

# THE FUTURE OF NATURAL GAS

## MARKETS AND GEOPOLITICS



*EDITORS*

**SILVIA COLOMBO, MOHAMED EL HARRAK AND NICOLÒ SARTORI**



# The Future of Natural Gas Markets and Geopolitics

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*Silvia Colombo, Mohamed El Harrak and Nicolò Sartori*



## The Future of Natural Gas. Markets and Geopolitics

Editors: Silvia Colombo, Mohamed El Harrak and Nicolò Sartori

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## Table of contents

List of Contributors .....	9
List of Abbreviations .....	11
Foreword .....	17
Introduction	
<i>Lorenzo Colantoni, Silvia Colombo, Lilia Rizk and Nicolò Sartori</i> .....	19
1. The Future of Gas: The Transition Fuel?	
<i>Luca Franza, Dick de Jong and Coby van der Linde</i> .....	25
1.1 The Case for Natural Gas as a Transition Fuel: Energy per Carbon Matters .....	26
1.2 The Failure of Policy-Making in Promoting Gas as a Transition Fuel .....	31
1.3 The Perception of Gas as a Politicised Commodity .....	34
Conclusions .....	39
2. On the Future of Global LNG Trade and Geopolitics	
<i>Chi-Kong Chyong</i> .....	41
2.1 Evolution of LNG Trade and Pricing .....	42
2.2 Spot and Short-term LNG Trade .....	46
2.3 Short-term Limits to Inter-Regional LNG Trade and Global Gas Market Integration .....	51
2.4 Future LNG Developments and Implications for International Trade and Geopolitics .....	54
Conclusions .....	60
3. The United States as a New Gas Exporter	
<i>David Koranyi</i> .....	63
3.1 US Natural Gas Production Potential .....	63
3.2 US Natural Gas Demand .....	65
3.3 Natural Gas Exports from the US .....	66
3.4 The Political and Regulatory Environment .....	68
3.5 Global LNG and Gas Market Developments .....	69
3.6 US LNG Export Competitiveness and Export Destinations .....	72
3.7 Energy Security Considerations in Europe and Asia .....	75
Conclusions .....	76

4. Gas in South America: Resources, Corridors and Policies	
<i>Gonzalo Escribano</i> .....	79
4.1 Resources .....	80
4.2 Corridors .....	85
4.3 Gas Policies .....	88
4.4 Looking Ahead .....	94
5. The EU and LNG as a Flexible Tool for Energy Security: Constraints and Opportunities	
<i>Giacomo Luciani</i> .....	101
5.1 The Global LNG Market: Developments and Perspectives .....	103
5.2 LNG in European Gas Supplies .....	106
5.3 The Commission's Proposed LNG Strategy .....	110
Conclusions .....	115
6. Eastern Mediterranean Gas: Source of Prosperity for the Region?	
<i>Ayla Gürel</i> .....	117
6.1 Eastern Mediterranean Gas Potential .....	118
6.2 Gas Discoveries and Development .....	120
6.3 Regional Political and Maritime Disputes .....	126
6.4 Markets for Eastern Mediterranean Gas .....	131
Conclusions .....	137
7. Western Mediterranean Gas: Towards North-South Convergence or Increasing Competition?	
<i>Houda Ben Jannet Allal</i> .....	139
7.1 Natural Gas Demand Is Booming in the Western Mediterranean Region .....	140
7.2 Natural Gas Supply in the Western Mediterranean Region .....	144
7.3 Natural Gas Trade in the Western Mediterranean Region .....	152
7.4 Western Mediterranean Gas: Driver for North-South Convergence and Win-Win Cooperation .....	155
8. Winds of Change. Challenging Future for Russia's Gas	
<i>Agata Łoskot-Strachota</i> .....	159
8.1 Potential: Russian Gas Reserves and Production .....	160
8.2 Russian Gas on the Domestic Market .....	162
8.3 Decreasing Role of the CIS Market .....	167
8.4 Europe and Turkey .....	171
8.5 Challenges and Changes in Gas Trade with Europe .....	173
Conclusions .....	177

9. Sub-Saharan Africa: A Future Global Gas Player?	
<i>Philippe Copinschi and Mark Smedley</i> .....	181
9.1 The Evolution of the Hydrocarbon Industry in West Africa .....	183
9.2 East Africa: A New Frontier for the Gas Industry .....	198
Conclusions .....	203
10. Asia's Natural Gas and LNG Market Trends	
<i>Wenran Jiang</i> .....	207
10.1 Asia's Thirst for Natural Gas and LNG .....	208
10.2 Impact of the Oil Price Decline on Asian Gas Dynamics .....	211
10.3 China's Gas and LNG Strategies .....	214
10.4 China-Russia Cooperation .....	217
10.5 Other Regional Dynamics .....	219
10.6 Prospects for Market and Policy .....	221
11. The Evolution of Japan's LNG Strategies and Their Geopolitical Implications	
<i>Jane Nakano</i> .....	223
11.1 The Growth of Natural Gas in the Japanese Energy System .....	223
11.2 The Fukushima Nuclear Accident and Natural Gas Renaissance .....	224
11.3 Diversifying the Supplier Country Pool .....	226
11.4 Diversifying LNG Procurement Models .....	227
11.5 Domestic Factors Influencing the Future of Gas in Japan .....	230
11.6 Blessing and Curse of Low Oil Prices .....	233
11.7 Geopolitical Developments Affecting Japanese LNG Strategies .....	234
Conclusions .....	238



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## List of Abbreviations

AGP	Arab Gas Pipeline
APEC	Asia-Pacific Economic Cooperation
APG	ASEAN Power Grid
ARI	Advanced Resources International
ASEAN	Association of Southeast Asian Nations
Bcm	Billion Cubic Metres
BDS	Boycott, Divestment and Sanctions
Bpd	Barrels per Day
Btu	British Thermal Unit
CAGR	Compound Annual Growth Rate
CCGT	Combined-Cycle Gas Turbine
CEE	Central and Eastern Europe
CIS	Commonwealth of Independent States
CNG	Compressed Natural Gas
CNPC	China National Petroleum Corporation
CO <sub>2</sub>	Carbon Dioxide
COP21	2015 United Nations Climate Change Conference
CTI	Carbon Tracker Initiative
DES	Delivered Ex-Ship
DoE	Department of Energy (US)
ECOWAS	Economic Community of West African States
EE	Energy Efficiency
EEZ	Exclusive Economic Zone
EGAS	Egyptian Natural Gas Holding Company
EGLNG	Equatorial Guinea LNG
EGPC	Egyptian General Petroleum Corporation
EIA	Energy Information Administration (US)
ENTSOG	European Network of Transmission System Operators for Gas
EOR	Enhanced Recovery Technique

## LIST OF ABBREVIATIONS

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EPA	Environmental Protection Agency
EPS	Emission Performance Standard
EPSA	Exploration and Production Sharing Agreement
ERI RAS	Energy Research Institute of the Russian Academy of Sciences
ETS	European Trading Scheme
EU	European Union
FERC	Federal Energy Regulatory Commission (US)
FID	Final Investment Decision
FLNG	Floating Liquefied Natural Gas
FOB	Free on Board
FSRU	Floating Storage and Regasification Unit
FSU	Former Soviet Union
FTA	Free Trade Agreement
GDP	Gross Domestic Product
GGFR	Global Gas Flaring Reduction Partnership
GHG	Greenhouse Gas
GIIGNL	International Group of Liquefied Natural Gas Importers
GJ	Gigajoule
GNEA	Gasoducto del Noreste Argentino
GNPC	Ghana National Gas Corporation
Gt	Gigatonne
GW	Gigawatt
IAA	Israeli Antitrust Authority
ICAO	International Civil Aviation Organisation
IEA	International Energy Agency
IGU	International Gas Union
IMF	International Monetary Fund
IMO	International Maritime Organisation
INDC	Intended Nationally Determined Contribution
IOC	International Oil Company
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Project
ISIL	Islamic State of Iraq and the Levant
ITGI	Interconnection Turkey Greece Italy
JBIC	Japan Bank for International Cooperation
JCC	Japan Customs-cleared Crude
JFY	Japanese Fiscal Year
JKM	Japan Korea Marker

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JKM	Japan, South Korea, Taiwan
JOGMEC	Japan Oil, Gas and Metals National Corporation
KRG	Kurdistan Regional Government
LNG	Liquefied Natural Gas
LoI	Letter of Intent
MENA	Middle East and North Africa
MERCOSUR	Mercado Común del Sur
MJ	Megajoule
MmBpd	Million Barrels of Oil per Day
MmBtu	Million Btu
Mmcm/d	Million Cubic Metres per Day
MoU	Memorandum of Understanding
MSR	Market Stability Reserve
MW	Megawatt
MWh	Megawatt-hour
NBP	National Balancing Point
NEPCO	National Electric Power Company
NIPP	National Integrated Power Project
NLNG	Nigeria LNG
NNPC	Nigerian National Petroleum Corporation
NOC	National Oil Company
NO <sub>x</sub>	Nitrogen Oxides
NPS	New Policies Scenario
NRGI	Natural Resources Governance Index
OCTP	Offshore Cape Three Point
OECD	Organisation for Economic Co-operation and Development
OME	Observatoire Méditerranéen de l'Énergie
PCI	Project of Common Interest
PdVsa	Petróleos de Venezuela S.A.
PGS	Petroleum Geo-Services
PKK	Kurdistan Workers' Party
PRC	People's Republic of China
PWh <sub>el</sub>	Petawatt-hour Electric Energy
PWh <sub>th</sub>	Petawatt-hour Thermal Energy
RES	Renewable Energy Source/System
RGGI	Regional Greenhouse Gas Initiative
RoC	Republic of Cyprus
SLNG	Singapore LNG

## LIST OF ABBREVIATIONS

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SNH	Société Nationale des Hydrocarbures
SO <sub>2</sub>	Sulphur Dioxide
SPA	Sales and Purchase Agreement
TAGP	Trans-ASEAN Gas Pipeline
Tcm	Trillion Cubic Metres
TCP	Trans-Caspian Pipeline
TEPCO	Tokyo Electric Power Company
TPAO	Turkish Petroleum Corporation
TPP	Trans-Pacific Partnership
TRNC	Turkish Republic of Northern Cyprus
TSGP	Trans-Saharan Gas Pipeline
TTF	Title Transfer Facility
TTIP	Transatlantic Trade and Investment Partnership
TWh	Terawatt-hour
TWh <sub>el</sub>	Terawatt-hour Electric Energy
TWh <sub>th</sub>	Terawatt-hour Thermal Energy
UFG	Union Fenosa Gas
UfM	Union for the Mediterranean
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USGS	US Geological Survey
USSR	Union of Soviet Socialist Republics
VOG	Victoria Oil and Gas
WAGL	West African Gas Limited
WAGP	West African Gas Pipeline
WEO	World Energy Outlook
YPF	Yacimientos Petrolíferos Fiscales

## About IAI

A non-profit organization, IAI was founded in 1965 by Altiero Spinelli, its first director. The Institute aims to promote understanding of international politics through research, promotion of political ideas and strategies, dissemination of knowledge and education in the field of foreign policy. IAI main research sectors are: European institutions and policies; Italian foreign policy; trends in the global economy and internationalisation processes in Italy; the Mediterranean and the Middle East; energy; defence economy and policy; and transatlantic relations.

[www.iai.it](http://www.iai.it)

## About OCP Policy Center

OCP Policy Center is a Moroccan policy-oriented think tank whose mission is to contribute to knowledge sharing and to enrich reflection on key economic and international relations issues, considered as essential to the economic and social development of Morocco, and more broadly to the African continent. For this purpose, the think tank relies on independent research, a network of partners and leading research associates, in the spirit of an open exchange and debate platform.

[www.ocppc.ma](http://www.ocppc.ma)



## Foreword

This book is the result of a journey into the present and the future of natural gas. The project was launched in 2015 in the framework of the strategic partnership between the Istituto Affari Internazionali (IAI) in Rome and the OCP Policy Center in Rabat. From its very inception the project has involved a solid group of renowned scholars and prestigious institutions from every corner of the world. The journey has been a rich and stimulating one from a scientific point of view, and has resulted in a book that we believe will be of interest to a broad readership including students, scholars and practitioners.

The topic itself – the evolution of natural gas markets against the backdrop of important geopolitical shifts – is a timely one. As argued in the introduction, the role of natural gas has evolved significantly in the past decades and a number of important discoveries, market opportunities as well as cooperative/conflictual relations at the inter-state level have emerged as a result of the ever more complex political and economic geography of natural gas. The book develops all of these topics by adopting a geographical perspective that benefits from the unrivalled expertise of a group of authors spanning key production or consumption regions such as Europe, the United States, South America, the Mediterranean basin, Africa and Asia. The result is a comprehensive and rigorous analysis that also offers insightful inputs from a policy perspective.

This is indeed the reason why two think tanks such as IAI and the OCP Policy Center have decided to engage with energy issues, and in particular with the future of natural gas from the technological, regulatory, commercial and geopolitical perspective, in the framework of their cooperation. The partners have selected this broad topic in light of its relevance in informing the readership about domestic, regional and international dynamics that are of the essence in understanding issues such as the evolution of the gas infrastructural map, the evolving economics of natural gas but also political resilience, and shifting balances of power at the global level. The current project represents the second such joint endeavour. A book entitled *Building Sustainable Agriculture for Food Security in the Euro-Mediterranean: Challenges and Policy Options* was published in 2015 and widely disseminated amongst the experts community in Rabat, Milan and Rome.



We are very glad that our mutual cooperation has again been fruitful, and would like to acknowledge the invaluable contribution of a number of people. In addition to the editors of this book, who have been the scientific and practical promoters of the project throughout all its phases, our thanks go to the authors, who have been constantly and highly committed to it. In addition, we wish to thank all the participants in the closed-door seminar held at IAI in mid-December 2015 and aimed at discussing the draft chapters of the book, which was followed by a high-level public event in Rome gathering prominent local and international experts. In particular, the discussion of the drafts has benefited from the top-quality expertise of Paolo d’Ermo, Fabrice Fortin, Marco Margheri and Silvia Pariente-David. Last but not least, our deepest gratitude goes to the editorial staff of the European Energy Review (EER), who have believed in this project and have partnered with our Institutes in the publication, marketing and dissemination phases. Finally, this book would not have seen the light without the ongoing support of the whole staff at IAI and at the OCP Policy Center, who have been involved in this project in different capacities, and in particular Rim Berahab, Alessandra Bertino, Lorenzo Colantoni and Maritza Cricorian.

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## Introduction

Lorenzo Colantoni, Silvia Colombo, Lilia Rizk and Nicolò Sartori

The key contribution of natural gas to the world energy mix is quite recent compared to its fossil fuel substitutes, namely coal and crude oil. For good part of the last century, indeed, gas has mainly been considered as an unwanted and difficult-to-exploit by-product of the oil industry. Therefore, without economic means of bringing them to market, gas resources discovered alongside crude oil were usually left unexploited, when not vented or flared, until shifts in technology and international dynamics led natural gas production to make its way into the world energy market.

At the end of the Cold War, the world's total production amounted to two trillion cubic meters (Tcm) of gas, with just three major regional markets: the US, Europe and the former Soviet Union. On the one hand, the US was insulated and self-sufficient, with just a moderate dependence on gas supplies from its northern neighbour Canada. On the other hand, Europe and the former Soviet Union were strongly interdependent due to a complex import–export relationship, and remain so to this day.

However, in the past two decades, and particularly in the last five years, significant changes have come about. In 2011, the International Energy Agency (IEA) predicted that the world would rapidly enter into “a golden age of gas,” during which gas demand would reach 5.1 Tcm (by 2035). According to the IEA's predictions, these trends will lead to an increase in shares of natural gas on the world market, namely from 21 percent to 25 percent, to the detriment of coal's contribution to the global energy mix. This optimistic outlook on the future of natural gas is due, for the most part, to the newly discovered abundance of the resource (equivalent to more than 120 years of current global consumption), as well as its wide geographical distribution with all major regions holding recoverable resources that can meet current demand for at least 75 years.

The exploitation of gas resources and the development of a global natural gas market have come with their share of obstacles, due to the complex system of infrastructure, technologies and processes necessary to extract, process, store, transport and

distribute it to customers. However, with pressing environmental concerns, and given that natural gas is low in carbon content when compared to conventional energy sources, the natural gas sector has been able to develop over the past decades, becoming an alternative at worst, and a substitute at best for both coal and crude oil. This has led gas to progressively become a vital component of the world's supply of energy and a factor in geopolitical competition. Between 1990 and 2010, global natural gas production increased by 60 percent, driven in particular by rising demand in emerging markets in the Middle East and Asia Pacific, China *in primis*. This global demand, growing faster than demand for the other fossil fuels, is being met also thanks to the emergence of new gas producers like Qatar, Nigeria, Trinidad and Tobago, Australia, Malaysia and Thailand. In addition, in the last few years technological developments both in the extraction and transportation sectors – the growth of shale gas production and the expansion of the liquefied natural gas (LNG) market – have contributed to reinforcing these forecasts. On the one hand, global unconventional natural gas resources are believed to be at least as large as conventional ones, with great potential not only in the US market, but also in China, India, Australia and Indonesia. On the other, global LNG trade – which has more than doubled in the last two decades – currently accounts for one third of the world's total gas supplies and is transforming the nature of the gas market, which is increasingly interconnected and globalized, as demonstrated by progressively convergent LNG prices in Europe and Asia.

The expansion of gas in the global energy mix is also justified by environmental and climate policies agreed at the international level. Natural gas has been identified as the “bridge fuel” towards a fully decarbonized energy sector. Its first and foremost importance is as a substitute for coal in the electricity mix, where it currently represents 27 percent of total generation, compared to 39 percent for coal. By producing, on average, half the carbon dioxide emissions when compared to lignite, and thanks to power conversion efficiencies of new generation combined-cycle power plants, gas could halt the growth of coal consumption in countries such as India, and reduce the current consumption level in countries such as China. This situation can only materialize into a tangible reality if regulatory frameworks such as carbon taxes and carbon prices are put in place and effectively implemented. In addition, gas has the flexibility required to cope with the intermittency of renewable energies. Gas power plants have indeed the shortest start-up time when compared to both coal and nuclear power plants, thus representing the ideal complement to expanding renewable energy capacity across the world. In particular, the combination between gas and renewables can be valuable in developing markets, where the electrification rate is still low and the establishment of electricity infrastructure is in the embryonic phase, as in parts of sub-Saharan Africa and Latin America.

The degree of flexibility in the use of gas is increased by its potential role in the

transport sector. The resource has been increasingly used for road transport, in vehicles fuelled by both LNG and Compressed Natural Gas (CNG), the latter in particular for long-haul, heavy duty and public transport. Nonetheless, maritime transportation has witnessed the fastest growth in gas use, thanks to low levels of taxation worldwide and the significantly low sulphur emissions. The use of gas in maritime transportation therefore fits the recent establishment of Sulphur Emission Control Areas in the North Sea, the Baltic and large areas of the Canadian and US coasts, as it represents a solution to recent restrictions on sulphur emissions.

The role of gas has significantly evolved in the past decades: production and consumption patterns have changed, consequently altering traditional importer/exporter relations. In this sense, the geopolitics of gas has influenced the relations among states, and vice versa.

For instance, the shale revolution in the US is bringing the country towards energy independence, *de facto* reducing the pressure by formerly key suppliers. It is also leading to a modification of the global energy market dynamics, affecting the supply–demand balance. US shale production, made possible by the combination of hydraulic fracking and horizontal drilling techniques, is expected to continue to increase, moving the country into the gas exporter group. This will significantly affect relations on all fronts, namely on the Atlantic side with Europe, and on the Pacific side with the great Asian gas consumers. China, for its part, is facing an increasing interest in expanding gas consumption, as it needs to address not only CO<sub>2</sub> emissions, but also the smog which is harming the health of its cities and its citizens.

Europe, despite an expected decrease in consumption, is constantly looking to diversify its energy sources, to avoid putting all its eggs in one basket. Therefore, due to its decreasing domestic production, the ongoing situation in Ukraine and the high dependence of some of its member states on Russian gas, the EU is looking to alternatives to secure its access to natural gas. Thus, the need to diversify gas supply is acting as one of the key drivers in the European foreign energy policy, as demonstrated by the recent initiative of the Energy Union, which clearly places a dominant focus on gas supply. On the other side Russia, threatened by the EU's diversification strategies and internal market regulatory framework, is looking eastward – particularly to China – to strengthen its export strategy and ensure those international energy revenues necessary to the sustainability of its budget and to the socio-economic stability of the whole country.

Moving South and East, the Mediterranean and Middle Eastern regions face increasing electricity and gas demand – driven also by generous longstanding subsidy policies – which not only risks to affect fiscal budgets of producing countries (severely hit also by the oil price decline) but also questions the capacity of the region to act as a global gas supplier. Looking at the internal situation, natural gas can play a role in

providing an alternative source of energy in the Southern Mediterranean and the MENA region, but greater infrastructure flexibility, stable foreign investments and effective technology transfer policies are needed to allow such a shift to occur.

Finally, Africa is emerging as a potential front-line actor in the global gas sector. As energy demand is growing on the African continent, in light of the increased electrification linked to economic development, natural gas can come to represent a significant player in the African energy mix. However, if faced with significant entry barriers, and if technology and investments do not follow, the continent may not be able to benefit from the advantages of the natural gas sector.

In this context of rapidly evolving market trends and reshaping dynamics between regional and global actors, the book analyses the role of natural gas in the future global energy mix, in light of the ambitious climate policies agreed by the international community, but also factoring issues of cost and the role of technological innovation into the broader global gas picture. Moving from these general analyses, the volume adopts a geographical perspective, describing the main developments in key supplying and consuming regions and countries. In its eleven chapters, the book offers a comprehensive picture of the global natural gas sector, addressing key geological features and resource potential, the development of internal policies and regulatory frameworks, the evolution of gas production and consumption patterns, as well as the implementation of import and export strategies elaborated by key regional and global gas players.

**Chapter 1** by Luca Franza, Dick de Jong and Coby van der Linde presents the potential offered by natural gas in the transition towards a cleaner energy mix thanks to its highest values of energy generated per carbon emitted. The chapter summarizes the traditional arguments in support of the environmental qualities of gas as a bridge fuel and analyses the different policy-making measures determining its current role in the global energy mix. In addition it discusses the geopolitical features of gas as a commodity, assessing how these have somehow prevented it from rapidly forming the core of the contemporary global energy architecture along with renewables.

**Chapter 2** by Chi-Kong Chyong focuses on the emergence of LNG as one of the fastest growing internationally traded commodities and on its potential contribution to the integration of once regional natural gas segments into a globalized market. It describes how the diversification of gas trade relations determined by the expansion of the LNG sector might affect the traditional dynamics of regional energy trade, potentially improving energy security of both consumers and producers. Despite this great potential, the chapter highlights how short-term limits to inter-regional trade in LNG still represent a constraint to the full globalization of the gas market. It also discusses the possible impact of new LNG export projects from the US and the Middle East on these dynamics, and more generally addresses the geopolitical nature of LNG at the global level.

**Chapter 3** by David Koranyi looks into the unprecedented energy revolution in the United States, assessing how the shale gas bonanza is about to modify the energy status of the country. It recaps the main technological, regulatory and market drivers leading to this exceptional energy outcome, discussing the US political and energy security considerations behind these developments. In addition, the chapter explores the potential for US natural gas production and exports, contextualizing these trends into the broader global LNG market picture and presenting the repercussions of US LNG exports for European and Asian energy security, and more broadly for the dynamics in the global natural gas market.

Gonzalo Escribano's **Chapter 4** offers an overview of the main natural gas dynamics in the Southern American continent, showing that despite the abundance of resources in the region, the gas policies implemented at the national level have slowed down the development processes and limited the actual regional gas output. While presenting the enduring obstacles to deeper regional market integration, the chapter finally discusses the opportunities offered by natural gas for South America's energy and economic development, and also to foreign players interested in investing in the region.

**Chapter 5** by Giacomo Luciani explores the current trends in EU gas demand, trying to assess the potential contribution of LNG trade as a flexible tool for European security of supply. It focuses on the status of available and planned LNG import facilities for the European gas network and on the main challenges to the full exploitation of liquefied gas by EU member states. Finally, the chapter analyses the content of the recent "EU LNG Strategy" proposed by the Commission, which aims to provide a coherent and effective usage of LNG across the European continent.

Ayla Gurel's **Chapter 6** analyses the recent gas developments in the East Mediterranean, assessing the potential gas discoveries made by Israel and Cyprus in the Levant Basin. The chapter offers an overview of the main political regional factors slowing down the development of the resources in the area. It then focuses on the market opportunities for East Mediterranean gas, presenting the different export options available, in terms of both pipeline and LNG, included the perspective for an "East Mediterranean gas hub" expected to contribute to the EU's gas diversification strategy and eventually to its energy security.

**Chapter 7**, by Houda Ben Jannet Allal, describes the evolution of the energy market in the West Mediterranean, providing an in-depth analysis of the main national trends in natural gas demand and supply in Algeria, Egypt, Libya, Morocco and Tunisia. The chapter explores the main gas trade dynamics at the regional level, assessing the current and potential contribution of West Mediterranean gas to European security of supply, and presenting the perspectives of North–South energy cooperation across the Mediterranean.

In **Chapter 8**, Agata Łoskot-Strachota offers an overview of the key trends in place in the Russian energy sector. This chapter analyses the evolution of Russia's internal market, focusing on the ongoing process of liberalization affecting Gazprom's dominant position, and then describes the changing role of Russian gas in its traditional export markets: CIS, Europe and Turkey. In light of these evolving relations, the chapter ends by assessing the strategic attempt of Russian leadership to diversify its export option by establishing deeper gas ties with emerging East Asian consumers, in particular China.

Mark Smedley and Philippe Copinschi's **Chapter 9** explores the great gas potential of the African continent. The first part of the chapter focuses on Sub-Saharan Africa, mapping the current and future gas export projects and LNG initiatives in the region, and assessing the potential contribution of natural gas to the establishment of functioning domestic energy markets necessary to meet the growing regional demand. The second part of the chapter looks into recent developments in East Africa, one of the most promising spots for natural gas production at the global level. It explores the potential of Mozambique and Tanzania as LNG exporters, but also assesses the possibility of using part of the huge reserves available to develop a regional gas market and ensure better access to energy for local consumers.

In **Chapter 10** Wenran Jiang describes the main gas market trends and perspectives for regional cooperation in the Asian continent, also in light of the current oil price decline. The chapter focuses in particular on the role of China, the key driver for natural gas and LNG demand in the region, which is developing a comprehensive supply strategy aimed at maximizing both domestic production and the diversification of external suppliers. The chapter investigates the status of gas cooperation between China and Russia, assessing the potential geopolitical implications of deeper partnership in the energy domain between the two countries.

**Chapter 11** by Jane Nakano addresses the role of Japan in the global LNG market and the strategies developed by the country – by far the world's largest importer of liquefied gas – to meet its huge domestic demand. It describes the surge of LNG in the country's energy supply mix following the 2011 Fukushima nuclear accident, presenting the different policies (diversification of suppliers, diversification of LNG procurement models) adopted by Japan to cope with this exogenous shock. Finally, the chapter evaluates the different internal factors determining the future of LNG in the country's energy mix, factoring in also the geopolitical developments that could affect the LNG strategies of Japan.

# 1. The Future of Gas: The Transition Fuel?

Luca Franza, Dick de Jong and Coby van der Linde

The environmental credentials of natural gas build on its potential to improve local air quality, its higher efficiency in power generation compared to oil and coal, lower greenhouse gas (GHG) emissions relative to other fossil fuels, and suitability for partnering with renewables as a back-up fuel. Alternative perspectives on the “carbon bubble” discussion invite a clear distinction between the incompatibility of exploiting oil and coal reserves on the one hand, and gas on the other, with the objective of remaining within a 2°C trajectory. More specifically, it appears that using all of the existing natural gas reserves would not in itself be in contradiction with this objective.<sup>1</sup> Using natural gas to satisfy fossil energy demand would actually give the world more time within this trajectory than if coal were used, indicating that gas could and should play a role in the transition towards a cleaner energy mix.

Yet, global gas consumption is not growing as much as anticipated.<sup>2</sup> It is also important to notice that, even in regions where gas consumption is growing, this expansion is usually not driven by deliberate policy decisions aimed at reducing CO<sub>2</sub> emissions.<sup>3</sup> In Europe, unlike renewables, gas appears to lack a specific policy support as a fuel. At the same time, technology-neutral instruments such as the European Trading Scheme (ETS) do not trigger coal-to-gas switching in their current design, as coal remains competitive and the generated CO<sub>2</sub> price is low owing to an oversupply of allowances. In the current context, local policy initiatives such as those aimed at improving air quality, especially in Asia, turn out to promote natural gas more incisively than more encompassing – and potentially more impactful – climate policies.

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<sup>1</sup> Emma Van Der Veen, “Why Energy per Carbon Matters”, in *CIEP Papers*, No. 2015|2 (March 2015), <http://www.clingendaelenergy.com/publications/publication/why-energy-per-carbon-matters>.

<sup>2</sup> Fatih Birol, *Are We Entering a Golden Age of Gas?* World Energy Outlook Special Report, Paris, IEA, June 2011, <http://www.worldenergyoutlook.org/goldenageofgas>.

<sup>3</sup> To the contrary, local clean air policy measures that favour gas are indeed being taken in many parts of the world, as will be discussed later in this chapter.



This chapter contributes to the discussion on the key factors affecting the role of natural gas in climate policies worldwide. One of our findings is that gas greatly suffers from security of supply considerations entrenched in geopolitics, in addition to national policy approaches to climate change. Europe in particular appears reluctant to give political credence to higher gas consumption, out of concerns over security of supply. The 2016 “winter package” is a case in point. The ongoing crisis in Ukraine – and more generally the emergence of a “new arc of instability” around Europe – aggravates this reluctance. Another factor that negatively affects the image of gas in Europe is the perception that it is more expensive than is justified in competitive markets, although this concern is less prevalent in the current oil and gas price environment. Moreover, in spite of its environmental credentials relative to other fossil fuels, gas is regarded as “part of the problem” in a number of policy-making circles. Finally, in policy-making, environmental advantages in the choice of gas relative to coal generally tend to be subordinated to considerations related to the national economy or employment, particularly when coal is abundant domestically. Price considerations also provide a substantial incentive to using coal rather than natural gas. The chapter focuses on the perception of gas as a politicised commodity, which has gained traction in the last two years in an increasingly volatile geopolitical context in gas producing and transit regions. The lack of targeted policy support risks hampering the contribution of gas to the transition towards a cleaner energy mix, and arguably the transition itself.

## 1.1 The Case for Natural Gas as a Transition Fuel: Energy per Carbon Matters

With 35 percent of total anthropogenic GHG emissions,<sup>4</sup> the energy supply sector is the single largest contributor to climate change. Gearing the energy mix to a more environmentally sustainable pattern is thus a priority for policy-makers worldwide. One of the most widely embraced goals to limit the adverse effects of climate change is that of containing the average temperature increase by 2050 to a maximum of 2°C as compared to the pre-industrial level (the so-called “2°C target”).<sup>5</sup> The 2015 United Nations Climate Change Conference (COP21) set an even more ambitious aim of keeping “a global temperature rise this century well below 2 degrees Celsius and [driving]

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<sup>4</sup> International Panel for Climate Change (IPCC), *Climate Change 2014*. Fifth Assessment Report, 2014, <http://www.ipcc.ch/report/ar5>.

<sup>5</sup> Including more recently at the G8 summit held in L’Aquila, Italy (2009).

efforts to limit the temperature increase even further to 1.5 degrees Celsius above pre-industrial levels.”<sup>6</sup>

Support for low-carbon-emitting sources of energy and promotion of energy efficiency stand out as the two main policy directions adopted to this end.<sup>7</sup> Given the current status of technology, and notably the lack of commercially viable electricity storage solutions at the moment, most renewable energy sources (RES) used in power generation need to be backed up by more predictable and reliable sources of electricity. As is also acknowledged by the New Policies Scenario (NPS) – the reference case of the World Energy Outlook (WEO) – this calls for a continued role for nuclear energy – albeit absent from a number of jurisdictions – and fossil fuels.<sup>8</sup> Natural gas has a fundamental role to play within the latter group, as the fuel that produces the lowest emissions per unit of energy produced. The importance of this factor becomes clear when we consider the narrowness of the world’s remaining “carbon budget.”<sup>9</sup>

In its 2014 Climate Change Report,<sup>10</sup> the Intergovernmental Panel on Climate Change (IPCC) indicated that limiting total human-induced warming to less than 2°C relative to the period 1861-1880 with a probability of more than 66 percent would require total CO<sub>2</sub> emissions from all anthropogenic sources since 1870 to be limited to about 2,900 gigatonnes (Gt). Considering that 1,900 Gt had already been emitted by 2011, the remaining carbon budget to 2,100 would then be 1,000 Gt. Previous scientific reports,<sup>11</sup> on which the carbon bubble discussion is based, concluded that total CO<sub>2</sub> emissions need to be capped at a total of 886 Gt during the first half of the 21st century in order to attain a likelihood of 80 percent that the 2°C target will be met. Taking into account CO<sub>2</sub> volumes that have already been emitted, the carbon budget for the period 2011-2050 amounts to 565 Gt of CO<sub>2</sub>. As the aggregate CO<sub>2</sub> emission potential of proven fossil fuel reserves is as high as 2,795 Gt of CO<sub>2</sub>, it is evident that a substantial share of these would have to be left in the ground. This triggered a well-known discussion led by the Carbon Tracker

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<sup>6</sup> United Nations Framework Convention on Climate Change (UNFCCC), *Historic Paris Agreement on Climate Change. 195 Nations Set Path to Keep Temperature Rise Well Below 2 Degrees Celsius*, 12 December 2015, <http://newsroom.unfccc.int/unfccc-newsroom/finale-cop21>.

<sup>7</sup> Institut français de relations internationales (IFRI) and CIEP, *Is Natural Gas Green Enough for the Environmental and Energy Policies?* Theme Paper for the IGU Task Force on Geopolitics, May 2015, <http://www.clingendaelenergy.com/publications/publication/the-new-dimensions-of-geopolitics>.

<sup>8</sup> International Energy Agency (IEA), *World Energy Outlook 2015*, November 2015, <http://energy.anu.edu.au/files/weo2015.pdf>.

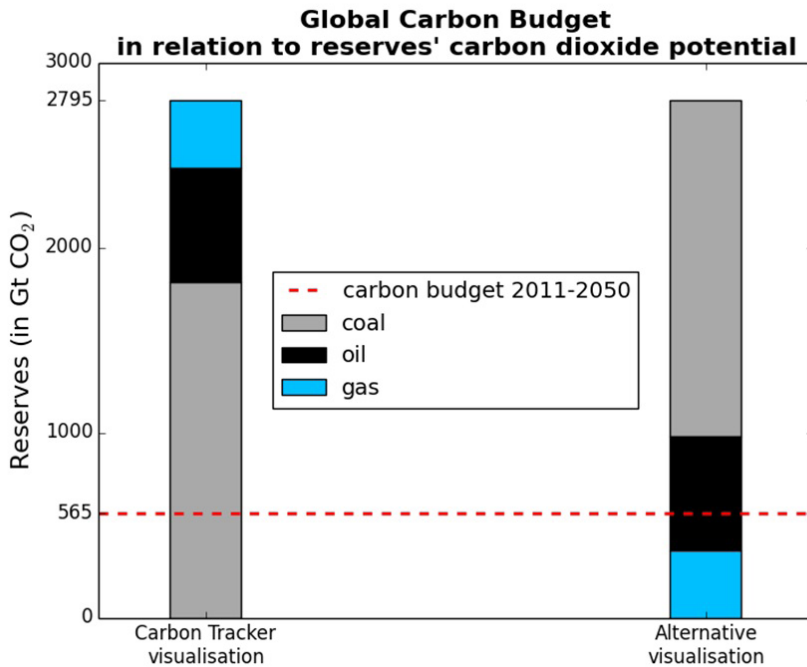
<sup>9</sup> Amount of carbon that can be burnt before it becomes unlikely we can avoid more than two degrees of global warming.

<sup>10</sup> IPCC, *Climate Change 2014*, cit.

<sup>11</sup> Malte Meinshausen et al., “Greenhouse Gas Emission Targets for Limiting Global Warming to 2°C”, in *Nature*, Vol. 458, No. 7242 (30 April 2009), p. 1158-1162, <http://dx.doi.org/10.1038/nature08017>.

Initiative (CTI) on whether the fossil fuel industry will incur a “carbon bubble” – a situation determined by the presence of stranded fossil assets.<sup>12</sup> What the CTI approach does not emphasize is that coal, oil and gas differ significantly in the amount of carbon dioxide that they emit. Two recent CIEP’s studies<sup>13</sup> attempt to redress this shortcoming.

Figure 1 | Alternative visualisation of the global carbon budget stacked by fuel



Source: Emma Van Der Veen, “Why Energy per Carbon Matters”, cit., p. 8.

An alternative visualisation of the figure prepared by CTI – which compares the CO<sub>2</sub> emission potential of various fossil fuels and the remaining carbon budget – invites a different perspective in the discussion on the exploitability of existing fossil fuel reserves (figure 1). By stacking the fuels with the lowest emitting sources at the bottom, a 2015 CIEP study shows that burning all of the world’s gas reserves and part of the oil reserves is not necessarily in conflict with meeting the carbon budget.<sup>14</sup> This scenario

<sup>12</sup> CTI, *Unburnable Carbon. Are the World’s Financial Markets Carrying a Carbon Bubble?* (Revised edition), May 2014, <http://www.carbontracker.org/report/carbon-bubble>.

<sup>13</sup> CIEP, “Transition? What Transition? Changing Energy Systems in an Increasingly Carbon Constrained World”, in *CIEP Papers*, No. 2014|09 (December 2014), <http://www.clingendaelenergy.com/publications/publication/transition-what-transition>; Emma Van Der Veen, “Why Energy per Carbon Matters”, cit.

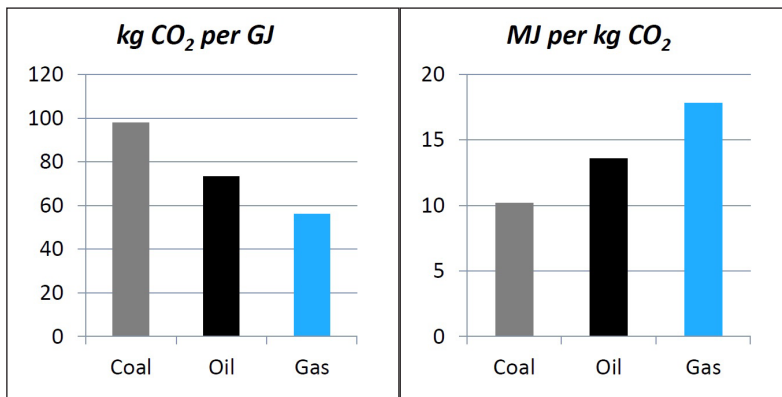
<sup>14</sup> Emma Van Der Veen, “Why Energy per Carbon Matters”, cit.

is certainly theoretical, as it would hinge on a complete halt of exploitation of coal worldwide.

It is however thought-provoking to highlight that if world nations were to make a concerted policy effort to promote a full coal-to-gas switch, we would be on track to meet the 2°C target while still benefitting from the predictability and reliability of a fossil fuel – which is necessary to keep the world’s economic growth pattern unchanged in default of viable technologies to store electricity. By not taking into account the differences in the carbon content of fossil fuels, important transition paths might be left underexplored, whereas the right choice of fuels could reduce emissions and ultimately push back the time of hitting the carbon ceiling.

The alternative visualisation in figure 1 shows that the remaining carbon budget would allow us to burn all of the world’s gas reserves and part of the oil reserves. Not only does the illustrated alternative prioritisation of the energy mix contain some 60 percent more energy for the same amount of CO<sub>2</sub> (figure 2), its effective contribution to the world’s energy needs is even higher.

Figure 2 | Energy content: coal versus oil versus gas



Source: CIEP.<sup>15</sup>

Note: GJ=Gigajoule; MJ=Megajoule.

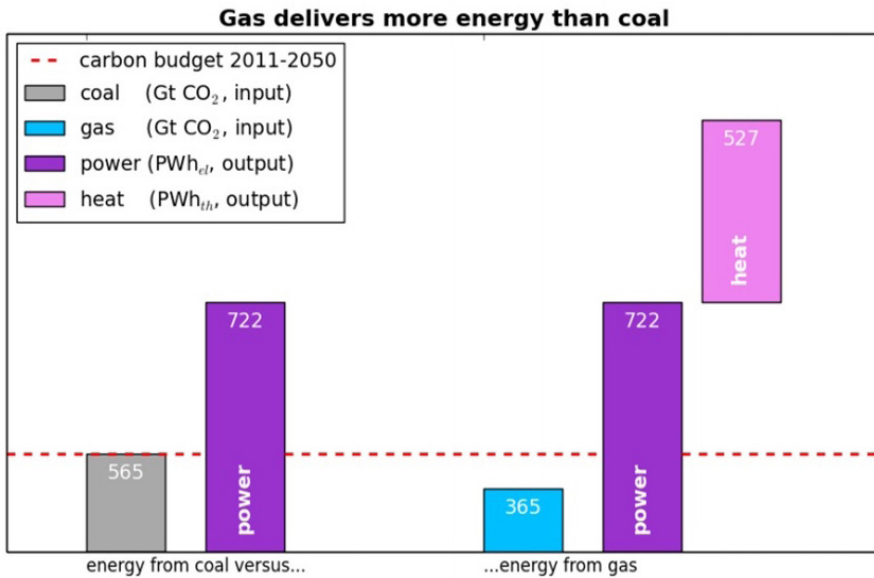
It should be kept in mind that coal is essentially used for power generation. This being said, gas-fired power generation would deliver around 100 percent more electricity relative to coal for the same amount of CO<sub>2</sub> emissions.<sup>16</sup> So, as is shown by figure 3, if the

<sup>15</sup> Coby van der Linde, *Transition? What Transition? And Why Energy per Carbon Matters*, Presentation at the Duienberg School of Finance, 25 March 2015, [http://www.clingendaelenergy.com/inc/upload/files/Presentation\\_Transition\\_-\\_Why\\_Energy\\_per\\_Carbon\\_Matters\\_25\\_March\\_2016.pdf](http://www.clingendaelenergy.com/inc/upload/files/Presentation_Transition_-_Why_Energy_per_Carbon_Matters_25_March_2016.pdf).

<sup>16</sup> Assuming the efficiencies of state-of-the-art Combined-Cycle Gas Turbines (CCGTs) relative to advanced

remaining carbon space (565 Gt of  $\text{CO}_2$ ) were filled by modern coal-fired power plants, the potential electricity output from the “burnable” coal reserves would be in the order of 722,000 TWh<sub>el</sub> (or 722 Pwh<sub>el</sub>). If instead gas-fired generation were used to produce the same 722,000 TWh<sub>el</sub> of electricity, only a portion of the carbon space would be used, thus leaving space for (1) the remainder of the global gas reserves for space heating, and (2) some 465 billion barrels of oil to be used in other sectors (figure 3).<sup>17</sup>

Figure 3 | Gas delivers more energy than coal



Source: Emma Van Der Veen, “Why Energy per Carbon Matters”, cit., p. 12.

Note: Gt=Gigatonne; PWh<sub>el</sub>=Petawatt-hour Electric Energy; PWh<sub>th</sub>=Petawatt-hour Thermal Energy.

Using natural gas to satisfy energy demand would thus give the world more time “within budget” than if coal were used. However, setting a cap on emissions and optimising energy output within the carbon budget is easier said than done. Rather than focusing on how to maximise energy production within the carbon budget, policies often aim to minimise carbon emissions by offering targeted support to renewables, without giving consideration to the differences in energy and carbon content among fossil fuels.

The IEA’s *Golden Age of Gas* scenario envisions a situation in which, also thanks to

super critical coal plants. Van der Veen, Why Energy per Carbon Matters.

<sup>17</sup> It should be noted that the calculations do not include the emissions resulting from production and transportation of coal and gas. Inclusion of these emissions would reduce the available carbon space, but still work to the advantage of gas.

a larger consumption of natural gas, it is possible to achieve an overall reduction of CO<sub>2</sub> emissions even with an increase in the share of fossil fuels in the energy mix.<sup>18</sup> Since the publication of this report by the IEA, however, coal consumption has kept on increasing worldwide and natural gas consumption has declined more than coal consumption in the EU.<sup>19</sup> Between 1990 and 2012, the compound annual growth rate (CAGR) of coal has been higher than that of gas on a global level.<sup>20</sup> This is casting a shadow on prospects for a significantly larger adoption of natural gas throughout the world, suggesting that the “golden age of gas” may be just an illusion, particularly in Europe.

The environmental qualities of gas are not limited to its lower CO<sub>2</sub> emissions relative to oil and coal. Gas can also help address problems of poor local air quality when used in power generation, as an industrial fuel and as a transportation fuel. Relative to oil and coal, it notably has lower sulphur dioxide (SO<sub>2</sub>) emissions, responsible for acid rain; lower nitrogen oxides (NO<sub>x</sub>) emissions, responsible for urban smog; and lower particulate matters emissions, responsible for health and visibility problems. The short response time of a CCGT plant relative to that of a coal-fired plant makes natural gas the most suitable fuel for complementing renewable energy systems, both operationally and at the lowest environmental costs.

### 1.2 The Failure of Policy-Making in Promoting Gas as a Transition Fuel

An examination of national energy policies worldwide – conducted for the 2015 IFRI-CIEP report<sup>21</sup> – reveals that no country has fully recognised the potential role of gas as a bridge fuel. Even the United States, which is often regarded as one of the most “gas-friendly” jurisdictions, has only seen a growing share of natural gas after technological and commercial factors had already pushed it into its energy mix. In Europe, policy-making has contributed to create conditions where gas is squeezed between policy-supported renewables and cheap coal in power generation. With the recent decline in international gas prices, however, the market may begin to support a switch from

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<sup>18</sup> Fatih Birol, *Are We Entering a Golden Age of Gas?*, cit.

<sup>19</sup> According to Eurostat data, the gross inland consumption of gas in the EU contracted by 14.7 percent between 2011 and 2014. In the same period, the gross inland consumption of coal contracted by only 6.5 percent.

<sup>20</sup> CAGR of coal: +2.55 percent; CAGR of gas: +2.46 percent (WEO 2014, historical data 1990-2012). However, a recent slowdown in Chinese coal consumption might signal that this trend is finally being reversed.

<sup>21</sup> IFRI and CIEP, *Is Natural Gas Green Enough for the Environmental and Energy Policies?*, cit.

coal to gas, but much will still depend on policy-making to make this change in the merit order more lasting. In the UK, a carbon floor price is already supporting such a switch. In the third key gas consuming region, Asia, it is possible to identify policies undertaken in favour of gas. However, these have been mostly initiated on the basis of security of supply and local air quality considerations rather than on the recognition of the potential of gas in the fight against climate change.

Carbon pricing mechanisms – mainly in the form of ETS and carbon taxes – have been adopted in 39 countries worldwide. One of the expectations was that these instruments would encourage the switch from coal to gas in power generation. However – also due to the recent economic downturn – most schemes have failed to interact properly with dynamic inter-fuel competition and did not facilitate the switch. The European ETS and the Californian Regional Greenhouse Gas Initiative (RGGI) provide notorious examples of unfulfilled expectations. Drawing on this lesson, some governments are promoting Emission Performance Standards (EPS) instead, with a strong focus on the power generation and manufacturing industry. It is however still too early to assess the effectiveness of these schemes. In particular, the jury is still out regarding the impact of the new rules proposed by the US Environmental Protection Agency (EPA) for reducing CO<sub>2</sub> emissions from power plants, which are a key part of President Obama's Climate Action Plan. Since 2012, the European Commission has proposed several amendments to the EU ETS such as backloading, the Market Stability Reserve (MSR) and structural reforms for its fourth trading phase starting in 2021. However, the oversupply of allowances has proven persistent so far and it remains unclear whether these proposals will be able to reduce it.<sup>22</sup>

As we mentioned, national policies in support of gas stemming from air quality considerations appear to have enjoyed more consistent support and to have generated more tangible results. Such policies have been pursued in a number of countries including Japan,<sup>23</sup> China<sup>24</sup> and India.<sup>25</sup> The promotion of natural gas in the transportation sector has also been the object of policy-making by international bodies such as the International Civil Aviation Organisation (ICAO) and the International Maritime Organisation (IMO), receiving special support from governments in regions such as the Baltic Sea, the North Sea, the Rhine Basin and North America. While these efforts are undoubtedly

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<sup>22</sup> Daan Rutten, *CIEP Briefing Paper on the EU ETS Reforms*, March 2016, [http://www.clingendaelenergy.com/other\\_work/briefing\\_papers](http://www.clingendaelenergy.com/other_work/briefing_papers).

<sup>23</sup> Tokyo Gas, *Developments Up to the Adoption of LNG: Tokyo Gas Looks to the Future*, unofficial translation by the Japan Gas Association, 1990.

<sup>24</sup> Sylvie Cornot Gandolphe, "Stratégie gazière de la Chine: Développer la concurrence entre production nationale et importations", in *Notes de l'IFRI*, October 2014, <https://www.ifri.org/en/node/8955>.

<sup>25</sup> AFP, "India court slams Delhi's worsening air pollution", in *The Guardian*, 27 November 2014, <http://gu.com/p/43kqb/stw>.

positive from an environmental perspective, they are too fragmentary and contingent to have an impact in a long-term strategy towards decarbonisation.

This section has shown that, in spite of its environmental qualities, natural gas has not conquered the hearts of policy-makers worldwide. As investigated in the 2015 IFRI-CIEP study, there are several reasons for this.

A prominent one is the widespread perception that natural gas is too heavily exposed to political and geopolitical influences, an element that, in line with the scope of this book, will be analysed in the next section of the Chapter. The objective is to show that the politicisation of gas is limiting its space as a transition fuel. As a consequence, an important message is that the proponents of natural gas as a transition fuel should have an interest in de-politicising gas trade.

As mentioned in the introduction, there are other reasons why policy-makers are reluctant to embrace natural gas as a transition fuel. First of all, the costs of generating power from existing gas-fired power plants are higher in most economies than those from coal-fired plants. For new-built plants the question of competitiveness is more complex, as a gas-fired plant can be built at considerably lower capital costs, but its fuel costs remain higher than those of a coal-fired plant. The economic choice will depend on expectations for gas and coal prices, operating hours and CO<sub>2</sub> price. Promoting gas at the expense of coal would thus come at a cost. Given the precarious state of many of today's economies and the importance of competitiveness, this is a price which countries are reluctant to pay. Additionally, it should not be forgotten that an encompassing, policy-driven transition towards a new energy mix often implies additional (initial) costs, as it typically requires the conversion of existing infrastructure geared towards the consumption of one specific source of energy. This is one of the reasons why energy systems tend to resist change.

Secondly, although relatively clean, natural gas is a fossil fuel, and given that the long-term objective of policy-making appears to be that phasing out all fossil fuels, measures in support of gas may be regarded as unnecessary distractions. A matter of special concern – amplified by unconventional production – is represented by methane emissions, which are hard to measure. Unconventional gas production and plans to tap gas reserves in the Arctic also raise other environmental concerns<sup>26</sup> that risk overshadowing the environmental credentials of natural gas as a whole.

A third reason why gas is not broadly advocated at a domestic level covers various energy sovereignty sensitivities, including sovereignty over energy resources, the diversity of the energy mix, employment and macro-economic considerations. Coal, notably,

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<sup>26</sup> Notably the fear of leakages, pollution of aquifers, negative effects on landscapes and important water usage requirements.



has a strong political base in countries where it is produced and supports the economy by being cheap and abundant. This is notably the case in China, the US, Poland, Russia, South Africa and Germany.

### 1.3 The Perception of Gas as a Politicised Commodity

A number of academic studies have elaborated on different aspects of the relationship of mutual influence that exists between the natural gas business and politics.<sup>27</sup> On top of these analyses, intense media coverage of “pipeline wars” – as well as of alleged grand strategic schemes involving energy interests – tend to inflate the perception that natural gas is a highly politicised commodity. This appears to discredit its image as a reliable source of energy, particularly in consuming countries that are highly dependent on a limited number of suppliers. This section provides an overview of the reasons why gas is perceived as political, and discusses to what extent this perception is well-grounded.

The concerns of consuming countries include anxiety about over-reliance on a limited number of suppliers, the geopolitical leverage conferred to gas-producing countries by their reserves, and the possibility that producers may coordinate to influence the market. The fact that almost 60 percent of the world’s total proven conventional gas reserves are concentrated in four countries (Russia, Iran, Qatar and Turkmenistan) certainly does not contribute to easing these concerns. Clearly, it is not only concentration *per se* that causes concerns, but also the geographic location of reserves and the political relationship between the main importers of gas and some of the key reserve holders – as will be explained in the coming pages. Subsequent to the Arab Spring (2011) and the Euromaidan street protests in Kiev (2013), a “new arc of instability” has emerged that stretches from the Arabian peninsula, the Sahel, and the Levant to Russia and the Former Soviet republics – roughly corresponding to the MENA and FSU regions. These

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<sup>27</sup> Aad Correljé and Coby van der Linde, “Energy Supply Security and Geopolitics: A European Perspective”, in *Energy Policy*, Vol. 34, No. 5 (March 2006), p. 532-543; Paul Stevens, “Transit Troubles. Pipelines as a Source of Conflict”, in *Chatham House Reports*, March 2009, <https://www.chathamhouse.org/node/5837>; Edward Chow et al., “Pipeline Politics in Asia. The Intersection of Demand, Energy Markets, and Supply Routes”, in *NBR Special Reports*, No. 23 (September 2010); Caroline Kuzemko et al. (eds.), *Dynamics of Energy Governance in Europe and Russia*, Basingstoke and New York, Palgrave Macmillan, 2012; Amy Myers Jaffe and Meghan L. O’Sullivan, *The Geopolitics of Natural Gas*, Cambridge, Belfer Center for Science and International Affairs, July 2012, <http://belfercenter.ksg.harvard.edu/publication/22218>; Margarita M. Balmaceda, *The Politics of Energy Dependency. Ukraine, Belarus, Lithuania Between Domestic Oligarchs and Russian Pressure*, Toronto, University of Toronto Press, 2013; Brenda Shaffer, “Natural Gas Supply Stability and Foreign Policy”, in *Energy Policy*, Vol. 56 (May 2013), p. 114-125.

two regions happen to host three quarters of the world's total proven conventional gas reserves. As will be explained later in this section, gas supply potential from a number of countries in these regions is being held up due to geopolitical instability.

As a response to their concerns, consuming countries seek to diversify energy imports or at least gas supply routes and sources, as well as, when possible, to promote the exploitation of domestic resources. Notable examples include Spain – which passed a law setting limits to dependence on one single source of gas out of concerns about over-reliance on Algeria – and China, which carefully weighed pipeline project proposals from different suppliers and ensured the building of connections to Turkmenistan and Myanmar as well as establishing a significant LNG infrastructure, before accepting pipeline gas from Russia.

To be sure, coal and oil reserves and production are also highly concentrated.<sup>28</sup> However, coal has a marked “domestic profile,” insofar as the share of coal that is locally consumed is higher than the equivalent for gas. Moreover, most of the largest coal exporters appear to be on good political terms with the largest importers and/or located outside of areas of major political instability.<sup>29</sup> Similar to gas, conventional oil reserves and production are quite heavily concentrated in the MENA and FSU regions.<sup>30</sup> Indeed, both history and recent events show that oil trade is exposed to geopolitical events, particularly in the MENA region. The main difference between oil and gas is that – generally speaking – oil is a freely traded commodity in a global market, whereas gas trade is limited by existing infrastructure, especially for pipeline trade.<sup>31</sup> This contributes to explaining the pattern whereby importers are generally more anxious about their dependence on gas imports relative to oil imports, as is visible in energy security discussions conducted in the context of the current political standoff between Europe and Russia. The presence of a deep, liquid global oil market with a considerable number of players reduces the space for the pursuit of discretion-

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<sup>28</sup> Using the same measurement applied to natural gas above, it appears that the first four oil reserve holders control 53 percent of the world's total oil reserves (Venezuela, Saudi Arabia, Canada and Iran) and that the first four coal reserve holders control 65 percent of the world's total coal reserves (US, Russia, China and Australia). See BP, *Statistical Review of World Energy 2015*, June 2015, <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.

<sup>29</sup> The main coal exporters are Indonesia, Australia, Russia, the US, Colombia, South Africa and Canada. The main international coal trade flows are those from Indonesia and Australia to China. Apart from Russia, Europe imports significant amounts of coal from South Africa, Colombia and the United States.

<sup>30</sup> Proved oil reserves in the MENA and FSU regions were 137.3 billion tonnes in 2014, or 57.2 percent of global proved reserves. Oil production in the MENA and FSU regions was 2141 million tonnes in 2014, or 50.7 percent of global production. See BP, *Statistical Review of World Energy 2015*, cit.

<sup>31</sup> William Nordhaus, *The Economics of an Integrated World Oil Market*, keynote address at the Venice International Energy Workshop, 17-19 June 2009, [http://aida.econ.yale.edu/~nordhaus/homepage/documents/iew\\_052909.pdf](http://aida.econ.yale.edu/~nordhaus/homepage/documents/iew_052909.pdf).

ary political agendas and reassures importers about their ability to substitute cargoes in case of disruptions.

Gas trade largely lacks this flexibility, at least as far as pipeline exchanges are concerned.<sup>32</sup> This stems in part from the physical characteristics of gas itself. A gaseous energy source with lower energy density than oil, gas is relatively expensive to transport – which has historically resulted in gas trade being mostly regional and in the lack of a deep and liquid global gas market. The necessity of long-term contracting to underpin pipeline investments, the rigidity of “point-to-point” deliveries, the relative lack of competition, and obsolescing bargains often characterise gas trade relationships. Particularly, the sheer size of investments and the need to aggregate demand along pipeline routes call for political agreements to flank commercial ones. This is visible in virtually all the international pipeline projects, including recent ones (Dolphin Gas Project, Nord Stream, South Stream, Blue Stream, Nabucco, Altai and Power of Siberia pipelines, Southern Gas Corridor, Central Asia-China, and others). Discomfort with long-term, point-to-point trade has emerged in a number of importing regions, where market reforms aimed at “empowering the consumer” by breaking monopolies and increasing the number of trading parties are being proposed or implemented, with various degrees of success.

The fusion of state and company interests, and the fact that NOCs control the majority of conventional gas reserves and production,<sup>33</sup> also contribute to the image of gas as a politicised commodity. Moreover, similar to oil, gas is often perceived as contributing to resource curse dynamics and rent-seeking behaviours, and to concentrating money and power in the hands of elites. Public opinions (especially in Western importing countries) often contest the political acceptability of such elites, and IOCs are subject to substantial pressures not to conduct business with countries that have poor records in fields such as corruption and human rights. This inevitably embroils gas (and oil) trade in political discussions and appears to negatively impact the image of fossil fuels vis-à-vis renewables.

Another recurring argument reinforcing the notion that gas is political is that countries are “either emboldened by energy wealth to instigate conflict and exploit market advantages and corporate profit-seeking as foreign policy tools, or prone to compete over unclaimed resources out of fear of vulnerability.”<sup>34</sup> Also, “impulses for conflict spe-

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<sup>32</sup> These still amount to more than two thirds of global exchanges.

<sup>33</sup> 68 percent of reserves and 52 percent of production. Marck Thurber, *NOCs and the Global Oil Market: Should We Worry?*, Presentation at the Stanford University Energy Seminar, 6 February 2012, [http://energyseminar.stanford.edu/sites/all/files/eventpdf/Thurber%20energy%20seminar%20NOCs%2006Feb2012%20final\\_0.pdf](http://energyseminar.stanford.edu/sites/all/files/eventpdf/Thurber%20energy%20seminar%20NOCs%2006Feb2012%20final_0.pdf).

<sup>34</sup> Adam N. Stulberg, “Out of Gas? Russia, Ukraine, Europe and the Changing Geopolitics of Natural Gas”, in *Problems of Post-Communism*, Vol. 62, No. 2 (2015), p. 112-130 at p. 114.

cific to the natural gas trade”<sup>35</sup> have been identified largely due to the specificities of gas trade explained above. Recent events in the world arena have strengthened this notion, including battles to take over natural gas fields in the Levant region and prospects for oil and gas findings seemingly re-igniting tensions for the control of maritime areas in the South and East China Seas.

