production is set to continue to dominate throughout the outlook period. Offshore production, currently at 5%, is projected to increase to 10% by 2050 (Figure 5.17), driven mainly by developments in the Kara Sea and Sakhalin in Russia.

The primary driver of gas production growth in the region is projected to stem from conventional gas extraction in new developments, adding a substantial 460 bcm by 2050. Leading this growth will be Russia, with Turkmenistan and Kazakhstan following suit. Key conventional projects including

Figure 5.17.

Eurasia natural gas production share outlook by field location, 2022-2050 (%)



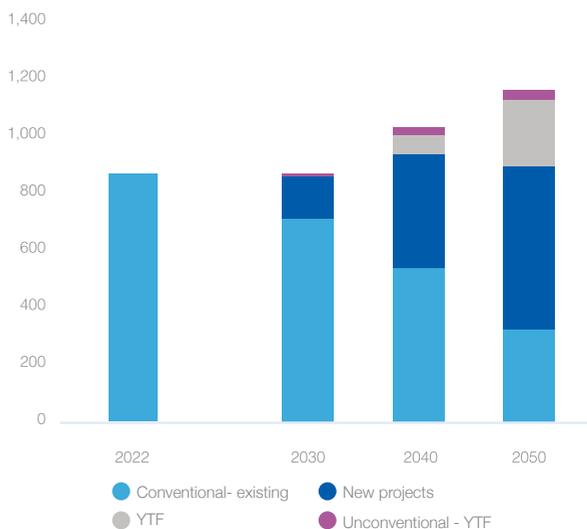
Source: GECF Secretariat based on data from GGM 2023

Kuzenshternskoye, Yashlar, Kashagan, and Arctic LNG-2 is set to play pivotal roles in this expansion. In contrast, production from unconventional fields is anticipated to remain limited, contributing negligibly to the region’s future production until 2050, primarily due to the abundant conventional resources available.

Over the outlook period, conventional YTF resources are expected to commence contributing to the region’s production profile in the latter half of the 2030s and will eventually account for a 22% share of the region’s production by 2050 (Figure 5.18).

Figure 5.18.

Eurasia natural gas production outlook by project types, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

Russia, the world's second-largest natural gas producer, is poised for long-term growth in natural gas production, despite facing various macro and geopolitical challenges in Europe, excluding Türkiye. In 2022, Russia experienced a 13% drop in natural gas production, primarily in the Yamal region. This decline was attributed to reduced imports from Europe, and limited infrastructure for redirecting natural gas exports from the Yamal Peninsula to the Asia Pacific region in the short term. However, looking ahead, Russia anticipates significant growth in natural gas production, driven by increased domestic demand and the projected expansion of natural gas exports to Asia. Russian production is projected to reach its 2021 level by mid 2030s and grow to a production level of 900 bcm by 2050.

Russia's strategic focus lies in harnessing its abundant untapped gas resources, particularly those in close proximity to China, including reserves in the East and Okhotsk regions. To achieve this goal, the Kovyktinskoye gas field, considered Eastern Siberia's largest gas field, commenced production in 2023.

In addition to expanding pipeline infrastructure to cater to the Asian market, Russia is actively pursuing LNG projects to gain access to global gas markets. This endeavour involves the development of gas reservoirs, exemplified by the onshore Utrenneye field situated on the Gydan Peninsula in 2024. This field is expected to serve as the supply source for the Arctic LNG-2 project, further solidifying Russia's presence in the LNG sector.

Turkmenistan has seen a remarkable 21% increase in its natural gas production between 2020 and 2022. Looking ahead, the outlook is promising, with expectations that Turkmenistan is set to achieve a gas production level of 110 bcm by 2050, cementing its position as a significant gas exporter in the Asia Pacific region.

Turkmenistan boasts vast natural gas reserves estimated at 13.9 tcm. Its strategic geographical location places it in close proximity to major natural gas-consuming countries, including the largest importer of natural gas, China, as well as India and Pakistan.

Notably, Turkmenistan stands as the largest supplier of gas to China through pipelines, is actively collaborating with the CNPC to further develop the Galkynysh gas field, which is estimated to hold reserves of 0.6 tcm. The Galkynysh 2 started production in 2022 and is expected to reach peak production by 2028 and Galkynysh 3 is expected to start production by mid 2030s. This field is poised to become a pivotal source of natural gas, supplying the Line D section of the Central Asia-China pipeline. This pipeline serves as a conduit for delivering natural gas to southern China, traversing through Uzbekistan, Tajikistan, and Kyrgyzstan, further enhancing Turkmenistan's role as a key gas provider in the region.

5.4.4 Europe

In 2022, Europe experienced a 3.8% increase in natural gas production, reaching a total of 213 bcm. This accounts for approximately 5% of global gas production. The growth in European gas production, is attributed to Norway and the UK, offsetting substantial decline in the Netherlands.

Despite the uptick in natural gas production in 2022, the European upstream oil and gas sector is grappling with growing maturity, and diminishing investment in upstream activities. Over the last decade, Europe's production has experienced a

significant decline of 70 bcm. Projections paint a challenging outlook, suggesting that Europe's natural gas production is projected to continue to dwindle in the years to come, plummeting to 88 bcm by 2050. Consequently, Europe's share of the global natural gas production pie is expected to contract from 5% in 2022 to a mere 1.6% by 2050.

The maturation of existing fields in countries such as Norway and the UK, coupled with the rising development costs associated with new fields (given that a significant portion of the continent's production is offshore), presents formidable challenges for the growth of natural gas production in Europe. Key factors contributing to this decline in production include reduced output from mature fields, and the scarcity of large-scale new development initiatives. When assessing the existing gas assets, it is anticipated that they are set to decline by 30 bcm by 2030, followed by a further decrease of 90 bcm from 2030 to 2050 (Figure 5.19).

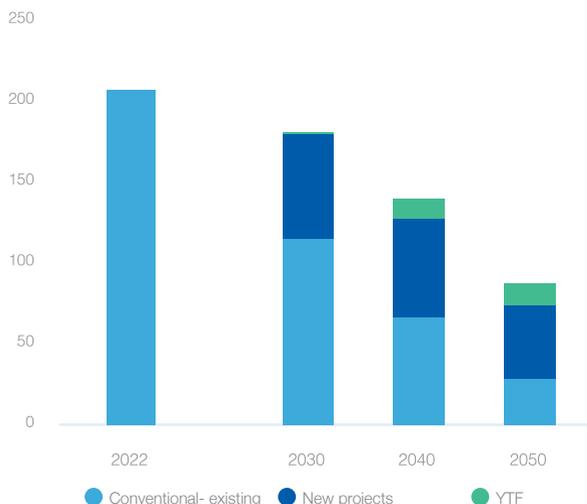
However, it is noteworthy that Türkiye and Romania are playing pivotal roles in mitigating the production decline across the continent. Collectively, they are expected to contribute to 30% of Europe natural gas production by 2050, compared to 4% in 2022.

Offshore natural gas production remains the predominant source of Europe's gas supply. Currently, and throughout the forecast period, a substantial 90% of Europe's natural gas production is derived from offshore fields. Looking ahead to 2050, it is projected that onshore production in Europe is set to witness a significant shift, with Romania taking the lead, and accounting for 55% of the onshore production (Figure 5.20).

As Europe grapples with ongoing energy security concerns, Norway's role as a significant natural gas exporter is becoming increasingly pivotal. The country is maintaining robust levels of gas production, and greenlighting numerous new oil and gas development projects, to enhance its hydrocarbon output. An illustrative example of this commitment is the Norwegian government's approval of 19 oil and gas fields in 2023, with

Figure 5.19.

Europe natural gas production outlook by project type, 2022-2050 (bcm)



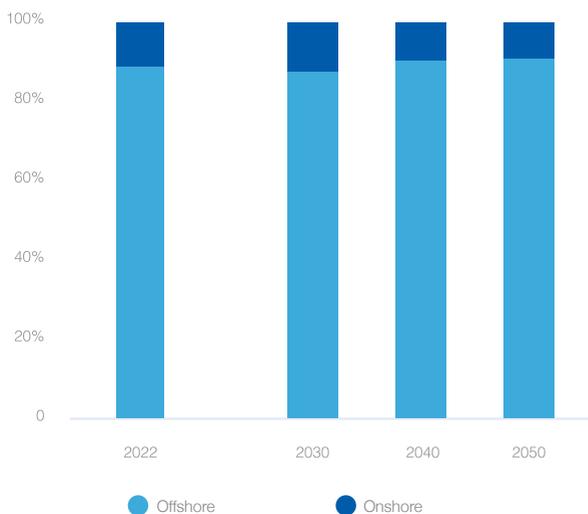
Source: GECF Secretariat based on data from GGM 2023

investments totalling \$18.5 billion. Furthermore, substantial projects such as the Troll field are at the planning phase.

Norway is intensifying its exploration endeavours to counteract the depletion of existing fields in the long term. In 2023, the Ministry of Energy offered 92 new blocks for oil and gas exploration and production, encompassing 78 in the Barents

Figure 5.20.

Europe natural gas production outlook by field location, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

Sea, which is believed to contain approximately two-thirds of the yet-to-be-discovered oil and gas resources, and 14 blocks in the Norwegian Sea. Success in tapping and developing these new discoveries, could fundamentally alter the trajectory of Norway's natural gas production after 2030.

Nevertheless, the long-term production outlook presents challenges, particularly in unexplored basins such as Barents Sea, which entails high costs and infrastructure requirements. The outlook anticipates Norway's gas production to reach 115 bcm by 2030, but subsequently decline to 50 bcm by 2050.

The UK has witnessed a continuous decline in natural gas production since its peak of 102 bcm in 2000, reaching 36 bcm by 2022. In response to environmental goals and the imperative of improving energy security, the UK government conducted a comprehensive evaluation of oil and gas licensing. The conclusion reached was that "continuing licensing for oil and gas is not inherently incompatible with the UK's climate objectives." Driven by a commitment to energy security, the UK has reversed its decision from 2020 to abstain from granting new exploration licences in the UK Continental Shelf. Substantial efforts have been made to expedite production in this region.

The launch of the 33rd UK Offshore Licensing Round in October 2022, marked a significant turning point in this strategic shift. The North Sea Transition Authority (NSTA) oversaw a highly competitive process, receiving a total of 115 bids from 76 different companies vying for the allocation of 258 blocks. This competitive process concluded in January 2023.

In the pursuit of heightened energy security, discoveries play a pivotal role for the UK. This year, the Pensacola gas field was discovered in the Southern North Sea. This region, known as one of the world's oldest gas-producing basins, continues to lead in gas discoveries in the UK. Additionally, there have been developments in the newly discovered Victory gas field. However, considering the declining reserves over the past two decades, and the limited exploration drilling, the outlook anticipates that the UK maintains a production level of around 35 bcm until 2033, followed by a steep decline to 5 bcm by 2050 unless major discoveries are made.

Over the past three decades, **Romania** has experienced a continuous decline in its natural gas production, which has dropped from 25 bcm in 1990. However, the approval of the Neptun Deep gas project in the Black Sea, has sparked optimism for the future of natural gas production. There are expectations of increasing production levels from the current 7 bcm to an estimated 10 bcm by 2030, followed by subsequent period of stabilisation at 7 bcm.

Romania's gas production is primarily concentrated in several key areas. First, there are onshore gas fields owned by Romgaz, boasting estimated recoverable volumes of a 740 bcm. Second, the Neptun Deep gas project in the Black Sea, located in a largely unexplored region, with the potential for significant reserves. The development of this project is estimated to cost USD 4.4 billion, in anticipated production commencement in 2027. Lastly, the discovery of the Lira gas condensate field in the Black Sea, further enhances the country's gas production potential.

Türkiye is rapidly emerging as a natural gas producer in Europe, with its production projected to reach 13 bcm by 2050. In the current year, the country's natural gas production is anticipated to reach 1.6 bcm, driven by the commencement of the first phase of the Sakarya field. This field, discovered in the ultra-deep waters of the Black Sea in August 2020, is expected to achieve peak production of 3.5 bcm. The second phase of development is poised to add 7.5 bcm at its peak, and is expected to start production by the end of this decade, resulting in a combined total production of 11 bcm from the Sakarya field.

With the expansion of the Sakarya field, and recent discoveries in the South Akcakoca Sub Basin, Türkiye is on track to reach a production level of 20 bcm toward 2040. However, in the absence of major discoveries, there is a possibility of a decline to 13 bcm by 2050.

5.4.5 Latin America

In 2022, Latin America's overall gas production remained stable at 158 bcm. However, there were notable changes in gas production at the country level. Argentina, Peru, and Trinidad and Tobago experienced increases in natural gas production, while Brazil, Bolivia, and Venezuela witnessed declines. Latin America's combined gas production accounted for 4% of the global total in 2022.

Looking ahead, natural gas production in the region is expected to reach 225 bcm by 2050, representing an increase of 67 bcm (Figure 5.21). Throughout the forecast period, Latin America is projected to maintain its 4% share of global natural gas production. Notably, Argentina, Brazil, and Venezuela are expected to contribute significantly, accounting for 80% of gas production in Latin America.

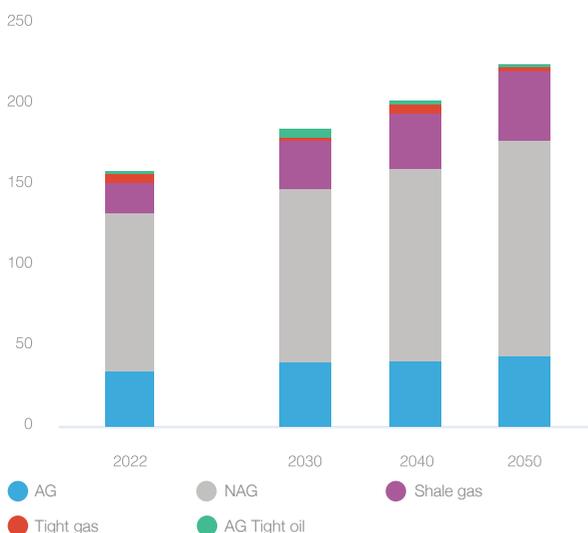
Non-associated gas is expected to dominate, as the primary source of gas in the region. However, there is expectation of slight growth in associated gas production over the forecast period, driven primarily by Brazil and Venezuela.

By 2050, conventional gas production is poised to lead the growth in overall gas production, with unconventional gas production accounting for 26 bcm, while conventional production is expected to contribute 40 bcm. This growth is primarily driven by Brazil, Venezuela, and Peru in the case of conventional production, while Argentina is set to be the sole driver of unconventional natural gas production in the region. Argentina's significant contributions is expected to stem from the Vaca Muerta and Neuquen shale basin.

The role of exploration is pivotal in shaping the energy outlook of the region. YTF resources are anticipated to play a substantial role, contributing a significant 65% share of the total regional gas production by 2050. While new conventional and unconventional projects are anticipated to propel natural gas growth until 2040, it is noteworthy that YTF resources are set to

Figure 5.21.

Latin America natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

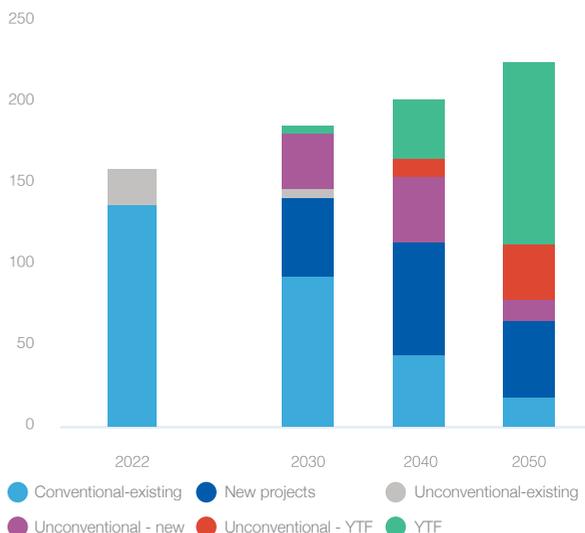
ultimately emerge as the primary driver of gas production in the region (Figure 5.22).

Offshore production is set to have a substantial impact on the dynamics of regional production. In 2022, it constituted 33% of total production, expected to rise to 50% by 2050 (Figure 5.23). This represents a significant 96% growth during the forecast period, contributing an additional 50 bcm to the overall production. The surge in offshore production is projected to be chiefly driven by Argentina, Brazil, and Venezuela.

Argentina natural gas production is poised to reach 80 bcm by 2050, accounting for 35% of the total production in Latin America. This upward revision in Argentina's supply, is attributed to a shift from conventional drilling to horizontal drilling, with hydraulic fracturing in the Vaca Muerta formation. Additionally, efforts to address infrastructure bottlenecks have

Figure 5.22.

Latin America natural gas production outlook by project type, 2022-2050 (bcm)



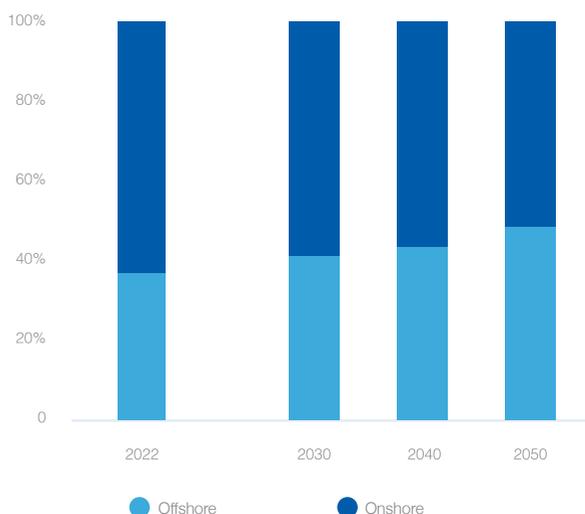
Source: GECF Secretariat based on data from GGM 2023

enabled the supply of natural gas both within the country and to neighbouring countries.

The application of horizontal drilling and hydraulic fracturing in the Vaca Muerta shale formation, has significantly boosted oil and gas production compared to conventional drilling methods. RystadEnergy has reported an increase in the number of horizontal wells in the field, reaching 285. This increase has led to the field's production growing from 10 bcm in 2020 to approximately 18 bcm in 2022.

Figure 5.23.

Latin America natural gas production outlook by field location, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

Argentina is actively expanding its gas pipeline network to reduce dependence on expensive natural gas imports, meet domestic natural gas demand, and potentially export to neighbouring Latin American countries. A significant step in this direction was taken with the launch of the first phase of the Nestor Kirchner pipeline in July 2023. This pipeline, with a capacity of 4 bcm, crucially connects the vast Vaca Muerta shale field to Buenos Aires. The second phase of the project, scheduled for completion by 2025, aims to extend the pipeline to the Santa Fe province, increasing its total capacity to 16 bcm. According to RystadEnergy assessment, the entire two-phase pipeline project is estimated to cost approximately USD 4.6 billion.

By addressing infrastructure constraints in Vaca Muerta, and intensifying exploration efforts, Argentina is positioned to transition into a natural gas exporter. Plans are underway to extend the Nestor Kirchner pipeline to San Jerónimo, located approximately 250 miles from the Brazilian border, within the next year.

Brazil is on track to substantially increase its natural gas production, with a projection of 44 bcm by 2050. This surge in activity and investments have been notably catalysed by the approval of the New Gas Law in March 2021.

The anticipated production increase is set to be fuelled by the expansion of major oil and gas projects in the Santos and Campos basins, including the pre-salt project Buzios. These approved projects, along with prospective ones such as Sergipe-Alagoas, Lapa, and the introduction of new FPSOs at Tupi, have the potential to double Brazil's natural gas production to 40 bcm by 2030, up from the current production level of 20 bcm. Investors are actively advancing the development of substantial oil and gas projects in Brazil. For example, Equinor, in partnership with others, have granted approval for the BM-C-33 project—a significant ultra-deepwater development in Brazil's Campos basin. This project encompasses three discoveries: Pão de Açúcar, Gávea, and Seat, with an investment of USD 9 billion. It is expected to add 5.7 bcm, of natural gas production by 2028.

In **Venezuela**, natural gas production experienced consistent growth, reaching its highest level in 2017 at 30 bcm. However, post- 2017, there has been a decline in natural gas production, attributed to the unilateral economic restrictions imposed by the United States.

Nevertheless, a turnaround is anticipated in Venezuela. In September 2023, after the United States issued a waiver from sanctions, officials from Trinidad and Tobago and Venezuela entered into a historical agreement for the development of the Dragon Field, and the use of the spare LNG and petrochemicals capacity in Trinidad and Tobago. Furthermore, in 2023, PDVSA is expanding its operations with the goal of increasing both oil and gas production. By 2050, the outlook anticipates Venezuela's natural gas production to exceed 40 bcm. The outlook expects that new projects in Peral and Dragon fields by the end of this decade, along with a substantial contribution from YTF resources in the Trinidad Basin and the Maracaibo Basin, are set to drive production growth in Venezuela. In addition, gas production is expected from the Blanquilla field, Block 5, and Barbacoa block that are planned for exploration and production. Furthermore, the country plans to monetise its flared and vented gas from the North of Monagas and Anaco region.

5.4.6 Middle East

Natural gas production in the Middle East experienced an increase from 670 bcm in 2021 to 685 bcm in 2022, representing a growth rate of 2.2%. This growth was predominantly attributed to Iran and Saudi Arabia. In 2022, the Middle East contributed 17% to the global natural gas production.

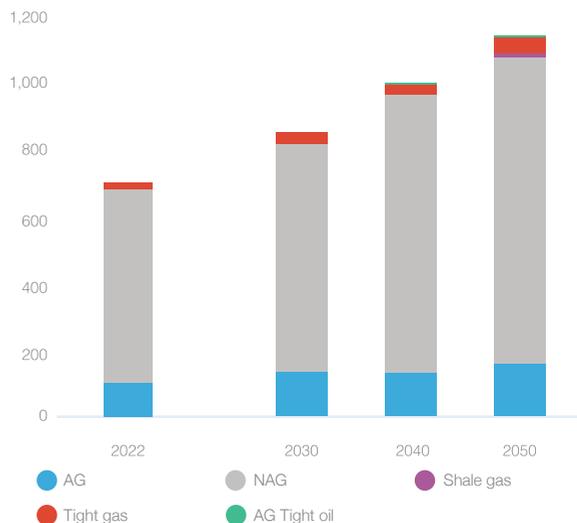
The region possesses substantial natural gas reserves, and significant potential for further production growth. From 2010 to 2022, the region witnessed a remarkable 50% increase in natural gas production, surging from 460 to 685 bcm. Looking ahead to 2050, the outlook anticipates another significant surge projected to reach 1,165 bcm by 2050. This represents an additional surge of 480 bcm, projected to raise the region's global share in natural gas production to 21%, from its 17% share in 2022.

The growth in natural gas production within the region is expected to be primarily driven by non-associated conventional gas projects, particularly in Iran, Qatar, Saudi Arabia, and the UAE. Simultaneously, associated natural gas production in the region is set to predominantly be propelled by Iraq (Figure 5.24).

Conventional gas production is set to lead the growth in gas production in the region, accounting for a substantial 94% of the total gas production growth until 2050. Iran, Qatar, and Saudi Arabia are to be at the forefront of this gas production expansion. Additionally, unconventional tight gas resources are expected to gradually contribute to production growth in the region, primarily from Oman, Saudi Arabia, and the UAE.

In 2022, unconventional gas reservoirs made a relatively modest contribution of 13 bcm, comprising just 1.8% of the Middle East's total gas production. However, unconventional gas production is expected to expand to 37 bcm by 2050, constituting 3.2% of the region's total natural gas output. Key unconventional projects driving this growth includes the Jafurah field in Saudi Arabia, which boasts an estimated original gas in

Figure 5.24. Middle East natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



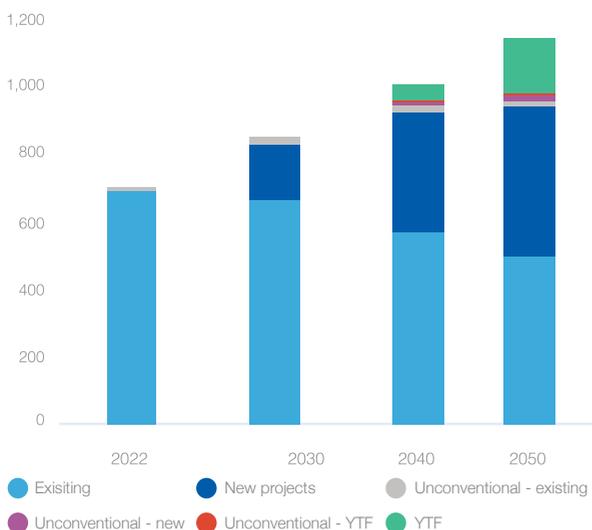
Source: GECF Secretariat based on data from GGM 2023

place of 200 tcf or 5.6 tcm, and is expected to start production in 2025, reaching peak production of 12 bcm by the start of 2040s. In Oman, the Khazzan-Makarem gas field, with an estimated original gas in place of 20 tcf (0.6 tcm), has been in production since 2017, is slated for expansion. Additionally, the Ruwais Diyah unconventional gas project in the UAE aims to achieve an output of 10 bcm by 2030.

New conventional projects are expected to be a significant driver of gas production growth in the region, projected to add 385 bcm by 2050. The expansion of the North Field project in Qatar is a major new development in the region, expected to contribute 110 bcm by 2050. Furthermore, YTF resources are set to emerge on the production horizon by 2037, with YTF resources projected to account for 14% of the total natural gas production by 2050 (Figure 5.25).

Figure 5.25.

Middle East natural gas production outlook by project type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

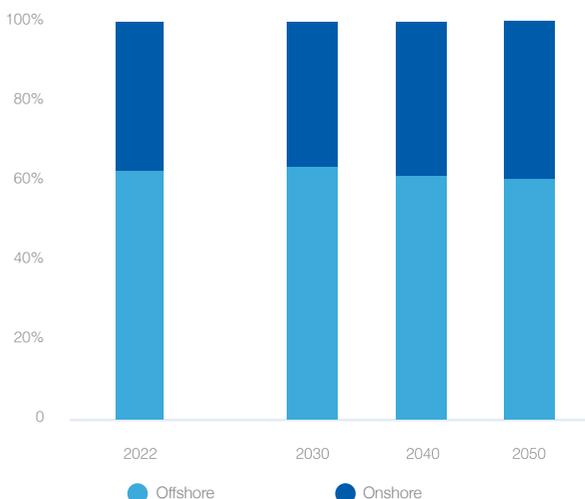
Offshore natural gas production in the region is anticipated to remain at its 2022 share of around 60% over the forecast period. Qatar, Iran, Saudi Arabia and the UAE are expected to drive offshore production in the region. The major projects include the North Field Expansion, South Pars, and Hail & Gasha sour gas fields expected to start in the second half of this decade (Figure 5.26).

Iraq is actively engaged in efforts to boost its natural gas production, with a specific focus on capturing flared gas, and developing its natural gas reserves. Over the last decade, Iraq has made strides in this regard, increasing its natural gas production from 5 bcm in 2013 to 15 bcm in 2022. Looking ahead, the outlook remains promising, as Iraq is expected to reach a production level of 55 bcm by 2050.

The majority of this production growth in Iraq is set to be attributed to associated gas, expected to remain the main source of natural gas production along the forecast period, accounting for 60% of natural gas production by 2050. Particularly, associated gas derived from oilfields such as West Qurna 2, Majnoon, Ratawi, Tuba, and Luhais, is planned to be captured and processed through a new facility developed by

Figure 5.26.

Middle East natural gas production outlook by field location, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

TotalEnergies. This processing plant is anticipated to reach a capacity of 6.7 bcm per year. upon completion.

Gas condensate fields are poised to play a pivotal role, in driving the projected gas production growth throughout the forecast period. Key projects in this category include the Basrah initiative, encompassing assets such as Zubair, Rumaila North & South, and Qurna West; the Pearl project, featuring multiple development phases in Khor Mor and projected to peak at 11 bcm in production; and the Bina Bawi gas project, scheduled to commence production in 2030, contributing 7 bcm to the overall output.

Oman has set its sights on increasing its natural gas production, with expectations of continuous growth until 2035, reaching 46 bcm, followed by stabilising at around 40 bcm by 2050. Over the past two decades, annual natural gas production has exhibited constant growth, surging from 18 bcm in 2002 to 38 bcm in 2022, more than doubling during this period. The rebound in natural gas production in 2021, can be attributed to the commencement of the Ghazeer project, after a 9% drop in 2020 due to the COVID-19 pandemic.

In the long term, it is projected that Oman is set to maintain its production at approximately 40 bcm throughout the forecast period. This is expected to be driven by the expansion of the Khazzan Makarim unconventional gas field and the Mabrouk North East FFD projects, phase 1 that started in 2023, and phase 2 expected to start in 2026. Furthermore, Oman intends to increase its gas resource base through accelerated exploration in gas-prone areas, with significant interest from major oil and gas companies. One of the most noteworthy discoveries in this regard was the Mabrouk North East field in 2018.

Qatar has achieved an impressive increase in its natural gas production, surpassing five-fold growth over the past two decades. The country is now on a trajectory to significantly boost its natural gas production, with an anticipated 70% increase by 2050. This substantial rise is expected to be spearheaded by two massive expansions in the world's largest

natural gas field, the North Field. The outlook takes into account the commencement of the North Field East and North Field South expansions, scheduled for 2026 and 2028, respectively.

Furthermore, Qatar is actively investing in eco-friendly measures to reduce its carbon footprint. These initiatives include a focus on carbon capture and storage, as well as efforts to reduce methane emissions.

Saudi Arabia is actively increasing its oil exports and promoting the expansion of domestic gas demand. The Kingdom's efforts include increasing its oil production potential to 13 million barrels per day (mb/d) by 2030. Saudi Aramco, in particular, is planning to significantly increase its gas output by 2030, driving increased exploration and production activities, and the development of processing facilities.

The outlook for Saudi Arabia anticipates the country reaching a natural gas production level of 145 bcm by 2050. This projection takes into account the successful development of conventional and unconventional gas projects, including newly discovered fields such as Awtad, AlDahna, Fadhili gas, and the Jafura field.

The **UAE** is actively pursuing the development of both conventional and unconventional natural gas fields, with the goal of increasing its production to 80 bcm by 2050. Non-associated natural gas production is expected to grow from 23% in 2022 to 51% by 2050.

Existing natural gas fields are projected to contribute approximately 20 bcm to the total production by 2050. However, the majority of the natural gas supply is expected from newly developed assets, including Bab Sour Gas, Jebel Ali, Hail & Ghasha, Ruwais Diyah, and Umm Shaif. These four projects are anticipated to contribute around 26 bcm to the total gas production by 2050.

One prominent conventional field within the UAE's outlook is Jebel Ali, which boasts estimated recoverable reserves of 135 bcm. Production is scheduled to commence by 2029, with peak production expected to reach 10 bcm. Additionally, in 2023, ADNOC awarded contracts worth USD 17 billion for the development of Hail & Ghasha, which is projected to produce 15 bcm by 2030.

A significant unconventional producing asset along the forecast period is the Ruwais Diyah unconventional field, situated in the Rub Al Khali basin in Abu Dhabi. The Ruwais Diyah unconventional gas concession aims to achieve an output target of 10 bcm by 2030.

5.4.7 North America

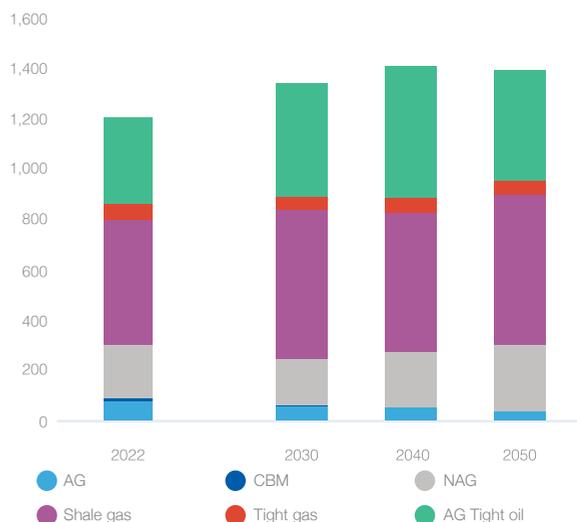
North America experienced a substantial increase in gas production, rising from 1,160 bcm in 2021 to 1,230 bcm in 2022, reflecting an annual growth rate of 6%. This growth in North America was primarily driven by the United States, with a significant contribution from associated gas from the Permian Basin, shale gas from the Haynesville, and Eagle Ford plays. North America accounted for the largest share of global natural gas production among regions, representing 30.6% of the total.

The region is poised to maintain its position as the largest natural gas producer by 2050. Over the past decade, natural gas production in North America has witnessed a remarkable 43% increase, surging from 860 to 1,230 bcm. Looking ahead, the outlook foresees a continued upward trajectory in natural gas production, with the region projected to reach 1,400 bcm

by 2050, representing an additional increase of 200 bcm. However, the region's share in global natural gas production is expected to decrease to 27% from its 31% in 2022, mainly due to significant growth in Eurasia and the Middle East.

Natural gas production growth in the region is expected to be primarily driven by associated gas production from unconventional oil reservoirs, notably in Canada and the United States. Followed by shale gas and, finally, NAG (Figure 5.27).

Figure 5.27. North America natural gas production outlook by hydrocarbon type, 2022-2050 (bcm)



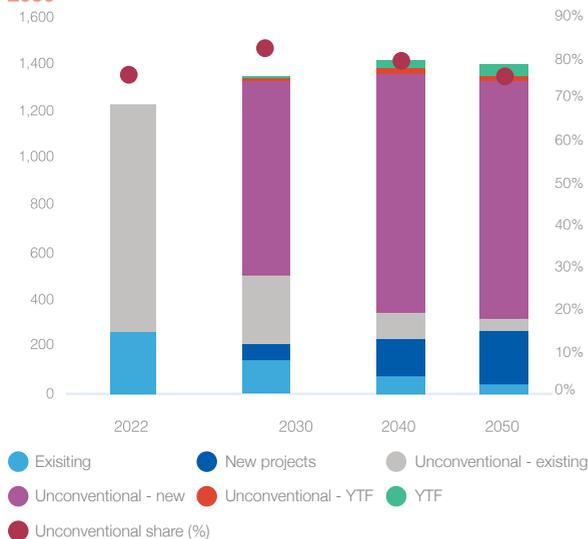
Source: GECF Secretariat based on data from GGM 2023

In North America, unconventional natural gas production dominates, accounting for under 80% of the region's gas production throughout the forecast period. The region's primary long-term focus centres on the continued development of unconventional gas resources. The growth in production is projected to be primarily driven by new unconventional projects in areas such as Haynesville, Permian, Marcellus, Montney, and Utica. New unconventional projects in the region are expected to make a significant contribution, reaching 1,000 bcm by 2050. However, the total share of unconventional production in the region is expected to decline after 2030. The share of unconventional production in the region is expected to decline from 83% in 2030 to 77% in 2050, and natural gas production from existing unconventional assets is projected to contribute only 50 bcm in 2050, a decrease from the 820 bcm of natural gas production in 2022. With new unconventional project addition, the fast decline of existing unconventional projects will result in a slow down of the overall growth of unconventional production in 2030s and a decline of the overall level in 2040s. This result in peaking of unconventional gas production in North America at 1,125 bcm in 2030 and decline to 1,080 bcm in 2050 (Figure 5.28).

The development of gas infrastructure plays a crucial role in facilitating natural gas production growth in the region, for example, the construction of pipelines for unlocking natural gas production from Haynesville and Appalachian regions, ensuring efficient transportation of natural gas to consumers.

Figure 5.28.

North America natural gas production outlook by project type (bcm) and unconventional share (%), 2022-2050



Source: GECF Secretariat based on data from GGM 2023

Most of the production is expected to originate from onshore assets, with offshore natural gas production in the region expected to remain relatively small throughout the forecast period, constituting only 5% of the region's total production (Figure 5.29).

The long-term outlook for natural gas production in the **United States** is promising, supported by various developments across different regions in field development and infrastructure expansion.

Natural gas production in the United States increased by 5% in 2022, reaching a total of 1,022 bcm. According to the United States Energy Information Administration (EIA), the primary driver of this growth was associated gas production. This witnessed a 9% increase in natural gas production in 2022, coinciding with 8% increase in oil production, particularly from the Permian Basin, which experienced a 15% increase in associated gas production. The growth in associated natural gas production can be attributed to the addition of new pipeline capacity.

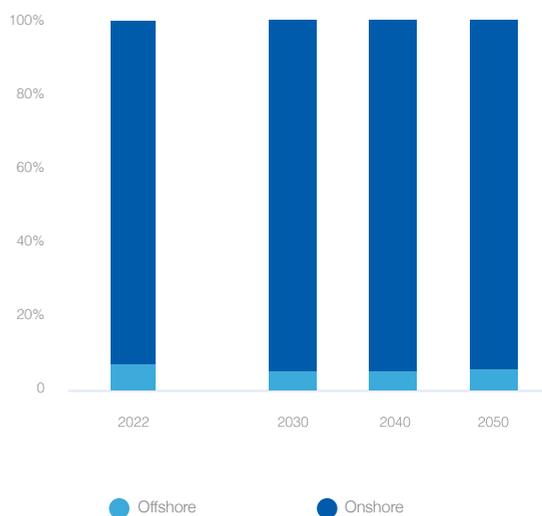
In 2023, United States is estimated to further strengthen its natural gas supply by an additional 65 bcm, primarily driven by Haynesville, the Permian Basin, and the previously constrained Appalachian Northeast. Over the long term, the outlook anticipates the United States to reach a production level of 1,080 bcm, maintaining its position as the top global natural gas producer.

A changing cost profile for gas production is anticipated in the United States. The associated gas from unconventional tight oil plays is expected to decline in the 2030s, leading to more expensive unconventional gas fields. Associated gas is set to peak at 40% of the total United States production, followed by a projected drop to 25% by 2050.

Among the key production areas, the Permian Basin stands out as the major producer of associated gas. Other significant

Figure 5.29.

North America natural gas production outlook by field location, 2022-2050 (%)



Source: GECF Secretariat based on data from GGM 2023

contributors, such as Eagle Ford, Bakken, Anadarko, and Niobrara also play a crucial role in ensuring a steady supply of natural gas. These resources form a substantial part of the long-term gas production strategy in the United States, promising a robust and stable supply over the outlook period.

Haynesville's role in the long-term supply is also noteworthy. Despite a significant build-up of drilled but uncompleted (DUC) wells in 2023, production was constrained due to low prices and midstream bottlenecks. However, upon expected completion of Energy Transfer's Gulf Run pipeline in 2024, this region's production capability is set to increase. According to forecasts by RystadEnergy, Haynesville's production will not exceed 60 bcm through the later part of the decade. This projection suggests a manageable production level that aligns with the current sanctioned capacity, ensuring stable production in the long-term.