In the last years, conflicts have resulted in a number of disruptions to gas production and transit, particularly in the MENA region. This is likely to have a negative impact on gas as a reliable source of energy, although new LNG suppliers around the world help in creating new supply options. Nevertheless, these disruptions may influence future choices by policy-makers on the role of gas in the energy mix. Examples include disruptions in Libyan exports to Italy through Green Stream; the shutdown of 10 percent of Algerian gas production in 2011 following the terrorist attack on In-Amenas; disruptions in Egyptian exports to Israel and Jordan due to attacks on pipelines in the Sinai Peninsula; PKK guerrilla activity increasingly targeting gas infrastructure in Turkey; and the interruption of Yemeni LNG exports owing to Houthi insurgency. In other instances, conflicts have hampered projects to construct new gas infrastructure. Examples include the abandonment of plans to build the Syria-bound Arab Gas Pipeline (AGP) project due to the Syrian civil war; the postponement of infrastructural projects to monetise Iraq’s vast gas reserves due to both ISIL activity and disagreements between the Kurdish Regional Government (KRG) and the central government in Baghdad; and the constant deferral of plans to build the long-discussed TAPI pipeline aimed to bring Turkmen gas to India through Afghanistan and Pakistan.

Even in the absence of outright conflicts, politics can interfere with gas trade and hinder projects that could potentially be viable from a commercial point of view. Political disagreements between Russia and the EU stemming from the Ukrainian crisis may leave unutilised as much as 150 Bcm of Ukraine-bound transit capacity. Until recently, Iran’s political isolation has left its gas potential largely under-utilised. Arguably, the same may hold true for cost-competitive Russian excess production capacity if Europe and Russia do not solve their political disagreements. Disputes over the definition of maritime or terrestrial borders can also lead to the non-utilisation of gas reserves or a lack of gas trade. Examples include the century-old Bolivian claim on Northern Chile – jeopardizing prospects to export Bolivian gas to Chile and to build an LNG terminal there; overlapping claims in the Caspian Sea – complicating the realisation of the Trans-Caspian Pipeline (TCP); disputes on borders and the status of Cyprus in the East Mediterranean – casting a shadow on fast gas monetisation in the region; and the abovementioned clashes between the KRG and the Baghdad-based government.

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<sup>35</sup> Ibid.

On the other hand, it is often argued that gas trade actually creates positive bonds of interdependence, in default of which conflicts may possibly escalate. This is well symbolised by the concept of “mutual hydrocarbon destruction”<sup>36</sup> applicable to the current relationship of interdependence between Europe and Russia. It is not a coincidence that the gas sector was excluded from European sanctions against Russia. Besides, it should be noted that in a context of tense EU-Russia relations and a civil conflict ongoing in Eastern Ukraine, gas trade between Russia and the EU – including through Ukraine – has continued virtually undisturbed. All the parties involved have exerted remarkable self-restraint when it came to discussing gas trade issues.<sup>37</sup> Gas is also at times quoted as one of the elements that encouraged the Japanese government to maintain especially good relationships with gas-supplying countries.<sup>38</sup> There are in fact numerous cases in which natural gas pipeline cooperation and gas trade has been possible even between political adversaries. As quoted in the 2015 IFRI-CIEP report, examples include the construction of the Maghreb-Europe pipeline in 1996 from Algeria to Spain through Morocco – even though relations between these two countries have been strained – and Soviet pipelines reaching Western Europe since the early 1970s.<sup>39</sup> Furthermore, countries entrenched in territorial border disputes have shown that cooperation in the energy sector is still possible. Many so-called “joint development” agreements exist in which countries decided to put aside – if temporarily – their border disputes for the sake of jointly exploring or exploiting hydrocarbon reservoirs that lie across a disputed boundary. Examples include cooperation between Malaysia and Thailand in the Gulf of Thailand, the Netherlands and Germany in the Eems Estuary, and the UK and Argentina in the waters surrounding the Falkland Islands.

Finally, it should be noted that political concerns are particularly related to pipeline gas trade. Thanks to its destination flexibility and lesser exposure to transit risks, LNG is a dynamic factor in gas markets and is seen as a potential contributor to the de-politicisation of gas trade. In long-lasting pipeline trade relationships, there are also higher chances that supply and/or market conditions on either side change, and that political or economic frictions arise. The share of LNG in total gas trade has been growing rapidly, particularly in the last 15 years, and more and more players

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<sup>36</sup> A provocative term suggesting that strong interdependence in oil and gas trade between two countries deters the escalation of what might be their stranded bilateral relationship.

<sup>37</sup> Adam N. Stulberg, “Out of Gas? Russia, Ukraine, Europe and the Changing Geopolitics of Natural Gas”, cit.

<sup>38</sup> Jan Hein Chrisstoffels, “Japan: Nieuwe agenda voor energieveiligheid”, in *Internationale Spectator*, Vol. 61, No. 7/8 (July/August 2007), p. 362-366, <http://www.internationalespectator.nl/article/japan-nieuwe-agenda-voor-energieveiligheid>.

<sup>39</sup> IFRI and CIEP, *Is Natural Gas Green Enough for the Environmental and Energy Policies?*, cit.

are participating in the LNG market, contributing to increasing its levels of liquidity. Even if it is still far from displaying the same features as the oil market, LNG certainly contributes to decentralising flows and globalising gas trade. Consuming countries in many regions therefore promote LNG supplies, even though pipeline supplies may be available at lower cost.

## Conclusions

Natural gas has the potential to play an important role in the transition towards a cleaner energy mix. Targeted support from policy-makers remains essential to this end because coal is outcompeting gas in net importing regions in default of a more robust CO<sub>2</sub> policy. The current period of low international gas prices, indicating the availability of ample supplies, might be regarded as an incentive to secure a switch from coal to gas for the future, by implementing measures that complement existing technology-neutral policies. As long as commercially viable technologies to store electricity are unavailable, our economic systems will hinge on predictable, reliable sources of power generation. At the moment, these are represented by either nuclear or fossil fuels. Natural gas is the fossil fuel with the highest amount of energy per carbon emitted, and emits less NO<sub>x</sub>, SO<sub>x</sub> and particulate matter than other fossil fuels. Besides summarising the traditional arguments in support of the environmental qualities of gas, this chapter attempted to quantify the advantage inherent to burning natural gas instead of coal with a view to staying within a 2°C trajectory. We showed the extent to which replacing coal with natural gas would help maximise the production of energy before the remaining carbon budget is exhausted. This highly theoretical exercise simply aims to invite the various players in the climate discussion to make a clear distinction between fossil fuels rather than generalising.

Yet, natural gas tends to lack targeted support from policy-makers. This is because natural gas is often not competitive and too expensive to import, not regarded as sufficiently clean, and not compatible with domestic macroeconomic interests. Crucially, natural gas production and trade are also highly exposed to geopolitics. This chapter discussed various aspects of this exposure and presented examples in which geopolitical factors hampered gas projects and/or choices to increase the share of natural gas in a country's energy mix. We also suggest that the perception of gas as a highly politicised fuel is somehow inflated – if we consider for example that Russia (currently at the centre of Europe's energy security concerns) has after all been a reliable gas supplier for decades and cases of disruptions have been very limited in number. However inflated,

this perception is in any case seemingly influencing energy policy-making. The chapter also concluded that some of the geopolitical concerns about natural gas only apply to molecules shipped through pipelines. Liquefied natural gas (LNG) is in fact standing out as a dynamic factor in gas markets, and can be regarded as a potential contributor to the de-politicisation of gas trade.

## 2. On the Future of Global LNG Trade and Geopolitics

Chi-Kong Chyong\*

Traditionally, gas markets were regional in nature because of large-scale infrastructure investment requirements along the whole value chain, especially capital requirements to build transport pipeline networks to supply gas to end consumers. However, since the late 1960s and until the mid-2000s there has been a general trend of cost reduction due to technological improvements in the whole liquefied natural gas (LNG) value chain. This cost reduction trend was coupled with demand uptake in remote consumption centres relative to production locations, and allowed LNG trade to emerge as one of the fastest growing internationally traded commodities in the period from late 1960 to 2012, during which annual growth of LNG exports averaged 14 percent. It was believed that LNG would help to integrate the once regional gas markets, adding diversity and hence improving energy security with implications for the geopolitics of regional energy trade. However, going forward the future of LNG trade and its potential to contribute to energy security and global energy trade faces uncertain geopolitical and economic prospects. This chapter has several objectives. Firstly, it aims to provide a short analysis of main trends in LNG trade and pricing, with a focus on the role of spot and short-term LNG trade. Secondly, it tries to summarize short-term limits to inter-regional trade in LNG as the main driver behind global gas market globalization. Lastly, the chapter analyses how new export projects from the US and the Middle East could change gas trade and geopolitics.

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## 2.1 Evolution of LNG Trade and Pricing

International gas trade has been regional in nature because of large-scale infrastructure needed along the whole value chain, and especially capital-intensive investment requirements to build transport networks to supply gas to end consumers. However, since the 1960s there has been a general trend towards cost reduction due to technological improvements, especially in the whole LNG value chain.<sup>1</sup> At the same time, global demand for natural gas grew rapidly thereby helping to unlock LNG trade potential further – in the last 40 years LNG trade was one of the fastest growing internationally traded commodities. During that period, starting with Algeria – the first LNG exporter – there has been a proliferation in the number of LNG exporting countries. In 1975 there were only four exporters, whereas in 1995 this figure had doubled to eight and, as of 2014, we now have 20 exporters (including re-exports from Europe), with Qatar emerging as the largest LNG producer and exporter globally, accounting for more than 30 percent of global LNG exports.

In general, the economics of gas trading via seaborne LNG transport are more advantageous relative to pipeline trading if the transportation distance is more than 4,000 km,<sup>2</sup> allowing for shipping super-cooled gas across continents at a lower cost than if using pipelines. Thus, in 2000, pipeline gas accounted for 78 percent of total gas traded, whereas LNG was 22 percent.<sup>3</sup> However, in 2014 LNG trade accounted for 33 percent of the global gas trade.<sup>4</sup> On the import side, the LNG trade has been dominated by Asian countries, in particular Japan, South Korea, Taiwan (JKT) and, more recently, China and India. Thus, in the late-1990s, JKT countries' LNG imports accounted for 78 percent of all trade but this figure has been reduced since then to below 60 percent (in 2014), primarily due to the rise of other buyers such as China and India in Asia, the UK in Europe and Mexico, Argentina and Brazil in South America.

Despite this tremendous growth in LNG trade in the last four decades, international gas trading is still dominated by cross-border pipelines. However, going forward we

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<sup>1</sup> Jonathan Stern, "The New Security Environment for European Gas: Worsening Geopolitics and Increasing Global Competition for LNG", in *OIES Papers*, No. NG15 (October 2006), <https://www.oxfordenergy.org/tag/ng15>; Mads Greker and Eirik Lund Sagen, "Explaining Experience Curves for New Energy Technologies: A Case Study of Liquefied Natural Gas", in *Energy Economics*, Vol. 30, No. 6 (November 2008), p. 2899-2911.

<sup>2</sup> Howard V. Rogers, "LNG Trade-flows in the Atlantic Basin: Trends and Discontinuities", in *OIES Papers*, No. NG41 (March 2010), <https://www.oxfordenergy.org/tag/ng41>; James T. Jensen, *LNG and Pipeline Economics*, presentation at the workshop "The Geopolitics of Gas", Stanford University, Palo Alto, 17-18 October 2002, [http://iis-db.stanford.edu/evnts/3917/jensen\\_slides\\_rev.pdf](http://iis-db.stanford.edu/evnts/3917/jensen_slides_rev.pdf).

<sup>3</sup> Authors' calculations based on ENI, *World Oil and Gas Review 2014*, [http://www.eni.com/en\\_IT/documentation/documentation.page?type=bil-rap](http://www.eni.com/en_IT/documentation/documentation.page?type=bil-rap).

<sup>4</sup> Authors' calculations based on ENI, *World Oil and Gas Review 2014*, cit.

expect LNG to take a substantial share in trade. In Europe, cross-border trading via pipelines accounts for about 43 percent of total consumption and only 6 percent is accounted for by LNG, while the rest is domestic production. In the Asia-Pacific – where gas demand is expected to grow in the future – due to geography the situation is completely reversed: LNG accounts for 36 percent of total consumption while pipeline trading accounts for only 9 percent and the rest is accounted for by domestic production (primarily in China). Other regional markets are predominantly either self-sufficient or import gas using pipelines (North and South America).

Pricing of natural gas is one of the most complex issues in the business and it often appears at the centre of geopolitical developments (e.g., the EU antitrust investigation into Russia's gas pricing strategy in Central-Eastern and Southern European markets). Gas is predominantly priced using two mechanisms: (i) oil price indexation, or oil price escalation, where the value of gas is determined based on the price dynamics of oil products, and (ii) market-based pricing where gas prices are discovered through the interaction between gas supply and demand.<sup>5</sup>

It is important to note that North America (US and Canada) is currently the only market with gas trading based purely on supply and demand conditions (i.e., market-based pricing), with the Henry Hub price as the dominant spot price index used in this market.

More recently, Europe has also begun to transition to market-based pricing, and it is reported that more than 50 percent of the European gas supply in 2014 was linked to European regional hubs (such as NBP in the UK and TTF in the Netherlands).<sup>6</sup> The rest of the international gas trade in Europe is still based on oil indexation; this is true in particular for gas coming from Russia, North Africa and Norway (marginally). Thus, Europe has emerged as a unique market place where two different pricing mechanisms exist – hub-based and oil-indexation pricing – with unclear prospects of moving to one pricing system or the other and when.

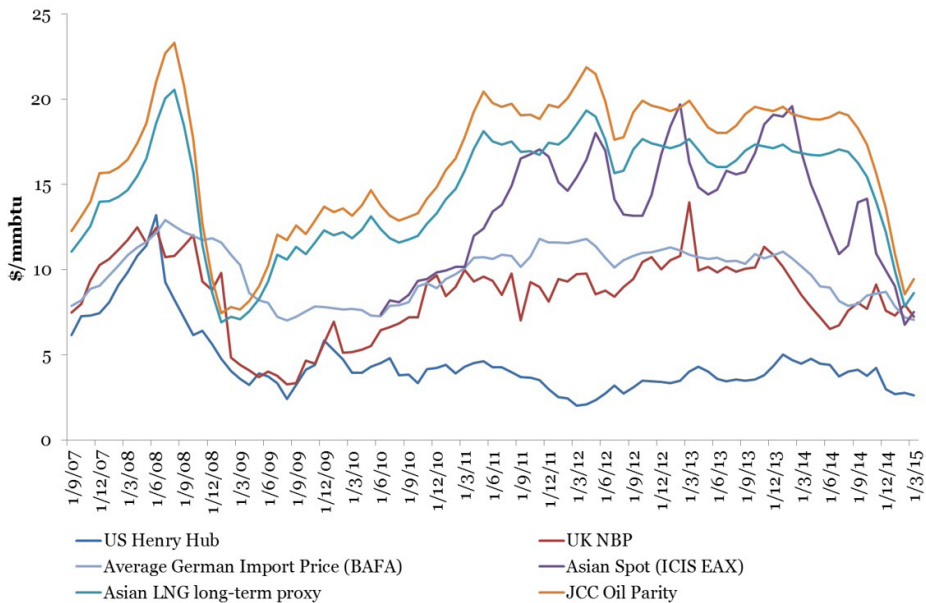
The Asia-Pacific gas market is dominated by an oil price indexation mechanism, and trade is supplemented by short-term and spot transactions to balance the positions of market players. The pricing of such short-term and spot transactions is believed to resemble market-based pricing and is assessed by price reporting agencies such as Platts (the spot index assessed by Platts is called the "Japan Korea Marker", JKM) or ICIS Heren (called the "East Asia Index", EAX).

Summing up the discussion on pricing and gas trade in the major consumption regions – Europe, Asia and North America – the different pricing mechanisms coupled

<sup>5</sup> IGU, *Wholesale Gas Price Survey - 2015 Edition: A Global Review of Price Formation Mechanisms 2005-2014*, June 2015, [http://www.igu.org/sites/default/files/node-page-field\\_file/IGU%20Whole%20Sale%20Gas%20Price%20Survey%20Report%20202015%20Edition.pdf](http://www.igu.org/sites/default/files/node-page-field_file/IGU%20Whole%20Sale%20Gas%20Price%20Survey%20Report%20202015%20Edition.pdf).

<sup>6</sup> Ibid.

Figure 1 | Evolution of regional gas prices



Source: Bloomberg and ICIS.

Note: Asian long-term proxy is based on formula as in BG, *Global LNG Market Outlook 2014/15*, 4 March 2015, <http://www.bg-group.com/~tiles/?tiletype=news&id=771>.

with market structure have produced a variety of price differentials in the last decade (figure 1). These have been driven by supply and demand balancing, oil price dynamics and discontinuities in trade and the regulatory environment, as well as demand (e.g., the Fukushima accident in Japan) and supply (e.g., shale gas in the US) shocks.<sup>7</sup>

<sup>7</sup> For a comprehensive review of gas pricing and trade dynamics in Europe see Jonathan Stern, "Is There a Rationale for the Continuing Link to Oil Product Prices in Continental European Long-Term Gas Contracts?", in *OIES Papers*, No. NG19 (April 2007), <https://www.oxfordenergy.org/tag/ng19>; Jonathan Stern, "Continental European Long-Term Gas Contracts: Is a Transition Away from Oil Product-Linked Pricing Inevitable and Imminent?", in *OIES Papers*, No. NG34 (September 2009), <https://www.oxfordenergy.org/tag/ng34>; Jonathan Stern, "International Gas Pricing in Europe and Asia: A Crisis of Fundamentals", in *Energy Policy*, Vol. 64 (January 2014), p. 43-48; Jonathan Stern and Howard V. Rogers, "The Transition to Hub-Based Gas Pricing in Continental Europe", in *OIES Papers*, No. NG49 (March 2011), <https://www.oxfordenergy.org/tag/ng49>; Jonathan Stern and Howard V. Rogers, "The Dynamics of a Liberalised European Gas Market: Key Determinants of Hub Prices, and Roles and Risks of Major Players", in *OIES Papers*, No. NG94 (December 2014), <https://www.oxfordenergy.org/tag/ng94>; Anthony Melling, "Natural Gas Pricing and its Future: Europe as the Battleground", in *Carnegie Reports*, October 2010, <http://carnegieendowment.org/publications/?fa=41716>; Luca Franza, "Long-term Gas Import Contracts in Europe: The Evolution in Pricing Mechanisms", in *CIEP Papers*, No. 2014|08 (December 2014), <http://www.clingendaelenergy.com/publications/publication/long-term-gas-import-contracts-in-europe>; Frank Asche, Bård Misund and Marius

It is, however, worth mentioning major structural shifts that produced these price dynamics:

- In mid-2008 the US spot Henry Hub price traded in the range of 13 dollars per million British thermal units (mmBtu) and since then has fallen to an average of 3.75 dollars (average over 2010-present); this 3.5 times slump in the US spot price was largely due to uptake in shale gas production.
- In the meantime, in Asia, starting from mid-2010, the price assessment for LNG spot cargoes was in the range of 7.4 dollars/mmBtu, which then peaked in February 2013 at 19.7 dollars/mmBtu – 1 percent above oil parity. This was largely due to Japan's decision to take its entire nuclear power fleet offline following the March 2011 Fukushima accident. However, since late-2014, the spot index has crashed to below 7 dollars/mmBtu, largely due to a mild winter in Asia, a crash in oil prices and expectation of new LNG capacity being created in the coming years.
- In Europe, regulatory changes in gas markets coupled with a surplus of LNG created by the US shale gas revolution, low gas demand due to the economic slowdown and increased inter-fuel competition (e.g., uptake of coal and renewables in electricity generation) have forced gas importers to renegotiate pricing mechanisms in their traditional contracts with suppliers. Thus, since about 2010, in Europe a pricing system has emerged based on long-term oil-indexed contracts as well as on hub trading (NBP in the UK and TTF in Continental Europe). It is believed that the pricing of Norwegian and Dutch gas volumes is now entirely based on hub prices, whereas for Russian gas the rebalancing consists of discounts from the base price plus rebates and spot indexation for marginal volumes.<sup>8</sup>

LNG, like pipeline gas trade, has been traditionally relying on a system of long-term bilateral contracts between buyers and sellers. These contracts are durable, often last more than 20 years, and have been designed to cover, amongst other things, fair rate of returns for participants and to finance the entire LNG value chain – from upstream production facilities, liquefaction terminals and LNG vessels to importation terminals and pipelines connecting to the main gas grid of the importing countries. The pricing mechanisms in those contracts are usually either oil price indexation or market-based

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Sikveland, "The Relationship between Spot and Contract Gas Prices in Europe", in *Energy Economics*, Vol. 38 (July 2013), p. 212-217; Caterina Miriello and Michele Polo, "The Development of Gas Hubs in Europe", in *Energy Policy*, Vol. 84 (September 2015), p. 177-190. For Asia see Babak Kiani, "LNG Trade in the Asia-Pacific Region: Current Status and Future Prospects", in *Energy Policy*, Vol. 19, No. 1 (January-February 1991), p. 63-75; Howard V. Rogers and Jonathan Stern, "Challenges to JCC Pricing in Asian LNG Markets", in *OIES Papers*, No. NG81 (February 2014), <https://www.oxfordenergy.org/tag/ng81>.

<sup>8</sup> See Howard V. Rogers and Jonathan Stern, "Challenges to JCC Pricing in Asian LNG Markets", cit.

pricing, as we discussed above. In recent years, however, the industry has also witnessed a tremendous growth in short-term and spot trading in LNG. An overview of this trading dynamic is provided in the next section.

## 2.2 Spot and Short-term LNG Trade

In the formative stages of the LNG trade, spot or short-term trading was viewed as an exception to the general pattern due to the overall low liquidity on the market. To present, there is no single accepted definition of what constitutes a spot LNG trade. Generally, however, it can be said that spot or flexible LNG volumes are those sold outside of long-term contracts for delivery within a calendar year. Spot volumes can be sold on a per-cargo basis or as several cargoes delivered over a pre-defined period of time at an agreed upon schedule and pricing terms. Occasionally, the term incremental is also used for cargoes traded between a buyer and a seller that already have an existing long-term sales contract. Such volumes can be sold at the existing contractual price or at a price agreed upon at the time of transaction.

The mechanism for spot transactions could involve bilateral negotiations between a buyer and a seller, open or restricted tenders and the involvement of a broker. Given that the market for LNG is still less than 50 active participants, the commodity is not heavily brokered and most transactions are concluded on a bilateral basis. The short-term market is dominated by portfolio suppliers such as Anglo-Dutch oil and gas major Shell and UK-based BP, as well as several Japanese trading houses – Mitsubishi, Itochu, Marubeni and Mitsui – and commodity traders like Trafigura, Vitol and Gunvor. Large producers will typically also engage in spot trading but more as a way of optimizing their existing supply positions than of focusing on short-term risks and arbitrage opportunities. Due to high entry costs and associated financial risks, there have been several instances where companies have ceased LNG trading operations.

On the buy side, the spot market has offered an opportunity to deal with short-term demand spikes, as well as allowing some buyers to take advantage of international pricing if domestic levels of gas or competitive fuels are deemed to be high. While very few buyers have relied exclusively on short-term volumes, there is a significant trend on the market towards allocating a portion of energy baskets to short-term deals. To date, Argentina, Brazil, Egypt, Israel and Pakistan have exclusively relied on short-term deals and buying tenders to secure supply. Notably, all of these importers also rely on floating storage and regasification units (FSRU) rather than a traditional on-land import terminal. Typically, such buyers either require LNG only during periods of peak demand or see the

commodity as a temporary feature of their market before they begin production of their own domestic supplies.

The portion of spot trade, according to its broad definition, in overall global commercial flows has expanded significantly over the course of the last 15 years, largely due to new entrants on the market and increasing sources of LNG production. According to our estimates, LNG trading made up less than 5 percent of global trade around the year 2000, whereas currently it constitutes around 25 percent of the global trade (figure 2). Around 4,000 LNG cargoes were traded in 2014, which means that about 1,000 were sold on a short-term or flexible basis. By the year 2020, the overall global production capacity is expected to reach 690 Bcm per year, which would equate to around 5,800 cargoes per annum or 1,450 short-term or flexible cargoes. However, with expectations of flows from North American LNG projects on the basis of shale gas production, the percentage of short-term trading could increase significantly, as many facilities in the United States and Canada are marketing tolling arrangements rather than a traditional long-term contractual structure (for details see next section). It is also important to add that the emergence of reload trading across terminals in Europe and Asia is also likely to add liquidity to the short-term market.

There is no prevailing pricing mechanism for the short-term LNG market. Transactions have been structured on a fixed-price basis for prompt deals that involve delivery within 30 days or have been indexed to Brent or JCC crude benchmarks. Other indexation mechanisms used include the US Nymex Henry Hub gas futures benchmark, the UK's NBP gas benchmark and increasingly the Dutch TTF gas benchmark. The choice of price mechanism is influenced by several factors, which could include buyers' requirements and risk management strategies for sellers. Buyers working with competitive fuels, such as fuel oil, will typically procure spot LNG as the basis of crude oil price indexation. This, however, leaves the seller exposed to the volatility of crude markets, which can in turn be countered by reliance on various crude-based hedging tools and derivative products. The choice of pricing benchmark is mostly influenced by the pricing dynamics of the buyer's domestic market and how sensitive it is to crude fluctuations.

As with long-term volumes, short-term LNG trading is very much Asia-focused. More than 70 percent of spot LNG has found a home in the Pacific Basin so far in 2015. Key markets for spot LNG have emerged in Japan, South Korea, China and India. Important short-term markets have also sprung up in Egypt, Jordan, Argentina, Mexico and Pakistan. More countries are expected to start importing LNG over the course of next five years, including Bangladesh, the Philippines, Vietnam and Indonesia. With the growing availability of flexible import infrastructure, LNG can find a home with virtually any buyer with a coastline. Other than Lithuania, Europe has seen declining LNG imports, and the importance of this market has been shrinking. This is largely due to the fact that pipeline

gas appears to be more competitive than LNG. Over the last five years, LNG has been traded at a strong premium to all the European gas hubs, making the economics of spot importing very difficult to justify. Short-term LNG markets are growing in areas where domestic gas production is declining and there is no alternative source of pipeline gas available internationally. The Pacific Basin as a whole is set to remain the key area for both long-term and short-term LNG imports going forward.

Figure 2 | Long- and short-term LNG trading



Source: GIIGNL, *The LNG Industry*, 2008-2014.<sup>9</sup>

Note: According to GIIGNL definition all contracts lasting less than five years are considered short-term contracts and spot trading.

The LNG shipping market, one of the most important factors in the future development of a truly global gas market, has evolved dramatically over the years. The general trend can be briefly described as an increase in both the size and number of vessels. Our research identified a total of 431 LNG tankers which are used for international trade. This number also includes FSRUs which, while they can be used as conventional tankers, are designed to act as floating LNG terminals. Currently, 142 vessels are on the order books with shipbuilders and expected to be added to the global fleet within the next five years.

<sup>9</sup> Available in the website of the International Group of Liquefied Natural Gas Importers (GIIGNL), <http://www.giignl.org/publications>.

Most LNG tonnage has been ordered to service specific production projects, and is commonly referred to as project tonnage. The cost of building an LNG carrier has varied dramatically due to fluctuations in global steel prices, technical specifications and carrying capacity. The cost of a new-build varies from 200-250 million dollars for a conventional vessel. Most LNG carriers are built in either South Korea or Japan. Due to the comparatively high cost of LNG ships, very few ship-owners have ordered vessels on a purely speculative basis, that is, without long-term supply contracts. Of 142 tankers on the order books, only 18 are being built without a long-term commitment from a charterer. In terms of the existing global fleet, less than 5 percent of the existing fleet has been built on a speculative basis. Rather than servicing any particular production project, the owners of these vessels target mid-term, short-term and spot markets.

Tonnage built and designed to service specific LNG projects will typically have a long-term charter agreement signed between the owner of the tanker and the operator of the project. The charter agreement will stipulate, firstly, the charter rate, which is typically expressed in dollars per day, servicing agreements, conditions for sub-chartering the tanker and so on. The sub-charter market is an important part of LNG trading which aims to deal with imbalances on the global market. There are several scenarios under which the operator of a project may consider offering project tonnage on the sub-charter market. These could include prolonged production outages at an LNG plant, lower-than-expected production or force majeure conditions experienced by project offtakers.

Depending on the market conditions, a sub-charter rate may be lower or higher than the long-term charter rate. Since 2010, LNG shipping has gone from feast to famine on several occasions. While a long-term charter rate is typically locked for the period during which a vessel is expected to service the project, which normally ranges between 10 and 15 years, short-term or spot rates fluctuate with the movements of the market and are therefore indirectly exposed to the price of LNG. During strong seller market periods, such as the one in the aftermath of the Fukushima incident in Japan, spot charter rates have reached highs of 140,000 dollars per day, whereas when the market hits bottom due to oversupply the very same vessel could attract only 25,000 dollars day. The periods of high charter rates normally coincide with arising arbitrage opportunities between the Atlantic and Pacific Basins. The longer the voyage between the buyer and the seller, the more strain it adds to the midstream component. This means that when available cargoes are mostly located in the Atlantic Basin and most demand is in the Pacific Basin, the pool of available vessels is greatly reduced as longer voyage times will on the whole absorb greater numbers of ships. The movement of cargoes between the Atlantic and Pacific Basins typically coincides with bull seller markets. Thus, short-term charter rates will typically follow the direction of spot LNG prices.



It should be added that all LNG carriers face operational costs which range from 30,000-40,000 dollars per day. These costs include items like crewing, insurance, technical servicing and finance re-payments. It is not uncommon during bear markets to see charter rates fall below operational costs as long-term charterers attempt to minimize their daily losses. In any scenario, idling an LNG carrier is an expensive exercise that costs about 1,000,000 dollars per month. Hence, shipping optimization aims to minimize idling time. On the short-term market, the employment of a vessel that is not on a long-term charter is primarily the responsibility of the owner. If the vessel is attached to an LNG production project via a long-term charter the financial burden falls on the charterer, who will seek alternative employment for the vessel if it is not utilized.

The carrying capacity of LNG tankers is a significant factor in terms of utilization. The short-term market requires vessels that are suitable for transporting spot volumes. While there is no standard size for a spot cargo, it tends to be between 135,000 and 142,000 cubic metres. The carrying capacity of the modern LNG fleet ranges from 138,000 to 177,000 cubic metres and represents a spectrum of tonnage suitable for short-term markets. While much has been said about the Q-flex and Q-max category tankers, which are used to transport volumes produced by Qatar's RasGas and Qatargas companies, these tankers are rarely used by third parties due to their large size. Q-flex category tankers, first introduced in 2007, have a carrying capacity of 210,000 and 216,000 cubic metres. Q-max category carriers have a capacity of 266,000 cubic metres. These vessels were specifically designed for Qatari projects and are used to service long-term contracts. The large size of such a vessel makes it impractical for carrying standard-sized cargoes produced by other projects. Q-flex and Q-max carriers require special modifications to be installed at the receiving terminal of the customer. Not all terminals in the world have the technical capacity to receive Q-flex and Q-max category tankers. As such, the infrastructure requires relatively heavy funding and the LNG buyers in the past have not typically installed infrastructure to accommodate carriers of this size without there being a long-term contract in place with either RasGas or Qatargas.

To sum up, unlike LNG trade via long-term contracts – which limits the geographical scope of trade due to contractual limitations – the emergence of a truly global gas market relies on the future evolution of the spot and short-term LNG trade. Therefore, the future of short-term and spot LNG trade will have important implications for energy geopolitics due to its ability to integrate regional markets and contribute to supply diversity. And although we have witnessed tremendous growth in LNG trade over the last four decades, the inter-regional trade has been relatively slow due to a number of factors, which we discuss below.

### 2.3 Short-term Limits to Inter-Regional LNG Trade and Global Gas Market Integration

Currently, there are number of factors that impede inter-regional trade in LNG and hence limit the degree of globalization or “interconnectedness” of the regional gas markets in general and LNG price responsiveness in particular. An important example to look at in order to understand the current limitations of short-term and spot LNG trade to arbitrage away regional price differences, that is, to “glue up” regional markets and provide more diversity, is the trade in LNG in 2010-2014, especially after the Fukushima incident in Japan.

In the aftermath of the Fukushima incident, Japan has switched off its entire nuclear power capacity thereby creating a demand shock in the LNG market. Due to this shock, the spot prices in North-east Asia reached 19.7 dollars/mmBtu in February 2013 from the level of ca. 7 dollars/mmBtu back in 2010. This created huge differences in prices between Europe and Asia and even more between North America and Asia (figure 1). Short-term and spot LNG trade is believed to respond to such demand shocks and price differences rather slowly – and indeed the price differences persisted up until mid-2014 when international markets saw the coming of excess of oil and gas capacities. There are several explanations for the slow LNG response to those large price differences, but most of them are related to the LNG long-term contracts and industry structure in the short-term, and pricing power of large LNG players in the longer term.

Apart from long-term strategic trade policy considerations, one reason why the price differentials were not fully arbitrated away after the demand shock in 2011 in Asia is contractual rigidities. For example, territorial restrictions (the so-called “destination clause” in long-term LNG SPAs) and other contractual barriers or logistical issues (shipping re-direction, cargo replacement) can make arbitrage a non-profitable venture, simply illegal or technically impossible.<sup>10</sup> Traditionally, LNG long-term sales and purchase agreements (SPAs) are concluded under either so-called DES (Delivered Ex-Ship) or FOB (Free on Board) delivery conditions.<sup>11</sup> One crucial difference between the two types of contracts is the question of ownership of the gas. Under the DES agreement, the exporter owns the LNG cargo until it is unloaded at its destination point and from there the ownership is transferred to the buyer, whereas under FOB the buyer is the

<sup>10</sup> For a long list of barriers to LNG arbitrage, see Polina Zhuravleva, “Nature of LNG Arbitrage, and an Analysis of the Main Barriers for the Growth of Global LNG Arbitrage Market”, in *OIES Papers*, No. NG31 (June 2009), <https://www.oxfordenergy.org/tag/ng31>.

<sup>11</sup> John Cogan, “LNG Sales and Shipping: The Evolution of Delivery Terms from the Empirical to the Existential”, in *Texas Journal of Oil, Gas, and Energy Law*, Vol. 2, No. 1 (2006), p. 35-55, [http://www.tjogel.org/archive/Vol2No1/cogan\\_12\\_2\\_final.pdf](http://www.tjogel.org/archive/Vol2No1/cogan_12_2_final.pdf).

owner of the cargo once the vessel is fully loaded at the port of shipment.<sup>12</sup> This has an implication for LNG arbitrage in that under a DES agreement the seller can enforce territorial restrictions, whereas under an FOB agreement such a restriction is difficult to oversee.<sup>13</sup> Hence, compared to the FOB condition, DES contracts are much more rigid and make LNG arbitrage almost impossible.<sup>14</sup> Currently, the majority of LNG contracts are concluded under DES conditions (52 percent of all contract volume) whereas FOB conditions affect 33 percent.

In addition to the contractual limitations, at the moment there are also operational limits to short-term and spot LNG trade. Due to mid-stream constraints, the LNG market cannot offer the same level of short-term flexibility as pipeline gas or crude markets given its technical and operational constraints. The vast majority of LNG tonnage on the water today is committed to servicing long-term contracts. Operationally, the arrival and discharge of an LNG carrier requires advance notice, reservation of a slot at the terminal, and arrangements with port and coastal authorities well ahead of discharge, particularly around congested maritime points. Out of around 400 LNG tankers in operation today, only around 30 were available for spot trading as of mid-2015. This availability is likely to shrink further as some vessels are awaiting the starting-up of the long-term projects for which they were built. There is no mechanism to ensure that sufficient tonnage will be available in a market facing a severe demand crisis. Redirecting a vessel from a long-term project to spot trading typically requires a buyer to absorb optimization costs. In fact, LNG is probably the most expensive commodity to transport when the mid-stream is reflected as a percentage of the cargo's costs.

Another technical consideration which often determines a vessel's employment potential is the boil off rate. Once LNG is loaded onto a vessel, the cargo will sustain a loss during its transportation which is expressed as percentage of the cargo per day. The lower the boil off rate, the fewer losses the seller will incur as a result of trans-

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<sup>12</sup> Eleonora Wåktare, "Territorial Restrictions and Profit-sharing Mechanisms in the Gas Sector: The Algerian Case", in *Competition Policy Newsletter*, No. 3/2007, p. 19-21, [http://ec.europa.eu/competition/publications/cpn/cpn\\_2007\\_3.html](http://ec.europa.eu/competition/publications/cpn/cpn_2007_3.html).

<sup>13</sup> Ashurst, "Destination Restrictions in LNG Sale and Purchase Agreements", in *Ashurst Energy Briefings*, April 2009, [https://www.ashurst.com/doc.aspx?id\\_Content=4413](https://www.ashurst.com/doc.aspx?id_Content=4413); Andrew Bruton and Franklin Morean, *Secondary Markets for LNG Exports: Legal Implications of 'Re-loads' for LNG Sales Agreements*, HWL Ebsworth commentary, 27 February 2014, <http://www.hwlebsworth.com.au/latest-news-a-publications/publications/energy-and-resources/item/1235>; Gavin Robert and Fiona Hobbs, "Profit Sharing Mechanisms in LNG Contracts: Sorting Fact from Fiction", in Linklaters' *In the Know*, 16 November 2005, <http://www.linklaters.com/Insights/Publication1619Newsletter/PublicationIssue20051116/Pages/PublicationIssueItem723.aspx>.

<sup>14</sup> Polina Zhuravleva, "Nature of LNG Arbitrage, and an Analysis of the Main Barriers for the Growth of Global LNG Arbitrage Market", cit.

porting the cargo. Highly efficient vessels will typically sustain a boil off rate of around 0.05-0.06 percent per day, while older tonnage could have a boil off rate as high as 0.1-0.12 percent per day. On a voyage lasting 30 days or more, such losses can be quite substantial. The boil off rate is also calculated into the equation if a vessel is used as storage. Typically, boil off and the pressure of charter payments makes LNG carriers a poor option for storing LNG. While there have been cases of traders “floating” or storing a cargo on water for a period of three months or more, such moves have rarely paid off and have resulted in heavy losses. This factor should also be accounted for in any delays in discharging the cargo.

In operational terms, the conclusion of spot LNG transactions typically requires several days to complete due to the complexity of credit terms. Therefore, LNG has never been a commodity of choice in terms of fast reactions to energy crises. The relative liquidity and operational simplicity of coal, crude oil and crude products is likely to keep LNG as a secondary choice for buyers with access to crude-fired and coal-fired power generation capacity. Some buyers, however, are entirely dependent on gas-fired power generation capacity and, therefore, have no recourse but to attempt to import LNG despite the costs. This was seen in Japan after the Fukushima incident, although most utility buyers have prioritized coal and oil products.

Furthermore, LNG terminals have restrictions in place in terms of what vessels they can accommodate. Vessels built before 1989, for example, rely on using low-grade bunker fuel, which is not compatible with environmental standards or the regulations of certain countries around Europe. Some production projects, such as Snohvit LNG in Norway and Sakhalin-2 in Russia’s Far East, require “winterization” for vessels lifting volumes during certain times of the year. Thus, there is no global compatibility between all LNG ports and vessels. Of the current global fleet, we have identified just under 50 vessels that have sufficient flexibility in terms of technical features and size to service the short-term market. Of these 50, only around 20 are available for three-month charters. Thus, it can be generally concluded that at present only about 5 percent of the total global LNG fleet can be dedicated to the spot trade. The proportion is likely to at least double by 2020 on the basis of the current order book. This would mean that 10 percent of the global LNG fleet could be dedicated to short-term or flexible trading by 2020 without taking into consideration any midstream lengths offered by production projects.

In the long term, the LNG market is very likely to offer more flexibility. The LNG market is set to grow with the onset of export projects in North America, Australia, Africa and Russia. Importers are being presented with more flexible contractual options that will allow diversions to take place more easily than they do now. In terms of technology, ship-to-ship transfer, FSRUs, as well as small-scale LNG projects and ships are bound to dramatically change the market past 2020. New options will allow a greater level of

flexibility and carry the potential to move LNG to the forefront of response options in a potential energy security crisis. An emerging feature of the global LNG trade is the so-called “tolling agreement” for access to LNG export infrastructure in North America (primarily the US). Implications of this and other trends in the LNG markets to energy geopolitics will be discussed next.

## 2.4 Future LNG Developments and Implications for International Trade and Geopolitics

As noted before, one of the main advantages of the uptake in LNG trade globally is its potential to contribute to global supply diversity and in particular to “depoliticize” pipeline gas trade. By the very nature of the LNG transport technology, gas trade via ships is more flexible than trade using pipelines that bind more than one nation state into long-term trade relations. A simple empirical analysis carried out by Chyong shows that LNG trade is in general more flexible than pipeline gas trade<sup>15</sup> (figure 3): (i) LNG contracts are on average shorter than pipeline gas contracts, (ii) recent LNG contracts not linked to particular production fields (supplied from portfolio players such as BG, Shell) are on average 2.5 years shorter than pipeline gas contracts, and (iii) these contracts by portfolio players are also one year shorter than other LNG contracts with dedicated production assets. Note that these findings are systematic, that is statistically significant.

The implications of these empirical findings reinforce our conclusion that short-term and spot trade in LNG will increase liquidity of global gas trade and hence increase supply diversity. As Noël noted, liquid gas market trading in Europe can reduce the political divisiveness of pipeline gas coming from Russia.<sup>16</sup> Therefore, it is important to understand trends in LNG trade going forward in the environment of low energy prices, and, in particular, LNG exports from North America as these are expected to be the most flexible sources of exportation, without contractual rigidities (e.g., destination clauses). This is the aim of the rest of this section (see also Koranyi’s chapter).

On the back of oversupply from shale gas in the US, almost all onshore LNG importation facilities are looking to re-develop into export projects. So far, of more than 30 export projects (or ca. 300 Bcm/year of export capacity) from the US and Canada, five

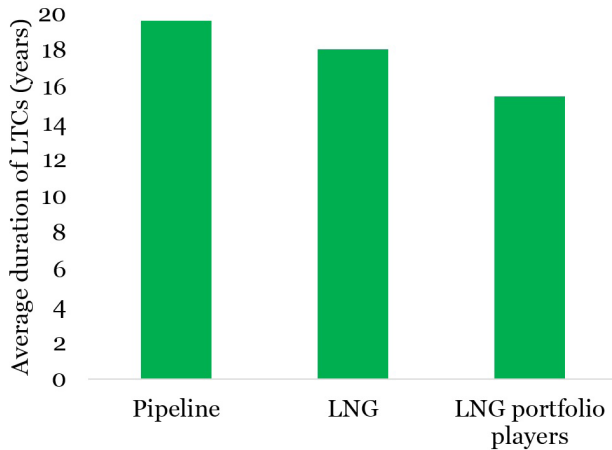
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<sup>15</sup> Chi-Kong Chyong, “Markets and Long-Term Contracts: The Case of Russian Gas Supplies to Europe”, in *EPRG Working Papers*, No. 1524 (December 2015), <http://www.eprg.group.cam.ac.uk/eprg-working-paper-1524>.

<sup>16</sup> Pierre Noël, “Beyond Dependence: How to Deal with Russian Gas”, in *ECFR Policy Briefs*, January 2009, [http://www.ecfr.eu/publications/summary/beyond\\_dependence\\_how\\_to\\_deal\\_with\\_russian\\_gas](http://www.ecfr.eu/publications/summary/beyond_dependence_how_to_deal_with_russian_gas).

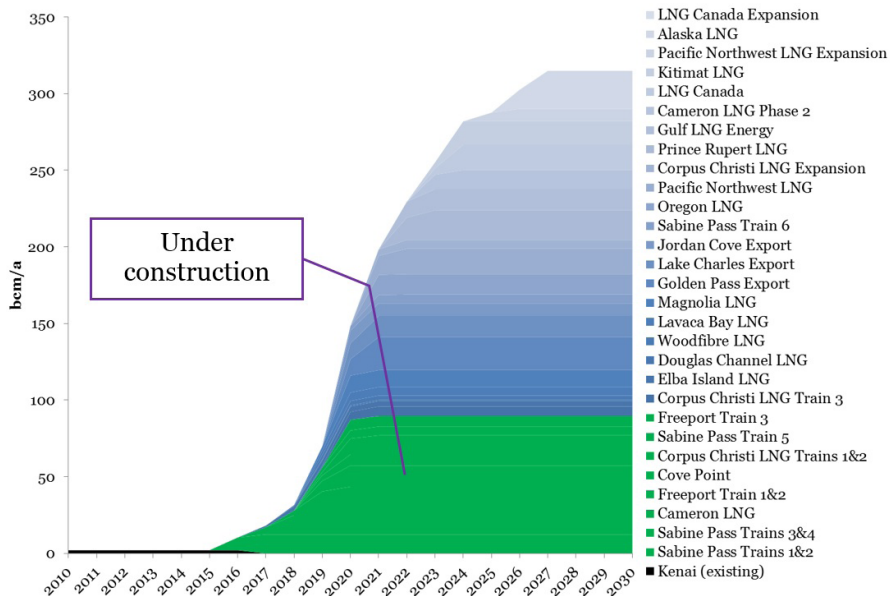
projects have made final investment decisions (FID) and have started the construction process (figure 4). The overall export capacity of these five committed projects is roughly 87 Bcm/year (once fully operational by 2020).

Figure 3 | Duration of gas contracts: LNG vs. pipeline gas



Source: Chi-Kong Chyong, "Markets and Long-Term Contracts", cit.

Figure 4 | LNG export capacity from North America

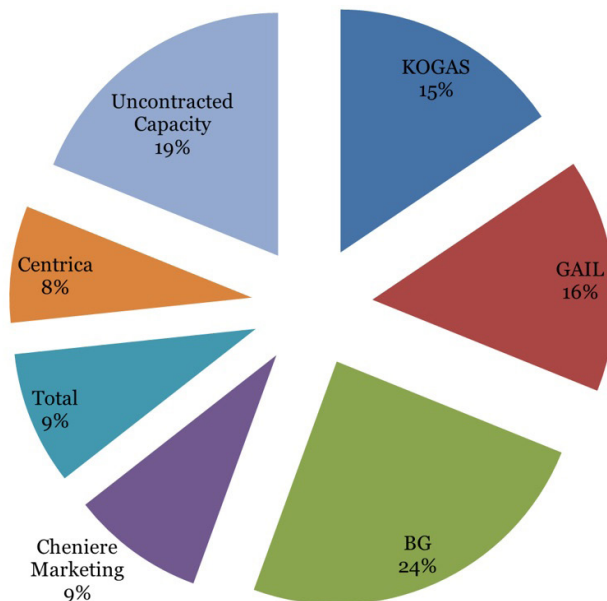


Source: Various trade press sources and official company websites.

These export terminals are: Sabine Pass (trains 1-5), Cameron LNG, Freeport, Corpus Christi (all on the US Gulf Coast) and Cove Point on the US East Coast. Of these projects, Sabine Pass and Corpus Christi are owned by Cheniere Energy, a Houston-based energy company involved mainly in LNG trading business. The other three export projects are owned by various energy market players such as Dominion (US-based energy utility), Osaka Gas, Sempra, ENGIE (formerly GDF Suez), Mitsui and Japan LNG Investment, and others. It is important to make this distinction since we believe that the business models of Cheniere Energy and the other project owners may have different market implications.

Cheniere Energy is an LNG (commodity) re-seller that developed the two projects based on the firm SPAs it has with various utilities around the world (e.g., Gas Natural from Spain, KOGAS from South Korea, GAIL from India, BG, Centrica, Total, etc.). Most of these SPAs are FOB-based contracts and hence are flexible for buyers to divert to the market of their choice, for a price which is linked to Henry Hub plus a fixed component to reflect capacity and other charges.

Figure 5 | SPAs from Sabine Pass project



Source: Various trade press sources and official company websites.

Note: The total export capacity of Sabine Pass project is 31 Bcm.

By contrast, the other projects – Cameron LNG, Freeport and Cove Point – are all developed based on “tolling agreements” which are basically capacity agreements that allow the buyer to access the greatest liquid gas market in the world – the US – when needed.

Thus, the tolling agreements are even more flexible than the SPAs with Cheniere in that they allow buyers to buy US gas when market conditions are right, whereas as we understand from public sources that SPAs with Cheniere involve firm offtake agreements. This means that buyers will have to offtake a minimum LNG and export to other destinations, contributing to global supply of gas and hence diversity. Depending on global supply and demand dynamics, some of these LNG cargoes may end up in Europe as the recent slump in energy prices in Asia does not justify exportation of LNG there and favours Europe as the final destination. The implication of this is that although there is 87 Bcm/year of firm export capacity from the US, only volumes under SPAs with Cheniere are certain to be exported to global markets and flows from other projects will depend on international market dynamics, giving capacity holders an option – but not an obligation – to buy US gas.

Nevertheless, the question of how much the US will export to the outside world is as important as the implications of the flexibility thus provided to LNG trade. This is because it is not only about physical supply availability from the US, it is about business models and contracts with US energy suppliers and infrastructure operators that give further flexibility and diversity to importing companies – which, as we discussed before, will increase trade liquidity and inter-regional trade.

Besides potential LNG projects from North America, Australia and East Africa, another region which has vast and cheap gas resources is the Middle East. In this region, Qatar is already the largest LNG exporter in the world with Iran deemed as a possible next large gas exporter due to the large size of its gas reserves – as of 2014, Iran is the largest gas reserve holder in the world with 34 trillion cubic metres of proven reserves.<sup>17</sup> Despite the large reserve sitting in this region the prospect of future growth in export capacity is rather uncertain – Qatar has declared a moratorium on new LNG export projects, while Iran lacked financial resources and technology to develop its export potential due to sanctions imposed by the international community. However, with the recent removal of these sanctions, there has been increasing attention from the international community to Iran as a potential new net gas exporter. The realization of its huge gas resource potential for exports to international markets, however, depends on a set of factors which may scale down Iran's ambition to a rather marginal performance.

First of all, its domestic gas market is heavily subsidized (prices below cost of production) therefore there is much wasteful consumption. Domestic gas prices were extremely low, making some portion of gas recovery either uneconomic or used for en-

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<sup>17</sup> BP, *Statistical Review of World Energy 2015*, June 2015, <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.



hanced oil recovery; according to the US Energy Information Administration, of the 230 Bcm produced in Iran in 2013, most of it was marketed (184 Bcm) and the remainder was re-injected into oil wells to enhance oil recovery (28 Bcm) or vented and flared (17 Bcm).<sup>18</sup> Note that Iran's 17 Bcm of gas flaring – the largest gas flaring country in 2013 – amounts to the total gas consumption of Poland or the total consumption of all three Baltic States, Czech Republic, Slovakia and Bulgaria (the so-called highly Russian-gas-dependent countries). Further, even with vast gas resources, Iran relies on imports particularly during winter months when residential space-heating demand peaks due to colder weather.

Secondly, to develop its gas export potential the country needs huge financial resources and mobilizing a rapid rise in funds to develop Iran's gas sector will, however, not be a simple matter, even with sanctions lifted.<sup>19</sup> Low energy prices are likely to limit domestic funds while attracting foreign sources would depend on terms and conditions of the newly proposed petroleum contract and other institutional setup. However, in reality, crude oil production and export will likely be prioritized over gas development, as an easier and more remunerative option entailing limited funding compared to enormous gas infrastructure requirements. This would however exacerbate the gas balance deficit since more gas will probably be used for re-injection, the main technology used for secondary oil recovery in Iran.

Currently, the country does not have infrastructure to export or import LNG and has limited pipeline connections with neighbouring countries (Turkey, Turkmenistan, Oman and Iraq). Therefore, the most likely scenario for the next 10 to 15 years is that Iran will become a marginal pipeline gas exporter to the neighbouring gas-hungry countries (Oman, the United Arab Emirates, Kuwait and Pakistan) and perhaps develop one LNG project called Iran LNG, on which the country has already made substantial capital investment, with many facilities in place already with the exception of the liquefaction plant. The project could have export capacity of ca. 13.8 Bcm sometime post-2020.

Thus, it appears that the real bottleneck for large-scale production and export from Iran is the investment needed to develop all necessary infrastructure capacities. Therefore, any meaningful gas export volume from Iran in the medium term depends on its domestic pricing and social policies towards energy and gas consumption and hence on political dynamics and stability in the country (figure 6). Despite greater efforts in recent years to raise prices, according to IEA gas for industrial customers is priced at 1-2 dollars/mmBtu while gas sold to power producers are set at under 1 dollar/mmBtu.<sup>20</sup> In

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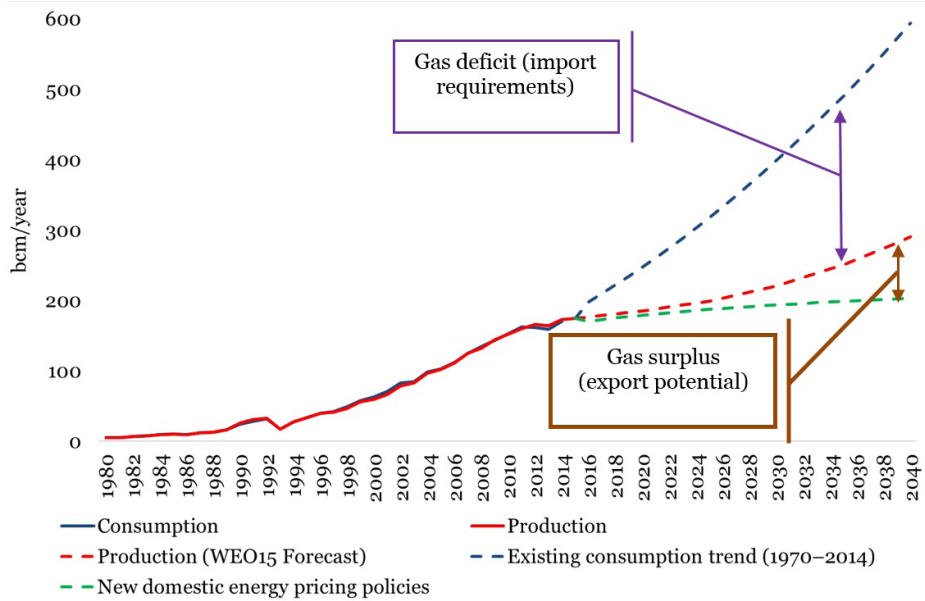
<sup>18</sup> EIA, *Country Analysis: Iran*, last updated 19 June 2015, <https://www.eia.gov/beta/international/analysis.cfm?iso=IRN>.

<sup>19</sup> IEA, *World Energy Outlook 2015*, November 2015, <http://energy.anu.edu.au/files/weo2015.pdf>.

<sup>20</sup> *Ibid.*, p. 209.

IEA's report *World Energy Outlook*, Iran's gas production is projected to rise progressively to 185 Bcm in 2020, 220 Bcm in 2030 and reach 290 Bcm in 2040.<sup>21</sup> Based on this data, one can see that should gas consumption keep following the historical trend since 1970 (that is, no reforms to energy subsidies in Iran), Iran may need more gas imports to meet its inefficient gas consumption (figure 6).

Figure 6 | Iran's natural gas consumption and production



However, should further policy reforms of energy subsidies be implemented thereby moderating gas consumption and creating spare capacity which could be exported (compare red with green lines: figure 6), we could reasonably expect that most of Iran's new gas production would be sold to neighbouring countries and to its domestic customers. For example, the domestic market can take most of gas coming from the South Pars (Iran's largest offshore gas field, accounting for ca. 40 percent of its entire proved gas reserves). Gas coming from new South Pars phases 12, 15 and 16 will most likely consumed by Iran's power sector while gas coming from other South Pars projects could potential be exported to neighbouring countries via pipelines.<sup>22</sup>

<sup>21</sup> Ibid., p. 83.

<sup>22</sup> Thomas Adolff et al., "Iranian renaissance", in *Credit Suisse Equity Research - Global Oil & Gas*, 25 June 2015, [https://doc.research-and-analytics.csfb.com/docView?language=ENG&format=PDF&-document\\_id=1050111921&source\\_id=emcsplus&serialid=gpMvrvjD%2B10Nnw5h7KavQ32cUJIG-Soh7z7c73BzyV6U%3D](https://doc.research-and-analytics.csfb.com/docView?language=ENG&format=PDF&-document_id=1050111921&source_id=emcsplus&serialid=gpMvrvjD%2B10Nnw5h7KavQ32cUJIG-Soh7z7c73BzyV6U%3D).

Therefore, it looks like that Iran will become (in a rather optimistic scenario) a regional pipeline gas supplier with marginal volumes sold as LNG and any sustainable volume that may come out of Iran to the international markets depends on (i) Iran's growth in gas demand, (ii) its oil production strategy and needs for gas to enhance oil recovery, and (iii) disagreements with potential buyers over gas prices and volumes.

## Conclusions

Natural gas, once a regionally traded commodity, is now becoming increasingly globalized. The main contribution of this process can be seen in the uptake in LNG trade in the last 40 years – which grew by more than 14 percent p.a. in this period. Cost reductions along the whole value chain of LNG, demand growth in remote and resource-limited countries and the general advantage of LNG relative to other transportation modes of gas contributed to this rapid penetration of LNG, linking regional markets of the Americas, Europe and Asia Pacific. Thus, currently, LNG trade is dominant in Asia Pacific due to the remoteness of this region from the resource-rich countries. In particular, Japan, South Korea, Taiwan, China and India together accounted for roughly two-thirds of the global trade in LNG in 2014, with the rest of trade directed towards the Americas and European countries. However, going forward we expect that the majority of growth in LNG trade will come from such regions as the Middle-East, South Asia, Latin America and Africa, while the dominance of Asian and European countries will still be felt.

Gas trade is a capital-intensive business and the question of pricing of this commodity is one of the most complex issues in the commercial and political relations between consumers and producers. Therefore, gas trade is “regionalized” not only by the nature of geography but also by the differences in the pricing systems. The evolution of trade and pricing in the last 40 years suggests that convergence to a single global pricing system, dominated by supply and demand balancing, the so-called market-based pricing, is not a smooth journey. Such a possibility of convergence also depends, amongst other important factors, on the evolution of short-term and spot trade in LNG. Further, short-term, spot trade and more generally LNG arbitrage not only contribute to the convergence of different regional prices but also to gas supply diversity of regional markets and hence limit possible political influence attached to such trade.

Although we have witnessed tremendous growth in LNG trade, especially short-term and spot trade, over the last four decades, the inter-regional trade has been relatively slow due to a number of factors, such as strategic trade policy considerations, contractual rigidities, and in particular territorial restrictions (the so-called “destination

clause”) as well as operational and technical limits related to arranging and closing short-term and spot deals. However, going forward, we expect that the market will offer more flexibility to facilitate short-term and spot trade in LNG due to growth in supplies coming from North America, Australia, Africa and Russia. Of particular note is the way the US LNG export is going to shape the future trade in LNG. Export coming from the US will predominantly be based on the business models which offer the most flexibility, encouraging more spot and short-term trade. Further, although the Middle East region in general and Iran in particular holds huge gas reserves and extremely cheap ones, it is not expected that Iran will contribute to international gas trade in the foreseeable future (at least in the next 15 years) due to a number of factors: (i) mismanagement of the domestic oil and gas sector, (ii) geopolitics and international sanctions, and (iii) market dynamics which favour the development of crude oil exports rather than natural gas.

Lastly, technological advancements and in particular ship-to-ship transfer, FSRUs, as well as small-scale LNG projects and ships are bound to dramatically change the market past 2020. These advancements in technologies and commercial practices will offer a greater level of flexibility allowing LNG to act not only as a bargaining option against traditional pipeline gas but also as one of the most important gas supply security response options in a potential energy security crisis.



## 3. The United States as a New Gas Exporter

David Koranyi

### 3.1 US Natural Gas Production Potential

The natural gas revolution that has gradually unfolded in the last three and a half decades in the United States is nothing short of remarkable. The unique combination of technological advancements, early government support, a regulatory and incentive system (landowners are entitled to rights to subsoil resources, thus profiting from the proceeds), and an entrepreneurial, risk-taking culture has resulted in a dramatic uptake of gas production from unconventional resources primarily in the Barnett, Haynesville and Fayetteville, and later the Bakken, Marcellus and Eagle Ford shale basins.

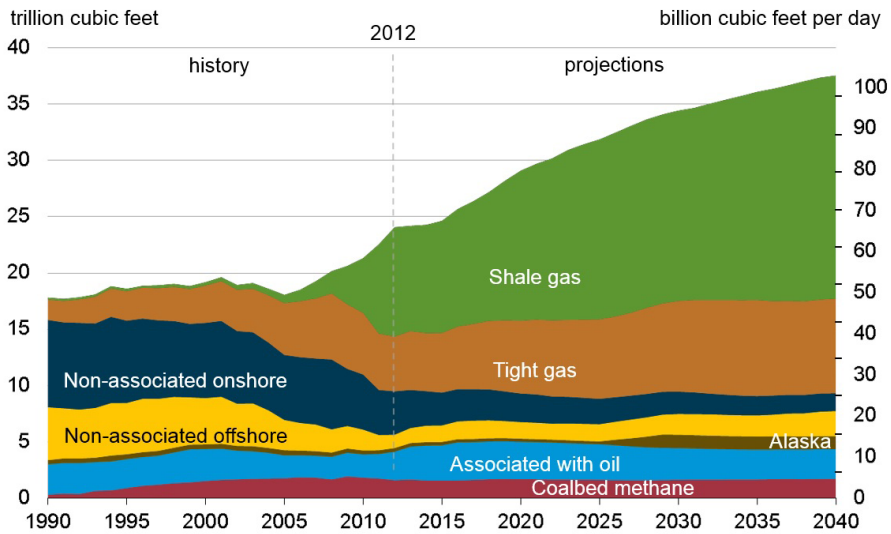
Shale gas was extracted first in the early 19th century in the United States from shallow, low-pressure fractures. Yet it took more than 150 years for industrial-scale shale gas production to pick up. The role of the US government was critical all along. Declining conventional gas well production prompted the federal government to invest in research in an attempt to boost productivity. The Eastern Gas Shales Project which took off in 1976 aimed to evaluate the gas potential of the extensive Devonian and Mississippian organic-rich black shales within the Appalachian, Illinois, and Michigan basins in the Eastern US. The purpose of the program was to “determine the extent, thickness, structural complexity, and stratigraphic equivalence of all Devonian organic-rich shales throughout the three basins; and to develop and implement new drilling, stimulation, and recovery technologies to increase production potential.”<sup>1</sup> The Gas Research Institute was also established in 1976 to spearhead natural gas research and development (the Institute’s funding was provided by a surcharge on shipments of natural gas sold by the interstate pipelines). The Department of Energy, working with private companies, completed the

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<sup>1</sup> See the website of the Pennsylvania Department of Conservation and Natural Resources, *Eastern Gas Shales Project*, [http://www.dcnr.state.pa.us/topogeo/econresource/oilandgas/marcellus/marcellus\\_egsp](http://www.dcnr.state.pa.us/topogeo/econresource/oilandgas/marcellus/marcellus_egsp).

first multi-fractured horizontal well in 1986. Tax credits for unconventional gas producers through the so-called section 29 proved to be very effective in incentivizing further production in the 1980s and 1990s.<sup>2</sup> Mitchell Energy, using new technologies such as microseismic imaging in addition to horizontal drilling and hydraulic fracturing, achieved the first commercially viable shale fracture in 1998.

Figure 1 | US dry natural gas production



Source: Adam Sieminski, *The U.S. Natural Gas and Shale Production Outlook*, for North American Gas Forum, 29 September 2014, [http://www.eia.gov/pressroom/presentations/sieminski\\_09292014.ppt](http://www.eia.gov/pressroom/presentations/sieminski_09292014.ppt).

Since the 1990s and especially from the mid-2000s unconventional natural gas production has been on a steady rise, reaching 47 percent of total dry gas production in the US in 2013.<sup>3</sup> Total gas production in the US increased by 35 percent between 2005 and 2013 to approximately 680 Bcm.<sup>4</sup> Despite depressed oil prices affecting associated gas production in the US, total US gas production will continue to grow. Gas production is projected to further increase by 45 percent to 1005 Bcm by 2040<sup>5</sup> on the back of the growth of Marcellus and Utica shale plays and flattening decline rates in other plays,<sup>6</sup>

<sup>2</sup> Jeff Reed, "The History of Shale in the U.S.", in *Oilpro*, 28 October 2013, <http://oilpro.com/post/645>.

<sup>3</sup> Ibid.

<sup>4</sup> EIA, *Annual Energy Outlook 2015 with Projections to 2040*, Washington, April 2015, [http://www.eia.gov/forecasts/aeo/pdf/0383\(2015\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf).

<sup>5</sup> Ibid.

<sup>6</sup> IEA, *Medium-Term Gas Market Report 2015*, Paris, June 2015, [http://www.iea.org/bookshop/707-Medium-Term\\_Gas\\_Market\\_Report\\_2015](http://www.iea.org/bookshop/707-Medium-Term_Gas_Market_Report_2015).

though with some caveats over the actual production increase, which is contingent upon the size and cost of tight and shale gas resources in Alaska, the Midcontinent region, the Gulf Coast and the Dakotas/Rocky Mountains, as well as technology improvements, domestic and international natural gas demand, and the relative price of oil<sup>7</sup> among other factors.<sup>8</sup>

## 3.2 US Natural Gas Demand

The US is the leader in gas consumption globally with 759.4 Bcm in 2014.<sup>9</sup> The role of gas particularly in electricity generation increased dynamically in the past decade as the shale gas revolution boosted the competitiveness of gas vis-à-vis coal. US gas demand is projected to grow further. In the EIA's Annual Energy Outlook 2015, reference case gas consumption increases to 841 Bcm in 2040. The lion's share of this growth will be in the power sector, where demand for natural gas grows from 232 Bcm in 2013 to 266 Bcm in 2040, partly due to a massive retirement of the coal-fired power plant fleet in the next decade.<sup>10</sup>

Industrial usage of natural gas is also projected to grow rapidly, especially in industries such as bulk chemicals using natural gas as a feedstock. Four major ethane-fed steam crackers are under construction already, and two large industrial facilities will commence operations this year. Most of the new industrial projects are located on the US Gulf Coast, but some are also planned in other gas-rich areas, such as North Dakota.<sup>11</sup> The United States will remain a very attractive destination for energy-intensive industries.<sup>12</sup>

Residential use of natural gas consumption is predicted to decline slightly from 2018 all the way to 2040, while it slightly increases in the commercial sector over the same period.<sup>13</sup> Gas usage for road transportation will also grow, albeit at a slower rate due to the loss of economic advantage over gasoline and diesel powered engines (lower oil prices).<sup>14</sup>

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<sup>7</sup> EIA, *Annual Energy Outlook 2015 with Projections to 2040*, cit.

<sup>8</sup> Ibid.

<sup>9</sup> Chris Pedersen, "US continues to distance itself as the world leader of natural gas", in *The Barrel Blog*, 2 October 2015, <http://blogs.platts.com/?p=21435>.

<sup>10</sup> EIA, *Annual Energy Outlook 2015 with Projections to 2040*, cit.

<sup>11</sup> Ibid.

<sup>12</sup> Ibid.

<sup>13</sup> Ibid.

<sup>14</sup> Ibid.



### 3.3 Natural Gas Exports from the US

The growing production of gas and the slower increase in demand opens up the possibility of substantial quantities of gas for export. Indeed, in the spring of 2016 Cheniere's Sabine Pass export terminal commenced its commercial operations, the first of a series of LNG export projects coming online in the next five years. Exports will ramp up in earnest from 2017 when most liquefaction plants will enter into operation, turning the US into a net exporter.<sup>15</sup>

Combined US pipeline<sup>16</sup> and LNG export quantities will depend on many factors and predictions range within a wide margin from 85 Bcm all the way up to 370 Bcm.<sup>17</sup> In the EIA Annual Energy Outlook 2015 Reference case US exports reach 96 Bcm by 2030 and remain at that level through 2040, accounting for 46 percent of US gas exports. In the High Oil and Gas Resource case LNG exports could go up to 292 Bcm by 2037, or 66 percent of total gas exports. In the Low Oil Price Case LNG exports will grow more slowly as they are less competitive internationally, capping at 22 Bcm already in 2018, or about 13 percent of total exports.<sup>18</sup>

Figure 2 | US shale gas production and total natural gas imports, 2005-40

Figure 2 U.S. shale gas production in four cases, 2005-40 (trillion cubic feet)

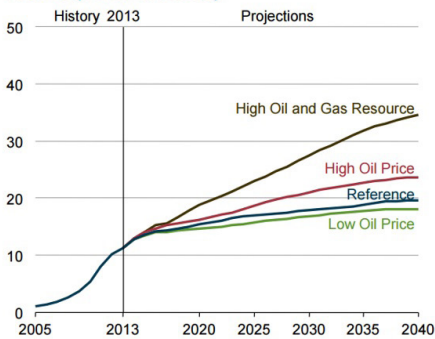
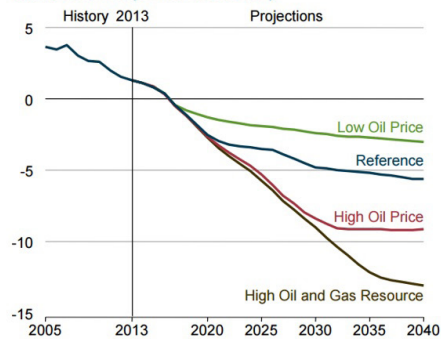


Figure 2 U.S. total natural gas net imports in four cases, 2005-40 (trillion cubic feet)



Source: EIA, *Annual Energy Outlook 2015 with Projections to 2040*, cit., p. 21.

There is no lack of commercial interest in US LNG exports. As of December 2015, 54 LNG export applications were filed with the US Department of Energy (DoE), to the tune

<sup>15</sup> Ibid.

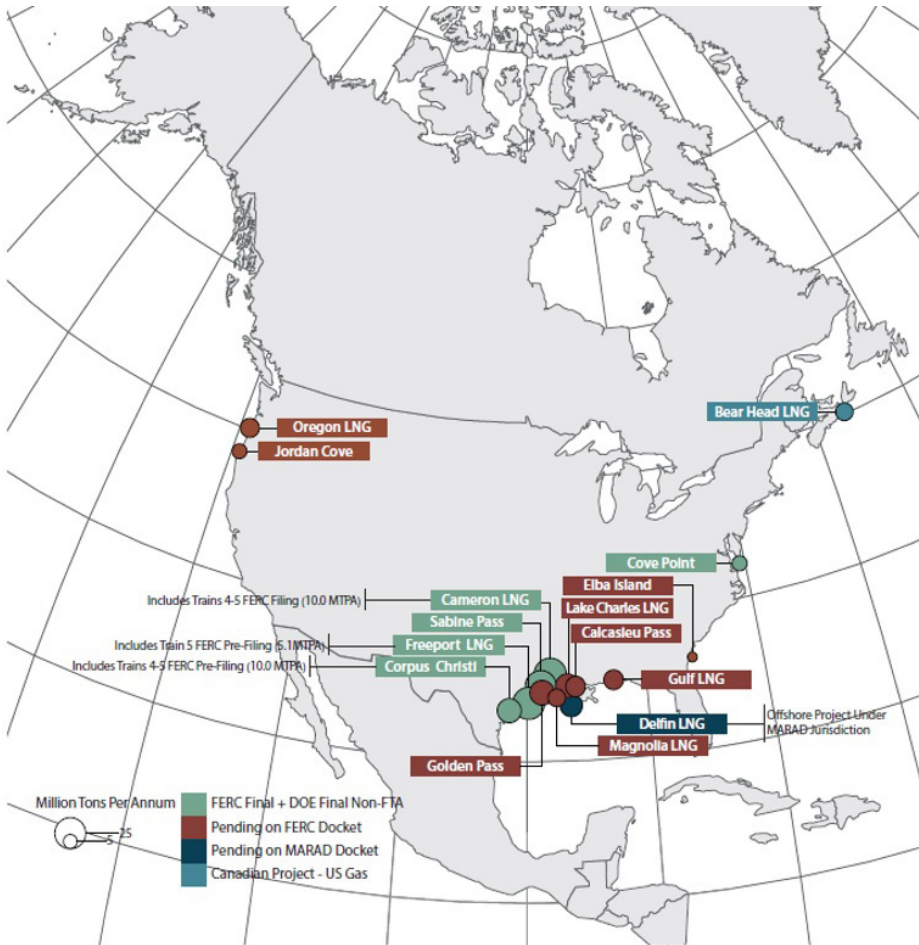
<sup>16</sup> Primarily to Mexico and to a much lesser extent Canada.

<sup>17</sup> EIA, *Annual Energy Outlook 2015 with Projections to 2040*, cit.

<sup>18</sup> Ibid.

of 450 Bcm of LNG export capacity.<sup>19</sup> Out of the 54 applications above, 16 projects in excess of 130 Bcm/year have already received authorization from DoE to export to non-FTA countries. Six of those are actually in construction (with a combined 109.8 Bcm/year export capacity), possessing the required approval from both DoE and the Federal

Figure 3 | LNG export applications with the US Department of Energy



Source: CEEP Report, No. 5(31), May 2015, p. 2, [http://www.ceep.be/www/wp-content/uploads/2015/05/CEEP-REPORT\\_MAY.pdf](http://www.ceep.be/www/wp-content/uploads/2015/05/CEEP-REPORT_MAY.pdf).

<sup>19</sup> US Department of Energy Office of Fossil Energy, *Summary of LNG Export Applications as of December 4, 2015*, <http://energy.gov/sites/prod/files/2015/12/t27/Summary%20of%20LNG%20Export%20Applications.pdf>. For updates, see the webpage: <http://energy.gov/node/622301>.

Energy Regulatory Commission (FERC),<sup>20</sup> with Cheniere’s Sabine Pass slated to commence operation first at the end of 2015. If these projects do indeed come online – a likely scenario – the United States will become the world’s third largest LNG exporter by 2020, after Australia and Qatar.<sup>21</sup>

It is important to note that many of the 54 applicant projects will never be realized. The critical – and expensive – part of the application process is the FERC segment, where there are currently nine pending applications and 12 applications in the pre-filing stage. FERC and DoE approvals still do not mean the project will make it to a final investment decision. It is also worth noting that the six terminals in construction are all brownfield investments: they are being converted from existing LNG import terminals that became defunct on the back of the shale gas bonanza. Jordan Cove (still waiting for FERC authorization as of January 2016) and Lake Charles (already approved by both FERC and DoE) with a combined 28 Bcm/year capacity would be the first greenfield projects, but both are struggling with financial problems – which for Lake Charles pushed back the final investment decision to 2016.<sup>22</sup>

### 3.4 The Political and Regulatory Environment

When discussing US LNG export potential, the most often cited issue is the political and regulatory bottlenecks LNG exporters face when trying to apply for the necessary licenses from FERC and DoE. Indeed, the United States has a somewhat arcane legislation in place in the form of the 1938 Natural Gas Act that restricts gas export in principle and puts in place a process to determine whether gas export projects are authorized to proceed. The permitting process differentiates between export destinations. Countries that have a free trade agreement (FTA) – among them South Korea being the only major LNG importer – with the US enjoy preferential treatment in the form of a quasi-automatic approval process, while export license applicants willing to ship gas to non-FTA countries have to undergo a cumbersome process to determine whether the export of natural gas in that particular case is in the “public interest.”

In practice this has resulted in a politicized and fundamentally opaque licensing process, with unpredictable timelines. Despite multiple attempts by the US Administration

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<sup>20</sup> FERC, *Approved North American LNG Import/Export Terminals* (as of January 6, 2016), <https://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf>.

<sup>21</sup> *Ibid.*

<sup>22</sup> *Ibid.*

and Congress to streamline the procedure, it remains convoluted. The adoption of the LNG Permitting Certainty and Transparency Act<sup>23</sup> currently in front of the US Congress could introduce more certainty by setting a deadline for DoE on final authorization of export projects. There is a chance that the Act itself will be adopted as a broader bipartisan energy package sometime in 2016.

As the prospects of a full blown liberalization that would do away with the current need to authorize each and every project are still slim, there is a longer term political risk with regard to large-scale US LNG exports connected to US domestic politics, where isolationism and populism are on the rise in the context of the 2016 election campaign. Coupled with rising gas prices, this could over time reopen the debate over gas (and oil) exports, and limit the availability of supplies from the United States on global gas markets. Revisiting existing export licenses is unlikely, but the slowing down or capping of export quantities is well within the realm of possibilities.

Interesting in this regard are the Transatlantic Trade and Investment Partnership (TTIP) and the Trans-Pacific Partnership (TPP). The conclusion of TTIP and TPP would automatically put partner countries into the category of FTA countries entitled to a streamlined LNG export licensing procedure. On top of that, the European Union insists on including a passage on the liberalization of gas trade to EU countries in the agreement itself, which could act as a safeguard against future shifts in US politics (liberalized gas trade enshrined in a legally binding international treaty that is difficult to change).

## 3.5 Global LNG and Gas Market Developments

To analyze the commercial challenges US LNG exports face, a brief outlook on global LNG and gas demand developments is in order. Inter-regional gas trade will grow by 40 percent by 2020, surpassing 780 Bcm. LNG will account for 65 percent of the increase. The global LNG market is at the cusp of a major expansion. New LNG projects are scheduled to come online all over the world in the next ten years. Global LNG export capacity has already doubled in the last decade and the IEA forecasts total LNG export capacities to reach 561 Bcm/year by 2020 as well as a 45 percent increase in global LNG trade by the same year (473 Bcm).<sup>24</sup> Liquefaction, transportation, and regasification costs have all come down, with improved technologies, the spread of floating liquefac-

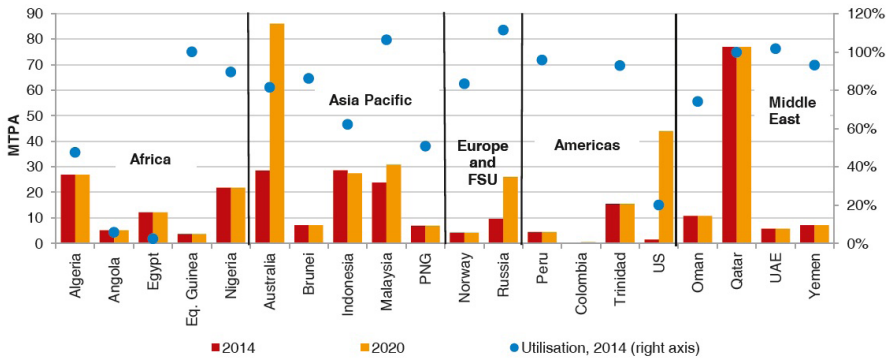
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<sup>23</sup> US Senate, *LNG Permitting Certainty and Transparency Act*(S.33), Washington, 6 January 2015, <https://www.congress.gov/bill/114th-congress/senate-bill/33>.

<sup>24</sup> IEA, *Medium-Term Gas Market Report 2015*, cit.

tion and regasification techniques, and a significantly expanded LNG tanker fleet. As of June 2015 there are 17 liquefaction projects under construction (total capacity of 175 Bcm/year).<sup>25</sup>

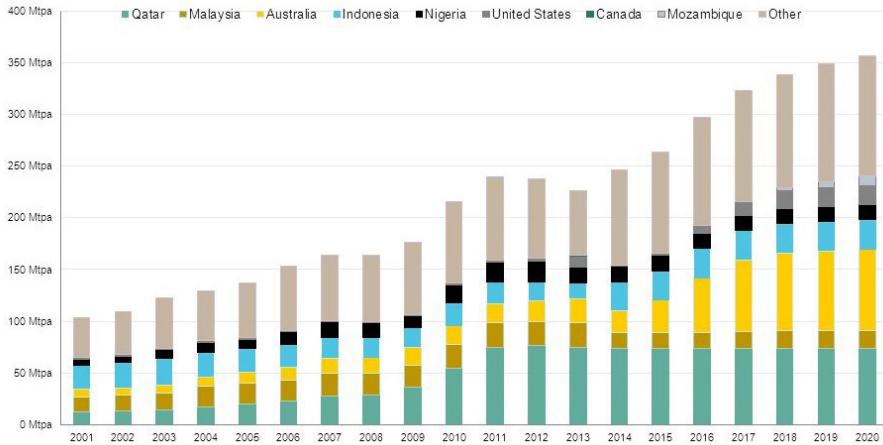
Figure 4 | Liquefaction Capacity by Country in 2014 and 2020



Source: IGU, *World LNG Report 2015*, June 2015, p. 21, <http://www.igu.org/publications>.

Note: Liquefaction capacity only takes into account existing and under construction projects expected online by 2020.

Figure 5 | Top LNG export countries by 2020



Source: Grant Willis, *The Australian Oil & Gas Industry*, January 2014, <http://aacc-houston.org/wp-content/uploads/2014/01/0830-Grant-Willis-AACC-Presentation-Slides-JV-280114.pptx>.

<sup>25</sup> Ibid.

Of the five countries where LNG export capacities are actually being built – Colombia, Malaysia, Indonesia, Australia and the United States – the latter two will be by far the most important incremental suppliers. The IEA estimates that these two suppliers will be responsible for 90 percent of new global LNG export capacity increase until 2020 (164 Bcm/year combined added capacity).<sup>26</sup> By 2020 Australia will become the world's largest supplier of LNG, while the US is on track to become the third largest (from its current net importer status).

From the demand side, the main LNG markets are in Asia today. OECD countries in Asia are responsible for more than half of total global LNG imports. At the same time, 80 percent of inter-regional pipeline imports go to Europe. In the next five years, trade patterns will become more diversified in both Asia and Europe, with the relative weight of LNG on the rise in Europe, while the bulk of the absolute demand growth is centred in Asia<sup>27</sup>.

In Asia, the sensitivity of gas consumption and imports to prices was a major factor behind softer demand growth over the past two years. At spiking price levels, the attractiveness of gas was significantly reduced, limiting the role of gas in the region's energy mix (e.g., Indian LNG terminals were significantly underutilized). With the steep fall of oil prices, oil-indexed LNG contracts have become far cheaper, as evidenced by the halving of LNG prices in Asia over the course of the last year.<sup>28</sup> Japan is now switching back some of its nuclear power plants, tempering the inflated gas demand in that country following the Fukushima-Daichi nuclear accident in 2011.

Gas demand growth is much slower than expected in China amidst an unexpectedly sharp downturn in economic growth and primary energy consumption. Yet as prospects for indigenous production increase from domestic shale gas reserves are moderate, hindered by low domestic prices and unfavourable investment policies, China is expected to emerge as a major pipeline and LNG importer in the coming decade, and as such also becoming a stabilizing factor for regional market balances. China's gas imports are projected to increase by 90 Bcm until 2020, with 60 percent of the increase coming via piped gas from Russia, Central Asia (primarily Turkmenistan) and Myanmar. China will also absorb significant LNG quantities (38 Bcm by 2020).<sup>29</sup>

While China is expected to play a key role in absorbing new LNG volumes, other non-OECD Asian countries will also be major outlets for incremental supplies, with re-

<sup>26</sup> Ibid.

<sup>27</sup> IEA, *Medium-Term Gas Market Report 2015*, cit.

<sup>28</sup> Henning Gloystein and Jacob Gronholt-Pedersen, "Asian LNG price faces steep fall as perfect storm brews", in *Reuters*, 31 August 2015, <http://www.reuters.com/article/2015/08/31/asia-lng-prices-idUSL5N11303420150831>.

<sup>29</sup> IEA, *Medium-Term Gas Market Report 2015*, cit.

gional LNG intakes more than doubling from 2014 to reach 96 Bcm in 2020.<sup>30</sup> Pakistan, Bangladesh, the Philippines and Vietnam will become LNG importers by 2020. Malaysia and Indonesia, producers themselves, will start to import LNG too. India is projected to take an additional 12 Bcm of gas compared with current levels.<sup>31</sup>

This new low in gas prices, coupled with an expected general push towards gas and away from coal in the wake of the Paris Climate Agreement, could affect regional gas usage calculations and add significantly to gas demand in the medium term. Asia as a whole is expected to remain a buyer's market until the end of this decade, with a possible tightening from 2020 onwards if demand picks up in China and elsewhere in Asia.

The convergence in gas prices between the European and Asian markets will enhance the prospects of US (and other) LNG being supplied to the European markets in larger quantities. Still, Europe will likely act as an important, but essentially residual market, importing leftover quantities from other regions due to its capability to arbitrage between pipeline and LNG flows.<sup>32</sup>

Overall, on the back of the rising import demand and fierce price competition, Europe's LNG imports are still expected to double, reaching 91 Bcm by 2020. There are 23 operating LNG terminals in the European Union as of October 2015,<sup>33</sup> with a 191 Bcm capacity – more than total imported Russian gas volumes. In 2014, 85 percent (163 Bcm) of the total regasification capacity stood idle due to cheaper pipeline gas availability and the fact that most LNG cargos ended up in the higher priced Asian markets.<sup>34</sup>

LNG imports in both Europe and Asia will be affected by a plethora of other factors, such as the price of competing resources in power generation and the falling cost of renewables in particular, or climate change measures indirectly affecting gas demand as the future of Europe's and China's emission trading systems. All of these variables could affect the projected numbers above.

### 3.6 US LNG Export Competitiveness and Export Destinations

The dynamically evolving market picture in both Europe and Asia will determine the overall volumes, pricing and competitiveness of US LNG supplies. The commercial via-

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<sup>30</sup> Ibid.

<sup>31</sup> Ibid.

<sup>32</sup> Ibid.

<sup>33</sup> Gas Infrastructure Europe, *LNG Map*, May 2015, <http://www.gie.eu/index.php/maps-data/lng-map>.

<sup>34</sup> Corrado Papa, *European LNG terminals: Status and outlook*, presentation at the Conference on LNG for Transport, Rome, 11 June 2015, [http://www.gie.eu/index.php/publications/cat\\_view/3-gle-publications](http://www.gie.eu/index.php/publications/cat_view/3-gle-publications).

bility of US LNG export from the supply side will also hinge on domestic (Henry Hub) gas prices, and liquefaction, transport and regasification costs.

Henry Hub price predictions vary significantly from scenario to scenario in the EIA's latest Annual Outlook. The Hub price will likely increase over time, from 4.88 dollars/mmBtu in 2020 to 7.85 dollars/mmBtu in 2040 in the Reference scenario, but only to 3.12 dollars/mmBtu in 2020 and 4.38 dollars/mmBtu in 2040 in the High Oil and Gas Resource case.<sup>35</sup> Any price increase will primarily occur due to growing domestic and international demand, and rising costs of production, but is highly contingent on actual demand as well as technical improvements.<sup>36</sup>

The cost of liquefaction hovers around 3 dollars per mmBtu in the case of brownfield projects, and significantly higher in the case of greenfields.<sup>37</sup> Transportation and regasification costs amount to around 3-4 dollars per mmBtu depending on the destination, with Europe enjoying a minor cost advantage vis-à-vis Asia when it comes to supplies from the Gulf and East Coasts – where the majority of the LNG terminals under construction are located.

Long-term contracts remain the backbone of the contract structure of LNG transactions, even if the role of the spot market is growing in both Europe and Asia. Especially, the major Asian LNG importers procure around three quarters of their gas purchases through long-term contracts, with significant differences over countries (India, China and Taiwan being notable exceptions). The share of long-term contracts is expected to grow as both Australia and the United States enter the market, marketing their gas primarily through long-term, although more flexible arrangements. US contracts in particular with Henry Hub-linked prices are expected to provide a more stable, yet flexible framework for consumers with no or limited take-or-pay obligations or destination clauses, providing major offtakers price index diversification, and more clout to renegotiate with existing suppliers. The six Australian LNG projects under construction have already sold about 90 percent of their capacity under short- and long-term deals (mostly to Japanese, Chinese, Korean and Indian companies), and 80 percent of the four US LNG projects under construction is underpinned by long-term offtake tolling agreements.<sup>38</sup> At the same time, the entry of US exporters will be a significant shift towards gas-on-gas pricing, more contractual flexibility, and the use of spot markets.

As far as the destination of US exports is concerned, Asian buyers are expected to

<sup>35</sup> EIA, *Annual Energy Outlook 2015 with Projections to 2040*, cit.

<sup>36</sup> Ibid.

<sup>37</sup> Bud Coote, *Surging Liquefied Natural Gas Trade: How US Exports Will Benefit European and Global Gas Supply Diversity, Competition, and Security*, Washington, Atlantic Council, January 2016, <http://www.atlanticcouncil.org/publications/reports/surging-liquefied-natural-gas-trade>.

<sup>38</sup> IEA, *Medium-Term Gas Market Report 2015*, cit.



lift around 70 percent while European companies will take roughly 30 percent of these capacities, though it is difficult to say where these quantities will ultimately end up: a primary buyer can always sell to a secondary buyer, rerouting the shipment.<sup>39</sup> While the price convergence between Asia and Europe in the past year may make the European market more attractive for US exporters, Asia due to its higher demand growth potential is expected to attract more shipments over the long term.

Though the role of oil indexation is severely diminished in European contracts, the low oil price still has an effect on piped gas prices in Europe, as evidenced by the sharp drop in prices in the last year. In September 2015, the German border price for Russian gas was 6.48 dollars per mmBtu, down from 10.45 dollars per mmBtu in December 2014.<sup>40</sup> Similarly, Japanese Liquefied Natural Gas import price levels dropped below 10 dollars per mmBtu, down from 15.62 dollars per mmBtu in December 2014.<sup>41</sup> In this price environment, US exporters will struggle to make money on exports to either Europe or Asia, but will fight for market share nevertheless. Suppliers are expected not to take into account their full costs (that include fixed costs), but only the shortrun marginal costs, trying to recover as much of their fixed cost as they can. US breakeven prices on such basis are low, therefore they will remain competitive with Russian (and Qatari) gas in the European and Asian markets.

The longer-term competitiveness of US LNG, particularly in Europe, will to a large extent depend on the reactions and shifting business strategies of incumbent suppliers, with special regard to Russia. Russia will remain the low-cost supplier of gas to Europe for the foreseeable future with the largest production potential, spare capacities and a vast export infrastructure geared towards European markets. Russia retains the ability to significantly undercut US LNG prices and still deliver gas at a profit to its European customers. Gazprom might very well adopt a business strategy that aims to secure its market share at lower prices, offering further discounts to European customers. This ability is constrained by the need of the Kremlin to generate revenue to sustain itself politically and economically and preserve social peace. In any case, a price war between Gazprom and LNG suppliers seems likely and would serve the interest of the European consumer, but raises longer term security of supply or wider political issues, discussion of which goes beyond the scope of this chapter.

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<sup>39</sup> Ibid.

<sup>40</sup> Index Mundi, *Russian Natural Gas Monthly Price - US Dollars per Million Metric British Thermal Unit*, <http://www.indexmundi.com/commodities/?commodity=russian-natural-gas&months=60>.

<sup>41</sup> YCharts, *Japan Liquefied Natural Gas Import Price*, [https://ycharts.com/indicators/japan\\_liquefied\\_natural\\_gas\\_import\\_price](https://ycharts.com/indicators/japan_liquefied_natural_gas_import_price).

### 3.7 Energy Security Considerations in Europe and Asia

The looming price war is particularly interesting in the context of the Ukraine-crisis-induced rethinking of European energy security, and EU-Russian gas relations. Russia's aggressive behaviour in Ukraine alarmed EU and US decision-makers and triggered a fundamental rethink of political and commercial relations between the West and Russia, including in the gas domain. In the wake of the crisis, lessening the dependence on Russian supplies and exploring available and prospective diversification options once again became a priority (though at significantly varying degrees in different member states). Parallel to the crisis, the EU has to face its declining conventional gas production. Hopes pinned on a European shale gas bonanza are fading rapidly<sup>42</sup> and the continent's dependence overall on external gas supplies is slated to increase further from the current 60+ percent to as high as 85 percent by 2035.<sup>43</sup> This means significant additional import demand, even if gas consumption stagnates.

This dual challenge triggered a rethink of the EU's natural gas supply security strategy. Natural gas will continue to play a critical role in Europe's energy mix as a relatively cleaner-burning fossil fuel and an ideal backup generation source for intermittent renewables, at least in the next two decades.<sup>44</sup> The European Union would face tremendous difficulties in trying to completely wean itself off Russian gas, as that would be physically challenging and prohibitively expensive. Granted, Europe has multiple gas diversification options at its disposal but most of those involve complex geopolitical challenges as well, and will be able to provide relatively small quantities at least in the short term. LNG from the United States is the least challenging and prospectively most stable from a geopolitical perspective, with a significant potential to boost European energy security both directly and indirectly.

A critical component of increasing gas supply security and tapping into a growing international LNG market – and US LNG in particular – is to complete the internal energy market to make suppliers compete. The EU has already made great strides towards this goal as its second and third energy packages<sup>45</sup> successfully promoted

<sup>42</sup> Neil Buckley, "Eastern European shale exploration on ice as boom turns to bust", in *Financial Times*, 28 October 2015, <http://on.ft.com/1ihvn69>.

<sup>43</sup> José Manuel Barroso, *Energy Priorities for Europe*, presentation to the European Council, 22 May 2013, [http://ec.europa.eu/europe2020/pdf/energy3\\_en.pdf](http://ec.europa.eu/europe2020/pdf/energy3_en.pdf).

<sup>44</sup> Anouk Honoré, "The Outlook for Natural Gas Demand in Europe", in *OIES Papers*, No. NG 87 (June 2014), <https://www.oxfordenergy.org/tag/ng87>.

<sup>45</sup> See the European Commission webpage: *Market Legislation*, updated 9 March 2016, <https://ec.europa.eu/energy/en/topics/markets-and-consumers/market-legislation>.

competition and market principles such as unbundling and third party access in a vertically integrated industry prone to monopolistic abuse, and forced dominant suppliers such as Gazprom to change their practices and offer fairer pricing and conditions. Yet Europe's gas market integration is still incomplete. That has repercussions on Europe's ability to tap into and internally distribute LNG supplies. Though overall Europe has huge and vastly underutilized LNG regasification capacities, the LNG terminals are geographically unevenly distributed. In addition to the lack of infrastructure, regulation such as artificially high transit tariffs can also hinder access to LNG. While South and North Western Europe is well endowed with LNG infrastructure, Europe's Eastern markets can still only sporadically access global LNG markets. The Communication "On an EU strategy for liquefied natural gas and gas storage" published by the Commission on February 16, 2016 aims at overcoming these vulnerabilities, in order to exploit the LNG contribution to ensure greater security and resilience to the EU gas sector<sup>46</sup> (see Luciani's chapter).

On the Asian side, LNG also plays a major role in energy security calculations of key players. In all major Asian importers there is a concern about higher import dependency on natural gas, partly due to the cautionary tales from Europe, that in addition to price competitiveness vis-à-vis coal and increasingly renewables, also puts a cap on gas usage. China considers a well-diversified gas import portfolio and secured shipping lanes for LNG supplies especially from the Middle East vital from a national security perspective and treats LNG imports as an important hedge against piped gas from Central Asia, Myanmar and most importantly Russia. South Korea and particularly India with huge demand potential are also concerned about import dependency and shipping lanes.

## Conclusions

The United States is expected to produce a significant surplus of natural gas in the coming decades, and US natural gas exports will have a major impact on the international gas markets. Though in the current depressed price environment US LNG export projects face considerable challenges from a commercial perspective, multiple factors – including elevated import demand and energy security considerations in Europe, improved demand prospects beyond 2020 in Asia, as well as climate considerations in

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<sup>46</sup> European Commission DG for Energy, *On an EU strategy for liquefied natural gas and gas storage* (COM/2016/49), 16 February 2016, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=celex:52016DC0049>.

both developed and developing markets – point towards robust and sustained US LNG exports beyond 2020.

It is hard to predict how much LNG will eventually come out of the US and to which markets. In any case US LNG exports will contribute to the emergence of a more liquid, more diversified and more global gas market. Indirectly US gas has already improved European energy security inasmuch as the lack of major import needs for the US has increased global gas supply liquidity and improved access conditions for European offtakers to LNG shipments, also strengthening Europe’s position vis-à-vis existing suppliers.

US LNG exports will help “depoliticize” gas relations in both Europe and Asia and improve the prospects of increased gas usage and coal-to-gas switching in major consumer countries especially in Asia, facilitating climate action. Price and security of supply are the primordial concerns of major coal users hesitant about a larger-scale switch to gas. US LNG exports could alleviate both.

The beginning of physical exports from the US will, on balance, have a further positive effect on European energy security, boosting supplies to and improving liquidity of gas markets. LNG supplies in general will act as a ceiling price for Russian gas,<sup>47</sup> severely limiting the ability of Gazprom – or any other current or future pipeline supplier – to charge unfair prices. Furthermore, US gas will provide a safe and reliable fallback supply option in case of a crisis. The availability and reliability of commercial US supplies will add significantly to Europe’s ability to respond to supply crises and act as a serious disincentive for Russia to consider using its “energy weapon” again, rendering it largely ineffective.

To fulfil the above goals, the US should consider fully opening its natural gas markets for exports and eliminating all export restrictions. In the absence of such a move, the US should further streamline the existing licensing procedures to ensure the timely approval of commercially viable projects. Longer-term political uncertainties in the US about gas export policy can be hedged against by pushing for the inclusion of gas export liberalization in major trade deals, with special regard to TTIP.

To reap the benefits offered by an expanded global LNG supply in general and US LNG exports in particular, Europe should complete its internal gas market and ensure that the necessary infrastructure and regulation is in place to utilize and leverage the coming LNG glut. This necessitates the strategic development of missing LNG and pipeline infrastructure, if need be making use of the limited public funding – Projects of Common Interest (PCIs), the Juncker fund and pooling regional government funding – to support critical infrastructure and interconnectivity, such as the North-South Corridor in

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<sup>47</sup> Colin Harrison and Zuzana Princova, “A quiet gas revolution in Central and Eastern Europe”, in *Energy Post*, 29 October 2015, <http://www.energypost.eu/quiet-revolution-central-eastern-european-gas-market>.

Central Europe and the realization of LNG terminals of strategic importance, as foreseen by the “EU strategy for liquefied natural gas and gas storage” published by the Commission in February 2016. In Asia, the US could provide technical assistance to facilitate the emergence of liberalized, open, liquid and integrated gas markets with well-developed trading hub(s) to boost competitive and secure gas usage.

## 4. Gas in South America: Resources, Corridors and Policies

Gonzalo Escribano

Latin America is one of the most dynamic regions for the development of natural gas markets at a global, regional and national level. Although unevenly distributed, natural gas is abundant in the region, with new reserves in Brazil and Argentina expected to come on stream over the next decade, including unconventional gas reserves. At the national level, gas industries started to develop in Argentina, Bolivia and Peru in the 1980s, when national energy policies turned towards combined-cycle gas generation plants substituting for other technologies, mainly coal but also nuclear.

However, with some exceptions, past national gas policies (including the reluctance to increase regional market integration) have failed to materialize these abundant reserves into significant production. In spite of having significant unconventional gas reserves, the region's capacity to replicate the US shale gas revolution remains to be seen. In any case, all the projections point to a significant increase in the degree of gas penetration in South America's energy markets.

Regarding regional market integration, some countries (Argentina, Bolivia, Brazil and Chile) tried to build an integrated gas network that was later extended and proposed as a model of "physical integration" (through gas pipelines) by Venezuela. However, poor national regulatory frameworks made gas integration impossible and led to crises such as the interruption of cross-border gas flows between Argentina and Chile in 2003. Moreover, in spite of the abundance of gas reserves in countries like Brazil, Argentina or Venezuela, all of them are net natural gas importers. As a further signal of fragmentation in regional gas markets, South America as a whole is increasingly dependent on LNG imports.

Despite the mistakes of the past, the abundance of gas resources entails significant opportunities for South America's energy development and therefore its economic growth. It also offers tangible opportunities to foreign companies to contribute to the

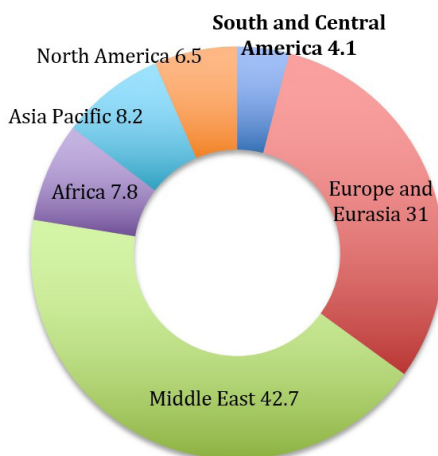
deepening of gas markets in the region, which would require substantial investment in physical infrastructure but also in increased technical and regulatory know-how.

This chapter will first briefly describe South America's natural gas profile regarding reserves, production and consumption. The next section turns to the existing regional gas corridors and their geopolitical and geo-economic implications. The following section summarizes the evolution of gas policies in the main regional actors. The chapter concludes with some final remarks on the regional and global implications of the South American gas outlook.

## 4.1 Resources

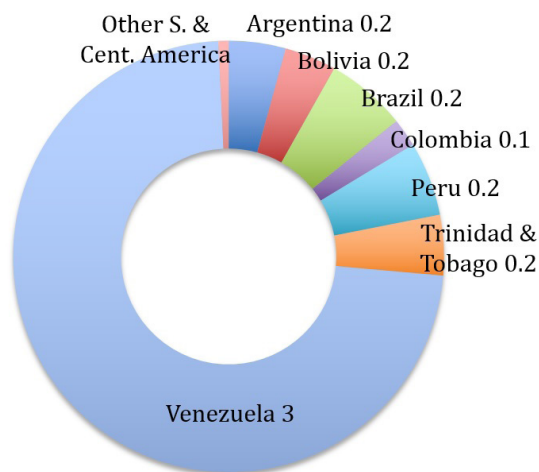
South America represents 4 percent of world gas proven reserves, 3 percent of which are located in Venezuela (figures 1 and 2). Both North and South America have significant gas reserves. In this regard, and from a comparative perspective, the distribution of gas reserves in the Americas seems more balanced than the asymmetric interdependence pattern developed by the EU with Russia and the Middle East and North Africa; or between Asian consumers and Persian Gulf suppliers. However, reserves are important only insofar as countries develop the capacity to materialize them into production, consumption and exports.

Figure 1 | World proven reserves by region, 2014 (%)



Source: BP Statistical Review of World Energy 2015.

Figure 2 | South and Central American proven natural gas reserves by country, 2014 (%)



Source: BP Statistical Review of World Energy 2015.

South America also holds significant shale gas reserves. Argentina has the second largest world unproven technically recoverable shale resources after China, and according to some analysts the most prospective reserves outside of North America.<sup>1</sup> Brazil has the second most recoverable shale gas reserves in South America, followed by Venezuela. Despite its excellent potential, the region has proven unable to date to replicate the North American shale gas revolution. Argentina is still struggling to produce relevant quantities, Brazil has not announced significant shale exploration leasing or drilling, and Venezuela has not attracted significant investments in spite of offering favourable terms to shale projects.

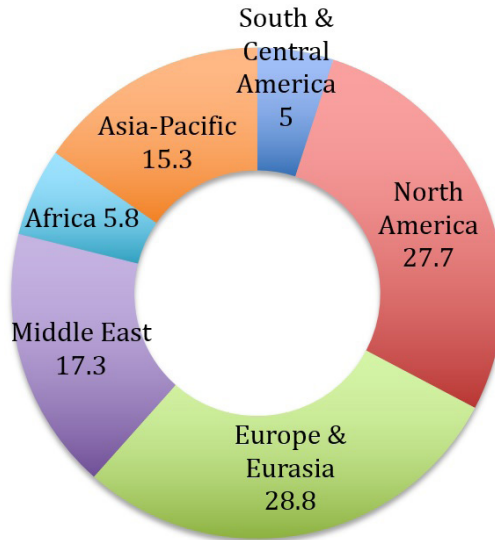
Paradoxically, countries with relatively minor reserves present the brighter potential, especially Colombia where the results of initial shale drilling and favourable investment conditions have attracted majors but also smaller companies. Chile also tries to incentivize shale exploration by requiring companies bidding for conventional exploration blocks to also explore for shale gas.<sup>2</sup> The capacity of South America to develop its unconventional oil and gas resources in more adverse price conditions is perhaps one of the main uncertainties regarding the evolution of natural gas in the region, but the recent evolution has been somewhat deceiving.

<sup>1</sup> Argentina holds 22,682 Bcm while China has 31,560 Bcm. EIA, *World Shale Resource Assessments*, updated 24 September 2015, <https://www.eia.gov/analysis/studies/worldshalegas>.

<sup>2</sup> Ibid.



Figure 3 | World production by region, 2014 (%)



Source: BP Statistical Review of World Energy 2015.

South America is also a second-rank gas producer, representing 5 percent of world production (figure 3). Figure 4 shows that the region's main producers are Trinidad and Tobago, Argentina, and Venezuela, followed by Brazil and Bolivia. While the region only has a small share of world production and reserves, natural gas production has been rapidly increasing over the past decade, as shown in figure 5.

For instance, Peru's production registered a tenfold increase in the last decade, and Bolivia, Brazil and Colombia almost doubled their production during the same period. However, the trend in more mature producers has been mixed. Trinidad and Tobago experienced an impressive surge in production to become the first regional gas producer, but production has stagnated below 45 Bcm since the beginning of the 2010s. Despite these production gains, the region is at risk of a decline in dry natural gas production because of maturing fields and a lack of continued investment.<sup>3</sup> For instance, production in Argentina and Venezuela, the second and third regional producers, has been declining during the last decade.

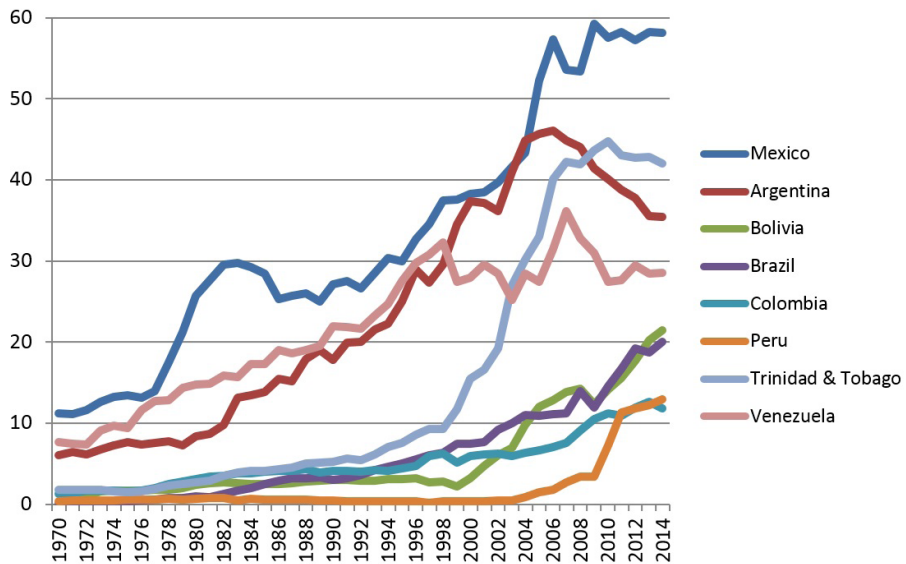
<sup>3</sup> EIA, *Liquid Fuels and Natural Gas in the Americas*, 30 January 2014, <https://www.eia.gov/beta/international/regions-topics.cfm?RegionTopicID=LFNGA>.

Figure 4 | South and Central American natural gas production by country, 2014 (% world total)



Source: BP Statistical Review of World Energy 2015.

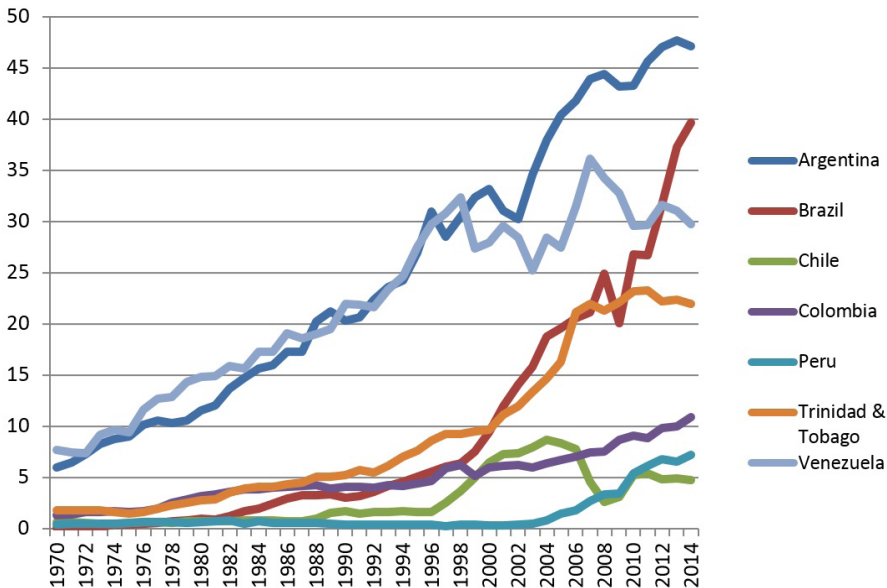
Figure 5 | Gas production by country, 1970-2014 (Bcm)



Source: BP Statistical Review of World Energy 2015.

Gas consumption in South and Central America has rapidly increased over the last decades. In 1990 natural gas represented 30 percent of regional energy consumption, rising to 49 percent in 2013, and existing projections point to a 53 percent share in 2035.<sup>4</sup> As can be seen in figure 6, over the last decade gas demand was especially dynamic in Peru with an almost tenfold increase, as well as in Brazil and Colombia, which almost doubled their consumption. Argentina continues to be the main South American gas market, with consumption growing around 40 percent in the last decade. This trend in the growth of domestic demand has fostered the efforts by many South American countries to expand production and reduce their dependence on gas imports.

Figure 6 | Gas consumption by country, 1970-2014 (Bcm)



Source: BP Statistical Review of World Energy 2015.

Finally, while this chapter focuses on natural gas it is worth highlighting that South America holds a well-diversified portfolio of energy sources that compete with natural gas. Besides significant oil resources in countries like Venezuela, Brazil, Colombia or Ecuador, only Colombia and Brazil hold significant coal reserves, and Argentina and Brazil are the only countries in the region with nuclear plants.

But the most promising element of such a portfolio is renewable energy. According

<sup>4</sup> BP, *Energy Outlook 2035*, February 2015, <http://www.bp.com/en/global/corporate/energy-economics/energy-outlook-2035/energy-outlook-downloads.html>.

to BP Statistical Review data, South and Central America represented 17.7 percent of world hydroelectric consumption in 2014. Brazil alone reached a 9.5 percent share in world hydro, second only to China. Hydro potential is being hampered by the difficulties in the transnational management of hydrological basins, the lack of transmission infrastructures, and increasing opposition from conservationist movements.

Other renewables include biofuels, wind and solar. Brazil is the second biofuel producer after the US, but Brazilian production has stagnated while that of the US has continued to grow. Argentina also plays a significant role in the biofuel world market. However, low oil prices and US exports have further complicated the economics of biofuels in the region. But it is in the field of solar, and especially wind, that the region has been booming over the last few years after having been previously very limited. The best perspectives are for wind energy, which benefits from high load factor sites that make public support schemes almost unnecessary, allowing them to freely compete with gas in electricity generation.

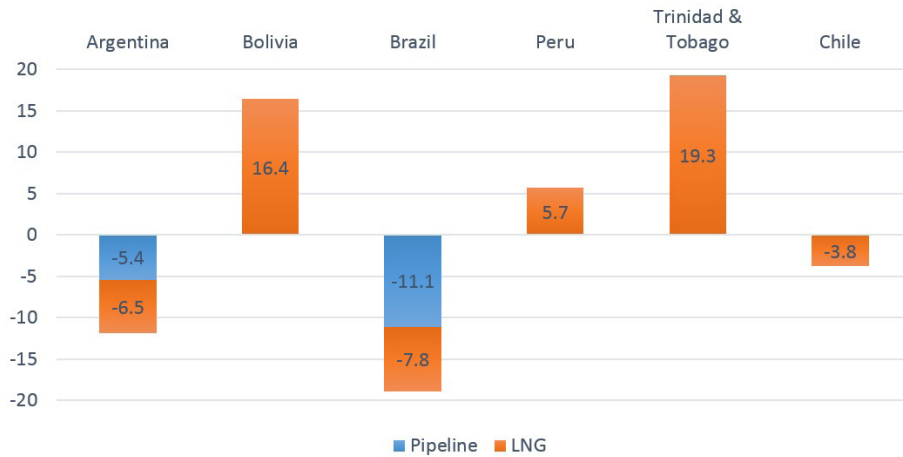
## 4.2 Corridors

Divergent production and consumption dynamics meant that, in spite of holding significant reserves, countries like Brazil and Argentina are the main gas importers in the region (figure 7). Both import gas from Bolivia via pipeline, as well as LNG from Trinidad and Tobago and other international suppliers. Chile imports LNG almost exclusively from Trinidad and Tobago. The latter is the main regional exporter, with around 40 percent of its exports going outside the region. Peru exports LNG mainly to Mexico, as well as to other international clients outside the Americas, especially Spain.

In spite of the efforts in the 1990s to use natural gas as a driver for regional integration, the scarcity of transport infrastructures and the uncertainties related to the energy policies of key countries like Argentina or Venezuela have inhibited the emergence of a well structured regional gas market. The pattern of gas interdependence in South America is quite distinct from the dense transcontinental network of physical and normative integration prevailing in Europe and its neighbourhood.

Transnational gas pipelines are scarce in the north (there is only a politically sensitive one from Colombia to Venezuela), and more abundant in the Southern Cone, running from Bolivia to Brazil (2 pipelines) and Argentina (1 pipeline). There are also seven gas pipelines from Argentina to Chile and two more to Uruguay that have been almost unused since the 2004 Argentinean gas crisis. But few of these pipelines involve the geopolitical problems of transit countries, at least not at the European scale. In the Bolivian-Chilean case, bilateral political differences have been more important than problems with transiting Argentina.

Figure 7 | Net exporters and importers, 2014 (Bcm)



Source: BP Statistical Review of World Energy 2015.

This does not mean that South America has been spared pipeline politics. The clearest example is the mid-2000s gas crisis between Argentina and Chile. The economic crisis in Argentina forced the government to freeze the price of natural gas to prevent further social unrest. This policy backfired, halting exploration and development of new resources to compensate for declining gas production from maturing fields. When the Argentinean economy recovered, gas demand surged and the government restricted exports to Chile, Brazil and Uruguay to preserve domestic supply. Electricity generation in Chile and Uruguay was heavily dependent on gas, which had to be replaced with expensive oil products in the short term. After a sour diplomatic struggle, Chile turned to LNG to ensure its gas supply.

Another well-known episode involves the vicissitudes of the *Gran Gasoducto del Sur*, signed in 2005 during an annual Mercosur meeting in Montevideo by the presidents of Venezuela, Argentina and Brazil. While the exact route was never precisely defined, it was intended to connect Venezuela, Brazil, Uruguay and Argentina through an over 8,000 km and 20 billion dollars gas corridor. Intended to help Argentina to deal with its gas crisis, the project rapidly met opposition from Bolivia, which was trying to improve access to the Southern Cone gas markets. By 2007 the technical, environmental and economic difficulties had proved insurmountable, and political interest rapidly cooled.

The Colombia-Venezuela gas pipeline has also occasionally been used politically. The Antonio Ricaurte pipeline operated by Chevron was built to import Colombian gas into Venezuela until the country's national company *Petróleos de Venezuela S.A.* (PdVsa) could develop its own gas production. At that point, the flow would be reversed to

export Venezuelan gas to Colombia. The contract concluded without PdVsa having fully developed its domestic gas resources, and was renewed for one more year. The relation between PdVsa and the Colombian counterpart Ecopetrol has been good, but in summer 2015 amidst growing political bilateral tensions, PdVsa announced that it would not renew the contract due to frequent failures in gas supply from Colombia.

Bolivia suffers from its poor political relations with Chile, not only a natural export market but also the optimal LNG export corridor for the landlocked Andean country. In 2003 an international consortium (Repsol YPF, British Gas and Pan American Energy, a unit of British Petroleum) presented the Pacific LNG project involving a pipeline from Bolivia to Chile, and an LNG export terminal. Historical animosity against Chile in landlocked Bolivia, which lost access to the Pacific following a war in the 1880s, raised political opposition and social unrest over gas exports and resulted in the resignation of two consecutive Bolivian presidents, paving the way for the first Morales presidency. Since then, gas exports to Chile have been an anathema for the Morales government, which took the case to the International Court of Justice in The Hague, demanding that Chile negotiate to grant Bolivian access to the Pacific coast.

There have been other gas pipeline proposals, including the *Gasoducto del Noreste Argentino* (GNEA), intended to increase the volumes exported from Bolivia to Argentina. In spite of being one of the main projects of the Kirchner presidencies the GNEA is progressing quite slowly. The new Argentinean Presidency has not cut the payments to contractors, but has delayed updating the contracts to account for inflation. LNG development in Brazil and Argentina due to security of supply and diversification concerns further limits the potential of Bolivia's gas resources. A similar political deadlock afflicts Peru and Chile. After the discovery of the Peruvian Camisea gas field, a gas pipeline to supply Chile was discarded due to strained bilateral political relations. The result was that both Peru and Chile opted for LNG export and import facilities, respectively. In June 2015, Peru and Bolivia agreed to study a project to export Bolivian gas by linking the country to a Peruvian pipeline being built in southern Peru and then exporting LNG from the Pacific coast.

In fact, as a general trend the flexibility of LNG seems to be preferred to the complexities and rigidities of regional pipeline diplomacy, and to the inconsistency of inter-connecting countries with diverging energy policies. While it is true that the Southern Cone orography (the Andes) poses economic and technical difficulties, divergences in policies and politics remain the main obstacle. There are several LNG liquefaction and regasification projects underway, including floating facilities: two LNG import terminals in Chile, with a third being built; two floating import terminals in Argentina; and three more in Brazil (and a fourth being planned). In Brazil (Guanabara), a larger floating import terminal (FSRU) replaced a smaller vessel, while in Chile a permanent onshore export

terminal took over from the FSRU moored at Mejillones. Another planned floating import terminal was recently cancelled by Uruguay.

Only Peru and Trinidad and Tobago have LNG export terminals, with Peru planning a second one. This preference for LNG shows that in terms of gas, the geopolitics of fragmentation and diversification prevails over the logic of regional integration. Only 46 percent of South America's LNG exports in 2014 were exported to the region, almost all of them from Trinidad and Tobago. That year, Peru only exported significant quantities to Mexico and Spain, and the country's prospects mainly target the Asian market. Pipeline regional gas trade, while economically optimal, remains clearly underdeveloped.

Past gas crises and strained political relations among key gas producers and consumers have raised geopolitical concerns regarding the security of gas supply and demand in the region. The securitization of gas corridors in South America has certainly hampered the emergence of a more functionalist and pragmatic approach towards market integration. But political differences are also expressed through different energy policies, which further inhibit regional energy integration. This is why most regional gas initiatives develop a more geo-economic, physical integration discourse, rather than a normative convergence narrative.