The approval of the Mountain Valley Pipeline in the United States is another significant development. This pipeline is set to unlock production from the long-constrained Appalachian Northeast, adding a capacity of 20 bcm from West Virginia into the Southeast.

On the exploration front, the Gulf of Mexico Lease Sale 259 in April 2023, during which 313 blocks were awarded, signals continued investment in the exploration and production of natural gas. This initiative both stimulates immediate production and also guarantees sustained long-term natural gas supply in the United States.

Natural gas production in **Canada** is experiencing a significant upward trend. Over the past decade, Canada has witnessed a significant 28% increase in natural gas production. In 2012, production stood at 140 bcm, and by 2022, it had surged to 180 bcm. This remarkable growth can be largely attributed to the expansion of the Montney play, which has experienced a 3.5-fold increase over the past decade, significantly contributing to the production, and yielding 90 bcm in 2022.

Looking ahead, the outlook for Canada's natural gas production is exceedingly optimistic, with expectations of a 50% growth by 2050. It is anticipated that Canada is projected to reach 265 bcm in natural gas production by 2050. The primary driver behind this growth will be the Montney play, which is expected to make a substantial contribution, with production reaching 170 bcm. The Montney play has garnered the attention of Canada's two largest natural gas producers, Tourmaline Oil and Canadian Natural Resources, and significant international companies including Petronas, ConocoPhillips and Shell. While the majority of production growth is expected to occur after 2030, medium-term growth is set to be limited as shale operators prioritise debt reduction and investor rewards over new investments.

The majority of the production growth in Canada is expected to emerge from associated gas of tight oil reservoirs. Unconventional production is also anticipated to play a crucial role, accounting for 85% of natural gas production growth by 2050.



6

Natural Gas Trade Outlook

Highlights

- ▶ Global natural gas trade is expected to rise by 39% between 2022 and 2050, reaching 1,730 bcm in 2050, or one-third of global gas demand compared to 31% in 2022.
- ▶ LNG trade is set to overtake long-distance pipeline trade by 2026 and is expected to more than double by 2050 reaching 805 Mt (1,110 bcm), or 64% of traded gas.
- ▶ The Asia Pacific region is projected to remain the dominant long-term LNG import market. China is poised to be the largest growth market this decade, but India is expected to assume that role after 2030. South and Southeast Asia are forecast to be the markets with the highest incremental LNG import growth, albeit from a lower base.
- ▶ The LNG share of EU gas imports is projected to rise from 24% in 2022 to 46% by 2030. The EU is expected to expand and add regasification capacity, especially using floating storage and regasification units (FSRUs), to meet short- and medium-term LNG import requirements.
- ▶ Global liquefaction capacity is forecast to top 1,000 Mtpa by 2050, compared with 476 Mtpa in 2022, with the utilisation rate expected to be maintained at around 80% over the forecast horizon.
- ▶ Regasification capacity is poised to reach 1,800 Mtpa by the end of the Outlook period, with a utilisation rate of just under 50%.
- ▶ Asia Pacific region is anticipated to witness the most significant growth in LNG regasification capacity by 2050, more than doubling its 2022 level and adding 580 Mtpa.
- ▶ Russia has been a dominant force in Eurasian regional exports. Various pipeline initiatives within Russia, such as the Far Eastern project aiming for 10 bcma and the potential 50 bcma supply from Power of Siberia 2, as well as Turkmenistan's Line D expansion with an additional 30 bcma, are in progress to enhance the transportation of natural gas to Asian markets, particularly to China.
- ▶ Middle East could potentially see an addition of over 130 Mtpa in liquefaction capacity by 2050, with Qatari expansion projects expected to be the primary drivers of this growth.
- ▶ LNG is projected to continue to dominate Latin America's natural gas trade as consumption is anticipated to grow and displace oil and support renewables use.
- ▶ LNG is forecast to account for 70% of Africa's natural gas exports by 2050, with Mozambique emerging as the largest player from the early 2030s. The continent's liquefaction capacity is projected to reach 200 Mtpa by 2050.
- ▶ North America is forecast to experience substantial growth in LNG exports, having the United States established as the leading global LNG exporter in 2023 and maintaining this position until 2050. The United States is projected to achieve a liquefaction capacity of 240 Mtpa by 2050.

6.1. Current natural gas market trends

In 2022, the natural gas trade experienced unprecedented turbulence, marking a historic transformation in its markets. Structural changes have fundamentally reshaped the landscape, with geopolitical factors emerging as the primary catalyst for altering trade routes and influencing investment patterns in both pipeline natural gas and LNG. As natural gas markets were in the process of rebalancing and adapting to the aftermath of the conflict in Europe in early 2022, a subsequent war erupted in the Middle East in October 2023. Despite the current limited impact on natural gas flows, there has been a significant rise in geopolitical risk within the region.

Natural gas markets are back on track to rebalancing. While security of supply concerns remain, natural gas prices are easing from a record historical high in 2022.

The year 2022 witnessed a monumental shift in the global gas market. A significant decrease in European pipeline gas imports from Russia compounded by an already tight natural gas market of 2021, resulted in soaring natural gas prices in both Europe and Asia, reaching historic highs. Remarkably, heightened European LNG demand propelled prices above those of Asian benchmarks, marking them as the highest ever documented worldwide. This led to a rise in fuel switching and industrial shutdowns, consequently decreasing demand. Europe bought LNG shipments at elevated prices, whereas other countries, especially in Asia, found themselves unable to access affordable natural gas. The global gas market in the second half of 2023 entered a phase of fragile equilibrium. While prices have substantially decreased from the peak levels, the limited availability of supply until 2026 is expected to sustain volatility, keeping prices towards the upper range for switching from coal to gas and in close proximity to oil parity. Following this period, a global rebalancing in the LNG market is anticipated, potentially leading to lower prices.

The European gas market is at the 'heart' of a structural shift. Structural shifts in Europe's gas market resulted from decreased pipeline gas imports from Russia and a notable increase in LNG imports. LNG has gained momentum as a means of ensuring European energy security, with LNG's share of total natural gas imports doubling, from 20% in 2018-2019 to 40% in 2022-2023. In 2022, the EU received slightly more than 130 bcm of LNG, marking just above a 60% rise from a year earlier. The significant driving force behind this was the surge in imports from the United States, where LNG imports expanded sixfold. Concurrently, there has been an increase in Russian LNG imports as well in 2022. Projections indicate that Europe's regasification capacity is set to grow substantially by nearly 48% by 2030, exceeding 290 Mtpa in the medium term.

European FSRU focus in the medium term. In Europe, the abrupt surge in LNG imports resulted in the prolonged overuse of regasification facilities and substantial price disparities between regions due to infrastructure constraints in addition to limitations on regasification capability. FSRUs played a pivotal role in Europe's response to the energy crisis, significantly contributing to the improvement in the continent's energy security. Europe has substantially boosted its FSRU capacity by roughly 60% from the end of 2022 to 2023, possessing 30 Mtpa of the FSRU and capturing 20% of the global market share. Europe, following this trajectory, is expected to outpace any other region globally in installed FSRU regasification capacity by 2024. Throughout 2022, Europe approved 17 new FSRU projects, potentially contributing about 65 Mtpa of

capacity once completed. The growing interest in FSRUs is rooted in a forward-looking strategy. Considering Europe's view of natural gas as a transitional energy source, it is preferable to retain the adaptability and flexibility that FSRUs providing.

A global surge in long-term LNG contracts. The increase in long-term contracts within the LNG market is a response to the elevated uncertainties expected in the market moving forward. These uncertainties primarily arise from the potential competition between Europe and the Asia Pacific region in securing their natural gas supplies. The current trends in long-term contracting underscore the robust demand for LNG in Asia. In 2023, Europe has secured only approximately 31% of the signed LNG contracts, whereas the Asia Pacific region has accounted for 46%. Contracts totalling approximately 57 Mtpa of LNG supply for upcoming projects slated between 2025 and 2027 were secured in 2023. The duration of these contracts averages around 16 years. This shift in contracting patterns is anticipated to keep Europe exposed to the risk of increased volatility in spot markets over the medium term.

Energy transitions and natural gas trade. While energy transitions are often seen as long-term trends, their anticipated impact has already begun shaping current investment and consumption decisions. The heightened risk aversion among investors, triggered by the uncertain future demand for natural gas and the potential adverse effects of climate change policies on revenue streams, stands as just a couple of factors reinforcing this shift. Despite experiencing growth and favourable sentiments, substantial uncertainty regarding the LNG market's future path and the role of natural gas in energy transitions remains a significant concern, particularly in Europe, North America and OECD Asia Pacific countries. Converting natural gas into LNG is expected to offer unprecedented scalability and flexibility, often replacing high-emission sources like coal and fuel oil as long as LNG remains cost-effective and affordable. Future infrastructure investments must be made with the compatibility and integration of low-carbon and renewable gases in mind. This strategic approach is critical to ensuring the long-term viability and financial sustainability of gas and LNG infrastructure.

6.2 Natural gas trade outlook

Between 2022 and 2050, the worldwide trade of natural gas is projected to surge by 40%, from 1,240 bcm to 1,730 bcm, to account for approximately one-third of the global gas demand of 5,360 bcm anticipated by 2050.

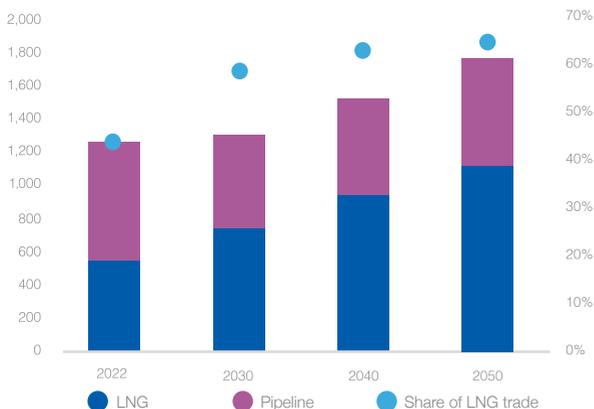
In the near to medium term, global pipeline export is expected to decrease from 700 bcm in 2022 by 23% by 2030, mainly due to the downward adjustment in Russian pipeline gas imports. Nonetheless, the long-term outlook for global pipeline exports remains to some extent improved, with an anticipated volume reaching 620 bcm by 2050. (Figure 6.1)

In general, global natural gas markets exhibit significant segmentation due to the required transport infrastructure, such as pipelines and LNG import and export terminals. However, over the long term, regional natural gas markets are set for continued integration and heightened interconnection, driven by the expanding significance of the LNG trade.

LNG exports are forecast to more than double and reach 805 Mt (1,110 bcm) by 2050, or 64% of the total traded volumes. The expected robust growth in LNG trade during the 2022-2050 period should lead to greater flexibility and market

Figure 6.1.

Global natural gas trade by flow type (bcm) and share of LNG trade (RHS, %) outlook, 2022-2050



Source: GECF Secretariat based on data from GECF GGM
 Note: re-export of LNG is not included

liquidity, thereby strengthening global energy supply affordability, reliability and sustainability.

6.2.1 Pipeline natural gas trade outlook

On a global level, a moderate decrease might be foreseen in the expansion of pipeline trade in the long run, driven primarily by a redirection of Eurasia’s gas exports from Europe to the Asian Pacific. In particular, this involves Russia and Turkmenistan supplying more gas to China.

In 2022, Europe consistently dominated the global market for pipeline gas trade, accounting for approximately 67% of total imports. However, due to decreased gas pipeline imports from Russia and the growing role of LNG in Europe since then, it is expected that by 2030, the European region will relinquish its leading position, representing less than one-third of the global volume of pipeline gas imports. Furthermore, by 2050, Europe’s share in the overall pipeline gas trade is projected to diminish significantly.

According to the GECF Annual Gas Market Report 2023, the EU imports natural gas by pipeline from five countries: Algeria, Azerbaijan, Libya, Norway, and Russia. The geopolitical tensions led to a notable reduction in the EU import of pipeline gas from Russia. Despite slight increases in supply from Azerbaijan and Norway thereafter, these additions were insufficient to offset the overall decrease in gas supply.

In 2022, the total EU pipeline gas imports reached 203 bcm, marking a precipitous decline of 26% or 70 bcm compared to 2021. Further decreasing by 21% in 2023, pipeline gas imports into the EU accounted for 161 bcm. Russian pipeline deliveries to the EU reached approximately 27 bcm in 2023. This amount is less than half of the 60 bcm delivered in 2022, which itself is less than half of the quantity supplied in 2021.

Concerning additional pipeline supply to Europe in the short term, the scope for growth is limited. Azerbaijan and Norway operated near their peak capacity in 2022-2023. There might be a slight increase in supply from Algeria due to the development of gas fields in the Berkine South basin.

On a global scale, in 2022, countries within the Asia Pacific region collectively accounted for approximately 12% of global imports of pipeline gas. Notably, China stands out as the predominant importer, representing roughly 70% of the total volume of regional pipeline gas imports. This dominance has intensified as China has significantly increased its gas imports in recent years. Highlighting this trend, in 2022, China’s pipeline gas imports amounted to 62 bcm, marking a threefold increase from the quantity imported in 2012. Throughout the forecast period, the Asia Pacific region’s collective share is expected to reach 24% of the world’s imports of pipeline gas by 2050 from 12% in 2022.

The surge in China’s pipeline gas imports has been notably supported by the supply from Russia, following the commencement of the Power of Siberia (PoS) pipeline in December 2019. With reduced pipeline exports to Europe, Russia has redirected its focus on pipeline gas exports towards China.

Consequently, Russia experienced a considerable 49% increase in total pipeline gas exports to China in 2022 equalling 15 bcm or nearly 25% of China’s overall pipeline gas imports. In 2023, Russia exported 23 bcm of pipeline gas to China. Turkmenistan retained its position as the primary supplier to China, providing 34 bcm of pipeline gas in 2022.

As Russia increases gas flow through the Power of Siberia pipeline to achieve its maximum design capacity of 38 bcma by 2025, China is expected to experience a surge in pipeline gas imports. In 2022, a second pipeline gas supply agreement was inked between Russia and China, entailing the transportation of 10 bcma of gas through the Far East route originating from Sakhalin. The Power of Siberia 2 project, targeting a capacity of up to 50 bcma, also is expected to commence operations in 2033.

China is expediting its gas supply strategies in Central Asia, with Turkmenistan serving as the primary pipeline gas exporter to the country. Presently, the supply is facilitated through the A, B, and C lines within the Central Asia-China Gas Pipeline corridor, boasting a total capacity of 55 bcma. The Central Asia-China Gas Pipeline D is expected to bring an additional supply of 30 bcma to western China starting in the early 2030s.

Within the North American region, in 2022, the United States witnessed an increase in gas imports from Canada, reaching 85 bcm, marking an 8% rise compared to the amount imported in 2021. Simultaneously, pipeline flows from the United States to Canada amounted to 27 bcm. At the southern border, gas exports from the United States to Mexico totalled 59 bcm in 2022. Overall, in 2022, the North American pipeline gas market maintained a neutral position concerning the net level of trade involving the United States.

In 2023, the North American pipeline natural gas market witnessed a notable increase, primarily propelled by the growth in LNG exports, solidifying the United States as the leading global LNG exporter. At present and over the forecast period, with all three North American countries — Canada, the United States and Mexico — either enhancing production from existing liquefaction terminals or investing in new facilities, the significance of the pipeline network in the region is set to continue to increase. An example of such a project is the nearing completion of the Coastal GasLink pipeline in western Canada, despite numerous delays and cost overruns. This pipeline is poised to facilitate LNG exports from British Columbia. Additionally, there are contemplations for other new

gas connections in the southern part of the region, aiming to augment the quantities of gas exported from the United States to Mexico.

Latin America holds the potential for expanding its pipeline gas trade. Bolivia serves as the primary pipeline gas exporter in this region, supplying southern Brazil and northern Argentina. However, Bolivia’s pipeline exports have experienced a downward trend in recent years. In 2022, the export volume decreased by 13% to 10 bcm. Brazil stands as the primary importer of pipeline gas, sourcing its entire natural gas pipeline supply exclusively from Bolivia.

6.2.2 LNG import outlook

In 2022, global LNG imports grew by 4.5%, reaching 389 Mt, marking an increase of 17 Mt compared to 2021. European purchasers resorted to the LNG market to substitute Russian pipeline supplies, absorbing a significant portion of the supply surge. Specifically, European LNG imports saw a remarkable 60% surge in comparison to the levels recorded in 2021. The dynamics of global LNG trade shifted, as Asian countries turned towards cheaper alternative energy sources, reducing their reliance on LNG.

As of December 2023, the count stood at 20 LNG exporting countries, the same number reported in 2022. Furthermore, there are 48 LNG importing countries, with Germany, the Philippines, and Viet Nam joining as new importers in 2023, expanding from the 45 importers recorded in 2022. El Salvador had previously become a part of the group of LNG importers in 2022. By the end of 2024, Antigua and Barbuda, Australia, Cyprus, and Nicaragua are expected to commence LNG imports. Additionally, Senegal and Mauritania are projected to initiate LNG exports in 2024, while Republic of Congo already started exporting LNG in early 2024. It is expected that the number of LNG exporting countries is set to reach 25 by 2050, while 58 countries are poised to import LNG.

The year 2022 marked another record for new long-term LNG contracts, with over 81 Mtpa of new contracts signed, primarily involving volumes from the United States and Qatar. The majority of these contracted volumes were secured by Asian buyers.

By 2050, the Asia Pacific and Europe are projected to collectively account for 89% of all LNG imports. Specifically, the Asia Pacific region alone is expected to contribute to 74% of the overall trade in LNG. Medium-term growth in the global LNG sector is being propelled by Europe as purchasers persist in diversification efforts, while long-term LNG demand continues to be primarily driven by the Asia Pacific region.

During the forecast period spanning from 2022 to 2050, it is noteworthy that the Asia Pacific region is forecast to maintain its position as the foremost global importer of LNG (Figure 6.2). Furthermore, it is expected to exhibit the most rapid growth among regions in terms of LNG imports. Asia Pacific region will account for 80% of global LNG incremental growth by 2050.

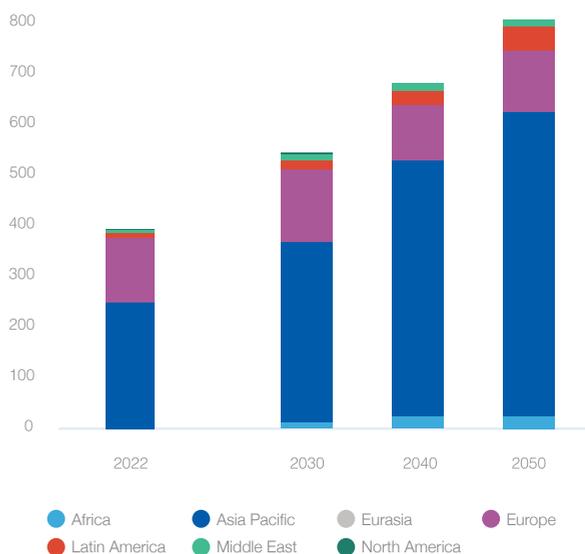
The trajectory for LNG demand growth in the Asia Pacific region indicates a strengthening trend, particularly from the late 2020s onward. In 2022, the demand for LNG experienced a decline of 6.6% to 256 Mt primarily attributed to significantly high prices, reduced affordability, particularly in South Asia, and heightened competition from Europe.

As prices are softening growth rates are anticipated to increase in this region. This acceleration is further expected to intensify

in the 2030s due to declining domestic production and a substantial surge in gas demand, particularly in emerging Asian economies. As a regional supply shortfall becomes evident,

Figure 6.2.

LNG imports outlook by region, 2022-2050 (Mt LNG)



Source: GECF Secretariat based on data from GECF GGM

LNG is poised to bridge this gap. A rise in LNG demand is expected to be around 505 Mt by 2040 and 600 Mt by 2050.

In 2023, China secured its position as the leading importer of LNG with an import volume of 71 Mt. In the long run, China is poised to continue to be a key factor driving growth, while Southeast and South Asia are projected to emerge as some of the fastest-growing LNG markets on a global scale after the 2030s.

Before the 2030s, global LNG trade appeared highly favourable across all regions worldwide. However, beyond the 2030s, uncertainty looms over gas demand and LNG trade due to the potential divergence in energy transition pathways adopted by various regions worldwide. Latin America and Africa are expected to also experience marginal growth in their respective LNG imports during this period.

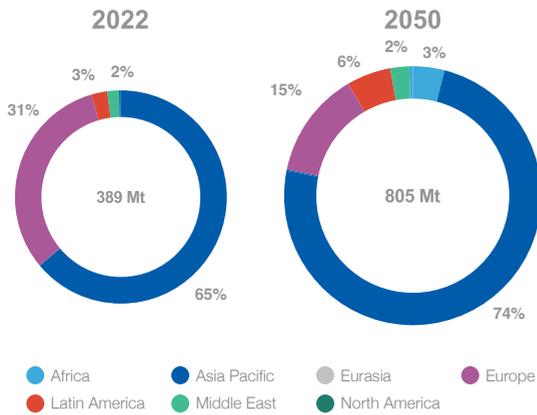
Conversely, Europe is poised to witness a decrease in LNG imports due to accelerated efforts in decarbonisation and ongoing energy transitions. Despite this decline, Europe is anticipated to remain the second-largest region for LNG imports by 2050, constituting 15% of the overall LNG imports (Figure 6.3). The anticipated volume of European LNG imports is expected to equal 119 Mt in 2050 and is comparable to the level seen in 2022, which stood at 120 Mt.

6.2.3 LNG export outlook

Qatar and Australia maintained their positions as the leading exporting countries, with 79 Mt and 78.5 Mt respectively in 2022. The United States followed closely, supplying 75.4 Mt of LNG in 2022, while in 2023, it became the biggest LNG exporter globally. In 2022, Russia ranked fourth with 32 Mt, trailed by Malaysia with 27.6 Mt. As seen in 2022, Qatar,

Figure 6.3.

LNG imports market share outlook by region, 2022 and 2050 (%)



Source: GECF Secretariat based on data from GECF GGM

Australia, the United States and Russia collectively contributed 68% of the global LNG supply.

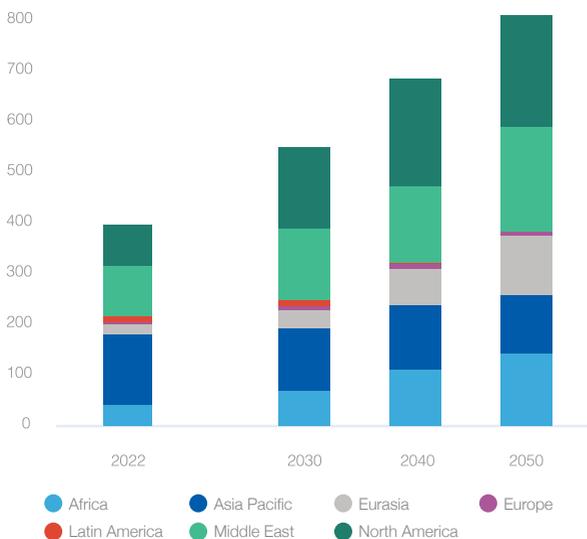
Over the long term, it is anticipated that North America (the United States) and the Middle East (Qatar) will be dominant forces in the development of LNG supply (Figure 6.4).

Both regions possess substantial reserves of natural gas and have made considerable investments in infrastructure, positioning them as key players in the global LNG market.

Despite an increase in global LNG imports, the rise in LNG exports was modest in 2022. The United States took the lead in boosting LNG supply, adding 8.4 Mt to the global market, which saw an increase of 17 Mt in total. This increase was primarily due to the expansion of the Sabine Pass liquefaction project's Train 6 and the commissioning of Calcasieu Pass.

Figure 6.4.

LNG exports outlook by region, 2022-2050 (Mt LNG)



Source: GECF Secretariat based on data from GECF GGM

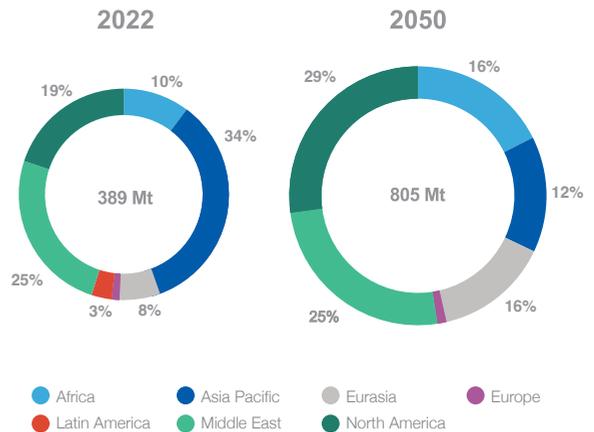
The momentum behind US LNG contracting and FIDs remains strong. However, the ongoing wave of US LNG development is susceptible to challenges such as cost inflation, increased marginal natural gas production cost, potential increases in interest rates and overall financing constraints, particularly in light of the global trend toward energy system decarbonisation.

In terms of basins, the Atlantic, Pacific, and Middle East all witnessed export growth, adding 10.5 Mt, 4 Mt and 2.5 Mt respectively in 2022.

Asia Pacific region remained the largest supplier of LNG in 2022 with 133 Mt (34% market share), trailed by the Middle East with almost 100 Mt (25% share) and North America with 75 Mt (90% share) (Figure 6.5). The supply gap between the Asia Pacific region and North America has notably decreased over the past years and is anticipated to reverse by 2050. As for the Asia Pacific, Australian LNG output remains relatively flat into the early 2030s, but as supply diminishes, output is set to decline.

Figure 6.5.

LNG exports market share outlook by region, 2022 and 2050 (%)



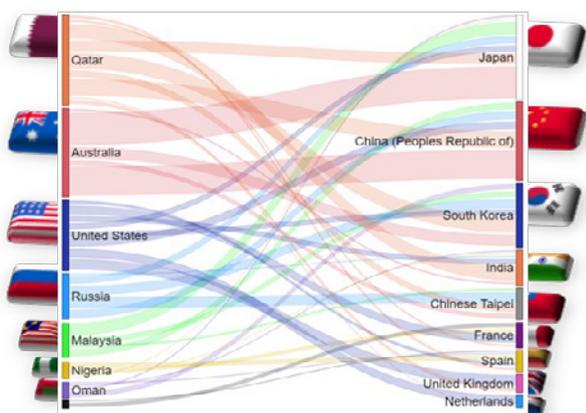
Source: GECF Secretariat based on data from GECF GGM

Qatar's plans for the development of LNG are expected to progress as scheduled, both in terms of capacity and timeline. In 2021, QatarEnergy took the FID for the North Field East (NFE) project, aiming to elevate Qatar's LNG production capability from the existing 77 Mtpa to 110 Mtpa by 2025. An additional FID is expected for the supplementary 16 Mtpa capacity at the North Field South (NFS) project, potentially pushing Qatar's LNG liquefaction capacity to 126 Mtpa by 2028. Moreover, the likelihood of further expansions or advancements beyond the North Field expansion project is steadily increasing.

Regarding Eurasia, the region is projected to increase its LNG exports to 125 Mt by 2050, driven by Russia. The limited availability of Western LNG technology and expertise is affecting Russia's recent LNG advancements and posing challenges for its existing projects. Nevertheless, Novatek is planning to apply its updated "Arctic Mix" technology, which uses mixed refrigerants across three cooling circuits to achieve pre-cooling, liquefaction and supercooling of the natural gas. This technology is set to enable the production of large-scale volumes of LNG and has no limitations regarding ambient temperature.

Figure 6.6.

LNG imports and exports in 2022 (Mt LNG)



Global LNG volume of trade: 389 Mt

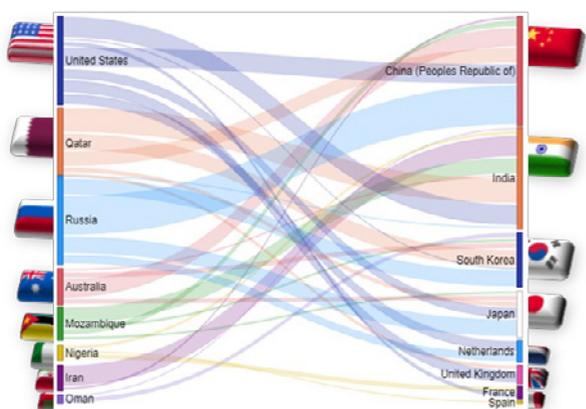
Source: GECF Secretariat based on data from GECF GGM

As for Africa's LNG supply, by 2050 the LNG industry in Mozambique is anticipated to experience robust growth with the initiation of its USD 20 billion Mozambique LNG project in the early 2030s. There is a possibility that floating LNG facilities or modular projects might emerge as more feasible alternatives for the development of LNG exports in Mozambique. Africa's LNG supply is anticipated to grow from the 2022 level by 93 Mt to reach around 132 Mt by 2050.

Regarding supply, the United States surpassed Qatar in 2023 and is set to stay the leading global LNG exporter by 2050 (Figure 6.6). Russia's gas projects are set to drive increased production, positioning the country to overtake Australia as the world's third-largest LNG supplier in the long run. Mozambique is expected to emerge as Africa's primary producer, potentially becoming the fifth-largest LNG supplier globally by 2050. LNG flows in Asia are experiencing significant growth due to an expanding regional imbalance between rising indigenous

Figure 6.7.

LNG imports and exports outlook in 2050 (Mt LNG)



Global LNG volume of trade: 805 Mt

Source: GECF Secretariat based on data from GECF GGM

demand and declining supply. On the demand side, the top four largest LNG importers - China, India, Japan, and South Korea - are primarily located in the Asia Pacific region. While these same four countries are set to remain top importers by 2050, their rankings are predicted to change (Figure 6.7). China is forecast to stay the largest LNG importer by 2050. China's LNG imports are estimated to exceed Japan's by more than threefold, whereas currently, both countries import comparable volumes of LNG. India is anticipated to become the second-largest LNG importer by 2050, followed by South Korea.

6.3. Natural gas trade balance outlook

By 2050, the Asia Pacific's net imports are anticipated to surge by 617 bcm between 2022 and 2050, while Europe, on the other hand, is expected to experience a reduction in net imports by 106 bcm by 2050.

Table 6.1.

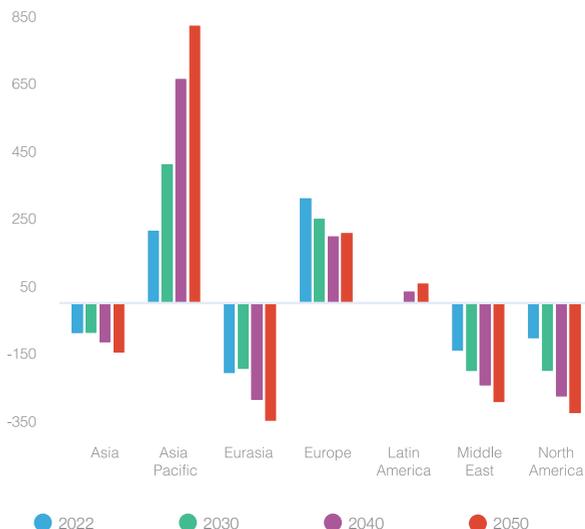
Natural gas balance (net imports) outlook by region, 2022-2050 (bcm)

Region	2022	2030	2040	2050
Africa	-86	-85	-111	-145
Asia Pacific	218	419	673	835
Eurasia	-206	-193	-284	-347
Europe	317	253	202	211
Latin America	-1	0	35	62
Middle East	-139	-198	-241	-292
North America	-102	-197	-275	-342

Source: GECF Secretariat based on data from GECF GGM

Figure 6.8.

Natural gas balance (net imports) outlook by region, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

A significant portion of this decline is foreseen to occur before 2040 due to decreased imports from Russia, decline in the European natural gas fields, particularly in Norway and the UK, along with natural gas demand reduction in Europe.

Latin America is expected to transition from being a marginal exporter of natural gas to becoming a net importer after 2030. It is anticipated that the region's natural gas imports will experience a rise of approximately 63 bcm between 2022 and 2050.

Over the long term, the rising demand for natural gas imports is expected to be balanced by substantial export increases primarily coming in 2050 from Eurasia (347 bcm), the Middle East (292 bcm), North America (324 bcm) and also Africa (145 bcm).

6.4 Gas trade infrastructure prospects

Investments in both pipeline and LNG infrastructure are expected to expand until 2050. Spending is poised to primarily focus on increasing liquefaction and regasification capacity until 2030, with a subsequent deceleration in growth anticipated post-2040. The development of export pipelines is projected to persist until 2050, particularly in Eurasia and Europe.

6.4.1 LNG liquefaction

In 2022, the global liquefaction capacity reached 476 Mtpa. A total of 14.9 Mtpa of new capacity was added during this period. Notably, the United States commenced the commissioning of the 10 Mtpa Calcasieu Pass LNG export project. In Russia, the 1.5 Mtpa Portovaya LNG plant initiated operations, while offshore Mozambique saw the 3.4 Mtpa Coral South FLNG producing its first LNG shipment.

In 2022, three FIDs were made, collectively contributing to a capacity of approximately 26 Mtpa. These decisions encompassed the 10.4 Mtpa Corpus Christi Train 3 liquefaction project, the 13.3 Mtpa first phase of the Plaquemines LNG project in the United States and a 2 Mtpa FLNG facility in Malaysia.

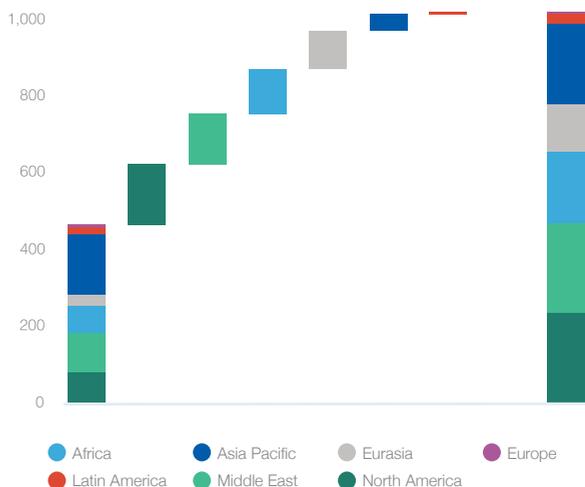
As of 2023, more than 55 Mtpa of new LNG capacity have been approved. With over 200 Mtpa of LNG supply currently in the construction phase, the market appears poised to meet demand comfortably until 2030. However, there is a potential concern of oversupply looming due to this significant increase in production capacity over the coming few years that may lead to further price falls.

The required LNG liquefaction capacity of 1,000 Mtpa by 2050, once realised, would surpass the anticipated LNG demand of approximately 805 Mtpa. If the necessary additional LNG liquefaction capacity is constructed and the corresponding investments are secured, particularly post-2030, it is anticipated that the LNG markets will remain sufficiently supplied throughout the forecast period. An estimated utilisation rate of 80% is expected to be maintained. It is essential to note that the overall liquefaction capacity has grown from 271 Mtpa in 2010 to 476 Mtpa in 2022.

The United States is set to contribute an additional 155 Mtpa of LNG liquefaction capacity, while the Middle East is planning to add around 130 Mtpa, predominantly led by expansion plans in Qatar over the projection horizon. By 2050, approximately 54% of the total LNG liquefaction capacity is anticipated to be attributed to the Middle East and North America.

Figure 6.9.

Global LNG liquefaction capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

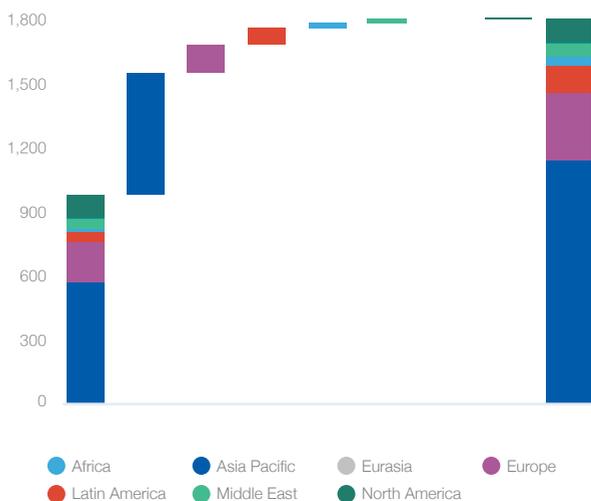
By 2050, Russia is expected to dominate LNG exports in the Eurasian region by augmenting its LNG liquefaction capacity by almost 100 Mtpa, whereas Africa anticipates an increase of 115 Mtpa in LNG liquefaction.

6.4.2. LNG regasification

By the conclusion of 2022, the global regasification capacity reached 1,068 Mtpa. 9 new regasification terminals commenced commercial operations during the year, contributing a combined capacity of 23.4 Mtpa. El Salvador initiated LNG imports through the 2 Mtpa FSRU-based Acajutla LNG terminal. Additionally, Brazil saw the launch of one FSRU project.

Figure 6.10.

Global LNG regasification capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

In 2022, within Europe, two projects began operations, including one floating-based terminal in the Netherlands and a smaller onshore terminal in Finland. Asia witnessed the initiation of operations at five new terminals, consisting of two land-based terminals in China, one each in Thailand and Japan, and a small scale in Indonesia. Other additions to regasification capacity in 2022 were the completion of the second phase at the Al-Zour terminal in Kuwait, capacity expansions and the successful conclusion of an expansion programme in China. Since the start of 2022 until October 2023, Europe has increased its LNG receiving capacity by 36.5 bcma (26.4 Mtpa). Europe has added six new import terminals in 2023 alone, plus a previously mothballed terminal and a new floating storage and regasification unit that is docked but not yet operational. In Germany, in 2023 three FSRUs have started operations at the ports of Wilhelmshaven (3.6 Mtpa capacity), Brunsbuettel (5.6 Mtpa capacity), and Lubmin (4 Mtpa capacity).

Global regasification capacity is anticipated to achieve 1,800 Mtpa by the end of the forecast period, with utilisation expected to hover just below 50% as per LNG import projections.

By 2050, around 80% of the total LNG regasification capacity is projected to be divided between the Asia Pacific and Europe, with the majority of the incremental growth in LNG regasification occurring in the Asia Pacific region.

6.5. Natural gas trade outlook by region

6.5.1. Africa

Africa's significant reserves of natural gas, coupled with its advantageous geographic location, present an opportunity to export natural gas, particularly LNG, to global markets. As the dynamics of LNG markets evolve due to geopolitical tensions and energy transitions, Africa leverages its strategic position to enhance the stability and reliability of the global energy market.

In 2022, Africa's natural gas net exports totaled approximately 86 bcm. Out of this, nearly 39 Mt (54 bcm), which accounts for roughly 63%, were exported as LNG, while Africa did not import LNG in 2022. The majority of LNG exports originated from the GECF Member Countries such as Algeria, Angola, Egypt, Equatorial Guinea, Mozambique and Nigeria. Meanwhile, the volumes transported through pipelines primarily came from Algeria and Libya.