### 4.3 Gas Policies

Differentiated and poorly integrated national energy models interact with these production, consumption and interdependence patterns. South American energy policies vary between different interpretations of what might be called the "Chavista" model, which in essence puts resource nationalism at the service of populism (petro-populism); and an "open nationalism" model preserving some control of energy resources, but able to attract the foreign investment needed to increase gas production and/or expand gas markets.<sup>5</sup>

This is especially evident in the case of oil, with Brazil and Colombia, two examples of open nationalism, being the only countries in the region where production has grown significantly. Something similar happens with natural gas, production of which has grown more in these and other countries implementing similar policies, such as Peru and Trinidad and Tobago. Nevertheless, production has also significantly increased in Bolivia, one of the closest defenders of the Chavista model. With some nuances, a

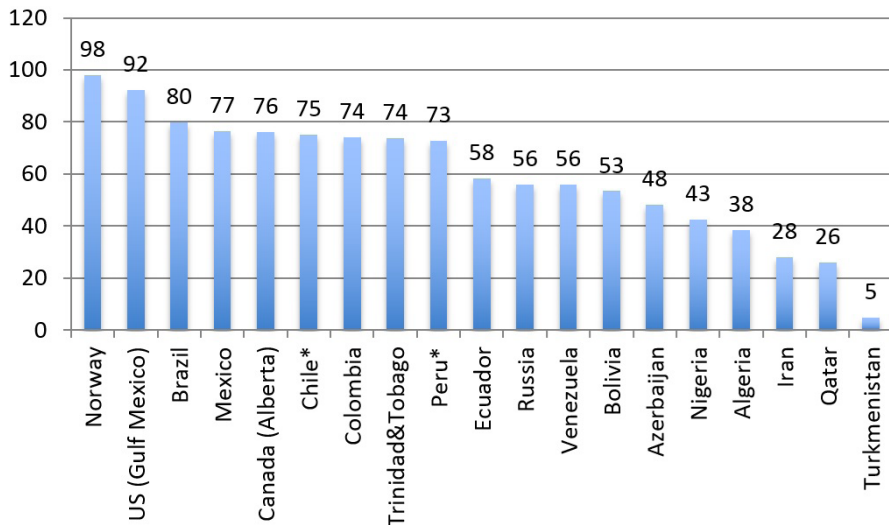
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<sup>5</sup> Gonzalo Escribano, "Ecuador's Energy Policy Mix: Development versus Conservation and Nationalism with Chinese Loans", in *Energy Policy*, Vol. 57 (June 2013), p. 152-159.

comparison of respective results would seem to favour open resource protectionism over petro-populism.

One way of approaching the nature of energy policy is to compare the quality of the governance of energy resources in the region. Figure 8 shows the results of the Natural Resources Governance Index (NRGI) for the main South American countries and compares them with other major world producers. The first finding is that the region has a comparatively high level of resource governance, with four countries in the ranking's top ten: Brazil, Chile, Colombia and Trinidad and Tobago, followed by Peru in 11th place. While for Chile and Peru the NRGI refers to mining due to its importance in these countries, similar practices occur in other extractive sectors in both countries. Ecuador, Venezuela and Bolivia rank 18th, 20th and 24th with scores similar to Russia.

Figure 8 | Resource Governance Index 2013, selected countries



Source: Natural Resource Governance Institute, Resource Governance Index 2013.

Note: (\*) Chile and Peru are ranked on mining.

Other indicators offer a similar regional picture. BMI's Risk/Reward Index places Brazil, Colombia, Peru, Chile, Argentina and Trinidad and Tobago among the most attractive countries in the region for foreign investment in the energy sector. In spite of their significant resources, Ecuador, Bolivia, and Venezuela receive low scores due to political uncertainty, resource nationalism and unattractive regulatory framework.

Other major world producers in the Persian Gulf, Africa and Central Asia record much worse indexes. South American countries following an open nationalism pathway are



at the top of the ranking, while followers of the Chavista model are at the same level of resource governance as Russia or Azerbaijan, but well ahead of other major gas producers like Nigeria, Algeria, Iran or Turkmenistan. These differences represent a significant comparative advantage for the better-governed energy sectors in attracting foreign investment compared to other regions.

Fossil fuel subsidies offer another element to evaluate the degree of market distortion. Peru and Colombia have the lowest energy subsidies in the region (close to zero), while higher subsidies are applied in Argentina (33.5 percent), Trinidad and Tobago (37 percent), and especially in Bolivia (43.6 percent), Ecuador (49.2 percent) and Venezuela (93.1 percent), which are among the biggest energy subsidizers in the world.<sup>6</sup> The IEA does not offer subsidy data on Brazil, but other sources place the country among regional subsidy reformers, but not to the extent of Colombia or Peru. Brazil prioritizes conditional targeted subsidies like *Bolsa Escola* and a social gas voucher.<sup>7</sup>

While not a relevant actor in the gas market, Venezuela is the South American oil producer with the biggest regional reach, and the only one with a global geopolitical projection.<sup>8</sup> In 2001, Hugo Chavez changed the Hydrocarbon Law to limit foreign participation to 49 percent and introduced tighter fiscal conditions. However both the gas and ultra-heavy oil sectors were spared such measures. In 2006, stricter measures were adopted regarding oil, but again the gas sector received more favourable conditions. Nevertheless, PdVsa was granted a majority share option in those projects that proved commercially viable. Together with high gas subsidies and with some exceptions, these conditions were found barely attractive by international majors.

Bolivia has shared the Chavista rhetoric, but its president Evo Morales has acted in a more pragmatic way.<sup>9</sup> A radical shift towards gas nationalism occurred in 2006, when the Morales government declared all contracts with international companies illegal and against the Constitution, and announced the nationalization of the hydrocarbon sector. While full nationalisation of the whole gas sector soon proved to be unfeasible and the government had to reduce its initial fiscal conditions, the role of foreign companies was scaled back. Most of them continued with existing operations, but new projects have been scarce. While new nationalizations cannot be ruled out, lower gas prices and the

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<sup>6</sup> Average fossil fuel subsidization rate for 2014. IEA, *Fossil Fuel Subsidy Database*, 2015, <http://www.worldenergyoutlook.org/resources/energysubsidies/fossilfuelsubsidydatabase>.

<sup>7</sup> Benedict Clements et al. (eds.), *Case Studies on Energy Subsidy Reform: Lessons and Implications*, Washington, IMF, 28 January 2013, <http://www.imf.org/external/np/pp/eng/2013/012813a.pdf>.

<sup>8</sup> Stephanie Pearce, "Chávez in the Americas: Increasing Autonomy in Latin America and the Caribbean", in *NACLA Report on the Americas*, Vol. 46, No. 2 (2013), p. 40-44, <https://nacla.org/node/9161>.

<sup>9</sup> Guillaume Fontaine, "The Effects of Governance Modes on the Energy Matrix of Andean Countries", in *Energy Policy*, Vol. 39, No. 5 (May 2011), p. 2888-2898.

need to attract investments seem to have changed the stance of president Morales on foreign companies.

Recently, the government has tried to increase the attractiveness of the country by adopting incremental and minor reforms. These included the opening of a few protected natural areas to drilling, raising strong contestation among environmentalists. The government even conducted a campaign to attract investment, including a contested (in Bolivia) “Investing in the New Bolivia Summit” organized by the *Financial Times*.<sup>10</sup> Difficult political relations with many neighbours, lack of infrastructure and reduced investment in the gas sector hamper Bolivia’s aims to become the Southern Cone’s geographical energy hub. Another feature of the “new Bolivia” would be using gas to establish an industrial base, mainly in the petrochemical sector, but also creating new generation capacity to export electricity to Brazil and Argentina. It is doubtful that these ambitions could materialize in a low gas price environment, unless more radical energy policy reforms were to be adopted.

The South American new left labels this energy model as “neo-extractivist,” considering that in fact it does not challenge neoliberal fundamental premises.<sup>11</sup> This ideological confusion afflicts most left-populist Latin American governments and goes well beyond energy policy, entailing the combination of a relatively macro-prudential approach with illiberal, dependency-theory-like micro-economic policies.<sup>12</sup> Argentina is a particular case where a shift from Peronism to post-neoliberal Chavism has been described.<sup>13</sup> This is especially evident in the shortcomings of an Argentinean energy policy marked by state intervention, the fragmentation of public responsibilities and export restrictions that have historically hampered investments in the gas sector. These elements have consolidated the twin effect of gas production decline and booming domestic gas demand, shifting the country towards the usual profile of a gas importer.

Blackouts in the mid-2000s forced Argentina to halt gas exports to Chile and Uruguay, to increase gas imports from Bolivia and electricity imports from Brazil and Uruguay, and then to make recourse to LNG imports. In Chile or Brazil, gas prices at the well are triple Argentinean rates, while consumer prices in Argentina are much lower. The government

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<sup>10</sup> James Wilson, “Bolivia wants to become the energy heart of South America”, in *Financial Times*, 26 October 2015, <http://on.ft.com/1LRQp3y>.

<sup>11</sup> Arturo Escobar, “Latin America at a Crossroads”, in *Cultural Studies*, Vol. 24, No. 1 (January 2010), p. 1-65.

<sup>12</sup> Carlos Malamud, *Populismos latinoamericanos. Los tópicos de hoy, de ayer y de siempre*, Oviedo, Nobel, 2010; Amy Kenmore and Gregory Weeks, “Twenty-First Century Socialism? The elusive Search for a Post-neoliberal Development Model in Bolivia and Ecuador”, in *Bulletin of Latin American Research*, Vol. 30, No. 3 (July 2011), p. 267-281.

<sup>13</sup> Jean Grugel and Pía Riggiozzi, “Post-neoliberalism in Latin America: Rebuilding and Reclaiming the State after Crisis”, in *Development and Change*, Vol. 43, No. 1 (January 2012), p. 1-21.

even subsidized gas imports with fiscal income while restricting gas exports through *retenciones* that have become a tax on gas exports. This reflects a lack of consistency in the country's energy policy, as well as a deficient institutional and regulatory framework. The 2012 expropriation of Repsol YPF culminated in convergence towards the Chavista model, harming the development of its own gas resources but also the emergence of a Southern Cone integrated energy space.<sup>14</sup> While a new Presidency may open the way for cautious reforms, there is a wide consensus that key issues like the role of YPF or redistribution through energy subsidies would not change much.

In all these countries gas policies have proved remarkably sub-optimal, but their reform has been unthinkable during the last commodities super-cycle. Resource nationalism tends to flourish with high and rising natural resource prices and to languish when the cycle is over. This is why having alternative models in the region under the current low price environment is so important. These are countries like Brazil, Colombia, Peru or Chile, characterized by a "co-governance" of energy resources rather than the "hierarchical" pattern directly controlled by the State observed in Venezuela, Bolivia or Argentina.<sup>15</sup>

Colombia was the first South American hydrocarbon producer to adopt comprehensive energy policy reforms, but they were only influential regarding oil production. Peru was the regional gas producer that adopted the fastest reforms, including market liberalization, the privatization of the national oil company Petroperú, and openness to foreign investments. Gas liberalization was associated to the Camisea project, a field discovered in the 1980s, whose development was repeatedly delayed due to differences between Shell and the Peruvian government, as well as opposition from conservationist and indigenist movements. Even today, attacks against facilities and workers are not uncommon.

Since Camisea came on stream, Peruvian energy policy has focused on managing gas income and attracting international companies.<sup>16</sup> The 2011 election of President Humala introduced some uncertainties regarding an eventual shift in Peruvian gas policies towards more interventionist and nationalist policies. To date, the Humala government has alternated between pragmatism and continuity with volatile decisions, like

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<sup>14</sup> Gonzalo Escribano, "La expropiación de YPF culmina el fracaso de la política energética argentina", in *Elcano Royal Institute Analysis*, No. 30 (23 April 2012), [http://www.realinstitutoelcano.org/wps/portal/rielcano/contenido?WCM\\_GLOBAL\\_CONTEXT=/elcano/elcano\\_es/programas/energiacambioclimatico/publicaciones/ari30-2012](http://www.realinstitutoelcano.org/wps/portal/rielcano/contenido?WCM_GLOBAL_CONTEXT=/elcano/elcano_es/programas/energiacambioclimatico/publicaciones/ari30-2012).

<sup>15</sup> Guillaume Fontaine, "The Effects of Governance Modes on the Energy Matrix of Andean Countries", cit.

<sup>16</sup> Guillaume Fontaine, "The Effects of Energy Co-governance in Peru", in *Energy Policy*, Vol. 38, No. 5 (May 2010), p. 2234-2244.

pushing Petroperú to take control of Repsol assets and then discarding the plan due to pressure from Congress and business associations.<sup>17</sup> Peru's LNG strategy was initially focused on the US market. However, the country started exporting in 2010 during the shale revolution and its destination rapidly shifted to Mexico and Spain. Prospects for further export growth are not clear due to increasing domestic consumption.

Chile was the frontrunner of energy reform in the region, starting with electricity reform in the 1980s. The Chilean energy model was tentatively applied in other countries in the region, but the lack of adaptation to very different institutional and economic contexts generated a protectionist and interventionist backlash.<sup>18</sup> While the scarcity of its conventional gas resources has prevented it from becoming a regional model for gas production, the conjunction of shale gas resources, good resource governance and openness to foreign investment have presented a significant window of opportunity for the country to become a pioneer in emulating the North American shale revolution in the southernmost Magallanes region. However, such a development has become less likely under the current price context. With shale expectations rapidly cooling, the new President Bachelet has announced the construction of a new LNG receiving terminal to match the expected rapid increase in domestic demand.

Trinidad and Tobago, the first regional gas producer and exporter, has also followed a pro-market policy of attracting foreign investment, with very positive results.<sup>19</sup> The country holds large reserves of natural gas, the best LNG facilities in the region, as well as technical and market expertise. While recent bidding rounds in more challenging deep-water blocks have not attracted much interest from foreign companies, new incentives such as more favourable fiscal terms and licensing could draw their interest in the new bidding round announced for 2016, which is expected to further increase production in the medium term. However, declining price trends for LNG and increasing competition from other global LNG exporters may affect the country's capacity to significantly expand its portfolio of clients beyond Latin America and Spain.

While the Brazilian energy model has been proposed as an alternative to resource nationalism in the region, the liberal character of Brazil's energy policy should be carefully nuanced. The Brazilian energy sector has undergone a gradual liberalization with mixed results, partly due to the fact that the magnitude of the challenges facing the

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<sup>17</sup> Economist Intelligence Unit, *Peru Oil and Gas: Quick View - U-turn on State Acquisition of Repsol Assets*, 3 May 2013.

<sup>18</sup> Carlos Battle, Luiz A. Barroso, and Ignacio J. Pérez-Arriaga, "The Changing Role of the State in the Expansion of Electricity Supply in Latin America", in *Energy Policy*, Vol. 38, No. 1 (November 2010), p. 7152-7160.

<sup>19</sup> Haydn Furlonge and Mark Kaiser, "Overview of Natural Gas Sector Developments in Trinidad and Tobago", in *International Journal of Energy Sector Management*, Vol. 4, No. 4 (2010), p. 535-554.

country exceeds the capabilities of the public (Eletrobras) or semi-public companies (Petrobras) that until recently completely monopolized the market. Liberalization is far from complete and the sector is still largely dominated by the public sector and closely regulated by policymakers. Gas is expected to gain importance in support of renewables and hydropower, and constitutes the main element of diversification in electricity generation.

After some initial expectations of becoming a gas exporter in the short term and even thinking of building an LNG export terminal, rising domestic consumption and the decision to move to gas as a support to hydro prompted the country shift to LNG imports. In 2011 Petrobras announced its 2020 Strategic Plan, which included pipelines, gas distribution and more LNG import terminals. Even before being corrected for excessive voluntarism, domestic demand was to exceed supply, and Brazil is expected to continue to be a gas importer at least until 2025. LNG imports are not on a long-term basis, mainly due to the uncertainty associated with hydro generation but also to reluctance of Petrobras to further weaken its financial balance. This has placed LNG prices in the country among the highest in the world.<sup>20</sup>

The Petrobras scandal is having additional negative repercussions for investment not only in the upstream, but also in infrastructure. As a result of financial market pressure, Petrobras has been divesting oil and gas assets, both in Brazil and abroad, to generate cash, including selling its 49 percent share of natural gas distribution firms in several Brazilian states to Japan's Mitsui & Co. This situation makes difficult to foresee any significant development of its unconventional gas resources, which are situated in distant areas without any existing gas infrastructure.

## 4.4 Looking Ahead

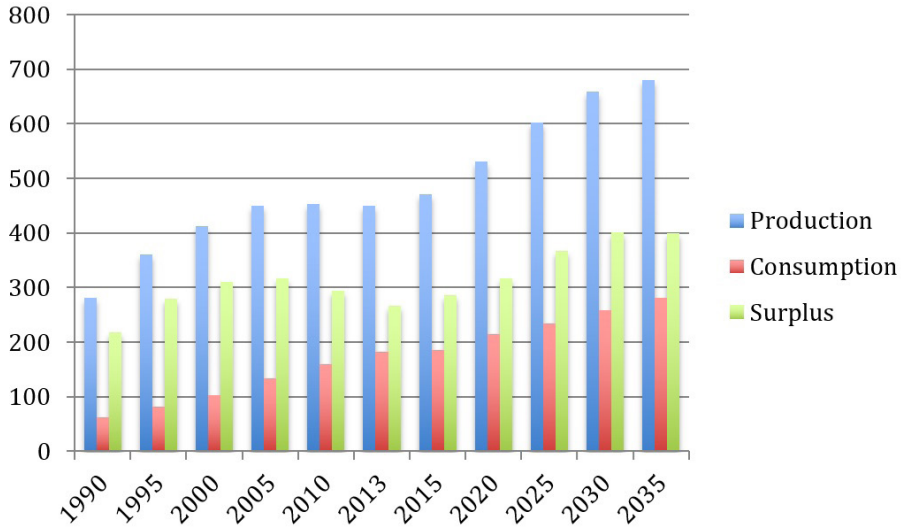
The observed trends in production/consumption, corridor geopolitics and gas policies point to a moderate outlook for regional gas markets. In spite of having significant resources, energy policies in key producers are sub-optimal, and some key companies like Petrobras (or YPF) are going through very difficult times. High expectations regarding shale gas, for instance in Chile, have cooled due to lower gas prices and also due to an unattractive investment environment in shale-rich Argentina and Brazil. Nevertheless,

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<sup>20</sup> For a detailed analysis of the Brazilian gas market see Ieda Gomes, "Brazil: Country of the Future or Has Its Time Come for Natural Gas?", in *OIES Papers*, No. NG-88 (June 2014), <https://www.oxfordenergy.org/tag/ng88>.

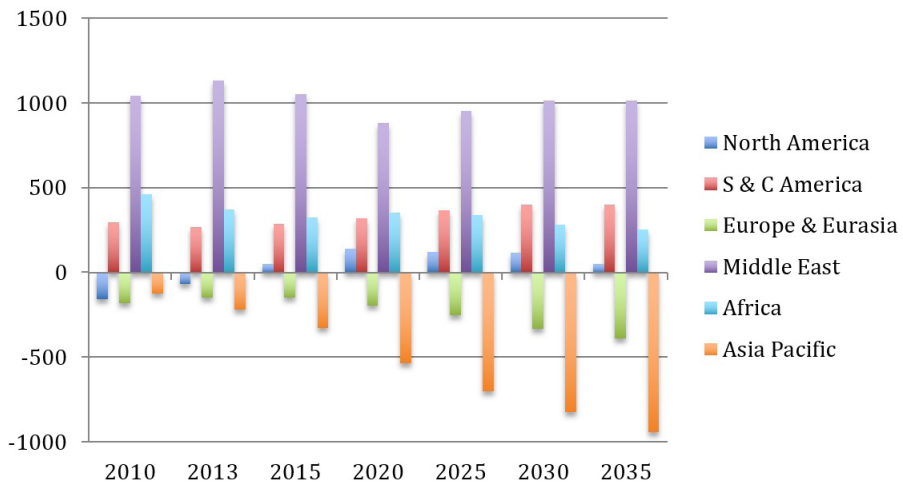
existing projections foresee an increasing gas surplus in South and Central America (figure 9), with aggregate regional production slightly exceeding domestic consumption growth.

Figure 9 | South and Central America: gas production, consumption and surplus until 2035 (Bcm)



Source: BP Energy Outlook 2035 (February 2015).

Figure 10 | Projected gas surplus/deficit by region until 2035 (Bcm)



Source: BP Energy Outlook 2035 (February 2015).

Figure 10 helps to put these numbers in global perspective. Southern and Central America had the third largest world gas surplus in 2013 after the Middle East and Africa (Europe and Eurasia being grouped together). The region is anticipated to overtake Africa by 2025, to maintain the second largest gas surplus until 2035. When the North American surplus starts to shrink in the mid-2020s, the South American surplus should continue growing. These are significant figures, which may have remarkable regional geopolitical implications and a moderate but non-negligible global impact depending on the evolution of other international drivers.

In general terms, perhaps the most relevant regional driver is whether, and to what extent, resource nationalism will survive in a low price environment. Political economy cycles tend to exacerbate resource nationalism with high prices and to favour market opening and foreign investment when prices register an abrupt and persistent decline.

The situation is especially critical in Venezuela, where the economic crisis is having devastating effects and president Maduro has proven unable to replace the charismatic Hugo Chavez as a national or regional leader. In December 2015, legislative elections took place amidst a degraded political climate, with the main opposition leader in jail. The defeat by Maduro's Partido Socialista Unido de Venezuela may entail serious political instability in the country, but also offers Venezuela a more promising path in managing its resource wealth. However, no radical shifts in gas policy should be expected until the current impasse between the Maduro government and a legislative body controlled by the opposition is resolved.

Argentina is expected to continue to be a gas importer, but in the medium and long term the country holds one of the few game changers for global gas markets in the region: the Vaca Muerta field discovered by Repsol and then expropriated by the government, containing over 8,490 Bcm of shale gas.<sup>21</sup> Several international companies are exploring with promising results, but investment has been deterred by a poor energy policy and regulatory environment. While production has started, mainly tight oil, it has already faced strikes and postponements. Argentina's default on part of its foreign debt has further damaged foreign investment. Companies seem to be waiting for the new presidency to decide to move from exploration to production, and this will be one of the main challenges facing the new Argentinean President, Mauricio Macri. His first steps have been promising, announcing significant tariff increases in electricity as well as gas market reform, but also settling a 15-year dispute with US hedge funds (*fondos buitres* or "vulture funds," in Kirchner's terminology).

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<sup>21</sup> EIA, *World Shale Resource Assessments*, cit. On the expropriation of YPF see for instance Gonzalo Escribano, "La expropiación de YPF culmina el fracaso de la política energética argentina", cit.; Fredrik Erixon, "Argentina, the Expropriation of Repsol YPF, and the Case for Improved Investment Protection Accords", in *ECIPE Policy Briefs*, No. 8/2013 (September 2013), <http://ecipe.org/app/uploads/2014/12/PB8.pdf>.

Nevertheless, incremental reforms and a less geopolitically driven foreign policy in Venezuela could greatly normalize South American regional integration, and therefore gas relations in the region. The current low price environment seems to have also moderated the ambitions of presidents Humala in Peru and Morales in Bolivia. While a radical policy shift should also be discarded in Bolivia, there are signs that the country is now conscious of the need to attract foreign investments. Morales's political situation is more comfortable, but his margin for manoeuvre is limited regarding some sensitive points like state control of gas resources, subsidies, gas exports to Chile, or the opposition from indigenist and environmentalist groups to drilling and infrastructure construction. In February 2016 Mr. Morales lost the referendum to amend the Constitution to allow him to be re-elected again, showing some signs of fatigue in the last feud of the so-called new Latin American left.

The evolution of Brazil, the main regional gas market, is also uncertain. The Petrobras scandal adds to the company's difficult financial situation, making energy reform a highly sensitive political issue. Here also, the difficulties of low prices and the lowering of the country's expectations regarding gas production may favour policy reform, or at least the opening of the gas sector, as has happened recently with the sale of some Petrobras distribution assets. While the current impasse may deter further investment in infrastructure, projected demand and Brazilian energy mix preferences will continue to require the development of the internal gas sector and imports from Bolivia and via LNG until at least the mid-2020s – and probably longer, given Petrobras's difficulties.

The regional geopolitical implications, while less drastic than for oil, may be substantial in the medium term. A more open interpretation of resource nationalism in statist producers can gradually converge towards sustained liberalization efforts in other regional markets. Accordingly, the most probable scenario is gradual and volatile regional energy integration limited by slowly converging energy policies, bilateral political differences and the memory of recent crises.

However, in the medium term, the development of Vaca Muerta could completely transform the regional gas picture, making the Southern Cone self-sufficient and posing serious problems for Bolivian gas ambitions. This may for instance further push Bolivian efforts to gain access to Pacific LNG exports. In the meantime, LNG flexibility will dominate new gas corridors for both exports and imports, especially if the trend towards greater liquidity in LNG markets keeps reducing price differentials with pipeline gas.

At the global level, the expected impacts would be felt in the long run, when the eventual exploitation of Vaca Muerta and other conventional and unconventional resources in the region will consolidate the regional surplus. But these impacts will be dependent on other global developments. The most significant events for the region could be the emergence of US gas exports, the consolidation of an Atlantic energy basin, and



the possibility that China could replicate its Latin American oil strategy in the gas sector. In this regard, South America's role in global gas markets will remain subordinated to other actors' strategies.

The US shale gas boom is being confirmed as the crucial transformation of global gas geopolitics, with relevant implications for South America. In the first phase it has shifted Peruvian and Trinidad and Tobago LNG exporting strategies from the US to highly competitive markets in Europe and Asia. New US exporting capacities in the medium term can also alter these markets and South American imports as well. A simulation of US LNG exports shows the following results for Latin America, including Mexico: given the low level of extra-regional LNG exports the impact would not be very high in absolute terms; however, it will significantly reduce annual natural gas export revenue in Peru and Trinidad and Tobago, precluding existing or potential South American LNG exporters from further participation in the global gas market in the medium to long term<sup>22</sup>.

US shale gas exports to Mexico and Guatemala are perhaps the most probable impact in the Americas, followed by LNG exports to Central America. While South American gas importing countries may benefit from a reduction in LNG prices, they are less likely to import significant amounts of US gas, with the relevant exception of Chile.<sup>23</sup> In August 2015, Chile announced US LNG imports starting in 2019 at a very competitive price in comparison with trucked gas or sporadic pipeline imports from Argentina, under a 20-year supply and purchase agreement from the Corpus Christi project in the US Gulf Coast. There are also some more cautious outlooks for US LNG export. Its economic viability has been put into question because oil-indexed LNG contracts are eroding the competitiveness of Henry Hub-linked LNG contracts, resulting in cancellation of the majority of liquefaction projects planned in the US.

The emergence of an Atlantic basin energy dimension has also recently been proposed as a macro-regional geopolitical driver, including the shale revolution together with other events like the Mexican energy reform, the already mentioned (and waning) pre-salt boom, and expected LNG exports from new discoveries and LNG terminals in Africa. Mexico has been importing LNG from Peru and Trinidad and Tobago, but it will increasingly import from the US. The Mexican energy reform is being stalled by low oil and gas prices, and in contrast to the oil situation, Mexican gas exports are not expected any time soon.

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<sup>22</sup> Jason Bordoff and Trevor Houser, "American Gas to the Rescue? The Impact of US LNG Exports on European Security and Russian Foreign Policy", in *CGEP Reports*, September 2014, <http://energypolicy.columbia.edu/node/839>.

<sup>23</sup> Lisa Viscidi, Carlos Sucre and Sean Karst, "Natural Gas Market Outlook. How Latin America and the Caribbean Can Benefit from the US Shale Boom", in *Inter-American Dialogue Energy Working Papers*, September 2015, <http://www.thedialogue.org/?p=20172>.

Nigeria has planned two more LNG export terminals and an additional one is under study. Cameroon, Mozambique and Tanzania also have plans for LNG exports. Nevertheless, African LNG prospects seem weaker than those of South America, and without a regional market of their own they will likely be among the most affected by future US exports. Significant LNG links between South America and Africa are not very promising either.

Asia also offers limited prospects to South American LNG exporters, which face tough competition from Middle East producers linked to Asian importers through long-term contracts. China's role is a different question. Some countries like Bolivia and Argentina have made attempts to reproduce the pattern of oil for loans established in Chinese oil deals with Venezuela or Ecuador. The absence of current production or export outlets has limited Chinese involvement in the Argentinean upstream, but YPF has recently signed alliances with the Chinese company Sinopec and the Malaysian Petronas (and the Russian Gazprom). Nevertheless, the short-term focus is on tight oil rather than gas, with the prospect of eventually supplying regional demand in the medium term.

In short, the ongoing reconfiguration of the Western Hemisphere gas balance will fully unfold over the next two decades. In the best regional scenario, the integration of gas markets will be gradual and volatile, limited by slowly converging policies and strained political relations among key actors. At a global level, South America will continue to be interdependent with the US, but in a completely different manner: rather than exporting to US markets, competing with US gas in regional and global markets. Imports of US gas are not foreseen to reach the level of Mexico, but have already become a reality for Chile.

Not until the mid-2020s, provided that proper gas policies in the region are gradually applied, countries like Argentina, Brazil or Bolivia could fully materialize their reserves into significant production levels and eventually develop export markets outside the region. According to most projections, this will coincide with the decline of North American shale gas production, allegedly rebalancing the gas interdependence pattern in the Americas. However, the uncertainty related to the evolution of regional gas policies and global gas markets could be compensated for by a more benign political cycle in the region.



## 5. The EU and LNG as a Flexible Tool for Energy Security: Constraints and Opportunities

Giacomo Luciani

Preoccupation with the security of European gas supplies has been steadily increasing over the past decade due to a complex set of causes:

- The enlargement process has brought into the Union countries that are highly (in some cases, wholly) dependent on a single supplier, i.e., Russia.
- Projects to bring additional gas by pipelines from sources different from Russia have not made the expected progress.
- Recurrent conflict in gas relations between Russia and Ukraine led to two interruptions in gas flows to the EU, in 2006 and again in 2009.
- The Russian occupation of Crimea and covert military intervention in Eastern Ukraine since 2014 has raised questions on the reliability of all Russian gas supply routes, including pipelines that do not cross Ukraine.

The same preoccupations have been mitigated by the steady decline in European gas demand, due to the persistent recession as well as replacement of traditional sources of power by subsidized renewable sources such as wind and solar. Although gas is a cleaner, more efficient and more flexible fuel for power generation, very cheap coal has favoured the continued operation of coal-fired power plants and the mothballing of gas-fired plants.

Furthermore, in reaction to the 2009 interruption of Russian supplies the EU enacted new rules aimed at strengthening internal solidarity and interconnectivity. A number of projects to allow reverse flow in pipelines or to establish new connections have considerably enhanced the flexibility of flows within the European pipeline grid. The stress test conducted by the Commission in the fall of 2014<sup>1</sup> concluded that the Union could

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<sup>1</sup> European Commission, *On the short-term resilience of the European gas system. Preparedness for a possible disruption of supplies from the East during the fall and winter of 2014/2015* (COM/2014/654), 16

withstand a complete interruption of Russian gas supplies for a period of six months,<sup>2</sup> but multiple emergency measures and tight coordination would be necessary.

As we look to the future, security of supply conditions may well deteriorate. European domestic production is expected to decline, and the process may accelerate due to cost or environmental considerations. Low prices are pushing some European production out of the market or delaying investment projects in frontier areas, while, on the environmental front, recent seismic activity has led to an enforced rapid decline in the output of the largest European gas field, Groningen.

A sequence of two exceptionally mild winters (2014/15 and 2015/16) has depressed European gas demand to a very low level from which it may or may not rebound. Beyond short-term climatic influences, if the Union is seriously committed to reducing GHG emissions (in line with the very ambitious objectives that the EU has successfully supported within COP21), it is inevitable that coal-fired power generation will be restricted and greater reliance placed on power from gas. However, current projections proposed by the European Commission are notably ambiguous in this respect, presenting a range of future demand paths, from continuously decreasing to the exact opposite. This is represented in figure 1.

It is evident that if gas demand continues to decline, the issue of security may also become less important, while by the same token investment in new infrastructure, whether for alternative imports from outside the EU or for improved interconnections within the Union, will also be discouraged. The net effect is unclear.

A common but logically flawed approach equates security of supply with lesser dependence on imports. In fact, a small internal gas market cannot easily support multiple suppliers, especially if imports are received by long-distance pipeline; small markets hence more easily end up being dependent on a single supplier. Larger demand justifies multiple import facilities and facilitates diversification of sources. LNG to some extent may allow for sufficient diversification also for smaller import volumes, because LNG cargos can be redirected.

On 16 February 2016 the European Commission published the so-called Winter Package for the implementation of the Energy Union, which, among several other measures, contains a Communication “On an EU strategy for liquefied natural gas and gas storage.”<sup>3</sup> This document is the outcome of widespread consultation of stakeholders, and is

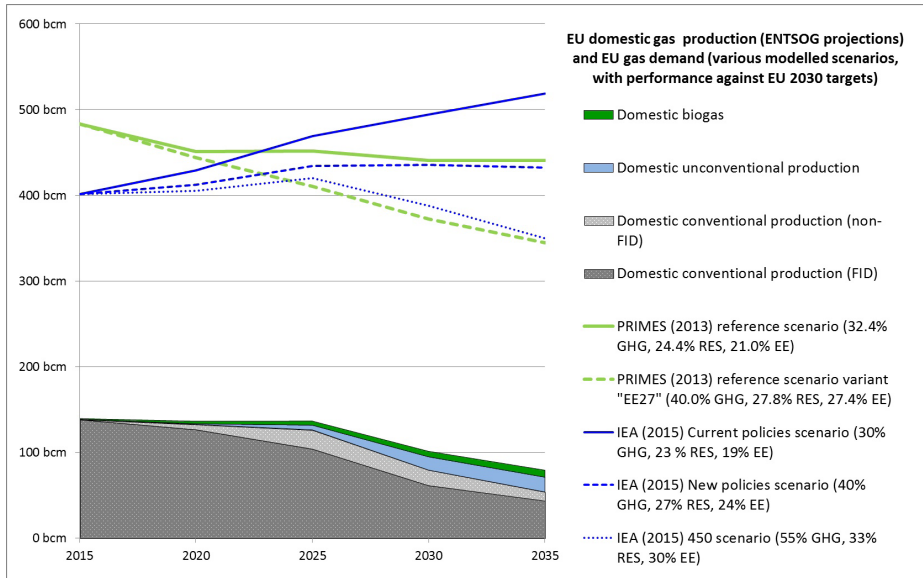
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October 2014, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=celex:52014DC0654>.

<sup>2</sup> “The ENTSOG analysis shows that cooperation based on optimized infrastructure use and relative burden-sharing ensures the supply of protected customers in Member States and Energy Community Contracting Parties as well as significant exports to Ukraine.” *Ibid.*, p. 16.

<sup>3</sup> European Commission, *On an EU strategy for liquefied natural gas and gas storage* (COM/2016/49), 16 February 2016, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=COM:2016:49:FIN>.

Figure 1 | EU domestic gas production (ENTSO projections) and EU gas demand (various modelled scenarios, with performance against EU 2030 targets)



Source: European Commission, *Commission Staff Working Document accompanying the document ... On an EU strategy for liquefied natural gas and gas storage* (SWD/2016/23), 16 February 2016, p. 3, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=celex:52016SC0023>.

accompanied by an extensive Staff Working Document.<sup>4</sup> In the rest of this chapter I will use these documents as key references.

The chapter is organised as follows: Section 1 reviews developments of the global LNG market, detailing existing and prospective demand/supply conditions. Section 2 describes the role that LNG has played in European gas supplies in recent years. Section 3 discusses the LNG strategy that the European Commission has proposed within the Winter Package. Section 4 summarises and concludes.

## 5.1 The Global LNG Market: Developments and Perspectives

Global gas trade has reached a trillion cubic metres of gas per year, of which 66 percent is transported by pipeline and 33 percent as LNG by tanker. The share of LNG in

<sup>4</sup> European Commission, *Commission Staff Working Document accompanying the document ... On an EU strategy for liquefied natural gas and gas storage* (SWD/2016/23), cit.

total gas trade has been increasing over the years. Total supply increased rapidly from approximately<sup>5</sup> 190 to approximately 330 Bcm/year between 2005 and 2011. The latter year saw a peak in LNG supply, primarily justified by the Fukushima nuclear power accident and the need to suddenly replace all nuclear-based power generation in Japan, leading to a sharp increase in demand and prices for LNG. Since 2011, total LNG trade has stagnated, due to progressive reduction of emergency demand in Japan and low global economic growth.

The number of countries that are importing gas has grown systematically, the number of exporting countries less so. It is to be noted that global regasification capacity vastly exceeds global gas trade, by a factor of three to one. This is a reflection of the fact that a regasification plant is a relatively cheap structure, by far the least expensive component in an LNG chain composed of a liquefaction plant, specialised tankers and regasification facilities. The over-dimensioning of regasification facilities adds flexibility to international LNG trade, allowing LNG to be redirected from its original destination for commercial or security reasons. Flexibility in regasification is further enhanced by the emergence of floating storage and regasification units (FSRU) that can be deployed or redeployed rapidly to address emergency conditions or unexpected supply disruptions.

LNG exports originate from 19 different countries, with three countries (Qatar, Australia and Malaysia) accounting for more than 50 percent of total exports. Qatar is by far the most important LNG exporter for the time being, but it has imposed a moratorium on further LNG projects and is expected to cede to Australia its position as leading exporter in the coming year.

The share of short- and medium-term LNG trade experienced rapid growth until 2012, but has marginally declined since then. That said, LNG traded on a long-term basis is not necessarily rigidly committed to the original importer, thanks to the rapidly increasing phenomenon of re-exports. These take place either because the original exporter and importer agree on a change of destination due to commercial expediency, or because the cargo is delivered to the original importer but then reloaded on a different ship and sent to a different destination. The latter activity has been especially prominent in Europe, with Spain, Belgium, France, Portugal and the Netherlands all increasingly resorting to re-exports.

The potential supply of LNG is expected to grow rapidly in the coming years, with several new liquefaction projects coming onstream between 2015 and 2020. Major increases are expected especially in Australia, the United States and to a lesser extent Russia.

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<sup>5</sup> There is some ambiguity in data concerning international gas trade because LNG received in one terminal may then be re-exported to other destinations. This phenomenon has been increasing over the years, generating a widening gap between net LNG production and global trade.

Australia will surpass Qatar in 2018 as the major LNG exporter in the world. Seven projects for a total of 79.4 Bcm/year will be added to Australian capacity by then, close to a 25 percent increase in global capacity. Australian projects are vertically integrated, i.e., promoted by the companies that own the upstream resources, and three of them are based on coal-bed methane rather than conventional natural gas deposits.

In contrast, US projects are based on sourcing gas from the free market, due to the very low price of natural gas sold on the Henry Hub. Four projects are currently under construction for a total of 60.8 Bcm/year. By 2020 the United States will be the third largest LNG exporter after Australia and Qatar. The price of methane on the Henry Hub has recently fallen even below 2 dollars/mmBtu; producers are suffering and keenly await an opportunity to export the surplus gas.

The first project – Sabine Pass, owned by Cheniere – came onstream at the end of 2015. It is based on a tolling concept, whereby Cheniere receives a fee for providing the service of liquefaction to companies that buy gas on the free market and then export LNG on their own account. This business model promises to lead to especially aggressive marketing on the part of the companies that have entered into tolling agreements.

Beyond 2020, more numerous projects could come onstream, in the United States as well as in other parts of the world where abundant gas resources have recently been discovered. This is in particular the case of East Africa, notably Mozambique, where important discoveries have been made and more are expected. After a few disappointing years, the recent major gas discovery made by Eni in the Egyptian offshore might allow restarting of Egyptian liquefaction capacity, which had been almost completely mothballed due to lack of gas (as Egyptian production was not even sufficient to cover rapidly growing domestic demand).

Much of the new LNG that will come on the market is not committed to specific destinations, and will contribute to increase the share of LNG that is traded on a short- or medium-term basis. As no bottleneck is predicted in availability of LNG tanker capacity, it is to be expected that the market will become increasingly liquid and arbitrage opportunities will increase. Until now, the market for gas has been regional rather than global, with three clearly separated regional gas markets: North American, European and East Asian. Transmission capacity and arbitraging opportunities between these three regional markets (and sometimes also within the same regional market) have been limited, allowing for persistent or even growing price differences, and in fact even different price discovery mechanisms. In the United States, gas is produced by a large number of companies and sold into a competitive and highly liquid market centred on Henry Hub. In Europe, some gas is freely traded on hubs but traditionally gas imported by pipeline has been indexed to either crude oil or petroleum products. In East Asia so far almost all gas has been indexed to crude oil prices.



Divergent regional dynamics and price discovery mechanisms have led to persistent gaps between prices in different regions. While the price of gas in the US has been completely decoupled from the price of oil and has remained low since 2009, the price in East Asia skyrocketed following the Fukushima crisis. Prices in Europe have remained in the middle, and intra-European differentials as measured by the difference between gas price on the UK National Balancing Point (NBP) and the average German import price have narrowed. However, since the beginning of 2015 the situation has evolved, and price differentials are considerably tighter, especially between East Asia and Europe.

In fact, the so-called Japan-Korea marker has at times even fallen below the NBP price. However, the Henry Hub price remains significantly lower than prices in either Europe or East Asia. This may progressively change with the coming onstream of US LNG projects between now and 2020. It is impossible to say at this stage whether these projects will be sufficient to eliminate the gap and effectively create a single global gas market, but clearly new LNG projects in the US will be undertaken for as long as an arbitrage opportunity exists.

## 5.2 LNG in European Gas Supplies

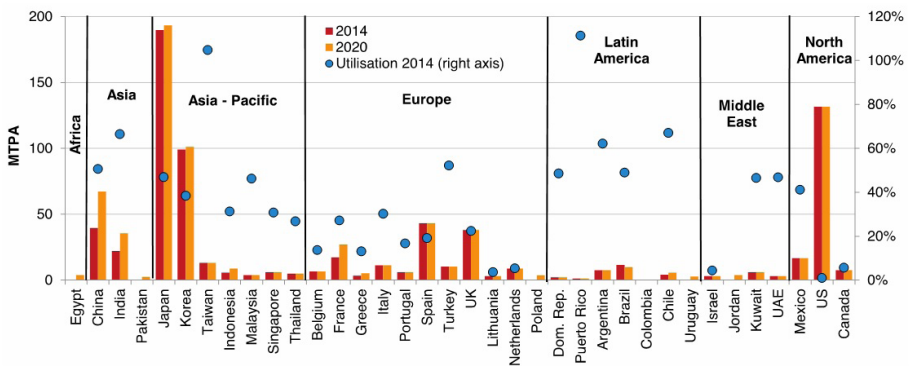
LNG has played a role in European gas supplies ever since the early projects were launched in Algeria. Regasification capacity is concentrated in Western Europe along the Mediterranean and Atlantic coast. The rate of utilisation of available capacity is low in all countries except Turkey, whose gas market is very rapidly growing. Figure 2 demonstrates this dynamic, indicating that in 2014 capacity utilisation was below 20 percent in Belgium, Greece, Portugal, Lithuania and the Netherlands; and at or barely above 20 percent in Spain and France. The Commission staff working paper reads: "The average rate of LNG terminal utilisation in Europe (of total installed capacity) has decreased since 2010, from 53% to 25% in 2013, and in 2014 just 19% of the total send out capacity was used (compared with a global average of 33 %)."<sup>6</sup>

In the past 10 years, Europe may be said to have played the role of residual LNG market at the global level. Liquefaction capacity expanded rapidly until the late years of the past decade thanks to investment projects, primarily in Qatar, which were sanctioned on the expectation that the United States would become a net gas importer and require rapidly increasing volumes of LNG. The companies that developed the Qatari

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<sup>6</sup> European Commission, *Commission Staff Working Document accompanying the document ... On an EU strategy for liquefied natural gas and gas storage*, cit., p. 12.

Figure 2 | Receiving terminal import capacity and utilisation rate by country in 2014 and 2020



Source: IGU, *World LNG Report 2015 Edition*, June 2015, p. 50, <http://www.igu.org/publications>.

projects, notably ExxonMobil, were their own anchor customers, in the sense that they expected to directly market the gas by selling it on the free domestic US market, where prices were expected to increase due to declining domestic production. However, reality evolved in the completely opposite direction: with the boom in shale gas production the prospect of US LNG imports evaporated and incremental LNG supply had to seek new markets. Europe was especially attractive because of the process of gas market liberalisation and creation of a single European gas market, allowing new entrants to offer gas on rapidly developing wholesale markets, and gas-to-gas competition within as well as across national boundaries. Qatari LNG (which is marketed primarily by Exxon-Mobil, in association with Qatar Petroleum), previously intended for the United States, was instead sent to Europe, and contributed to the creation of competitive conditions that had been quite elusive in previous years, notwithstanding successive EU legislative packages intended to stimulate competition.

In the latter years of the past decade EU LNG imports increased and so did the share of gas traded on European hubs. However, conditions suddenly changed following the Fukushima accident. The disabling of the entire Japanese nuclear power generation fleet led to a sudden surge in Japanese gas demand, while Chinese demand also continued to grow strongly. This led to a widening price gap and to a surge of re-exports of LNG out of Europe. In 2014, 80 percent of Europe's gas imports from the rest of the world came as pipeline gas and 20 percent as LNG.

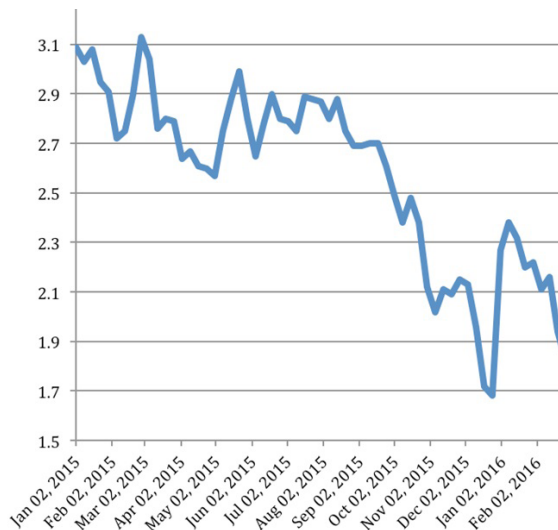
Regasification capacity is therefore abundantly available, but there is a regional mismatch from the point of view of security of supply: regasification capacity is located in the Western part of the continent and along the Atlantic coast, while the threat to security of gas supplies is especially acute in Central and Eastern Europe, where dependency on Russian pipeline gas is the highest. Intra-European transmission capacity is not suf-

ficient to send gas molecules, which might be received in currently largely non-utilised regasification terminals, to countries that are most vulnerable to interruption of pipeline supplies, notably from Russia. Hence an enhanced role of LNG through better utilisation of existing terminals requires reinforcement of interconnections within the Union itself.

The trends in the global LNG market described in the previous section may, according to one line of thinking, lead to a seriously depressed European gas market for at least the next five years. According to this analysis, Europe will continue to be the market of last resort because it is open, and capable of receiving large volumes of LNG on a spot basis with no need for long-term contracts. East Asian markets are not expected to grow, as the Japanese nuclear power fleet is progressively brought back into operation and the Chinese economy is widely expected to slow down. Furthermore, China may increase its reliance on pipeline gas, if the two major export projects out of Eastern and Western Siberia respectively come to fruition.

If gas prices on the Henry Hub remain below 4 dollars/mmBtu (as they have been since 2014, see figure 3) US LNG might penetrate a European market where prices oscillate between 6 and 7 dollars/mmBtu. The price gap would not be sufficient to fully recover the liquefaction, transportation and regasification costs (which add up to 4-5 dollars/mmBtu), but, this reasoning goes, companies having booked liquefaction services from Sabine Pass and other projects will be bound to pay for those services even if they do not use them, and will prefer to recover at least some of their money by dumping their LNG into the European market rather than taking a total loss.

Figure 3 | Weekly Henry Hub natural gas spot price (dollars per mmBtu)



Source: EIA, *Natural gas spot prices*, <http://www.eia.gov/dnav/ng/hist/rngwhhdw.htm>.

But if such extraordinary conditions were to occur, surely they could not last for very long. It is not credible that Europe would be the sole market of last resort – market forces would come into play and restore some form of equilibrium. This can take place in a variety of ways:

- Through the creation of additional demand for gas elsewhere in the world, especially in connection with the drive to reduce GHG emissions and prevent global warming. A movement to substitute gas for coal is already underway in the US and China; Europe has been moving in the opposite direction, but can be expected to align, especially if preoccupation with the security of gas supply becomes less intense; and India is a very significant potential major importer, due to its overwhelming dependence on coal, especially if a protracted period of relatively cheap LNG can be envisaged. There are also more exotic solutions such as higher penetration of LNG in the transport sector – but demand could increase even independently of such factors.
- Through delays in the implementation of new upstream or pipeline projects. Throughout 2015 oil companies have announced cutbacks in investment in upstream projects, due to the low price of oil, for a total of close to 400 billion dollars.<sup>7</sup> In addition, some of the pipeline projects, notably the Russian projects to serve China (the Altai and Power of China pipelines), require significant finance, which might not be readily available. In an environment of very competitive LNG prices, China would certainly not commit to pay more for pipeline gas than it pays for LNG, meaning that the two Russian exporters, Gazprom and Rosneft, would face some very lean netbacks for their exports.

On the basis of the above analysis the European gas price environment may remain competitive until at least 2025. The future of gas demand in Europe remains uncertain, while projects that are justified primarily by strategic rather than commercial considerations – such as the doubling of the Nord Stream – will face considerable financing challenges. The Russian government is deeply involved in gas affairs, and notwithstanding all difficulties the State has the possibility of supporting Gazprom in the implementation of projects that make little or no commercial sense – but there is a cost to this policy.

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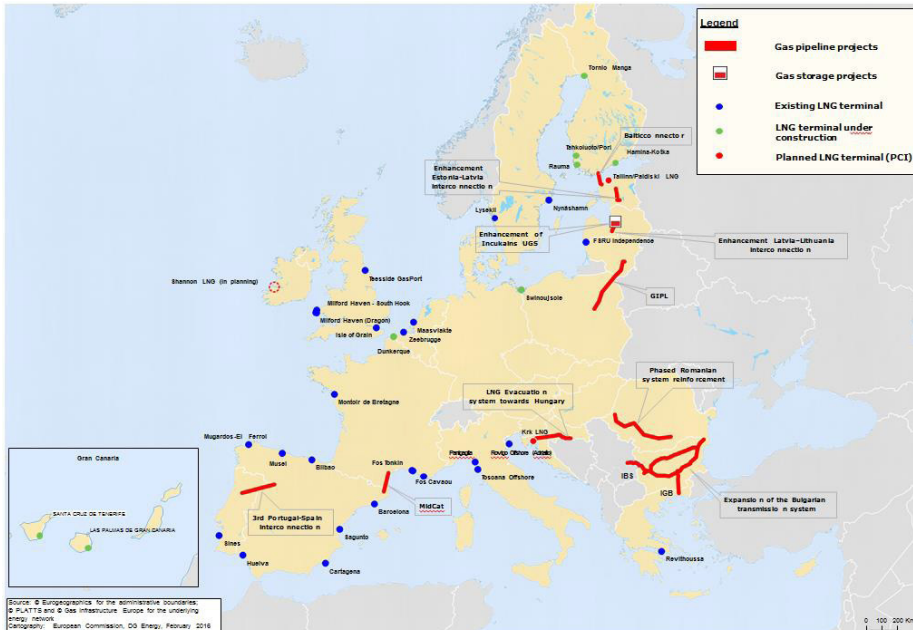
<sup>7</sup> Christopher Adams, “Delayed oil projects total nears \$400bn”, in *Financial Times*, 14 January 2016, <http://on.ft.com/1mX1lqK>.

### 5.3 The Commission’s Proposed LNG Strategy

Conditions of abundant supply and low prices, as described in the previous section, can be favourable to LNG playing an important role in guaranteeing security of supply. The opportunity is very clear and the European Commission is well aware of it. At the same time, problems persist for some member countries:

As regards LNG, the prospect of a dramatic (50%) expansion in global supply over the next few years and consequently of lower prices presents a major opportunity for the EU, particularly when it comes to gas security and resilience. While many Member States enjoy mature and liquid gas markets, as the 2014 EU Energy Security Strategy and the Communication on the short term resilience of the European gas system make clear, four Member States in the Baltic, central-eastern and south-eastern European regions are heavily dependent on a single supplier, and hence vulnerable to supply interruptions.<sup>8</sup>

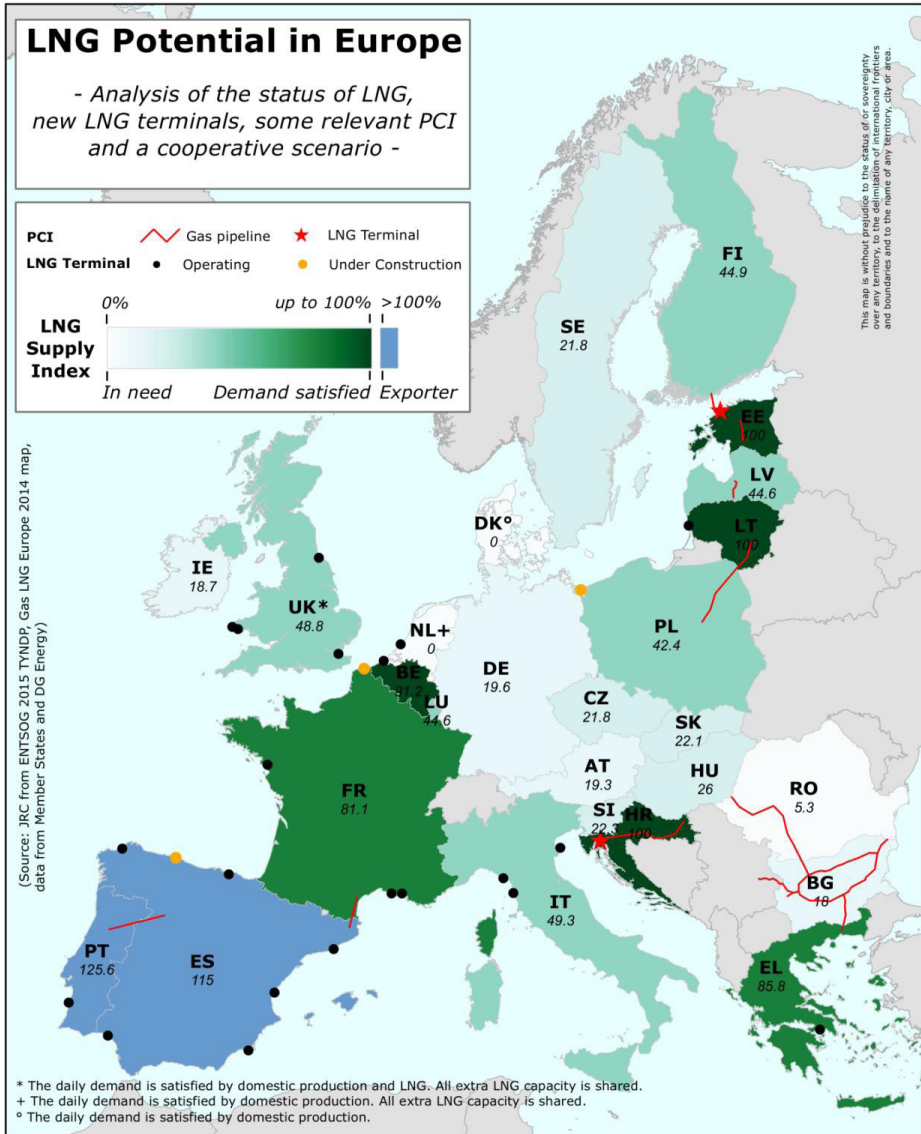
Figure 4 | EU infrastructure relevant for the LNG and storage strategy



Source: European Commission, *On an EU strategy for liquefied natural gas and gas storage*, cit., p. 6.  
 Note: Missing links: Infrastructure to be built/reinforced to improve connections of LNG terminals to the internal market. The blue dots indicate existing LNG terminals.

<sup>8</sup> European Commission, *On an EU strategy for liquefied natural gas and gas storage*, cit., p. 2.

Figure 5 | Potential penetration of LNG after completion of relevant PCIs and with cooperation between countries



Source: European Commission, *Commission Staff Working Document accompanying the document ... On an EU strategy for liquefied natural gas and gas storage*, cit., p. 33.

Note: 35 percent of demand is covered for Member States in need.

The Commission therefore proposes to accelerate the implementation of a subset of projects of common interest (PCI) identified by the relevant regional groups of countries, in order to achieve the goal of allowing every member country to have at least two po-

tential sources of supply. These projects are identified in the map reproduced in figure 4, in which existing LNG regasification terminals are indicated with blue dots, terminals under construction with green dots, and the two new strategically important terminals (Krk in Croatia and Tallin/Paldiski in Estonia) with red dots. In addition, several new interconnection projects, highlighted in red, are also supported.

According to the Commission's modelling exercise, the implementation of these projects would enable considerable improvement in security of supply for the more critically exposed member countries. The staff working paper evaluates the potential impact of the envisaged PCIs through the discussion of four scenarios. The fourth scenario, which is based on the assumption that all the proposed PCIs are implemented and member countries share available supplies to the maximum on an average winter day, is represented in figure 5.

The scenario is based on the assumption that only LNG and domestic production are available, with no pipeline gas or gas from storage. Such assumptions are of course extreme: it is unconceivable that no pipeline gas at all would be available, especially in countries that receive pipeline gas from multiple suppliers. The assumptions are only tenable for countries that depend entirely on Russia, i.e., the Central and Eastern member countries.

The Commission's propositions thus are relatively modest and do not amount to a dramatic shift towards an increased role of LNG. Considering that only two new LNG terminals are envisaged, and the bulk of the proposal is about enhanced interconnection capacity – which is not necessarily linked to LNG (certainly at least for the interconnections in the Iberian peninsula and between France and Italy) – it is clear that what is being proposed falls well short of a revolution.

The truth of the matter is that it is not at all clear and universally accepted that more significant penetration of LNG would be required. This is due to the uncertainty of future gas demand in Europe, but also to divergent opinions concerning the reliability of pipeline supplies from Russia, or the likelihood of new pipeline supplies from the Middle East and Central Asia across Turkey.

Divergent opinions concerning Russian gas are evidenced by the launch of the Nord Stream 2 project, aiming at doubling the capacity of the Nord Stream pipeline. This project was proposed by Gazprom and is supported by a powerful consortium of European companies; it is also explicitly supported by the German government, albeit opposed by almost all Eastern members and Italy. Previously Gazprom had pushed for the realisation of the South Stream, soliciting considerable resistance from the Commission, notably through the refusal to grant an exception from third party access rules for the portion of the pipeline within the European Union. Having abandoned the South Stream when work on it had already begun, Russia launched the idea of the Turk Stream, which even-

tually ran into trouble because of the sharp deterioration of relations between Russia and Turkey.

Furthermore, notwithstanding the demise of the Nabucco pipeline project, the prospect of major supplies of pipeline gas from the Middle East and Central Asia across Turkey has certainly not disappeared. With the end of sanctions, the perspective of importing gas from Iran is open again, in addition to supplies from Azerbaijan and possibly Iraq and Turkmenistan.

In total, this means that even the two proposed LNG terminals in Krk and Estonia might end up being minimally utilised. The Commission is keen to highlight their value as tools to enhance competition and prevent market segmentation, and constantly refers to the experience of the Lithuanian terminal: “The example of the Klaipeda FSRU shows that just the prospect of a new LNG source in the market can drive improvements in terms of gas security of supply and price competitiveness.”<sup>9</sup> There is indeed little doubt that the mere availability of a regasification terminal may enhance the importer’s competitive position vis-à-vis pipeline gas suppliers, but this comes at some cost and raises problems of financing. With respect to financing, the Commission’s Communication states:

In principle, LNG terminals should be financed through tariffs but in some cases market participants bear the risk of the investment. EU funds can help to make up for the weak commercial viability of terminals that are particularly important for security of supply. European Investment Bank loans, including under the European Fund for Strategic Investments (EFSI), may be another source of long-term financing for LNG infrastructure. However, it is still important that the full economic case for new terminals be considered and the most cost-effective solutions be adopted.<sup>10</sup>

But financing LNG terminals through tariffs may be problematic when such terminals are meant to serve not just the security concerns of the country where the terminal is located, but also neighbouring countries, which may be landlocked and thus not have the possibility of establishing their own regasification terminal. In these cases, how is the burden to be divided? To whose tariffs should the cost of the regasification plant be added?

We are thus in a sense back to a familiar dilemma with respect to energy security: providing for security requires maintaining excess capacity, but the latter has no commercial justification. Regulatory intervention is required to ensure that sufficient

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<sup>9</sup> Ibid., p. 4.

<sup>10</sup> Ibid.



excess capacity is created and maintained. This is what the EU did in October 2010 when the N-1 standard was adopted for gas networks, effective at the end of 2014.<sup>11</sup> Countries not already satisfying the standard had to undertake the appropriate additional investment, which could take the form of acquiring sufficient regasification capacity. By the end of 2014 Bulgaria was the only member country that did not comply with the standard.<sup>12</sup>

If European gas demand increases again, the N-1 standard – which is based on satisfying the demand of protected customers under emergency conditions – may automatically require increasing available import capacity. Thus in the coming years multiple factors may converge to stimulate further expansion and geographical diversification of regasification capacity, including projects that are currently not listed as PCI, notably:

- abundant availability of cheap LNG;
- competition among LNG suppliers to acquire new markets;
- the effect of the N-1 standard;
- further measures at the national or European level to foster greater diversification in gas import sources (i.e., actively discriminating against existing suppliers, notably Russia).

In particular, it should be recalled that some of the existing regasification terminals were established by entities owned by or closely related to LNG exporters, whose motivation was gaining access to promising markets. Some of these terminals have been exempted from third party access obligations. As competition on the global LNG market

<sup>11</sup> The N-1 standard is defined as follows: “Member States [...] shall ensure that the necessary measures are taken so that by 3 December 2014 at the latest, in the event of a disruption of the single largest gas infrastructure, the capacity of the remaining infrastructure [...] is able [...] to satisfy total gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years.” Article 6 of Regulation (EU) No 994/2010 of 20 October 2010 concerning measures to safeguard security of gas supply, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=celex:32010R0994>. The Winter Package includes a Proposal for a Regulation in which some further refinement of the N-1 standard definition is envisaged, notably to take into account not just the existence of alternative infrastructure, but also its hydraulic characteristics, which must be sufficient for emergency use. See European Commission, *Proposal for a Regulation concerning measures to safeguard the security of gas supply repealing Regulation (EU) No 994/2010* (COM/2016/52), 16 February 2016, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=celex:52016PC0052>.

<sup>12</sup> More precisely, 20 member countries fully complied with the standard, two (Cyprus and Malta) use no gas, and three (Slovenia, Sweden and Luxembourg) are exempted. Of the remaining three, Lithuania became compliant in 2015, and Greece will become compliant upon completion of the TANAP pipeline bringing Azeri gas through Turkey. In the case of Bulgaria, no clear solution is yet identified. See European Commission, *Report on the implementation of Regulation (EU) 994/2010 and its contribution to solidarity and preparedness for gas disruptions in the EU* (SWD/2014/325), 16 October 2014, p. 7-8, <http://eur-lex.europa.eu/legal-content/en/TXT/?uri=celex:52014SC0325>.

intensifies, establishing receiving plants in hitherto isolated and peripheral market areas may be viewed as a strategy to acquire market share in protected niches.

At the same time, it would be a mistake for the EU to become complacent, and conclude that LNG and LNG operators can solve all security of supply problems. It remains true that pipeline gas, by establishing a rigid bilateral relationship of interdependence, is more stable – if less flexible – than LNG. In this sense, the drive to diversify pipeline gas imports through the development of new projects from new suppliers – notably from the Caspian and the Near East – remains of utmost priority.

## Conclusions

There can be little doubt that conditions in the coming years will be extremely favourable to increased reliance on LNG imports and thereby also increased security of gas supply. This represents a golden opportunity for taking European energy policy back to a more sensible path.

Excessive emphasis on the promotion of specific renewable sources (picking winners) through ad hoc subsidies and administrative measures has led to paradoxical outcomes, whereby security of supply has been eroded and emissions have been reduced less than they might have been. Had it not been for prolonged low economic growth, Europe might not have been able to meet its decarbonisation targets for 2020. Gas in particular has suffered, being perceived as insecure due to geopolitical factors; being undermined by subsidies extended to renewable sources; and being more expensive than coal.

It is increasingly recognised, including in EU deliberations, that a sensible decarbonisation policy must be based on imposing a sufficiently high price for carbon, which will create a market response towards decarbonisation. Relying on a carbon price as main policy tool to promote decarbonisation will promote the adoption of the cheapest decarbonisation solutions, notably rational use of energy; and will also highlight the attractiveness of gas relative to other fossil fuels, notably coal.

Contrary to widespread perception, especially in the Central and Eastern European countries that are excessively dependent on Russia as their main or sole source, gas is an abundant and secure source of energy – besides being clean, flexible and reliable as a source of power. In a rational world growing reliance on intermittent renewable sources would be accompanied by a growing role for gas – but the opposite has been the case so far. If such an irrational outcome continues, then demand for gas will stagnate or even further decline, and security of supply will not be a problem, because

excess capacity will automatically be available. This, however, is certainly not an optimal scenario.

In the context of a more rational EU energy policy, demand for gas will grow again and security of supply will become more of a problem. In this scenario, LNG is capable of providing precious operational flexibility, diversification and capacity to withstand emergency conditions. The experience of Japan following the Fukushima disaster demonstrates that LNG is indeed an extraordinarily flexible source and an essential component of a reliable energy system.

Market forces and existing regulations may be sufficient to encourage the required further expansion of regasification facilities, but attention should be given to promptly removing barriers that may arise in this respect. The lack of sufficient interconnections within the Union is an obvious obstacle to greater reliance on LNG and hindrance to security of supply, as the Winter Package effectively recognises. The Commission is well aware of the importance of the challenge, and in the context of greater European cohesiveness around energy policy, attracting the needed investment in new receiving facilities should be eminently possible.

## 6. Eastern Mediterranean Gas: Source of Prosperity for the Region?

Ayla Gürel

For some years now the Eastern Mediterranean has been a centre of attention as a potentially important natural gas province in the making. This is essentially due to a succession of sizable gas finds by Israel and the Republic of Cyprus in their offshore areas that fall in what is known as the Mediterranean's Levant Basin. In 2009-10 Israel discovered two large gas fields, Tamar and Leviathan. About a year later the first ever exploratory drilling offshore Cyprus led to the discovery of a substantial amount of natural gas in the Aphrodite field. Tamar, Leviathan and Aphrodite are geographically fairly close to each other. Their estimated total capacity of about 990 Bcm is a fairly modest amount in global terms but clearly quite significant as regards the potential to transform the regional energy landscape by providing energy supply security and reducing dependence on energy imports, in addition to its impact on relations between the countries of the region.

Another of these countries, namely Egypt, has actually been an important gas producer and exporter since the early 2000s. As of 2014 its proved natural gas reserves, over three quarters of which lie in the Mediterranean Sea, amounted to more than 2,100 Bcm. Egypt's most recent and significant gas find, announced in August, the Zohr field which is hailed as a "giant field" and is estimated to hold as much as 850 Bcm, is also in the Mediterranean. This massive gas discovery, incidentally, has potential implications for plans regarding monetisation of the gas reserves in the nearby Leviathan and Aphrodite fields, both of which still await development.

Undoubtedly all this points to a future for the Eastern Mediterranean as an important gas province. But so far progress in that direction has in general been frustratingly slow. And this is for a number of reasons: the impact of energy price volatility and turbulent economic and financial conditions globally, uncertainties in the countries' energy policies, regulatory and fiscal policies, and, not least, the region's own geopolitical challenges which constitute a major source of difficulty.

This chapter presents an overview and analysis of the complexities associated with developing the Eastern Mediterranean natural gas reserves, and also discusses the chances of the new gas finds realising their potential as a source of prosperity for the region rather than becoming a serious source of further conflict.

## 6.1 Eastern Mediterranean Gas Potential

Recent substantial gas discoveries in the Levant Basin by Israel and the (*de facto* Greek-Cypriot-administered<sup>1</sup>) Republic of Cyprus (RoC), estimated at around 990 Bcm, although too modest in volume to be of much consequence at the global level (compare, for example, with the estimated 14 Tcm of Iran's South-Pars field<sup>2</sup> or the 3.9 Tcm of Russia's Shtokman field<sup>3</sup>), have attracted a lot international interest. The present resources represent a huge opportunity for the region. If developed wisely and optimally, they could help to transform the energy landscape in the Eastern Mediterranean. They can provide supplies necessary to meet the rapidly growing energy demand in the countries of the region as well as enable exports and even redefine regional political relations. They also seem to confirm the basin's resource potential as assessed by the US Geological Survey (USGS). According to a March 2010 USGS report, the Levant Basin Province holds an estimated mean of 3,453 Bcm of recoverable gas.<sup>4</sup> In other words, there is possibility of more finds under Eastern Mediterranean waters in volumes comparable to the present proved gas reserves of Iraq,<sup>5</sup> or in the order of three-quarters of the proved gas reserves of Algeria, the country with the biggest proved reserves in the Mediterranean Region and the second-largest external natural gas supplier to Europe.<sup>6</sup>

Egypt has actually been an important gas producer and exporter long before the large Israeli and Cypriot finds in the Levant Basin. As of January 2015 its proved natural gas reserves are appraised at 2,179 Bcm.<sup>7</sup> Over three quarters of these resources lie in

<sup>1</sup> The significance of this qualification becomes clear in the section dealing with regional political and maritime disputes.

<sup>2</sup> US Energy Information Administration (EIA), *Iran*, 19 June 2015, <http://www.eia.gov/beta/international/analysis.cfm?iso=IRN>.

<sup>3</sup> Märta Carlsson and Niklas Granholm, "Russia and the Arctic: Analysis and Discussion of Russian Strategies", in *FOI Reports*, No. FOI-R-3596-SE (March 2013), [http://www.foi.se/ReportFiles/foir\\_3596.pdf](http://www.foi.se/ReportFiles/foir_3596.pdf).

<sup>4</sup> Christopher J. Schenk et al., "Assessment of Undiscovered Oil and Gas Resources of the Levant Basin Province, Eastern Mediterranean", in *U.S. Geological Survey Fact Sheets*, No. 2010-3014 (March 2010), <http://pubs.usgs.gov/fs/2010/3014>.

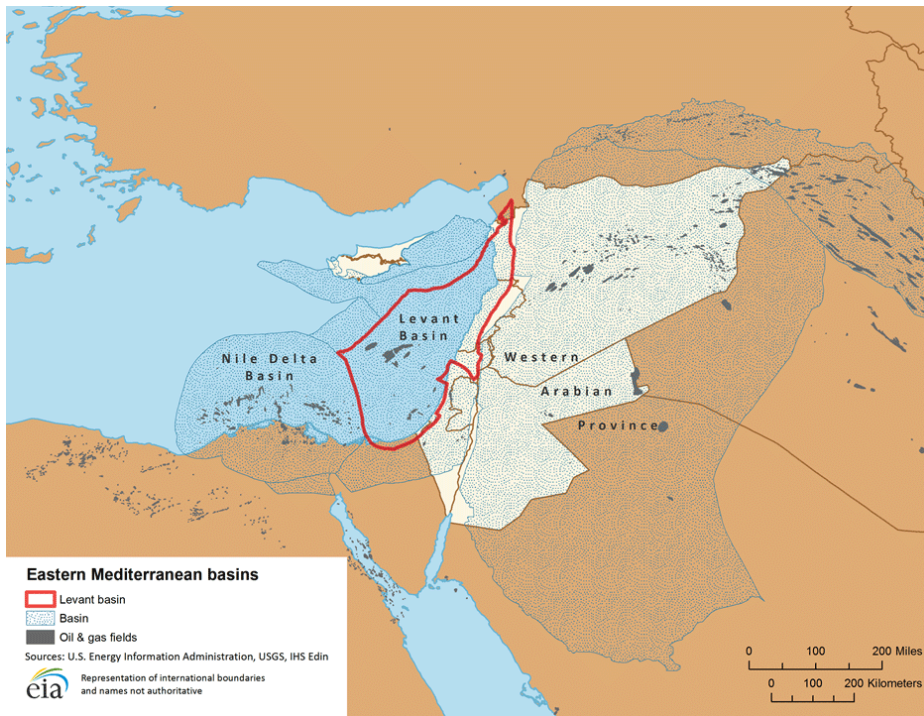
<sup>5</sup> EIA, *Iraq*, 30 January 2015, <http://www.eia.gov/beta/international/analysis.cfm?iso=IRQ>.

<sup>6</sup> EIA, *Algeria*, 11 March 2016, <https://www.eia.gov/beta/international/analysis.cfm?iso=DZA>.

<sup>7</sup> EIA, *Egypt*, 2 June 2015, <http://www.eia.gov/beta/international/analysis.cfm?iso=EGY>.

the Mediterranean Sea. Moreover, a May 2010 USGS assessment put the estimated mean of technically recoverable natural gas contained in Egypt's Nile Delta Basin at 6,310 Bcm, most of it in the sea,<sup>8</sup> nearly three times the present proved reserves of the country. As extensively argued in the chapter by Houda Ben Jannet Allal, Egypt's most recent find of August 2015, the Zohr field, said to be the largest ever Mediterranean find, is estimated to hold up to 850 Bcm. Located in Egypt's Shorouk, it is only 6 km away from the Egypt-Cyprus maritime border.

Figure 1 | Oil and natural gas fields in the eastern Mediterranean region



Source: EIA, *Overview of Oil and Natural Gas in the Eastern Mediterranean Region*, 15 August 2013, <https://www.eia.gov/beta/international/regions-topics.cfm?RegionTopicID=EM>.

Undoubtedly all this points to a future for the Eastern Mediterranean as an important gas province. This in turn has important implications as regards the energy outlook and economy of the countries of the region, such as increased energy supply security, re-

<sup>8</sup> Mark A. Kirschbaum et al., "Assessment of Undiscovered Oil and Gas Resources of the Nile Delta Basin Province, Eastern Mediterranean", in *U.S. Geological Survey Fact Sheets*, No. 2010-3027 (May 2010), <http://pubs.usgs.gov/fs/2010/3027>.

duced dependence on energy imports, and diverse economic opportunities. But so far progress in that direction has in general been frustratingly slow. Major reasons for this include volatility of energy prices and turbulent economic and financial conditions globally, uncertainties in the countries' energy policies, regulatory and fiscal policies and, not least, the region's own geopolitical challenges.

## 6.2 Gas Discoveries and Development

### 6.2.1 Israel

Israel has been at the forefront of exploration in the Eastern Mediterranean, persistently searching for hydrocarbons since 1969. The country made its first noteworthy offshore discoveries in 1999-2000: Noa (1.1 Bcm, production 2012) and Mari-B (42.5 Bcm, production 2004) at shallow waters offshore Ashkelon.<sup>9</sup> These small fields provided gas for domestic consumption and, as evidence of the region's offshore gas potential, helped sustain industry interest in further exploration.

Israel's first major deep-water find, Tamar, located 90 km west of Haifa, was discovered in January 2009 by a consortium including the US's Noble Energy and Israeli Isramco, Delek Drilling, Avner and Dor. In late 2010 a similar partnership containing Noble and Delek discovered the even bigger deep-water deposit of Leviathan, 50 km west of Tamar. The latter's recoverable reserves are nowadays appraised at 303 Bcm. Leviathan's reserves, initially estimated at 509-538 Bcm, have since been increased to 620 Bcm.<sup>10</sup> Other smaller offshore gas finds by Israel include Dalit (2009, 14.2 Bcm), Dolphin (2011, 2.3 Bcm), Shimson (2012, 8.5 Bcm), Tanin (2012, 34 Bcm) and Karish (2013, 51 Bcm).<sup>11</sup>

Between 2004 and 2011 Israel's gas consumption increased from 0.8 Bcm to a peak of 5 Bcm.<sup>12</sup> From 2008 onwards the country was also importing Egyptian gas to meet up to half of its demand.<sup>13</sup> Starting in early 2011, however, Egyptian supplies became

<sup>9</sup> EIA, *Overview of Oil and Natural Gas in the Eastern Mediterranean Region*, 15 August 2013, <https://www.eia.gov/beta/international/regions-topics.cfm?RegionTopicID=EM>.

<sup>10</sup> "Israel's Leviathan gas reserves estimate raised by 16 pct", in *Reuters*, 13 July 2014, <http://reut.rs/U1kqJJ>.

<sup>11</sup> EIA, *Overview of Oil and Natural Gas in the Eastern Mediterranean Region*, cit.

<sup>12</sup> Index Mundi, *Israel Dry Natural Gas Consumption by Year*, <http://www.indexmundi.com/energy.aspx?country=il&product=gas&graph=consumption>.

<sup>13</sup> Simone Tagliapietra, "Towards a New Eastern Mediterranean Energy Corridor? Natural Gas Developments between Market Opportunities and Geopolitical Risks", in *FEEM Note di Lavoro*, No. 12/2013

unreliable due to frequent sabotage attacks on the pipeline carrying the gas and on 23 April 2012, cancelling the relevant agreement, Egypt stopped sending gas to Israel altogether.<sup>14</sup> During this period, with Mari-B almost depleted, Israel's gas consumption plummeted as the country struggled to replace lost supplies and deal with power shortages.<sup>15</sup> This experience was a stark reminder to both the government and the public of Israel's vulnerability as regards energy supply security, and served to heighten the intensity of the debate concerning Israel's natural gas policy – that is, the extent to which Israel should prioritise energy independence over becoming a gas exporter.

Tamar's coming on-stream in April 2013 ended Israel's gas supply crisis. With the bulk of the gas dedicated to feeding the rapidly growing domestic market,<sup>16</sup> it now meets most of Israel's gas demand, with 80 percent of the production fuelling over half of the country's electricity generation while the rest is used by big industrial companies.<sup>17</sup> Tamar's timely development is a "rare success story" in the fledgling Israeli gas industry which has been held back by a host of regulatory obstacles since the discovery of a gas bonanza 5-6 years ago. Leviathan still remains undeveloped as plans towards that goal keep getting bogged down in political and regulatory controversies.

### 6.2.2 End of Leviathan's Development Saga?

To keep up with its growing domestic gas demand Israel is now relying on Tamar's expansion as well as Leviathan's long-awaited development. Especially in connection with the latter, there is also the no less important matter of Israel's becoming a gas exporter and thus reaping even more benefits from these resources<sup>18</sup> – economically by bringing in additional foreign investment and tens of billions of dollars in tax revenues, and geopolitically by helping to improve the country's relations with its neighbours. Indeed, it is thanks to Leviathan that the historically resource-poor Israel is now poised

(February 2013), <http://www.feem.it/getpage.aspx?id=5321>.

<sup>14</sup> "Egypt scraps Israel gas supply deal", in *BBC News*, 23 April 2012, <http://www.bbc.com/news/world-middle-east-17808954>.

<sup>15</sup> "With unrest in Egypt, Israel faces blackouts", in *Reuters*, 28 February 2012, <http://reut.rs/xPX06N>.

<sup>16</sup> Israel's total gas demand is projected to rise from about 9 Bcm in 2015 to 20 Bcm in 2035. See IEA, *World Energy Outlook 2013*, <http://www.iea.org/publications/freepublications/publication/world-energy-outlook-2013.html>.

<sup>17</sup> OECD, *OECD Economic Surveys: Israel 2016*, January 2016, <http://www.oecd.org/eco/surveys/economic-survey-israel.htm>.

<sup>18</sup> The advent of gas has already brought some economic benefits to the country: in February 2015 the government put the last decade's savings thanks to increased use of gas at about 9 billion dollars. See Sharon Udasin, "Natural gas consumption hits record highs", in *The Jerusalem Post*, 24 March 2015, <http://go.shr.lc/25Mh7Y5>.



to become an energy exporter. Double the size of Tamar, Leviathan has been described as a game-changer for energy-dependent Israel. Indeed, at the time of its discovery it was one of the world's largest offshore gas finds of the past decade, prompting the then energy minister of Israel to talk about "the most important energy news since the founding of the state."<sup>19</sup>

Yet, more than five years on, Leviathan's path to development is still not absolutely clear. Progress is constantly being held up by controversies over various regulatory and policy issues. The issue of regulating gas exports has been one of the most sensitive. It took more than two years for Israel to decide whether to allow gas exports and if so how to set the balance between export and ensuring the country's future gas supply security. Following the recommendations of the Zemach Committee<sup>20</sup> in August 2012 and taking into account concerns about Israel's energy supply security, as well as the fact that companies need to be able to export part of the gas if they are to continue exploring and also investing in the development of the country's gas sector, the government decided on 23 June 2013 on a limit of 40 percent of the reserves.<sup>21</sup> Finally in October 2013, the Israeli Supreme Court upheld this decision by rejecting petitions against it from environmental NGOs and some opposition politicians.<sup>22</sup>

However, this wasn't the end of regulatory uncertainties that kept delaying gas field development/expansion plans. Another highly divisive issue concerns the actions of the Israeli Antitrust Authority (IAA) and the government's handling of the resulting situation. In November 2012, IAA General-Director David Gilo announced that the Tamar partners, including Noble, Delek, et al., have "a monopoly on the supply of natural gas" in Israel.<sup>23</sup> This meant that they were subject to special restrictions as regards their natural gas activities not just in Tamar but also elsewhere, e.g., Leviathan. In January 2014 Noble and Delek were informed that, unless they took measures to comply with "the conditions required [by IAA] for effective competition, action

<sup>19</sup> Ethan Bronner (2010), "Gas field confirmed off coast of Israel", in *The New York Times*, 30 December 2010, <http://nyti.ms/1PPIU09>.

<sup>20</sup> A special inter-ministerial committee appointed by the government to examine its natural gas policy, headed by Shaul Tzemach, the then Energy Ministry Director-General. See Israel, *The Recommendations of the Inter-Ministerial Committee to Examine the Government's Policy Regarding Natural Gas in Israel*, September 2012, <http://energy.gov.il/English/Subjects/Natural%20Gas/Pages/GxmsMniNGPolicyIsrael.aspx>.

<sup>21</sup> "Israeli government approves 40 pct limit on natural gas exports", in *Reuters*, 23 June 2013, <http://reut.rs/15vpjcx>.

<sup>22</sup> Sharon Udasin, "Government approves natural gas export policy", in *The Jerusalem Post*, 23 June 2013, <http://go.shr.lc/1YfRPfe>; and Hila Raz, "Supreme Court rejects petition to halt Israel's natural gas exports", in *Haaretz*, 21 October 2013.

<sup>23</sup> Israel Antitrust Authority, *The General Director of Restrictive Trade Practices Declares the Partners in the Natural Gas Reservoir 'Tamar' to have a Monopoly on Israel's Natural Gas Supply*, 13 November 2012, <http://www.antitrust.gov.il/eng/subject/182/item/32858.aspx>.

will be taken against them in court for their removal from Leviathan.”<sup>24</sup> It was now the government’s task to negotiate with the companies the terms that would break their control over Israel’s gas supplies without putting them off from investing in the development of Leviathan.

After a long-drawn-out process, a framework was announced in July 2015.<sup>25</sup> Despite strong resistance from the civil society and from the Knesset, as well as the IAA’s refusal to sanction it, Prime Minister Netanyahu (acting as Economy Minister to overrule IAA) approved the deal in December 2015.<sup>26</sup> This action removed a major obstacle in the way of Leviathan’s development and Israeli gas export plans. Although effective as of the Prime Minister’s approval, the agreement is still subject to a High Court of Justice hearing, which started in February 2016, about a number of petitions seeking to block the implementation of the natural gas regulatory framework.<sup>27</sup>

On 24 February 2016 the Leviathan partners submitted their latest version of the gas field’s development to the Israeli Ministry of Energy. With the investment decision for the project expected by the end of 2016, the plan foresees production at Leviathan to begin by the end of 2019. The new plan increases Leviathan’s production capacity to 21 Bcm/year from the 16 Bcm/year of the original plan. In addition to Leviathan’s development, the framework agreement covers expansion of production at Tamar. The Leviathan plan foresees several production wells linked by a subsea pipeline to a fixed gas treatment platform whence the gas will be sent via pipelines to the Israeli gas grid and to export destinations.<sup>28</sup>

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<sup>24</sup> Israel Antitrust Authority, *Safeguarding the Natural Gas Market from Monopolies*, 22 January 2014, <http://www.antitrust.gov.il/eng/subject/182/item/33008.aspx>. However, as one researcher put it: “Since Israel is a relatively small market for gas, with 85 percent consumed by only one source – the Israeli Electric Company – it was hard to see how competition can emerge over the remaining 15 percent, and by whom.” See Elai Rettig, *Obstacles to Israeli Natural Gas Development*, paper read at the conference on “Global Energy Debates and the East Mediterranean”, Nicosia, 15 November 2015.

<sup>25</sup> It stipulated the sale of two smaller gas fields, Karish and Tanin, to a new developer, and reduction of the two companies’ shares in Tamar and Leviathan. In return, they were offered more favourable conditions that would enable them to develop Leviathan and to export gas more quickly.

<sup>26</sup> Sharon Udasin, “Netanyahu signs off on controversial natural gas deal”, in *The Jerusalem Post*, 17 December 2015, <http://go.shr.lc/1m9ZVsG>. To do so the Prime Minister went against the Knesset Economics Committee’s advice and, in his capacity as the economy minister, invoked a legal clause (Article 52 of the Restrictive Trade Practices Law) in order to overrule the Antitrust Authority.

<sup>27</sup> Hedy Cohen, “Netanyahu: Gas agreement vital for economy, security”, in *Globes*, 14 February 2016, <http://iglob.es/?en1102914>.

<sup>28</sup> “Revised plan pushes Leviathan development”, in *Oil&Gas Journal*, 25 February 2016, <http://www.ogj.com/articles/2016/02/revised-plan-pushes-leviathan-development.html>.

### 6.2.3 Cyprus

RoC has been exploring for offshore hydrocarbons since 2006 in a 13-block exploration area to the south of the island. So far it has held two international tenders (in 2007 and 2012) and recently announced plans for a third.<sup>29</sup> In the first round block 12 was licensed to Noble Energy and its Israeli partners Delek Drilling and Avner Oil (companies that are also partners in Israel's Leviathan and Tamar fields). The second round resulted in blocks 2, 3 and 9 being leased to Italian-South Korean Eni-KOGAS; and blocks 10 and 11 to France's Total.<sup>30</sup>

The first drilling by Noble and Delek in the autumn of 2011 at the so-called Aphrodite site resulted in the discovery of an estimated mean of 147-198 Bcm of natural gas. The latest appraisal put the size of the reservoir at 128 Bcm.<sup>31</sup> Though not exactly massive, this is still a significant volume of gas. Given the small size of the country and its domestic market, most of the gas can be exported, provided other conditions are right for the field's development, e.g., availability of markets, and high enough gas prices to ensure commercial viability of development projects.<sup>32</sup> After Eni's failure in 2014-15 to detect any exploitable gas in two drilling operations in block 9,<sup>33</sup> and Total's finding of no tangible evidence of deposits worth drilling for in blocks 10 and 11,<sup>34</sup> Aphrodite remains for now the only Cypriot gas discovery.

RoC made a decision early on to construct a land-based LNG plant,<sup>35</sup> which offers the greatest flexibility in exporting the surplus gas, including to distant lucrative markets. Also it was seen by RoC as a way to turn the island into an "energy hub" capable of attracting natural gas from neighbouring countries (Israel, Lebanon) for processing and shipping.<sup>36</sup> However, after a while it became clear that the Aphrodite gas alone was not

<sup>29</sup> Elias Hazou, "Third licensing round for EEZ", in *Cyprus Mail*, 16 February 2016, <http://cyprus-mail.com/?p=76788>.

<sup>30</sup> Ayla Gürel, Fiona Mullen and Harry Tzimitras, "The Cyprus Hydrocarbons Issue: Context, Positions and Future Scenarios", in *PRIO Cyprus Centre Reports*, No. 1/2013, <http://www.prio.org/Publications/Publication/?x=7365>.

<sup>31</sup> "Firms developing Cyprus gas field raise reserve estimate 12 pct", in *Reuters*, 18 November 2014, <http://reut.rs/11gnMMJ>.

<sup>32</sup> Sergey Paltsev et al., *Interim Report for the Study Natural Gas Monetization Pathways for Cyprus. Economics of Project Development Options*, Cambridge, MIT Energy Initiative August 2013, [http://mitei.mit.edu/system/files/Cyprus\\_NG\\_Report.pdf](http://mitei.mit.edu/system/files/Cyprus_NG_Report.pdf).

<sup>33</sup> "Eni, KOGAS find no exploitable hydrocarbons off Cyprus", in *Reuters*, 26 March 2015, <http://reut.rs/1GsPw5>.

<sup>34</sup> George Psyllides, "Total likely to ditch Cyprus offshore gas search", in *Cyprus Mail*, 21 January 2015, <http://cyprus-mail.com/?p=42134>.

<sup>35</sup> "East Mediterranean gas politics: A third corridor?", in *Natural Gas Europe*, 28 March 2012, <http://www.naturalgaseurope.com/east-mediterranean-gas-third-corridor>; Cyprus News Agency, "A decision for LNG terminal has already been taken, Minister says", 7 June 2012.

<sup>36</sup> Karen Ayat, "Lakkotrypis: Cyprus and ENI/KOGAS sign MoU", in *Natural Gas Europe*, 30 July 2014,

sufficient to make an LNG terminal commercially viable.<sup>37</sup> Encouraged by apparent possibilities of pooling resources with Israel<sup>38</sup> and/or of additional finds in further drillings in block 12 and other licensed blocks, until the summer of 2014 the RoC government continued to pursue what it called its “strategic goal” of building an onshore LNG plant.<sup>39</sup> The idea which had started fading was effectively abandoned in early 2015 when it became clear that the chances of finding the required additional volumes of gas in the near future were quite slim.

Since then, and especially with the plunge in petrol prices that also affected gas prices and hence the oil and gas investment climate, there has been a shift towards the apparently more feasible idea of exporting to regional markets, such as Egypt. In June 2015 Aphrodite partners Nobel and Delek submitted to the RoC government a development plan which includes construction of an independent floating production platform and a gas pipeline to Egypt.<sup>40</sup> According to a Cypriot energy analyst, however, the cost identified so far for getting the gas to Egypt, let alone exporting it – say, to Europe – is too high to make such plans feasible.<sup>41</sup>

Another problem holding up exploitation of Aphrodite, which is partially in Israeli waters, is the continued lack of a RoC-Israeli unitisation agreement. The parties’ differing views over the field’s extent into the Israeli EEZ seem to have become an obstacle in the inter-governmental negotiations for such an agreement which have been ongoing for over five years. Israel now claims that the gas reservoir extends into its EEZ in commercial quantities, while Cyprus asserts that only 1 percent of it is on the Israeli side.<sup>42</sup> In the absence of a unitisation agreement, the two sides could in theory go ahead separately developing their part of the Aphrodite field, although experts think neither side would want to go down that road.

What created some excitement, however, was the announcement on 23 November

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<http://www.naturalgaseurope.com/eni-kogas-cyprus-gas-mou>.

<sup>37</sup> Elias Hazou, “Experts debate the viability of a LNG plant”, in *Cyprus Mail*, 25 November 2013, <http://cyprus-mail.com/?p=13854>.

<sup>38</sup> “Anastasiades urges Israel to export gas from Cyprus”, in *Kathimerini*, 8 August 2013, <http://www.ekathimerini.com/152854>; Elias Hazou, “Minister pushes plan for joint gas exports with Israel”, in *Cyprus Mail*, 22 October 2013, <http://cyprus-mail.com/?p=11567>.

<sup>39</sup> Elias Hazou, “Noble exploring floating LNG option”, in *Cyprus Mail*, 3 January 2014, <http://cyprus-mail.com/?p=16119>; “Talks with Egypt on potential natural gas sale after ENI-KOGAS drilling results”, in *Cyprus Mail*, 21 August 2014, <http://cyprus-mail.com/?p=31141>.

<sup>40</sup> “Delek and Noble present Aphrodite development plan”, in *Globes*, 11 June 2015, <http://iglob.es/?en1043737>.

<sup>41</sup> Charles Ellinas, “Energy turbulence”, in *In-Cyprus*, 26 December 2015, <http://wp.me/p59S63-9RI>.

<sup>42</sup> Hedy Cohen, “Cypriot President to visit Israel for gas talks”, in *Globes*, 10 November 2015, <http://iglob.es/?en1080015>; Hedy Cohen, “Cyprus unhappy with Israel’s Ishai discovery declaration”, in *Globes*, 22 November 2015, <http://iglob.es/?en1083018>.

2015 of acquisition by British Gas (BG) of half of Noble's interest (amounting to 35 percent) in the RoC's block 12 which includes Aphrodite. The RoC government hopes that this could facilitate the field's development and enable Cypriot gas exports to Europe via BG's LNG plant at Idku in Egypt, with the Cypriot energy minister saying production at Aphrodite could start in 2020. Yet, energy analysts are more cautious, pointing out that BG's involvement does not solve the problem of low gas prices discouraging investment, a situation which is generally expected to prevail into the early part of the next decade.<sup>43</sup>

As regards exploration in other RoC blocks, Total, which gave up its interest in block 10 while renewing in December 2015 its licence in block 11, seems to be intending to drill there in the summer of 2016.<sup>44</sup> The government's efforts to keep Total in Cyprus, not least for strategic reasons, combined with the Egyptian discovery in August of the giant Zohr field only 6 km away, helped to convince the company to stay and carry out further exploration in block 11. Eni-KOGAS also received a two-year extension of its lease to blocks 2, 3 and 9, with drilling tentatively scheduled for mid-2017.<sup>45</sup> Meanwhile, the consortium is "to re-evaluate the energy potential [...] following the developments in the Egyptian EEZ with the discovery of the Zohr deposit."<sup>46</sup>

### 6.3 Regional Political and Maritime Disputes

The Eastern Mediterranean is mired in long-standing political conflicts and a number of complex maritime border disputes. Some of the maritime disputes here even fall outside the standard mechanisms for international maritime dispute settlement because the parties to the dispute are unable to recognise one another's formal status due to the nature of an associated political conflict. Of interest here are Israel's sea border dispute with Lebanon which, since 2007, has come to involve Cyprus too, and its potential dispute with Egypt, as well as disputes relating to the Cyprus problem and involving, in particular, the island's Greek Cypriot and Turkish Cypriot communities and Turkey.

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<sup>43</sup> Charles Ellinas, "East Med gas export risk", in *In-Cyprus*, 10 January 2016, <http://wp.me/p59S63-a8Y>.

<sup>44</sup> George Telaveris, "Total is back in Cyprus", in *In-Cyprus*, 5 December 2015, <http://wp.me/p59S63-9oU>.

<sup>45</sup> Angelos Anastasiou, "Government extends ENI-KOGAS gas exploration by two years", in *Cyprus Mail*, 28 December 2015, <http://cyprus-mail.com/?p=72233>.

<sup>46</sup> "ENI licence renewed", in *In-Cyprus*, 28 December 2015, <http://wp.me/p59S63-9UD>.

### 6.3.1 Israel-Lebanon Dispute and Cyprus

Since the large Levant Basin gas discoveries, Israel and Lebanon have been at loggerheads over a triangular sea area of 860 km<sup>2</sup> which they both claim. In fact, in Lebanon there is even a debate that the reservoirs discovered by Israel actually extend into Lebanese waters and that Israel is “stealing Lebanon’s gas.”<sup>47</sup>

The Israeli-Lebanese maritime border dispute flared especially after the Israel-RoC EEZ delimitation agreement of December 2010, when Lebanon protested that the zones demarcated in the said agreement “absorb” part of Lebanon’s EEZ.<sup>48</sup> This in effect made the RoC – which negotiated its boundaries with both Israel and Lebanon – a party in a complex diplomatic row. Indeed, Lebanon has not yet ratified its agreement with the RoC and now says it will do so after it has been renegotiated. However, this cannot happen unless the RoC manages first to renegotiate its boundary with Israel, which the latter is unlikely to accept.

Various factors complicate settlement of the Israel-Lebanon maritime dispute, including the fact that the two countries are formally at war and the lack of mutually agreed land borders.<sup>49</sup> There have been efforts to get the parties to negotiate under UN auspices as well as with the US facilitation,<sup>50</sup> but with not much success to date. Although an intensified confrontation between the two countries on the issue remains possible, both sides have so far managed to keep trouble away by being careful about any activity in the disputed areas pending diplomatic initiatives to help find a compromise.<sup>51</sup>

### 6.3.2 Israel-Egypt Dispute

At present there is no maritime delimitation agreement between Israel and Egypt even though both countries are engaged in serious exploration in their coastal areas. Howev-

<sup>47</sup> Matt Nash, “Is Israel stealing Lebanon’s gas?”, in *Now*, 8 July 2013, <http://mme.cm/QAWS00>; Jean Aziz, “Will Offshore Gas Spark New Lebanon-Israel Conflict?”, in *Al-Monitor*, 10 July 2013, <http://almon.co/ax7>.

<sup>48</sup> Adnan Mansour, *Letter from the Minister for Foreign Affairs and Emigrants of Lebanon addressed to the Secretary-General of the United Nations* (UN Doc. 2082.11D), 20 June 2011, [http://www.un.org/depts/los/LEGISLATIONANDTREATIES/PDFFILES/communications/lbn\\_re\\_cyp\\_isr\\_agreement2010.pdf](http://www.un.org/depts/los/LEGISLATIONANDTREATIES/PDFFILES/communications/lbn_re_cyp_isr_agreement2010.pdf).

<sup>49</sup> Martin Wählisch, “Israel-Lebanon Offshore Oil & Gas Dispute: Rules of International Maritime Law”, in *ASIL Insights*, Vol. 51, No. 31 (5 December 2012), <http://ssrn.com/abstract=2078583>.

<sup>50</sup> Nicholas Blanford, “Maritime gas feud moves toward resolution”, in *The Daily Star*, 5 April 2012, <http://www.saidaonline.com/en/news.php?go=fullnews&newsid=35953>.

<sup>51</sup> Amiram Barkat, “Israel-Lebanon deadlocked over offshore border”, in *Globes*, 22 April 2014, <http://iglob.es/?en933038>.

er, the issue could arise at some point given some of the relevant discussions in Egypt. Although no formal moves have ever been made by Egyptian governments, claims have been made, including by people in high level positions in the administration, about Israel's gas finds partly lying in Egyptian waters.<sup>52</sup>

Demarcation of maritime borders between Egypt and Israel could indeed be potentially rather complex. This is not so much because of claims such as the one mentioned above, but more importantly because of the possibility of a future state of Palestine that would have Egypt, Cyprus and Israel as maritime neighbours. In such a scenario, determination of Palestine's EEZ would most likely necessitate revision of the present Egypt-RoC and Israel-RoC sea border agreements, the result of which would, at the same time, be relevant to whether Egypt and Israel would still remain maritime neighbours and if so how their border would be delimited. This means, at any rate, that some of the existing concessions close to these border areas, especially on the Israeli side, could in the future become open to challenge.<sup>53</sup>

### 6.3.3 Israel-Turkey Dispute

Since the 2010 Mavi Marmara crisis relations between Israel and Turkey have been strained, with no high-level political dialogue, military cooperation suspended and mutual diplomatic representation reduced to the level of second secretary. Yet, the two countries' commercial ties have continued to thrive, a fact that has led many to wonder whether such ties could expand further to include a pipeline deal to carry Israeli gas to Turkey and possibly from there to Europe.<sup>54</sup> In March 2013 Prime Minister Benjamin Netanyahu apologised to Turkey for deaths during the Mavi Marmara incident. This was followed by negotiations to normalise the relations between the two former allies. For a while an Israeli-Turkey rapprochement coupled with Israeli gas exports to Turkey looked like a real possibility.<sup>55</sup> However, a breakthrough remained elusive as the climate for mending fences disappeared in the run-up towards the August 2014

<sup>52</sup> Hélène Machline, "L'Égypte pense revendiquer le gaz des gisements Tamar et Leviathan", in *Economist*, 27 January 2011, <http://xfu.it/V8zLdP>; Fahmi Huwaidi, "Israel's plunder of Egyptian gas must be investigated", in *Middle East Monitor*, 13 December 2013, <https://shar.es/1jmNQk>.

<sup>53</sup> James Stocker, "No EEZ Solution: The Politics of Oil and Gas in the Eastern Mediterranean", in *The Middle East Journal*, Vol. 66, No. 4 (Autumn 2012), p. 579-597.

<sup>54</sup> Dan Arbell, "Turkey-Israel relations: A political low point and an economic high point", in *Brookings Markaz*, 19 February 2015, <http://brook.gs/1Vz1y0s>.

<sup>55</sup> Matthew J. Bryza, "Eastern Mediterranean Natural Gas: Potential for Historic Breakthroughs Among Israel, Turkey, and Cyprus", in *Turkish Policy Quarterly*, Vol. 12, No. 3 (Fall 2013), p. 35-44, [http://www.turkishpolicy.com/dosyalar/files/vol\\_12-no\\_3-bryza.pdf](http://www.turkishpolicy.com/dosyalar/files/vol_12-no_3-bryza.pdf).

presidential elections in Turkey which coincided with another Israeli military operation in Gaza.<sup>56</sup>

Since December 2015 negotiations for normalisation of ties have picked up again while President Erdoğan appears to have changed his habitual scathing rhetoric towards Israel and started making statements like Turkish-Israeli rapprochement is “to the benefit of the whole region” and Israel needs Turkey but “we also need Israel.” The shift came after the fallout between Turkey and Russia less than a month earlier due to Turkey’s downing of a Russian warplane at the Turkish-Syrian border. President Putin’s subsequent reaction of imposing economic sanctions on Turkey, although not involving energy trade, nevertheless seems to have increased Turkey’s unease about its dependence on Russia for more than half of its natural gas supplies and its sense of urgency for additional alternative resources which Israel’s Leviathan field could meet.<sup>57</sup> However, currently it is doubtful that Israel and Turkey will be able to achieve normalisation any time soon. While signals from the Turkish side indicate a definite keenness to move forward, Israel looks much less ready, for various geopolitical reasons. Although it remains engaged in the process and wants to improve relations with Turkey, Israel feels that (a) its gains from such a development will be rather limited so long as Erdoğan remains in power; and hence (b) at this point in time it may be more critical to protect its interests which depend on its ties with other regional actors<sup>58</sup> and, most importantly, with Russia whose leader – as mentioned above – is waging a campaign against Turkey and thus is hostile to an Israeli-Turkish rapprochement.<sup>59</sup>

### *6.3.4 The Cyprus Problem and Offshore Exploration and Maritime Disputes*

The RoC was established in 1960 as a bi-communal state of the Greek Cypriots and Turkish Cypriots. This structure broke down in 1963 due to violent inter-communal strife and the Greek Cypriots assumed sole governance of the RoC. Over time and without any formalities – such as a renegotiation of the relevant international treaties – having

<sup>56</sup> Arad Nir, “Relations with Turkey sink lower after Erdogan’s Israel comments”, in *Al-Monitor*, 21 July 2014, <http://almon.co/251n>.

<sup>57</sup> Kadri Gürsel, “Did Erdogan give up Gaza in return for Israeli gas?”, in *Al-Monitor*, 23 December 2015, <http://almon.co/2khi>; Barak Ravid, “Five years after Gaza Flotilla Raid, Israel and Turkey reach understandings on ending crisis”, in *Haaretz*, 17 December 2015, <http://www.haaretz.com/israel-news/1.692478>.

<sup>58</sup> Yossi Melman, “Three’s company: Israel, Turkey, and Egypt”, in *The Jerusalem Post*, 5 February 2016, <http://go.shr.lc/20eqaeP>.

<sup>59</sup> Russia’s value relates primarily to Israeli security concerns regarding Syria and Lebanon, especially Netanyahu’s efforts to convince Putin to disengage himself from Iran and Hezbollah. See Ben Caspit, “Why Israel needs Putin more than it needs Erdogan”, in *Al-Monitor*, 7 March 2016, <http://almon.co/2lyy>.



taken place, this Greek Cypriot administration came to be internationally accepted as the legitimate RoC government. In 1974, in response to a coup by Greek and Greek Cypriot armed forces seeking to effect *enosis* (union of Cyprus with Greece), Turkey intervened militarily<sup>60</sup> and divided the island into a Turkish-Cypriot-administered northern sector guarded by the Turkish army, and a southern sector controlled by the Greek-Cypriot-administered RoC. In 1983 the Turkish Cypriots established the Turkish Republic of Northern Cyprus (TRNC) which is recognised only by Turkey. The latter does not accept the RoC's statehood. In May 2004 the RoC, formally acting on behalf of the whole island, became an EU member state.<sup>61</sup>

The latest round of UN-sponsored Cyprus negotiations began in 2008 and is still carrying on despite being interrupted by periods of stalemate every few years. Such hitches are almost always related to the parties' differences on the so-called "sovereignty issue,"<sup>62</sup> as happened in the latest offshore exploration crisis of autumn 2014.<sup>63</sup> At the root of this crisis was a dispute between Turkish Cypriots and Turkey, on the one side, and Greek Cypriots, on the other, over sovereign rights in the island's EEZ, which has in turn accentuated the parties' fundamental differences at the settlement negotiations on the crucial and persistent question of sovereignty.<sup>64</sup>

The Greek Cypriots, being in charge of the internationally recognised (although *de facto* Greek-Cypriot-administered) RoC government, maintain that they have the sovereign right to explore offshore natural resources and that this right is "inalienable and non-negotiable" and not conditional on a Cyprus solution. They accept that natural resources are shared and will come under the two communities' joint competence in the event of a reunification of the island but dismiss any suggestion to share the revenues before such a settlement. The international community generally supports the Greek Cypriot position, although some international actors have emphasized more firmly than others that revenues must be shared with the Turkish Cypriots.<sup>65</sup>

Contrariwise, the Turkish Cypriots and Turkey argue that the RoC, which was

<sup>60</sup> Turkey and Turkish Cypriots officially describe this action as a "peace operation" while Greek Cypriots and most of the international community view it as an "invasion."

<sup>61</sup> For a more detailed exposition of the conflict, see Ayla Gürel, Fiona Mullen and Harry Tzimitras, "The Cyprus Hydrocarbons Issue", cit.

<sup>62</sup> Security Council Report, *January 2014 Monthly Forecast: Cyprus*, 20 December 2013, [http://www.securitycouncilreport.org/monthly-forecast/2014-01/cyprus\\_3.php](http://www.securitycouncilreport.org/monthly-forecast/2014-01/cyprus_3.php).

<sup>63</sup> Stefanos Evripidou, "Gas stand-off strangling peace talks hopes", in *Cyprus Mail*, 26 October 2014, <http://cyprus-mail.com/?p=35614>.

<sup>64</sup> For a comprehensive discussion of the positions of all interested parties and references, see Ayla Gürel, Fiona Mullen and Harry Tzimitras, "The Cyprus Hydrocarbons Issue", cit., p. 41-60.

<sup>65</sup> Ayla Gürel and Laura Le Cornu, "Can Gas Catalyse Peace in the Eastern Mediterranean?", in *The International Spectator*, Vol. 49, No. 2 (June 2014), p. 11-33.

co-founded by both communities, cannot legitimately be represented by the Greek Cypriots alone. Therefore, the latter may not unilaterally exercise jointly possessed sovereign rights, as in the case of rights in the EEZ. So, Turkey and the Turkish Cypriots argue, offshore exploration by the Greek Cypriots is a unilateral act of one community and would be reciprocated by the (internationally unrecognised) TRNC's own unilateral steps. Hence the TRNC-Turkey continental shelf delimitation agreement of September 2011, and TRNC's issuing about the same time of offshore exploration licences to the national Turkish Petroleum Corporation (TPAO) including in areas which partly overlap the RoC exploration area in the island's southeast, which came in response to Noble's first drilling at the Aphrodite in RoC block 12. Meanwhile, Turkey also claims that parts of RoC blocks 1, 4, 5, 6 and 7 in the southwest overlap its own continental shelf and has made quite strong statements about its intentions, should there be any exploration by the RoC in these areas. Perhaps not accidentally, these five blocks have to date not been licensed. In the same logic, seismic surveys have been conducted by TPAO on behalf of the TRNC in areas to the south of the island, most recently in October-December 2014.<sup>66</sup> The latter expedition was an action of "equal political significance" meant to counter the RoC-authorized drilling activity in Block 9 by Eni; to which the Greek Cypriot leader and RoC president responded by suspending his side's participation in the settlement negotiations.<sup>67</sup> This crisis lasted until April 2015, with no further negotiations during this period.

Thus, contrary to the common expectation that the potential commercial benefits of the island's offshore natural gas resources would act as an incentive to solve the Cyprus problem, the sovereignty-related dispute over exercise of offshore exploration and exploitation rights prior to a settlement has actually hardened the parties' stances and hence complicated the settlement negotiations.

## 6.4 Markets for Eastern Mediterranean Gas

### 6.4.1 Israel

Israel and Cyprus are desperate to monetise their gas finds, which will happen only if they can secure export markets for the gas. Thus the two countries, both separately and together, have been pursuing a number of options.

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<sup>66</sup> "We are watching every step taken by Greek Cypriots and Greeks", in *The Kibkom Times*, 23 October, <http://kibkomtimes.com/?p=2669>.

<sup>67</sup> Stefanos Evripidou, "Gas stand-off strangling peace talks hopes", cit.

The Israeli government and partners in Leviathan and Tamar have been looking at various possible gas export options, including pipelines to regional markets (Palestinian Authority, Jordan and Egypt as well as Turkey and Greece), LNG schemes for more distant markets and compressed natural gas (CNG) for closer markets. Until spring 2014 Australian Woodside Petroleum was in talks with Israel for the purpose of purchasing a 25 percent interest in Leviathan. After 18 months of negotiations, Woodside Petroleum pulled out due to failure to reach a “commercially acceptable outcome.”<sup>68</sup> This outcome indicated that Israel preferred, at any rate in the short and medium term, a regional pipelines strategy rather than options involving construction of an LNG or floating LNG (FLNG) plant.<sup>69</sup>

With focus on regional opportunities for the purpose of monetising Israeli gas resources through exports, there are now a number of preliminary agreements signed between Tamar or Leviathan developers and customers in some of Israel’s immediate neighbours. In general, these deals are politically delicate and still have to develop into binding contracts.

In January 2014 the Leviathan partners made a preliminary agreement to sell 4.75 Bcm of gas from Leviathan over a period of 20 years (said to be worth 1.2 billion dollars according to prices at that time) to the West Bank utility Palestine Power Generation Company.<sup>70</sup> However, 15 months later the Palestinian company cancelled the deal, citing regulatory and other delays in the development of the field.<sup>71</sup> Some reports suggested political reasons, linking the cancellation to pressure on the Palestinian Authority from the opponents to the deal among Palestinian politicians and civil society groups, including the National Committee of the Boycott, Divestment and Sanctions (BDS).<sup>72</sup>

As regards gas exports to Jordan, until now there have been two separate tracks, one for gas from Leviathan and the other from Tamar. The US State Department is known to have been actively involved in the negotiations concerning both. The US supports such deals between Israel and its neighbours as a means of enhancing stability in the Eastern Mediterranean by “fostering a new level of cooperation between the countries in the region.”<sup>73</sup>

<sup>68</sup> Angela Macdonald-Smith, “Woodside pulls out of Leviathan project”, in *The Sydney Morning Herald*, 21 May 2014, <http://www.smh.com.au/action/printArticle?id=5442348>.

<sup>69</sup> Karen Ayat, “Noble Energy’s pipeline strategy in the East Med”, in *Natural Gas Europe*, 13 November 2014, <http://www.naturalgaseurope.com/noble-energy-pipeline-strategy-in-the-east-med>.

<sup>70</sup> “Palestinian firm is first to sign gas deal with Israel’s Leviathan”, in *Jewish Telegraphic Agency*, 7 January 2014, <http://www.jta.org/?p=836493>.

<sup>71</sup> “Palestine power firm cancels Leviathan natural gas deal”, in *Reuters*, 11 March 2015, <http://reut.rs/1Bq66xb>.

<sup>72</sup> Dania Akkad, “Palestinians call on PA to cancel Israeli gas deal”, in *Middle East Eye*, 18 February 2015, <https://shar.es/1j0H7X>; Dania Akkad, “Palestinian company calls off \$1.2bn Israeli gas deal”, in *Middle East Eye*, 11 March 2015, <https://shar.es/1j0H6D>.

<sup>73</sup> Amiram Barakat, “US special envoy: Gas fields must be developed quickly”, in *Globes*, 4 January 2015,

In February 2014 Noble and Delek made a preliminary deal to sell, over a period of 15 years, up to 2.2 Bcm of gas from the Tamar field to Jordan. The gas would be sold to two private customers, namely the Jordanian companies Arab Potash and Jordan Bromine. This is a case where things seem to be going forward. In 2015 the Israeli Energy Ministry as well as Prime Minister Netanyahu authorised the agreement. On 10 March 2016, it was reported that the first natural gas pipeline to Jordan, currently under construction, was scheduled to begin delivering Tamar gas to the two Jordanian companies in 2017. Also mentioned in the report was that a second pipeline was to be built for the purpose of supplying gas from the Leviathan reservoir to Jordan's National Electric Power Company (NEPCO).<sup>74</sup>

This second pipeline is associated with a non-binding letter of intent (LoI) signed by Noble, acting on behalf of the partners, in March 2014. The LoI concerns supply of about 45 Bcm of natural gas from Leviathan to NEPCO over a 15-year period.<sup>75</sup> This preliminary agreement which has yet to be turned into a binding deal has since run into trouble, however. News in February 2016 of renewed negotiations between Noble and the Jordanian government to carry things forward in that direction triggered a forceful political and public campaign in Jordan against any deal to import gas from Israel.<sup>76</sup> The Jordanian Energy Minister Ibrahim Saif stated that there was no deal yet and that the government was still reviewing the relevant preliminary agreement in light of developments in the energy market.<sup>77</sup>

Israel has also been hoping to export gas to energy-thirsty Egypt, an option which became more feasible after Abdel Fattah al Sisi's take-over of government in July 2013. In May 2014 Noble Energy broke the news about a letter of intent between the Tamar partners and Union Fenosa Gas (UFG) for the supply of natural gas from Tamar to UFG's existing LNG facilities in Damietta, Egypt. The non-binding agreement concerns exports of up to 70 Bcm of natural gas over 15 years via the Damietta plant.<sup>78</sup>

<http://iglob.es/?en998337>.

<sup>74</sup> Noble Energy, *Noble Energy announces agreement to sell Tamar gas to multiple customers in Jordan*, 19 February 2014, <http://investors.nobleenergyinc.com/releasedetail.cfm?ReleaseID=826568>; Sharon Udasin, "Israel approves gas export deal with Jordan", in *The Jerusalem Post*, 4 February 2015, <http://go.shr.lc/1Kfy15U>; "Jordan to receive natural gas from Israeli pipeline by 2017", in *Albawaba*, 15 March 2016, <http://www.albawaba.com/node/817094>.

<sup>75</sup> Sharon Udasin, "Israel's Leviathan signs preliminary deal to sell Jordan 15-year gas supply", in *The Jerusalem Post*, 9 March 2014, <http://go.shr.lc/1XiGafq>.

<sup>76</sup> Maayan Groisman, "Jordanian BDS campaign launched against renewed negotiations for Israeli gas imports", in *The Jerusalem Post*, 2 February 2016, <http://go.shr.lc/2057z4N>; Daoud Kuttab, "Gas and the people of Jordan", in *The Jordan Times*, 17 February 2016, <https://shar.es/1j0bAW>.

<sup>77</sup> Raed Omari, "Confusion prevails over gas deal with Israel", in *The Jordan Times*, 16 February 2016, <https://shar.es/1j0bUX>.

<sup>78</sup> Operated by UFG – a joint venture between Spain's Gas Natural and Italy's Eni – the Damietta plant is 80 percent owned by UFG, with the remaining 20 percent equally divided between state-owned EGAS and

A month later, the British Gas Group signed with the Leviathan partners a non-binding agreement about purchasing 7 Bcm/year of gas over a period of 15 years, to feed into its LNG facility at Idku, Egypt.<sup>79</sup> It was later reported that the Egyptian government would be willing to approve such a deal as long as the parties involved agreed to allocate some of the gas to the domestic market at reasonable prices.<sup>80</sup>

The deals with BG and Union Fenosa Gas are important because the LNG export facilities constitute an opportunity for Israel to reach markets beyond its immediate neighbourhood, e.g., in Europe. However, achieving the final agreements related to these deals, or the others mentioned earlier, is far from simple and is conditional on a number of factors. A crucial immediate factor – among others, including the commercial viability issues due to the prevailing low oil and gas prices – of course is the still unresolved final status of the controversial natural gas framework.<sup>81</sup>

Another important potential market is Turkey, albeit involving various political hurdles.<sup>82</sup> Energy experts generally agree that exporting gas to Turkey either by pipeline or by CNG tankers is one of the most economically beneficial options for Israel.<sup>83</sup> In 2014 there was even a tender by the Leviathan partners for supplying 7-10 Bcm of gas annually to Turkey via a subsea pipeline but it flopped because of Turkey's reaction to Israel's Gaza offensive in the summer of the same year.<sup>84</sup>

However, even with Turkey-Israel relations restored, an Israel-Turkey gas pipeline

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Egyptian General Petroleum Corporation (EGPC). Eran Azran, "Israel's Tamar partners to sell \$20 billion of gas to Europe via Egypt", in *Haaretz*, 7 May 2014.

<sup>79</sup> The two-train Idku terminal is owned by the BG Group (35.5 percent), Malaysian Petronas (35.5 percent), EGAS (12 percent), EGPC (12 percent) and Gaz de France (5 percent).

<sup>80</sup> Sharon Udasin, "British Gas Group mulling Leviathan gas for Egyptian LNG plant", in *The Jerusalem Post*, 29 June 2014, <http://go.shr.lc/25MCnwl>; Summer Said, "Egypt would approve BG's Israel gas deal if local demand is met", in *The Wall Street Journal*, 7 July 2014, <http://on.wsj.com/1jh9Rys>.

<sup>81</sup> At the time of writing, there is a standoff between the Israeli High Court and the government over a clause included in the framework which prevents the state from making any substantial changes to it for 10-15 years. The court's recommendation to anchor the clause in legislation is dismissed by the government which holds a single-seat majority in the Knesset and would have trouble passing such a new law. See John Reed, "Israeli supreme court puts Leviathan gas project at risk", in *The Financial Times*, 15 February 2016; "State rejects High Court's gas stability legislation proposal", in *Globes*, 21 February 2016, <http://iglob.es/?en1105127>.

<sup>82</sup> Ayla Gürel and Laura Le Cornu, "Can Gas Catalyse Peace in the Eastern Mediterranean?", cit.; Orhan Coşkun and Dan Williams, "Expected restoration of Israel-Turkey ties seen paving way for gas import deal", in *Reuters*, 18 December 2015, <http://reut.rs/1RWkxkF>.

<sup>83</sup> Sharon Udasin, "Israel must not put all gas export eggs in one basket, industry expert tells Post", in *The Jerusalem Post*, 18 November 2013, <http://go.shr.lc/25ME1yj>.

<sup>84</sup> Amiram Barkat, "10 bids for Leviathan export tender to Turkey", in *Globes*, 23 March 2014, <http://iglob.es/?en926526>; Orhan Coşkun, "Turkey snubs possible energy deals with Israel after Gaza offensive", in *Reuters*, 9 September 2014, <http://reut.rs/1xDnmmf>.

would not be possible without a settlement of the Cyprus problem, as discussed above. Given the lack of diplomatic relations between Israel and Lebanon and the ongoing civil war in Syria, a pipeline from Israel to Turkey would have to run through Cyprus's EEZ, and would therefore need the RoC's consent. The RoC government's position, however, is that such consent could be granted only after a solution in Cyprus.<sup>85</sup>

### 6.4.2 Cyprus

On 16 February 2015, the RoC and Egypt signed a memorandum of understanding (MoU) authorising Egyptian Natural Gas Holding Company (EGAS) and the Cyprus Hydrocarbons Company "to examine technical solutions for transporting natural gas, through a direct marine pipeline, from the Aphrodite field to Egypt."<sup>86</sup> The RoC's main aim here seems to be exporting its own gas via Egypt's existing LNG facilities.<sup>87</sup>

The MoU with Egypt allows the RoC government to take advantage of the window of opportunity afforded by the delays in the Israeli field development/expansion plans for Leviathan and Tamar. In fact, Leviathan and Tamar partners Nobel and Delek, also partners in Aphrodite, have plans to export Israeli gas via Egypt's LNG infrastructure (see below), projects that are in direct competition with the RoC's plans.<sup>88</sup> It has even been suggested that sales to Egypt from the much larger Leviathan were still the preferred option for the partners, but Aphrodite would be "Plan B" in case of continued delays. Therefore, Cypriot gas could possibly end up as part of a wider agreement that involves sales from Leviathan. However, according to Professor Brenda Shaffer of University of Haifa, the Cyprus-Egypt MoU still remains insignificant due to its non-binding nature, though it indicates a mutual political will for their oil and gas companies to cooperate. Nonetheless, Shaffer believes the present volumes of Cyprus gas "do not commercially justify an international export project, even to Egypt" and so Cyprus "would need additional discoveries or to join forces with export volumes from Israel or another future source in the region."<sup>89</sup>

<sup>85</sup> Ayla Gürel and Laura Le Cornu, "Can Gas Catalyse Peace in the Eastern Mediterranean?", cit.