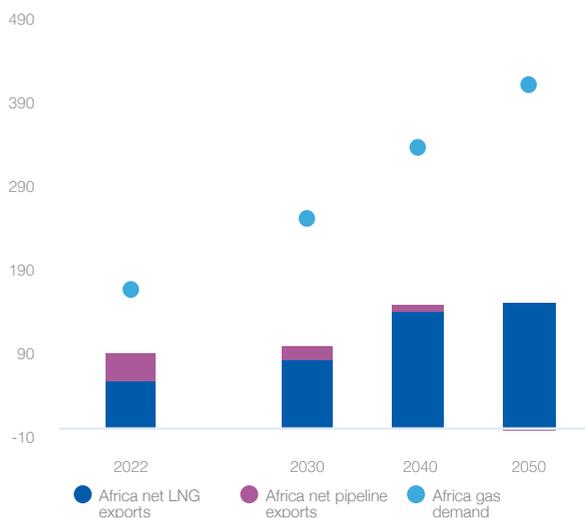
Due to Africa's proximity to Europe and its substantial supply of LNG, the continent holds a significant advantage in meeting Europe's energy needs. The RePowerEU plan has further solidified the strategic importance of African LNG in Europe. This strategy has positioned Africa as the prime choice for Europe's efforts to diversify its natural gas importing sources, leading to a notable 7% increase in LNG imports from the continent in 2022. Algeria secured its place as Europe's fourth-largest LNG supplier, providing 9.2 Mt, while Nigeria, boasting the largest natural gas reserves in Africa, rose to become Europe's fifth-largest LNG supplier, supplying 8.6 Mt during the same year.

Projections suggest that by 2050, the African continent will export approximately 145 bcm of natural gas, utilising both pipelines and LNG channels. An overwhelming majority of the net gas exports is anticipated to be in LNG form and equal to over 100 Mt by 2050.

Nigeria and Algeria stand out as the primary players in the LNG export markets, with Mozambique joining them in the upcoming

Figure 6.11.

Africa natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

decades. Mozambique is expected to play a crucial role on the global stage, emerging as the primary producer and exporter of LNG, contributing 53% to Africa's LNG exports by 2050. Nigeria, on the other hand, is forecasted to be the second-largest LNG exporter, providing approximately 29 Mt or 29% of the total African LNG exports by 2050.

The dynamic trajectory of Africa's LNG trade is primarily influenced by the region's capacity to surpass its supply in contrast to demand. Overall LNG exports are anticipated to rise to 63 Mt by 2030, further increasing to 198 Mt in 2040, and sustaining a strong 132 Mt by 2050.

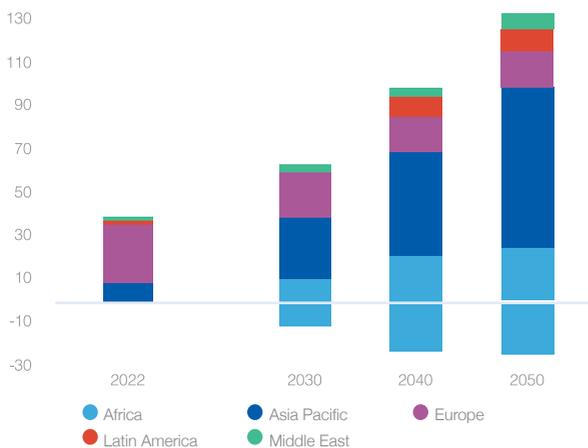
In 2022, Africa possessed 78 Mtpa of LNG liquefaction capacity located across Algeria, Angola, Cameroon, Egypt, Equatorial Guinea, Mozambique and Nigeria. Algeria and Nigeria with 25.5 Mtpa and 22.2 Mtpa respectively hold nearly 60% of this operational LNG liquefaction capacity. Mozambique became an LNG exporter in 2022 with the launch of the 3.4 Mtpa Coral Sul FLNG facility. However, utilisation of this overall African capacity stood at only 53% due mainly to upstream supply limitations.

According to the GECF Global Gas Model, the landscape of LNG infrastructure in Africa is poised for substantial expansion, projecting a remarkable increase to an estimated 190 Mtpa by 2050. Liquefaction capacity growth is set to be primarily led by Mozambique, Nigeria, Congo, Mauritania and Senegal, with potential incremental growth anticipated in countries such as Algeria, Egypt and various other African countries like Tanzania.

The outlook for Sub-Saharan Africa's LNG industry shows significant variations in both scale and timing. Currently, there are ongoing LNG liquefaction projects totalling 23 Mtpa in Mozambique (12.88 Mtpa), Mauritania/Senegal (2.5 Mtpa) and Nigeria (7.6 Mtpa). Additionally, Mozambique has completed the front-end engineering design (FEED) stage for 15.2 Mtpa of liquefaction capacity at Rovuma LNG 1. Moreover, proposed projects amount to approximately 67 Mtpa, while there may be potential for an additional 20 Mtpa of projects.

Figure 6.12.

Africa LNG exports (+) by destination and imports (-) by origin outlook, 2022-2050 (Mt)

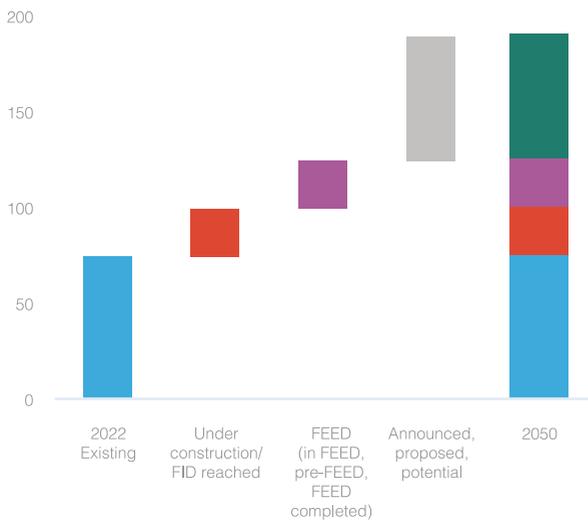


Source: GECF Secretariat based on data from GECF GGM
 Note: Regional LNG exports and imports include intraregional trade

Developers of LNG projects encounter challenges specific to each country, including with regards to security, infrastructure, bureaucratic hurdles and financial obstacles. Ensuring timely execution and expedited project development will be vital for African countries to realise their potential, especially considering the increasing competition arising from stable, established export regions with clear and transparent regulatory frameworks. In the near term, Africa has the potential to increase LNG exports by maximising the utilisation of its current plants and using additional floating LNG (FLNG), contingent

Figure 6.13.

Africa LNG liquefaction capacity outlook, 2022-2050 (Mtpa LNG)



Source: GECF Secretariat based on data from GECF GGM

upon securing an adequate supply of feed-in gas.

Despite limited existing infrastructure, represented by only a few pipelines facilitating regional gas trade – The Algerian pipeline to Tunisia, the West African Gas Pipeline from Nigeria to Benin, Togo and Ghana, and the Mozambique-South African Gas Pipeline – the trajectory points toward the emergence of additional regional gas pipelines. The prospect of more pipelines might signify an important step forward in bolstering Africa’s intra-continental natural gas trade and connectivity, potentially transforming the energy landscape within the region. By 2050, Africa is anticipated to expand its intraregional pipeline trade. Region’s pipeline exports are expected to remain at 48 bcm by 2050 compared to 49 bcm in 2022.

Algeria stands as the primary gas supplier to Southern Europe, delivering roughly 70% of its exports to Europe through pipelines and the remaining 30% as LNG. Algeria exported 52 bcm of natural gas in total in 2022, including via pipeline and in LNG form. The gas primarily travels from the Hassi R’Mel field onshore to LNG terminals along the coast and through three pipelines for subsea export, collectively exporting approximately 36 bcm of natural gas in 2022.

The majority of Algerian LNG shipments are directed towards Europe. In 2022, Algeria exported a total of 10 Mt of LNG, with approximately 9.2 Mt supplied to Europe. Algeria’s LNG facilities, with a collective capacity of 25.3 Mtpa, are situated across three sites: Arzew, Bethioua, and Skikda. Currently, the country operates four LNG plants. Algeria is projected to maintain its status as a significant natural gas supplier to the European market, both through pipeline and LNG exports, until 2050.

In 2022, **Angola’s** LNG exports totalled 3.2 Mt. Around 73% of these volumes were shipped to Europe, contrasting with the 77% directed to the Asia Pacific region in 2021, where India accounted for one-third of the total shipments. Angola LNG plant has a capacity of 5.2 Mtpa. The plant is supplied with associated gas sourced from the Kizomba A and B, and Saxe/Batuque fields. There are currently no imminent intentions to increase LNG liquefaction capacity in the foreseeable future.

Egypt foresees establishing itself as a natural gas hub, connecting trade among Africa, the Middle East and Europe following the discovery of the substantial Zohr gas field. The country has increased its LNG exports, to about 6.8 Mt in 2022, out of which approximately 4.8 Mt LNG was exported to Europe and 1.7 Mt to Asia countries, compared to 6.6 Mt LNG exports in 2021. Egypt currently operates the 7.2 Mtpa Iduku LNG liquefaction facility and Damietta LNG, with a capacity of 5 Mtpa.

The majority of **Equatorial Guinea’s** gas production is directed towards LNG exports. The 3.7 Mtpa EGLNG liquefaction facility, situated on Bioko Island near Malabo, commenced operations in 2007. In 2022, the facility exported 3.4 Mt of LNG, with exports nearly evenly distributed among the European, the Asia Pacific and Latin American markets. The country’s government entered into a Strategic Partnership and Cooperation Agreement with Vitol to establish a gas processing and LNG export terminal known as the Gas Megahub project. In 2022, a coalition consisting of Angola, Cameroon, Chad, the Republic of the Congo, the Democratic Republic of the Congo (DRC), Equatorial Guinea, and Gabon collectively signed a memorandum of understanding (MOU) to build a 6,500-km regional oil and gas pipeline known as the Central African Pipeline System (CAPS).

Significant gas reserves were discovered in the Grand Tortue Ahmeyim (GTA) gas field in 2014, extending across the border between Mauritania and Senegal. **Mauritania and Senegal** are set to commence their journey as LNG exporters in 2024 with the launch of the 2.5 Mtpa Greater Tortue Phase 1 project. This venture utilises gas from the GTA field. Phase 2 is anticipated to double the capacity to 5 Mtpa. Potential capacity could eventually reach 10 Mtpa. The Yakaar-Teranga field in Senegal and Bir Allah in Mauritania are additional fields being considered for the region. Initially, Yakaar-Teranga is expected to supply gas for domestic use, yet both areas are believed to have the potential for 10 Mtpa of LNG. The Mauritania/Senegal complex is anticipated to have a combined capacity of around 30 Mtpa.

By the mid-2030s and continuing through 2050, **Mozambique** is projected to become the largest LNG producer in Africa. In November 2022, Mozambique officially joined the group of LNG exporters when the initial shipment left from the Coral Sul FLNG facility situated offshore. This facility marks the first deployment of a floating liquefaction facility in African deep waters. Mozambique has a collective capacity exceeding 30 Mtpa scheduled to commence operations before or right after 2030. Long term by 2050, Mozambique is expected to reach 71 Mtpa of LNG liquefaction capacity.

Mozambique LNG represents the country's inaugural onshore LNG initiative. The current blueprint includes the construction of two liquefaction trains, totalling a capacity of 12.9 Mtpa. Approximately 90% of the project's LNG production has already been committed through long-term contracts with major buyers in Asia and Europe. Notably, the project has the potential for expansion up to 43 Mtpa. The FID for the project was finalised in 2019, however, in 2021, the project declared force majeure, with works suspended due to the security situation's escalation. The improvement in the security situation is anticipated to enable the resumption of work in 2024. The other project, Rovuma LNG, involves constructing two trains capable of producing 15.2 Mtpa. Gas feed is sourced from three offshore fields situated in Area 4 of the Rovuma Basin. The FID for Mozambique's Rovuma LNG facility has been rescheduled to 2024 due to notable downside risks, particularly concerning security concerns. With this four-year postponement to the FID, the project's commencement is also likely to be delayed, and estimated to start operations around 2030.

Since 1999, **Nigeria** has been exporting LNG from its Bonny Island liquefaction facility, with volumes accounting for 14 Mt in 2022 from the 22.3 Mtpa six-train Nigeria Liquefied Natural Gas (NLNG) facility. Projections indicate that the country's LNG exports could potentially reach between 28 to 30 Mt by 2030-2050. NLNG reached an FID on Train 7 in 2019. This expansion aims to increase the venture's capacity to 30 Mtpa by adding one additional train and debottlenecking other trains. Construction commenced in June 2021 and is expected to conclude by 2026. Nigeria's international gas trade also involves the West African Gas Pipeline (WAGP), covering a 680-km route with a capacity of 1.2 bcma. This pipeline facilitates gas deliveries from Nigeria's Niger Delta to Benin, Togo and Ghana.

6.5.2. Asia Pacific

The Asia Pacific region's economy is rapidly growing and is anticipated to require 30% more energy in 2050 than now. Natural gas has gained prominence as a key component of many Asian countries' energy and climate policies, calling for improved air quality and reduced GHG emissions along with enhancing reliability and affordability of energy supply. Ramping

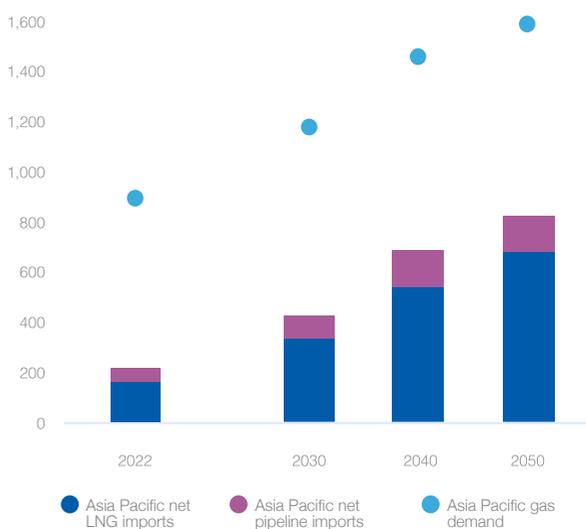
up electrification and coal-to-gas switching are the primary drivers behind the region's natural gas demand growth.

During 2022, the Asia Pacific region received a net total of 218 bcm of natural gas imports, with roughly 75% (164 bcm or 119 Mt) of this supplied through LNG, representing the net LNG imports. Concurrently, the region's overall gross LNG imports amounted to 252 Mt, encompassing intra-regional imports from countries such as Australia, Brunei, Indonesia, Malaysia and Papua New Guinea.

The heightened demand for LNG in Europe in the aftermath of the recent energy crisis had a significant impact on the Asian markets in 2022. Despite Europe becoming a prominent destination for premium LNG, the global pricing dynamics led to a situation where spot prices in Asia surged, becoming unaffordable for many countries. Consequently, China and India, both having substantial exposure to spot purchases, experienced a decrease in their LNG imports of 20% and 17% respectively in 2022 compared to 2021. Additionally, the heightened prices led to a decline in LNG imports by 16% in Pakistan and 13% in Bangladesh during 2022. Japan retained its position as the top LNG importer, bringing in 72 Mt, while

Figure 6.14.

Asia Pacific natural gas demand and net imports outlook by flow type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

South Korea imported 47 Mt, and Chinese Taipei imported 20 Mt of LNG in 2022.

Demand for LNG in developing Asia is set to rebound strongly on LNG supply availability increase and prices moderate further. China, Southeast and South Asia are poised to be the fastest-growing LNG markets and are projected to account for all the medium to long-term growth upside of the APAC. At the same time, Northeast Asian demand remains flat and declines after 2030.

Asia Pacific region is expected to remain the largest centre for LNG demand globally and the main destination for LNG imports over the outlook horizon. By 2050, just under 75% of overall global LNG trade is anticipated to be attributed to

the Asia Pacific alone. Over 2022-2050, Asia Pacific is set to also account for the majority of the incremental LNG imports – over 80%. Anticipated growth in Asia Pacific's LNG imports is projected to surge by 2.4 times, reaching around 505 Mt by 2040 and further escalating to 600 Mt by 2050. China continues to play a crucial role in propelling growth during the 2020s, while Southeast and South Asia emerge as some of the fastest-growing LNG markets worldwide beyond the 2030s.

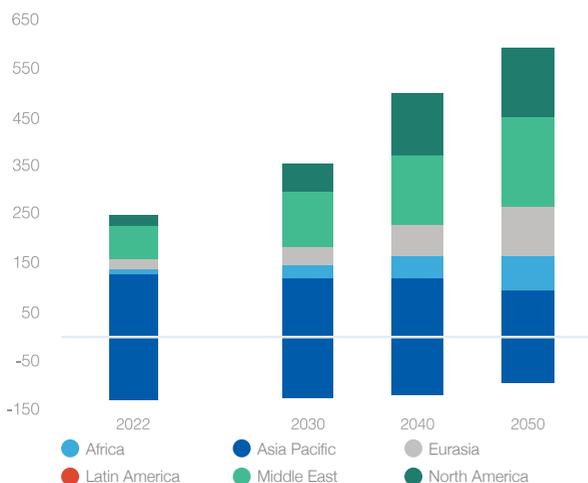
In 2022, the Asia-Pacific area boasted approximately 566 Mtpa of regasification capacity, with a significant 82% primarily situated within the legacy JKT (Japan, South Korea, Chinese Taipei) group, constituting 64%, while China held an 18% share. The rest, comprising South and Southeast Asia, contributed to the remaining 18% of the regasification capacity. Among these, Japan leads with 210 Mtpa in regasification capacity, followed by South Korea with 139 Mtpa, China with 100 Mtpa and India with 40 Mtpa (Figure 6.16). In 2022, construction was underway for approximately 121 Mtpa of regasification capacity in the Asia Pacific region, with China (74 Mtpa) and India (24 Mtpa) taking the lead in these advancements. China represents around 60% of the regasification capacity under construction, while India is responsible for roughly 20% of the ongoing development of regasification infrastructure.

Proposed LNG import projects totalling 455 Mtpa are also in consideration within the region, predominantly distributed across countries such as China, representing 42% of the proposed regasification capacity, followed by South Asia accounting for 25% and South East Asia contributing 21%. Thus, China, South, and Southeast Asia collectively contribute 88% of the total proposed LNG import projects in the region.

In 2022, the major share of the Asia Pacific's LNG imports was predominantly sourced from within the region itself, representing 53%, while the Middle East supplied 28%, combining to contribute 81% from these two regions alone. Looking ahead to 2050, the composition of the region's LNG supply is expected to undergo significant diversification. Africa, Eurasia and North America collectively are poised to account for more than half

Figure 6.15.

Asia Pacific LNG imports (+) by origin and exports (-) by destination outlook, 2022-2050 (Mt)



Source: GECF Secretariat based on data from GECF GGM
 Note: Regional LNG exports and imports include intraregional trade

of the entire LNG supply, 53%. In contrast, the intra-regional supply of LNG is projected to decrease substantially to only 16% from the above-mentioned 53% by 2050.

In terms of supply, five countries in the Asia Pacific region collectively exported 134 Mt LNG in 2022, with nearly all of these shipments delivered within the same region. Globally, Australia ranked as the second-largest LNG exporter, shipping 78.5 Mt, while Malaysia and Indonesia followed closely with exports of 27.6 Mt and 14 Mt, respectively. Papua New Guinea exported 8.4 Mt, and Brunei exported 4.8 Mt during the same year.

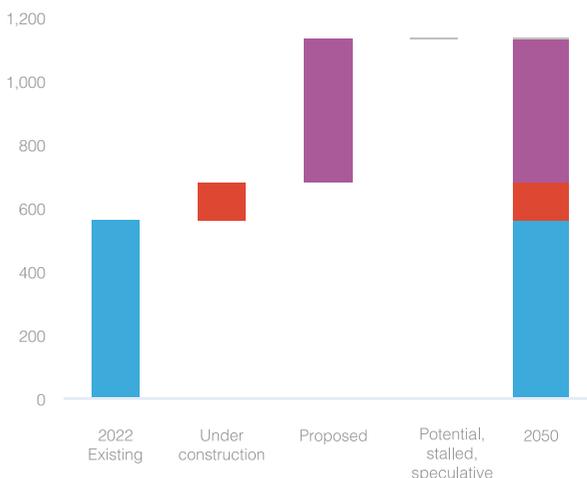
There is an expected decrease of approximately one-third in LNG exports from the Asia Pacific region by 2050, reaching around 96 Mt. Australia is projected to maintain its position as the primary leader among the Asia Pacific LNG exporters during this period, despite its expected fall in LNG export volume, particularly owing to the restriction imposed by new climate change policies and regulations making part of oil and gas upstream investment non-commercial.

In 2022, the region boasted approximately 159 Mtpa of liquefaction LNG capacity, with Australia accounting for over half of this at nearly 88 Mtpa. Moreover, Malaysia and Indonesia possessed 30.5 Mtpa and 26.5 Mtpa of established export capacity, respectively. Presently, Australia (5 Mtpa), Indonesia (3.8 Mtpa) and Malaysia (2 Mtpa) have a combined 10.8 Mtpa of liquefaction projects under construction, while an additional 15 Mtpa are in various stages of front-end engineering design (FEED). Furthermore, the region has a total proposed, potential and stalled export capacity of 12 Mtpa. Consequently, Australia is set to maintain its position as one of the leading global suppliers, with nearly 103 Mtpa of liquefaction projects, with the total region's liquefaction capacity expected to reach 197 Mtpa by 2050.

Decline in Japanese, South Korean, and Chinese Taipei (JKT) LNG Demand. The share of regional LNG imports by legacy LNG markets - Japanese, South Korean and Chinese Taipei – is expected to decline from 56% in 2022 to 20% by

Figure 6.16.

Asia Pacific LNG regasification capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

2050, primarily due to further accelerated energy transitions and decarbonisation measures, implying a further push for renewables and nuclear power as well as for energy efficiency improvements. The countries have been leaders in LNG consumption for many years, however, they are likely to expedite their transitions efforts towards cleaner and more sustainable energy sources to reduce carbon emissions. Increased emphasis on energy efficiency and conservation is set to also reduce the overall demand for LNG in these countries.

Japan continues to lead as the top LNG importing country, importing 72 Mt of LNG in 2022, representing a 19% share

Figure 6.17.

Asia Pacific LNG liquefaction capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

of the global LNG market. The country has sourced LNG from sixteen countries, with Australia leading the list at 30 Mt, followed by Malaysia (12 Mt), Russia (7 Mt) and the United States (4 Mt). According to the GECF Global Gas Model, Japan operates 37 regasification terminals, featuring an existing capacity of 210 Mtpa. Projections indicate a decline in LNG imports in Japan by over 40% throughout the forecast period. Despite this, Japan is expected to maintain its position as the world's third-largest LNG importer, with an estimated demand of 43 Mt (58 bcm) of LNG by 2050. While natural gas is poised to continue to play a significant role as a transitional energy source in the Japanese energy landscape, the country is expected to remain inclined towards pro-nuclear policies. Simultaneously, as Japan intensifies its focus on achieving a net zero target by 2050, the rate of decline in natural gas demand is projected to accelerate, reflecting the growing momentum of the energy transitions for this country.

South Korea's natural gas imports are forecasted to decrease by 15% from 47 Mt (63 bcm) in 2022 to 40 Mt (54 bcm) by 2050. The sourced LNG is expected to primarily come from Qatar, Australia, Russia, and the United States. At present, South Korea maintains a regasification capacity of 140 Mtpa.

China: the main contributor to the growth of global gas

imports. In an attempt to enhance national energy security and energy security, China is aiming to diversify further its natural gas supply sources, including by ramping up pipeline gas and LNG imports as well as its domestic production. Hence, China is the only region within the Asia Pacific where significant production growth is expected.

China has been importing increasing quantities of LNG and natural gas by pipeline. In 2022, China's natural gas imports were equal to 150 bcm. The main suppliers were Turkmenistan, Australia, Russia, Qatar and Malaysia, accounting for 81% of the total volume. China has significantly increased its pipeline imports accounting for 62 bcm in 2022. Turkmenistan and Russia accounted for 80% of China's pipeline imports providing 33 bcm and 16 bcm respectively. The total Chinese gas import pipeline capacity stands at 105 bcma. Three primary pipeline networks facilitate gas transportation to China. The 55 bcma Central Asia-China pipeline from Turkmenistan through Uzbekistan and Kazakhstan to China, the 38 bcma Power of Siberia gas pipeline, supplying Russian gas to China, and the 12 bcma Myanmar-China gas pipeline. Continued growth in China's pipeline imports is anticipated due to ongoing projects including the Far Eastern pipeline extension from Russia's East, expected to add 10 bcma; the anticipated Power of Siberia 2 pipeline from Russia, estimated to provide 50 bcma; and the Line D expansion from Turkmenistan, contributing an additional 30 bcma. Projections suggest that China's gas pipeline import capacity could potentially reach 195 bcma by 2050. Forecasts indicate that Chinese pipeline imports might reach 130 bcm by 2050, primarily sourced from Russia and Turkmenistan.

In 2022, China was the second-largest LNG importer worldwide but regained the number one LNG importer title in 2023. The country's LNG imports stood at 63 Mt in 2022. Australia was the largest LNG supplier (34%) to China in 2022, followed by Qatar, Malaysia, and Russia. For the medium- and long term, China is expected to be the main growth market in the Asia Pacific region for gas exports. Therefore, it is set to be a primary destination for any new pipeline and LNG projects initiated in the next decade. In China, natural gas imports are expected to increase from 150 bcm in 2022 to 265 bcm in 2050, while LNG imports are expected to rise from around 63 Mt in 2022 to 125 Mt in 2040 and 120 Mt in 2050. As for LNG regasification capacity, China's total LNG receiving capacity equalled 106 Mtpa at the end of 2022. Some 74 Mtpa of regasification capacity is under construction. In addition, around 190 Mtpa worth of projects are in different stages of planning. Total capacity could reach 370 Mtpa by 2050.

South and Southeast Asia are projected to increase their LNG share in total Asia Pacific imports from 18% in 2022 to 56%, becoming the region's largest long-term demand bloc. The region's population and economies are growing rapidly, leading to increased energy demand. Rapid urbanisation in countries such as India and Indonesia is also driving up energy needs, including LNG for power generation and industrial use. The development of industries in these regions is poised to also boost LNG consumption for manufacturing and other industrial processes.

Southeast Asia: regional 'switch' from net exporting to net importing region. Overall, the combination of electrification, fuel-switching and supportive natural gas policy measures, especially in the power sector, can lead to robust growth for natural gas in Southeast Asia. Continued infrastructure expansion and improved regulation are anticipated to remain critical to unlocking growth in many Asian natural gas markets.

Population increases and robust economic growth provide a strong foundation for LNG demand to grow in South and Southeast Asia. Stagnant or declining domestic gas production in the long run in some of the countries of the region is projected to be another factor supporting increased LNG imports.

Both **Malaysia** and **Indonesia** have historically been significant net exporters of LNG. As of 2022, Malaysia held the position of the 5th largest LNG exporter globally, contributing 27.6 Mt, while Indonesia ranked 7th, exporting 14 Mt of LNG. LNG is essential for their economies, but they face challenges related to depleting reserves and the need to incentivise exploration to maintain their production levels. The success of projects such as Tangguh Train 3 and ZLNG, and the need for ongoing exploration efforts, will play a significant role in determining their energy export futures in the 2020s and beyond. Over the long term, Indonesia and Malaysia are expected to transition from being net exporters to becoming net importers. Within Southeast Asia, the **Philippines** and **Viet Nam** have initiated reliance on LNG as they commenced imports in 2023. However, the increase in imports is expected to take place gradually due to elevated worldwide prices and unfavourable macroeconomic conditions.

South Asia: net natural gas importing trend accelerating but with a high price sensitivity boundary. Near-term natural gas demand growth stalls in price-sensitive sectors in South Asia that are reliant on high prices of spot LNG. But very strong demand recovery is expected post-2026 as LNG prices are set to soften further. The anticipated outcomes of regional expansion and market liberalization include the emergence of a varied spectrum of new buyers.

As for **India**, the government has pledged net-zero by 2070 and its strategic plan envisions widespread growth in gas consumption. Despite a robust government ambition for natural gas to reach a 15% share in the energy mix in 2030, up from the 5% in 2022, this target is unlikely to be met. India's gas demand is forecast to be met via expanded gas pipeline and LNG regasification capacity. In 2022, India imported 20 Mt LNG, accounting for approximately 48% of the country's gas consumption. However, this marked a significant 17% decline from the preceding year due to elevated spot prices. Estimations indicate that Indian LNG imports could double, reaching 39 Mt by 2030, and rise to 80 Mt by 2040 and 105 Mt by 2050. Realising such an outcome necessitates substantial investment in both supply and distribution infrastructure. By 2050, it is anticipated that India will increase its regasification capacity by 75 Mtpa, reaching a total of 115 Mtpa, which marks a significant rise from the existing capacity of 40 Mtpa. Currently, 24 Mtpa of this planned capacity is already under construction.

Urban growth, stricter air quality norms and industrialisation coupled with increased pipeline connectivity are projected to drive long-term gas and LNG demand in the power sector in the case of **Pakistan** and **Bangladesh** and industry in the case of India.

India does not rely on gas imports through pipelines. There is potential for Central Asia to provide more gas; however, uncertainty envelops most new projects aiming to transport this gas to the market. This uncertainty notably pertains to the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline, with a potential capacity of 33 bcma, that might supply gas over 30 years to India (14 bcma) and other countries.

Between 2009 and 2012, **Australia** witnessed a significant surge in LNG investment. These endeavours led to the substantial expansion of Australia's LNG export capacity, reaching approximately 88 Mtpa. As a result of these developments, Australia has emerged as the world's third-largest LNG exporter. In 2022, LNG exports were mainly channelled within the Asia Pacific, primarily China, Japan, and South Korea. Australia is poised to uphold its status as a prominent global LNG supplier, boasting 103 Mtpa of liquefaction capacity by 2050. However, the sustained reduction in operational output over the long term, primarily attributed to declining upstream production, is anticipated to potentially lead to a decline in LNG exports.

6.5.3. Eurasia

In 2022, according to the GECF Global Gas Model, Eurasia's aggregate gas exports reached approximately 254 bcm, with Russia accounting for around 170 bcm. Over 80% of these exports were transported via pipelines. Russia contributed the highest volume of piped gas, exporting around 129 bcm, of which approximately 89 bcm were supplied to Europe and 16 bcm to China. In 2022, other countries including Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan collectively exported roughly 76 bcm through pipelines, primarily transported across Central Asia. The Central Asia-China pipeline corridor is currently operating close to its maximum capacity of 55 bcm annually. There is potential for expansion to 85 bcm per year by constructing Line D, originating from Turkmenistan through Uzbekistan, Tajikistan, and Kyrgyzstan, and connecting to China.

In 2022, **Russia** experienced a 25% decrease in its gas exports to 170 bcm. Despite restricted Russian pipeline exports to Europe, Russian LNG exports increased. Russia was the world's fourth-biggest LNG exporter after Qatar, Australia, and the United States in 2022. Its exports grew to 32 Mtpa, giving it a global LNG market share of around 8%. Remarkably, the EU increased its imports of LNG from Russia by 30% in 2022, constituting 15% of the EU's total overall LNG imports. In 2023, Russia exported 16 Mt of LNG to Europe.

The geopolitical tensions are anticipated to persistently affect the trade dynamics between the EU and Russia in terms of energy, particularly concerning Russian pipeline gas exports. This ongoing situation is adding complexities to the financing and logistics of current agreements. The EU's REPowerEU plan entailed specific restrictions on its natural gas imports from Russia, including objectives to eliminate the usage of Russian gas by 2027.

Russia had been engaged in efforts to broaden its export infrastructure, exploring the possibility of increasing gas sales to the Asia Pacific region. Russia sets increased LNG exports as a priority with a major strategic focus on the Asia Pacific markets – China in particular.

Russia initiated gas supply to Asia in 2009, delivering around 38 bcm of gas to the region in 2022 using both LNG and the Power of Siberia pipeline. This contrasts with the European market, which typically imported between 160 to 200 bcm of gas from Russia. Being Beijing's second-largest gas supplier, Russia exported 24 bcm of gas to China in 2022. Specifically, through the Power of Siberia pipeline, which commenced operations in late 2019, Russia supplied China with 15.4 bcm of gas in 2022.

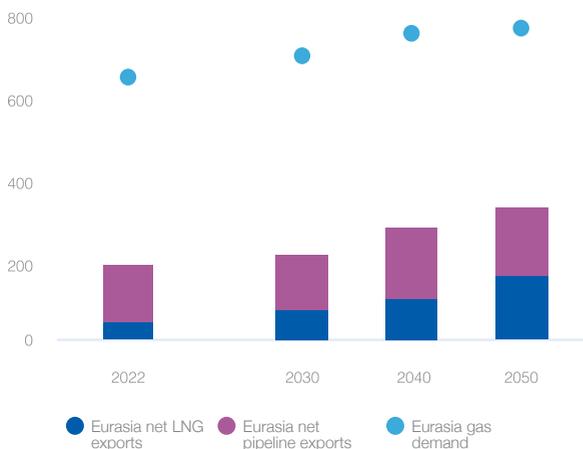
Regarding the Asia Pacific region, the existing infrastructure

includes the Power of Siberia gas pipeline, linking the Yakutia and Irkutsk production centres to China, with a capacity of 38 bcma. Under construction and proposed pipelines targeting the Chinese market include The Far Eastern pipeline, designed to connect Russia's Far East region to northeast China, with a proposed capacity of 10 bcma; and Power of Siberia 2, intended to supply China via Mongolia from western Russia, with a proposed capacity of 50 bcma. A significant shift could occur with the introduction of the Power of Siberia 2 (PoS2) pipeline, capable of transporting 50 bcma from West Siberia's fields to China. If anticipated to be operational in the early 2030s, Power of Siberia 2 has the potential to escalate Russian gas supplies to Asia, potentially matching the levels supplied to the EU.

Russia aimed to achieve a 20% share of the global LNG market by 2035, intending to expand its annual LNG production to 120-140 Mt from the current approximate output of 30 Mt.

Figure 6.18.

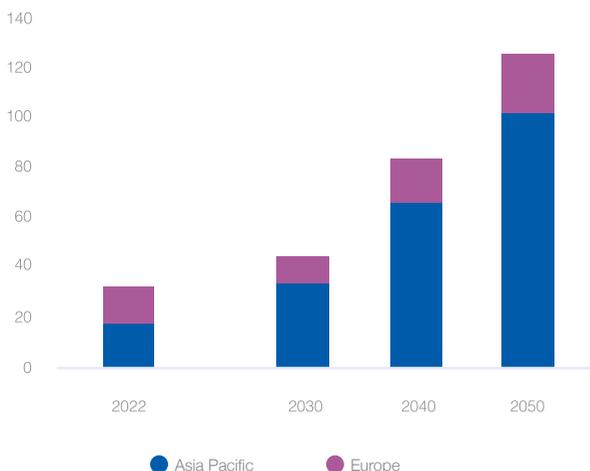
Eurasia natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

Figure 6.19.

Eurasia LNG exports outlook by destination, 2022-2050 (Mt)



Source: GECF Secretariat based on data from GECF GGM
 Note: Regional LNG exports and imports include intraregional trade

However, EU sanctions directed at equipment necessary for enhancing gas production (liquefaction) might impose constraints on these plans. This challenge could potentially be addressed by substituting Western technologies with Russian proprietary technologies developed over time, along with alternative sources from Asian countries such as China.

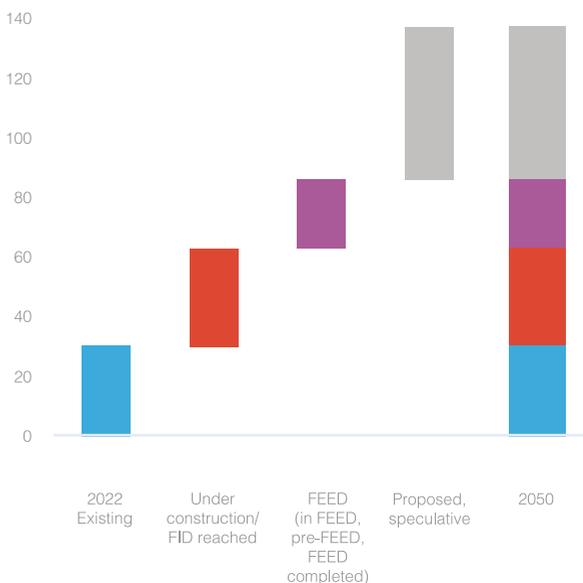
Russia is aiming to become a major player in global LNG markets. It is estimated that if all proposed, stalled and speculative LNG projects become operational, Russia's LNG liquefaction capacity could reach around 140 Mtpa by 2050. Russia is projected to overtake Australia as the world's third-largest LNG supplier by 2050, and overall Russia's natural gas exports are set to rise from 170 bcm in 2022 to around 310 bcm by 2050. Natural gas initiatives in regions such as the Yamal Peninsula, the Arctic, East Siberia, and the Far East are expected to significantly elevate Russian natural gas production by 2050. Forecasts indicate that Russia will maintain its position as one of the largest net gas exporters throughout the foreseeable period.

Since the inauguration of Shah Deniz in 2007, according to the GECF Global Gas Model, **Azerbaijan** has been actively exporting gas, with exports gaining momentum from 2010 and reaching 19 bcm in 2022. A significant portion of these exports went to Italy (43%), to Türkiye (37%) and Georgia in 11% in 2022. In 2022, Azerbaijan contributed 12.2 bcma to the EU's gas imports. Over the forecast period (2022-2050), projections indicate that natural gas exports from Azerbaijan will grow to 26 bcma by 2050.

A preliminary agreement with the EU bloc in July 2022 aimed to double Azeri gas deliveries to at least 20 bcma by 2027. As part of this plan, there are intentions to increase the capacity of the Trans-Anatolian Natural Gas Pipeline (TANAP) from 16 to 32 bcma and the Trans-Adriatic Pipeline (TAP) from 10 to 20 bcma. The SGC pipelines span from Azerbaijan to Italy, traversing Georgia, Türkiye, Greece, and Albania. The SGC

Figure 6.20.

Eurasia LNG liquefaction capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

consists of four projects: Shah Deniz natural gas-condensate field operation (SD1) and full-field development (SD2), South Caucasus Pipeline (SCP) operation and expansion (SCPX), the Trans-Anatolian Natural Gas Pipeline (TANAP), and the Trans Adriatic Pipeline (TAP).

6.5.4 Europe

The European natural gas market is anticipated to retain its position as the second-largest importing market globally, following the Asia Pacific market. However, over the longer term, a decline in imports is expected, owing to a decrease in domestic demand, lower imports from Russia and a hastened shift towards alternative energy sources.

The demand for natural gas in Europe is declining due to efforts focused on decarbonisation and initiatives such as the Green Deal, which aims to reduce the presence of gas within the European energy mix.