<sup>86</sup> "Cyprus eyes gas export pipeline to Egypt", in *Kathimerini*, 16 February 2015, <http://www.ekathimerini.com/167373>.

<sup>87</sup> Charlie Charalambous, "Egypt eyes Cyprus gas supply", in *In-Cyprus*, 16 February 2015, <http://wp.me/p59S63-2L0>.

<sup>88</sup> Elias Hazou, "Changes to Israel gas regime a possible threat", in *Cyprus Mail*, 3 November 2015, <http://cyprus-mail.com/?p=67116>.

<sup>89</sup> Sharon Udasin, "Cyprus, Egypt sign MoU on gas export from Aphrodite reservoir", in *The Jerusalem Post*, 16 February 2015, <http://go.shr.lc/1XiMH9P>.

### 6.4.3 Prospects of a “Mediterranean Gas Hub”

At an Israel-Cyprus-Greece tripartite summit in January 2016 the countries’ leaders repeated their commitment to support the development of the ambitious Eastern Mediterranean Gas Pipeline project, one of the EU’s Projects of Common Interest (PCIs) since 2013. It is for exporting Israeli and Cypriot gas by pipeline to Europe via Crete and mainland Greece. Although there are some doubts about the geological and commercial viability of such a pipeline,<sup>90</sup> a study investigating the project’s technical, commercial and financial feasibility, with half of the cost financed by the EU, has been underway since May 2015 and is scheduled for completion by December 2017.<sup>91</sup>

Both Israel and the RoC have been scrambling for deals to export their gas to Egypt, which they need in order to be able to develop their gas fields. Originally an LNG exporter but with its gas production in decline since 2010, Egypt presently needs to import gas to meet its rapidly growing domestic demand. Thus, after the Turkey option which continues to be unavailable for political reasons, Egypt represents the next best regional destination for Israeli and Cypriot gas, though not without issues of commercial viability.<sup>92</sup> While a definite expectation on the part of Israel and the RoC, until recently the Egypt option, also enabling Europe-bound gas exports via the country’s presently idle LNG plants, has generally been considered doubtful (because of commercial challenges posed by the worsening LNG glut and plummeting prices in the global market, even if Egypt allowed such exports, waiving its preference for using the gas domestically).<sup>93</sup> This picture is now set to change due to the 850 Bcm Zohr find offshore Egypt by Eni of Italy in August 2015, where according to the company’s field development plan production is actually expected to begin by the end of 2017.<sup>94</sup>

One possibility raised immediately after the massive Egyptian discovery has been that Israeli and RoC gas plans, if not completely annulled, would face hard competition from Zohr for the Egyptian domestic market as well as for use of Egypt’s LNG facilities to export to Europe.<sup>95</sup> More recently, however, a new momentum seems to have emerged

<sup>90</sup> Anastasios Giamouridis, “Natural Gas in Cyprus: Choosing the Right Option”, in *GMF Mediterranean Paper Series*, September 2013, <https://shar.es/1j0seZ>; Michael Leigh, “A subsea Mediterranean pipeline does not look viable”, in *The Financial Times* (Letters), 5 December 2014, <http://on.ft.com/1w4Eg8V>; Elias Hazou, “‘Tripartite’ gas would be double the price, experts say”, in *Cyprus Mail*, 7 February 2016, <http://cyprus-mail.com/?p=75923>.

<sup>91</sup> European Commission, *Eastern Mediterranean Natural Gas Pipeline. Pre-FEED Studies*, January 2016, <https://ec.europa.eu/inea/en/node/1977>.

<sup>92</sup> Charles Ellinas, “Egypt’s gas problems”, in *In-Cyprus*, 18 July 2015, <http://wp.me/p59S63-67Q>.

<sup>93</sup> Charles Ellinas, “East Med gas export risk”, in *In-Cyprus*, 10 January 2016, <http://wp.me/p59S63-a8Y>.

<sup>94</sup> Erica Mills, “Eni’s first appraisal well at massive Zohr field tests positive”, in *Natural Gas Europe*, 10 March 2016, <http://www.naturalgaseurope.com/enis-first-appraisal-well-at-massive-zohr-field-tests-positive>.

<sup>95</sup> Gal Luft, “Will ENI’s discovery in Egypt sink Israel’s Leviathan?”, in *Journal of Energy Security*, 30 Au-

around the notion of “coordinated development” of Zohr, Leviathan and Aphrodite, with the ultimate aim of creating an “Eastern Mediterranean gas hub.”<sup>96</sup> As conceived by Eni, the idea concerns establishment of a regional gas export infrastructure by linking the various offshore gas fields in the region – Israel’s, the RoC’s, and at a later stage possibly even Libya’s – to the existing LNG facilities in Egypt from where gas would go to Southern Europe, mainly Italy and Spain. The scheme could facilitate development of Levant Basin gas fields and might indeed be “the key to unlocking untapped regional potential.”<sup>97</sup> Also it is an opportunity for Europe to diversify its gas supplies and meet its future gas import needs as its domestic production declines.

The proposed cooperation including Italy, Egypt, Israel and Cyprus clearly makes a lot of commercial sense as it would provide the economies of scale needed to make gas exports from the region sufficiently competitive. However, there are obvious challenges in other spheres. Israel’s regulatory hurdles, tense or fragile relations between the countries, not to mention competing aspirations for regional hub status are among the issues that could make pulling off the Mediterranean gas hub idea rather difficult. The public in Israel and Egypt might object to such strategic cooperation between the two countries. In the Cypriot case, matters can be complicated due to Turkish opposition so long as the Cyprus problem remains unresolved. Also Turkey which sees itself as the regional gas hub for supplies to Europe from the Caspian and potentially from the Eastern Mediterranean is bound to resist what it would consider losing ground to Egypt.

## Conclusions

The Eastern Mediterranean is marked by intricate conflicts or frictions or poor relations between several of the regional political actors, some of which are at odds over questions of sovereignty, as in the contexts of the Cyprus problem and the Israeli-Palestinian

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gust 2015, [http://www.ensec.org/index.php?option=com\\_content&view=article&id=583](http://www.ensec.org/index.php?option=com_content&view=article&id=583); Karen Ayat, “Interview with Dr Charles Ellinas: The implication of the Zohr discovery on Cyprus’ gas aspirations”, in *Natural Gas Europe*, 10 September 2015, <http://www.naturalgaseurope.com/interview-dr-charles-ellinas-implications-zohr-discovery-on-cyprus-gas-aspirations-25332>.

<sup>96</sup> Tal Shalev, “Italy seeking Israeli-Egyptian-Italian natural gas export cooperation”, in *i24news*, 25 October 2015, <http://www.i24news.tv/en/news/international/90257-151025-exclusive-italy-seeking-israeli-egyptian-italian-natural-gas-export-cooperation>; Simone Tagliapietra and Georg Zachmann, “Egypt: The catalyst for a new Eastern Mediterranean gas hub?”, in *Bruegel Blog*, 30 November 2015, <http://bruegel.org/?p=11204>.

<sup>97</sup> Simone Tagliapietra and Georg Zachmann, “Egypt: The catalyst for a new Eastern Mediterranean gas hub?”, cit.



conflict, the latter being the ultimate source of grievance between Israel and its Arab neighbours. Moreover, there are a number of maritime disputes between the countries in the region, notably between Turkey and Cyprus, but also between Israel and Lebanon. Such political issues, often coupled with domestic political concerns, complicate the exploitation of the Eastern Mediterranean gas potential.

After abandoning the idea of constructing their own LNG facilities, both Israel and the RoC have turned their attention to gas sales to regional markets as a way to enable development of their gas fields. However, the best possible regional market, i.e., Turkey, which can also be a gateway for exports to Europe, has remained out of reach because of the ongoing Cyprus problem and strained relations between Israel and Turkey. Other potential regional customers exist in Egypt, Jordan and Palestine, but concluding deals with these countries is also complicated by various factors.<sup>98</sup> Some of these are again of an outright political nature, as in the cases of Israel's potential exports to Palestine and Jordan's NEPCO, or depend on delicate political balances as in the case of exports from Israel to Egypt.

Yet, major hindrance to development of Israel's gas industry has so far come from a series of policy and regulatory uncertainties relating to tax, export quotas and restriction of monopoly. On the other hand, the foremost challenge to the RoC's efforts to link its Aphrodite field to Egypt has been commercial, i.e., having to do with the low volumes, high cost and hence price competitiveness.

Since Eni's discovery in August 2015 of the massive Zohr field at a location not far from the Levant Basin's Aphrodite-Leviathan-Tamar constellation, Egypt has emerged as the country that may hold the key to tapping the Eastern Mediterranean gas potential. Italy and Eni are now promoting the idea of establishing a Mediterranean gas hub, a regional gas export infrastructure that would collect gas from the fields offshore Israel and Cyprus as well as Egypt for exporting to Europe using Egypt's existing scalable LNG facilities. It is too early to gauge the chances of Italy, Egypt, Israel and Cyprus pulling off such an ambitious joint project in such a politically fragile region, but what seems clear is the benefits for all the parties involved, including of course Europe.

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<sup>98</sup> Karen Ayat, "Commercially sensible, politically sensitive", in *Natural Gas Europe*, 21 October 2014, <http://www.naturalgaseurope.com/commercially-sensible-politically-sensitive>.

## 7. Western Mediterranean Gas: Towards North-South Convergence or Increasing Competition?

Houda Ben Jannet Allal

The Western Mediterranean region is composed of five North African countries: Morocco, Algeria, Tunisia, Libya and Egypt. It is strategically located at the crossroads of Europe, Africa and the Middle East. Its geographical position makes it an important energy transit corridor for Europe in particular, and for global energy markets in general.

The Western Mediterranean countries are currently facing sustained demographic and socio-economic growth. Consequently, energy demand is increasing rapidly and this situation is expected to prevail in the coming decades. The recent socio-political changes in the region are putting even higher pressure on the energy sector, as drivers of social and economic development, job creation and well-being. Indeed, the events which unfolded in the region, the so-called “Arab Spring,” and which are characterised by significant social, political and economic transformation, present a challenge to policy makers. A better life, access to jobs and an improved standard of living are among the fundamental aspirations of the citizens in the region. In this context, while energy is of little interest in itself, it is obvious that it is an essential ingredient of the socio-economic development and economic growth that all countries in the region are aspiring to.

In parallel, the vulnerability of the Western Mediterranean region to climate change is now fully recognised. Indeed, the region is considered as one of the most vulnerable ones in this regard. It is also extremely vulnerable to global change due to its geostrategic position. Together, global and climate changes affect seriously sustainable development in this region. Environmental concerns are therefore rising. Consequently, except for Libya because of the situation the country is facing, each of these countries submitted to the United Nations Framework Convention on Climate Change (UNFCCC) their Intended Nationally Determined Contributions (INDCs) on the occasion of the Paris 21st Conference of Parties (COP21). It is interesting to underline that all INDCs suggest

energy to play a role in mitigating climate change effects in the region, in particular with the development of renewable energy and energy efficiency. Natural gas, as the cleanest fossil fuel, is also part of the solution.

The chapter<sup>1</sup> focuses on natural gas in the Western Mediterranean region, the current situation and prospects, and its possible role as a driver for prosperity and sustainable development.

## 7.1 Natural Gas Demand Is Booming in the Western Mediterranean Region

Today the Western Mediterranean region accounts for 171 million inhabitants (33 percent of total Mediterranean population and about 2 percent of total world population). Algeria and Egypt together account for 70 percent of the population of the region. An additional 60 million inhabitants are expected by 2040 in the Western Mediterranean, 78 percent of them in Algeria and Egypt. In 2040, the region will represent 37 percent of total Mediterranean population.

Economic growth in the region has increased over the last two decades despite the upheavals. Indeed, economic reforms and greater openness to trade have been associated with surging growth rates in several countries in the region, although growth has slowed since 2011, in particular in Egypt, Libya and Tunisia. As for the perspectives, the International Monetary Fund (IMF) scenarios foresee a more than doubling of the current level by 2040.

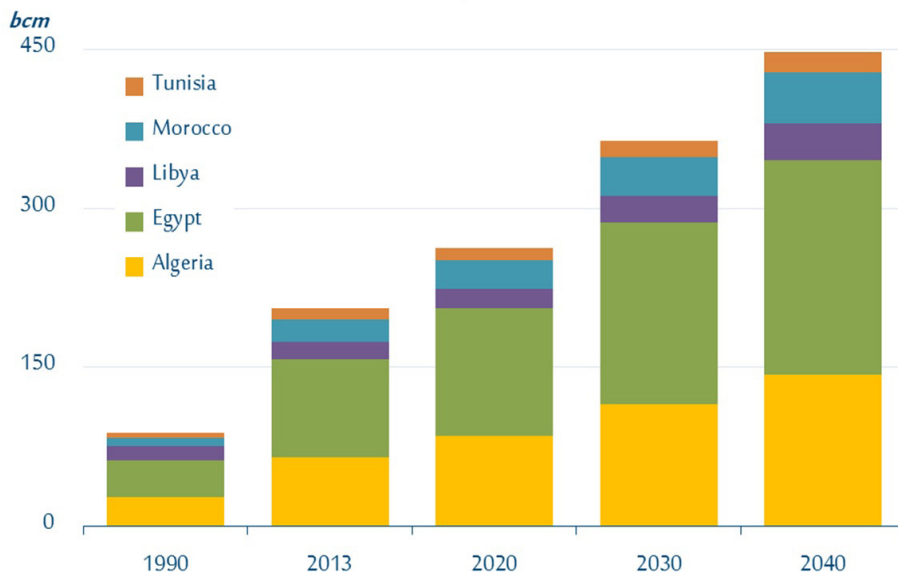
In 2013, the Western Mediterranean region consumed 19 percent of total energy demand of the Mediterranean region.<sup>2</sup> This share is expected to increase to reach 28 percent by 2040 under a business as usual trend. As illustrated in figure 1 and compared to the 2013 level, energy demand will more than double by 2040.

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<sup>1</sup> The chapter is based on *Mediterranean Energy Perspectives*, and in particular the chapter on hydrocarbons. The author acknowledges the extensive contribution of Dr. Sohbet Karbuz, Hydrocarbons Director at OME, as lead author of Chapter 4 of that work. *Mediterranean Energy Perspectives* presents two scenarios: a conservative scenario, which is a business as usual scenario, and a proactive scenario. The proactive scenario emphasizes energy security and environmental concerns through the implementation of strong energy efficiency programmes and increased diversification in the energy supply mix. This includes more renewable energy sources and the introduction of nuclear power for some Southern Mediterranean countries. It assumes a decline in oil input to electricity generation capacity and favours clean energy fuels and technologies.

<sup>2</sup> Both Northern Mediterranean and Eastern and Western Mediterranean countries (from Portugal to Morocco).

Figure 1 | Western Mediterranean primary energy demand (conservative scenario), 1990-2040



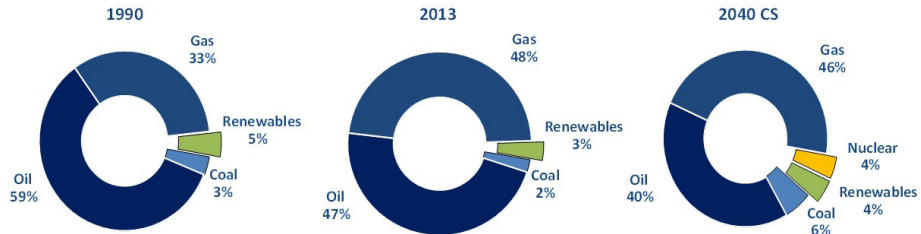
Source: OME database, 2016.

The energy mix in the region is expected to remain fossil fuel based, although high potentials for renewable energy resources and energy efficiency exist. Natural gas is the fuel of choice and renewables will play an increasing role, in particular to address the booming electricity demand.

Demand for natural gas has faced continuous growth in the Western Mediterranean, with a major driver being a policy approach to promote natural gas for domestic use in order to free up more oil for export in producing countries in the region. As a result, the region has the largest share of natural gas in the primary energy mix of the whole Mediterranean region, at 48 percent in 2013. As illustrated in figure 2, natural gas share in the total region's primary energy demand has increased from 33 percent in 1990 to 48 percent in 2013. Over the outlook period, this share is expected to be maintained under a business as usual trend. In 2013, about 90 percent of gas demand was concentrated in Algeria and Egypt and power generation accounted for half of its use. The share of Algeria and Egypt is expected to decrease to 70 percent by 2040. This is explained by a more rapid growth of natural gas demand in Morocco (4.4 times) and Libya (3.5 times) over the outlook period.

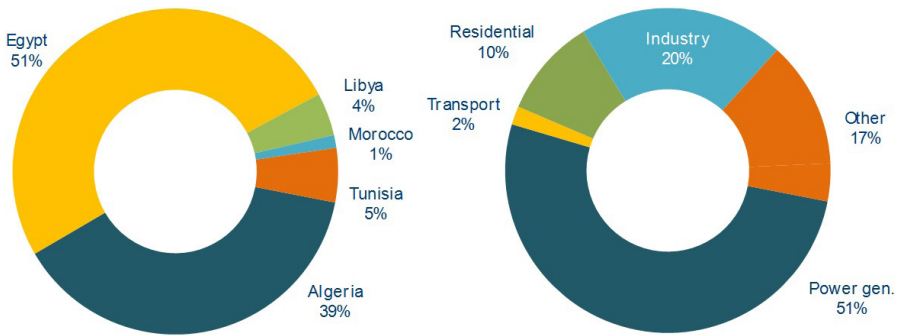
To address the growing electricity needs in the region, electricity generation is expected to almost triple over the period 2014-2040 (2.6 times), from 316 TWh in 2014 to 808 TWh in 2040. Natural gas is the fuel of choice in power generation, although its share in the electricity generation mix will decrease from 72 percent in 2013 to 61 percent in 2040.

Figure 2 | Western Mediterranean energy mix, 1990-2040



Source: OME database, 2016.

Figure 3 | Western Mediterranean natural gas demand in 2013



Source: OME database, 2016.

In the late 1990s, natural gas was used mainly in power generation and the industry sector in the Western Mediterranean region. Indeed, the power and industry sectors accounted for more than half of the region’s natural gas demand. With a 38 percent share of total demand, the power generation sector was the largest user of gas in the region, followed by industry (19 percent).

During the 2000s, natural gas-based electricity generation increased rapidly. Indeed, natural gas use in the power sector was 4.6 times higher in 2013 than in 1990. In 2013, almost 48 Bcm of gas was consumed in the power sector in the Mediterranean, accounting for 51 percent of total regional gas demand (see figure 3). By 2040, natural gas demand for power generation will range between 95 and 147 Bcm, depending on the path that is followed by the countries, with more or less renewable energy and energy efficiency.

Among the Western Mediterranean countries, Egypt is expected to remain the largest gas consumer in 2040. Its natural gas demand will almost double and may increase

by around 50 percent if renewable energy and energy efficiency are better exploited. Algeria also significantly increases its gas demand in a business as usual trend with domestic consumption more than doubling by 2040. Significant energy savings could however be achieved with gas demand reduced by a third in Algeria.

Power generation is expected to remain the largest gas-consuming sector, accounting for about 46 percent of total regional gas demand in 2040. Despite the impressive increase in volume, gas use in industry and residential heating will grow at a faster rate than in power generation. Gas use in industry is expected to account for about 25 percent of the total in 2040, and the residential sector will consume around 13 percent.

If the countries succeed in reaching the targets they announce for renewable energy integration in their energy mix and in better exploiting their energy efficiency potential, a different gas picture will be seen in the region. In this case, less natural gas will be needed for power generation. However, with more than 52.5 Bcm needed by 2040, the power sector remains the largest gas-consuming sector in this scenario, closely followed by the industry sector at 45 Bcm. A significant increase is expected in the use of gas in the transport sector over the next 25 years. From only 1.93 Bcm in 2013, gas consumption for transport could range between 4.3 and 5.4 Bcm by 2040.

Exploiting renewable energy and energy efficiency potentials in the region and thus allowing substantial energy savings, including for natural gas, would require removing several obstacles that hinder their optimal development at present. Among others, the adoption of strong and stable policies and measures is necessary. One of the main obstacles in the region is the high level of energy subsidies, gas included. Such subsidies represent a substantial burden for all countries, both producers and consumers. As an illustration, it is recognised that fuel subsidies have turned Egypt from a net energy exporter into a net importer over the past few years. These subsidies have long weighed on the state budget, contributing to the economic stagnation in the country. In the 2014/2015 fiscal year, Egypt spent around 70 billion Egyptian pounds (9 billion dollars) on oil and natural gas product subsidies. In its draft 2015/2016 budget, the country has earmarked 61 billion pounds (8 billion dollars) for fuel product subsidies. The expected reduction in 2015/2016 is the consequence of the lower global oil prices.<sup>3</sup>

The Egyptian government is trying to reform the decades-old system of subsidies without angering Egypt's rapidly growing population, now at more than 90 million. In addition to switching to coal from natural gas in the cement industry, the government had a plan to reduce domestic fuel consumption by 3-5 percent from one side and to remove

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<sup>3</sup> "Egypt earmarks \$8 bln for fuel subsidies in 2015/2016", in *Reuters*, 20 June 2015, <http://af.reuters.com/article/energyOilNews/idAFL5N0Z608A20150620>.

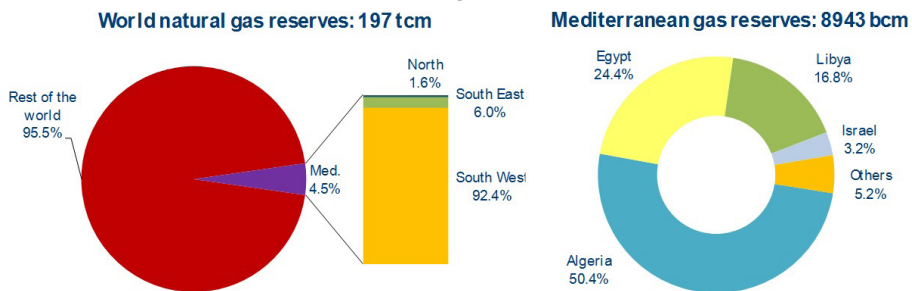
subsidies from the other side. The government indeed cut fuel subsidies in summer 2015, raising prices by up to 78 percent, in a move lauded by economists but criticised by some Egyptians accustomed to cheap energy. More subsidy cuts are expected in the coming years.

## 7.2 Natural Gas Supply in the Western Mediterranean Region

### 7.2.1 Conventional Hydrocarbon Resources

The Mediterranean region contains an estimated 8.9 Tcm of proven natural gas reserves, representing 4.5 percent of the world’s total. Of the total Mediterranean proven gas reserves, more than 92 percent are in the South West, 6 percent in the South East and less than 2 percent in the North sub-region. Algeria has proven natural gas reserves of 4.5 Tcm (50 percent of the region’s gas reserves), Egypt 2.2 Tcm and Libya 1.5 Tcm.

Figure 4 | World and Mediterranean region natural gas reserves, 2015



Source: OME, based on *Oil & Gas Journal* and EIA.

Volatile prices and weak market fundamentals, a rather unattractive fiscal and regulatory environment or changes therein (in some cases unpredictable and non-transparent), concerns about physical security and political instability, as well as lengthy bidding rounds, licensing procedures and ratification processes are likely to damage investors’ confidence and have a negative impact on exploration activities and investments in upstream projects. If a risk aversion sentiment surrounds the upstream industry, companies may prefer to focus their efforts in more robust and investor-friendly markets with less political and economic volatility.

What is more, a series of other obstacles, particularly the lengthy and difficult process involved in obtaining licenses and the necessary authorisation for drilling, due to a high level of bureaucracy and cumbersome environmental permitting, may hinder the efforts of companies to explore and to bring the discovered fields into production.

Many of the abovementioned issues have caused deterioration in investor confidence and impaired investment for exploration in Western Mediterranean countries in the past decade. However, further increases in Mediterranean hydrocarbon reserves in the future are still possible.

Despite significant oil and gas reserves, Algeria's hydrocarbon sector is largely under-explored. In the future, natural gas is more likely than oil to be found in deeper formations, while recoverable reserves of some mature fields could also increase with the use of enhanced recovery techniques (EOR). Proven natural gas reserves in Algeria totalled 4.77 Tcm in 2014, with an additional 1.47 Tcm of undiscovered natural gas resources estimated by the US Geological Survey and more than 21 Tcm of technically recoverable shale gas resources estimated by US Energy Information Administration and Advanced Resources International (EIA/ARI).<sup>4</sup> To date, most of the oil and gas fields discovered are located in the central and eastern part of the Saharan platform, which has been well explored. The Talsinnt area near the Algerian-Moroccan border is a prospective area for oil and gas, while the Tindouf, Bechar and Southeast Constantinois basins are not yet well explored.

For years, Algeria has been trying to turn around the diminishing interest of investors in its hydrocarbons sector. In January 2013, the Algerian parliament amended its 2005 Hydrocarbon Law regarding foreign investment in hydrocarbons in an attempt to attract the investment and technology improvements needed to help stop production decline.

Plenty of new discoveries have been reported in the past few years but average field size seems rather small. In 2014, of the 30 discoveries, 29 were made by the national oil and gas company Sonatrach. The great majority of discoveries were made in extensively explored mature basins and were dominated by gas. Similarly, the same year, of the 113 exploration wells, 103 were drilled by Sonatrach.

Also in 2013, Sonatrach offered 33 blocks located in four sedimentary basins with high shale gas and oil potential. This auction resulted in Sonatrach signing five contracts with Repsol, Shell, Statoil and Dragon Oil-Enel. In May 2014, the Algerian Council of Ministers gave formal approval for foreign partners to join Sonatrach in the exploration and development of shale gas resources.

Overall, results of the last bidding round indicate however that the contractual terms

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<sup>4</sup> EIA, "Algeria is reforming its laws to attract foreign investment in hydrocarbons", in *Today in Energy*, 4 August 2015, <https://www.eia.gov/todayinenergy/detail.cfm?id=22352>.



and/or blocks offered are still not sufficiently attractive to the international oil and gas industry. They underline the challenges Algeria faces in trying to give renewed impetus to foreign investment in exploration, and to attract international partners so as to increase Algeria's hydrocarbon reserves. One of the main obstacles is probably the fact that, by law, Sonatrach takes a mandatory majority share (at least 51 percent) of any resulting projects.

The company's 2015-2019 development plan aims at the expansion of the reserves base, which requires intensification of exploration efforts (an average of 125 wells per year), both in less well known areas in the north of Algeria and offshore. But the planned fifth bid round which was expected to be launched in 2015 was cancelled due to low oil prices, which reduce the profitability of new hydrocarbon explorations.

Algeria's offshore is considered a promising deepwater frontier. To date, however, only a few exploration wells have been drilled, all in the 1970s, and only one in deep water. Sonatrach plans to start drilling the first offshore exploration well in early 2016.

In the recent past, Egypt has been the focus for exporting gas from the offshore gas fields of Cyprus and Israel. However, with its estimated 850 Bcm of gas, the discovery of the super-giant Zohr field offshore Egypt in August 2015 is a game changer. This discovery has confirmed once again the substantial hydrocarbons potential in the Mediterranean Sea, hence the importance of the Mediterranean region in the global exploration and production industry.

In fact, the Zohr discovery has confirmed that "Egypt has potential for additional hydrocarbons discoveries, as the country is still relatively under-explored, particularly the deep-waters [...] In the future more gas fields would be discovered than oil fields [...] There is little doubt that deep reservoir accumulations will eventually be discovered."<sup>5</sup>

ENI's Zohr find, the largest discovery of its kind in the Mediterranean Sea, is a game changer at least from an exploration perspective. Zohr is a completely new reservoir structure, Miocene reef carbonates, as opposed to conventional sandstone formations observed in the discoveries so far made in the region. In other words, Zohr is the first discovery within carbonate targets in the region. Similar discoveries may follow.

More natural gas, and perhaps oil, resources could be located in the western zone of Egypt's territorial Mediterranean water which is under-explored or unexplored. In June 2015 the largest seismic survey project in the Mediterranean, covering Egypt's Western Mediterranean Sea, was signed by Egyptian Natural Gas Holding Company (EGAS) and Petroleum Geo-Services (PGS).

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<sup>5</sup> See the conclusions of the OME's in-depth analysis of the Egyptian energy sector (Mediterranean Energy Perspectives 2011). OME's estimated ultimate recoverable resources for gas are much higher than the Egyptian Natural Gas Holding Company (EGAS) estimates.

In the last two years, Egypt launched several exploration bid rounds, signed 56 exploration agreements and is in the final stage for signing 21 new agreements and amendments.<sup>6</sup> The most recent international bidding rounds were launched in December 2014 by Ganope and in March 2015 by EGAS. Of the 10 blocks on offer in the South Gulf of Suez, West and East Nile by Ganope, the company announced that five blocks had been awarded for seven bids received.<sup>7</sup> Regarding EGAS exploration bidding, 12 blocks were on offer in total in the Mediterranean Sea with a closing date of 30 July 2015.<sup>8</sup> Blocks 4, 7, 12 and 14 were awarded for four bids received. In July 2015, EGAS announced it was already preparing the launch of new bid rounds covering the western part of Egypt's Mediterranean offshore.<sup>9</sup>

Besides Zohr, numerous other significant gas discoveries have been made recently in Egypt. In 2015, ENI announced an important gas discovery in the Nooros exploration prospect in the Nile Delta, while BP made a second significant gas discovery in its North Damietta Offshore Concession in the East Nile Delta. The first discovery in the licence was Salamat, the most important oil and gas discovery in 2013 outside Mozambique. According to BP, the potential estimated in the concession goes beyond 140 Bcm.

Several factors have played a role in the success of bidding rounds, attracting further foreign companies and hence these discoveries. Pricing policy – the price Egypt pays for gas to the operator – is one of them. The Oil Ministry has signed several agreements with IOCs that increased the gas price paid to companies. Normally, those amendments only apply to gas produced from new discoveries, but both parties also discuss modifications to existing agreements. Concerted efforts are made by the Egyptian government to bring back international oil and gas companies and with them investment opportunities. As an illustration, in July, EGAS and Italian energy company ENI, agreed to raise the cost of gas from 2.65 dollars per million British thermal units (mBtu) to between 4 and 5.88 dollars per mBtu, applicable to gas produced on new discoveries.<sup>10</sup>

In Libya most gas activity is concentrated in the Sirte Basin. The neighbouring basins to the west (Ghadames) and southwest (Murzuq) also attract much interest in the search for hydrocarbons. The relatively unexplored regions of Kufra to the South-East and Cyrenaica to the North-East hold promise.

<sup>6</sup> Egyptian Ministry of Petroleum, Press releases, 30 August and 3 October 2015.

<sup>7</sup> "With a potential volume in place of up to 30 trillion cubic feet, Eni has achieved the largest gas discovery to date off Egypt", in *Arab Oil & Gas*, Vol. 44, No. 1054-1055 (1 September 2015), p. 13-18.

<sup>8</sup> Originally the licensing round was for eight blocks with a closing date of 31 May 2015.

<sup>9</sup> "EGAS signs an agreement with BP for the supply of 18 cargoes of LNG in 2015-2016", in *Arab Oil & Gas*, Vol. 44, No. 1051 (1 July 2015), p. 20-21.

<sup>10</sup> Dania Akkad, "Egypt's gas superfield find and its energy future", in *Middle East Eye*, 4 September 2015, <http://www.middleeasteye.net/node/46432>.

After the United Nations and United States sanctions were lifted in 2003 and 2004 respectively, there have been four international licensing rounds. These were organised by the Libyan National Oil Company (NOC) under exploration and production sharing agreement (EPSA) terms.<sup>11</sup> The first three rounds were oriented to oil, while the last one focused on natural gas. Since 2007, Libya has not held a licensing round, although it has signed exploration and production licenses with individual companies.

The volatile socio-political situation has clearly affected gas exploration as well as production activities in the country. Arrangements for some successful bids have still not been finalised and formal discussions to set out the long-promised new hydrocarbons law have been stopped. The last hydrocarbon law dates back to 1955 and lacks information on natural gas developments and Enhanced Recovery Technique (EOR) projects. Since 2014, there have been two governments, two Parliaments and two oil ministries in the country. The course of drilling operations is rather uncertain. Several foreign companies left the country or suspended their activities due to the political instability and the deterioration of the security environment. Still, in 2015 ENI made two discoveries of gas and condensates in Libyan offshore Area D, in the Sabratah basin.

Despite favourable legislation, oil and gas exploration activity in Morocco and Tunisia remains limited. Morocco is largely underexplored for hydrocarbons. Less than 320 wells have been drilled in the country to date, less than 15 percent of which were offshore. 2014 was a year of reinforced interest in offshore exploration, with the arrival of a number of large companies and some modest exploration success. Of the 13 exploration wells drilled (eight onshore, five offshore), 10 revealed the presence of hydrocarbons. Currently there are more than 40 onshore and 90 offshore concessions as well as five reconnaissance permits in the country. Thanks to Morocco's having one of the most competitive fiscal terms in the world, and due to new seismic interpretation and the understanding of resource development in rift basins along the Atlantic margin, deepwater prospects have gained momentum. A number of hydrocarbon discoveries in 2015, though small in size, indicate that exploration activities in the country may expand substantially.

In Tunisia exploration activities have remained in general at low levels in the past six years, together with the number of blocks awarded. Commercial success rate in the period was below 30 percent, compared to above 30 percent between 2001 and 2008. A total of 37 exploration licenses were in force in 2014, down from 54 in 2009. A few wells discovered oil and gas shows but not economic volumes. In 2014, only three wells were

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<sup>11</sup> The EPSA-IV was built on previous frameworks but it increases transparency and more open competition. It also features standardised terms for exploration and production contracts, stipulates joint developments and the marketing of associated natural gas, and non-recoverable bonuses.

drilled offshore, two of which had hydrocarbon shows while the third was plugged and abandoned. Activities in 2015 have so far yielded only one commercial oil and gas field.

### *7.2.2 Natural Gas Production in the Western Mediterranean Region*

Natural gas production in the Western Mediterranean region increased by 36 percent between 2000 and 2013, from 109 Bcm to 148 Bcm. This is the lead producing sub-region of the Mediterranean, with an 86 percent share of total Mediterranean gas output in 2013.

OME projects natural gas production in the Western Mediterranean region to continue to increase from about 148 Bcm in 2013 to 188 Bcm in 2020 and 257 Bcm by 2040. Production is expected to plateau around 2035 at about 263 Bcm when both Algerian and Egyptian gas production peak, and start declining before 2040. In this context, Egyptian and Algerian gas production would increase the most in the region in absolute terms, up to about 60 and 50 Bcm respectively. Production in Libya is expected to rise by around 20 Bcm by 2040.

Algeria is the largest natural gas producer in the Mediterranean, with an output of about 76 Bcm in 2013, accounting for 44 percent of the total gas production in the whole Mediterranean region. However, marketed gas production in the country is declining.

The large Gassi Touil field in the South-Eastern Illizi province entered production in late 2013, after several years of delay. When fully operational, the field will add 3.6 Bcm/year to gas production capacity of the country. The development of El Merk fields (ENI's Menzel Lejmat East project and Anadarko's El Merk project) also in 2013 did not add significant volumes of marketed gas because most of the produced gas is reinjected. As a result of the January 2013 terrorist attack, one of the three gas processing trains of the In Amenas gas facility did not come back on stream until two years later.

Algeria has the potential to increase its production significantly by the end of the decade with the realisation of several gas development projects. The Reggane Nord, Timimoun and Touat projects (part of the South West Gas project), initially planned by 2014, are not expected to come onstream before 2016. On the Isarene tract, the Ain Tsila gas and condensate field is scheduled to come onstream in late 2018. Once all fields are producing they are expected to add more than 12 Bcm/year to Algeria's gas output. Moreover, the project at In Salah (to offset the decline of the northern fields already in operation) is expected to be completed by 2016. Other gas fields (Hassi Ba Hamou, Hassi Mouina, etc.) are also scheduled to start production before 2020.

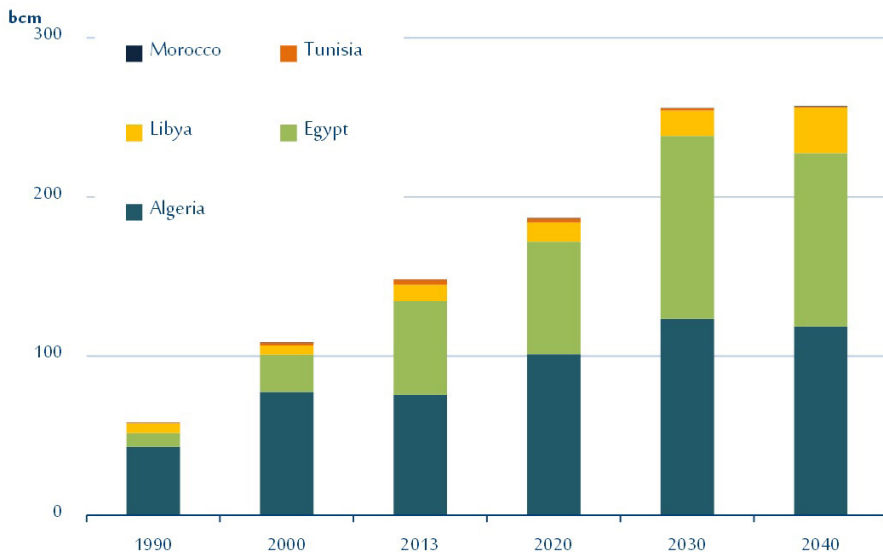
Libya's gas output has been limited over the years due to sanctions imposed by the United Nations, the European Union and the United States. The country's gas sector remains largely underdeveloped. Most of the gas is produced in association with crude oil

and almost half of gross production is reinjected or flared. Plans to further increase the marketed gas output have been announced but, like oil projects, since 2011 development of the natural gas sector is dependent on the end of the volatile situation in the country.

In Egypt, a hydrocarbon exploration boom resulted in a tremendous increase in natural gas reserves, and production increased six-fold over the last 20 years. But in recent years, gas production in the country has been stagnant or declining. The reason was not availability of gas but political unrest, debts owed to foreign partners, the price paid for gas and delays in the commissioning of several new projects. Recent efforts by the government to resolve administrative problems and restore investor confidence have speeded up developments in the upstream sector.

The Denis-Karawan fields on the offshore Tamsah concession in the east of the Nile Delta started production in summer 2014. Development of the West Nile Delta project resumed in July 2014 after three years of inactivity due to the unstable political situation. Phase 9a of the West Delta Deep Marine development started in mid 2014 though it only partly offset the decline in production from the concession. The Assil and Karam fields on the Alam El-Shawish West concession in the Western Desert started production in early 2015. When they reach their full capacity, probably in 2016, they will add about 4 Bcm/year to the country's gas output.

Figure 5 | Mediterranean gas production, 1990-2040



Source: OME database, 2016.

Several major projects are expected to be finalised in the near future. The West Nile Delta project, consisting of North Alexandria and West Mediterranean Deepwater offshore concessions, is one of the largest development projects in the country. Production from the project fields is expected to start by 2017, and a peak level of more than 12 Bcm/year is anticipated for 2019.

In the Nile Delta region, the second-phase development of the Disouq fields will add 1.6 Bcm/year before summer 2016. Phase 9b of West Delta Deep Marine development is expected to start in 2016 for completion by 2020, awaiting the final outcome of negotiations with the government.

In addition, some recent discoveries are expected to be put on production in an accelerated way: the super-giant Zohr discovery is expected to start producing in a few years' time, and production from the March 2015 Atoll discovery (in the North Damietta Offshore Concession in the East Nile Delta) is anticipated to begin in 2018.

### *7.2.3 Unconventional Gas Resources*

Available estimates on shale gas resource developments and activities in some countries indicate that Algeria, Egypt and Libya have by far the largest potential in the Mediterranean region.<sup>12</sup> They show that Tunisia also has also good potential in shale gas and tight gas resources.

Algeria is very interested in evaluating and developing its unconventional gas resources to supplement its conventional gas production. The EIA 2013 study upwardly revised Algerian technically recoverable shale gas resources from 6.5 Tcm to about 20 Tcm. This made Algeria the third or fourth largest (according to whether the EIA or the ARI resource estimate for the US is used) shale gas holder in the world. However, the progress on the ground is quite slow. Development of shale gas in Algeria is facing many hurdles and U-turns. Concerns with respect to the use of water resources, especially in the south of the country, and the lack of public debate have led to growing opposition among the population and have entailed sometimes violent demonstrations.

In Egypt, in December 2014, the Egyptian General Petroleum Corporation (EGPC), Apache and Shell signed the first agreement for the exploration of unconventional gas in the north-eastern region of Abu El Gharadiq, 200 km west of Cairo, in the Western Desert. The two foreign companies will drill three wells into shale rock in the Apollonian structure. The project will be the first in Egypt to feature horizontal drilling, and the first to deploy hydraulic fracturing techniques to extract the tight gas. Production

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<sup>12</sup> Also France. See EIA, *Technically Recoverable Shale Oil and Shale Gas Resources*, June 2013 and updates, <https://www.eia.gov/analysis/studies/worldshalegas>.

of gas could start in early 2016. However, several obstacles exist and at a time of low oil prices the economic feasibility of shale exploration in the country is questioned. Unconventional gas extraction in the Western Desert would require drilling to depths of over 4,000 metres, about 50 percent deeper than for an average Marcellus Shale well.<sup>13</sup>

In Morocco, the Tindouf basin (stretching across Morocco, Mauritania and Algeria), and to a minor degree the Tadla basin, in the central part of the country, have shale oil and gas potential according to the EIA study. As in the rest of the region, exploration for unconventional resources is in the early stages in Morocco.

### 7.3 Natural Gas Trade in the Western Mediterranean Region

Currently the Mediterranean region as a whole is a net importer of natural gas. The Western Mediterranean is a net exporter but those exports are outweighed by imports in the Northern and South-Eastern sub-regions. Looking into the future, the Mediterranean region as a whole is expected to remain a net gas importer.

In the Western Mediterranean, major disparities exist among countries. As of today, Algeria and Libya are still net gas exporters but Egypt became an LNG importer in April 2015, with the use of an floating storage and regasification unit (FSRU) located in the port of Ain Sokhna, on the Red Sea. Egypt leased a second FSRU that reached Ain Sokhna at the end of September 2015, and that is scheduled to start operating in early 2016. Egypt is expected to import up to 10 Bcm/year in total in the coming years, while this situation will reverse early in the next decade and the country will start exporting gas again when new production (i.e., in the Zohr field) becomes operational. Morocco also envisages to import gas via LNG through a terminal planned at the industrial centre of Jorf Lasfar on the Atlantic coast. Morocco plans to import 2.4 Bcm of LNG in the first four-year phase starting in 2020 or 2021. In the second phase, Morocco foresees another 2.4 Bcm of LNG imports. About 70 to 80 percent of the LNG will be imported under long-term contracts and the rest from the spot market.

The Suez Canal is an important transit route for oil but also for LNG from the Middle East to European countries. Connecting Port Said on the Mediterranean Sea with Port Toufiq on the Red Sea, the canal is owned and managed by the Suez Canal Authority. According to EIA, LNG transit accounted for 7 percent of total Suez cargoes in 2014 and

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<sup>13</sup> "Work to start on Apache, Shell fracking project in Egypt", in *Shale Gas International*, 26 May 2015, <http://www.shalegas.international/?p=4000>.

around 10 percent of total LNG traded worldwide. However, with the decrease of LNG imports from the US and Europe, volumes of LNG transported through the canal have significantly declined from their peak in 2011. In August 2015, a new stretch of canal was inaugurated. It will enable the number of ships utilising the waterway every day to almost double.

Algeria's natural gas exports have been declining in the past few years. The country's gas export potential decreased in parallel to the decline of its production since the mid 2000s. It fell from over 50 Bcm in 2010 to below 40 Bcm in 2013, levels reached 20 years ago. Algeria's export potential is anticipated to be slightly more in 2030 than in 2010, but much less, some 35 Bcm/year, in 2040. The country's export potential could double by 2030 and remain above 60 Bcm/year in 2040 in case of increased development of energy efficiency and renewables in the country.

This means that Algeria may have in the future a large amount of underutilised gas export capacity due to supply shortage arising from delays in production developments and rising domestic demand. As of the end of 2015, almost 90 percent of gas export capacities in operation in the Mediterranean region are in Algeria. The two LNG mega trains completed in 2013-14 will account for about 13 Bcm/year of extra export capacity.<sup>14</sup> In 2014, the new LNG train at Skikda saw its first full year of operation while a new Gassi Touil LNG train in Arzew was commissioned in November of that year.<sup>15</sup> There is still talk about the Galsi pipeline from El Kala to Sardinia. If and when completed, it would provide direct access to the Italian market. However, the additional costs incurred, competition from Russia, the low market price and low economic returns have led to important delays in the project.

Libya's natural gas exports are not expected to grow in the future. Although the gas infrastructure has been less disrupted by the political turmoil in the country than its oil assets, maintaining the full operation of the Greenstream pipeline (which connects Mellitah in Libya with Sicily in Italy) over time is still difficult. Gas exports have been interrupted several times since 2011, and in 2015 pipeline flows are running at a rate equivalent to 7 Bcm/year.<sup>16</sup> The country will continue exporting relatively small amounts of gas to Italy through the Greenstream pipeline in the coming years. After 2030, assuming that the political and security situation has improved by then, gas exports could be bound by the capacity of the Greenstream pipeline. The country's gas export potential could increase significantly after 2030 and reach almost 20 Bcm/year. Although all plans have been postponed due to the current unrest, Libya will need to create new export

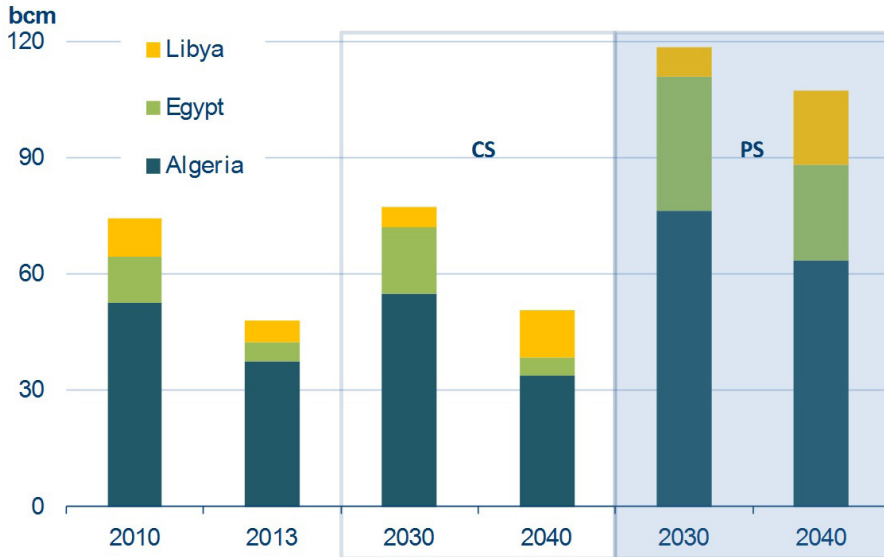
<sup>14</sup> This is in theory, as it is understood that soon after start-up of the new train at Skikda, the three old trains (4 Bcm/year) will probably be shut down permanently.

<sup>15</sup> IGU, *World LNG Report 2015 Edition*, June 2015, p. 9, <http://www.igu.org/publications>.

<sup>16</sup> OME estimates based on SNAM Rete Gas data.



Figure 6 | Export potential of main natural gas producers in Western Mediterranean countries, 2010 to 2040



Source: OME database, 2016.

Note: CS = conservative scenario; PS = proactive scenario.

infrastructure or substantially expand its existing facilities in order to be able to meet this potential within the next 25 years. This means constructing major new LNG export plants to replace the Marsa El Brega LNG plant, which is considered decommissioned after suffering substantial damage during the 2011 civil war.

With the beginning of the riots in February 2011, the export potential of Egypt changed completely. The Arab Gas Pipeline (AGP) connecting Egypt to Jordan, Syria, Lebanon and Israel<sup>17</sup> has been sabotaged several times and only small volumes of gas have reached Jordan.<sup>18</sup> Exports to Israel were halted in April 2012. Due to a major shortage of gas on its domestic market Egypt became a net gas importer in 2015. There have been no exports from the LNG plant in Damietta since February 2013 and the second LNG plant in Idku operated at only 4 percent of its capacity on average in 2014. Today, a combined LNG

<sup>17</sup> The AGP connects Egypt with Israel, Jordan, Syria and Lebanon. In addition, a subsea gas pipeline, the El Arish-Ashkelon, connects the AGP with Israel.

<sup>18</sup> The pipeline was attacked for the 28th time in February 2015. Until the Arab Spring, the attacks were carried out by Bedouin complaining of economic neglect and discrimination. The pipeline has since been targeted by militants several more times. Due to persistent natural gas shortages in Egypt, the gas supply to Israel was suspended indefinitely while the supply to Jordan was resumed, but at a rate substantially below the contracted amount.

export capacity of some 19 Bcm/year remains idle. Due to intensified upstream activities, recent large discoveries and ongoing field development plans, Egypt is expected to regain its net gas exporter status after 2020. It is likely that the country's export potential will be as much as 17 Bcm in 2030 but maintaining those levels to 2040 could be a challenge. By 2040, Egypt may export only a small amount of gas. However, if domestic energy needs are more efficiently addressed and with a higher share of renewables, export potential could exceed 30 Bcm and decline thereafter to some 25 Bcm in 2040.

By 2040, Algeria, Egypt and Libya could export more than 50 Bcm/year of natural gas (compared with about 48 Bcm/year from the region in 2013) in a business as usual trend, and 107 Bcm/year in a proactive scenario.

To conclude, the Western Mediterranean energy balance is and will remain fossil fuel based. Energy demand in general and natural gas demand in particular are expected to maintain impressive growth. The countries in the region have mixed energy policies with clear guidelines: move from oil to gas era, and diversify the energy mix by promoting renewables. Some countries are also considering the introduction of nuclear in their electricity mix.

As for the supply side, huge hydrocarbon resources are located in the region, most of which are still under/unexplored for a set of political, economic and security reasons discussed above. In order for the region to better benefit from these resources, it is important for these countries to create adapted frameworks with an attractive investment climate and security of regulation.

### 7.4 Western Mediterranean Gas: Driver for North-South Convergence and Win-Win Cooperation

West Mediterranean countries and North Mediterranean countries are historical partners with regard to gas relations in the Euro-Mediterranean region, and are traditionally interdependent. Considering the trends of energy demand in the region and the place of natural gas, this situation is expected to prevail.

Algeria is the first supplier to the EU in the region, and the third after Russia and Norway. In terms of outlook, as already mentioned Egypt is expected to start exporting gas again by 2020, and Tunisia, which is currently facing a major energy transition, has called for stronger regional cooperation in gas exchange. In the context of rising energy security concerns in Europe, one can note the clear political will of stakeholders to accelerate discussions and to open bilateral or regional dialogues. This gives room to rethink the nature of energy cooperation in the Mediterranean region.

Regional cooperation in the Mediterranean has been underway for decades and is still being developed. The EU has long aimed at establishing a coherent cooperation strategy towards the Mediterranean region, including the Western Mediterranean, by introducing several initiatives such as the Euro-Mediterranean Partnership, the European Neighbourhood Policy and the Union for the Mediterranean (UfM), covering a broad spectrum of topics including energy.

As far as energy cooperation is concerned, oil and in particular natural gas have brought about fruitful cooperation among Mediterranean neighbours and for decades have contributed to building long-term partnerships. Indeed, several regional gas infrastructure projects connecting the region to Europe, such as the Trans-Mediterranean Pipeline (TransMed; also Enrico Mattei gas pipeline), a natural gas pipeline from Algeria via Tunisia to Sicily and thence to mainland Italy, were made possible in this context. Nowadays electricity – especially electricity generated from renewable energies – and energy efficiency emerge as other strong drivers for reinforcing regional cooperation. Natural gas however remains a priority issue, as a contribution to improving security of supply in the EU.

As explained in greater detail in the chapter by Giacomo Luciani, Europe today is facing major decline in its gas production and is importing two-thirds of its gas; the market is therefore increasingly dependent on imports. This leads to the need to diversify the sources and routes of supply in order to increase the EU's supply security. In this light, the Western Mediterranean region offers huge opportunities for Europe. Although there are some country risks in the region due to the current instability, the EU can play a strategic role by placing energy at the heart of regional cooperation, thus ensuring strategic and stable relationships between the EU and Western Mediterranean countries. It is obvious that the EU has much to gain in joining forces and deepening dialogue with Mediterranean countries to lessen its dependency. Mediterranean countries' energy demand is constantly on the rise, and production capacities as well as investment needs may represent viable options for future production, trade and cooperation.

The launch of three energy platforms under the auspices of the UfM and the definition of a new neighbourhood policy represent positive signals of willingness to revitalise energy cooperation in the Mediterranean region. It can reasonably be predicted that these will translate into concrete and conclusive results, to the benefit of all.

In particular, the UfM Gas Platform aims at establishing a regional structured dialogue allowing the gradual development of a Euro-Mediterranean gas market to promote security, transparency and predictability of both demand and supply in a manner that correctly and fairly balances the interests of producing and consuming countries, and should provide a basis for the long-term secure development of the abundant reserves in the region.

The Platform will bring together policymakers, industry representatives, regulators, energy stakeholders, traders and shippers, and representatives from financing institutions from across the Euro-Mediterranean region to develop shared viewpoints and proposals on natural gas issues in order to reinforce the security of gas supply and regional gas exchanges. It is designed chiefly to act as a conduit for dialogue and exchanges of views and information between the various public and private stakeholders concerned. Over time, it is expected that this role will become more active, with the Platform providing advice and consultation to stakeholders with a view to identifying energy projects of common interest to UfM members and concrete partnership actions, and following up on their implementation. It is obvious that if successful, the Platform will contribute to strengthening cooperation and co-development between the two shores of the Mediterranean.

In addition to regional cooperation, bilateral agreements are also important. Such agreements, in terms of strategic energy partnerships and bilateral projects, are indeed likely to proceed faster than their regional counterparts simply because of their focused orientation and the number of parties involved. The EU-Egypt Memorandum of Understanding on Strategic Partnership on Energy in 2008, the establishment of a strategic energy partnership with Algeria in 2013 and the EU-Algeria political dialogue on energy matters launched in May 2015, for instance, could boost investments in Egyptian and Algerian gas with the knock-on effect of improving Europe's energy security.

In answering the question "Western Mediterranean Gas: towards North-South convergence or increasing competition?," the present chapter demonstrates that both answers may be valid.

Indeed, in all cases Northern Mediterranean countries will remain gas consumers in the coming decades and will need to import gas from the Western Mediterranean region for many obvious reasons. From its side, the Western Mediterranean region is still underexplored and natural gas production may increase substantially as illustrated by the Zohr discovery in Egypt, if adapted and stable policies and measures are put in place so as to attract the huge investment needed to exploit these resources in a sustainable way.

In addition, the chapter highlights that Western Mediterranean countries, both consuming and producing ones, are facing rapid increase in their domestic natural gas demand. In this context, the producing countries will be facing increasing competition between addressing internal gas needs, and exporting gas to the benefit of their economy.

In this context, a business as usual trend would lead the region to move from an overall exporting trend to an importing one. In such case, the answer to the question would be *competition*. Northern and South-Western Mediterranean regions would indeed in such case compete to have access to gas.

However, an alternative future is possible. In order to reduce tensions, in addition

to the optimal and sustainable exploitation of natural gas resources, promoting renewable energies and energy efficiency would allow saving a substantial amount of gas, which would then be made available for export. Promoting regional cooperation for better exploiting gas resources but also promoting low carbon and efficient economies in the region would clearly benefit all and tilt the balance in favour of *convergence* and cooperation.

## 8. Winds of Change. Challenging Future for Russia's Gas

Agata Łoskot-Strachota

Russia is the world's key gas producer, and Gazprom the world's biggest gas exporting company. The country has the world's largest gas pipeline network, a long-term record of exports to the world's biggest gas importer (the EU) and the quickest growing gas market (China) in its neighbourhood. Gas has for years played a key role in Russian economy and policy. Despite this global leadership in gas, established position, infrastructural connections and geographical proximity to key export markets, Russia and Gazprom have in recent years been encountering more and more challenges affecting volumes and profitability of gas sales. These challenges are related to significant changes in global, European and Commonwealth of Independent States (CIS) gas markets: decreased demand, oversupply and intensified competition (due also to growing availability of LNG), low prices environment, regulatory changes, drive to diversify away from Russian gas (and Gazprom in particular) and/or to modify conditions of Russian gas imports. Additionally, there has also been increasing competition on the internal gas market, which challenges the role and strategy of Gazprom and, in the longer term, may affect modes of development of the cost-intensive new gas fields and Russian gas export strategy. As a consequence, we are witnessing a major rethinking of Russian and Gazprom's gas strategy. The exact global role of Russian gas is not predetermined, and the developments of the next few years could be pivotal in defining and shaping both the internal gas market and Russia's gas relations with Europe and China.

This chapter aims to present Russian gas potential when it comes to reserves and output (first section) and then to discuss the situation and challenges facing Russian gas in its main markets: domestic (second section), CIS (third) and European (fourth) as well as in its developing Asian export direction (fifth).

## 8.1 Potential: Russian Gas Reserves and Production

Russia holds the second largest proven gas reserves at 32.6 Tcm constituting 17.4 percent of global reserves.<sup>1</sup> In addition Russia holds significant probable reserves in East Siberia reaching 7.5 Tcm.<sup>2</sup> Russia has also substantial unconventional gas reserves<sup>3</sup> which have not yet been properly explored.

The main region for Russian conventional gas production remains Western Siberia, but due to aging and depletion of the traditional production base<sup>4</sup> we observe the growing role of new deposits and regions. Substantial investments, mostly by Gazprom, have made feasible a steadily increasing production in the last few years from new fields in the Russian Far East and Yamal peninsula (including the huge Bovanenkovo field<sup>5</sup>). The importance of these production centres will continue to grow in the future, together with an increased role for East Siberia and the Russian North West.<sup>6</sup>

In 2014 Russian gas production reached 642.1 Bcm, recording a decline of 3.9 percent y/y and remaining below the 2008 (pre-economic crisis) levels. The most important producer in Russia is Gazprom, which in 2014 produced 444 Bcm.<sup>7</sup> This was the worst result in Gazprom's history and well below its potential production estimated in 2014 at 600 Bcm.<sup>8</sup> Non-Gazprom production was significantly lower, amounting to roughly 197 Bcm.

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<sup>1</sup> BP, *Statistical Review of World Energy 2015*, June 2015, p. 20, <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>. BP 2014 statistics show an increase in proven reserves of 1.2 percent y/y.

<sup>2</sup> James Henderson and Tatiana Mitrova, "The Political and Commercial Dynamics of Russia's Gas Export Strategy", in *OIES Papers*, No. NG102 (September 2015), p. 7, <https://www.oxfordenergy.org/tag/ng102>.

<sup>3</sup> For Gazprom's VNIIGAZ (high) estimates of unconventional gas, see "Russia Touts Unconventional Gas Promise", in *Natural Gas Europe*, 31 December 2012, <http://www.naturalgaseurope.com/russia-touts-unconventional-gas-promise>. For US estimates of Russia's shale gas resources, see EIA, *Technically Recoverable Shale Oil and Shale Gas Resources: Russia*, September 2015, <https://www.eia.gov/analysis/studies/worldshalegas>.

<sup>4</sup> Producing fields of the Tyumen region have been depleted by 76-79 percent according to the Institute of the Russian Academy of Sciences (ERI RAS), *Global and Russian Energy Outlook to 2040*, Moscow, August 2014, p. 140, [http://www.eriras.ru/files/2014/forecast\\_2040\\_en.pdf](http://www.eriras.ru/files/2014/forecast_2040_en.pdf).