By 2050, it is forecast that net gas imports will reach 211 bcm – a significant decrease from the 317 bcm recorded in 2022. But Europe is still anticipated to represent around 20% of the global gas imports. Germany, Italy, France, Spain and the UK are expected to maintain their positions as the primary natural gas markets in Europe for an extended period.

Amid the gas source diversification policy and the expansion in infrastructure, a larger proportion of imports are expected to come from LNG, marking an increasing share in the overall import volume. In 2022, the EU's LNG imports amounted to slightly more than 130 bcm (95 Mtpa), marking a 60% surge from the 80 bcm (59 Mtpa) imported in 2021.

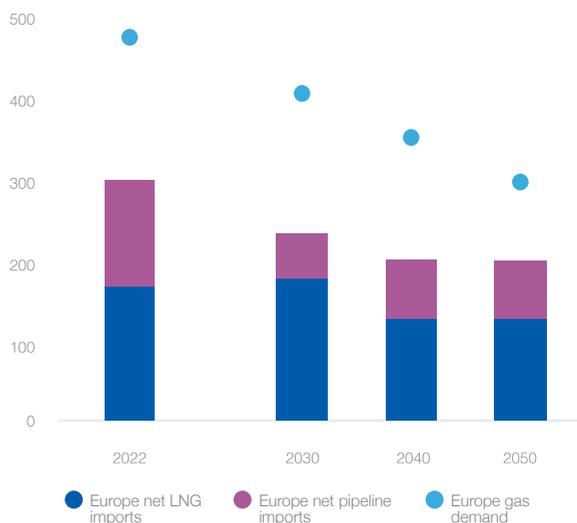
The EU's strategy is focused on LNG. The bloc is actively engaged in expanding regasification capacity while addressing current limitations in gas infrastructure. Considerable investments are made in LNG infrastructure, resulting in the operation of more than 20 large-scale terminals integrated into the grid. The total European LNG import capacity stood at 222 Mtpa in 2022. Europe added 27 Mtpa of new LNG capacity in 2022-2023. European governments have swiftly increased regasification capacity by employing rapid FSRU deployment. It is projected that Europe could add 60-80 Mtpa by 2025, with this growth arising from both expansions of existing infrastructure and the development of new projects. While the primary location for new terminals is expected to be in Germany, plans are also in place for facilities in Greece and Italy.

Looking further ahead, the cost of developing new LNG infrastructure is set to dictate long-term price trends. As Europe sustains its competition with Asia for LNG, while the adaptability of established markets diminishes, natural gas prices are likely to become more volatile in structure. As piped gas imports from Norway and other sources gradually diminish, the proportion of LNG in the European supply mix is set to grow.

Norway is the world's fourth-largest exporter of natural gas as well as Europe's biggest supplier with almost all natural gas that is produced on the Norwegian shelf being exported. Due to domestic heavy reliance on hydropower, the country can export nearly the entire oil and gas it produces. Norway supplied a total of about 117 bcm of gas in 2022 via pipeline, out of which 86 bcm was routed to the EU-27 and the remaining 31 bcm to the rest of Europe (the UK). Five gas pipelines connect the Nordic country to continental Europe, and two stretch to the UK, with a combined export capacity of around 138 bcm. Due to the great flexibility and the ability to adjust production

Figure 6.21.

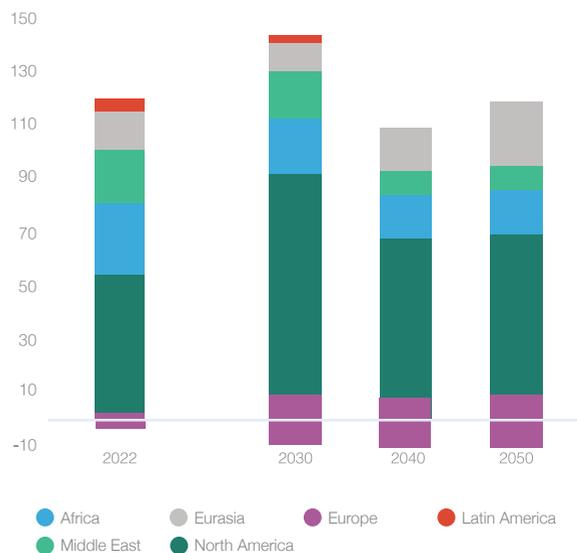
Europe natural gas demand and net imports outlook by flow type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

Figure 6.22.

Europe LNG imports (+) by origin and exports (-) by destination outlook, 2022-2050 (Mt)

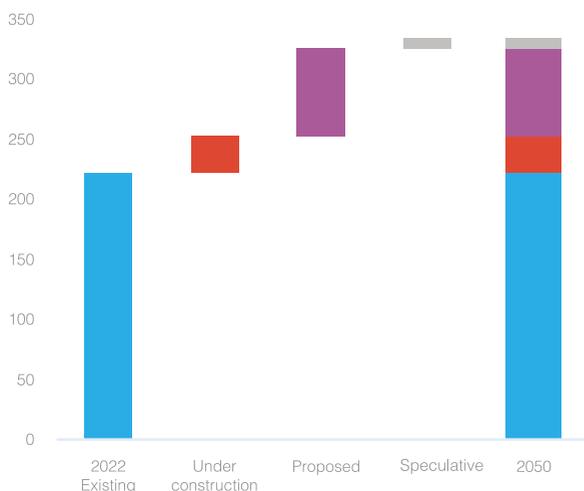


Source: GECF Secretariat based on data from GECF GGM
Note: Regional LNG exports and imports include intraregional trade

from specific fields, as well as production and transport costs, Norwegian piped gas to Europe is the most competitive source of supply and is expected to remain high and stable in global markets, especially in European markets over the short- to medium term. Norway exported marginal volumes of LNG in 2022, or less than 3% of its overall country's natural gas exports, targeting European consumers. Norway's anticipated gas exports are projected to account for a reduced 85 bcm by 2030. However, due to declining production, these exports are

Figure 6.23.

Europe LNG regasification capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

expected to decrease significantly to approximately 27-30 bcm by 2050.

In the **UK** in 2022, there was a decrease in net natural gas imports, but both gas imports and exports reached unprecedented levels. Gas exports from the UK tripled in 2022 compared to 2021, setting a new record. The disruption in global gas supply caused significant shifts in the UK's trading patterns. Imports also hit a record high, rising by 10%, largely due to a substantial increase in LNG imports. LNG accounted for nearly half of the total imports. Norwegian gas imports constituted 55% of the total UK gas imports in 2022. Regarding gas import-export infrastructure, the UK boasts the second-largest LNG regasification infrastructure in Europe, following Spain. The UK functioned as a land bridge using interconnectors for gas exports to Belgium and the Netherlands. The country's total import capacity amounts to 168 bcm and comprises nine pipelines and three LNG terminals, totalling 36 Mtpa. The UK does not expect to considerably expand its regasification capacity by 2050. The UK is expected to net import around 47 bcm of natural gas by 2050, out of which the lion's share is forecast to be attributed to the LNG imports. By then, a marginal 4-5 bcm is anticipated to be the UK's pipeline exports to Europe. In 2030 and 2040, the UK is expected to import 15 Mt and 18 Mt of LNG respectively, while reaching 35 Mt by 2050.

As **Germany** moves away from nuclear power and strives to phase out coal, natural gas is projected to persist in its transitional role for electricity generation. Germany is heavily dependent on natural gas imports. 95% of the country's gas consumption in 2022 was met by imports. In 2022 the country's natural gas imports were at 83 bcm, all through import pipeline infrastructure. Germany is set to reinforce its LNG capacity established in 2022 to maintain energy diversity in response to the ongoing vulnerability of the energy supply. In 2023, Germany began importing LNG. In a move to increase LNG import capacity, Germany is adopting FSRUs to boost its import capabilities in the short term. Some of these FSRUs

will be substituted by onshore terminals, scheduled to become operational in the latter half of this decade. Germany aims to establish a peak LNG import capacity of 71 Mtpa by 2030. Three FSRUs are operational at the ports of Wilhelmshaven, Brunsbuettel, and Lubmin in Germany. Anticipated by the end of 2024, is the activation of three additional FSRUs at Wilhelmshaven, Stade, and Mukran.

Over the outlook period, net gas imports to Germany are expected to reach a ceiling before 2025 in the range of 76-83 bcm. Then they are anticipated to witness a sharp decrease to 20 bcm (four times less than the current levels) by 2050, in line with the country's natural gas demand projections. Regarding LNG imports, Germany is expected to witness a surge from zero in 2022 to a peak of 20 Mt between 2030 and 2032. Subsequently, due to the challenges posed by the energy transition, these imports are forecasted to decrease to 10-11 Mt by 2050.

Türkiye has been striving to establish itself as a significant participant in the global energy sector, strategically positioning itself between key Western markets and major energy suppliers in the Middle East and Russia. Türkiye relies entirely on imports for this resource, procuring substantial amounts from Russia. Türkiye has begun moving towards the role of a regional hub thanks to its pipeline connectivity to the rest of Europe and its reloading facilities at three of its regasification terminals. Since 2022, Russia and Türkiye have been contemplating the establishment of an international gas hub in the latter country, aiming for substantial involvement of Russian gas in this initiative.

In 2022, the country imported 54 bcm of natural gas, with pipelines being the primary source, accounting for 72% of the total imports. Specifically, Türkiye acquired 21 bcm from Russia, 9 bcm from Iran, and under 9 bcm from Azerbaijan. On top of that, LNG imports totalled 11 Mtpa. Apart from Russia's gas pipeline export system to Türkiye, Türkiye receives natural gas from Iran via a 325 km-long gas pipeline and from Azerbaijan through the South Caucasus and TANAP pipelines. Türkiye possesses five LNG regasification terminals, collectively capable of handling 27 Mtpa.

Throughout the projected period, it is anticipated that net natural gas imports into Türkiye are set to reach 55 bcm by 2050. In terms of LNG imports, Türkiye is predicted to undergo a marginal reduction to 8 Mtpa by 2050. This expectation arises from the efficient supply of pipeline gas from various countries such as Russia, Azerbaijan, and Iran, diversifying the Turkish market's sources.

6.5.5 Latin America

In 2022 the region imported approximately 26 bcm of gas, with 13.5 bcm (9.8 Mt) arriving as LNG. Simultaneously, it exported roughly 27 bcm of gas, with LNG accounting for 17 bcm (12 Mt). All trade via pipelines occurs within the region, predominantly sourced from Bolivia.

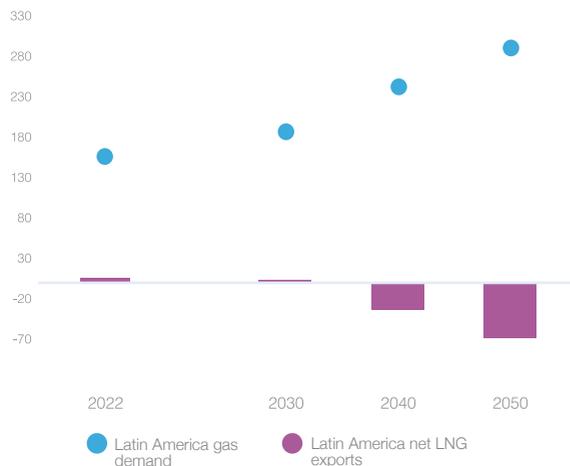
Forecasts suggest a substantial increase in net natural gas imports to 62 bcm by 2050, marking a notable transformation as the region transitions from a marginal net exporter in 2022, to becoming a net importer of natural gas in the early 2030s. LNG is projected to be the prevailing force in shaping the natural gas trade across the Latin American continent. The entirety of pipeline-based trade is forecast to persist in originating from Bolivia, gradually diminishing in volume. Additionally, Argentina is expected to transition to exporting

more pipeline gas after the mid-2030s or potentially earlier, in contrast to its current status as a pipeline importer.

Due to various hurdles confronting the initiation of new gas projects in Latin America, the supply is anticipated to fall short of meeting the increasing demand, thereby necessitating the expansion of imports into the region in the coming decades. Countries situated in the middle of the continent also might face greater difficulties in natural gas integration.

Figure 6.24.

Latin America natural gas demand and net exports outlook, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GGM 2023

In Latin America, the increased use of natural gas is set to be driven by the shift away from coal, the substitution of oil in power generation and the role of the fuel as a fundamental energy source to aid the intermittency challenges of the growing renewables sector, thus facilitating the energy transition as well as backing up hydroelectricity capacity. The primary drivers for natural gas demand are projected to be the expansion of power generation within the region, industrial development, and to a certain extent, the growth of gas usage in road transportation.

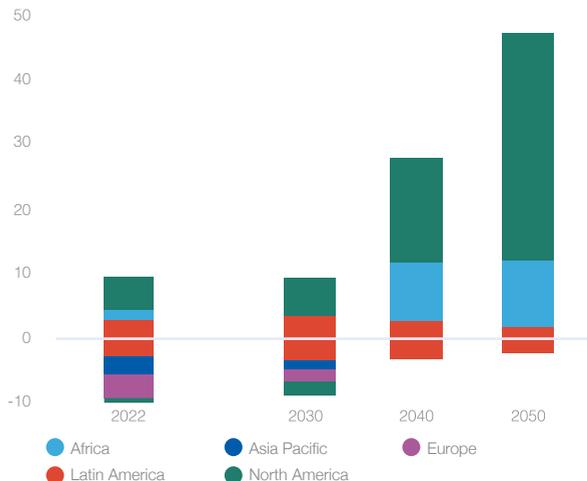
The primary shift in Latin America revolves around Argentina's potential to supply gas to its neighbours. Gas exports to Chile primarily moved via the GasAndes pipeline, with smaller quantities traversing to Uruguay in 2022. Additionally, there are intentions to establish LNG facilities in Argentina, potentially encouraging exports to different regions. The rapid increase in shale production in Argentina's Vaca Muerta, hosting the world's second-largest shale gas reserves following the United States, is poised to significantly alter the landscape in Latin America. The development of extensive gas export pipeline infrastructure within the Vaca Muerta area, such as the Nestor Kirchner Gas Pipeline, is expected to facilitate the operation of a planned 25 Mtpa LNG export terminal in Bahia Blanca, expected to commence operations around 2032.

At present, within Latin America, Trinidad and Tobago and Peru are the exclusive major LNG exporters, having supplied 8.1 Mt and 3.9 Mt of LNG in 2022. In the long run, the region is anticipated to target a reduction in LNG exports, primarily supplied by Argentina.

Conversely, looking ahead, there is an expectation of a substantial increase in LNG imports within the region. Starting from 9.8 Mt in 2022, the projection indicates a rise to around 47 Mt by 2050. LNG constitutes the majority of gas imports in Chile, making it the foremost Latin American importer of LNG in 2022. Additionally, Argentina, Brazil, the Dominican Republic and Puerto Rico primarily imported LNG, with Colombia, El Salvador, Jamaica, and Panama importing it to a lesser extent. In 2022, El Salvador entered the league of LNG-importing

Figure 6.25.

Latin America LNG imports (+) by origin and exports (-) by destination outlook, 2022-2050 (Mt LNG)



Source: GECF Secretariat based on data from GECF GGM
Note: Regional LNG exports and imports include intraregional trade

countries by launching the Acajutla LNG terminal. Concurrently, a separate FSRU project commenced operations in Brazil.

The presence of substantial quantities of US LNG in Latin America presents a dual prospect – both advantageous and challenging. Importers in the region stand to benefit from the chance to broaden their energy sources by accessing affordable US LNG. Conversely, exporters face the challenge of vying for market share, both domestically and internationally, against the backdrop of competitively priced US LNG.

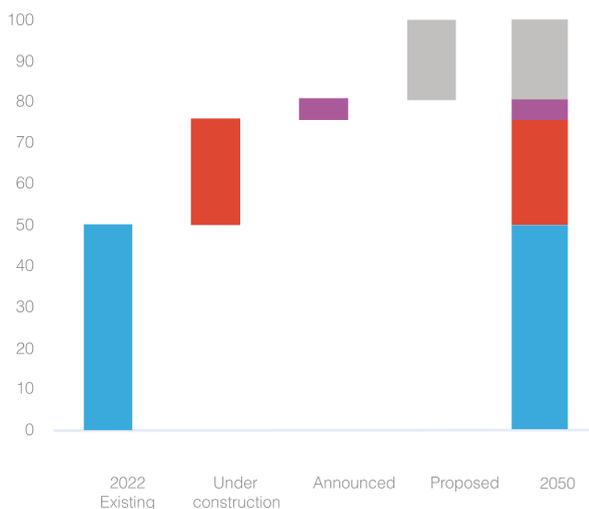
Approximately 50 Mtpa of LNG regasification capacity currently exists in the region, with an additional 26 Mtpa under construction and a further 25 Mtpa potentially planned for development in countries such as Brazil, Chile, Colombia, the Dominican Republic, El Salvador, Bahamas, Nicaragua and other locations during the forecasted period.

Bolivia plays a significant role as a major natural gas provider to its neighbouring countries, Brazil and Argentina, through dedicated export gas pipelines. In 2022, Bolivian pipeline gas exports amounted to 6.3 bcm to Brazil and 3.8 bcm to Argentina. The natural gas industry holds immense importance for Bolivia's economy, with sales to Brazil and Argentina currently constituting over 70% of total gas sales and representing approximately 20% of the country's overall exports. Bolivia exports natural gas through interconnecting pipelines with Brazil and Argentina. via three international gas pipes: GIJA to Argentina with 10.2 bcma capacity, Gasbol with

11.5 bcma capacity, and Gasyrg to Brazil. Bolivia is attempting to diversify its export markets by exploring the possibility of sending its natural gas to both Peru and Uruguay. By connecting with the Gasoducto Sur Peruano in Peru, and with the Uruguayan Port of Montevideo, landlocked Bolivia would be able to gain access to ports on both sides of South America and reach other export markets.

Figure 6.26.

Latin America LNG regasification capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

Brazil is expected to experience a notable surge in the demand for gas imports in the coming years. Simultaneously, the country has developed LNG import options, offering viable alternatives that could significantly supplement the diminishing pipeline imports from Bolivia over an extended period. Brazil witnessed a considerable drop in total gas imports to 9 bcm in 2022, marking a substantial decline of nearly 50% compared to 2021 as the country recovered from its most severe drought in two decades as it heavily relies on the hydropower system. In the long-term, by 2050 Brazil is expected to remain a net importer of natural gas with up to 50 bcma, primarily in the form of LNG (around 34 Mt) and to have 66 Mtpa of LNG regasification capacity in place.

In 2022, Brazil imported 1.9 Mt of LNG, with approximately 80% of its imports coming from the United States. Presently, the country operates five LNG import terminals with a combined capacity of 24 Mtpa. Additionally, Brazil is in the process of constructing regasification capacities totalling 14 Mtpa. One of these developments, the FSRU Terminal Gás Sul (TGS), boasting a capacity of 4 Mtpa, is anticipated to start commercial operations ahead of schedule in early 2024. The country imported 6.3 bcm via pipeline exclusively from Bolivia in 2022. However, it is set to increase gas imports from the Vaca Muerta gas field due to an extension expected to further interconnect Brazil and Argentina. The project, aimed at importing 1.9 bcma, has already secured the necessary construction permit.

Argentina stands out as one of Bolivia's major markets for gas exports. Simultaneously, with the expanded production from the Vaca Muerta shale deposit and the development of the Nestor

Kirchner gas pipeline system within Argentina, the country is projected to transition into a net exporter in the long term. As of 2022, Argentina remained a net importer of natural gas, totalling 4 bcm. Its imports consisted of 3.8 bcm of pipeline gas sourced from Bolivia and 2.1 bcm of LNG, primarily obtained from the United States. Looking ahead to 2050, there is a belief that Argentina is poised to transition to become a net exporter of natural gas, potentially reaching up to 10 bcma.

Argentina is actively expanding its gas pipeline network. A significant stride in this effort was the commencement of the initial phase of the Nestor Kirchner pipeline in July 2023 with a capacity of 4 bcma, establishing a crucial link between the Vaca Muerta field and Buenos Aires. The project's second phase, slated for completion by 2025, aims to connect Vaca Muerta to the Santa Fe province, boosting the pipeline's total capacity to 16 bcma. In 2022, Petronas and YPF entered into initial agreements to construct the first phase of an LNG facility capable of producing 5 Mtpa at Vaca Muerta with a construction timeline of 10 years. Upon reaching full operational capacity, the project is anticipated to be capable of exporting up to 25 Mtpa of LNG.

Trinidad and Tobago stands as the primary LNG producer and exporter in Latin America. In 2022, Trinidad and Tobago exported 8.1 Mt of LNG. This included 44% of exports to Latin and North America, and the rest to Europe and the Asia Pacific region. Atlantic LNG, the exclusive LNG producer in the country, facilitates exports via its 15 Mtpa Point Fortin facility situated in southwest Trinidad. Forecasts suggest that Trinidad and Tobago's LNG exports will stabilise at 8.4 Mtpa by 2030. The upside potential lies in the joint development of the Dragon field with Venezuela, aimed at exporting natural gas utilising Trinidad and Tobago's liquefaction infrastructure. Additionally, the exploration and development of new gas fields remain under consideration, further influencing potential revisions to these forecasts.

Peru stood as the second-largest LNG exporter in Latin America in 2022, exporting 3.9 Mt of LNG via the PERU LNG liquefaction plant with a capacity of 4.4 Mtpa. Projections suggest that Peru's LNG exports will stabilise at 2.2 Mt in 2030, eventually declining through 2050. Venezuela presently does not engage in the import or export of natural gas, despite possessing significant potential. There is a possibility that Venezuela might initiate natural gas exports to Trinidad and Tobago. Such exports could potentially supply Trinidad's primary Atlantic LNG plant, thereby ensuring a consistent source for Trinidad and Tobago's gas exports. Venezuela has been receiving gas imports from Colombia. Efforts are underway to revive the pipeline project between Venezuela and Colombia, presenting a feasible export avenue for the latter.

6.5.6 Middle East

In recent years, the Middle East has experienced a notable surge in the demand for natural gas, propelled by a growing population and by reduced gas prices, which were subsidised to stimulate economic expansion, promote energy-intensive industrial development and share some benefits with the local population.

Simultaneously, the vast natural gas reserves within the Middle East have unleashed opportunities for increased natural gas trade. The primary focus of gas trading within the Middle East has been centred on exporting LNG to destinations primarily in Asia and Europe. Regional gas trade – intraregional and interregional – on the other hand, involves relatively modest

quantities transported through export pipelines, such as from Qatar to the UAE and Oman, from Iran to Iraq and Türkiye, as well as to Armenia and Azerbaijan, and from Israel to Jordan and Egypt.

The primary force propelling natural gas exports from the Middle East is set to be growth in LNG supplies, notably led by Qatar. The upward trajectory of Qatar's position as a leading global LNG exporter in 2022 indicates a growing momentum towards additional expansions or advancements post-2030s and 2040s following the North Field expansion projects. With ambitions to increase its current capacity of 77 Mtpa by 64%, Qatar aims to reach 126 Mtpa through the North Field expansion by 2028.

In 2022, net gas exports from the Middle East amounted to 139 bcm. Projections indicate a significant surge in overall net exports to 292 bcm by 2050. In 2022, the Middle East contributed 96 Mt to global LNG exports, representing 25% of the total global LNG exports. Qatar secured the top position as the leading global LNG exporter, shipping 79 Mt, while Oman and the UAE exported 11 Mt and 5.5 Mt respectively. Notably, Qatar supplied 16% of European LNG imports. However, Europe only represented 24% of Qatar's overall LNG exports, while the principal market for Qatari LNG continued to be Asia, accounting for 72% of the total.

In 2022, the Middle East region imported a total of 6.7 Mt of LNG. Kuwait stood out as the primary importer, accounting for 6 Mt. Meanwhile, the UAE and Jordan were marginal LNG importers. Since 2020, Jordan's gas market has shifted towards relying on regional pipeline gas imports, relegating LNG imports to a supplementary role in fulfilling the country's gas requirements.

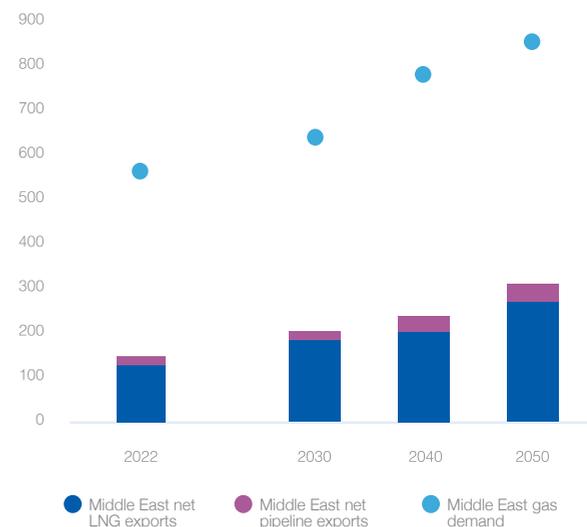
By 2050, LNG exports from the Middle East will reach 205 Mt, largely due to the expansion efforts in Qatar. Anticipated long-term LNG imports are predicted to reach 16 Mt by 2050. Consequently, the long-term outlook suggests an expansion of LNG net exports to reach 189 Mt. Primary destination for Middle Eastern LNG is expected to continue being Asia, with that region set to have an even more significant role in the long run. By 2050, the Asia Pacific region is poised to receive 186 Mt of LNG sourced from the Middle East, constituting over 90% of all LNG exported from that region.

The region possesses 101 Mtpa of liquefaction capacity, primarily dominated by Qatar's 77 Mtpa. Oman accounts for 11 Mtpa and the UAE for 6 Mtpa. Plans are in progress from 2022 to 2050 to add approximately 130 Mtpa of extra LNG liquefaction capacity to the region, with Qatar leading expansion efforts. The utilisation rate of this increased LNG liquefaction capacity is projected to be high, surpassing 90% by 2050. Furthermore, there are plans to consider an extra 1 Mtpa of liquefaction facilities in Oman, along with the prospective development of LNG liquefaction facilities in Iraq post-2030s and in Iran post-2040s. The construction of a new liquefaction facility in the UAE initially planned in Fujairah has been relocated to Ruwais (Abu Dhabi) with a capacity of 9.6 Mtpa. Currently, 33 Mtpa of liquefaction capacity is under construction at Qatar's NFE expansion project. Additionally, there is FEED work underway on the NFS expansion project, which would add a further 16 Mtpa.

Regarding the pipeline trade within the Middle East, the Dolphin gas pipeline stands out as the largest in the region. Linking the North Field in Qatar to the UAE and Oman, this pipeline has a capacity of 33 bcma, operating at around 60% of this level. In 2022, it supplied 18.7 bcm to the UAE and 1.5 bcm to Oman

Figure 6.27.

Middle East natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

Figure 6.28.

Middle East LNG exports (+) by destination and imports (-) outlook by origin, 2022-2050 (Mt)



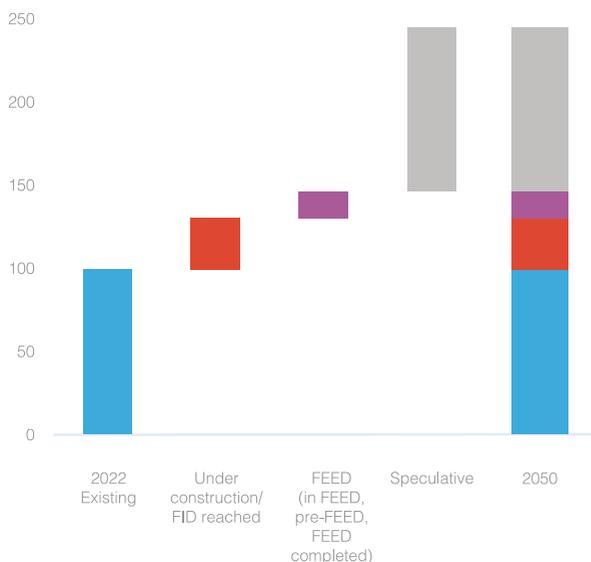
Source: GECF Secretariat based on data from GECF GGM
Note: Regional LNG exports and imports include intraregional trade

under long-term agreements that expire in 2032. Two pipelines transport natural gas from Iran to Iraq, servicing the Baghdad region and the Basra region in the southern part of the latter country. In 2022, Iran utilised export pipelines to send 19 bcm of natural gas, splitting this amount equally between Iraq and Türkiye. Additionally, smaller quantities were directed to Armenia and Azerbaijan. Despite proposed plans for multiple pipelines connecting Iran to Pakistan, Oman and the UAE, advancements have been limited.

The potential for **Qatar's** LNG exports envisions a growth of 2.6 times, reaching 208 Mt by 2050 from the current level of 79 Mt, with pipeline exports reduced from the present 20 bcm. The UAE participates in both the export and import of LNG, alongside pipeline gas imports. In 2022, the UAE exported 7 bcm of LNG and predominantly sourced gas imports from Qatar via the Dolphin gas pipeline, totalling 18.7 bcm. LNG exports are facilitated through the Das Island liquefaction plant situated in Abu Dhabi, possessing an overall capacity of 5.6 Mtpa. By 2050, the UAE is projected to become a net exporter of LNG, with its overall LNG exports expected to reach 13 Mt, starting with an increase from the current 5.5 Mt after 2036.

Figure 6.29.

Middle East LNG liquefaction capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

In the medium and long term, Oman's natural gas trading landscape is expected to be predominantly led by LNG exports. In 2022, Oman exported 11 Mt of LNG, with over 90% of this volume directed to the Asia Pacific region. The country's LNG exports will maintain a steady level of 11 Mt by 2030, gradually declining to 9 Mt by 2040, followed by a further marginal decrease by 2050. Oman operates a solitary LNG liquefaction facility for exports, housed in Qalhat, comprising three units with a combined capacity of 10.4 Mtpa.

Iran possesses immense gas export potential. Last year, it exported roughly 19 bcm of gas through pipelines to Iraq, Türkiye, and to a lesser extent, Armenia and Azerbaijan. Presently, export capabilities have expanded to an average of 25 bcma following the initiation of three significant oil and gas ventures. Iran has contractual agreements to sell 18.3 bcma of natural gas to Iraq, facilitated by two operational gas pipelines connecting Iran to Baghdad and Basra. Iraq relies on Iranian gas for its power generation sector. Since the early 2000s, Iran has also been exporting approximately 8-9 bcma of gas to Türkiye. However, this purchasing agreement is set to expire by 2026.

Iraq as well possesses immense gas export potential but is currently an importer of pipeline gas from Iran in the amount of

9.4 bcm in 2022. In late 2023, Iraq was nearing the completion of a long-pursued deal to import natural gas from Turkmenistan through a swap arrangement involving Iran, effectively bridging the gap between the two countries. The agreement involved the cross-border delivery of about 10 bcma of gas from Iran to Iraq. Simultaneously, a comparable volume is set to be provided by Turkmenistan to the north and northeast regions of Iran. Iraq's gas export prospects are projected to remain constrained, due to limitations in export pipelines and no LNG liquefaction infrastructure in the short to medium term but the country is anticipated to consider starting LNG exports post 2030.

Although **Saudi Arabia** maintains a substantial presence in the global oil market, all of its gas production is currently allocated for domestic use, and there are no immediate intentions or outlined strategies to commence LNG or pipeline exports.

6.5.7 North America

At present, North America is the biggest global consumer of natural gas. While natural gas demand is projected to remain at the level of 2022 only marginally declining by 10 bcm by 2050, there is an anticipated surge in natural gas net exports of the region of 2.5 times between 2022 and 2050, increasing from 102 bcm in 2022 to reach 325 bcm in 2050, primarily driven by the surge in LNG exports, contributing nearly 90% to this growth.

In 2022, North America's total natural gas exports, involving both intra- and inter-regional trade, amounted to approximately 271 bcm. Among these exports, approximately 75 Mt or 38% of the overall natural gas exports were specifically transported as LNG. This LNG solely originated from the United States and was directed toward consumer markets, predominantly targeted at Europe.

The prospects for LNG exports continue to appear promising, supported by a strong portfolio of pre-FID projects, primarily in the United States. The driving force behind this trend is the consistent momentum in contracting activity from both Asian and European buyers who seek secure and predictable gas supply. In 2022, the activity in LNG contracting highlighted a shift toward extended contract durations and a heightened preference for larger-volume contracts.

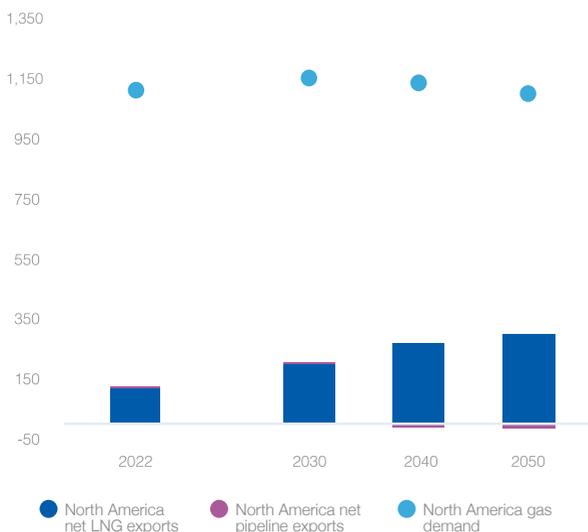
From 2022 to 2050, North America is anticipated to play a pivotal role in driving the global growth of LNG supply. LNG exports from this region are anticipated to experience a rapid surge, outpacing the growth rates of other regions. This surge is expected to culminate in LNG exports reaching approximately 235 Mt of LNG by 2050.

In 2022, all of the 88 Mtpa of LNG liquefaction capacity in North America was located in the United States. It is anticipated that by 2050, roughly 30% of the potential LNG production capacity worldwide is set to come from North America, reaching an approximate total of almost 300 Mtpa (Figure 6.31). The majority of this capacity is expected to be attributed to the United States (230 Mtpa), followed by Canada and to a lesser extent, Mexico. Consequently, the United States is anticipated to spearhead the expansion in global LNG liquefaction capacity and is poised to stay the largest LNG supplier globally from 2023 to 2050.

Canada is a net exporter of natural gas. According to GGO projections, Canada's net exports are forecast to surge from 58 bcm in 2022 to 105 bcm by 2050, thanks mainly to a rapid increase in LNG exports, particularly directed towards the Asia

Figure 6.30.

North America natural gas demand and net exports outlook by flow type, 2022-2050 (bcm)



Source: GECF Secretariat based on data from GECF GGM

Pacific region. Canada's share of LNG exports within the North American market is anticipated to climb to 14% by 2050.

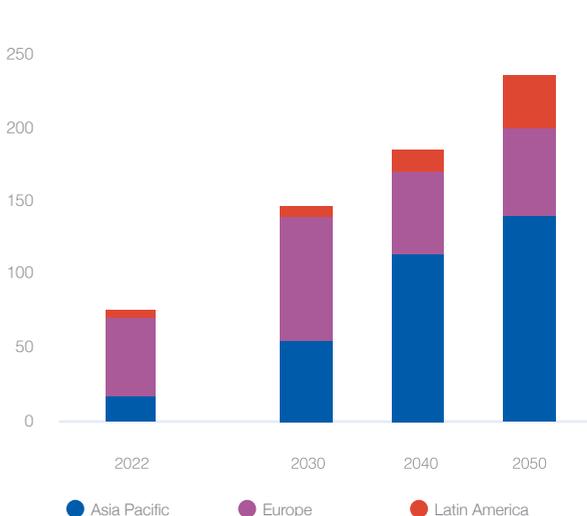
Canada's natural gas market is intricately connected to the United States through an extensive gas transmission network, primarily functioning as a net exporter of natural gas, with the United States as the main recipient. The primary hub for this export is the United States Midwest region, interconnected with Canada via pipelines and featuring substantial gas-fired electric power generation. Canadian exports play a crucial role in managing seasonal consumption variations, especially during the peak demand periods in the United States winter when heating needs surge due to cold temperatures. Natural gas exports to the United States through pipelines will remain nearly unchanged over the forecast horizon, standing at 80 bcm by 2050.

Numerous proposals for LNG export projects emerged along Canada's West Coast and in its eastern regions over the past decade, obtaining export licences. However, as of 2024, only one project, LNG Canada, is actively under construction, while others remain at varying stages of development. LNG Canada is poised to become Canada's inaugural LNG export terminal. Its initial phase, aiming to produce 14 Mtpa is on schedule to commence shipments around 2025. Considering a potential expansion, LNG Canada is contemplating a second phase that might double its capacity to 28 Mtpa by 2035.

Meanwhile, two other projects are awaiting an FID. The advancing LNG liquefaction terminal is Woodfibre LNG, which may receive the FID in 2024 and commence construction. This project is expected to augment LNG export capacity by 2.1 Mtpa upon anticipated completion in 2027. Cedar LNG is the second project aiming to reach an FID in 2024. Envisaged as a floating LNG facility, Cedar LNG anticipates exporting up to 3 Mtpa. Ksi Lisims LNG, a project in northwest Canada with a proposed capacity of 11 entered into the FEED stage in mid-2023 and might become operational by 2027 or 2028.

Figure 6.31.

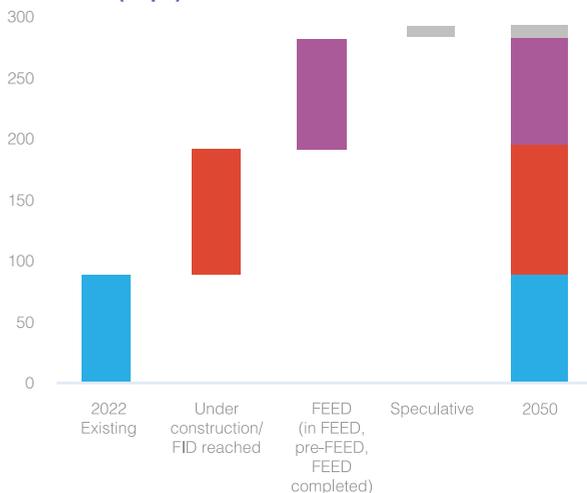
North America LNG exports (+) by destination and imports (-) outlook by origin, 2022-2050 (Mt)



Source: GECF Secretariat based on data from GECF GGM
Note: Regional LNG exports and imports include intraregional trade

Figure 6.32.

North America LNG liquefaction capacity outlook, 2022-2050 (Mtpa)



Source: GECF Secretariat based on data from GECF GGM

Should all four projects move forward, the aggregate export capacity would potentially reach nearly 44 Mtpa by 2035, with an anticipated additional speculative capacity of 9 Mtpa by 2040, elevating Canada's LNG capacity to 53 Mtpa within the projected timeline.

In 2022, Mexico's natural gas trade was confined to importing 59 bcm solely from the United States through an interconnected pipeline network. These imports from the United States via pipelines are expected to surge to 104 bcm by 2050 due to a decline in domestic natural gas production coupled with an anticipated increase in power sector demand and LNG exports.

Mexico is strategically tapping into the burgeoning LNG export potential along its Pacific coast, leveraging the abundance of cost-effective US natural gas resources and well-established infrastructure. This initiative capitalises on the robust expertise within the United States natural gas industry and Mexico's strategic geographic location, offering seamless logistical access to the thriving markets in the Asia Pacific region. With a majority of the United States LNG export terminals clustered along the Gulf of Mexico coast as the West Coast states do not permit any projects, the Mexico Pacific region remains an open opportunity for prospective LNG projects. This places Mexico in an advantageous position within the rapidly expanding LNG export market, particularly as it aims to cater to the burgeoning demands of the Asia Pacific region. The GGO forecast shows that Mexico's LNG exports could exceed 15 Mtpa by 2050, indicating a substantial growth trajectory and underlining the country's potential in the international LNG market.

The pioneering floating LNG (FLNG) hub near Altamira, Tamaulipas, involves three NFE FLNG units. The modular design of the FLNG hub allows for incremental activation and expansion in response to market demands, with up to three 1.4-Mtpa FLNG units to be deployed by 2026. The first unit (1.4 Mtpa) is on schedule to become operational in early 2024 when Mexico is anticipated to join the LNG exporters' group. Energia Costa Azul (ECA) LNG Phase 1 exemplifies this vision, transforming an existing LNG import terminal into a single-train export facility. Anticipated to commence commercial operations in 2025, ECA boasts a nameplate capacity of 3.3 Mtpa. Looking ahead, Phase 2 of ECA, aims for an additional 12 Mtpa.

Saguaro Energia emerges as another significant player, proposing a 14.1 Mtpa LNG export facility at Puerto Libertad in Sonora state. The initial phase involves three trains, each boasting a capacity of 4.7 Mtpa. Commercial operations are slated to kick off in 2026, with the first two trains. The subsequent phase is expected to see the construction of the third train, expected to be operational by 2028.

In the **United States**, the net export of natural gas in 2022 was estimated at 114 bcm, comprising 107 bcm (78 Mtpa) from LNG exports coupled with approximately 90 bcm transported through pipelines to Mexico and Canada, offset by 84 bcm of pipeline imports from Canada. The United States directed 55.2 Mt to Europe, marking a remarkable 148% annual increase, alongside an export of 14.2 Mt to the Asia Pacific region.

In the long-term projection, it is anticipated that the United States net exports will surge to 292 bcm. Natural gas imports, primarily through pipelines from Canada, are set to remain restricted, serving to stabilise the United States power system for peak shaving. Simultaneously, LNG export is expected to grow rapidly, reaching 272 bcm (200 Mtpa). This surge in LNG export is projected to constitute slightly over 70% of the total US natural gas exports by 2050, a significant rise from the approximately 55% observed in 2022.

In the United States, several upcoming LNG projects are on the horizon, with notable ones including Golden Pass and Plaquemines. Golden Pass is scheduled to launch its first 5.2 Mtpa train in 2024, while Plaquemines aims for Phase 1 in 2024 and Phase 2 in 2026, with each phase having a capacity of 10 Mtpa. The Port Arthur project reached an FID for Phase 1 (13 Mtpa) in March 2023. Phase 1 of Port Arthur expects the initial two trains to commence operations in 2027 and 2028,

respectively. Meanwhile, the Rio Grande project reached FID for Phase 1 (17.6 Mtpa) in July 2023, targeting launch dates between 2027 and 2028. Collectively, these FID-approved projects are forecasted to contribute 58.6 Mtpa of additional US LNG export capacity from 2024 to 2028, potentially increasing to 81 Mtpa if an FID is secured for Port Arthur Phase 2 and Rio Grande. The 10 Mtpa expansion of the Corpus Christi liquefaction terminal, approved in June 2022 is expected by late 2025. Expansion of Sabine the Pass terminal, which is currently operating at 30 Mtpa, involves the construction of three more 6.5 Mtpa trains starting in 2025, aiming for gas initiation by 2030 and full capacity by 2032. There are other promising projects in the United States, such as the potential expansion of the Cameron LNG, Calcasieu Pass 2 and Lake Charles. If these projects materialise, they have the potential to add approximately 43.2 Mtpa of US LNG export capacity by the end of the decade, potentially followed by supply from the Sabine Pass expansion in 2030.

The majority of current US LNG contracts extend beyond 2030. Notably, the flexibility of most US LNG contracts is a key feature: approximately 75% are on a free-on-board (FOB) basis, with an additional 13% incorporating a FOB/DES arrangement, leaving only 12% as destination ex ship (DES). This distribution leans approximately 60-40 between end users and re-sellers, providing significant destination flexibility for current US LNG buyers. A closer look at the upcoming 93 Mtpa in contracts for future US LNG supply, effective between 2024 start and 2027 end, reveals intriguing statistics. Among these contracts, 32% of the total are committed to Asian utilities and industrial consumers, while 26% are allocated to European buyers, indicating that 58% of these future supply contracts are designated for end users. Interestingly, even contracts serving these buyers predominantly operate under FOB terms, implying considerable flexibility for redirecting and reselling surplus supplies.



7

Natural Gas Investment Outlook

Highlights

- ▶ The recent energy crisis has instigated a global re-evaluation of energy security, catalysing a remarkable 22% surge in upstream oil and gas investment in 2022. This marks a pivotal reversal after nearly a decade characterised by chronic underinvestment in the sector.
- ▶ The oil and gas industry has undergone profound structural changes in response to the energy crisis. These include heightened price elasticity in both oil and gas demand and supply, an increased sense of risk aversion among investors and a strategic shift towards resilience against low prices.
- ▶ The present global oil and gas supply landscape relies increasingly on short-cycle and brownfield production, notably exemplified by the ongoing prominence of United States shale oil production. This trend, initiated before the COVID-19 pandemic, persists to the present day, shaping the industry's response to evolving market conditions.
- ▶ Cumulative global investment required in the period to 2050 is projected to amount almost USD 9 trillion, with the upstream accounting for USD 8.2 trillion and the midstream for USD 0.7 trillion.
- ▶ Upstream investment in conventional gas assets is expected to account for a substantial USD 5.3 trillion over the forecast period to 2050 while unconventional investments are projected to make up USD 2.8 trillion.
- ▶ Natural gas production in Africa is projected to reach 550 bcm by 2050, necessitating an upstream investment of USD 1.1 trillion.
- ▶ China is anticipated to spearhead upstream investment requirements in the Asia Pacific region, accounting for a substantial USD 650 billion.
- ▶ In Eurasia, investment of USD 1.5 trillion in the gas upstream sector is envisaged to achieve a production forecast of 1,150 bcm by 2050, with a predominant focus on substantial investments in Russia.
- ▶ Out of substantial USD 740 billion opportunity for gas midstream investments projected until 2050, LNG developers are expected to channel more than USD 438 billion towards liquefaction projects. Infrastructure entities are expected to need to invest around USD 230 billion in regasification.
- ▶ The Asia Pacific region is forecast to take the lead in spending on natural gas infrastructure from 2022 to 2050. This region is poised to experience the most substantial investment, reaching nearly USD 205 billion or 28% of the overall global midstream investment.

7.1 Upstream oil and gas investment

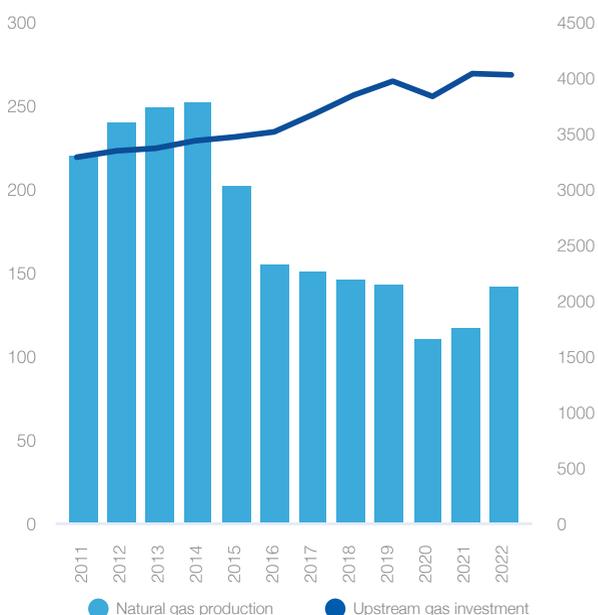
In 2022, there was a significant 22% upsurge in upstream oil and gas investment, marking a reversal after nearly a decade of chronic underinvestment. The trajectory of upstream oil and gas investment since 2014 has underscored the industry’s cyclical nature and the historical pro-cyclicality of oil prices and capital expenditures. However, during the preceding price cycle, the oil and gas sector experienced profound structural changes. Notably, an increased price elasticity in both oil and gas demand and supply leads to more resiliency, coupled with heightened risk aversion among investors. These shifts have reshaped the characteristics of the industry cycle and stand as pivotal factors in predicting future trends in oil and gas upstream investment.

In the aftermath of the 2008 global financial crisis, upstream oil and gas investment witnessed a sustained increase in spending. Many oil and gas companies benefited from accommodating monetary policies and had access to low-cost debt. Consequently, nominal upstream oil and gas investment peaked in 2014, reaching approximately USD 850 billion. However, the highly leveraged oil and gas sector faced a significant challenge when oil prices plunged in 2014. This impacted their operational cash flow and their ability to service the accumulated debt.

In response to this predicament, companies were compelled to make adjustments to their investment strategies and production levels and, in some cases, even sell assets, including rights, facilities and equipment. Concerning production, highly leveraged producers attempted to maintain or even increase output levels despite falling oil prices. This was done to maintain liquidity, meet interest payments, and navigate through tighter credit conditions.

Figure 7.1.

Upstream investment (USD billion) and natural gas production (bcm, RHS), 2011-2022



Source: GECF Secretariat based on data from Rystad Energy

Between 2015 and 2019, the United States shale boom experienced unprecedented growth, exerting deflationary pressure on oil prices and challenging long-term investments in conventional resources. This production surge, driven by increasing negative free cash flow due to outspending in excess of cash flow, was funded through debt and equity markets. In response to escalating debt levels in the pre-COVID era, shale investors and company stakeholders began demanding a shift toward fiscal discipline and returns over production growth. Consequently, investment and production growth started to slow down.

Meanwhile, an elevated focus on resilience to low prices through cost reduction and enhanced operational and capital efficiency prompted oil and gas companies to embrace advanced technologies, notably a wide range of digital solutions, and engage in mergers and acquisitions. Simultaneously, the increased adoption of unconventional drilling techniques across various asset categories, including conventional and deep-water offshore projects, enabled companies to expedite production more efficiently and within shorter development cycles. These structural advancements within the upstream sector, along with a focus on short-cycle and brownfield projects, produced a notable outcome. Although there was a significant decrease in capital expenditure during the prolonged price cycle from 2015 to 2021, oil and gas production did not decline. Notably, natural gas production increased from 3.4 tcm in 2015 to slightly above 4 tcm in 2021 despite experiencing a more than 50% decline in capital expenditure (Figure 7.1). However, it did bring about a structural impact on the oil and gas market by enhancing the price elasticity of the oil and natural gas supply through significant efficiency improvements.

Throughout the same period, notably after the adoption of the Paris Agreement in 2015, concerns surrounding climate change intensified, resulting in increased perceived uncertainties regarding the future demand for oil and gas. The emergence of energy transition risks as a substantial and enduring concern began to shape the risk preferences of investors involved in oil and gas endeavours. Investors started to demand notably higher hurdle rates as a precondition for engaging in long-term oil and gas projects. Moreover, investors applied pressure on oil and gas corporations to curtail their carbon emissions while regulatory standards for new investments in upstream infrastructure became more rigorous. In reaction to these challenges, oil and gas companies restructured their strategies for capital allocation, shifting focus towards decarbonisation and exploring low-carbon alternatives.

Following the demand shock triggered by the COVID-19 pandemic in the oil market, which had multifaceted consequences, including price collapse and a wave of consolidation, oil and gas companies reduced their capital expenditures by a further 28% in 2020 to restore their financial position. This development reinforced the fiscal discipline strategy and significantly diminished the capacity of shale oil producers to respond to oil price fluctuations, leading to amplified market volatility and higher oil and gas prices in the 4Q2021 and beyond.

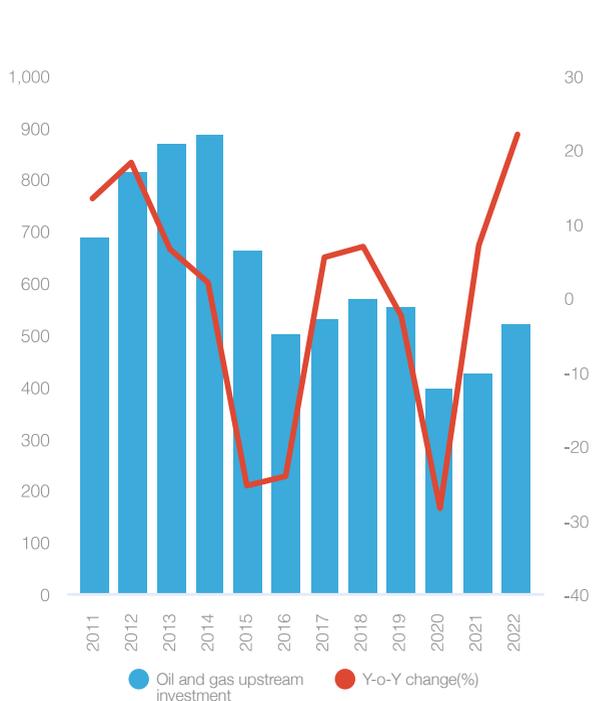
In 2022, the oil and gas industry cycle entered into an upward trajectory, with capital expenditures increasing by 22%, reaching nearly USD 520 billion (Figure 7.2). This growth was driven by higher and more volatile oil and gas prices, resulting in increased profits for oil and gas companies. While part of

this increase was attributed to inflating costs, there was also a noticeable uptick in activity, particularly in North America. Although improvements in capital efficiency achieved over the past decade have reduced the investment required for adequate supply, the rising production costs mean that more expenditures are needed to produce the same volume.

Those profits allow companies to fund investments directly from their operational cash flows. This shift has transformed the principal limitation on investment, moving away from the issue of capital availability, which had been a concern in recent years due to weak cash flows, heavy reliance on external capital, and diminishing interest from investors. As reported by S&P Global, companies continue to possess significant cash reserves even after prioritising the interests of shareholders, conducting share buybacks, and managing debt payments. This situation leads to considerations regarding whether these companies are set

Figure 7.2.

Upstream oil and natural gas investment (USD billion) and annual change (RHS, %), 2011-2022



Source: GECF Secretariat based on data from Rystad Energy

to reinvest their cash reserves and, if so, where they will allocate these funds.

Numerous oil and gas companies are currently facing pressure from their investors to allocate their cash flows toward decarbonisation and diversification initiatives, such as CCUS, hydrogen production and renewable energy ventures, while maintaining strong dividends. Recognising the cyclical nature of the oil and gas industry, which entails unpredictable future profits despite today's earnings, some companies exercise caution to avoid over-commitment or optimistic project economics based on the present business environment.

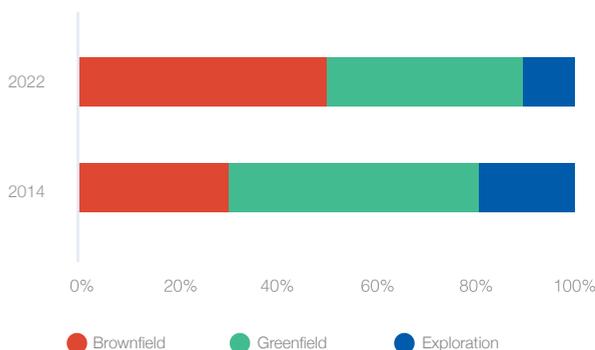
As per data from S&P Global, despite elevated prices, there remains a greater emphasis on small-to-medium scale projects

compared to the initiation of new large-scale greenfield projects in the forthcoming five years. This preference is attributed to the smaller capital requirement, shorter payback periods, and reduced exposure to long-term risks associated with these projects that could become stranded assets later on in the energy transitions.

The current global oil and gas supply has increasingly leaned on short-cycle and brownfield production which began prior to the COVID-19 pandemic period and has continued to the present day (Figure 7.3). This trend has somewhat concealed the repercussions of underinvestment in long-cycle conventional oil and natural gas assets prior to 2020. Furthermore, the larger share of short-cycle production has raised the average annual natural decline rate on a global scale. Consequently, with the decline in the responsiveness of United States shale production

Figure 7.3.

Natural gas upstream investment by type, 2014 and 2022 (%)



Source: GECF Secretariat based on data from Rystad Energy

to oil and gas price increases due to strict fiscal discipline strategies, expediting investments in conventional and long-cycle projects has become imperative for maintaining market stability and mitigating the risk of substantial supply shortages.

It is important to emphasise that the drive for ongoing investment is not solely fuelled by demand-side factors. A consistent flow of investment is necessary to counteract the natural depletion of existing fields. This is particularly relevant considering that, over the medium term, existing fields continue to be the primary source for meeting the ongoing demand for oil and gas, given the commencement of production from current investments.

In a long-term perspective, as indicated by the RCS projections, it is important to emphasise that natural gas supply is anticipated to originate from higher-cost fields throughout the forecast period. Figure 7.4 provides a visual representation of the projected long-term natural gas supply curve for various resource types in both 2030 and 2050.

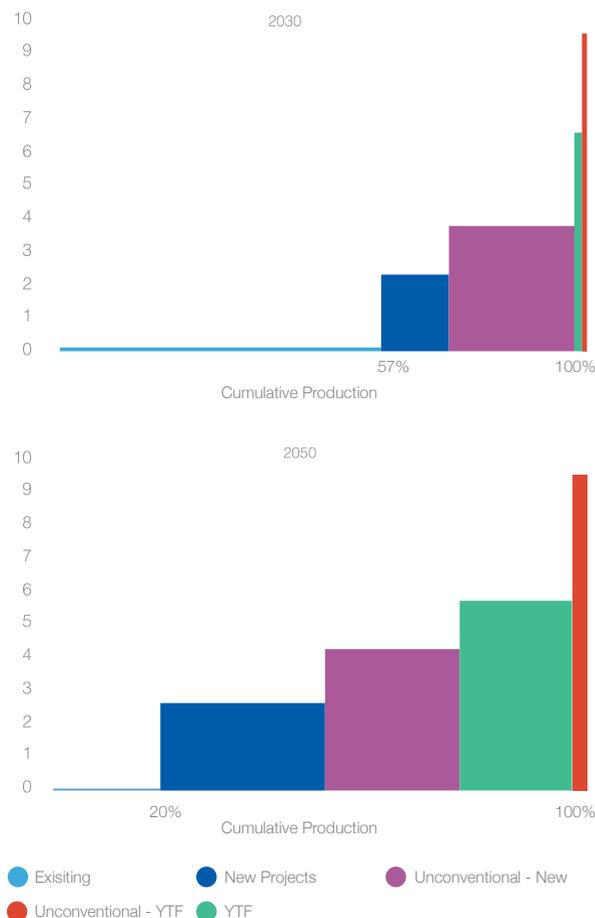
This projected natural gas supply cost curve is expected to shift upwards over the longer term, particularly at the back end of the curve. This underscores the necessity for increased gas production from new long-cycle conventional green field projects together with conventional and unconventional discovered and under-discovery resources with relatively higher costs of production. Furthermore, the declining production from current operational fields is set to necessitate significant

expansion into costlier resources to achieve production growth and compensate for the decline in natural gas production from existing fields.

While current natural gas production predominantly depends highly on existing operational fields (brownfields), their share in meeting overall expected natural gas demand is projected to decrease to 57% by 2030 and approximately 20% by 2050. This underscores the expected shift towards a greater dependence on new projects and Yet to Find (YTF) resources. Consequently, investments in new assets and exploration activities become not only crucial but also of paramount significance in guaranteeing stable and sufficiently supplied

Figure 7.4.

Natural gas supply CAPEX by project type, 2030 and 2050 (USD/1,000 cf)



Source: GECF Secretariat based on data from GGM 2023

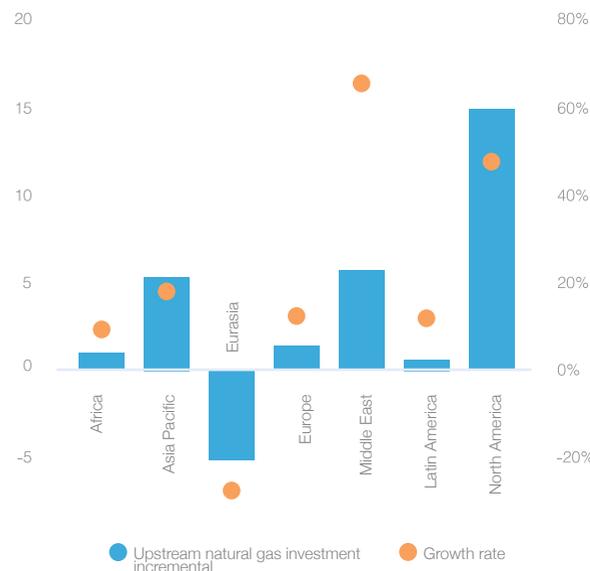
natural gas markets. This suggests that more investment will be necessary not only to offset the natural decline in existing fields but also to tap into more expensive discovered and yet-to-be-discovered assets.

7.1.1. Current development in upstream natural gas investment

In 2022, there was a notable uptick in global natural gas investment, driven by several factors, including heightened

Figure 7.5.

Regional upstream natural gas investment incremental contribution (USD billion) and growth rate (RHS, %) in 2022



Source: GECF Secretariat based on data from Rystad Energy

energy demand, a surge in natural gas prices, and the resulting increase in industry profitability. Specifically, natural gas upstream investment increased USD 24 billion during 2022 and accounted for USD 141.7 billion. This surge in investment was predominantly observed on a regional basis, with Eurasia being the exception.

The growth in global upstream investment was primarily propelled by North America, which contributed the largest incremental growth of USD 14.9 billion. In contrast, the Middle East exhibited the highest growth rate, registering an impressive increase of 64.5%.

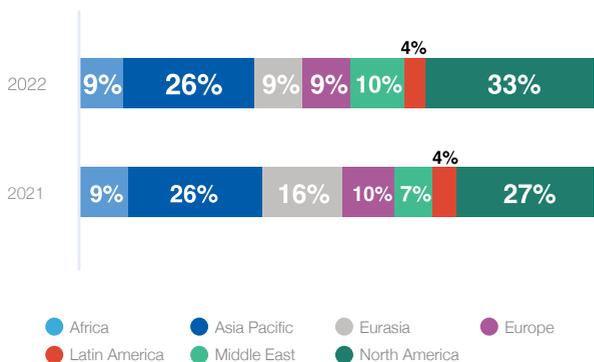
The most significant surge in natural gas upstream investment occurred in North America, where investments soared by USD 14.9 billion, reaching a total of USD 46.5 billion in 2022. This growth represented a substantial increase of 47%. The driving force behind this expansion was the intensified investment in shale gas within the United States, which surged from USD 23.3 billion in 2021 to an impressive USD 35.8 billion in 2022.

Natural gas investment in the Middle East experienced a substantial increase, surging by USD 5.7 billion to reach a total of USD 14.5 billion, marking an impressive growth rate of 64.5%, the highest among all regions. This increase was primarily propelled by Qatar, followed by the UAE, Iran, Saudi Arabia, and Iraq.

In the Asia Pacific region, there was a noteworthy uptick in upstream gas investment, amounting to USD 5.3 billion, resulting in a total of USD 36 billion invested in 2022. This represents a substantial 17% increase in natural gas investment, driven by heightened investment activities in Australia, China, India, and Malaysia.

Figure 7.6.

Regional upstream gas investment share in 2021 and 2022



Source: GECF Secretariat based on data from Rystad Energy

Meanwhile, Europe saw an increase of USD 1.4 billion in natural gas investment, reaching a total of USD 13.2 billion in 2022, reflecting a 12% growth. This growth is primarily attributed to increased upstream gas investment in Türkiye, which experienced a remarkable USD 1.6 billion increase in 2022.

Africa witnessed a USD 1 billion surge in upstream gas investment in 2022, totalling USD 12.1 billion, marking a 9% increase. This increase was primarily propelled by Egypt and Nigeria, followed by Angola and Mauritania.

In Latin America, natural gas investment expanded by USD 600 million, accounting for a total of USD 5.8 billion, indicating a 12% increase. This growth was mainly driven by increased investment in Argentina, Brazil, and Colombia.

However, Eurasia experienced a decline in upstream gas investment, with a decrease of USD 5.2 billion, resulting in a total of USD 13.2 billion in 2022, reflecting a significant 28% decline. This decline was primarily attributed to Russia.

While conventional natural gas investments continue to represent the majority of global upstream investment, the growth rate of investment in unconventional natural gas assets has exceeded that of conventional assets. In 2022, unconventional investments experienced a notable surge, increasing by USD 14 billion, reached USD 43.9 billion. In contrast, conventional assets saw a growth of USD 9.9 billion, reached USD 97.8 billion. This translates to a remarkable growth rate of 47% for unconventional assets, whereas conventional investments recorded a growth of 11%. Consequently, unconventional resources accounted for 31% of global upstream gas investment in 2022, a notable increase from the 25% share in 2021 (Figure 7.7).

The surge in upstream gas investment in unconventional assets was primarily concentrated in North America, primarily driven by the United States, which contributed to 74% of the total growth. Other noteworthy contributors included China, Canada, and Argentina.

On the other hand, upstream investment in conventional assets was more evenly distributed among various regions and countries. Growth in this category was propelled by Australia, Qatar, the United States, Türkiye, Egypt, and the UAE.

Figure 7.7.

Natural gas upstream investment in 2021 and 2022 (billion USD)



Source: GECF Secretariat based on data from Rystad Energy

While conventional natural gas investments continue to represent the majority of global upstream investment, the growth rate of investment in unconventional natural gas assets has exceeded that of conventional assets. In 2022, unconventional investments experienced a notable surge, increasing by USD 14 billion, reached USD 43.9 billion. In contrast, conventional assets saw a growth of USD 9.9 billion, reached USD 97.8 billion. This translates to a remarkable growth rate of 47% for unconventional assets, whereas conventional investments recorded a growth of 11%. Consequently, unconventional resources accounted for 31% of global upstream gas investment in 2022, a notable increase from the 25% share in 2021 (Figure 7.7).

The surge in upstream gas investment in unconventional assets was primarily concentrated in North America, primarily driven by the United States, which contributed to 74% of the total growth. Other noteworthy contributors included China, Canada, and Argentina.

On the other hand, upstream investment in conventional assets was more evenly distributed among various regions and countries. Growth in this category was propelled by Australia, Qatar, the United States, Türkiye, Egypt, and the UAE.

Investment in onshore natural gas assets witnessed a greater incremental growth compared to offshore assets. In 2022, upstream investment in onshore natural gas assets accounted

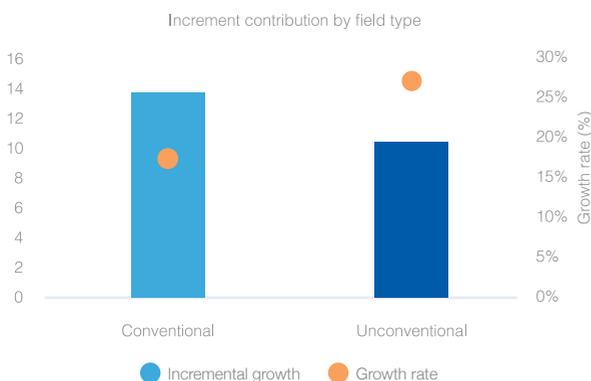
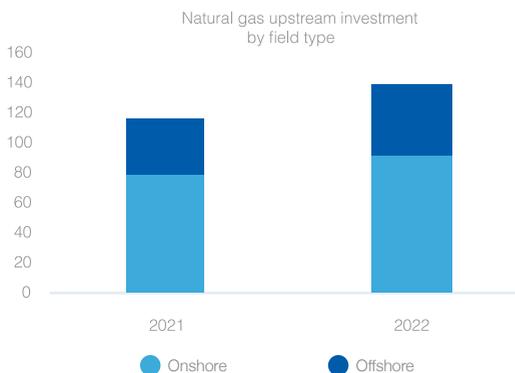
for USD 93 billion compared to USD 48.7 billion for offshore investments. However, it is noteworthy that investment in offshore assets exhibited a higher growth rate. In 2022, upstream investment in onshore gas assets increased by USD 13.6 billion, while offshore assets saw an increase of USD 10.3 billion. Nevertheless, the growth rate for investment in offshore assets was higher, reaching 27%, in contrast to the 17% growth seen in onshore gas investment (Figure 7.8).

The upswing in upstream gas investment in onshore assets was primarily propelled by countries such as the United States, Canada, Australia, China, Nigeria, and Qatar, among others. Conversely, offshore investment was mainly driven by Türkiye, Australia, Qatar, Egypt, India, and Iran.

Investment in onshore natural gas assets witnessed a greater incremental growth compared to offshore assets. In 2022, upstream investment in onshore natural gas assets accounted for USD 93 billion compared to USD 48.7 billion for offshore investments. However, it is noteworthy that investment in offshore assets exhibited a higher growth rate. In 2022, upstream investment in onshore gas assets increased by USD 13.6 billion, while offshore assets saw an increase of USD 10.3 billion. Nevertheless, the growth rate for investment in offshore assets was higher, reaching 27%, in contrast to the 17% growth seen in onshore gas investment (Figure 7.8).

Figure 7.8.

Natural gas upstream investment in 2021 and 2022 (billion USD)



Source: GECF Secretariat based on data from Rystad Energy

The upswing in upstream gas investment in onshore assets was primarily propelled by countries such as the United States, Canada, Australia, China, Nigeria, and Qatar, among others. Conversely, offshore investment was mainly driven by Türkiye, Australia, Qatar, Egypt, India, and Iran.

7.1.2. Global upstream gas investment requirement

Global gas production is anticipated to reach 5.3 tcm by the year 2050. Achieving this substantial growth in gas supply will necessitate sustained investment across all segments of the natural gas value chain. The natural gas sector is expected to require USD 9 trillion of investments along the value chain. The total upstream global investment required is projected to amount to USD 8.2 trillion.

The lion's share of gas investments is expected to be allocated to conventional assets, accounting for USD 5.3 trillion (Figure 7.9). In contrast, unconventional investments are projected to make up USD 2.8 trillion, representing 34% of the total global upstream gas investment.

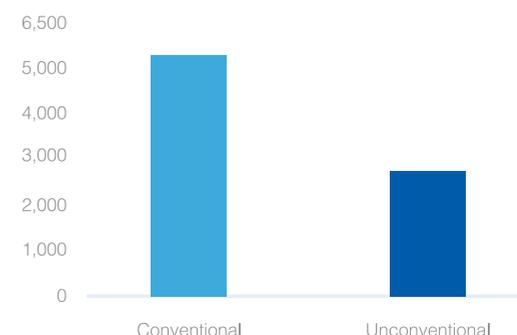
Natural gas investment exhibits regional disparities in distribution. In that order, leading the way in upstream investment are the Asia Pacific and North America, followed by Eurasia, Africa, the Middle East, Latin America and Europe.

Eurasia, the Asia Pacific and Africa are projected to account for 70% of the total upstream investment in natural gas. Conversely, North America and the Asia Pacific are anticipated to be at the forefront, requiring 77% of the global upstream investment in unconventional assets.

The differences in required capital expenditure across regions can be attributed in part to factors like the type of hydrocarbon, location, and project type of natural gas supply. Globally, the projected rise in natural gas supply is anticipated to primarily come from non-associated conventional hydrocarbons located in offshore and YTF fields. However, the degree of this transition varies from region to region. As a result, the capital expenditure necessary for each unit of marginal production varies across these regions. This divergence is likely to impact the allocation of invested funds and consequently influence natural gas prices.

Figure 7.9.

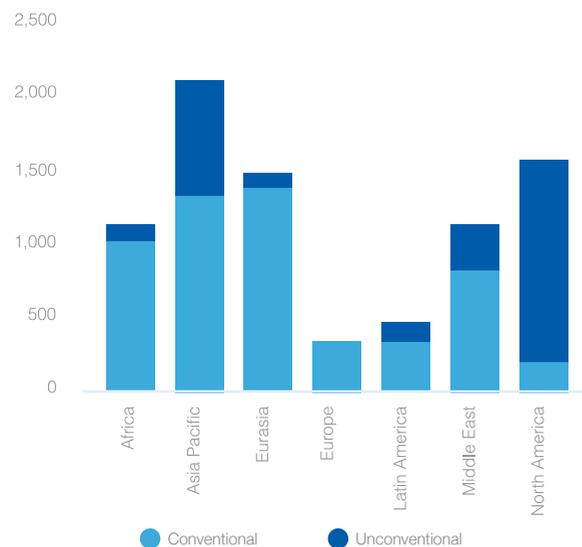
Natural gas global cumulative upstream CAPEX required by reservoir type, 2023-2050 (real billion USD base=2022)



Source: GECF Secretariat based on data from Rystad Energy

Figure 7.10.

Upstream natural gas CAPEX required, 2023-2050, (real billion USD base=2022)



Source: GECF Secretariat based on data from Rystad Energy

7.1.3. Regional upstream gas investment requirement

7.1.3.1 Africa

Natural gas production in Africa is poised for remarkable growth, with the region projected to achieve the fastest annual gas production growth rate of 2.8%. By 2050, natural gas production is expected to reach 550 bcm from the 254 bcm recorded in 2022. The growth in natural gas production is set to primarily be fuelled by the expansion of offshore production, which accounts for 28% in 2022 and is projected to reach 73% by 2050.

The region is forecast to require USD 1.1 trillion upstream investment. Algeria, Egypt, Mozambique and Nigeria are projected to account for 88% of this amount.

Egypt is poised to lead investment requirements in Africa considering the shift of its production structure towards offshore by 2050, mainly through the development of the Nile Cone basin. In the medium term, Egypt is planning investments of USD 1.2 billion in new gas exploration in the Mediterranean Sea and the Nile Delta.

Nigeria is set for a huge development in its natural gas investment, building on its huge reserves of 5.9 tcm. Together with support to international companies through policy instruments, including the Petroleum Industry Act, Nigeria is positioned to experience a surge in its natural upstream investment. Nigerian National Petroleum Corporation (NNPC) expects the country to experience an increase in oil and gas investment estimated at USD 20 billion, including at the Agbami gas project and the Bonga North, Owowo, Preowei and Ubeta developments.

Mauritania and Senegal are set to build their gas boom with the planned development of BirAllah gas offshore Mauritania, which is planned to start production by 2029, and the Yakaar-Teranga project offshore Senegal, with first gas estimated in 2027.

Tanzania in Eastern Africa is set for a huge investment in its Tanzania LNG project estimated at USD 42 billion, with the project aiming to export 10 to 15 bcm annually.

A newcomer on the gas production front is **South Africa**, in which USD 3 billion is estimated to be invested in developing Luiperd and Brulpadda fields.

In Africa, the majority of upstream investment is expected to be in conventional gas resources, accounting for 90% of upstream capital expenditure required in the region except for Algeria, where the development of the Franian shale in the Timimoun basin is factored in.

7.1.3.2 Asia Pacific

The Asia Pacific region is poised for substantial growth in its natural gas production over the coming decades. The outlook foresees a continued upward trajectory in natural gas production, with the region projected to reach 760 bcm by 2050. This marks an additional increase of 110 bcm from the 2022 levels.

The region is projected to require USD 2.1 trillion of upstream capital investment to achieve this production profile by 2050. China, Australia, Indonesia and India are anticipated to account for 80% of the investment required in the upstream gas sector. China is expected to lead in the investment requirement in the region, accounting for USD 650 billion, to achieve a production level of 360 bcm by 2050. Upstream investment in gas unconventional reservoirs is projected to account for 37% of the total gas upstream investment in Asia Pacific. China is expected to lead unconventional investment in the region, standing at USD 470 billion, followed by Indonesia.

Australia experienced a surge in upstream capital investment in natural gas, with a 44% increase in 2022 to USD 10 billion, with the majority being driven by investment in conventional resources. Australia is expected to witness USD 3.6 billion to develop the offshore Barossa giant gas field development, with start-up expected in 2025. In addition, investments were allocated to develop Gorgon Stage Two, in which additional drilling and offshore production pipelines and subsea structures were to be installed to maintain gas supply to Barrow Island processing facilities. By 2050, Australia is expected to require an upstream capital investment of USD 515 billion.

China experienced an 18% increase in its upstream capital investment in its natural gas resources, which stood at USD 12.6 billion in 2022. The growth in investment was driven by unconventional resources that experienced a growth of USD 1.4 billion, equivalent to 30%, compared to conventional gas resources that experienced 9% growth. Driven by energy security and diversity concerns, China is poised to keep developing its natural gas resources over the long term. China will develop the South China Sea's Pearl River Mouth basin as well as intensify exploration and the competitiveness of its upstream sector. Over the long term to 2050, China is expected

to require USD 650 billion of upstream gas investment to develop its gas production to 360 bcm, driven by spending on the Ordos, Bohai Gulf, Sichuan, and Tarim basins.

Indonesia is increasing investments in upstream exploration. In support of exploration efforts, the Indonesian government has conducted exploration surveys and regional studies, including at the Spermonde, Northeast Java, and the South Makassar basins. These initiatives helped identify significant prospects, improved access to data and provided more attractive fiscal incentives. According to Rystad Energy, Indonesia expects exploration activity to increase, with an average of 100 wells expected to be drilled annually, driven by an increase in exploration expenditure, which is expected to account for 20% of total annual capital investments in the country from 2025. The outlook projects Indonesia to require USD 370 billion of upstream gas investment by 2050 to achieve a gas production target of 80 bcm by 2050.

7.1.3.3 Eurasia

Despite the decline in natural gas production in 2022, the outlook anticipates an increase in production from the current 835 bcm in 2022 with a significant upswing in natural gas production, particularly beyond the current decade, with the region expected to reach 1,150 bcm by 2050. This represents a substantial additional gain of 330 bcm, signifying a noteworthy growth trajectory. The region is projected to require USD 1.5 trillion in the gas upstream sector to achieve this production forecast. Most of the investment in the region is expected to be required in Russia, which is forecast to account for 70% of the upstream gas investment in the region. The majority of the investment is anticipated to be directed towards developing the following: Yamal, Yenisey-Khatanga, and West Siberian Central Bazhenov.

As the region is characterised by huge conventional basins, the majority of investments are poised to be directed toward conventional assets, accounting for 93%. Investment in unconventional assets is to develop the Lensky, Rapsadskaya Dnieper-Donets and Carpathian Foreland basins.

Upstream capital investment in gas resources in **Russia** decreased by USD 4.7 billion in 2022 and recorded USD 8.6 billion, driven by the impacts of the geopolitical situation in Eastern Europe. However, investment in offshore gas resources experienced an increase of 60% and accounted for USD 1.27 billion in 2022, driven by the Kamennomyskoye offshore project in West Siberia, the Kaliningradmorneft offshore project in the Baltic basin and the Ledovoye project in the Southern Barents basin. By 2050, Russia is expected to reach a production level of 900 bcm at an estimated upstream capital of USD 600 billion.