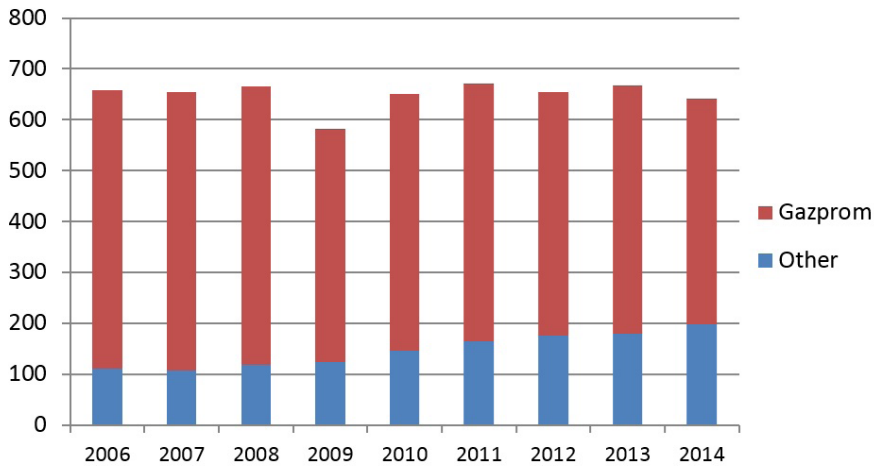
<sup>5</sup> James Henderson and Tatiana Mitrova, *The Political and Commercial Dynamics of Russia's Gas Export Strategy*, cit., p. 6.

<sup>6</sup> ERI RAS, *Global and Russian Energy Outlook to 2040*, cit., p. 141-142.

<sup>7</sup> I add to Gazprom's own gas production also gas production by Gazpromneft (in Ministry of Energy calculated separately).

<sup>8</sup> IEA, *Energy Policies Beyond IEA Countries. Russia 2014*, Paris, OECD/IEA, June 2014, p. 82, <https://www.iea.org/publications/freepublications/publication/russia-2014---energy-policies-beyond-iea-countries.html>.

Figure 1 | Russian gas production 2006-2014 (Bcm)



Source: Russian Ministry of Energy, <http://minenergo.gov.ru/en/activity/statistic>.

Gas imports from Central Asia and Azerbaijan have for many years been complementing internal production, to meet both domestic and export needs. Since 2009, mostly due to demand-side constraints,<sup>9</sup> Russian import volumes from the CIS have also declined – falling from above 50 Bcm to around 20 Bcm in 2014 with expected further declines.

Despite the past trends, Russian gas production is forecast to resume growth, at least in the longer term. According to more optimistic forecasts by the Energy Research Institute of the Russian Academy of Sciences (ERI RAS), production will increase by 33-49 percent to 870-970 Bcm, depending on the scenario. Only the most optimistic scenario foresees a need for new discoveries.<sup>10</sup> More recent IEA forecasts are more conservative, foreseeing a prolonged period of stagnant production at ca. 650 Bcm, which would start rising after 2025 to less than 720 Bcm in 2040.<sup>11</sup> The main limitation to Russian output growth remains stagnant demand on both domestic and key export markets (EU and CIS countries). Continued demand-side challenges and market uncertainties – in Europe, Ukraine and Russia itself – seem especially important in the short- to mid-term period.<sup>12</sup> This outlook may mean decreasing output – already visible in the case of Bovanenkovo – or even putting on hold major production projects and challenging future upstream investments. This situation constitutes also the key driver for diversification of Russian

<sup>9</sup> But also changes in the Russian internal gas market and in Central Asian and Azerbaijan gas sectors.

<sup>10</sup> ERI RAS, *Global and Russian Energy Outlook to 2040*, cit., p. 140.

<sup>11</sup> IEA, *World Energy Outlook 2015*, Paris, OECD, November 2015, p. 205, <http://energy.anu.edu.au/files/weo2015.pdf>.

<sup>12</sup> IEA, *Medium-Term Gas Market Report 2015*, Paris, June 2015.



gas exports to Asia, which would speed up changes in the geography of Russian gas production with increasing importance of Eastern Siberia and Far East fields.<sup>13</sup>

## 8.2 Russian Gas on the Domestic Market

Russian gas is consumed domestically and exported via pipelines to Europe, Turkey and the CIS region. In the last few years relatively small volumes of Russian LNG have begun to be exported – mostly to Asia. In 2014 Russia produced 640.3 Bcm of gas<sup>14</sup>; more than two-thirds of this amount was consumed internally, while the rest was exported abroad.<sup>15</sup>

Russia is the world's second largest gas consumer, and the single biggest consumer of its own domestic gas production, with demand in 2014 reaching 452.7 Bcm.<sup>16</sup> Gas accounts for 55 percent in the Russian energy mix. Domestic consumption decreased significantly in 2009 after the economic crisis and since 2011 has been declining again by an average of 1.05 percent y/y, which is connected *inter alia* to lower growth in the Russian GDP.

The ongoing economic problems in Russia related to low oil prices, inflation, depreciation of the ruble and the international economic sanctions regime – among other factors – may contribute to prolongation of this trend. According to the IEA, demand will be quasi-stagnant between 2014 and 2020, falling by about 0.2 percent annually.<sup>17</sup> Longer-term forecasts are more ambiguous. Gas consumption may restart a growth trend – according to 2014 forecasts by ERI RAS, on average 0.8-1 percent per year, reaching in the best case 506 Bcm in 2040.<sup>18</sup> Yet, according to each of the more recent IEA scenarios, Russian gas demand will decrease until 2040.<sup>19</sup> The IEA's baseline scenario<sup>20</sup> assumes contraction by 8.6 percent till 2030 and then recovery to 460 Bcm in 2040 – over 3 percent below the 2013 level. That would decrease the share of gas

<sup>13</sup> IEA, *World Energy Outlook 2015*, cit.

<sup>14</sup> Russian Ministry of Energy, *Short brief about Russian fuel and energy complex*, <http://minenergo.gov.ru/en/node/1116>. On Russian language website (<http://minenergo.gov.ru/node/1215>) this production amounts to 642.1 Bcm and includes gas production in annexed Crimea.

<sup>15</sup> Russian Ministry of Energy, *Short brief about Russian fuel and energy complex*, cit.

<sup>16</sup> According to Russian Ministry of Energy statistics (<http://minenergo.gov.ru/en/activity/statistic>); 409.2 Bcm according to BP. See BP, *Statistical Review of World Energy 2015*, cit., p. 23.

<sup>17</sup> IEA, *Medium-Term Gas Market Report 2015*, cit., p. 45.

<sup>18</sup> ERI RAS, *Global and Russian Energy Outlook to 2040*, cit., p. 169-170.

<sup>19</sup> IEA, *World Energy Outlook 2015*, cit., p. 197.

<sup>20</sup> IEA *World Energy Outlook 2015* baseline scenario is called the New Policy Scenario; for details see <http://www.iea.org/publications/scenariosandprojections>.

in the Russian energy mix to 49 percent.<sup>21</sup> The final outlook will depend mostly on the final design, consistency and effectiveness of implementation of reforms (including gas market liberalization and pricing, as well as energy effectiveness measures) but also on the country's economic situation – for instance, a prolonged economic downturn could result in steeper declines in the next years.

### *8.2.1 Challenging Times for Gazprom: Market Structure and Governance*

Natural gas is a strategic asset of the Russian Federation. Gas and oil sales revenues account for about 52 percent of Russian federal budget income<sup>22</sup> and 68 percent of total export revenues, with gas alone accounting for 14 percent of these revenues.<sup>23</sup> Regulated gas prices have remained an important tool for subsidizing the Russian economy and are an element of social policy. This has been among the factors hampering completion of reforms of the sector by the state. Gas export has also been playing a role in Russian foreign policy, allowing for a kind of “stick-and-carrot” policy recently most visible in the CIS area where preferential gas supply conditions (low prices, postponing debt repayment, etc.) were offered to Russian allies (for instance to Belarus and Armenia, customs union participants) and non-preferential or even quite tough (high or quickly rising prices, etc.) conditions used as punishment (as in the case of Ukraine).<sup>24</sup> The gas sector remains under significant state control: all gas resources belong to the state by law, state agencies issue exploration and production licenses, legal restrictions exist<sup>25</sup> on foreign investments in so-called strategic fields, and preference is given to state-controlled companies. Those companies, most importantly Gazprom,<sup>26</sup> dominate the sector and together with state policy shape its future.

<sup>21</sup> Own calculations based on IEA, *World Energy Outlook 2015*, cit.

<sup>22</sup> See Energy Minister Alexander Novak's interviews in 2015. For example: “Share of oil and gas revenues in Russian budget to decline by 5% in 20 years - minister”, in *TASS*, 6 February 2015, <http://tass.ru/en/economy/775919>. On Russia's GDP dependency on oil and gas see also Andrey Movchan, “Just an Oil Company? The True Extent of Russia's Dependency on Oil and Gas”, in *Carnegie.ru Commentaries*, 14 September 2015, <http://carnegieendowment.org/publications/?fa=61272>.

<sup>23</sup> Mostly via 30 percent gas export tax. See EIA, “Oil and natural gas sales accounted for 68% of Russia's total export revenues in 2013”, in *Today in Energy*, 23 July 2014, <http://www.eia.gov/todayinenergy/detail.cfm?id=17231>.

<sup>24</sup> See Randall Newnham, “Oil, Carrots and Sticks: Russian Energy Resources as a Foreign Policy Tool”, in *Journal of Eurasian Studies*, Vol. 2, No. 2 (July 2011), p. 134-143, <http://dx.doi.org/10.1016/j.euras.2011.03.004>.

<sup>25</sup> Recently these restrictions were relaxed to some extent. See Eugene Gerden, “Russian government to ease resource investment access for foreign investors”, in *InvestorIntel*, 12 November 2015, <http://investorintel.com/?p=105797>.

<sup>26</sup> The state directly or indirectly owns 50.232 percent of Gazprom shares. See Gazprom website: *Equity capital structure*, <http://www.gazprom.com/investors/structure>.

Gazprom is the most important actor in the Russian gas sector. It is not only the key gas producer (see figure 1), supplier and investor but also the sole owner and operator of the huge Russian gas infrastructure system. Beside the world's largest transmission and distribution network this system consists of numerous gas production, processing and storage facilities.<sup>27</sup> Gazprom is also the world's largest gas exporter and an important actor (as both supplier and investor) on the European and CIS gas markets. As such, the company has been of strategic importance for Russian economic and foreign policy.

Despite its role and assets Gazprom's position has been slowly eroding in recent years, which is best illustrated by the changing structure of Russian gas production and the growing role of non-Gazprom producers<sup>28</sup> (figure 1). While Gazprom sells its gas internally at prices regulated by the state,<sup>29</sup> those traditionally low prices have gradually been increased – on average by 15 percent per year between 2008 and 2013, when they reached 115 dollars/mcm.<sup>30</sup> This has resulted in both more profitable<sup>31</sup> Gazprom sales on the domestic market and increased competition from non-Gazprom producers. Together with incentives (i.e., tax exemptions and more flexible upstream licensing) granted by the state to certain producers, the consequence has been an increase in non-Gazprom supplies on the internal market.<sup>32</sup> Gazprom's share in Russian gas production has accordingly been decreasing, from 83.5 percent in 2007 to 69.1 percent in 2014.<sup>33</sup> Non-Gazprom gas production during the same period has almost doubled, reaching a 30 percent share in total Russian output in 2014.<sup>34</sup> This trend of declining Gazprom output and increasing output of non-Gazprom producers seems set to continue in 2015 according to early estimates and media reports.<sup>35</sup> Most important non-Gazprom producers include Novatek (8.4 percent of total Russian output), Rosneft (5.8 percent)

<sup>27</sup> Tatiana Mitrova, *The Geopolitics of Russian Natural Gas*, Houston, Baker Institute, 21 February 2014, <http://bakerinstitute.org/files/7356>.

<sup>28</sup> James Henderson, *Non-Gazprom Gas Producers in Russia*, Oxford, Oxford University Press, 2010.

<sup>29</sup> Yet Gazprom holding companies (e.g., Gazpromneft) and Gazprom itself sell part of its gas at free/unregulated prices, e.g., on the gas exchange.

<sup>30</sup> James Henderson, "The Domestic Gas Sector in Russia: Gradual Progress Towards a Competitive Market?", in *Oxford Energy Forum*, No. 97 (August 2014), p. 23-25 at p. 24, <https://www.oxfordenergy.org/publications/oxford-energy-forum-issue-97>.

<sup>31</sup> Starting to enable cost recovery, especially important in the context of new, capital-intensive fields being developed.

<sup>32</sup> IEA, *Energy Policies Beyond IEA Countries. Russia 2014*, cit., p. 82-83.

<sup>33</sup> Source: Russian Ministry of Energy.

<sup>34</sup> It includes also gas produced in joint ventures with foreign investors. Ibid.

<sup>35</sup> Interfax, "Gas production in Russia down 1% in 2015", in *Russia Beyond the Headlines*, 2 January 2016, [http://rbth.com/news/2016/01/02/gas-production-in-russia-down-1-in-2015\\_557001](http://rbth.com/news/2016/01/02/gas-production-in-russia-down-1-in-2015_557001); "BRIEF: Russia's Novatek Says Natural Gas Output Up 9 pct in 2015", in *Reuters*, 13 January 2016, <http://uk.reuters.com/article/idUKFWN14W04420160113>.

and Lukoil (3 percent). Growth of non-Gazprom production is likely to continue, with Rosneft and Novatek<sup>36</sup> actively seeking to increase their domestic market share. Rosneft has been signing contracts with subsequent industrial consumers for supplies of almost 88 Bcm/year by 2020<sup>37</sup> (an increase of 134 percent over 2014). Novatek plans to increase output to over 110 Bcm by 2020, exploiting its substantial resource base.<sup>38</sup>

For many years Gazprom has not only been the sole user of the domestic transmission system, but also the legally defined monopolistic exporter of Russian gas. Yet this situation too has started to slowly change. The first modification was introduced in 2012 when the state granted (limited<sup>39</sup>) access to transmission capacity to all non-Gazprom producers. Also in 2012, Novatek signed a 10-year gas supply deal with German company EnBW,<sup>40</sup> *de facto* bypassing Russian law.<sup>41</sup> Then, at the end of 2013, Novatek and Rosneft succeeded in obtaining the right to export LNG independently from Gazprom.<sup>42</sup> This *de jure* ended Gazprom's monopoly over exports, although the company still controls the most important pipeline export sector. Following these developments, lobbying aiming at ending also this Gazprom privilege has continued: in summer 2015 Rosneft strengthened its appeals for liberalization of Russian gas exports and the unbundling of Gazprom,<sup>43</sup> in early 2016 both Rosneft and Novatek kept seeking for the possibility to export their gas to EU via Gazprom<sup>44</sup>. Such a proposal evidences an increased internal competition and pressure on Gazprom.

These developments demonstrate that the Russian state is allowing, or even pro-

<sup>36</sup> Lukoil does not openly compete with Gazprom, selling most of its production to Gazprom.

<sup>37</sup> See *Argus FSU Energy*, Vol. XX, No. 41 (22 October 2015).

<sup>38</sup> Especially new fields with total potential gas reserves of 2.5 Tcm of gas on the Yamal and Gydan peninsulas, with Gydan peninsula gas production designated for the Yamal LNG Novatek project being offered special tax exemptions.

<sup>39</sup> Independent producers are granted access when there is spare capacity, and pay higher tariffs for gas transportation.

<sup>40</sup> See "Russia's Novatek signs deal with Germany's EnBW to ease LNG sales", in *Reuters*, 20 September 2012, <http://www.reuters.com/article/novatek-europe-idUSL5E8KKIW020120920>.

<sup>41</sup> See Andrei V. Belyi, "Gazprom-Rosneft competition for Asian markets: opportunities and challenges", in *Russian Analytical Digest*, No. 174 (26 October 2015), p. 13-16 at p. 14, <http://www.css.ethz.ch/content/dam/ethz/special-interest/gess/cis/center-for-securities-studies/pdfs/RAD-174.pdf>; "Novatek starts gas delivery to Europe, despite Gazprom monopoly", in *Russia Today*, 16 October 2012, <https://www.rt.com/business/novatek-gas-europe-supply-561>.

<sup>42</sup> Act entered into force in December 2013. See Szymon Kardaś, "A feigned liberalisation: Russia is restricting Gazprom's monopoly on exports", in *OSW Commentaries*, 28 November 2013, <http://www.osw.waw.pl/en/node/21429>.

<sup>43</sup> "Russia's Rosneft seeks end to Gazprom gas export monopoly - RIA", in *Reuters*, 22 July 2015, <http://www.reuters.com/article/russia-rosneft-gas-idUSL5N10243N20150722>.

<sup>44</sup> See Elena Mazneva, "Novatek Said to Seek Approval to Send Gas to EU via Gazprom", in *Bloomberg*, 2 March 2016, <http://bloom.bg/1Y0CfX>.

moting, a structural evolution of the Russian gas market towards partial liberalization, with a slow decrease in the role of Gazprom and favourable conditions for development granted to two companies either less (Novatek) or more formally (Rosneft<sup>45</sup>) linked to the state. Also demonstrated is the sustaining duality of the Russian gas market, which is characterized by two coexisting<sup>46</sup> models of gas trade – regulated and non-regulated – and with still unclear perspectives for the completion of gas pricing reform. The pattern indicates that from the state's point of view more competition within the gas market as well as among key state-controlled companies may be desirable.<sup>47</sup> It is not yet clear what final design is intended for Russia's internal gas market and Gazprom's ultimate role in it – or even if such a design has been developed at this point. Different public initiatives – including the launch of a gas exchange platform for domestic trade in late 2014 – which until now haven't attracted much attention, at least from Gazprom,<sup>48</sup> suggest that the state is actively looking for solutions tailored to Russian needs and to the dynamically changing circumstances of the gas markets.

The changes visible in the Russian gas market constitute an important challenge to Gazprom's strategy. Decreasing internal gas demand and increased state-supported competition have already translated into lowering both the share and the volumes sold domestically by Gazprom. In addition, despite the fact that the growing regulated gas prices increase the profitability of internal gas sales, this policy also limits Gazprom's flexibility in pricing while competing with Rosneft or Novatek. It may push Gazprom for greater engagement in the non-regulated segment of the Russian gas market in order to defend its market share, regain its most profitable customers (the power sector), and gain more influence in this market segment. Increased competition, in the longer run, may also undermine Gazprom's interest in developing all capital-intensive and strategically important upstream projects, as increased production costs put it in a less advantageous position compared to its competitors.

The current unfavourable economic and political context makes it unlikely that the Russian state will institute reforms that would clearly further challenge Gazprom and undermine the strategic role it plays. This point is in fact explicitly stated in the draft

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<sup>45</sup> For ownership structure as of 1 November 2015. See Rosneft website: *Shareholder Structure*, [http://www.rosneft.com/Investors/structure/share\\_capital](http://www.rosneft.com/Investors/structure/share_capital).

<sup>46</sup> Catherine Locatelli, "The Russian Gas Industry: Challenges to the 'Gazprom Model'", in *Post-Communist Economies*, Vol. 26, No. 1 (2014), p. 53-66.

<sup>47</sup> According to Locatelli, it may serve both to discipline Gazprom as well as to reduce asymmetry of information in state-Gazprom relations. *Ibid.*

<sup>48</sup> An exchange in St. Petersburg allowing for sales of up to 35 Bcm of gas, where Gazprom has the right to sell half of total volumes and independent producers the other half, was launched after the experimental period 2006-09. See for example Gazprom website: *Marketing: Russia*, <http://www.gazprom.com/about/marketing/russia>.

Russian Energy Strategy 2035.<sup>49</sup> Yet these same unfavourable conditions constitute a call for optimization of Russian gas strategy and Gazprom's role in it. To a significant extent Gazprom's future will depend on its ability to effectively act and adapt to the more volatile conditions of today's European and Russian markets. Similarly, Russia has to adapt its gas strategy to these more challenging circumstances, which currently means further support for a controlled liberalization process (as illustrated for example by remarks by president Putin calling for increased trade on the St. Petersburg gas exchange<sup>50</sup>). As a consequence, we can expect the persistence of a dual gas market in Russia, with increasing sales at unregulated prices, and a somewhat dualistic gas policy supporting liberalization yet protecting Gazprom from its most severe effects. At the same time necessary adjustments in both Russian gas strategy and Gazprom's internal and external strategy should lead to reframing Gazprom's role to allow it more flexibility in adapting to and competing within a more liberalized environment, in both Russian and European markets. This would necessarily also mean passing to other actors some of the functions Gazprom has been fulfilling until now, with the ultimate result of a more oligopolistic structure for the Russian gas market.

## 8.3 Decreasing Role of the CIS Market

### 8.3.1 Demand

The CIS is the smallest market for Russian gas, and its share continues to diminish. Russian gas sales to the CIS peaked in 2006 at over 96 Bcm (ca. 13.6 percent of total sales) but since then have declined, mostly due to rising export prices and economic problems. The most important CIS consumer of Russian gas has been Ukraine<sup>51</sup> (only few years ago with up to 60 percent of total Russian gas sales to the CIS), followed by Belarus.

Recent years brought visible changes: in 2014 CIS-directed exports of Russian gas were already at less than half of 2006 volumes (44.2 Bcm). Declining Ukraine gas consumption and imports – dropping dramatically in 2015 by 58 percent y/y to 6.1 Bcm<sup>52</sup>

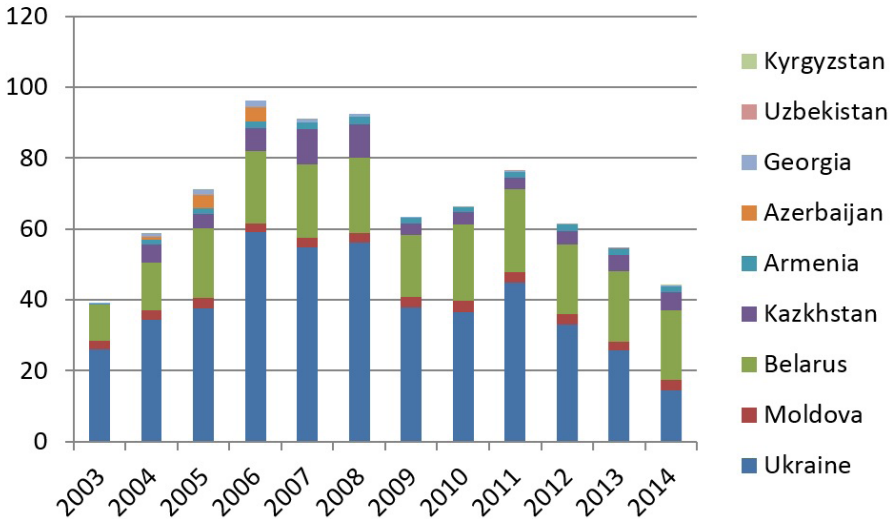
<sup>49</sup> Russian Ministry of Energy, *Proyekt Energostrategii Rossiyskoy Federatsii na period do 2035 goda* (Draft Energy Strategy of Russia for the period up to 2035), updated 30 September 2015, <http://minenergo.gov.ru/node/1920>.

<sup>50</sup> "Putin highlights gas priorities", in *Argus FSU Energy*, Vol. XX, No. 42 (29 October 2015). Russian Presidency, *Meeting of the Commission for Strategic Development of the Fuel and Energy Sector and Environmental Safety*, 27 October 2015, <http://en.kremlin.ru/catalog/keywords/83/events/50571>.

<sup>51</sup> A few years ago it was also the biggest importer of Russian gas globally.

<sup>52</sup> Naftogaz Ukraine, *Ukraine purchased 63% of its imported gas in Europe in 2015*, 2 February 2016,

Figure 2 | Russian gas exports to the CIS (Bcm)



Source: Gazprom annual reports, <http://www.gazprom.com/investors/disclosure/reports>.

– have played a major role in the decrease of Russian gas exports headed towards the CIS. The second reason behind this decrease was Azerbaijan and Georgia, which minimized Russian gas imports after launching production from Azeri Shah Deniz field in 2006.<sup>53</sup>

CIS demand for Russian gas is not expected to recover,<sup>54</sup> in particular due to the continued low Ukrainian demand. Future levels remain uncertain as the situation on the gas markets and at the political level remains unstable, opening possibilities both for further reduction of Ukrainian imports as well as for their increase (if any kind of Russian-Ukrainian compromise is reached). Beside Ukraine's gas imports, the future of Russian gas in the CIS may be influenced by possible wider application of energy efficiency measures in the region, related to possible alignment of Russian gas export prices with "European" levels (e.g., for Belarus) and increasing diversification of gas supplies by other CIS countries (mostly via integration with the EU gas market<sup>55</sup>).

<http://www.naftogaz.com/www/3/nakweben.nsf/0/8FD7A9A348A0844DC2257F4C005802FD>.

<sup>53</sup> Simon Pirani and Katja Yafimava, "CIS Gas Markets and Transit", in James Henderson and Simon Pirani (eds.), *The Russian Gas Matrix. How Markets Are Driving Change*, Oxford, Oxford University Press, 2014, p. 181-215.

<sup>54</sup> See Cedigaz or IEA forecasts.

<sup>55</sup> See for example the realized Romania-Moldova gas interconnector.

### 8.3.2 Changes and Challenges in Russian Gas Trade with the CIS

Gazprom – often integrating its own production with Central Asian volumes – has long been the main gas supplier in the CIS area due to strong post-USSR links between Russia and the other countries of the region, including their economies and gas systems. These interlinkages have resulted in historically low, subsidized export prices and excessive gas demand in the region. To a certain extent, changes in the gas relations of CIS countries with Russia (in pricing, etc.) mirror the process of transition within the region, with probably the most significant changes having occurred in Russian-Ukrainian relations.

Gas supply contracts for CIS customers have been politicized, with their specific conditions often bundled to transit agreements<sup>56</sup> or other non-gas-related issues.<sup>57</sup> Already a decade ago Gazprom was starting the process of gradual alignment of supply contracts with “European” standards and unbundling supply and transit contracts (in 2009 in Ukraine). This is probably best reflected in rising gas export prices, which in 2014 were already on average 136 percent higher in the CIS than in Russia.<sup>58</sup> Yet widely divergent prices for different CIS countries – Ukraine vs. Belarus and Armenia – show that this process has been selective and is still unfinished. Additionally, aligning supply conditions with market principles has not necessarily meant an end to the political role of bilateral gas relations, as Gazprom has kept its – in some cases important – assets which enable it to influence internal developments (for instance in Moldova<sup>59</sup>).

Rising gas prices were among the key reasons behind decreasing CIS demand for gas, with the biggest decreases observed where the biggest price hikes were implemented, such as in Ukraine. Other factors include increase in efficiency of gas use – somehow related to rising prices – and economic downturn in the CIS region. Since early 2014, due also to the ongoing Ukraine-Russia dispute on gas supply conditions, we observe an even steeper decline in Ukraine’s imports from Gazprom (figure 2). Beside falling consumption, the key factor underlying the change is Ukraine’s policy of diversification of sources<sup>60</sup> and gradual integration – not only physically, but also thanks to mar-

<sup>56</sup> As in the Ukrainian case, which ended in 2009.

<sup>57</sup> For instance the so-called Kharkiv agreement with Ukraine in 2010 which granted a 100 dollars decrease in gas export prices in exchange for prolongation of stationing the Russian Black Sea Fleet in Crimea.

<sup>58</sup> See Gazprom 2014 annual report, which measures average Gazprom price on the domestic market at 3,673.8 RUB/mcm and average price for CIS and Baltics at 8,677.9 RUB/mcm. Gazprom, *Annual Report 2014*, May 2015, p. 79-80, <http://www.gazprom.com/investors/disclosure/reports/2014>.

<sup>59</sup> See for example Florent Parmentier, “Moldova”, in David Cadier (ed.), *The Geopolitics of Eurasian Economic Integration*, London, LSE IDEAS, June 2014, p. 46-53, <http://www.lse.ac.uk/IDEAS/publications/reports/SR019.aspx>.

<sup>60</sup> Via increased imports of gas from the EU using the so-called reverse gas flow.



ket reforms – with the EU gas market. In 2015 Ukraine reversed its import dependency structure, importing over 60 percent of gas from Europe<sup>61</sup> and succeeding in surviving the whole 2015/16 winter season without Russian gas imports.<sup>62</sup>

For Gazprom, this indicates important changes in the gas sales model in its key CIS market: not only decreased demand for its gas but also greater uncertainty over exported volumes and prices, along with the need to compete with other suppliers for share in the once key Ukrainian market. At present, there is no stable arrangement on gas trade between Ukraine and Russia, as both supply and transit contracts have been challenged in international arbitration, which still is processing Russian and Ukrainian claims. Since 2014 the framework for each year's Russian gas supplies has been negotiated individually with the help of the European Commission in the so-called trilateral gas talks format.<sup>63</sup> Yet also those framework conditions are aimed primarily at safeguarding sufficient storage level (needed for both Ukrainian security of supply and EU transit security) and do not translate into a substantial increase in Ukrainian gas imports from Russia.<sup>64</sup>

Proven ability to buy gas in substantial quantities at competitive prices from non-Russian suppliers increases Ukraine's chances for an advantageous ruling by the Stockholm arbitration court, which beside making it possible to settle the longstanding gas disputes would create the basis for a new Russia-Ukraine gas relationship. Unless there is a substantial retreat from present Ukrainian gas policy (market reforms, efficiency-driven gas demand decrease, limiting dependency on Russian gas and diversification of sources of supply), any future stable agreements between Russia and Ukraine will have to reflect greater competition in the Ukrainian market and its increasing flexibility. It is probable that in such a case, especially if continuing its policy of limiting dependency on transit states and particularly Ukraine, Gazprom will try to offset decreasing gas export volumes by at least partially indirectly supplying Ukraine via the EU: supplying increased volumes of Russian gas to Ukrainian customers via the EU gas market and infrastructure (as for instance the existing system of Nord Stream and the planned Nord Stream 2 and via Slovakia), possibly in cooperation with certain EU companies. It cannot be excluded that in order to defend its position on CIS markets Gazprom will also try to hamper the integration of countries in the region with the EU, including implementation of EU law, as might be the case already in Moldova.<sup>65</sup> It

<sup>61</sup> Naftogaz Ukraine, *Ukraine purchased 63% of its imported gas in Europe in 2015*, cit.

<sup>62</sup> Tadeusz Iwański, "Ukraine: Successful Diversification of Gas Supply", in *OSW Analyses*, 3 February 2016, <http://www.osw.waw.pl/en/node/24057>.

<sup>63</sup> "EU, Russia, Ukraine agree winter gas supply deal", in *EurActiv*, 28 September 2015, <http://eurac.tv/hp0>.

<sup>64</sup> Under the terms of the 2015 winter gas deal Ukraine was obliged to buy 2 Bcm of gas from Russia, and did not exceed this volume.

<sup>65</sup> See, for example, Valeriu Gonta interview with Emmet Tuohy, "Russia uses Transnistrian gas debt as

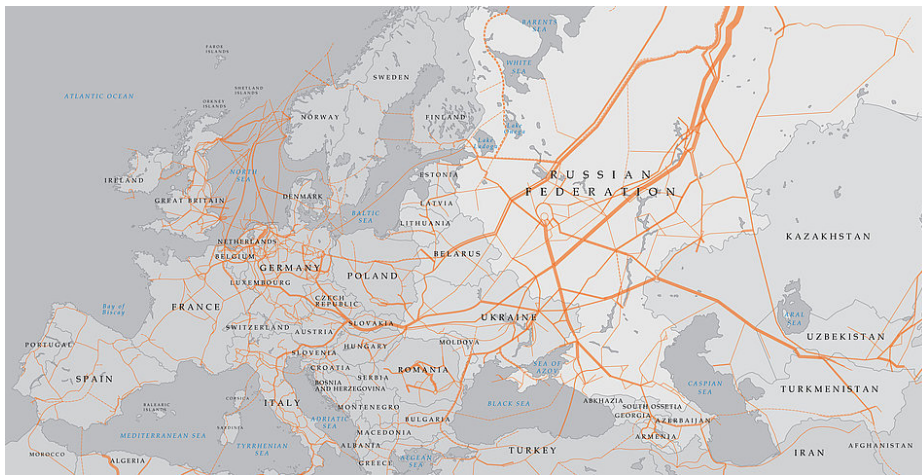
would seem that Gazprom's future sales volumes and strategy in Ukraine and in the CIS will be related to its relations with the EU as well as to the effectiveness of the EU's energy policy in its neighbourhood.

## 8.4 Europe and Turkey

### 8.4.1 Supply Routes

Europe for years has been the key market for Russian gas. European and Turkish sales traditionally represent the key source of revenues for the Russian Federal government, as domestic prices are still significantly below European rates (in 2014 on average over two-thirds lower<sup>66</sup>). Exports to Europe and Turkey (plus LNG sales) are particularly important for Gazprom, accounting for almost 60 percent of its total revenue.<sup>67</sup> Additionally, Turkey has been the quickly growing market and the second largest importer of Russian gas.

Figure 3 | Gas transmission networks in CIS and Europe



Source: Gazprom website, *Transmission*, <http://www.gazpromquestions.ru/en/transmission>.

political weapon against Moldova”, in *Moldova.org*, 26 July 2013, <http://www.moldova.org/en/?p=267297>.

<sup>66</sup> See Gazprom 2014 annual report, which measures the average Gazprom price on the domestic market at 3,673.8 RUB/mcm and the average far abroad price (Europe, Turkey and LNG sales) at 11,299.3 RUB/mcm. Gazprom, *Annual Report 2014*, cit, p. 79 and 77.

<sup>67</sup> Author's calculations based on Gazprom, *Annual Report 2014*, cit.

There are three major export routes to Europe: the Ukraine route, the Yamal-Europe route (via Belarus) and the Nord Stream pipeline. The first two routes supply both the EU gas market and Western CIS markets, the Balkans and Turkey. In addition, Russia exports gas via direct connections to some customers, including the Blue Stream pipeline to Turkey as well as links to Finland and the Baltic states.

For many years now Russia has been pursuing a strategy of diversification of its gas export routes to Europe, first by building new pipelines (Yamal-Europe, Blue Stream, Nord Stream) which have de-emphasized the role of what was once its only export route, via Ukraine, and then by promoting subsequent pipeline projects such as South Stream (which in December 2014 was replaced by the Turkish Stream project and more recently by revived ITGI-Poseidon project<sup>68</sup>) and the Nord Stream 2 project.

#### 8.4.2 Demand

EU gas demand has been falling in recent years due to the economic downturn, energy transition and competition with cheaper or subsidized alternative fuels (coal and renewables, respectively), reaching the record low of 387 Bcm in 2014.<sup>69</sup> Despite mild recovery in 2015<sup>70</sup> the trend of lowered European gas demand is not expected to be reversed in the near future. According to the IEA, EU demand is forecast to fall by ca. 4 percent till 2020<sup>71</sup> and not to recover significantly until 2040.<sup>72</sup> Simultaneously, mostly due to decreasing internal production and stalled unconventional gas developments, Europe is becoming more import dependent. IEA mid-term forecasts expect European and Turkish import needs (in fact, Turkey is predicted to be the quickest growing gas market of the OECD European region<sup>73</sup>) to increase by 70 Bcm by 2020, an increase of roughly 33 percent over 2014 levels, with further growth anticipated in the more distant future.

For several years already European dependence on Russian gas imports has been increasing, growing from 28 percent in 2009 to over 32 percent in 2014, despite almost stagnant total import volumes. There is a possibility for this dependency to further increase in the next few years due to decreasing average contract prices linked to low oil

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<sup>68</sup> Edison, *Gazprom, DEPA, and Edison sign the Memorandum of Understanding*, 24 February 2016, <http://www.edison.it/en/gazprom-depa-and-edison-sign-memorandum-understanding?mliid=828>.

<sup>69</sup> BP, *Statistical Review of World Energy 2015*, cit.

<sup>70</sup> As suggested by media reports. See "EU gas demand increases 4.4% in 2015 – SocGen", in *Gas to Power Journal*, 11 January 2016.

<sup>71</sup> IEA, *Medium-Term Gas Market Report 2015*, cit.

<sup>72</sup> IEA, *World Energy Outlook 2015*, cit.

<sup>73</sup> IEA presents some forecasts and statistics aggregated for OECD Europe and Turkey.

prices<sup>74</sup> and decreasing gas supplies from North Africa.<sup>75</sup> The exact future (and share) of Russian gas on the European gas market will however depend in the short term on Gazprom's ability to remain competitive in face of rapidly growing volumes of relatively cheap LNG available for European customers in 2016-20.

The IEA forecasts that European imports of Russian gas will stay stagnant at 150-160 Bcm,<sup>76</sup> or even decline slightly in the longer term. The conservative scenario presented in Russia's draft Energy Strategy to 2035 also foresees stagnant volumes of Russian gas exports to Europe, with a 10 percent increase appearing in the optimistic scenario.<sup>77</sup> The indications therefore are that Russian gas will remain an important element of the EU's gas imports in the future<sup>78</sup> – in the short term due to contractual obligations but more generally due to size of reserves, their proximity and relatively low marginal costs of production costs. Yet the exact future share of Russian gas is uncertain and depends on both the EU's gas market and policy developments (*inter alia*, the effective implementation of EU climate goals) and changes in global gas markets.

## 8.5 Challenges and Changes in Gas Trade with Europe

Most of Russia's gas exports have been sold via a system of long-term (LT) contracts with clauses restricting resale of gas, and pricing linked to oil. Until recently Russia and Gazprom in particular have pursued a strategy of defence of this system: both LT contracts and oil-indexed pricing which was justified by the need to underpin capital-intensive upstream and infrastructural projects. Gazprom has also defended its strategy of market segmentation and discrimination between customers, whereby different gas supply conditions and prices are applied in different countries and regions (Western Europe, Central and Eastern Europe - CEE, CIS) in order to maximize profits. Yet for several years now Gazprom's modus operandi in Europe has been challenged by changes in the global (increased supply) and the EU gas market (depressed demand, ongoing liberalization and gradual integration – also affecting the CEE region, most dependent on Russian gas imports). Among other developments, we are seeing increased gas-to-gas

<sup>74</sup> Elena Mazneva, "Gazprom Said to See Its Lowest Europe Gas Price in 11 Years", in *Bloomberg*, 23 October 2015, <http://bloom.bg/1R09c05>.

<sup>75</sup> Anna Shiryayevskaya, "EU Reliance on Russia Gas to Deepen as N. Africa Imports Ebb", in *Bloomberg*, 17 November 2015, <http://bloom.bg/1kBmh6i>.

<sup>76</sup> IEA, *Medium-Term Gas Market Report 2015*, cit.

<sup>77</sup> Russian Ministry of Energy, *Draft Energy Strategy of Russia for the period up to 2035*, cit.

<sup>78</sup> Unless there is some important technological breakthrough.

competition in Europe, resulting more frequent successful price renegotiations (aimed at lowering prices and/or greater linkage with hub prices) and more flexible take-or-pay clauses, on the part of multiple EU companies. These changes have contributed to swings in demand for Russian gas in the EU. Another hurdle has been EU competition and gas law implementation leading *inter alia* to gradual modifications of long-term contract conditions (destination clauses) and launching of an antitrust case related to Gazprom's activities in the CEE,<sup>79</sup> which could ultimately limit possibilities for market segmentation within the EU.

An additional challenge to Gazprom's traditional model of gas relations with the EU (and European companies) has been deterioration of political relations in the aftermath of the Ukraine crisis, increased distrust and perceived risks linked to Russian gas imports (especially via Ukraine which remains a key transit country), which have led to renewed EU focus on diversification of sources and routes<sup>80</sup> as a key instrument for guaranteeing security of gas supply. All this has triggered a major, ongoing rethink of Russia's gas export strategy. For the moment Gazprom seems to be developing and investigating a number of new (or renewed) export options. At the same time – due to the dynamic situation and uncertain future, both on the political level and in terms of gas markets – it seems it still has not decided on the final model of its gas strategy *vis-à-vis* the EU.

Current Gazprom and Russian state gas-related activity and decisions indicate that despite a bigger focus on Asian/Chinese gas export directions,<sup>81</sup> Europe is and will remain at least in the short and medium term the main export direction for Russian gas. The same also holds true for Turkey. Despite recently difficult political relations,<sup>82</sup> Turkey is the second biggest market for Russian gas, with perspectives of growth and already existing export infrastructure. Due to ongoing changes in the EU gas market and in EU regulations, increased competition from other gas suppliers and other energy sources and the challenges on the Russian internal market, Gazprom seems more willing to comply with the EU rules, which is shown *inter alia* by the media-reported<sup>83</sup> search for a

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<sup>79</sup> European Commission, *Antitrust: Commission sends Statement of Objections to Gazprom for alleged abuse of dominance on Central and Eastern European gas supply markets*, 22 April 2015, [http://europa.eu/rapid/press-release\\_IP-15-4828\\_en.htm](http://europa.eu/rapid/press-release_IP-15-4828_en.htm).

<sup>80</sup> Visible both in the European Commission February 2015 document on the Energy Union and in the recently developed EU LNG and gas storage strategy.

<sup>81</sup> See, for example, Russian Ministry of Energy, *Draft Energy Strategy of Russia for the period up to 2035*, cit.

<sup>82</sup> In consequence of Turkey's shooting down a Russian military plane at the Turkey-Syria border in November 2015.

<sup>83</sup> See for example, Jack Farchy and Christian Oliver "Gazprom proposes talks to settle EU antitrust case", in *Financial Times*, 21 September 2015; Katya Golubkova and Foo Yun Chee, "Gazprom aims for

compromise on the EU's antitrust case. At the same time Gazprom seems to be seeking increased flexibility for its operations within the EU by several means: further diversification of export routes (by developing Nord Stream 2, possibly the Turkish Stream or ITGI-Poseidon project and in the longer term LNG capacities); increasing access to and shares in internal EU gas infrastructure including storage and hubs; and diversifying modes of supply by supplementing long-term contracts with short-term trade/auctions, oil-indexed prices with spot pricing, etc. If successful, Gazprom should be able to take full advantage of its market power to effectively defend its market share in Europe by, among other means, entering price competition (for example with increased LNG supply expected in the next few years) and influencing EU hub prices. This could result specifically in an increased market share of Russian gas in North-Western Europe (the main market for Russian gas, supplied by multiple pipelines) and limiting diversification of gas supply sources there. Success of such a strategy would depend *inter alia* on developments on the global and EU gas markets and feasibility of key Gazprom investment projects (Nord Stream 2, investments in EU storage) and rules governing their use. But first and foremost, success depends on Gazprom's own determination to engage in this new strategy for gas exports to Europe, and consistency in its implementation. Effectiveness of Gazprom's European strategy will influence overall Russia's gas export strategy and the role of both Gazprom and non-Gazprom producers in it.

### 8.5.1 Asia and Pacific

Asian and specifically Chinese markets have been one focus of Russian gas export strategy for two decades already, attractive due to constantly growing demand and proximity to Russia's big eastern gas fields. These markets also present an opportunity to diversify Russian export markets, supported by decreased European gas demand and tense political relations. This direction seems to be acknowledged in the draft Energy Strategy until 2035, which anticipates up to a 9-fold increase in Russian gas exports to the Asia-Pacific (to 128 Bcm).<sup>84</sup> Simultaneously and in relation to its Asian plans Russia has been planning to increase its presence in the global LNG trade – according to the draft Strategy, a 5-fold increase to 74 Bcm. For now the only Russian gas export to Asia (mostly Japan) is in the form of LNG, reaching 14.5 Bcm or 7 percent of total Russian gas exports in 2014.<sup>85</sup>

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amicable solution in EU antitrust case", in *Reuters*, 9 March 2016, <http://www.reuters.com/article/us-russia-gazprom-eu-antitrust-idUSKCN0WB2CZ>.

<sup>84</sup> Russian Ministry of Energy, *Draft Energy Strategy of Russia for the period up to 2035*, cit.

<sup>85</sup> See BP, *Statistical Review of World Energy 2015*, cit.

Gas consumption in Asia is forecast to grow until 2040 by 117 percent to ca. 1.3 Tcm, which would constitute roughly one quarter of total global gas demand according to the IEA, with 3-fold growth in China alone (whose share in Asian gas demand is set to rise in the long run from the current 30 percent to 44 percent).<sup>86</sup> Yet Russian access to Asian markets may be constrained by several factors. One is the expected increase in gas supply worldwide – with rising LNG capacities and exports by well-established (as in Australia) or new sources (as in the US) expected in the short term, and in the longer term possible increased competition from Iran.<sup>87</sup> Also, the recent slowdown of gas demand growth<sup>88</sup> and the decline of prices in Asian markets may at least in the short term limit the economic viability of Russian Asia-directed gas export plans.

In mid-2014 Russia accelerated its decades-long plan to diversify its export markets: a commercial agreement on gas sales and pipeline construction from Eastern Siberia to China (Power of Siberia) was signed, followed by negotiations of the second agreement on gas supplies and another pipeline, this time from Western Siberia to China (the Altai project). If realized, the two initiatives would enable Russia's to export up to 70 Bcm of gas from its Eastern and Western Siberia fields to China. Yet actual implementation of both projects hinges on agreeing to the details<sup>89</sup> and granting financing (the IEA estimates capital costs of developing the resource base and constructing a pipeline from East Siberia to China in excess of 60 billion dollars), which in the short to medium term may be constrained by the sanctions regime, Russian economic problems, etc. The longer term outlook could prove to be more optimistic. At least one gas pipeline to China is likely to be completed and, as forecast by the IEA, Russian gas exports to China could reach almost 80 Bcm in 2040, constituting about 30 percent of total exports. The feasibility of this solution remains conditional on the implementation of infrastructure projects and development of new upstream sites in Eastern Russia, on Asian and Chinese demand developments, and on availability and pricing of alternative gas supplies.

In parallel, Russia has been planning construction of new LNG terminals that would allow the expansion of its role in the global gas market. Russian LNG sales were initiated from its first (and for the moment only) Sakhalin-2 LNG facility in 2009, reaching a volume of about 15 Bcm<sup>90</sup> of LNG a year. Several other LNG terminals have been

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<sup>86</sup> IEA, *World Energy Outlook 2015*, cit.

<sup>87</sup> See for example "Iran targets 10% share of global gas trade", in *Tehran Times*, 18 November 2015, [http://www.tehrantimes.com/index\\_View.asp?code=250944](http://www.tehrantimes.com/index_View.asp?code=250944).

<sup>88</sup> And in the Japanese case, decrease in demand and expected stagnation.

<sup>89</sup> Not many details on the first agreement were made public, and the second deal has yet to be negotiated and signed.

<sup>90</sup> In 2011, Russia exported 14.6 Bcm LNG, 14.9 Bcm in 2012 and 13.4 Bcm in 2013. IEA, *Energy Policies Beyond IEA Countries. Russia 2014*, cit., p. 113.

planned and are supported by tax exemptions and regulatory changes.<sup>91</sup> Yet present LNG market developments – increased competition from alternative LNG projects going onstream (including US and Australian projects) and well established LNG exporters, as well as low gas prices – may postpone realization of most of these projects, with only Yamal LNG (FID taken) forecast to be implemented in the short to medium term (once it succeeds in solidifying financing).

The visible drive to diversify Russian export markets needs in consequence a strong underpinning in the form of a consistent long-term strategy and viable financing. This strategy should provide for enabling (despite financial constraints) construction of infrastructure and trading mechanisms, which would ensure the Russian share in Asian/LNG markets in the more distant future. It should also take into account visible intensified competition related to Asian exports between Gazprom on the one hand and Rosneft and Novatek on the other, and the effects of this competition on the feasibility of concrete export plans.<sup>92</sup>

## Conclusions

The Russian/Gazprom model of gas sales has recently been challenged on each of its markets. At the domestic level, Gazprom remains the strategic company of choice, retaining key role for the Russian economy and policy as the main supplier to the domestic market and *de facto* monopolistic exporter. Yet its internal role has started to gradually diminish under increased competition, with a domestic share being taken by non-Gazprom producers, especially Rosneft and Novatek. This process is supported by state policy promoting partial liberalization of the gas sector, and encouraged by decreasing internal gas demand. Rosneft and Novatek have also been challenging Gazprom's export monopoly. This has resulted in legal changes allowing both companies to export LNG independently of Gazprom, and may lead to the diminishment of Gazprom's pipeline monopoly, especially in the new Chinese direction. In parallel to the increased competition, a dual gas market has been developing in Russia with gradual augmentation of the segment where gas is sold at non-regulated prices. The Russian gas market has thereby become more flexible and more volatile at the same time, which in turn is both a challenge and a trigger for change in Gazprom. Gazprom has to focus on defending its market share, specifically via defending its share in the most profitable power-generation

<sup>91</sup> *Inter alia* those allowing for LNG exports also by Gazprom's competitors.

<sup>92</sup> See Andrei V. Belyi, "Gazprom-Rosneft competition for Asian markets...", cit.



market but also possibly by increasing engagement in the non-regulated segment of the gas market. In the longer term, state support for gradual and selective liberalization of the internal Russian gas market and the possibility of increased liberalization of exports may become a factor challenging the consistency of the country's gas export strategy, with Russian companies increasingly competing with each other on external markets.

Increased volatility and uncertainty, coupled with decreasing demand, has been facing Gazprom in all its export markets (with the exception of Turkey). In the CIS area, the demand for Russian gas has slumped – reflecting mostly the major decrease in Ukrainian imports in consequence of increased prices, economic downturn and recently (since 2014) intensified efforts to diversify away from Russia – and is not expected to recover. In parallel, there is no stable gas sales agreement with Ukraine as the current agreement has been challenged in international arbitration, and each year's supplies of gas from Russia need to be negotiated separately and compete in price with EU supplies. This represents a substantial loss of market share and quite a significant change in the conditions of gas supply to the all-important Ukrainian market (a few years ago the biggest single recipient of Russian gas). In this dynamically changing situation, the future of Gazprom's sales in the whole CIS area remains uncertain, making it necessary for the company to define a new strategy for the region. It may try on the one hand to defend its share and engagement in regional gas markets by attempts to hamper CIS integration with the EU, in the gas sector. On the other hand it may switch to supplying the region indirectly with Russian gas, via the EU.

Also, European demand has been decreasing in recent years and is not expected to recover. Together, oversupply (growing availability of LNG) and ongoing liberalization and integration of the EU gas market have led to decreasing hub prices and resulted in increased pressure on Gazprom to adapt and modify its modus operandi in the EU – an example of which is the ongoing antitrust case between Gazprom and the Commission. Additionally, since the 2014 Ukraine crisis, deterioration in political relations between the EU and Russia has taken place, which has resulted *inter alia* in the imposition of sanctions on Russia and increased drive to diversify away from Russian gas. Those challenges have triggered a major rethinking of Gazprom's overall gas export strategy and of its European dimension, which has yet to be completed. It does seem, however, that Gazprom has become open to greater adaptation to the changing structure and legal environment of the EU market. At the same it seems to be developing instruments increasing its flexibility of operation in the EU, using market power in order to more effectively defend its market share (instead of price defence). If successful Gazprom may also succeed in postponing further liberalization of Russia's gas exports to Europe, that has been lobbied for more and more intensively by Rosneft and Novatek.

In consequence of the changing market and political environment Russia and Gaz-

prom have also accelerated a strategy of gas export diversification, specifically by pushing forward two pipeline projects to gas-thirsty China. Despite having signed a supply agreement last year and continuing negotiations on the next one, there are economic challenges to implementation of these deals, at least in the short term. These concerns are related to the unclear financial structure of both pipeline projects, in face of decreased growth of gas demand in China and increasing competition on global gas markets. Similar challenges set also economic limits to the development of majority of the planned Russian LNG terminals. Those challenges have become much more serious in the context of the present economic and financial problems in Russia. At the same time, enabling actual diversification of exports and increasing flexibility of operations (e.g., by increasing its share in global LNG trade) seems necessary for Russia not only to reaffirm its position on the increasingly interconnected and volatile global gas markets but also in order to be able to more effectively influence their development.



## 9. Sub-Saharan Africa: A Future Global Gas Player?

Philippe Copinschi and Mark Smedley

“Sub-Saharan Africa is rich in energy resources but very poor in energy supply.” So began the *Africa Energy Outlook* published by the International Energy Agency (IEA) in 2014.<sup>1</sup> “Making reliable and affordable energy widely available is critical to the development of a region that accounts for 13% of the world’s population, but only 4% of its energy demand.” Its argument remains true two years on.

Despite Sub-Saharan Africa being home to 13 percent of the world’s roughly 7 billion population, more than 620 million people – about two-thirds of the region’s inhabitants – remain without access to electricity and some 730 million rely on solid biomass (wood and charcoal) for cooking. This “acute scarcity of modern energy services” across much of the region<sup>2</sup> is highlighted by the fact that gas – the cleanest fossil fuel, with sizeable proved reserves in much of the region – represents just 14 percent of Sub-Saharan Africa’s on-grid power generation capacity (most of that in Nigeria), against 45 percent for coal (mainly South Africa), 22 percent for hydro and 17 percent for oil. For comparison, OECD-wide gas accounts for 24 percent of power generation, and globally the figure is about 22 percent.<sup>3</sup>

Oil and gas in the region were developed primarily for export, with opportunities to build up local gas markets often side-lined. Sub-Saharan Africa produced 5.7 million barrels of oil per day (mmBpd) in 2013, primarily in Nigeria and Angola, of which 5.2 mmBpd was exported, while the region’s 27 billion cubic metre (Bcm) gas consumption in 2012 was similar both to the volume exported and to the volume flared. The historical, post-colonial context for this legacy is explained later in this chapter.

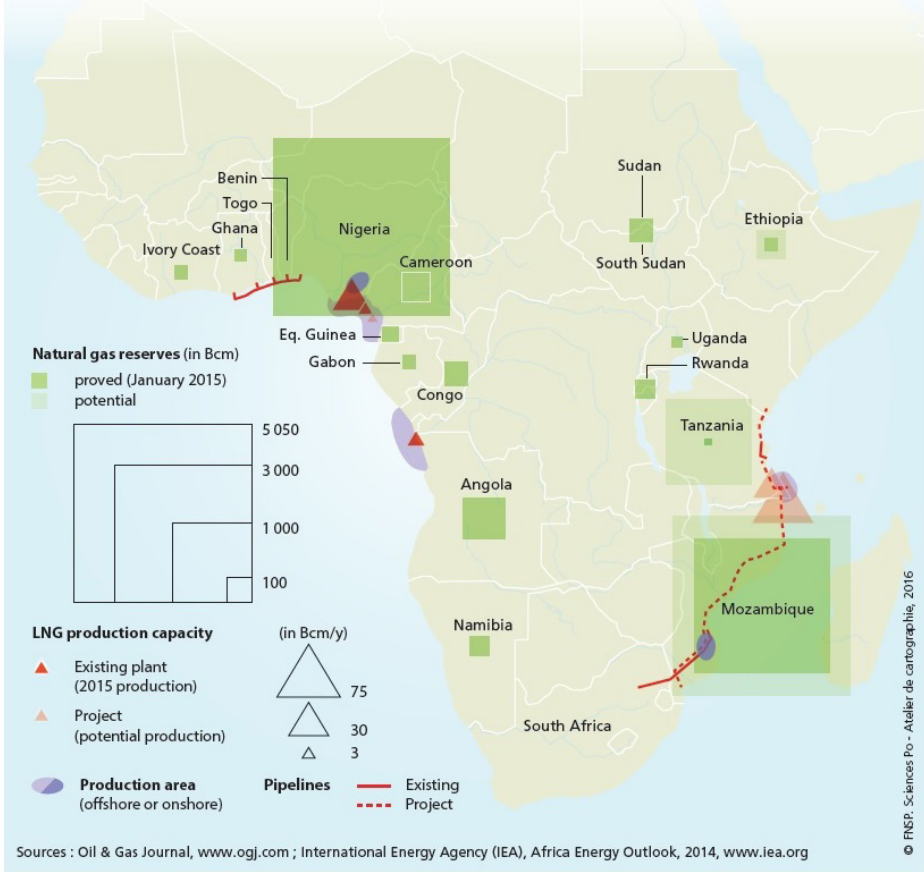
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<sup>1</sup> IEA, *Africa Energy Outlook 2014*, Paris, OECD/IEA, October 2014, mainly p. 13 and 19, <https://www.iea.org/publications/freepublications/publication/weo-2014-special-report-africa-energy-outlook.html>.

<sup>2</sup> *Ibid.*, p. 13.

<sup>3</sup> See excerpt of IEA, *Electricity Information. 2015 Edition* (with 2014 data), Paris, OECD/IEA, July 2015, p. 4, [https://www.iea.org/bookshop/666-Electricity\\_Information\\_2015](https://www.iea.org/bookshop/666-Electricity_Information_2015).

**Natural gas in Sub-Saharan Africa, 2015**



The late 1990s (in Nigeria) and the 2000s saw more serious effort given to gas monetisation, primarily for liquefied natural gas (LNG) exports, but it was not until this decade that major exploration led to huge discoveries offshore East Africa (Mozambique and Tanzania) that may lead to important LNG projects in the 2020s.

The 2014-16 slump in world oil and gas prices may, of course, lead to a long-term investment exodus from the region. Some developers though are proceeding, having scaled back projects and reined in costs. Others are deferring projects but are using extra time to harness newer technology. While Mozambique and Tanzania’s offshore gas projects will require major investment, however, there’s a sense that the resources are so important that their development is only a matter of time.

Moreover, while many gas ventures remain offshore and targeted at LNG exports, a few – stimulated by a firming in local market prices – are allocating some gas to domes-

tic markets, including for power generation. More of this type of investment is needed to sustain the region's longer-term economic growth.

## 9.1 The Evolution of the Hydrocarbon Industry in West Africa

West Africa made its appearance on the oil and gas map relatively recently when compared with other hydrocarbon-producing regions like North and Latin America, the Middle East and North Africa. It was only in the 1960s that oil production started, after discoveries were made in Nigeria (1956), Angola (1955) and Gabon (1956), followed by Congo-Brazzaville and Cameroon (1970s) and more recently Equatorial Guinea (1990s). Although the Gulf of Guinea remains the central point of focus for oil and gas players in Sub-Saharan Africa, exploration and production have spread out since the 1990s across the whole continent, both offshore along the Atlantic Coast with discoveries made in Mauritania, Ghana, Côte d'Ivoire, Senegal, Sao Tome and Principe, and onshore (Uganda, Niger, Chad, etc.).

At the time the hydrocarbon industry began in Sub-Saharan Africa in the 1960s, the continent was just emerging from colonialism. This post-colonial context heavily shaped the oil and gas scene in the region, especially in the former French colonies (Gabon, Congo-Brazzaville and Cameroon) which were all incorporated in France's energy strategy.<sup>4</sup> In Nigeria, which gained independence in 1960, as well as in Angola, independent in 1975, the oil industry is an institution older than the State itself.

Sub-Saharan oil production first substantially got underway in the 1970s, after the end of the Nigeria Civil War (1967-1970) during which the oil-producing region of Biafra tried to secede. Production was helped by the sharp increase in oil price after the 1973 and 1979 oil shocks and by the wave of nationalisations in OPEC countries. Sub-Saharan oil production rose from about 400,000 barrels per day (Bpd) in the late 1960s to 2.5 mmBpd in the mid-1970s (essentially from Nigeria), before reaching 4 mmBpd by the late 1990s and nearly 6 mmBpd since 2010 (with Nigeria and Angola contributing about 2.5 and 2 mmBpd respectively). During the same period, oil reserves in Sub-Saharan Africa rose from about 10 billion barrels in 1970 to 20 in 1975, 30 in 1996, 40 in 2000 and 65 today.<sup>5</sup>

<sup>4</sup> In these countries tied with strong diplomatic links to France, oil production was mostly taken in charge by the French public oil company Elf and intended to be exported to France to supply its needs. The clientelist system, which didn't only concern oil, is known as "Françafrique." Though the oil dimension has disappeared with the privatisation of Elf (and its merger with rival Total) in the 1990s, close links between France and its former African colonies remain, including in the military sector.

<sup>5</sup> BP, *Statistical Review of World Energy 2015*, June 2015, <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.