7.1.3.4 Europe

Despite the uptick in natural gas production in 2022, the European upstream oil and gas sector is grappling with growing maturity and diminishing investment in upstream activities. Projections paint a challenging outlook, suggesting that Europe's natural gas production is set to continue to dwindle in the years to come, plummeting to 88 bcm by 2050. Consequently, Europe's share of the global natural gas production pie is expected to contract from 5% in 2022 to a mere 1.6% by 2050.

Considering this production gas production outlook for the region, the region is forecasted to require USD 330 billion to

achieve this gas production forecast. Norway, the UK, Türkiye, and Romania are projected to account for the majority of upstream gas investment, accounting for 93% of the total capital investment in the region. All the investment in the upstream gas sector in the region is anticipated to be towards conventional assets.

Norway experienced a decline of upstream capital investment in gas by 5.8% after an increase of 18% in 2021. To protect against overall production decline, Norway offered 92 blocks for oil and gas exploration in 2023 in the Barents Sea, which is estimated to hold two-thirds of the YTF resources in the country, and the Norwegian Sea. Successful exploration and development of natural gas resources are key to Norway's long-term gas production outlook. The outlook expects Norway to require a capital investment in the upstream gas sector of USD 190 billion along the forecast period to 2050.

Türkiye experienced a huge development in its natural gas investment in 2022. The upstream gas investment increased by USD 1.6 billion and recorded USD 2.3 billion in 2022, driven mainly by the first phase of the Sakarya project in the Black Sea. Over the long term, Türkiye is expected to reach a gas production of 13 bcm at an upstream capital investment of USD 8.7 billion.

7.1.3.5 Latin America

Natural gas production in the region is expected to reach 225 bcm by 2050, representing an increase of approximately 65 bcm. Throughout the forecast period, Latin America is projected to maintain its 4% share of global natural gas production. Notably, Argentina, Brazil, and Venezuela are expected to contribute significantly, accounting for 80% of gas production in Latin America. The region is forecasted to require USD 455 billion to achieve this gas production growth. Argentina, Brazil, Venezuela and Trinidad and Tobago are expected to account for 74% of the total region's investment.

The majority of investment in the region is set to be directed toward conventional gas assets, while unconventional assets are anticipated to account for 28% of the total upstream gas investment in the region. All unconventional investments in the region are projected to be in Argentina, specifically in Vaca Muerta and Neuquen basins.

Argentina witnessed an investment increase in its upstream sector, increasing by USD 0.6 billion in 2022, a 29% increase from the 2021 level, driven by unconventional gas resources in Vaca Muerta. The outlook projects Argentina to grow its natural resources to reach 80 bcm in 2050 at a capital investment in the upstream gas sector of USD 170 billion.

7.1.3.6 Middle East

The Middle East region holds substantial natural gas reserves and significant potential for further production growth. Looking ahead to 2050, the outlook anticipates a significant surge in natural gas production, with the region projected to reach 1,165 bcm by 2050. This additional increase of 480 bcm is expected to elevate the region's share in global natural gas production to 21% by 2050, up from its 17% share in 2022.

The region is forecast to require USD 1.1 trillion to achieve this production growth. Iran, Qatar, Saudi Arabia, and the UAE are poised to account for 87% of the gas upstream required investment in the region. Saudi Arabia is forecast to require the largest share of investment in the upstream gas sector in the region, accounting for 30% of total investment in the region,

followed by the UAE, Iran and Qatar at 25%, 16% and 14%, respectively.

The majority of upstream investments are expected to be directed toward conventional gas reservoirs, while unconventional assets are anticipated to require 28% of the investment in the region, specifically in the UAE, Saudi Arabia, and Oman.

In 2022, **Qatar's** upstream capital investment witnessed a remarkable doubling, reflecting an increase of USD 2.2 billion. This surge can be attributed to two substantial expansions within the world's largest natural gas field, the North Field. The outlook considers the initiation of both the North Field East and North Field South expansions, slated for 2026 and 2028, respectively. These expansions are anticipated to propel Qatar's production to 310 bcm in 2050, requiring a total upstream investment of USD 160 billion.

In 2022, **Saudi Arabia** experienced an increase of USD 0.7 billion in upstream gas investments driven by conventional resources and, to a lesser extent, unconventional resources. Conventional resources accounted for 85% of the investment growth, and unconventional resources accounted for 15%. The outlook expects Saudi Arabia to require USD 330 billion of upstream capital investment in natural gas resources to develop its resources and achieve a production level of 145 bcm in 2050.

The **UAE** experienced an increase of USD 0.8 billion in upstream gas investments in 2022 driven by conventional resources. The country is projected to require USD 280 billion of investments in the upstream sector of natural gas to reach a gas production level of 80 bcm. This outlook factors into developing unconventional fields, including the Ruwais Diyab unconventional gas.

7.1.3.7 North America

The region is poised to remain the largest natural gas producer by 2050. Over the past decade, natural gas production in North America has witnessed a remarkable 43% increase, surging from 860 bcm to 1,230 bcm. Looking ahead, the outlook foresees a continued upward trajectory in natural gas production, with the region projected to reach 1,400 bcm by 2050, representing an additional increase of 170 bcm.

To achieve this gas production forecast, the region is projected to require USD 1.6 trillion of upstream investment in the natural gas sector. The United States is forecasted to lead the investment requirement in the region with USD 677 billion, closely followed by Canada at USD 630 billion.

Investment projections for all regions indicate a focus on conventional gas assets, with North America being the notable exception. In North America, the majority of upstream investments are directed towards unconventional gas assets, representing a significant 88% of the region's required investment.

7.2 Midstream natural gas investment

Investments in natural gas midstream are expected to surge to USD 740 billion between 2022 and 2050, propelled by increased global demand for LNG. Europe is anticipated to experience significant LNG demand growth in the coming decade, while the Asia Pacific region is expected to sustain elevated LNG appetite in the longer term.

Although a substantial portion of the investment will be directed towards capital-intensive natural gas upstream activities, the midstream sector, encompassing pipelines and facilities for LNG liquefaction and LNG regasification, will primarily see a focus on expanding liquefaction capacity.

Of the USD 740 billion earmarked for midstream investment from 2022 to 2050, 60% of this amount, totalling USD 438 billion, is anticipated to be directed towards the development of LNG liquefaction infrastructure. An allocation of USD 230 billion might be dedicated to LNG regasification infrastructure, leaving the remaining USD 72 billion designated for the construction of gas export pipelines.

While navigating through the complexities of 2023 and beyond, the natural gas sector is expected to maintain its enduring significance, playing a pivotal role in the expanding global energy market. Until 2050, fossil fuels are projected to dominate energy usage due to substantial prior investments and their superior energy density and reliability.

The persistent lack of adequate investment or the shortfall in natural gas supply is a primary factor driving the global energy crisis. Such a deficit also represents the most significant risk to global energy security in the times ahead.

Global natural gas's long-term investment direction is shaped by two critical factors: energy security and the evolving landscape of energy transitions. Energy security ensures a stable and reasonably priced natural gas supply to the market, necessitating investment in midstream gas projects with lengthy development phases. Conversely, the changing landscape of energy transitions introduces greater uncertainties in investments in natural gas infrastructure. This means that what seems economically feasible presently might risk profitability in the future due to evolving energy dynamics.

The natural gas midstream industry at a global level appears to be undergoing a period of change, encompassing shifts in its growth patterns, investment cycles, methods of capital acquisition and the fluctuating levels of competition within the business. The challenges and opportunities within this sector frequently vary based on specific regions, thus necessitating region-specific strategies to effectively navigate and thrive in this evolving environment.

Most of the investments are expected to prioritise the capital-intensive natural gas upstream sector. However, within the midstream sector encompassing pipelines, LNG liquefaction, and LNG regasification facilities, the bulk of spending is set to focus on expanding liquefaction capacity.

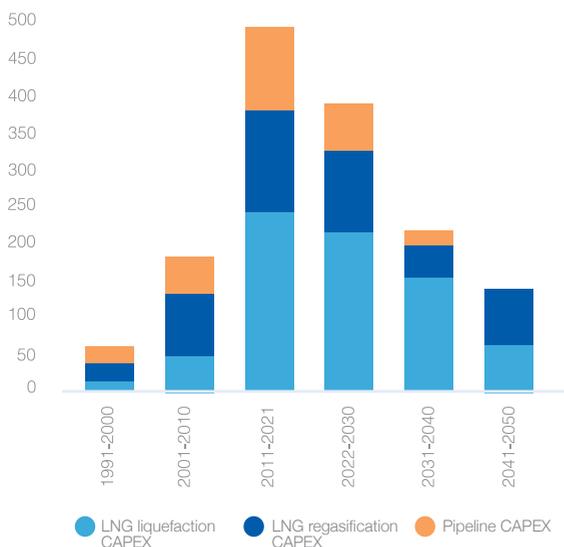
7.2.1 Historical background and current trends

In 2022, global oil and gas producers witnessed exceptional profitability due to soaring revenues driven by elevated fuel prices. The net income derived from fossil fuel sales more than doubled compared to the typical averages of recent years, collectively earning approximately USD 4 trillion for the oil and gas industry.

Increased spending plans have been announced by numerous major oil and gas companies due to record revenues. However, concerns about long-term demand uncertainties, rising costs and the emphasis from investors and owners on prioritising returns over production growth have resulted in only the large national oil companies in the Middle East significantly increasing their spending on long-cycle green fields in 2023 compared to 2022.

Figure 7.11.

Historical and future global outlook of midstream investment (real billion USD, base year = 2022)



Source: GECF Secretariat based on data from Rystad Energy

Decreased Russian gas shipments to Europe have led to a surge in investments across the continent for the expansion of LNG infrastructure in 2022. The trend is expected to persist, necessitating more substantial investments in onshore LNG regasification terminals to ensure consistent LNG provisions from global gas producers in the foreseeable future. However, the primary infrastructure for receiving natural gas in Europe is projected to be finalised by the 2030s. FSRUs (floating storage regasification units) are supposed to be a short-term solution.

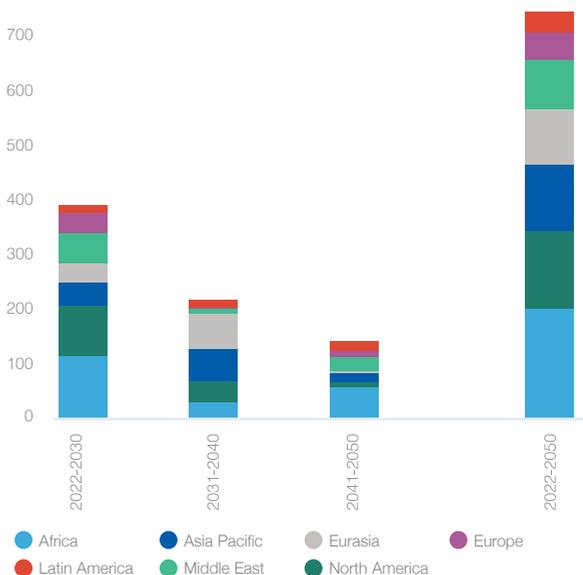
Despite the rise in European LNG demand, developing markets in Asia are expected to remain the primary recipients of global LNG supplies until 2050. As Asia diminishes its reliance on coal, the demand for and investment in LNG infrastructure is anticipated to continue to ascend after the 2030s in the long run. According to the RCS, China is poised to lead the surge in LNG demand, while South and Southeast Asia are anticipated to follow suit. The Southeast Asia region is set to swiftly transition into a net importer of LNG. This transition occurs as conventional LNG-producing regions such as Indonesia and Malaysia reach maturity and aspiring importers such as the Philippines and Viet Nam enter the market.

In 2022, investment in oil and gas midstream reached USD 294 billion, significantly rising from the lower levels experienced due to COVID in 2020, which were at USD 225 billion. Anticipations for 2023 suggest a continuation of this upward trend, projecting an increase to USD 307 billion, surpassing the pre-COVID figures of USD 277 billion observed in 2019.

On one side, elevated energy and gas prices are anticipated to persist in 2024 in stimulating investment in natural gas midstream. On the other side, gas midstream projects might encounter cost pressures due to constrained markets for services and labour, along with escalated raw material expenses.

Figure 7.12.

Global midstream CAPEX outlook by region, 2022-2050 (real billion USD, base year = 2022)



Source: GECF Secretariat based on data from Rystad Energy

In 2022, there was a remarkable surge in capital expenditures within the global gas midstream sector, surpassing USD 80 billion, which stands as a notable increase compared to the average annual expenditure of USD 60 billion over the previous five years (2017-2021). Notably, North America and Qatar experienced the most significant spike. The escalation in spending is attributed to both heightened costs due to inflation and increased operational activity. Costs surged between 15 to 20% in 2022, and further increases are estimated in 2023.

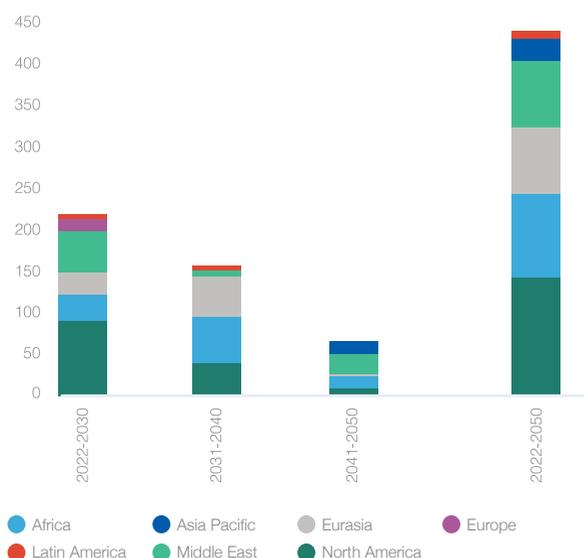
There is a substantial USD 740 billion opportunity for gas midstream investments projected until 2050. Considerable investments are crucial to facilitate the anticipated growth across the complete value chain.

Increased demand for LNG globally, especially in Europe in the coming years, alongside a sustained high interest in LNG in the Asia Pacific region over the long run, is anticipated to serve as significant factors propelling the industry forward. LNG developers are expected to channel around USD 438 billion towards liquefaction projects to support supply expansion. Infrastructure entities are expected to need to invest around USD 230 billion in regasification. The scale of this opportunity is vast, with the primary risk being concerns related to energy transition boundaries.

The periods spanning from the 2010s to the 2020s are poised to be regarded as the 'golden' era for midstream investment, especially in the realm of LNG infrastructure investment. However, there is an anticipated substantial decline in expenditure, both in terms of supply and demand, post-2030. GECF member countries, notably Qatar and Russia, in addition to non-GECF countries such as Australia and the United States, have been pivotal in propelling significant expansion in liquefaction investment over the last thirty years.

Figure 7.13.

Global LNG liquefaction CAPEX outlook by region, 2022-2050 (real billion USD, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

The cumulative global midstream capital expenditure surged by almost eight times, escalating from the 1991-2000 decade to the 2011-2021 period, reaching USD 490 billion. Predictions indicate that global midstream capital expenditure will remain elevated, stabilising at USD 386 billion from 2022 to 2030. However, a swift decline is anticipated in the period between 2041 and 2050, dropping to a level 2.8 times lower than that of 2022 to 2030.

Between 2022 and 2050, the larger share of midstream investment, amounting to 60%, is expected to be directed towards LNG liquefaction capital expenditure on a global scale. Concurrently, pipeline capital expenditure is anticipated to steadily decrease from constituting 10% of the overall gas midstream investment in 2022-2030 to reaching zero between 2041 and 2050.

A streak of unprecedented investment activities has occurred, yet worldwide competition and a growing emphasis on cleaner energy sources are starting to catch up. In 2023, there have been approvals for the construction of over 36 Mtpa of new export capacity, marking the United States's highest-ever sanctioned volume. The gas shortage experienced last year notably compelled European importers to escalate their LNG acquisitions from America. This surge in demand attracted investor attention in the United States. However, the opportunity for further United States LNG projects is diminishing. As Europe hastens its transition to using more LNG in its energy mix, there is a parallel effort to reduce reliance on fossil fuels by 2030, aligning with more ambitious 'green' European objectives.

Qatar is expeditiously aiming to sell the LNG generated from its substantial USD 30 billion North Field Expansion, implying upstream development and LNG liquefaction infrastructure. The announcement from Qatar entails a planned 64% surge in LNG

production by 2027.

The investment in pipelines is expected to decrease due to ample existing capacity and decreasing capital costs, aided by technological advancements. The completion of spending on major pipelines such as TurkStream, Power of Siberia, South Caucasus Pipeline, and TANAP, as well as upgrades in the North American pipeline network, contribute to this trend.

Investment in FSRUs across Europe and the rise of floating LNG (FLNG), especially in Africa, are on the ascent. The adoption of floating technology introduces flexibility and enhances the potential for continued growth in the LNG industry. A crucial factor contributing to this growth is the decreased development time. Moreover, FLNG and FSRU capacities are more economically efficient. Additionally, there are evident environmental advantages, as they enable the storage of natural gas without the need for expensive, time-consuming onshore construction.

FIDs for new liquefaction capacities experienced a decline in 2022, but there is an anticipation of an upsurge in FIDs in the near future to cater to the robust growth in LNG demand in the medium term. The liquefaction capacities that obtained FID in 2022 decreased to 34 Mtpa, down from 52 Mtpa in 2021, with the United States accounting for over two-thirds of these capacities. Other contributors included Suriname, Congo, Canada, and Malaysia. However, in 2024, there is an ambitious target of nearly 60 Mtpa of new liquefaction capacities seeking FID, predominantly led by the United States, alongside Qatar, Mexico and the UAE. This surge is underpinned by substantial LNG contracts secured over the past couple of years and the expectations of a constrained LNG market until the middle of this decade.

Continued investment in liquefaction facilities is anticipated, primarily focusing on North America (the United States and Canada), specific liquefaction projects in the Middle East (such as the Qatari LNG expansion), Africa (Mozambique, Mauritania/Senegal, Nigeria) and Eurasia (Russia). However, the outlook for new liquefaction projects in Asia appears limited, as the easily accessible LNG resources in that region, primarily based off the Australian coast and Papua New Guinea (PNG), have largely been tapped into in recent years.

Approximately USD 217 billion of the total expected liquefaction investments of USD 438 billion by 2050 are projected to be allocated between 2022 and 2030. Ensuring timely execution will be essential for project developers, considering that this decade (2022-2030) will require 3.3 times more funding compared to the 2041-2050.

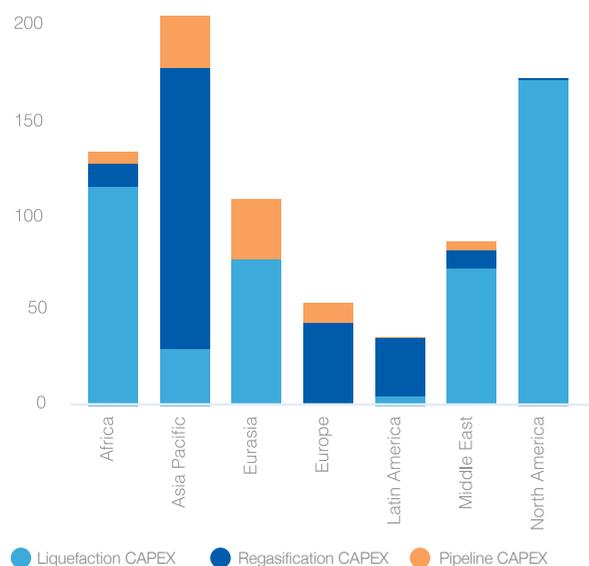
7.2.2 Midstream natural gas investment by region

Investment in midstream natural gas infrastructure varies significantly across regions due to differences in geography, resource availability, regulatory frameworks, and market demands (Figure 7.14).

There is a noticeable uptick in investments directed at LNG infrastructure, particularly in Asia Pacific, North America and Africa, owing to the heightened global demand. Simultaneously, there is a focus on the modernisation and expansion of current pipeline networks to adapt to shifting supply dynamics and facilitate the integration of renewable gases. Moreover, there is

Figure 7.14.

Midstream natural gas investment outlook by region, 2022-2050 (real billion USD, base year = 2022)



Source: GECF Secretariat based on data from the GECF GGM

a growing emphasis on environmentally sustainable practices, exemplified by the adoption of carbon capture, utilisation and storage (CCS) technologies.

7.2.2.1 Africa

African midstream investment is set to be propelled by new ventures in Mozambique, Tanzania, Mauritania, Nigeria, Egypt and Senegal, with varying degrees of impact. The projected expenditure is estimated to reach USD 120 billion, with approximately half of this sum anticipated to be invested in the 2030s. Distribution of funds is predicted as follows: roughly USD 43 billion in the current decade (2022-2030), around USD 60 billion in the subsequent decade (2031-2040), and approximately USD 17 billion in the period between 2041 and 2050.

By the mid or late 2030s, Mozambique is poised to become the largest LNG exporter in Africa, maintaining this position through to 2050. Mozambique joined the league of LNG producers in November 2022, marking the departure of the first LNG shipment from the Coral Sul FLNG facility situated offshore Mozambique. This facility represents the first-ever deployment of a floating LNG facility in the deep waters of the African continent.

The initial phase involves the Coral field development through the Coral Sul FLNG unit, with an FID worth USD 7 billion made in 2017. The subsequent phase of Coral Sul FLNG is projected to encompass the development of Mamba South, and the production from a two-train onshore LNG facility is expected to commence by the end of this decade.

By 2030, Mozambique is anticipated to have three primary LNG projects with a collective LNG export capacity surpassing 30 Mtpa. Alongside the Coral Sul LNG, the country's first onshore LNG project, the USD 20 billion Mozambique LNG, with a total capacity of around 12.9 Mtpa, and the USD 30 billion Rovuma LNG project, with a combined capacity of 15.2 Mtpa, are significant contributors to this capacity deployment.

7.2.2.2 Asia Pacific

The Asia Pacific region is forecasted to take the lead in spending on natural gas infrastructure from 2022 to 2050. This area is poised to experience the most substantial investment, reaching nearly USD 203 billion or 28% of the overall global midstream investment. Approximately 73% of this investment is anticipated to be directed toward LNG regasification infrastructure, underscoring the increasing demand for LNG in this region.

Additionally, the Asia Pacific region is set to uphold its position as the foremost long-term importer of LNG. This is propelled by the region's rapid economic expansion and escalating demand for cleaner energy sources, a need that cannot be met solely through domestic natural gas production.

The investment landscape for global LNG regasification in the Asia Pacific region is undergoing a shift away from traditional markets like Japan, South Korea and Chinese Taipei. Instead, it is gravitating towards newer markets such as China, India and developing nations in South and Southeast Asia. These regions are actively expanding their regasification capabilities. China and India are anticipated to be the top global LNG importers by 2050, investing significantly in regasification facilities. India has even unveiled a draft LNG policy aiming to more than double its regasification capacity to 100 Mtpa by 2040.

The Southeast Asia region is forecasted to transition from being a net gas exporter to a net importer in the long run. This transformation is propelled by the region's escalating demand for natural gas, driven by economic growth, urbanisation and improved living standards. Increased industrial activities and electricity needs in the region are anticipated to contribute to the surge in gas demand. In the long run, Malaysia and Indonesia are expected to transition from being net LNG exporters to net importers as their domestic gas demand surpasses their supply capacities.

Australia has witnessed substantial growth in LNG exports over the past decades, boasting a total LNG liquefaction capacity of 88 Mtpa and LNG exports of 79 Mtpa in 2022. However, in the long term, Australia does not plan to expand its existing LNG liquefaction capacity. Maintaining its current level of LNG exports by 2050 might pose challenges as the country aims to phase out most of its coal-fired plants by 2030. Moreover, domestic natural gas demand is projected to rise as a balancing factor in transitioning from coal to renewable energy sources.

Nevertheless, there are inherent risks associated with the development of natural gas imports and related infrastructure in Asia. Firstly, South and Southeast Asian gas markets are highly sensitive to prices, and the affordability of gas in these regions heavily relies on future natural gas prices. Secondly, major developing Asian countries such as China, India, and leading ASEAN member countries have committed to achieving net-zero emissions, placing added pressure on gas demand in the long run. China aims to peak its CO₂ emissions before 2030 and achieve carbon neutrality by 2060, while India targets carbon neutrality by 2070. Consequently, given their substantial consumption of thermal coal globally, these countries are expected to need to expedite their transition and clean air policies, promoting the shift from coal and oil to gas across various sectors.

Long-term LNG purchasing agreements, typically linked to oil prices and spanning 15-20 years, serve as a mutual alignment of interests between producers and customers. These agreements provide producers with a degree of certainty regarding the

recovery of significant initial investments in projects, ensuring a reliable and secure supply for many importers across Asia.

7.2.2.3 Eurasia

Eurasia's midstream infrastructure might undergo a substantial transformation with the introduction of several key regional export pipelines and further LNG expansion in Russia. The projected gas midstream expenditure is estimated to reach almost USD 102 billion.

Firstly, the Power of Siberia 2 pipeline can transport 50 bcma from West Siberia's fields to China. If operational post-2030, Power of Siberia 2 holds the potential to significantly increase Russian gas supplies to Asia, possibly matching the levels supplied to the EU.

Secondly, the Central Asia-China pipeline corridor is presently operating near its maximum capacity of 55 bcm annually. There is potential for expansion up to 85 bcma by constructing Line D, originating from Turkmenistan through Uzbekistan, Tajikistan, and Kyrgyzstan, and linking to China.

Thirdly, the TAPI pipeline aimed at providing gas to Afghanistan and Pakistan (5 and 14 bcma, respectively), besides India, could significantly contribute to the region's gas resources.

One of Russia's primary strategic objectives involves diversifying the nation's natural gas exports, gradually shifting the focus away from Western markets towards the swiftly expanding markets in the South and East Asia. Russia initiated gas supply to Asia in 2009, delivering around 38 bcm of gas to the region in 2022 using both LNG and the Power of Siberia pipeline. This contrasts with the European market, which typically imports between 160 and 200 bcm from Russia.

Gas projects located in areas such as the Yamal Peninsula, the Arctic, East Siberia and the Far East are anticipated to notably boost Russian gas production and exports by the year 2050.

The Russian LNG sector commenced its evolution in 2013 when the government identified LNG expansion as a significant investment and commercial priority, opening opportunities for third-party involvement. Novatek has been at the forefront of Russian LNG advancement, successfully launching its Yamal LNG project within schedule and budget. This endeavour secured the largest-ever project financing in Russia. If Russia effectively manages technological and financing hurdles, it is poised to secure the third position among global LNG producers by 2050.

Russia's objective was to secure a 20% share of the global LNG market by 2035, intending to increase its annual LNG production from the current approximate output of 32 to 120-140 Mtpa. However, EU and United States sanctions targeting essential equipment required for enhancing gas production (liquefaction) might pose limitations to these aspirations. This obstacle could potentially be mitigated by replacing Western technologies with Russian proprietary technologies developed over time, as well as exploring alternative sources from Asian countries such as China.

7.2.2.4 Europe

Europe is projected to invest approximately USD 52 billion in regasification infrastructure throughout the forecast period, with an estimated over two-thirds of this funding anticipated to be allocated before 2030.

Over the past decade, the EU has committed substantial investments in LNG infrastructure, resulting in more than 20 large-scale operational terminals integrated into the grid, as well as additional terminals currently under construction.

A key objective of the EU's energy union strategy involves ensuring that all member countries have access to liquid gas markets, with LNG positioned at the core of this strategy. The EU aims to elevate LNG imports and expand existing regasification capacities while addressing the bottlenecks within the current gas infrastructure. European governments have swiftly initiated the installation of new regasification capacity, particularly through the rapid deployment of FSRUs in the initial phase. By 2025, Europe is anticipated to add between 60 Mtpa and 80 Mtpa of capacity, deriving growth from both new projects and expansions of existing terminals.

New regasification terminals in Europe are expected to primarily be situated in Germany, with a projected 47 Mtpa capacity, including 20 Mtpa from FSRUs (totalling 65 bcma by 2027). Italy plans for 7 Mtpa, all from FSRUs (exceeding 10 bcma by 2027), and Greece aims for 7.3 Mtpa, incorporating 3.3 Mtpa from FSRUs (amounting to 10.1 bcma by 2027).

Following 2030, minimal to negligible investment is expected in natural gas midstream infrastructure in Europe, notably within the EU. This trajectory aligns with the EU's steadfast dedication to the ambitious energy transitions and its strengthened interim objectives for 2030, targeting a 55% reduction in GHGs.

7.2.2.5 Latin America

Regasification is slated to take precedence in Latin America, with projected regional gas midstream investments reaching USD 33 billion by 2050. Key importers in the region include Brazil, Chile and the Caribbean region. Brazil boasts the largest LNG regasification capacity in the region. Also, Brazilian requirements exhibit high seasonality.

Approximately 50 Mtpa of LNG regasification capacity currently exists in the region, with an additional 26 Mtpa under construction and a further 76 Mtpa potentially planned for development in countries such as Brazil, Chile, Colombia, the Dominican Republic, El Salvador, Bahamas, Nicaragua, and other locations during the forecast period.

In Latin America, factors such as uncertainties surrounding domestic production, geopolitical challenges, and the accessibility of abundant United States LNG are expected to diminish the necessity for export pipelines, although domestic networks are slated for expansion.

With Trinidad and Tobago and Peru serving as the continent's primary LNG exporters, only Argentina has anticipations for expanding LNG liquefaction capacity in the foreseeable future.

7.2.2.6 Middle East

The projected gas midstream expenditure is estimated to reach around USD 89 billion, with the bulk of this sum anticipated to be invested into the LNG liquefaction infrastructure.

For numerous decades, Qatar has been a prominent exporter of LNG to global markets, especially in Asia. Qatar's North Field East (NFE) and North Field South (NFS) expansions are poised to augment liquefaction capacity by 48 Mtpa, supplementing the existing 77 Mtpa of LNG liquefaction capacity. The total estimated cost for these expansions is anticipated to reach

USD 50 billion. Qatar has set an objective to elevate LNG export capacity to 126 Mtpa by 2028.

The Middle East region is anticipated to witness limited pipeline expansion, as several proposed projects aiming to connect producing countries (Cyprus, Egypt, and Israel) with both regional consumers (Jordan, Lebanon) and external markets (Greece, Italy, Türkiye) are unlikely to materialise.

7.2.2.7 North America

The projected gas midstream expenditure is estimated to reach almost USD 143 billion, with almost all of this sum anticipated to be invested into the LNG liquefaction infrastructure.

The global energy crisis has created opportunities for United States LNG exporters to position themselves within a potential ‘third wave’ of projects aiming to finalise investment decisions in the upcoming years. The third wave of new United States LNG projects could potentially increase the capacity by 70-190 Mtpa by 2030, propelling the United States significantly ahead as the leading global LNG supplier. However, challenges in securing finance arise due to cost inflation and heightened competition in the industry. Heightened by record prices and the imperative for energy security, there is substantial momentum building behind United States LNG projects.

These projects might witness investments exceeding USD 90 billion by the decade's end. Anticipated investments amounting to three-quarters of the total are projected to be allocated to projects before the final investment decision (pre-FID). The majority of pre-FID project developers are presently in the process of securing external financing for these investments. Typically, project financing is expected to cover approximately 60-80% of the necessary capital, while the remaining portion is set to be financed through equity raises or from the balance sheet.

With exports reaching 75.4 Mt in 2022, the United States ranked third globally in LNG exports, trailing behind Australia and Qatar. However, once operations recommenced at the Freeport liquefaction facility in March, the United States surpassed Australia and Qatar and became the world's foremost exporter of LNG in the first six months of 2023.

In recent years, FIDs have been made for four new projects in the United States, namely a USD 10 billion Golden Pass LNG, Plaquemines LNG Phase 1, Corpus Christi Stage 3, New Fortress Energy's Louisiana Fast LNG project. Collectively, these projects are anticipated to add nearly 45 Mtpa of new capacity in the United States starting from 2024. Potentially, a wave of new FIDs might even further significantly expand the capacity in the near future.



8

Sustainable Energy Scenario

Highlights

- ▶ Navigating the dual objectives of transitioning to lower-carbon energy systems for climate change mitigation and fostering sustainable socio-economic development is a complex endeavour, fraught with complexities, interdependencies and trade-offs.
- ▶ There is no universal solution in the energy landscape that can independently realise the ambitious sustainable development goals and tackle climate change. Instead, achieving these objectives requires a harmonious integration of diverse energy sources and technologies.
- ▶ The Sustainable Energy Scenario (SES) emerges as a promising pathway, highlighting the key role of natural gas in a multifaceted approach, simultaneously combatting energy poverty, driving economic prosperity and contributing to environmental protection at the local level (air pollution reduction) and the global level (climate change mitigation).
- ▶ Global primary energy consumption projections in SES is set for substantial growth, increasing by 23% between 2022 and 2050, ultimately reaching to 18,478 Mtoe, exceeding the RCS by 555 Mtoe by 2050.
- ▶ In the SES framework, natural gas assumes a crucial role, overtaking both oil and coal, constituting 29% share of the global energy mix by 2050. Its demand is primed for robust expansion, surging to 6,210 bcm by 2050, a remarkable 55% increase over the forecast period, exceeding RCS projections by 21 p.p.
- ▶ Natural gas significantly reshapes the global power generation mix in the SES, contributing approximately 26% by 2050. This transformation is underpinned by substantial demand growth, with estimates indicating an increase of 921 bcm, reaching 2,303 bcm by 2050, a substantial variation compared with RCS forecasts.
- ▶ The Asia Pacific region emerges as a primary driver of natural gas demand growth in the SES, led by a significant shift from coal to natural gas in the power generation sector. It surpasses RCS estimates by a hefty 405 bcm.
- ▶ Blue hydrogen, derived from natural gas, increases from a negligible presence in 2022, to a substantial 147.5 MtH₂ by 2050, exceeding RCS projections by approximately 90 MtH₂, and contributing nearly 40% to global hydrogen generation.
- ▶ Despite the anticipated expansion of the energy system, and significant strides towards sustainable development goals, especially in ensuring universal access to affordable, reliable and sustainable modern energy, the SES forecasts energy-related emissions to decline to 22.6 GtCO₂e by 2050. This figure significantly undercuts RCS scenarios, denoting a 42% reduction from 2022 levels, while RCS anticipates a more modest 18% decline in emissions.
- ▶ The accelerated upscaling of CCUS emerges as the primary driver for emissions abatement within SES. These technologies, designed to mitigate emissions arising from energy combustion, are set to make substantial contributions, with emissions savings projected to escalate from 12 MtCO₂e in 2022 to 7.5 GtCO₂e by 2050 in the SES—a significant contrast to the 1.7 GtCO₂e projected by RCS.

8.1 Introduction

Energy serves as the fundamental force that propels and sustains our daily lives, playing a central role in both driving economic development and promoting social progress while fostering environmental sustainability.

It is paramount to recognise that majority of the UN SDGs is tied to the widespread availability of modern energy services. Yet, despite the significance of energy in our modern world, a noteworthy 2.3 billion people, equivalent to nearly one-third of the global population, still rely on traditional energy sources such as wood and charcoal to meet their essential needs for cooking and heating. Furthermore, an estimated 700 million individuals are faced with the harsh reality of living without access to electricity, limiting their opportunities for growth and development.

To effectively address the issue of energy poverty, it becomes paramount to expedite economic growth and empower individuals residing in economically disadvantaged countries. This multifaceted approach not only equips the people of these countries with the resources necessary to satisfy their fundamental requirements, encompassing nutrition, housing, healthcare, and education, but also fosters a sense of security, thereby reducing the likelihood of them slipping back into the relentless cycle of poverty.

Remarkably, the pursuit of economic empowerment and the eradication of energy poverty generate a heightened demand for energy. This phenomenon gains even more significance when considering the projected population growth in low-income countries, predominantly in regions such as Sub-Saharan Africa and the developing Asia Pacific, within the foreseeable future. Nonetheless, this surge in energy consumption brings forth a concerning negative externality – a worsening of GHGs that contribute to global warming.

Navigating the transition to a low-carbon energy system in order to mitigate climate change, while simultaneously promoting sustainable socio-economic development for an expanding global population, represents a dual objective laden with intricacies and tensions that must be managed. One of the immediate challenges involves addressing the impending gap between energy supply and demand, which necessitates the utilisation of various energy sources. It is crucial to recognise that how this gap is bridged is far from neutral or inconsequential.

While renewable energy sources have witnessed rapid growth and gained substantial market share, particularly in the power sector, these alternative low-carbon solutions have not yet reached a level of maturity sufficient to fully bridge the anticipated gap between supply and demand. This stems from a multitude of well-known factors, including technological readiness, the development of necessary infrastructure, notably grids, and potential bottlenecks within the supply chain.

In reality, there is no universally applicable energy source or technology that can independently fulfil the goals of sustainable development and climate change. The shift toward a clean energy system and a carbon-neutral economy necessitates the seamless integration of a multitude of energy sources and technologies. Moreover, it is crucial to acknowledge the existence of various pathways toward attaining a clean energy future. Therefore, it is more fitting to consider energy transitions rather than prescribing a singular, rigid energy

transition pathway for the global community. Energy pathways are nationally determined, in the light of national circumstances, capabilities, and priorities.

The future of energy thus remains remarkably uncertain. While the imperative of combatting climate change and the ensuing necessity of transitioning to a low-carbon energy system are undeniable, the challenges of widespread poverty and population growth in low-income countries emphasise the need to prioritise energy affordability and energy security. However, the composition of the energy mix in the decades ahead appears considerably indeterminate. This uncertainty arises primarily because accurately projecting the maturation, commercialisation, and extensive deployment of alternative technologies remains a challenge.

In light of these objectives and challenges, this Chapter endeavours to investigate an alternative and feasible energy pathway. This trajectory places a strong emphasis on the urgent need for an accelerated transformation within energy systems, highlighting an orderly, equitable, and just approach to energy transitions. This approach recognises the central importance of energy security, lends support to sustainable development initiatives, and plays an active role in tackling energy poverty. Furthermore, it underscores the presence of substantial financial resources and advanced technology, with special attention given to ensuring accessibility in developing countries.

This Chapter specifically presents an alternative scenario along with the outlook presented in the RCS. The alternative scenario, Sustainable Energy Scenario (SES), in the 8th edition of the GGO, builds upon the combination of last edition's alternative scenarios. In the previous edition, the Energy Sustainability Scenario (ESS) underscored the role of natural gas in promoting sustainable development and tackling energy poverty in Africa. Concurrently, the Accelerated Energy Decarbonisation Scenario (AEDS) demonstrated the potential of natural gas in facilitating the decarbonisation of energy systems through a pragmatic transition approach.

In the current edition, drawing from the experience of the previous year, we have developed a unified alternative scenario that highlights the potential growing role of natural gas in simultaneously addressing energy poverty eradication, fostering economic prosperity, and contributing to environmental protection by decarbonising energy systems. By integrating these aspects into a single alternative scenario, our objective is to emphasise the multifaceted benefits of natural gas. This includes its pivotal role in achieving sustainable development, ensuring access to affordable energy, driving economic growth, and aligning with environmental objectives through the reduction of carbon emissions.

8.2 SES assumptions

The development of the SES is shaped by a synergy between sustainable development goals and climate change mitigation efforts—two interconnected facets of a holistic strategy. The realisation of climate change objectives hinges on providing residents with adequate energy access to meet the UN SDGs and ensuring climate change mitigation strategies. As of the UN mid-journey assessment report released in 2023, progress towards the 2030 targets is off track. However, the SES envisions a transformative shift in the energy landscape, aiming to facilitate widespread access to energy, thereby enhancing living standards. This is coupled with the strategic application of technologies and implementing policies to effectively address

and reduce emissions, aligning with the intertwined goals of sustainable development and climate change.

8.2.1 Per capita GDP assumptions

One of the primary objectives of the SES is to achieve UN SDGs by 2050, with a particular focus on eradicating energy poverty. In this context, when we define the comprehensive Sustainable Development Goals as the collective progress towards ensuring universal access to health and wellbeing, quality education, affordable basic necessities, and the creation of sustainable communities, it becomes apparent that tackling extreme poverty levels, as defined by the World Bank, requires supplementary benchmarks to measure progress beyond this threshold.

The concept of economic empowerment, which is defined as achieving a minimum acceptable standard of living that includes access to nutrition, education, healthcare, housing, clean water, sanitation, and energy, serves as a relevant benchmark in this context. Empowerment embodies the aspirations encapsulated in the SDGs and begins with a baseline that lifts individuals beyond the point where they are at an extreme risk of falling back into poverty. Research conducted by McKinsey Global Institute (2023) suggests that this baseline is set at USD 12 per person per day in terms of PPP for the year 2017. This threshold also aligns with the poverty lines introduced by the World Bank specifically for upper-middle-income countries.

Within the SES framework, it is assumed that the list of low and lower-middle-income countries in 2022 will progress to reach the empowerment level or the upper-middle-income poverty line by the year 2050. This assumption is based on the cumulative impact of long-term annual growth rates that, on average, surpass those of the RCS by approximately 0.3 p.p. This higher rate of growth is significant enough to elevate global GDP levels within this scenario by approximately USD 12 trillion by 2050. A substantial portion of this growth is anticipated to take place in regions such as Sub-Saharan Africa and the developing Asia Pacific, which concurrently face challenges related to the lack of access to modern energy.

8.2.2 Power sector assumptions

On a global scale, the SES scenario entails a transition away from unabated coal in power generation, towards a mix of natural gas and renewables, taking into account regional circumstances. The objective is to mitigate emissions from the power sector and improve energy efficiency. In the Asia Pacific, where coal dependency has been prevalent, there is a deliberate effort to swiftly phase out unabated coal use. The momentum for coal-to-gas switching is anticipated to accelerate from 2030 onward, resulting in a substantial reduction in carbon emissions and a significant enhancement in energy efficiency. This transition, coupled with the integration of solar and wind power, aligns seamlessly with the sustainability and climate objectives set forth in the SES framework.

The SES has a fundamental objective to establish a stable, reliable, and cost-effective electricity supply that can meet both base and peak load demands. Achieving this objective necessitates a strategic utilisation of diverse energy sources, each possessing unique dispatch capabilities to cater to the varying needs of the electricity grid, irrespective of the time of day or prevailing weather conditions. This approach involves adjusting the LCOE calculations to account for intermittency

and the need for backup from dispatchable energy sources, with a particular emphasis on natural gas to provide real-time balance in power systems.

8.2.3. Rapid low-carbon hydrogen adoption assumptions

The SES scenario envisions a substantial increase in the use of low-carbon hydrogen within the industrial sector, setting the timeline for this transformative shift to commence from the year 2030. This strategic move is targeted at regions with significant industrial activities, recognising the potential of low-carbon hydrogen to serve as a cleaner alternative fuel. The SES assumes increased use of low-carbon hydrogen, particularly in Europe, North America and the Asia Pacific. By introducing hydrogen into industrial processes and other final energy sectors, these regions aim to reduce carbon emissions associated with their manufacturing and production activities, aligning with global efforts to transition towards more sustainable and environmentally friendly industrial practices.

8.2.4 Residential segment assumptions

The SES prioritises transforming Africa's residential energy sector to achieve UN SDG7, focusing on modern energy access. This includes reducing reliance on traditional biomass for cooking, while introducing cleaner and more efficient options such as natural gas, LPG, and renewables. This transition not only improves indoor air quality and reduces mortality from indoor pollution but also enhances cooking efficiency, freeing up time for education and career pursuits, thus empowering individuals and communities. Furthermore, the SES accounts for the growing efficiency of dual-purpose heat pumps in residential heating and cooling segments of Europe and North America. This shift toward electric heat pumps replacing standalone boilers in some regions is incorporated into the scenario to reflect observed policy trends.

8.2.5 Accelerated CCUS upscaling assumptions

In the SES scenario, a pivotal strategy for mitigating emissions involves accelerated upscaling CCUS technologies to capture emissions from various high-emission sectors, including iron and steel, mining, chemical industries, and power generation. This ambitious initiative is anticipated to gain its significant applications from 2030, signifying a concerted effort to curb emissions from industries with historically significant carbon footprints. The scenario envisions a gradual and sustained progression in the adoption of CCUS technologies, with the ultimate goal of capturing the absolute majority (approximately 90%) of emissions from the industrial sector by the year 2050.

Specifically addressing power generation, the SES scenario outlines a crucial aspect of its emissions reduction strategy. The scenario assumes that newly constructed power generation capacities, intended to replace unabated coal-fired generation, are set to be equipped with CCUS technologies. This forward-looking approach emphasises the importance of integrating CCUS into the core infrastructure of power generation facilities as a prerequisite for ensuring cleaner and more sustainable energy production. By strategically incorporating CCUS into the development of new power generation capacities, the SES scenario aims to contribute to the reduction of carbon emissions associated with power generation, thereby aligning with global climate targets and sustainable development goals.

8.3. SES results

8.3.1 Primary energy demand

In the context of the SES and the RCS, the projected size of the energy system in 2050 is expected to be influenced by contrasting factors. These divergent drivers are primarily shaped by economic and efficiency considerations. Firstly, the anticipated increase in income (GDP per capita) among countries burdened by energy poverty, is expected to lead to a notable upsurge in global primary energy consumption when compared to the RCS. This boost is aimed at improving the quality of life for those affected by energy poverty, gradually attaining empowerment. Conversely, strategic measures focused on improving energy efficiency, primarily through fuel-switching strategies such as transitioning from coal to natural gas in power generation, and replacing traditional biomass with piped gas and LPG in specific residential segments, are set to reshape the overall size of the energy system. These initiatives are designed to minimise energy wastage and reduce the environmental footprint associated with energy production and consumption.

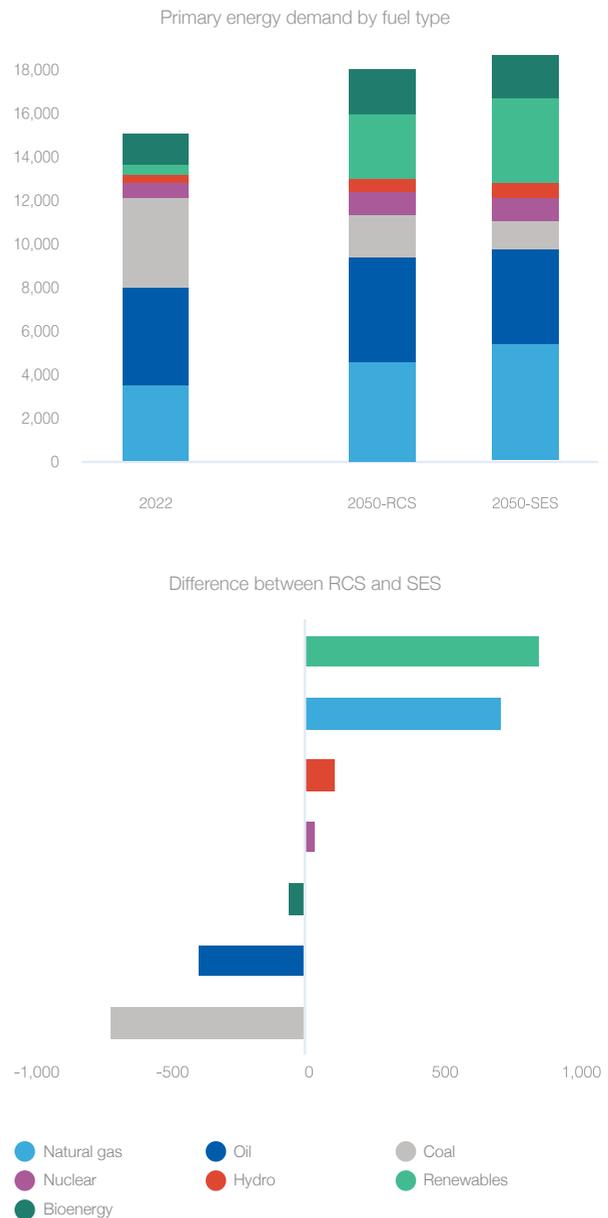
Taking into consideration these factors, the projected global primary energy consumption in the SES for the year 2050 is expected to grow by nearly 3,400 Mtoe between 2022 and 2050, reaching a total of 18,478 Mtoe. This represents a significant 23% increase compared to the 2022 levels, as compared with the 20% increase projected in the RCS (Figure 8.1). The global primary energy demand in the SES by 2050 exceeds the RCS by 555 Mtoe. Consequently, considering the assumption that GDP per capita is set to rise at a higher rate compared to the RCS, resulting in a subsequent relative increase in global primary energy consumption, the energy intensity improvement based on PPP terms in the SES is projected to be 2.4% p.a. This is slightly lower compared to the 2.5% p.a. improvement projected in the RCS for the period from 2022 to 2050.

These findings emphasise the connection between economic activity and global energy consumption at global scale. As we strive to achieve inclusive and sustainable development goals while meeting climate change targets, it becomes apparent that this pursuit anticipates an increased demand for energy. Attempting to entirely decouple energy use from economic activity on a global scale through improved energy efficiency alone may not be realistic. Although, the results obtained demonstrate that energy efficiency is set to weaken the tie between energy consumption and economic expansion, going forward.

Here, it is crucial to emphasise that improvements in energy efficiency do not necessarily translate to reduced energy consumption. In many instances, gains in energy efficiency have been utilised not to decrease energy usage, but rather to enhance comfort, especially in the case of vehicle fleets. Furthermore, a phenomenon known as the rebound effect comes into play, where increased energy efficiency results in lower energy expenses, subsequently leading to higher energy consumption. For example, enhancing home insulation makes heating more cost-effective, often resulting in higher indoor temperatures while not necessarily reducing overall energy consumption, as much as expected in theory. This phenomenon is particularly significant for low-income households struggling with energy poverty. The benefits derived from energy efficiency improvements, such as transitioning from traditional biomass to natural gas or LPG, are expected to lead to additional energy-intensive expenditures to improve quality of life.

Figure 8.1.

Global primary energy demand outlook in SES and RCS (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

8.3.1.1 Global energy mix

Building upon our previous section, it is important to highlight that the assumptions underpinning the SES not only lead to an expansion of the energy system size, but also induce a significant transformation in the composition of energy sources. The dynamics of this transformation involve a combination of substitutions and partnership among different energy sources. These are all rooted in practical considerations such as affordability, reliability, and sustainability criteria. Particularly noteworthy is the prevalence of substitutions, where

natural gas, recognised as the cleanest hydrocarbon, often replaces coal and oil in various applications. Concurrently, complementary relationships emerge between renewable energy sources and natural gas, particularly within the power sector. The rapid expansion of low-carbon hydrogen and the accelerated adoption of CCUS play a crucial role in exhibiting the variations in the demand for different energy sources within the SES, in contrast to the RCS.

In the SES, the total consumption of **fossil fuels** in 2050 is expected to stabilise in 2040 but decline thereafter to about 10,915 Mtoe. This fossil fuel demand in the SES scenario is 395 Mtoe lower compared to the RCS in 2050. This shift in consumption patterns is attributed to a significant reduction in coal consumption combined with a slight decline in oil usage within the SES. Conversely, natural gas is projected to witness substantial growth in the SES. This expected substitutive trend for natural gas, coal, and oil within the fossil fuel category primarily focused from initiatives aimed at transitioning to energy sources characterised by higher energy efficiency and lower carbon intensity. Additionally, the accelerated expansion of CCUS and low-carbon hydrogen technologies plays a key role in mitigating the carbon footprint of hydrocarbons and decarbonising the energy system in the SES. Consequently, the proportion of fossil fuels in the overall energy mix is projected to decrease to 58% in the SES scenario, a notable shift down from the 63% observed in the RCS.

In the SES, there is a significant surge in **natural gas** demand, particularly within the power sector of developing countries. Natural gas demand in this scenario is projected to increase by almost 1,880 Mtoe, reaching 5,310 Mtoe by 2050, marking nearly a 16% increase compared to the RCS. This growth is notable, with a 55% rise in the SES compared to a 34% increase in the RCS by 2050. Consequently, the share of natural gas in the global energy mix grows substantially, reaching 29%, in contrast to the 26% witnessed in the RCS. Natural gas holds the largest share among energy sources in the SES energy mix by 2050.

Several factors contribute to this growth, including the expansion of the natural gas grid in Africa, the transition from coal to natural gas in the power sector, the shift from traditional biomass in Africa's residential segment, and the heightened utilisation of natural gas in blue hydrogen generation. Additionally, the adjustment of the LCOE metric to account for the intermittency of wind and solar power, has led to an increased demand for natural gas as a backup energy source, to ensure power grid stability during the anticipated electrification ramp-up trend. Furthermore, the widespread adoption of CCUS technology at a large scale is set to enable the industrial use of natural gas in hard-to-abate sectors, substantially reducing emissions in these areas.

In the SES, there is a modest decrease in the demand for **oil** compared to the RCS. Oil demand is expected to experience a decline, contracting by 207 Mtoe, ultimately reaching around 4,330 Mtoe by 2050. Oil demand in the SES is approximately 397 Mtoe lower than that in the RCS, with oil's contribution to the energy mix also decreasing by 3 p.p. compared to the RCS, accounting for 23% of the global energy mix by the end of the outlook period. The reduction in oil demand in the SES, relative to the RCS, can be attributed to the limited oil demand growth in the residential and commercial sector due to substitution, complete phase-out of oil-fired power generation as well as higher penetration of alternative fuels in the transport sector in some regions. However, the upscaling of CCUS and

other Circular Carbon Economy (CCE) initiatives reduce the need for substituting oil in hard-to-abate sectors, such as the industrial and petrochemical industry. It is important to highlight that the primary driver of oil demand in the alternative scenario is emerging economies. For instance, according to the SES projections, demand for oil in Africa is expected to increase in road transport due to assumptions of per capita GDP growth in countries lacking access to modern energy.

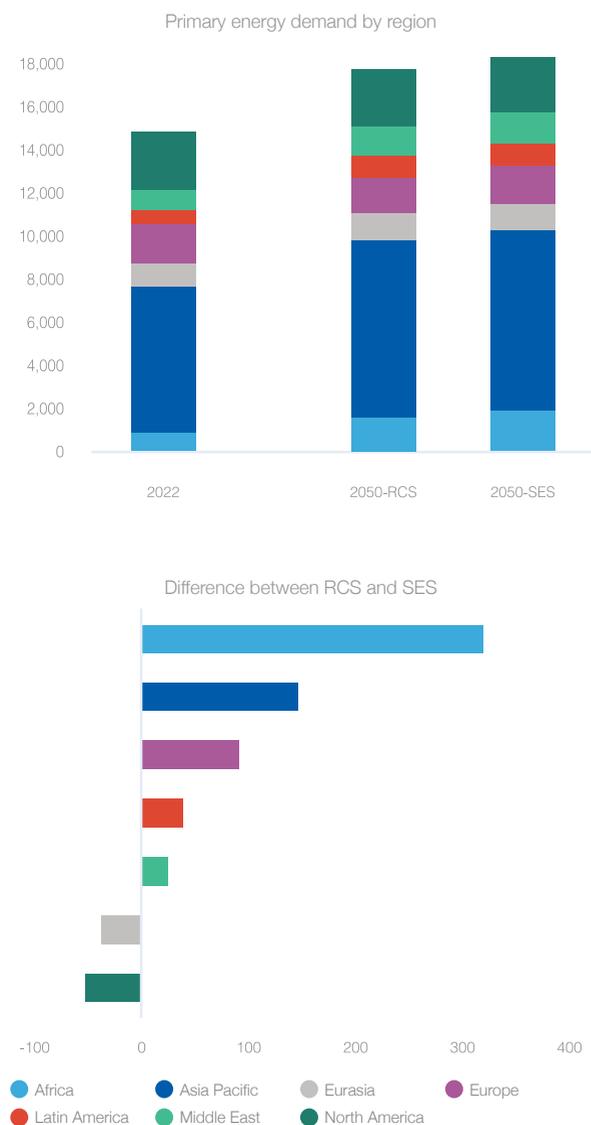
In contrast to natural gas, there is a substantial expected drop in **coal** demand within the SES. This reduction is primarily attributed to the rapid phase-down of unabated coal-fired power generation. In the SES scenario, coal demand is projected to decline significantly by 2,740 Mtoe, reaching 1,280 Mtoe by 2050, which represents a nearly 36% decrease compared to the RCS. The share of coal by 2050 in the SES energy mix is projected at 7%, which is 4 p.p. lower than its contribution in the RCS. This shift is primarily driven by the assumption of accelerated transitioning away from coal to natural gas, especially in the power generation sector of the Asia Pacific region in the SES. This substantial reduction in coal demand not only leads to notable improvements in energy efficiency, but also contributes significantly to the mitigation of greenhouse gas emissions in the SES compared to the RCS. It is important to highlight that this reduction in coal demand has also facilitated the expansion of wind, solar and hydro within the SES.

While natural gas continues to grow steadily in the SES, the most significant surge in demand, compared to the RCS, is witnessed in **renewable** energy sources. In the SES, the demand for renewables is projected to reach 3,883 Mtoe by 2050, surpassing RCS projections by nearly 872 Mtoe. Consequently, renewables make a substantial contribution, accounting for 21% of the global energy mix within the SES, as opposed to the 17% in the RCS. This expansion can be attributed to the anticipated rapid economic growth experienced by developing countries, and the subsequent increase in electrification. Furthermore, the adoption of renewable electricity as a replacement for the inefficient use of coal plays a pivotal role, allowing for the generation of a comparable amount of electricity with a lower input of fossil fuels. It is essential to emphasise that the SES scenario includes the adjustment of renewable energy supply costs to account for intermittency, the evaluation of grid development and replacement costs, and the availability of CCUS technology. These factors collectively influence the substitution of renewable energy for fossil fuels, particularly natural gas, in the SES.

In response to the assumed shift from traditional biomass to natural gas and LPG, and the expansion of the electricity grid in Africa, the demand for **bioenergy**, which includes both traditional and modern biomass, is expected to reach 1,960 Mtoe by 2050, marking a rise of 523 Mtoe. This bioenergy demand in the SES is approximately 63 Mtoe lower than the RCS projection by 2050. Notably, while the demand for modern biomass is projected to exceed the RCS estimate by 67 Mtoe in 2050, the demand for traditional biomass is anticipated to decrease by approximately 130 Mtoe. These shifts result in improved energy efficiency in residential segment of Africa.

Figure 8.2.

Global primary energy demand outlook in SES and RCS (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

8.3.1.2 Energy demand by region

The growth in primary energy demand is not consistent across regions in the SES. Africa and the Asia Pacific are set for significant increase in energy consumption compared to the RCS projections. In contrast, North America and Eurasia are anticipated to experience a reduction in energy demand relative to the RCS (Figure 8.2).

In anticipation of income improvements across multiple countries in **Africa** currently lacking access to modern energy sources, the demand for primary energy in this region is set to experience a significant surge in the SES, reaching a total of 1,977 Mtoe by 2050. This projection surpasses the RCS estimate by nearly 333 Mtoe, representing almost 60% of the global variation in

primary energy consumption between the two scenarios. This substantial increase can be attributed to several driving forces. One factor is the intensified demand for oil in the transport sector, coupled with a reduction in the contribution of oil in residential and commercial sectors. Furthermore, the residential segment is set to witness a substantial contribution from natural gas. This shift leads to a higher share of natural gas in household energy consumption, and a reduced reliance on traditional biomass within the region. Moreover, natural gas, renewables and hydropower are anticipated to expand their share in Africa's power generation mix in the SES, helping to phase out coal, particularly in South Africa, and oil-fired generation across many Sub-Saharan African countries. It should be emphasised that the onshore wind growth forecasted in the RCS scenario is reduced in the SES. Additionally, the concurrent enhancement in energy efficiency has effectively offset the expected growth in energy consumption solely arising from economic expansion assumptions in the region. Collectively, these factors are projecting Africa's energy landscape towards sustainability and climate progress.

The substitution of energy consumption in the **Asia Pacific** region in the SES is primarily driven by accelerated coal-to-gas switching and efforts to provide modern energy access to people in need. In this scenario, energy demand in Asia Pacific is projected to rise significantly, reaching 8,420 Mtoe by 2050, which is 153 Mtoe higher than the RCS projection. Similar to the expected trends in Africa, the improvement in income levels across the Asia Pacific region empowers its residents to enhance their living standards, resulting in increased energy usage. A vital aspect of this transformative energy transition in the region is the shift from coal to natural gas in the power sector. The contribution of coal to the Asia Pacific's energy mix is set to decline by 34 p.p. between 2022 and 2050, reaching 13% in the SES, which is 7 p.p. lower than the RCS projection. This shift aligns with an increased share of natural gas in the region, reaching 20% in 2050, which is 4 p.p. higher than the RCS projection. Emphasising the significance of transitioning away from unabated coal in the Asia Pacific, it becomes clear that a greater share of electricity coming from wind, solar and hydro, in addition to gas-fired power generation is crucial. This transition not only improves energy efficiency but also minimises transformation losses in comparison to coal-fired power generation.

The key driver of energy consumption changes in **Eurasia** in the SES is the transition from coal to natural gas in power generation. Eurasia's energy demand is expected to experience a modest increase, growing by 163 Mtoe and reaching 1,239 Mtoe. This figure is slightly lower than the projection in the RCS, by nearly 39 Mtoe, attributed to natural gas CCGT efficiency. In the SES, the role of coal in Eurasia's energy mix is set to decline significantly by 9 p.p., reaching just 8% by 2050. This is 4 p.p. lower than the RCS estimate. Conversely, the share of natural gas in Eurasia's fuel mix is anticipated to reach 61% in the SES, in contrast to the 54% projected in the RCS by 2050. The primary reason for this reduction in energy consumption in the SES, relative to the RCS, is the improved energy efficiency resulting from the transition from coal-fired to natural gas-fired thermal power plants.

In **Europe**, higher total energy demand in the SES compared to the RCS emerges from the assumed increase in low-carbon hydrogen generation, particularly from renewables. In the SES, the projected decrease in energy demand for the European region from 2022 onwards is relatively modest, amounting to just 63 Mtoe, and is expected to reach 1,788 Mtoe by 2050. This sharply contrasts with the RCS, where a substantial reduction

of almost 160 Mtoe is projected over the same period. Green hydrogen generation in Europe is anticipated to reach nearly 75 Mth₂ in the SES, a substantial increase compared to the approximately 35 Mth₂ estimated in the RCS. Consequently, the electricity input for hydrogen generation is forecast to rise to 294 Mtoe in the SES, showing a significant increase from the 138 Mtoe in the RCS. Green hydrogen is set to play a significant role in the European industrial sector, particularly within hard-to-decarbonise industries such as iron and steel. Furthermore, the contribution of renewable energies to Europe's energy mix in the SES is estimated to be 44%, representing a substantial 10 p.p. increase compared to the RCS by 2050.

Primary energy demand in **Latin America** is projected to increase by about 415 Mtoe, reaching 1,085 Mtoe by 2050 in the SES, compared to a 375 Mtoe incremental growth in the RCS. The inclusion of intermittency costs in the LCOE calculation, and upscaling CCUS in the SES have led to a reduced contribution of oil in power generation, with natural gas as substitute. Additionally, there is a slight reduction in the share of electricity produced by wind and solar compared to the RCS, with natural gas taking their place in the power generation. Consequently, the share of natural gas in the energy mix in the SES grows by 10 p.p. and reach 30% by 2050, which is 6 p.p. higher than the RCS by 2050. The contribution of oil in the regional energy mix in the SES decreases to 30%, following a 12 p.p. decline since 2022, which is 4 p.p. lower than the RCS. It is worth emphasising that the increased adoption of CCUS technology in Latin America is expected to pave way for natural gas substitution in power and hard-to-abate sectors in the SES, contributing significantly to achieving emission reduction targets.

The **Middle East** primary energy consumption changes in the SES, compared to the RCS, are driven by adjustments in the cost of electricity generation and the accelerated upscaling of CCUS technology, mirroring the trends seen in Latin America. The Middle East's energy demand in the SES exhibits minimal deviation from the RCS. Beginning from almost 900 Mtoe in 2022, energy demand is projected to reach 1,400 Mtoe in the SES by 2050, nearly 25 Mtoe higher than in the RCS. The adjustment of the LCOE to account for intermittency, combined with the increased integration of CCUS technology for carbon removal in the SES, has led to improved consumption of natural gas, and reduced demand for wind and solar energy in the power sector, compared to the RCS. In the Middle East, the contribution of natural gas in the energy mix in the SES is estimated at 57%, representing a 4 p.p. increase over the RCS. It should be emphasised that part of the difference in primary energy consumption between the scenarios is attributed to the assumed income effect resulting from an increase in per capita GDP in some countries.

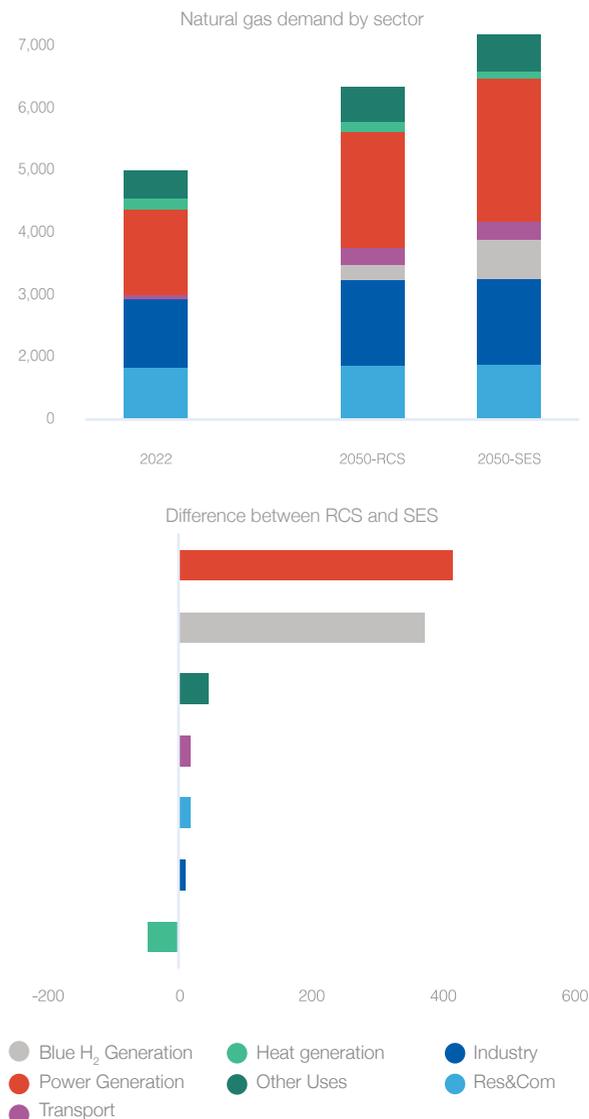
Throughout the forecasting period in the SES, **North America's** energy mix is undergoing a significant transformation. Starting at 2,745 Mtoe in 2022, North America's energy demand is expected to decrease to 2,567 Mtoe in the SES by 2050. This slight reduction of 54 Mtoe compared to the RCS can be attributed to several key factors. One of the primary drivers of this shift is the rapid adoption of heat pumps within North America's residential segment. This transition has led to a substantial increase in the utilisation of renewable energy sources in residential settings, consequently reducing the region's reliance on natural gas and oil. Furthermore, North America is experiencing a surge in the production of low-carbon hydrogen in the SES favoured by low natural gas prices in the region. This hydrogen is sourced from both renewables and natural gas, and is primarily directed towards meeting the energy needs of the industrial sector. Additionally, there is a decrease in

wind power generation growth, accompanied by an increased demand growth for natural gas in the power sector.

8.3.2 Natural gas demand

In the SES, natural gas demand is shaped by a multifaceted set of factors, encompassing affordability, reliability, and sustainability in energy supply. These criteria are fundamental to achieving inclusive and sustainable development, while concurrently addressing the pressing challenges posed by climate change. Within the SES framework, natural gas emerges as the dominant energy source, exceeding both oil

Figure 8.3. Natural gas demand outlook in SES and RCS (bcm)



Source: GECF Secretariat based on data from the GECF GGM
 Note: 1) Industry includes gas used as energy fuel and feedstock as well as for grey hydrogen generation and the production of liquid fuels; 2) Transport includes road transport and marine bunkers; 3) Other uses include gas demand for energy industry own use, for rail and pipeline transport.

and coal, constituting a substantial 29% share of the energy mix by 2050. Its demand is anticipated to experience robust growth, reaching 6,210 bcm by 2050, which stands at 850 bcm more than the RCS projections. This signifies a substantial growth of 55% in the SES over the forecast period, significantly surpassing by 21 p.p. compared to RCS projections (Figure 8.3).

The SES scenario places a spotlight on the key role of natural gas, particularly in regions where increased income levels are expected among countries facing energy access challenges. Natural gas is envisioned as a catalyst for providing affordable, accessible, and reliable modern energy. This not only contributes to elevating living standards, but also highlights the versatility of natural gas in simultaneously addressing both energy and environmental challenges, reducing emission footprints, and paving the way for a more sustainable energy future.

8.3.2.1 Natural gas demand by sectors

In the SES, natural gas is anticipated to make a substantial contribution to the global **power generation** mix (excluding electricity used for green hydrogen production) estimated at approximately 26% by 2050. This represents an increase of approximately 7 p.p. compared to the RCS. The demand for natural gas in the power sector is projected to witness significant growth, with an estimated increase of around 920 bcm, reaching 2,303 bcm by 2050 in the SES. This reflects a 422 bcm rise compared to RCS projections. In terms of the power sector's total natural gas demand, it is expected to account for 37% of the total in the SES by 2050, as opposed to 35% in the RCS. This growth is primarily driven by the shift from coal to natural gas and the synergy between natural gas and intermittent renewable energy sources.

The **industrial** sector's natural gas demand is forecast to rise from 1,107 bcm in 2022 to around 1,390 bcm in the SES by 2050, exceeding the RCS projections by only 10 bcm. Nevertheless, despite this growth, the proportion of industrial gas demand of the total natural gas volume is anticipated to experience a decline, decreasing from 28% in 2022 to 22% in the SES by 2050. This represents a 4 p.p. decrease compared to the RCS.

Blue hydrogen generation emerges as a substantial driver for the demand for natural gas in the SES. It is anticipated to experience remarkable growth, rising from nearly negligible levels in 2022 to reach 618 bcm by 2050 in the SES. This represents an increase of 378 bcm compared to the RCS projection. The expansion of the blue hydrogen use is expected to cater to various sectors, including industrial, power generation, transport, and residential consumption. Moreover, it will serve as a blend with natural gas and facilitate international exports by utilising existing natural gas infrastructure, thus further bolstering the overall growth of the natural gas industry.

The demand for natural gas in the **transport** sector is higher in the SES compared to the projections in the RCS. This increase can be primarily attributed to expanded economic growth and the advancement of low-income countries that lack access to modern energy. In the SES, natural gas demand in the transport sector is expected to grow by 240 bcm, reaching almost 310 bcm by 2050. This figure exceeds the RCS projection by around 20 bcm. This trend underscores the substantial impact of socio-economic development, especially in low-income Sub-Saharan Africa countries, on the transport sector. Increasing income levels play a pivotal role in facilitating intra-regional trade

and enhancing the affordability of transportation, thereby driving the ownership of natural gas vehicles (NGVs).

In the SES, the demand for natural gas in the **residential and commercial** sector by 2050 is anticipated to be higher than in the RCS. The expected increase in natural gas demand in this sector amounts to 23 bcm since 2022, reaching around 880 bcm in the SES by 2050, which surpasses the RCS projection by almost 20 bcm. This trend can be attributed to the net effect of two primary factors. Firstly, in developing countries, particularly in Sub-Saharan Africa, the SES forecasts a rising demand for natural gas in this sector. This growth is mainly a result of transitioning from traditional biomass to natural gas and LPG, which is a by-product of natural gas production. This shift promotes cleaner and more efficient energy sources. Conversely, there is a growing adoption of heat pumps, particularly in North America and Europe, leading to the substitution of natural gas with renewables in this sector. Consequently, the combined impact of these opposing factors indicates that the global demand for natural gas in the residential and commercial sector is projected to be higher in the SES compared to the RCS by 2050.

8.3.2.2. Natural gas demand by region

The global increase in natural gas demand in the SES relative to the RCS by 2050, is estimated to be 850 bcm. This difference is primarily concentrated in the developing Asia Pacific and Sub-Saharan Africa, where low-income countries lacking access to modern energy are situated. The assumption of increasing per capita GDP in these countries is expected to have a direct impact on natural gas demand in the SES. Furthermore, the increased adoption of low-carbon hydrogen, particularly green hydrogen, along with the use of heat pumps, is the primary driver for the reduced natural gas demand in Europe.

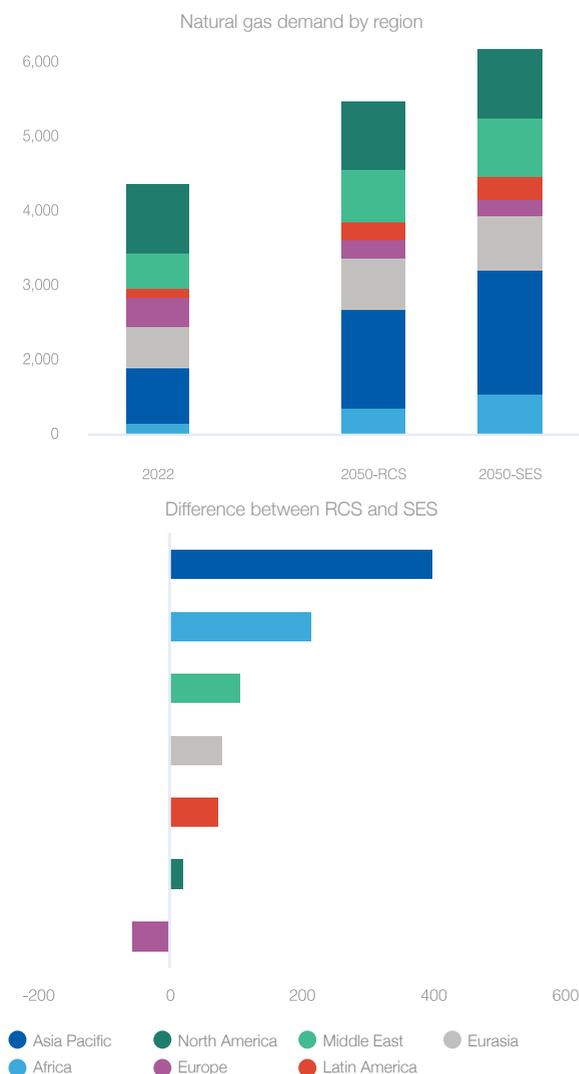
Africa is poised for a substantial upsurge in natural gas demand within the SES. This surge is expected to elevate natural gas consumption from 165 bcm in 2022 to a remarkable 628 bcm by 2050 in the SES, surpassing the estimates of the RCS by 218 bcm (Figure 8.4). The primary driver of this natural gas demand growth in the SES, compared to the RCS, is the power generation sector. In the SES, natural gas is projected to constitute 54% of Africa's power generation mix by 2050, which is 10 p.p. higher than the RCS. Another significant factor contributing to the rise in natural gas demand in the SES is the transition from traditional biomass to natural gas and LPG. Consequently, the share of natural gas in total household energy consumption is anticipated to increase from approximately 4% in 2022 to 20% by 2050 in the SES. This represents an increase of approximately 15 p.p. compared to the RCS. Furthermore, the transport sector is another source of natural gas demand growth in the SES scenario for Africa. This is driven by increasing incomes and improved affordability of transportation for the African population in this scenario.

The **Asia Pacific** region is poised for a significant upsurge in natural gas demand within the SES. Projections indicate that the region's gas demand will increase by a substantial 1,100 bcm, reaching a total of 1,995 bcm in the SES by 2050. This surpasses the estimates of the RCS by 405 bcm. The primary driving force behind this increased natural gas demand in the Asia Pacific within the SES is the shift from coal to natural gas in the power generation sector. By 2050, natural gas is expected to account for 20% of the region's power generation mix in the SES, in contrast to approximately 13% in the RCS. It is

noteworthy that the share of coal in the Asia Pacific's electricity generation is projected to be a mere 2.5% in the SES by 2050, marking a significant reduction from around 14% in the RCS. To provide context, in 2022, coal's estimated share in the Asia Pacific's power generation mix stands at approximately 57%.

Figure 8.4.

Natural gas demand in SES and RCS (bcm)



Natural gas demand in **Eurasia** is poised for an estimated increase of 240 bcm in the SES. By 2050, it is expected to reach 890 bcm, surpassing the projections in the RCS by 80 bcm. The primary driver behind this surge in natural gas consumption, compared to the RCS scenario, is the transition from coal to natural gas in Eurasia's power sector. In the SES, there is a more aggressive phase-down of coal in Eurasia's power generation, leading to an increased reliance on natural gas. This transition is expected to raise the contribution of natural gas to power generation by approximately 12 p.p., reaching 54% during the period from 2022 to 2050. Furthermore, there is an additional uptick in the demand for natural gas as an input for blue hydrogen generation in Eurasia.

In the SES, **Europe** is expected to witness a significant reduction in its natural gas demand, declining by 237 bcm to reach 243 bcm by the year 2050. This projection is notably lower, by 57 bcm, when compared to the estimates in the RCS. Several factors contribute to this contrast in natural gas demand between the two scenarios. A major factor leading to the decreased natural gas demand in Europe is the diminishing direct consumption of natural gas in the industrial sector. This decrease is coupled with a growing trend of substituting natural gas with low-carbon hydrogen. However, an increased demand for natural gas as an input for blue hydrogen generation partially offsets the decline in natural gas usage in Europe within the SES scenario. Nevertheless, the most significant reason for the lower natural gas demand in the SES compared to the RCS in 2050 is the increased production of green hydrogen in Europe. Green hydrogen serves as a substitute for blue hydrogen, contributing to the shift away from natural gas in the industrial sector. Additionally, the substitution of natural gas in the residential segment with renewables, facilitated by the accelerated adoption of heat pumps in Europe, is another key factor reducing the demand for natural gas in this region.

In **Latin America**, the demand for natural gas is poised to experience moderate growth, with an increase of 215 bcm expected to reach 370 bcm by 2050 in the SES. This projection is notably higher, surpassing the RCS estimates by 75 bcm. The primary driver behind this increase in natural gas demand in the SES, compared to the RCS, is the power generation sector. In the SES, the adjustment of renewable electricity supply costs to account for intermittency has resulted in reduced power generation from wind and solar sources in comparison to the RCS. To compensate for this reduction, there is an increased utilisation of natural gas in power generation. Furthermore, this adjustment has led to a shift from oil to gas in the power generation of Latin America, driven by the accelerated adoption of CCUS technology. The contribution of natural gas to the power generation mix is projected to be 27% in the SES by 2050, which represents an increase of approximately 8 p.p. compared to the RCS for the year 2050.

In accordance with the SES projections, the **Middle East** anticipates a significant uptick in natural gas demand, surging from 560 bcm in 2022 to 964 bcm by 2050. This projection exceeds the earlier estimates outlined in the RCS by 109 bcm. The utilisation of natural gas for blue hydrogen production in the Middle East is a pivotal factor contributing to the divergence in natural gas demand between the two scenarios. Additionally, similar to Latin America, the power sector plays a role in the variance of natural gas demand between the SES and RCS in the Middle East. In the SES, the growth of wind and solar power generation is comparatively lower than in the RCS. To compensate for this reduction, natural gas serves as a backup for intermittent renewable power sources. Consequently, the contribution of natural gas to electricity generation in the Middle East, as projected in the SES for 2050, stands at 70%, a figure that remains consistent with the 2022 data. In contrast, in the RCS scenario, this contribution is expected to be 59%, primarily due to increased power generation from renewable sources. The incorporation of intermittency costs in the calculation of the LCOE ensures that natural gas remains competitively viable in the Middle East's electricity market, maintaining a stable market share over the ensuing decades.

In **North America**, the demand for natural gas is expected to undergo a modest growth, with projections indicating a stabilised trend from the current 1,110 bcm to 1,120 bcm in the SES by the year 2050. This represents a 20 bcm increase

in natural gas demand by 2050 in the SES, compared to the RCS and can be attributed to several key factors. A significant driver of this shift is the accelerated adoption of heat pumps within North America's residential sector. This transition has led to a substantial increase in the utilisation of renewable energy sources in residential settings, resulting in a notable decrease in the reliance on natural gas and oil. In the SES, the direct use of renewables is expected to comprise 9% of the residential sector's energy mix by 2050, representing a substantial increase from just above 1% in the RCS. Furthermore, the region is experiencing a rise in the production of low-carbon hydrogen in the SES. This hydrogen is primarily sourced from natural gas, with a focus on meeting the energy demands of the industrial sector and other final energy sectors. This shift has led to a reduction in direct natural gas demand in the industrial sector, amounting to approximately 37 bcm less compared to the RCS. However, it is important to note that there is an overall increase in natural gas demand, particularly in the form of blue hydrogen, where natural gas serves as the primary input. This demand is expected to rise by 178 bcm in the SES by 2050 compared to the RCS. As a result, the net effect on natural gas demand in the industrial sector is considered positive.

8.3.3 Hydrogen demand and generation

In recent years, hydrogen has garnered substantial attention as a pivotal energy carrier crucial for decarbonizing hard-to-abate sectors and achieving climate targets. Serving as a litmus test, various trials have showcased commendable successes as well as occasional setbacks, contributing to the ongoing evolution of the hydrogen landscape. In the SES, the demand for hydrogen is projected to experience substantial growth. It is expected to surge from 101.5 Mth₂ in 2022 to 377.6 Mth₂ by 2050, surpassing the RCS projections by 80 Mth₂. This signifies that hydrogen will account for 5.5% of total energy mix in the SES by 2050, as opposed to the 4.5% in the RCS.

The disparity in hydrogen demand between the SES and the RCS in 2050 is primarily concentrated in Europe and North America, where they constitute 56% and 31% of the overall change in projections between the two scenarios, respectively. Meanwhile, the Asia Pacific region is expected to witness a demand for hydrogen reaching 144 Mth₂ by 2050, which is 10 Mth₂ more than what the RCS projected. On the other hand, the demand for hydrogen in Africa, Eurasia, Latin America, and the Middle East does not exhibit significant change in the SES when compared to the RCS.

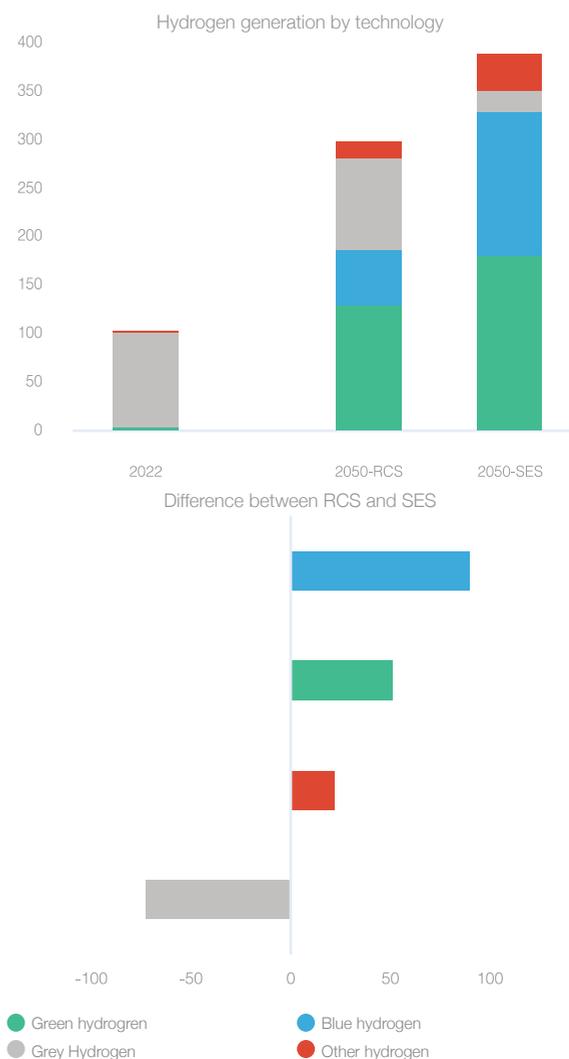
The industrial sector plays a central role in driving the demand for hydrogen in the SES compared to the RCS, contributing to just over 90% of the 81 Mth₂ difference between the two scenarios. Another notable contributor to hydrogen demand in the SES relative to the RCS is the blending of hydrogen into the natural gas network. This demand is expected to reach 15 Mth₂ by 2050 in the SES, marking an increase of approximately 5 Mth₂ compared to the RCS projections. Conversely, the demand for hydrogen in the power sector in the SES scenario is lower than in the RCS. This decrease can be attributed to energy efficiency setbacks and the adjustment of renewable electricity production to include intermittency costs. The demand for hydrogen in power generation in the SES is anticipated to reach 74 Mth₂, which is nearly 20 Mth₂ less than what was projected in the RCS.

8.3.3.1 Hydrogen generation based on technology

While there are multiple drivers for hydrogen demand in the energy sector's decarbonisation efforts in the SES, especially in challenging-to-decarbonise sectors, it is important to note that the technologies for hydrogen generation are diverse. They come with varying expected market penetration rates, production costs, and associated supply chain infrastructure. The findings from the SES reveal that the growth of hydrogen generation will be closely tied to the adoption of clean technologies. In this scenario, green hydrogen and blue hydrogen, produced from natural gas with CCUS, are projected to make up 85% of hydrogen generation by 2050. This is a significant increase from the 62% seen in the RCS. Additionally, the contribution of grey hydrogen to global hydrogen generation in the SES is expected to be just above 5% by 2050, compared to 31% in the RCS (Figure 8.5). These results highlight that in the SES, hydrogen as a potential energy carrier possesses a lower carbon footprint and serves as a viable means for decarbonising the global energy system.

Figure 8.5.

Hydrogen generation outlook in SES and RCS (Mth₂)



Source: GECF Secretariat based on data from the GECF GGM

In accordance with the SES projections, the generation of green hydrogen is poised for substantial growth, surging from 3.5 Mth₂ in 2022 to a remarkable 180.4 Mth₂ by 2050. This projection surpasses the RCS scenario by 51 Mth₂. Green hydrogen is expected to make up a significant portion of total hydrogen generation in the SES, accounting for 48% by 2050, which is 5 p.p. higher than the RCS. The driving force behind this disparity is primarily attributed to Europe and North America, where green hydrogen is allocated to address the challenges in hard-to-abate industrial sectors, especially within steel and iron production. In the SES, the electricity specifically dedicated to green hydrogen generation is projected to reach 692 Mtoe by 2050. This amount represents an increase of 282 Mtoe compared to the RCS scenario, contributing to 67% of the incremental growth in overall fuel input allocated for the hydrogen generation. This increase is 4 p.p. higher than in the RCS, emphasising the pivotal role of green hydrogen in the transition to a sustainable energy future.

Blue hydrogen, produced from natural gas, is poised for substantial demand growth in the SES. Starting from virtually zero in 2022, blue hydrogen production is projected to reach a significant 147.5 Mth₂ by 2050 in the SES, surpassing RCS estimates by approximately 90 Mth₂. Blue hydrogen's contribution to global hydrogen generation in the SES by 2050 is expected to be just under 40%, which is double the RCS projection. This significant growth in blue hydrogen generation is particularly concentrated in North America and Asia Pacific. The fuel input from natural gas for blue hydrogen generation in the SES by 2050 is estimated to be 533 Mtoe, representing a substantial increase of nearly 325 Mtoe compared to the RCS scenario. This figure constitutes approximately 52% of the incremental change in overall fuel input for hydrogen generation in the SES during the same period, which is 19 p.p. higher than the RCS. This emphasizes the pivotal role of blue hydrogen as a substantial contributor to the hydrogen landscape, supporting the pursuit of sustainable and low-carbon energy solutions in the SES projections.

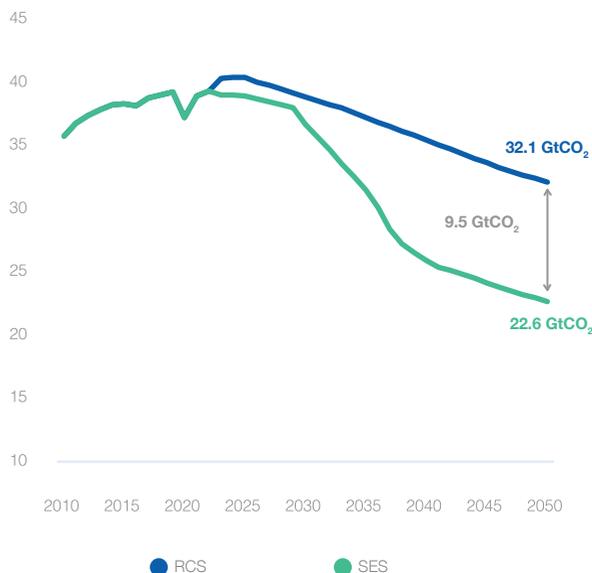
Grey hydrogen, despite its current cost advantages and the highest production volume of 98 Mth₂ in 2022, is poised for a significant reduction in the upcoming decades. In the SES, its production is projected to decline sharply to approximately 21.2 Mth₂ by 2050, in stark contrast to a more moderate decrease to 94 Mth₂ in the RCS. The share of grey hydrogen in the overall hydrogen mix is anticipated to undergo a noteworthy transformation, diminishing to a mere 6% in the SES by 2050. This represents a 26 p.p. decrease compared to the RCS. Grey hydrogen generation is expected to persist primarily in North America and the Middle East in the SES scenario by the end of the forecast period. The fuel input, in the form of natural gas, coal, and oil, for the generation of grey hydrogen is estimated to be 76 Mtoe in the SES by 2050. This is 281 Mtoe less than the RCS, highlighting a sector where natural gas has replaced oil and coal in the SES.

8.3.4 Energy-related emissions

Despite the projected growth in the size of the energy system and progress toward achieving sustainable development goals, especially in providing access to affordable, reliable, and sustainable modern energy, the SES anticipates that energy-related emissions will amount to 22.6 GtCO₂e by 2050. This figure is notably lower, by 9.5 GtCO₂e, compared to the RCS scenario. This level of emissions represents a 42% decline from the 2022 level, whereas the RCS scenario projects only an 18% reduction in emissions (Figure 8.6).

Figure 8.6.

Energy-related emission outlook in SES and RCS (GtCO₂e)



Source: GECF Secretariat based on data from the GECF GGM

Asia Pacific is projected to experience the most substantial emission reduction in the SES. The region's energy-related emissions are expected to decrease by 12.4 GtCO₂e, reaching 7.5 GtCO₂e by 2050, which is 6.8 GtCO₂e lower than the RCS. This difference accounts for just over 70% of the variation in energy-related emissions between the two scenarios. The primary catalyst for this significant reduction in energy-related emissions in Asia Pacific is the transition from coal to natural gas. In Europe, energy-related emissions are set to decline by 2.6 GtCO₂e, reaching 1.3 GtCO₂e by 2050 in the SES, which is 0.6 GtCO₂e lower than the RCS projections. North America is also expected to witness a reduction in energy-related emissions, with a decline of 2.6 GtCO₂e by 2050 in the SES, reaching 3.8 GtCO₂e, which is 0.4 GtCO₂e less than the RCS projections. In contrast, despite increased energy consumption in the SES compared to the RCS to tackle energy poverty, Africa's energy-related emissions are projected to only slightly increase by 0.9 GtCO₂e by 2050, reaching 2.5 GtCO₂e. This is 0.4 GtCO₂e lower than the RCS. The primary driver behind this emission abatement in Africa is natural gas CCUS saving.

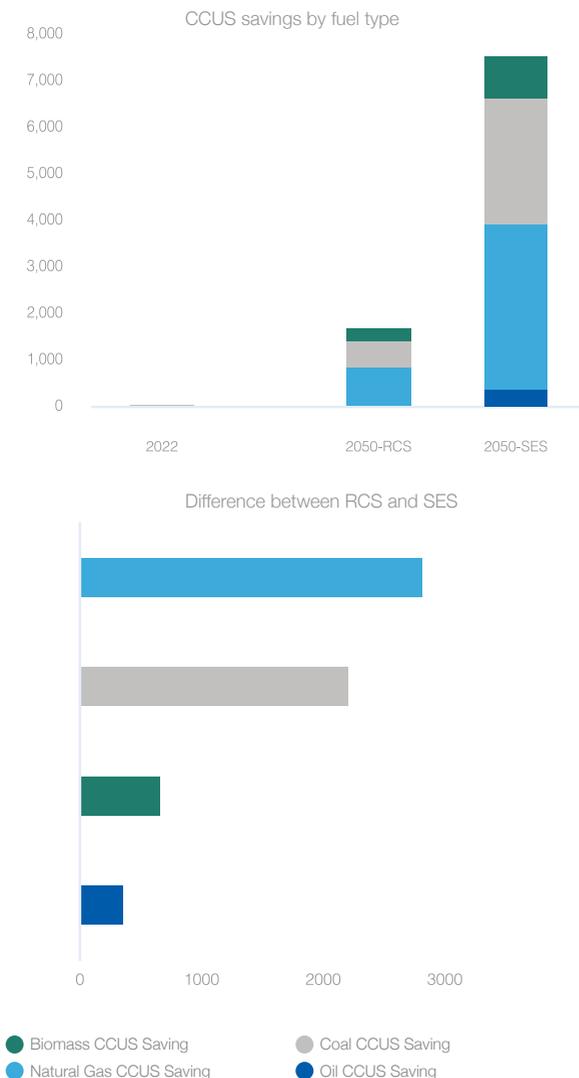
According to the SES projections, CO₂ emissions are anticipated to decrease by 15.5 GtCO₂, reaching 21 GtCO₂ by 2050. This is approximately 9 GtCO₂ lower than the RCS, representing a 42% reduction in CO₂ emissions in the SES compared to 2022. This reduction is 24 p.p. higher than what was projected in the RCS. The power generation and industrial sectors are the main contributors to this significant reduction in CO₂ emissions in the SES, accounting for 48% and 34% of the variation in CO₂ emissions between the two scenarios, respectively.

The accelerated upscaling of CCUS, as described in the rapid CCUS adoption assumptions of the SES scenario, stands out as one of the primary drivers for reducing energy-related emissions in the SES. Carbon capture and storage

technologies, aimed at mitigating emissions from energy combustion, are expected to make substantial contributions, with emissions savings projected to grow from 12 MtCO₂e in 2022 to 7.5 GtCO₂e by 2050 in the SES. This figure is notably higher, by 5.8 GtCO₂e, compared to the RCS scenario. In particular, natural gas CCUS saving is expected to account for just over 3.5 GtCO₂e in emissions savings by 2050 in the SES, marking an increase of 2.7 GtCO₂e compared to the RCS. Natural gas CCUS saving represents almost half of the disparity in carbon capture and storage savings between the two scenarios. Additionally, coal CCUS saving is projected to contribute 2.7 GtCO₂e in emissions savings by 2050 in the SES, an increase of 1.9 GtCO₂e compared to the RCS. This coal CCUS saving constitutes 35% of the difference in CCUS savings between the two scenarios. Biomass and oil CCUS savings account for 11% and 6%, respectively, of the difference in CCUS savings between the two scenarios (Figure 8.7).

Figure 8.7.

CCUS savings projection in SES and RCS (MtCO₂e)



Source: GECF Secretariat based on data from the GECF GGM

Asia Pacific countries, particularly countries reliant on coal, play a pivotal role in CCUS savings within the SES, contributing to nearly 70% of the total CCUS savings by 2050. It is worth highlighting that a substantial 46% of these CCUS savings in 2050 can be attributed to coal CCUS saving in this region. Meanwhile, natural gas CCUS saving account for 36% of the overall CCUS savings in Asia Pacific. In contrast, across all other regions covered by the SES by 2050, natural gas CCUS saving represent a significant portion of the total CCUS savings. For instance, in the Middle East, almost the entire 369 MtCO₂e CCUS savings by 2050 in the SES are associated with natural gas. In Africa, natural gas CCUS saving make up just over 80% of the 375 MtCO₂e total CCUS savings in the region by 2050 in the SES scenario. Similarly, in North America, this share is 75% of the 414 MtCO₂e CCUS savings by 2050. The power sector, industrial sector, and hydrogen generation sector are the primary sectors utilising CCUS savings, as indicated by the SES projections.

It is important to emphasise that, within the SES, the projected volume of GHG emissions stands at 32.7 GtCO₂e by 2050, a notable contrast to the 44 GtCO₂e estimated in the RCS. This places the SES approximately 6 GtCO₂e above the annual range of GHG emissions measured to achieve the 2-degree Celsius temperature goal. It is essential to acknowledge that the SES currently does not incorporate potential emission reductions through nature-based solutions, carbon sinks, and other carbon removal technologies such as Direct Air Capture (DAC). In light of these considerations, one could argue that the SES remains in alignment with the goal of reaching the 2-degree Celsius goal set forth in the Paris Agreement.

8.4. Implications

Meeting the dual objectives of sustainable development and climate change mitigation requires an increase in energy consumption, particularly in low-income and developing countries facing issues of limited access to modern energy. As countries strive to empower their citizens and elevate living standards, there is a noticeable increase in per capita energy consumption, especially in regions undergoing rapid development and transitioning from low-income status. While per capita energy consumption has stabilised in some advanced economies, it continues to follow an upward trajectory in developing countries, where the majority of population expansion is concentrated. This surge is crucial in low-income countries, contributing to poverty alleviation and improved living standards. Additionally, we foresee a reduction in energy consumption per capita inequality among countries, along with increased energy consumption.

It is essential to remember that bridging the gap between energy supply and demand, while concurrently decarbonising energy systems, cannot depend solely on a singular energy source or technology, such as solar and wind power, while renewables offer distinct advantages. However, as their share in the power supply increases, challenges are set to emerge related to intermittency, variability, infrastructure constraints, and shortage of critical minerals. Therefore, as a complementary partner to renewables, natural gas assumes a key role in providing backup and stability to power systems and hydropower in periods of drought.

Foreseeing a significant growth in natural gas demand, the SES scenario exceeds its designated role in the RCS, particularly in power generation and blue hydrogen production.

This expanded role extends to the Asia Pacific and Africa, positioning natural gas as a supplier of cost-effective, reliable, and sustainable energy. For instance, the adoption of pipe natural gas and LPG, displacing traditional biomass, significantly improves living conditions in Sub-Saharan Africa. These energy transitions not only facilitate enhanced access to clean cooking, but also mitigate indoor pollution leading to averting premature deaths, and curtailing deforestation.

Despite the abundant and globally diversified reserves of natural gas, the expanding demand for natural gas emphasises the necessity for ongoing investments to ensure a secure and reliable supply, coupled with the development of essential infrastructure for extraction, transportation, and trade. This emphasises the need for sustained investment in existing and new projects covering all segments of the natural gas supply chain.

Although natural gas is a cleaner energy source, there is potential for improvement to enhance its environmental credentials. The SES results, as a realistic and orderly energy transition pathway, highlight the need for increased natural gas demand and the accelerated expansion of cleaner energy sources and technologies. This includes wind and solar power, transitioning from coal to gas, adopting carbon removal technologies such as carbon capture, utilisation, and storage, and advancing blue and green hydrogen production. In the longer term, the advancement and deployment of direct air capture technology is also crucial. These technologies have the potential to limit global temperature increases to below 2 degrees Celsius, while simultaneously mitigating adverse economic impacts on developing countries. However, their successful implementation requires comprehensive policy support, fiscal and monetary incentives, and well-designed market mechanisms.

Annex A

Abbreviations

AEDS	Accelerated Energy Decarbonization Scenario
AG	Associated Conventional Gas
CAFE	Corporate Average Fuel Economy
CAPS	Central African Pipeline System
CBAM	Carbon Border Adjustment Mechanism
CBM	Coal Bed Methane
CCE	Circular Carbon Economy
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation, and Storage
CGD	City Gas Distribution
CHP	Combined Heat and Power Plant
DAC	Direct Air Capture
DES	Destination ex Ship
DOE	Department of Energy
DRC	Democratic Republic of the Congo
ECA	Energia Costa Azul
EHB	European Hydrogen Backbone
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESS	Energy Sustainability Scenario
ETSs	Emission Trading Systems
EU	European Union
EUR	Euro
EVs	Electric Vehicles
FEED	Front-End Engineering Design
FID	Final Investment Decision
FLNG	Floating Liquefied Natural Gas facility
FOB	Free-On-Board
FSRUs	Floating Storage and Regasification Units
FYP	Five-Year Plan
G20	Group-20
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GGM	Global Gas Model
GGO	Global Gas Outlook
GHGs	Greenhouse Gases
GST	Global Stocktake
GTA	Grand Tortue Ahmeyim
HDVs	Heavy-Duty Vehicles
HELP	Hydrocarbon Exploration and Licensing Policy
HGV	Heavy Goods Vehicle
HH	Henry Hub
IDD	Indonesia Deepwater Development
IMO	International Maritime Organization
IOCs	International Oil and Gas Companies
IRA	Inflation Reduction Act
JTP	Just Transition Pathway
LCOE	Levelised Cost of Electricity
LDCs	Least-Developed Countries
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LRMC	Long-run Marginal Cost of Supply
MOU	Memorandum of Understanding

NAG	Non-Associated Gas
NDCs	Nationally Determined Contributions
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEP	National Electricity Plan
NFE	North Field East
NFS	North Field South
NGVs	Natural Gas Vehicles
NLNG	Nigeria Liquefied Natural Gas
NNPC	Nigerian National Petroleum Corporation
NSTA	North Sea Transition Authority
OALP	Open Acreage Licensing Policy
OECD	Organization of Economic Cooperation and Development
ONGC	Oil and Natural Gas Corporation
OPEC	Organisation of Petroleum Exporting Countries
OPEC+	OPEC Plus
p.a.	per annum
PDP	National Power Development Plan
PNG	Papua New Guinea
PoS	Power of Siberia
p.p.	percentage point
PPP	Purchasing Power Parity
PSAs	Production Sharing Agreements
PV	Photovoltaic
RCS	Reference Case Scenario
RPO	Renewable Purchase Obligation
RSC	Revenue-sharing contracts
SAF	Sustainable Aviation Fuel
SCP	South Caucasus Pipeline
SD1	Shah Deniz I
SDGs	Sustainable Development Goals
SES	Sustainable Energy Scenario
SIDS	Small Island Developing States
SIGHT	Strategic Interventions for Green Hydrogen Transition Programme
SMRs	Small Modular Nuclear Reactors
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TAPI	Turkmenistan-Afghanistan-Pakistan-India pipeline
TCTF	Temporary Crisis and Transition Framework
TTF	Title Transfer Facility
UBI	Universal Basic Income
UAE	United Arab Emirates
UK	United Kingdom
UN	United Nations
UNEP	United Nations Environmental Programme
UNFCCC	UN Framework Convention on Climate Change
WAGP	West African Gas Pipeline
WTO	World Trade Organization
YTF	Yet-To-Find

Annex B
Geographical Coverage

Advanced economies

Bulgaria	Lativa	OECD
Croatia	Lithuania	Romania
Cyprus	Malta	

Africa

North Africa	Congo	Southern Africa
Algeria	Eastern Africa	Namibia
Egypt	Eritrea	Zambia
Libya	Ethiopia	Zimbabwe
Morocco	South Sudan	Western Africa
Tunisia	Sudan	Benin
Sub-Saharan Africa	Tanzania	Ghana
Angola	Uganda	Ivory Coast
Central Africa	Equatorial Guinea	Mali
Cameroon	Ghana	Mauritania
Chad	Kenya	Niger
Central African Rep.	Mozambique	Senegal
Dem. Rep. of the Congo	Nigeria	Togo
Gabon		

Asia Pacific

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

Developed Asia

Australia	South Korea
Japan	New Zealand

Developing Asia

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

Developing economies

All other countries not included in the “advanced economies” regional grouping

Eurasia

Armenia	Kazakhstan	Tajikistan
Azerbaijan	Kyrgyzstan	Turkmenistan
Belarus	Moldova	Ukraine
Georgia	Russia	Uzbekistan

Europe

Albania	Montenegro	Switzerland
Bosnia and Herzegovina	FYR Macedonia	Türkiye
European Union	Norway	United Kingdom
Gibraltar	Republic of Moldova	
Iceland	Serbia	

European Union

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

GECF Members

Algeria	Libya	Russia
Bolivia	Iran	Trinidad and Tobago
Egypt	Nigeria	Venezuela
Equatorial Guinea	Qatar	United Arab Emirates

GECF Observers

Angola	Malaysia	Mozambique
Azerbaijan	Mauritania	Peru
Iraq	Senegal	

Latin America

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

Middle East

Bahrain	Kuwait	Saudi Arabia
Iran	Lebanon	Syria
Iraq	Oman	United Arab Emirates
Israel	Qatar	Yemen
Jordan		

Middle East and North Africa (MENA)

Middle East and North Africa regional groupings

North America

Canada	Mexico	United States
--------	--------	---------------

OECD

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

Southeast Asia

Brunei Darussalam	Malaysia	Thailand
Cambodia	Myanmar	Viet Nam
Indonesia	Philippines	
Laos	Singapore	

Annex C

Conversion Table

	Billion cubic feet (bcf)	Billion cubic meters (bcm)	Million barrel oil equivalent (mboe)	Trillion British thermal units (tbtu)	Million tonnes LNG (Mt)	Million tonnes oil equivalent (Mtoe)	Giga Joule (GJ)	kilowatt-hour (kWh)
Multiply by								
Billion cubic feet (bcf)	1	0.028	0.167	0.966	0.021	0.024	1.08x10 ⁶	3x10 ⁸
Billion cubic meters (bcm)	35.315	1	5.833	34.121	0.735	0.860	3.8x10 ⁷	1.05x10 ¹⁰
Million barrel oil equivalent (mboe)	6	0.170	1	5.800	0.125	0.146	5.75x10 ⁶	1.6x10 ⁹
Trillion British thermal units (tbtu)	1.035	0.029	0.172	1	0.022	0.025	1.05x10 ⁶	2.92x10 ⁸
Million tonnes LNG (Mt)	48.028	1.360	8.001	46.405	1	1.169	5.48x10 ⁷	1.52x10 ¹⁰
Million tonnes oil equivalent (Mtoe)	41.071	1.163	6.842	39.683	0.855	1	4.22x10 ⁷	1.17x10 ¹⁰
GigaJoule (GJ)	9.3x10 ⁻¹¹	26.3x10 ⁻⁹	1.7x10 ⁻⁷	9.4x10 ⁻⁴	1.8x10 ⁻⁵	2.38x10 ⁻⁸	1	277.78
kilowatt-hour (kWh)	3.3x10 ⁻⁹	9.5x10 ⁻¹¹	6.14x10 ⁻¹⁰	3.4x10 ⁻⁹	6.5x10 ⁻¹¹	8.6x10 ⁻¹¹	3.6x10 ⁻³	1

Based on global average natural gas and crude oil calorific values.

Annex D

Definitions

Associated gas

Natural gas which coexists with oil in a primarily oil field. It may be cap gas or solution gas, where the differences are the behaviour and treatment.

Barrel of oil equivalent (boe)

A unit of energy based on the approximate energy released by burning one barrel of oil.

Biofuels

Biofuels are liquid fuels derived from biomass or waste feedstock, including ethanol and biodiesel.

Biomass and waste

Biomass and waste comprise 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

Bunkers include both international marine bunkers and international aviation bunkers.

Coal

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 (CBM)

Coal bed methane is methane that is or can be recovered from coal seams. Also well-known as Coal Seam Gas. Wells are drilled into suitable coal seams and the pressure in the rock is reduced, usually by pumping out water in order to recover CBM. The pumped out water may be saline and cause environmental issues until the methane can be desorbed from the coal. CBM is not trapped beneath a seal like conventional natural gas but is adsorbed into the coal.

Condensate

Condensate is a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at the 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 pentanes-plus that are the main constituents of condensate.

Conventional resources

Conventional resources refer to 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 localised 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.

Crude oil

Crude oil refers to a mixture of hydrocarbons that exists as a liquid in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil is the raw material which is refined into LPG, naphtha, gasoline/petrol, kerosene, diesel/gas oil, fuel oil, lubricating oil, paraffin wax and asphalt.

Decommissioned LNG project

Decommissioned LNG project refers to a project that is officially announced by the owner as decommissioned (mothballed) or has been inactive for a significant period of time.

Distributed energy system

Distributed energy system includes 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 sector

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

Dry gas is natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognised that this is a resource assessment definition and not a phase behaviour definition. Also called lean gas.

Electricity generation

Electricity generation is 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

Energy sector covers the use of energy by the 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)

EOR is the processes that increase the ability of oil to flow to a well by injecting chemicals, or gases into the reservoir or by changing the physical properties of the oil.

Existing gas production facilities

Those gas production facilities that are in production as of 2022.

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 completed LNG project

FEED completed LNG project is a project that has finished front-end engineering and design (FEED). This is valid for both the upstream and liquefaction segments.

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

Feedstock refers to hydrocarbons used as raw material in an industrial process, not as a fuel. The principal uses of natural gas as a feedstock are in the manufacture of ammonia, ammonia-based fertilisers, blue hydrogen and methanol.

Final Investment Decision (FID)

The project approval stage when the participating companies have firmly agreed to the project and the required capital funding.

Flared gas

Flared gas is the total quantity of gas vented and/or burned as part of production and processing operations and not as fuel.

Floating LNG (FLNG)

FLNG is the use of purpose built or converted ships to enable regasification of LNG (and liquefaction) to be carried out offshore. FLNG has the advantage that LNG production and importation can start more quickly than could happen onshore, where lead times are often lengthened by the local approval process. It also enables the processes to move location to satisfy short term demand.

Gas exports - upstream volumes

Gas exports refer to natural gas volumes shipped by a gas-exporting country to an importing country including all the losses along 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

Gas imports refer to net gas volumes delivered by an exporting country to an importing country, not including the losses during the shipment.

Gas liquefaction

The conversion of natural gas into LNG

Gross Heating Value (GHV)

The gross heating value represents the amount of heat released through the complete combustion of 1 kilogram, 1 mole, or 1 standard cubic meter (mass-based, molar-based, or volume-based) of gas. This calculation is conducted under specific conditions where the pressure remains constant, and all combustion products return to the same temperature as the reactants. All components, except for water formed by combustion, are maintained in the gaseous state, with water condensed to the liquid state. Expressed in units of energy, the gross heating value is measured in megajoules per kilogram (MJ/kg) for mass-based calculations, kilojoules per mole (kJ/mol) for molar-based calculations, and megajoules per cubic meter (MJ/m³) for volume-based calculations. These values are determined under standard conditions of 15°C and 101,325 Pascals of pressure.

Heat energy

Heat energy is 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.

Henry Hub (HH)

Henry Hub, the largest centralised point for natural gas spot and futures trading in the United States, is owned and operated by Sabine Pipe Line, LLC, a wholly owned subsidiary of ChevronTexaco. Situated in Louisiana, Henry Hub is formed through the physical interconnection of nine inter-state and four intrastate pipelines. The New York Mercantile Exchange (NYMEX) designates Henry Hub as the notional point of delivery for its natural gas futures contract. Deliveries at Henry Hub by NYMEX are treated akin to cash-market transactions. Furthermore, numerous natural gas marketers utilize Henry Hub either as their physical contract delivery point or as the benchmark for spot trades of natural gas.

Heat generation

Heat generation refers to fuel use in heat plants and combined heat and power (CHP) plants.

Heat plants

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

Hub

Most frequently in the U.S. and now used in Europe. There are many hubs in the U.S., of which the most important is Henry Hub (HH). In Europe, National Balancing Point (NBP) in the U.K. and Title Transfer Facility (TTF) are the most widely used.

Hydropower

Hydropower covers the energy content of the electricity produced in hydro power plants.

Industry sector

The industry sector 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.

In-FEED LNG project

In-FEED LNG project is a project that has started FEED, valid for either the upstream or liquefaction segment.

International aviation bunkers

International aviation bunkers cover 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

International marine bunkers cover 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.

Liquefied Petroleum Gas (LPG)

LPG refers to a mixture of propane and butane which has been liquefied by reducing the temperature, increasing the pressure or a combination of both. LPG is commonly called bottled gas, cooking gas, etc. It is principally sourced from natural gas processing plants, LNG plants and crude oil refineries.

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)

NGL refers to heavier hydrocarbons found in natural gas production streams and extracted for disposal separately. Within defined limits ethane, propane and butane may be left in the gas to enrich the calorific value. The terms natural gas liquids and condensates are in practice used virtually interchangeably.

Natural gas production capacity

Natural gas production capacity refers to the potential volumes of natural gas ready to be produced by developed wells and processing units associated with a production entity.

Natural gas production

Natural gas production stands for marketed production including domestic sales and exports.

Natural gas proven reserves

Natural gas proven reserves refer to existing reserves, new projects and unconventional (existing) gas resources.

Natural gas

Natural gas is a gaseous fuel obtained from underground sources and consisting of a complex mixture of hydrocarbons, primarily methane, but generally also including ethane, propane and higher hydrocarbons in much smaller amounts. It generally also includes some inert gases, such as nitrogen and carbon dioxide (CO₂), plus minor amounts of trace constituents. Natural gas remains in the gaseous state under the temperature and pressure conditions normally found in service.

New project gas production

New project gas production contemplates fields that have been discovered but have yet to be developed or are in development.

Non-Associated gas

Non-Associated gas is a natural gas found in a reservoir that contains no crude oil, and can therefore be produced in patterns best suited to its own operational and market requirements.

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

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

Oil

Oil includes demand for crude oil both conventional and unconventional and petroleum products including 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 products

Oil products comprise refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes, petroleum coke and other oil products.

Oil sands

Oil sands are 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 lithology, including siltstones and carbonates.

Petrochemical feedstock

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

Power generation refers to electricity generation from all sources of electricity, including electricity-only power plants and combined heat and power plants.

Pre-FEED LNG project

A pre-FEED LNG project refers to a project that has officially announced that it has started pre-FEED, valid for either the upstream or liquefaction segment.

Probable reserves

Probable reserves are 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 the actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved and 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 production entity is 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

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

Proposed LNG project

A proposed LNG project is a proposed and planned capacity that has not yet started FEED. Includes projects that have completed pre-FEED but not yet begun FEED.

Proved reserves

Proved reserves are hydrocarbon reserves 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 feedstock

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

Renewables include geothermal, solar photovoltaics (PV), concentrating solar power (CSP), onshore and offshore wind, and marine (tide and wave) energy for electricity and heat generation.

Reserves

Reserves are quantities of petroleum that are 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.

Solar photovoltaic (PV)

Solar PV electricity refers to electricity produced from solar photovoltaics, i.e. by the direct conversion of solar radiation through photovoltaic processes in semiconductor devices (solar cells), including concentrating photovoltaic systems.

Speculative LNG project

A speculative LNG project is a capacity that is a long-term possibility for future liquefaction supply based on available reserves, but which has not been officially proposed by a company.

Spot trading

A loose term covering the buying and selling of gas other than under a long term contract. Generally, it means immediate delivery in trading parlance "spot delivery".

Stalled LNG project

A stalled LNG project is a project that is not officially cancelled but has not made progress in recent years.

Take or pay (TOP)

TOP refers to a general provision in gas contracts under which, if the buyer's annual purchased volume is less than the Annual Contract Quantity (ACQ) minus any shortfall in the seller's deliveries, minus any Downward Quantity Tolerance (DQT), the buyer pays for such a shortfall as if the gas had been received. The buyer may have the right in subsequent years to take the gas paid for but not received, either free or for an amount to reflect changes in indexed prices.

Tight gas

Tight gas is 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 (TFC)

Total final consumption is 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 (TPED)

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

Transport includes all 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

Unconventional gas production refers to the 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).

Under construction LNG project

Under construction LNG project refers to the capacity that is currently under construction or going through commissioning.

Wind

Wind electricity refers to electricity produced from devices driven by wind.

Wobbe Index

Occasionally referred to as the Wobbe number. A measure of the rate at which gas will deliver heat on combustion and hence of the compatibility of a gas with gas burning equipment.

Yet-to-Find (YTF)

Yet-to-find reserves refer 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.



GECF

Gas Exporting Countries Forum, GECF

GECF Headquarters
P.O.Box 23753, Tornado Tower
47th & 48th Floors, West Bay, Doha