By raising the oil price, the two successive oil shocks opened new exploration and production opportunities everywhere in the world. This was especially so in Africa where governments, keen on attracting foreign investors to boost development, offered favourable fiscal regimes. Having been kicked out of OPEC countries, international energy companies were very happy to diversify their activities and to invest in Africa. Sub-Saharan Africa was one of the oil and gas regions – along with the North Sea, the Gulf of Mexico and Alaska – that benefited the most from the nationalisations in OPEC countries in the 1970s.

Today, all major energy companies, as well as many independent and even some public (mostly Asian) companies are involved in oil and gas exploration and production in Sub-Saharan Africa, often in cross-partnerships. Although the region represents less than 7 percent of global oil production and less than 4 percent of global oil reserves, it accounts for a quarter to a third of the activities of all the major international energy companies.<sup>6</sup> While Africa is key for private international oil and gas companies, the continent also remains dependent on those companies for the development of its hydrocarbon resources, as no country has ever managed (or even attempted) to play a central role in the local oil and gas industry, leaving the entire sector to foreign (mostly private) companies.<sup>7</sup> As a consequence, the development of the oil and gas industry in Sub-Saharan Africa has always depended on the interests of the international oil business, which explains why the gas sector stayed marginal for so long.

Until quite recently, international oil companies operating in Sub-Saharan Africa showed no real interest in developing gas production. From the companies' point of view, the local markets were too small and the distances to major market centres (Europe, North America and Asia) too great to make gas production and its associated transportation infrastructures (pipelines and liquefaction plants) economically viable. As an example, oil fields in Nigeria are generally scattered, and the associated gas collected from these fields must first be piped to a common collection point, compressed and transported to a processing unit before being available for economic purposes, all of which increases production costs. It was only in 1999, after gas had been flared for decades, that the first LNG plant in Nigeria came on stream, followed by Equatorial Guinea (2007) and Angola (2013).

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<sup>6</sup> Africa (including North Africa) accounts for 12 percent of ExxonMobil's net oil and gas production, 17 percent of Chevron's, 20 percent of Shell's, 24 percent of BP's (despite the fact that BP has been absent from Nigeria since it was expelled from the country in 1979 in protest against British support for the apartheid regime in South Africa), 30 percent of Total's, and more than 55 percent of Eni's. Source: companies' annual reports 2014.

<sup>7</sup> Reflecting the weakness of the State in Africa, none of the oil-producing countries in Sub-Saharan Africa ever nationalised their oil industry. Although OPEC encouraged its members to nationalise their oil industry to further their economic independence, Nigeria (which became member of the cartel in 1971) never took control of operations through its national company, and neither Angola nor Congo ever nationalised the foreign private companies' interests, even after having established Marxist regimes.

Even so, during Nigeria LNG's first decade, most of its gas feedstock was non-associated – and several Bcm of associated gas continued to be flared or vented in Nigeria.

Along with the development of LNG that offers an outlet for associated as well as non-associated gas, the region's proved reserves have increased substantially over the last two decades.<sup>8</sup> West Africa's proved natural gas reserves were 5.74 trillion cubic metres (Tcm) at end-2015, according to the US Energy Information Administration (EIA), with just under 90 percent in Nigeria<sup>9</sup> and 5 percent in Angola. The region has one-third of the continent's total 17.1 Tcm gas reserves, compared to nearly 50 percent in North Africa and just above 17 percent in East Africa, whereas the south and interior of Africa are largely unexplored.<sup>10</sup> West Africa accounts for some 3 percent of global proved natural gas reserves, yet represents only 1.5 percent of the world's production according to the EIA; it accounts for 2.5 percent of the world's gas exports but a tiny 0.6 percent of global gas consumption, and that mainly in Nigeria.

### 9.1.1 West African Gas Export Projects and the Role of LNG

Most West African gas exports are as LNG. The region's share of global LNG trade in 2015 was 9.5 percent – chiefly delivered to Asia, Europe and Latin America.<sup>11</sup> Five sixths of the 29.45 Bcm of LNG sourced from the region came from Nigeria with the remainder from Equatorial Guinea and none from Angola. The total volume should grow from 2016 if Angola ramps up. However, West Africa's share of global LNG trade will decline towards the end of this decade as new giant LNG projects in Australia and the US come online in 2016-19.

Nigeria LNG,<sup>12</sup> launched in stages<sup>13</sup> between 1999 and 2008, has 30.3 Bcm annual

<sup>8</sup> The term "proved reserves" refers to those volumes of gas that are commercially recoverable from known accumulations. It requires the existence of an established market, available infrastructure and an approved field development plan.

<sup>9</sup> Nigeria had an estimated 5.1 Tcm of proved natural gas reserves as of January 2015, according to the *Oil & Gas Journal* (Worldwide Look at Reserves and Production, January 2015). Yet some studies put that figure at just 3.3 Tcm and possibly as low as 1.4 Tcm if the strictest commerciality criteria are applied. See David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas. A New Opportunity for Africa's Energy Agenda?", in *World Bank Reports*, No. 89622 (October 2014), p. vii, <http://hdl.handle.net/10986/20685>.

<sup>10</sup> EIA, International Energy Statistics database, <http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm>. Data used here are mainly for 2014 (2015 for reserves).

<sup>11</sup> Data from table "Source of imports 2015". See International Group of Liquefied Natural Gas Importers (GIIGNL), *The LNG Industry in 2015*, Paris, March 2016, <http://www.giignl.org/publications>.

<sup>12</sup> Nigeria LNG (NLNG) is jointly owned by state-owned Nigerian National Petroleum Corporation (NNPC) 49 percent, Royal Dutch Shell 25.6 percent, Total 15 percent and Eni 10.4 percent – thus, equity, profits and costs are roughly evenly split (49-51 percent) with multinational oil investors, unlike West Africa's two other LNG export ventures.

<sup>13</sup> NLNG liquefaction trains opened as follows: train 1 (4.5 Bcm per year capacity) in 1999, followed by



capacity, is one of the largest LNG terminals in the world today, and produced 8 percent of the world's LNG in 2015.<sup>14</sup> It cost 9.3 billion dollars<sup>15</sup> to build, comprises six liquefaction trains, and sold 85 billion dollars of LNG in its first 15 years.<sup>16</sup>

Equatorial Guinea LNG (EGLNG) has 5.1 Bcm per year production capacity,<sup>17</sup> cost 1.5 billion dollars to build and was completed six months ahead of schedule in 2007.<sup>18</sup> BG Group – since mid-February 2016 owned by Royal Dutch Shell – lifts the lion's share of EGLNG's output and in 2013 its contract was reckoned to be the world's most lucrative ever LNG contract.<sup>19</sup>

Angola LNG<sup>20</sup> opened in mid-2013 at a cost of some 10 billion dollars but shut soon afterwards due to a series of technical faults, before a rupture on its flare line forced a two-year shutdown for repairs in April 2014.<sup>21</sup> The cost of the substantial repairs has not been divulged. At full capacity, it is to receive 10.3 Bcm/year of associated gas and produce 7.2 Bcm per year of LNG exports (some feed gas at all LNG plants is used to

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trains 2 (same size) in 2000 and 3 (4.1 Bcm/year) in 2002; the next three each had capacity of 5.6 Bcm/year and opened in 2006, 2006 and 2008 respectively – for a total of 30.3 Bcm/year. See International Gas Union (IGU), *World LNG Report 2015 Edition*, June 2015, p. 76-77, <http://www.igu.org/publications>; and the Nigeria LNG website: <https://shar.es/1jgGF0>.

<sup>14</sup> The final investment decision for Nigeria LNG's first three liquefaction trains was taken in 1995 amid major controversy. The World Bank was to have held 2 percent equity – so that NNPC's 49 percent would have been balanced by a joint 49 percent shareholding by the three multinationals. But the Bank pulled out when the then military government executed Ken Saro-Wiwa on 10 November 1995 along with eight fellow activists from the Niger Delta region of Ogoniland.

<sup>15</sup> Sebastine Obasi, "NLNG spends \$9.3bn on 6 trains", in *Vanguard*, 14 April 2015, <http://www.vanguardngr.com/2015/04/nlng-spends-9-3bn-on-6-trains>.

<sup>16</sup> AFP, "Nigeria LNG exports reach \$85bn in 15 years", 20 June 2015, <https://www.yahoo.com/news/nigeria-lng-exports-reach-85-bn-15-years-085709715.html>.

<sup>17</sup> EGLNG is owned by US firm Marathon Oil Corp with 60 percent, host nation's state-owned Sonagas with 25 percent (part of state oil producer GEPetrol) and Japan's Mitsui and Marubeni with 8.5 percent and 6.5 percent. See EGLNG, *EG LNG Completes Delivery of First LNG Cargo from Train 1 Plant in Equatorial Guinea*, 27 May 2007, <http://www.eglng.com/News>.

<sup>18</sup> Bechtel, *First LNG Cargo from Equatorial Guinea Project Delivered Six Months Ahead of Schedule*, 24 May 2007, <http://www.bechtel.com/newsroom/releases/2007/05/Inq-cargo-equatorial-guinea-months-ahead-schedule>. According to EIA, EGLNG consumes 6.7 Bcm/year of natural gas from the Alba gas field. See EIA, Equatorial Guinea, April 2015, <https://www.eia.gov/beta/international/analysis.cfm?iso=GNQ>.

<sup>19</sup> Edward McAllister and Oleg Vukmanovic, "Exclusive: How one West African gas deal makes BG Group billions", in *Reuters*, 12 July 2013, <http://reut.rs/12IXGfC>.

<sup>20</sup> Angola LNG is owned by Chevron 36.4 percent, Angolan state Sonangol 22.8 percent, BP 13.6 percent, Eni 13.6 percent and Total 13.6 percent. See GIIGNL, *The LNG Industry in 2015*, cit., p. 22.

<sup>21</sup> Sarah McFarlane and Oleg Vukmanovic, "Angola LNG export project commences recommissioning - spokesperson", in *Reuters*, 26 January 2016, <http://reut.rs/1QpSiIW>; Mark Smedley, "Angola LNG still eyes 2Q restart: Chevron", in *Natural Gas Africa*, 26 February 2016, <http://www.naturalgasafrika.com/angola-lng-still-eyes-2q-restart-chevron-1742>.

fuel the liquefaction process). The plant is also built to supply up to 1.3 Bcm/year to the local market in Soyo province.<sup>22</sup>

Other gas export ventures in West Africa are the 22,000 Bpd Atlantic Methanol<sup>23</sup> in Equatorial Guinea, opened in 2001, and the 10 billion dollars, 33,000 Bpd Escravos Gas-to-Liquids (GTL) plant<sup>24</sup> in Nigeria opened in August 2014, which mainly produces a low-sulphur synthetic diesel. No further plants like these are expected to be built soon, due to the high investment costs involved, and current low world diesel prices.

Indeed, low oil prices have impacted investors' appetite for involvement in any large gas export projects. Three major LNG projects proposed a decade ago in Nigeria – Brass LNG, Olokola LNG and Nigeria LNG train 7/8<sup>25</sup> – have failed to get off the drawing board. The same holds true for others onshore in Equatorial Guinea and Cameroon. This is all because rival LNG projects built or being built in Australia, the US and Russia are exacerbating today's global LNG supply glut and are likely to depress prices until at least 2022.

World LNG production reached 345 Bcm in 2015, registering a slight increase compared to 2014.<sup>26</sup> Experts conservatively estimate that global LNG production capacity

<sup>22</sup> See Angola LNG website: *Onshore Development*, <http://www.angolalng.com/project/onshore.htm>.

<sup>23</sup> The Atlantic Methanol plant cost 400 million dollars to develop, while EGLNG cost 1.4 billion dollars. Both are fed by gas from the Marathon-operated offshore Alba gas-condensate field. See the website of the Equatorial Guinea Ministry of Mines, Industry and Energy: <http://www.equatorialoil.com/introduction.html>. The methanol plant is owned by US firms Marathon Oil Corp and Noble Energy, and Equatoguinean state gas company Sonagas, and can produce 1 million tonnes per year of methanol. See Atlantic Methanol Production Company website: <http://www.atlanticmethanol.com>.

<sup>24</sup> The Escravos GTL plant development was originally budgeted at 1.9 billion dollars but cost spiralled to 10 billion dollars. Owners are Chevron and Nigerian state NNPC, although Sasol as the technology provider has a 10 percent economic interest. Mark Smedley, "Chevron's Escravos GTL Late and Costly", in *World Gas Intelligence*, 13 August 2014.

<sup>25</sup> The Brass LNG project dates back to at least 2005 as a twin-train planned complex totalling 13.8 Bcm/year associating NNPC, ConocoPhillips, Eni and Total; in 2006 it initialled 20-year sales agreements for 2.7 Bcm/year each to BG, BP and Engie. Olokola LNG (OKLNG) also dates back to 2005, with Chevron, Shell and BG partnering NNPC in what was a 27.6 Bcm/year concept; but first BG, then in 2013 Chevron and Shell backed out. NNPC today calls it a two x 17.3 Bcm/year complex, totalling 34.6 Bcm/year. See the OKLNG website: <http://oklng.com/?p=4208>. NLNG trains 7 and 8 would each have had 11.7 Bcm/year capacity; but since 2009, train 7 – which would have taken NLNG capacity to 41.3 Bcm/year – has effectively been shelved, despite its 11 Bcm/year of planned sales having been earmarked in early 2007 to BG, Shell, Eni, Total and Occidental. Also a small floating project "Progress LNG" offshore Nigeria – comprising Norwegian shipowner Flex LNG, local producer Peak Petroleum and Japan's Mitsubishi – hoped to launch by 2011 but weak Atlantic basin LNG demand and regulatory dithering in Abuja caused it, like the three others, to stall.

<sup>26</sup> Wood Mackenzie, "US & Australian LNG start-ups in 2016, but real LNG growth yet to come", 13 January 2016, <http://www.woodmac.com/media-centre/12530450>. Whereas WoodMac gives a 2015 production figure equivalent to 345 Bcm, and GIIGNL (*The LNG Industry in 2015*, cit.) gives a delivered volume equivalent to 309.52 Bcm, it should be noted that they may use different conversion factors and are actually

will reach 455-470 Bcm by late 2020, up 33 percent – excluding projects that have been shelved – with an average of 27.6 Bcm/year added each year until then, and more than that in 2016.

For now, therefore, any LNG projects not already under development have mostly been shelved. Reasons why include: the current supply glut; weak Chinese economic growth; the fall in both Brent crude's value to between 26 and 45 dollars per barrel (from a high of 147 dollars in 2008) and spot LNG prices to between 4 and 5 dollars per million Btu (mmBtu) in March 2016 (from as high as 20 dollars into east Asia in 2013-14); and term contractual LNG prices trending lower in line with oil prices.<sup>27</sup>

West Africa though has two projects that are progressing: a small innovative floating LNG export project off Cameroon took Final Investment Decision (FID) in autumn 2015 and another such offshore Equatorial Guinea may get the go-ahead in 2016. If oil returns to 70-80 dollars per barrel,<sup>28</sup> investors may reconsider shelved large African LNG projects in the expectation that today's glut may end in 2025. But these are likelier to be in East Africa, the region close to Asia's markets, than in West Africa.

Concerning the first of the two West African projects, Africa's first floating LNG (FLNG) project is being developed by UK-French firm Perenco and Cameroon state partner Société Nationale des Hydrocarbures (SNH), which agreed terms with Golar LNG in 2015 for the up-to-700 million dollar conversion of its existing *Hilli* LNG carrier into an FLNG platform to be moored offshore Cameroon. Scheduled to start production in mid-2017, it will have 3 Bcm/year production capacity but initially only 1.65 Bcm/year will be used to liquefy gas from Perenco/SNH's Sanaga offshore gas field.<sup>29</sup> Gazprom has contracted to lift that entire initial output for 8 years.<sup>30</sup>

As for the second, UK-based Ophir Energy plans to take FID in mid-2016 on a similar

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different figures. LNG produced toward the end of one year may not be counted until the next year's (GIIGNL) import data, as it may still be en route to its destination.

<sup>27</sup> The (preliminary) contract LNG average price for that month for all origins into Japan was 7.10 dollars per mmBtu, while the actual average delivered price of cargoes arriving that month was 7.90 dollars. A year earlier (in January 2015) prices were respectively 10.20 and 13.90 dollars. Japan Ministry of Economy, Trade and Industry, *Spot LNG Price Statistics*, January 2016, <http://www.meti.go.jp/english/statistics/sho/slng>.

<sup>28</sup> Eni, a major investor in sub-Saharan Africa, forecast in its mid-March 2016 Strategy outlook that Brent will average 40 dollars in 2016, 50 in 2017, 60 in 2018 and 65 in 2019. See first Appendix slide in Eni, *2016-2019 Strategy Presentation*, London, 18 March 2016, <http://bit.ly/23kKT7v>.

<sup>29</sup> ICIS Heren reported on 1 October 2015 that feed gas is cheaper than US Henry Hub gas, so that LNG produced in Cameroon could be profitable if sold to Europe at 5.50 dollars per mmBtu net of liquefaction and transport costs.

<sup>30</sup> Perenco press release, 27 November 2015, [http://www.perenco.com/sites/default/files/press\\_release\\_27112015\\_final.pdf](http://www.perenco.com/sites/default/files/press_release_27112015_final.pdf). Gazprom also issued a press release on 30 November: *Gazprom Marketing & Trading Singapore Pte Ltd, Perenco Cameroon S.A. and Société Nationale des Hydrocarbures announce the signing of an eight year LNG sales and purchase contract*, <https://shar.es/1jgl7x>.

project, Fortuna LNG, that will use gas from Equatorial Guinea offshore block R's 73.7 Bcm reserves. If all goes to plan, first LNG production would be in mid-2019. Golar LNG was again chosen to provide the 3 Bcm/year floating platform, and the project will cost 600 million dollars to develop – representing only a fifth of the 3 billion dollar cost to develop an onshore liquefaction plant of equivalent size.<sup>31</sup> In January 2016 oil services giant Schlumberger signed a deal, as yet non-binding, to acquire a 40 percent stake in the Fortuna venture (half of Ophir's 80 percent stake) and to reimburse 50 percent of Ophir's past costs in the venture.<sup>32</sup>

Offshore northwest Africa, along the maritime border between Mauritania and Senegal, recent gas discoveries by US independent Kosmos have raised the prospect that, post-2020, a floating LNG venture might be developed. Kosmos said in mid-March 2016 that its 425 Bcm gas resources in the Tortue West field are "sufficient [...] to underpin a world-scale LNG project."<sup>33</sup> Investment decisions are a long way off, but raise hopes that gas finds by Tullow and Cairn nearby may be monetised.

### 9.1.2 Natural Gas Contribution to West African Domestic Energy Markets

West Africa continues to flare a significantly high proportion of its gross gas production. Across Sub-Saharan Africa, an estimated 28 Bcm of gas was flared in 2012, with Nigeria accounting for nearly two thirds of that amount, followed by Angola, Congo and Gabon. According to the IEA, if that volume had been used in gas-fired power plants, it would have increased Sub-Saharan electricity production by 35 percent.<sup>34</sup>

Flaring is known to cause heat radiation and thermal conduction into the immediate environment, lead to the production of toxic gases during combustion, produce high noise levels, and generate and disperse particulate and other gases such as carbon dioxide (CO<sub>2</sub>) into the atmosphere – thereby contributing to climate change. There are

<sup>31</sup> Fortuna is "oversold by several times" with final sales and purchase agreements "expected within Q1 2016." It also said its original 800 million dollar costing for an FLNG project had been reduced by 25 percent to 600 million dollars. Ophir Energy, *Heads of Agreements signed for sale of gas and Capex reductions for Fortuna FLNG*, 9 December 2015, <https://www.ophir-energy.com/press-release/heads-of-agreements-signed-for-sale-of-gas-and-capex-reductions-for-fortuna-flng>.

<sup>32</sup> Ophir Energy, *Equatorial Guinea Farm in, Operations and Trading Update*, 25 January 2016, <https://www.ophir-energy.com/press-release/equatorial-guinea-farm-in-operations-and-trading-update>.

<sup>33</sup> Kosmos Energy, *Kosmos Energy Announces Successful Appraisal of Gas Discovery Offshore Mauritania and Senegal*, 16 March 2016, <http://www.businesswire.com/news/home/20160316005234/en>. See also Mark Smedley, "Mauritania's Tortue West 'Could Underpin LNG Project'", in *Natural Gas Africa*, 16 March 2016, <http://www.naturalgasafrika.com/mauritania-tortue-west-could-underpin-lng-project-1820>.

<sup>34</sup> IEA, *Africa Energy Outlook 2014*, cit., p. 116.

serious health consequences for people living nearby (respiratory problems, skin rashes and eye irritations, as well as damage to agriculture due to acid rain). In Nigeria in particular, as onshore producing fields are often located near villages, the population is forced to live with constant noise, heat and light, which in the longer term can affect the heart and lungs.<sup>35</sup>

For the oil and gas companies, this situation arises primarily because domestic demand for gas is too small to justify using all the associated gas produced, and because of the inadequacy of domestic gas infrastructure to distribute gas to potential consumers. But it is also a reflection of the relative weakness or ineffectiveness of governments in the region, relative to the oil industry, to take steps to harness the resource for use in power generation.<sup>36</sup>

At an international level, latest efforts to combat gas flaring have come from the World Bank through its Global Gas Flaring Reduction Partnership (GGFR), which aims to eliminate routine flaring no later than 2030.<sup>37</sup> Nigeria still has about 100 continuously burning gas flares in the Niger Delta and just offshore, some of which have been burning since the early 1960s.<sup>38</sup> Only Russia, where gas production is far higher, flares more. However, flaring in Nigeria decreased from 15.3 Bcm in 2010 to 10.7 Bcm in 2014,<sup>39</sup> thanks to GGFR incentives for associated gas recovery now being implemented. Angolan gas flaring however has remained stubbornly high at 7 Bcm/year in 2010-14.<sup>40</sup> This may decline once Angola LNG permanently starts up and offshore gas is fed to that complex.

Given Nigeria's population (over 75 million people in 1980, about 178 million to-

<sup>35</sup> For a complete review of the consequences of flaring, see Francis Idowu Ibitoye, "Ending Natural Gas Flaring in Nigeria's Oil Fields", in *Journal of Sustainable Development*, Vol. 7, No. 3 (June 2014), p. 13-22, <http://dx.doi.org/10.5539/jsd.v7n3p13>.

<sup>36</sup> Gas flaring has been prohibited in Nigeria since 1984 under the Associated Gas Re-Injection Act No. 99 of 1979, yet there was no enforcement of the law. See the web blog of international law firm Dentons, *Outlook for the Nigerian Oil and Gas Market*, 15 September 2015, <http://www.dentons.com/en/insights/alerts/2015/september/15/outlook-for-the-nigerian-oil-and-gas-market> (first published in the August 2015 edition of *Financial Nigeria*).

<sup>37</sup> The GGFR is a public-private initiative comprising the oil industry, national and regional governments, and international institutions, that works to increase use of natural gas associated with oil production by helping remove technical and regulatory barriers to flaring reduction, providing guidelines for the oil and gas operators in line with international best practices and developing country-specific gas flaring reduction programmes. See World bank website: <http://goo.gl/38UMoa>.

<sup>38</sup> "Gas flares still a burning issue in the Niger Delta", in *IRIN News*, 8 March 2012, <http://www.irinnews.org/node/251736>.

<sup>39</sup> OPEC, "Natural Gas Data", in *Annual Statistical Bulletin 2015* (see Table 8.2 for members' gross gas production, sales gas, and flaring), [http://www.opec.org/opec\\_web/en/publications/202.htm](http://www.opec.org/opec_web/en/publications/202.htm).

<sup>40</sup> EIA also states that gross natural gas production in Angola was 10.8 Bcm in 2013, of which 65 percent was vented and flared, 24 percent was reinjected, and only 6 percent was marketed. See EIA, *Angola*, 20 March 2015, <https://www.eia.gov/beta/international/analysis.cfm?iso=AGO>.

day<sup>41</sup>) and the low rate of electrification – only 55 percent of the population has access to electricity<sup>42</sup> – gas could have been used for power generation. But lack of creditworthiness among potential consumers held back producing companies from investing in using the gas, despite the obvious benefits to the local population.

### 9.1.3 Nigeria: A Call for More Gas in Power Generation

Producers in West Africa have more and more reason to sell gas into the local market, rather than for export. The principal incentive is that local gas prices have trended higher in recent years and reached, in early 2016, roughly 2.50 to 3 dollars per mmBtu in Nigeria<sup>43</sup> – so on a par with netbacks from LNG exports which have collapsed in recent years.<sup>44</sup> It is worth recalling that the Nigerian domestic market a few years earlier paid just 0.25 dollar per mmBtu for gas. Some Nigerian power plant developers may therefore be ready to pay well above 3 dollars per mmBtu for a guaranteed firm supply, and much higher prices are already paid in Ghana and Cameroon.<sup>45</sup>

Nigeria's 2010 Roadmap for Power Sector Reform set a goal of 20,000 MW of gas-fired generation capacity by 2020.<sup>46</sup> But delivery of this programme under former President Goodluck Jonathan was patchy, and daily deliverable generation capacity as of late 2015 remained about 5,000 MW – only two-thirds of which was gas-fired.<sup>47</sup>

Going from less than 4,000 to 20,000 MW gas-fired generation by 2020 will require significant investment both upstream and in power generation/distribution. The Jonathan government (2010 to mid-2015) failed to privatise 10 power plants, dubbed National Integrated Power Projects (NIPPs), and only one of its planned new Independent

<sup>41</sup> World Bank gave Nigeria's 2014 population as 177.5 million (<http://data.worldbank.org/country/nigeria>), while UN data gives a current (September 2015) estimate of 178.5 million (<http://data.un.org/CountryProfile.aspx?crName=NIGERIA>).

<sup>42</sup> Nigeria 55.6 percent, Ghana 64.1 percent, Angola 37 percent (data for 2012). See World Bank Data, *Access to electricity (% of population)*, <http://data.worldbank.org/indicator/EG.ELC.ACCS.ZS>.

<sup>43</sup> Nigerian independent producer Seplat Petroleum gives its average 2015 realised gas price in Nigeria as 2.50 dollars per mmBtu, up 34 percent on 2014. See Seplat Petroleum, *Full Year 2015 Preliminary Financial Results*, 24 March 2016, p. 2, <http://seplatpetroleum.com/investor-centre/results-centre>.

<sup>44</sup> The netbacks on a LNG export cargo is the value paid for gas on final markets, minus the cost of liquefaction and delivery (shipping) costs. The netback for spot Nigerian LNG exports into east Asia had collapsed to between 3 to 3.50 dollars per mmBtu in March 2016, down from around 16 dollars two years earlier.

<sup>45</sup> Local prices of 7-8 dollars in Ghana and upwards of 9 dollars per mmBtu in Cameroon prevailed as of early 2016.

<sup>46</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 7.

<sup>47</sup> This includes power plants owned by oil majors Shell (650 MW) and Eni (480 MW). See Nigeria Presidency, *Presidential Task Force on Power: 2014 in Review*, 2015, p. 52-53.

Power Projects (IPPs) has been fully financed. This 890 million dollars, 459 MW Azura Edo gas-fired power project, near Benin City in western Nigeria, reached financial close in 2014, placed its order with Siemens in early 2016 and is due to start generating in 2017, backed by local and international investors.<sup>48</sup>

According to OPEC, in 2014 Nigeria marketed some 44 Bcm of gas, but the volume supplied to the home market was only 21 Bcm. The country is thus the largest Sub-Saharan gas market, yet one should be wary of official forecasts that Nigeria's gas consumption will top 103 Bcm/year by 2020 on the back of a "dash for gas" in power generation. That is because reaching 20,000 MW gas-fired generation by 2020 in Nigeria – and a quintupling of the domestic gas market volume – would require an estimated 850 Bcm extra gas supply dedicated to the power sector, itself requiring a massive 20 billion dollars-plus capex upstream.<sup>49</sup>

However, there is at least recognition of problems and opportunities. President Muhammadu Buhari has said: "It is a national shame that an economy of 180 million generates only 4,000MW, and distributes even less."<sup>50</sup> He named Lagos state governor Babatunde Fashola as power minister, and Ibe Kachikwu, a former senior Exxon Mobil executive in Africa, as minister of state for oil. Kachikwu, who is also CEO of state-owned Nigerian National Petroleum Corporation (NNPC), is welcomed by many in non-state upstream firms for his advocacy of tax concessions for indigenous producers and desire both to overhaul NNPC and to push through a revised Petroleum Industry Bill – in limbo since 2007.<sup>51</sup>

Gas-fired power remains "the lowest-cost thermal generation option by a large margin" for Nigeria, according to a 2014 World Bank analysis.<sup>52</sup> A narrowing of the gap

<sup>48</sup> Azura, *Azura Power Signs \$890 Million Financing for Azura-Edo IPP*, 25 November 2014, [http://www.azurawa.com/index.php/download\\_file/view/258/179](http://www.azurawa.com/index.php/download_file/view/258/179); Siemens, *Siemens to Supply Turnkey Power Solution in Nigeria*, 10 February 2016, <https://www.siemens.com/press/PR2016020153PGEN>. In mid-2014 the World Bank announced partial risk guarantee approvals for two IPPs: Azura Edo, and the 533-MW Qua Iboe power plant (QIPP), also gas-fired, at Ibeno in Akwa Ibom, that ExxonMobil wanted to develop. The latter has yet to progress. See World Bank, *World Bank Group Approves Project Series to Boost Local Power Output in Nigeria*, 6 May 2014, <http://goo.gl/fqlkqo>; Exxon Mobil, *NNPC/MPN Joint Venture Signs Agreement on Qua Iboe Power Project*, 22 April 2013, [http://www.exxonmobil.com/Nigeria-English/PA/news\\_akwaibom\\_220413.aspx](http://www.exxonmobil.com/Nigeria-English/PA/news_akwaibom_220413.aspx).

<sup>49</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 7.

<sup>50</sup> Buhari's inauguration speech on 29 May 2015: <http://www.vanguardngr.com/2015/05/read-president-buhari-inaugural-speech>.

<sup>51</sup> Kachikwu in March 2016 said he will split state NNPC into 30 autonomous units with more accountable managers and cited Buhari's call to develop Nigeria's gas resources. See NNPC, *FG Moves to Unbundle NNPC into 30 Companies*, 3 March 2016, <http://nnpcgroup.com/PublicRelations/NNPCinthenews/tabid/92/articleType/ArticleView/articleId/625/FG-Moves-to-Unbundle-NNPC-into-30-Companies.aspx>.

<sup>52</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. x. This is based on costs of gas-fired power estimated by the World Bank at 41 and 68 dollars per mega-

between international and local prices should foster more investor interest in gas for the local market, although indigenous producers believe that a local gas price near to 4-4.50 dollars would be best to spur more gas development.<sup>53</sup>

### 9.1.4 Ghana Goes for Local Gas

The first Nigerian gas reached Ghana via Benin and Togo in late 2008 through the newly installed West African Gas Pipeline (WAGP), launching commercial operations in 2011.<sup>54</sup> But the region's first cross-border pipeline remains under-used, with gas deliveries through it described as erratic. This explains why Ghana has fostered the start-up of an indigenous gas industry since 2010.

With its population of 25mn, Ghana's mineral-rich economy enjoyed strong economic growth to 2014, but its electricity supply was more fitful, due to water shortages for hydropower and erratic WAGP gas deliveries. Ghana by 2019 though is expected to produce over 3 Bcm/year, one-third from Jubilee and two-thirds from TEN/Sankofa – from nothing in 2009 – achieved with little flaring.

Tullow Oil discovered the offshore Jubilee oilfield in 2007, brought it onstream in December 2010, and supplied gas to shore during the first ten months of 2015 at an average rate of 1.25 Bcm/year. Its next offshore Ghana oil project, named TEN, is on target to produce first oil in mid-2016 and to pipe 310 mmcm/year of gas to shore by mid-2017.<sup>55</sup>

Further, Italy's Eni and partner Vitol in 2015 committed 7.9 billion dollars of new private investment for their Sankofa offshore gas project, gas from which should fuel up to 1.000 MW of clean power, replacing dirtier plants to the equivalent to 40 percent of Ghana's current installed generation capacity.<sup>56</sup>

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watt-hour (MWh) based on, respectively, gas prices of 2 dollars per mmBtu (its early 2014 estimate of the minimum wholesale price in Nigeria) and 5.60 dollars per mmBtu, the then prevailing spot LNG export netback. As we already explained, netbacks for spot Nigerian LNG exports into east Asia have since fallen to between 3 to 3.50 dollars per mmBtu as of early March 2016.

<sup>53</sup> Nina Chestney, "Nigeria should charge more for gas to boost production - Oando Gas&Power", in *Reuters*, 3 June 2015, <http://af.reuters.com/article/energyOilNews/idAFL5N0YK1PU20150603>.

<sup>54</sup> See the website of the West Africa Gas Pipeline Authority: <http://wagpa.org/wagpa.html>.

<sup>55</sup> See Tullow Oil website, *Jubilee Field*, <http://www.tullowoil.com/operations/west-africa/ghana/jubilee-field>. Tullow's partners on the Jubilee field are Kosmos, Anadarko, South Africa's PetroSA and state-owned Ghana National Gas Corporation (GNPC). The TEN development is primarily named after the Tweenboa, Enyenra and Ntomme offshore fields. GNPC will pay only 0.50 dollar per mmBtu for associated gas and 3 dollars per mmBtu for non-associated gas from TEN – down from an initial proposed gas price of 9.50 dollars per mmBtu – according to this GNPC posting dated 30 March 2016, "What has TEN to offer Ghana?" (<http://www.gnpcghana.com/press9.html>) which is sourced to Basiru Adam, "What's in TEN for Ghana?", in *TheBFTOnline*, 29 March 2016, <https://shar.es/1jsVtL>.

<sup>56</sup> World Bank, *What Is the Sankofa Gas Project?*, 30 July 2015, <http://goo.gl/A1WtZx>.



Once the Sankofa starts producing gas in early 2018, Ghana will be able to reduce its oil imports by up to 12 Mb/year, according to the World Bank.<sup>57</sup> Eni and Vitol – who call the Sankofa project Offshore Cape Three Point (OCTP) because output will come from five fields – expect first oil in 2017, first gas in 2018, and production of 80,000 boe/d by 2019. OCTP will access some 42.5 Bcm of gas-in-place and 500 million barrels of oil-in-place, says Vitol, providing enough gas to run Ghana’s power plants for 15 years.<sup>58</sup> Gas will be contractually priced at 7-8 dollars per mmBtu, according to details available in 2015.<sup>59</sup>

### 9.1.5 Other Market Developments in the Region

The World Bank’s *Harnessing African Natural Gas* report said that limited infrastructure in Cameroon, Congo-Brazzaville and Gabon meant that these “oil producer” nations were either flaring or reinjecting their associated gas, and thus marketed only 0.465, 1.45 and 0.31 Bcm/year in 2013 – in each case flaring much more. Gas-fired generation capacities are respectively 216 MW, 350 MW and 175 MW – this last at plants in Libreville and Port Gentil.<sup>60</sup>

In Cameroon, with government support, the 216 MW Kribi coastal power plant start-

<sup>57</sup> This was described by the World Bank at the time as “the biggest foreign direct investment in Ghana’s history.” It was triggered following the World Bank’s release of 700 million dollars of investment guarantees. See World Bank, *World Bank Approves Largest Ever Guarantees for Ghana’s Energy Transformation*, 30 July 2015, <http://goo.gl/n9kLjR>. Eni forecasts first oil from Ghana’s OCTP in 2H2017 (see slide 9 of its *2016-2019 Strategy Presentation*, cit.); first gas will take longer.

<sup>58</sup> Vitol, *Ghana, Vitol and ENI announce transformational gas project for Ghana*, 27 January 2015, <http://www.vitol.com/?p=2571>.

<sup>59</sup> Ghana’s energy minister Kofi Buah said in 2015 that the OCTP contractual gas price to be paid by state Ghana National Petroleum Corp. is 8.075 dollars per mmBtu which, provided GNPC makes onshore investment in pipes of 193 million dollars, will be lowered to 7.0135 dollars. This is dearer than both Nigerian gas imports and current spot LNG prices. It is unclear if the OCTP price is indexed to oil prices and might therefore soften. The price has been criticised by one local think tank. But minister Buah defended it, saying that OCTP would generate an estimated revenue of 11.115 billion dollars to the state over its 18-year project life and create new jobs. The World Bank’s 2014 report calculated a minimum wholesale gas price necessary for Sankofa’s development of 9.50 dollars per mmBtu – so about 6.50 dollars for capex, 1.50 for opex and 1.50 for fiscal expenses – which would seem to suggest Ghana secured a fair price. For more information, see David Santley, Robert Schlotterer and Anton Eberhard, “Harnessing African Natural Gas”, cit., p. 14 (Figure 2.2), p. 48-49; Kwabena Adu Koranteng, “ACEP Exposes Govt, GNPC for Signing Bad Gas Contract with ENI and Vitol”, in *News Ghana*, 11 March 2015, <http://www.newsghana.com.gh/?p=721090>; Joe Okyere, “Parliament approves Sankofa, Gye Nyame oil and gas project”, in *Graphic Online*, 12 December 2014, <https://shar.es/1jgN5Z>; Parliament of Ghana, *Official Report for 11th December 2014*, <http://www.parliament.gh/publications/30/1001>.

<sup>60</sup> David Santley, Robert Schlotterer and Anton Eberhard, “Harnessing African Natural Gas”, cit., p. 54-56.

ed up in 2013 using non-associated gas from the offshore Sanaga South. Also, since 2009 UK-based Victoria Oil and Gas (VOG) has developed the tiny Logbaba onshore field, near Douala, for the local market, and in late 2015 was still selling at prices between 9 and 16 dollars per mmBtu.<sup>61</sup> When the country starts producing LNG in 2017, it is possible that some may be landed and regasified for local markets at lower prices.

In the Republic of Congo, as part of its role in developing offshore oil and gas and running the nearby Djeno oil terminal, Italy's Eni built two gas-fired power stations with a capacity of 350 MW, co-owned with the government, as well as a 550 km-long transmission network that has enabled 1.5 million inhabitants of the coastal city of Pointe Noire (40 percent of Congo's total population) to have electricity at home.<sup>62</sup>

About only a third of Angolans have access to electricity (and only 6 percent in rural areas) as the country's electricity infrastructure was substantially damaged during its civil war (1975-2002). Helped by China, the Angolan government has made notable improvements to its power sector, and electricity capacity has more than doubled since the end of the war (about 70 percent of the electricity being generated by hydroelectric facilities).<sup>63</sup> On the other hand, although the government plans to substantially increase its domestic gas-to-power production,<sup>64</sup> further growth in domestic demand for natural gas will probably be slow because high-quality hydropower projects currently being implemented will theoretically be able to cater for the growth in electricity demand.<sup>65</sup>

### 9.1.6 LNG Imports and Pipeline Politics in West Africa

The globally glutted LNG market – with spot prices sub-5 dollars per mmBtu as of March 2016 – shows few signs of any sustained rise in prices out to 2020. As such, LNG imports may be attractive to African nations that lack indigenous gas, not least given that

<sup>61</sup> VOG's subsidiary Gaz du Cameroun (GDC) sold 43 mmcm during the six months to November 2015, most at contractual prices ranging between 9 and 16 dollars per mmBtu. Customers include brewer Guinness, Dangote's cement works, utility Eneo for a 50 MW gas-fired plant in Douala, and the local subsidiary of global cocoa processor Barry Callebaut. See VOG half-year results published on 29 February 2016: <http://www.victoriaoilandgas.com/investors/annual-interim-reports>. GDC foresaw Cameroon's overall gas demand reaching 1.55 Bcm/year in the VOG annual report published on 4 November 2015 (inside cover and p. 9).

<sup>62</sup> Eni, *Eni and Congo, a long-standing friendship*, 29 June 2015, <http://bit.ly/1T0gP8s>; Eni, *Eni and Republic of Congo launch a new integrated model of cooperation*, 19 May 2008, <http://bit.ly/1SnUkHQ>.

<sup>63</sup> EIA, *Angola*, 20 March 2015, <https://www.eia.gov/beta/international/analysis.cfm?iso=AGO>.

<sup>64</sup> A first 400 MW gas-fired power plant is under development and a second one, with the same capacity, is planned for the next decade. David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 9.

<sup>65</sup> *Ibid.*, p. viii.

the annual cost to charter an LNG Floating Storage and Regasification Unit terminal (FSRU) from specialist shipowners such as Golar, Hoegh, Excelebrate and Exmar is about 40-45mn dollars per year, if taken on a five-year charter.<sup>66</sup>

In November 2015, Golar LNG signed a firm contract with West African Gas Limited (WAGL) – a joint venture of Nigerian state NNPC 60 percent and local business Sahara Energy 40 percent – to provide an FSRU on a five-year charter at Tema in Ghana for start-up in Q2 2016 at a new jetty to be built by WAGL.<sup>67</sup> It is possible that LNG might enable WAGL<sup>68</sup> to top up supplies in the WAGP pipeline, whenever gas imports from Nigeria or indeed gas supplies from Ghana's own offshore fields fall short.

Early in 2015 French power developer Eranove, US giant GE and smaller US Endeavor Energy chose US shipowner Excelebrate to provide an FSRU for their planned 1,200 MW "Ghana1000" power plant, with Shell named as a potential LNG supplier.<sup>69</sup> By March 2016 a project for a 4.7 Bcm/year FSRU, proposed by Quantum Energy to be installed 12km offshore Tema, was gaining traction.<sup>70</sup> Yet neither the Eranove nor Quantum projects has yet chartered the prerequisite FSRU, so both lag behind the WAGL (NNPC/Sahara) venture.

Similar planned FSRU ventures, so far without ships committed but linked to planned

<sup>66</sup> Golar LNG, *Golar and West African Gas Limited Agree Ghana FSRU Contract*, 4 November 2015, [http://www.golarlng.com/index.php?name=seksjon/Stock\\_Exchange\\_Releases/Press\\_Releases.html&pressrelease=1964023.html](http://www.golarlng.com/index.php?name=seksjon/Stock_Exchange_Releases/Press_Releases.html&pressrelease=1964023.html). The charter (or lease) is for an initial period of 5 years, with the option to extend for a further 5 years, and covers the new build FSRU Golar Tundra – with storage capacity for 170,000 cubic meters of LNG – which was due to be delivered to Golar from Samsung in South Korea in November 2015. Golar expects some 44 million dollars pre-tax earnings in year 1 of the lease.

<sup>67</sup> A recent news article suggests that WAGL and Golar may struggle to install the FSRU offshore Tema, because work has yet to begin on building the jetty. See Leigh Elston, "Ghana Struggling to implement its LNG import plans", in *Interfax*, 29 February 2016, <http://interfaxenergy.com/19408>.

<sup>68</sup> WAGP is owned by Chevron (36.9 percent), Nigerian state NNPC (24.9 percent), Shell (17.9 percent), Ghana's Takoradi Power Company Limited (16.3 percent), Société Togolaise de Gaz (2 percent) and Benin's Société BenGaz (2 percent) as WAGP's company profile shows: [http://www.wagpco.com/index.php?option=com\\_content&view=article&id=46&Itemid=78](http://www.wagpco.com/index.php?option=com_content&view=article&id=46&Itemid=78).

<sup>69</sup> GE, *Ghana 1000 Consortium Partners with Excelebrate Energy on Gas-to-Power Project*, 28 January 2015, <http://allafrica.com/stories/201501301696.html>; Eranove, *Ghana – General Electric, Eranove and Endeavor Energy partner for electricity generation*, 28 May 2014, <http://www.eranove.com/en/?p=2394>. However, Ghana1000 had not reached financial close by its intended end-2015 target, and Endeavor in May 2015 began talking about a second smaller power project (<http://endeavor-energy.com/?p=772>); and again here in February 2016 (<http://endeavor-energy.com/?p=954>). Both the Quantum and Ghana1000 projects may find reaching FID more of a challenge, now that OCTP is definitely going ahead. Also, competition for FSRUs from projects in other African and Latin American nations is heating up.

<sup>70</sup> Leigh Elston, "Ghana Struggling to implement its LNG import plans", cit.; Quantum, *Micoperi and Quantum Power Have Reached Agreement on the EPC Role for the Tema Liquefied Natural Gas (LNG) Import, Storage, Regasification and Delivery Facility, Commencing Construction in Ghana in 2016*, 4 March 2016, <http://www.businesswire.com/news/home/20160303006329/en>.

power projects, have been talked of in Benin, Côte d'Ivoire, Senegal, Togo and South Africa, linked to real, or more often potential, US, French, Japanese and even Azeri investors.<sup>71</sup>

LNG imports could help balance out shortfalls in WAGP, potentially adding supply security if the pipe were extended west to Côte d'Ivoire. The 2014 World Bank report noted that "expanding [Nigerian] pipeline deliveries to Ghana through the existing WAGP pipeline is clearly economically attractive, and extending WAGP further to Côte d'Ivoire could also be interesting" but dismissed extending WAGP beyond Côte d'Ivoire as unviable.<sup>72</sup> UK-based contractor Penspen was awarded a feasibility study contract by the Economic Community of West African States (ECOWAS) in 2015, due for completion in late 2016.<sup>73</sup> Penspen told the authors that the study envisages a possible "subsea pipe to extend [WAGP] up the west coast towards the north of the continent" but named no states.

Whereas WAGP may still have legs, the Trans-Saharan Gas Pipeline (TSGP) project does not. Algerian state company Sonatrach and its Nigerian counterpart, NNPC, in 2002 launched a joint venture to build an up-to-30 Bcm/year, 4,128 kilometre pipe, eyeing first gas flows by 2015, and Penspen finalised a study the next year. But nothing was built and TSGP's estimated cost had soared from 7 billion dollars in 2001 to 21 billion dollars by 2010<sup>74</sup> while the EU gas market contraction,<sup>75</sup> the absence of any US or Chinese backing and the "geopolitically dangerous" route have all become major hurdles. Insecurity became yet more challenging when al-Qaeda attacked the BP-run In Amenas gas plant and killed 40 staff in January 2013,<sup>76</sup> and since then thousands have been killed by Islamist group Boko Haram across Nigeria, Niger and Chad; it has also conducted mass kidnappings and rapes.<sup>77</sup> In 2014 Nigeria's government said that

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<sup>71</sup> Most however of these projects may remain projects, as they have yet to reach FID, or a deal for an FSRU ship. Leigh Elston, "Ivory Coast, Senegal to join the LNG party", in *Interfax*, 29 May 2015, available at <http://www.gasandoil.com/news/africa/d41f6071e72c8699b36b77cf2141d66a>.

<sup>72</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 52.

<sup>73</sup> Penspen, *ECOWAS and Penspen Sign Contract for a Feasibility Study for the Extension of the Gas Pipeline Network in West Africa*, 22 June 2015, <http://www.penspen.com/europe-africa/ecowas-and-penspen-sign-contract-for-a-feasibility-study-for-the-extension-of-the-gas-pipeline-network-in-west-africa>.

<sup>74</sup> Benjamin Augé, "The Trans-Saharan Gas Pipeline: An Illusion or a Real Prospect?", in *Notes de l'Ifri*, June 2010, p. 2 and 4-5, <https://www.ifri.org/en/node/5000>.

<sup>75</sup> EU gas consumption in 2014 shrank to its lowest level since the mid-1990s.

<sup>76</sup> A rocket-propelled grenade attack on 18 March 2016 on another Algerian gasfield, In Salah, left no casualties and did not interrupt production, but renewed concerns, prompting a temporary evacuation of foreign staff. See Terje Solsvik and Patrick Markey, "Militants fire rockets at Algerian BP/Statoil gas plant, no casualties", in *Reuters*, 2016, <http://reut.rs/1Ulzgro>.

<sup>77</sup> Boko Haram overtook the jihadist group Islamic State (IS) to become the most deadly terrorist group in the world in 2014. Deaths attributed to Boko Haram increased by 317 percent in 2014 to 6,644, while IS was

a 950km “TSGP stage one” from Calabar in the Niger Delta to Kano in northern Nigeria might flow gas by 2018; the World Bank said it might open a market for “enough gas to generate 5.000 MW of power.”<sup>78</sup> But it too is stalled.

## 9.2. East Africa: A New Frontier for the Gas Industry

### 9.2.1 Huge Discoveries and Mega LNG Projects

For many years, quantification of Sub-Saharan Africa’s natural gas resource endowment has focused almost entirely on the Gulf of Guinea and especially on Nigeria, with East Africa being virtually ignored by international gas players. The presence of gas has been known in Mozambique and Tanzania since the 1960s, when the Songo Songo field was discovered offshore central Tanzania, and the Temane and Pande fields in southern Mozambique were found. However, at the time, energy companies were exclusively looking for oil, and it took three decades to first produce natural gas. The gas from these fields is now used to generate electricity in the case of Tanzania, and is exported by pipeline to South Africa in the case of Mozambique.<sup>79</sup>

Until recently, few geologists believed in the region’s potential. A new era began in the late 2000s when major oil companies were awarded exploration blocks in the offshore Rovuma Basin, straddling the maritime border of Mozambique and Tanzania. From 2009 onwards, a series of huge natural gas discoveries, large enough to support LNG

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responsible for 6,073 deaths. Terrorist deaths in Nigeria increased by over 300 percent in 2014 to 7,512 – the highest ever recorded by any country. See the *2015 Global Terrorism Index* published in November 2015 by the Institute for Economics and Peace: <http://economicsandpeace.org/reports>.

<sup>78</sup> Dennis Mernyi, “Kano-Calabar gas pipeline ready in 2018 – FG”, in *SunOnline*, 28 May 2014, [http://marketwatch.ng/News/post/2014/05/28/Kano-Calabar\\_gas\\_pipeline\\_ready\\_in\\_2018\\_-\\_FG.aspx](http://marketwatch.ng/News/post/2014/05/28/Kano-Calabar_gas_pipeline_ready_in_2018_-_FG.aspx). See also the interview with Dolapo Oni, an oil and gas analyst at Nigeria’s Ecobank: “Update on Nigeria’s Trans-Saharan Gas pipeline project”, in *CNBC Africa*, 4 June 2014, <http://www.cnbc africa.com/video/?bc-tid=3604608011001>.

<sup>79</sup> In Tanzania, the Songo Songo field came onstream in 2004 and produces about 1 Bcm/year of gross natural gas, feeding a gas-fueled power plant that supplies electricity for the economic capital Dar es Salaam. According to Canada’s Orca, the operator of the field, total recoverable resources exceed 30 Bcm of natural gas (2011). The country expects to marginally increase natural gas production over the next few years from the Mnazi Bay Concession, operated by France’s Maurel and Prom. Mnazi Bay has produced small volumes since second half 2015 while the UK Aminex-operated Kiliwani North field, also small, began producing in April 2016. In Mozambique, the onshore Temane and Pande fields, operated by South Africa’s Sasol, started producing in 2004 and 2009 respectively. They currently produce roughly 4 Bcm/year of natural gas, mostly exported to South Africa through a 850km pipeline, the only long-haul international gas pipeline yet built in the region.

projects, were made by the US company Anadarko and the Italian major Eni in Mozambique,<sup>80</sup> and by Norway's Statoil and London-listed and -based Ophir Energy in Tanzania.<sup>81</sup> These discoveries changed the oil and gas industry's interest in the whole region.

Although Tanzanian discoveries are sizably smaller than those in Mozambique, East Africa has emerged as one of the most promising new gas frontiers, even if uncertainties remain about the exact size of the resources, and the schedule for their development. As oil companies tend to work by imitation, offshore exploration is still being carried out all along the coast, from Somalia to South Africa, including around the Comoro Islands, as well as onshore.<sup>82</sup>

Depending on the sources, Mozambique's recoverable gas resources are estimated between 2.8 and 5.1 Tcm, and Tanzania's at about 1.1 Tcm.<sup>83</sup> Given the size of the resource base (especially in Mozambique), license-holders are moving ahead aggressively on plans to build LNG trains, both in Mozambique and in Tanzania. As a sign of confidence about the future development of these resources, the *Oil & Gas Journal* decided, on January 2014, to raise Mozambique's proved natural gas reserves to 2.8 Tcm, up from 127 Bcm the previous year, placing the country as the second-largest proved natural gas reserve holder in Sub-Saharan Africa, after Nigeria. In contrast, Tanzania's proved reserves have been maintained as low as 6.5 Bcm, reflecting the slower pace of commercial development in the country compared to Mozambique, where production is expected to start a couple of years earlier than in Tanzania.

In Mozambique, Anadarko and Eni have agreed to conduct a coordinated exploration programme and to jointly construct an onshore LNG facility in the country's north.<sup>84</sup> Ini-

<sup>80</sup> Anadarko operates Area 1 with a 26.5 percent stake, in partnership with Japan's Mitsui E&P (20 percent), the national oil company of Mozambique ENH (15 percent), Indian companies Beas Rovuma Energy Mozambique, BPRL Ventures Mozambique and ONGC Videsh (10 percent each), and Thailand's PTT (8.5 percent). Eni operates Area 4 with a 50 percent interest, in partnership with China National Petroleum Corporation (20 percent), Portugal's GalpEnergia (10 percent), Korea's Kogas (10 percent) and ENH (10 percent). Of the other blocks, acquired by Malaysia's Petronas (blocks 3 and 6) and by Canada-based Wentworth Resources and Statoil (blocks 2 and 5), none had revealed exploitable quantities of hydrocarbons by 2015.

<sup>81</sup> Ophir were initially granted blocks 1, 3 and 4, but farmed out 60 percent to the British gas company BG (now Shell) in 2010 when the first discoveries were made, relegating Ophir to the role of secondary partner (20 percent) along with Singapore's Pavilion Energy (20 percent). Statoil operates block 2 with a 65 percent stake, in partnership with Exxon (35 percent).

<sup>82</sup> Benjamin Augé, "Oil and Gas in Eastern Africa: Current Developments and Future Perspectives", in *Notes de l'IFRI*, March 2015, <https://www.ifri.org/en/node/9417>.

<sup>83</sup> In Tanzania, blocks 1 and 4 operated by BG Group (now Shell) hold 450 Bcm of "total gross resources" and block 2 operated by Statoil has 620 Bcm of "in-place volumes", according to the companies. In Mozambique, Eni estimates the "resource base" of the Area 4 at 2.5 Tcm, and Anadarko declared that the fields of Area 1 hold more than 2.1 Tcm of "recoverable resources." It is unclear what portion of these resource estimates are economically viable as companies use different bases to report estimates.

<sup>84</sup> As the fields discovered by the two companies straddle the boundary of Areas 1 and 4, unitisation

tially four LNG trains (with a capacity of nearly 7 Bcm/year each) are expected to be built by 2018 (even if the production start date will almost certainly be pushed beyond that date, probably not before 2020).<sup>85</sup> Up to 10 trains could ultimately be put in operation with a production capacity of 70 Bcm/year, which would make the country one of the biggest LNG producers in the world. Moreover, Eni is also considering building a 4.7 Bcm/year floating LNG facility on the Coral field located in Area 4, with the first LNG sales expected in 2019 if, as Eni anticipates, a final investment decision is taken by mid-2016.<sup>86</sup> Developing all 10 planned LNG trains will nevertheless take time to accomplish, at least 20 years, and would require about 2 Tcm to supply the plant.<sup>87</sup> This would not be a constraint and would still leave enough uncommitted gas to meet the needs of the domestic market (for electricity production for instance), given the size of the resource base and the fact that additional gas discoveries are likely as exploration is still ongoing. Only a few hundred wells have been drilled in East Africa, compared with 15,000 in West or North Africa.<sup>88</sup>

In Tanzania, projects are much more modest. Like in Mozambique, Tanzania has requested the operators of the different blocks (BG Group in blocks 1 and 4, and Statoil in block 2) to cooperate in the development of a joint onshore LNG facility (although the offshore developments remain as independent projects operated by BG Group and Statoil respectively). The current objective is to build two initial liquefaction trains with a capacity of about 6.9 Bcm/year each, and two more LNG trains are planned for the future.<sup>89</sup>

Despite significant discoveries, the project remains in limbo. The building of the LNG plant has not yet been sanctioned by any of the companies involved in the development of the resources. Tanzania's regulatory environment is perceived as highly uncertain as the country plans to introduce a new oil and gas legislation, with the aim of securing more government take in the projects. In addition, Tanzania offers tighter fiscal terms in comparison to other current and potential producers on the continent. The fiscal and reg-

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(joint development of reserves that are under separate licenses) between the overlapping areas is required under Mozambican law.

<sup>85</sup> Luca Franza, "Gas in East Africa. Assessing the Potential for Various Stakeholders", in *CIEP Papers*, June 2013, p. 18, <http://www.clingendaelenergy.com/publications/publication/gas-in-east-africa>; EIA, *Emerging East Africa Energy*, 23 May 2013, <https://www.eia.gov/beta/international/regions-topics.cfm?RegionTopicID=EEAE>.

<sup>86</sup> The project received the Mozambican government's approval in February 2016. See Eni, *Eni: Approval of the development plan for Eni's Coral discovery offshore Mozambique*, 24 February 2016, <http://bit.ly/1WIGy6r>. See also Mark Smedley, "Coral FLNG 'Very Viable' Thanks to Cost Savings - Eni", in *Natural Gas Africa*, 18 March 2016, <http://www.naturalgasafrika.com/coral-flng-viability-cost-savings>.

<sup>87</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 8.

<sup>88</sup> Benjamin Augé, "Oil and Gas in Eastern Africa", cit.

<sup>89</sup> EIA, *Emerging East Africa Energy*, cit.

ulatory uncertainty, coupled with the drop in natural gas prices globally, has contributed to delays Tanzania's LNG development projects and will likely continue to do so. According to industry analysts, companies will not make decisions about investing before 2016 or even 2017, and the start of exports is not expected before 2025 at the earliest.<sup>90</sup>

The first two LNG trains would require 400 Bcm of gas, and the two additional ones a further 400 Bcm.<sup>91</sup> Given that the contingent resources are estimated at 1.1 Tcm, the gas resource base could be a constraint, especially as the Tanzanian government is, in parallel, aggressively pursuing a domestic gas-to-power agenda that could result in over 220 Bcm of gas being committed to the domestic market. Unless new discoveries are made, Tanzania's domestic gas agenda and LNG export plans may collide, forcing the country to make difficult choices between its export and domestic markets.<sup>92</sup>

In addition to offshore Mozambique and Tanzania, about 130 Bcm of gas (and 13.6 million barrels of associated liquids) have been identified in two Ethiopian onshore gas fields, Calub and Hilala. Small firms, such as China's GCL-Poly Petroleum Investments, have shown interest in developing the Ethiopian resources, and building a 4 billion dollar pipeline to neighbouring Djibouti on the Red Sea in order to export the production.<sup>93</sup> However, no investment decision has been officially made yet as the size of the resource found has not been considered as commercially viable, especially since the drop in gas prices on the international market from mid-2014 onwards. Moreover, the fields are located in the Ogaden Basin, a region known to be plagued by security concerns, with rebel groups fighting for independence and Islamic terrorism regularly spilling over from Somalia.

### *9.2.2 LNG Exports, Regional Supply or Local Consumption?*

While licence holders are mainly interested in LNG and see domestic monetisation as uneconomical, no clear choice has been made yet by the government among all the possible monetisation options.<sup>94</sup> The large discoveries have clearly rekindled the Tanza-

<sup>90</sup> Benjamin Augé, "Oil and Gas in Eastern Africa", cit.

<sup>91</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 8.

<sup>92</sup> *Ibid.*, p. viii.

<sup>93</sup> The 700-km pipeline would transport up to 12 Bcm/year of natural gas to a liquefaction plant in Djibouti with a capacity up to 14 Bcm of LNG per year after completion of the project. Stephanie Roker, "Djibouti announces mega gas project", in *Energy Global*, 3 March 2016, <http://www.energyglobal.com/pipelines/project-news/03032016>.

<sup>94</sup> For profit-oriented organisations such as the oil and gas companies, allocating gas supply between LNG exports and domestic power markets involves economic trade-offs, particularly with respect to gas pricing. These trade-offs almost always strongly favour LNG because of the superior contract terms usually available from foreign buyers. The minimum wholesale price (i.e., the sum of upstream capital and operating costs, royalties and taxes, and a minimum after-tax rate of return) is estimated at 2 dollars per mmBtu in Nigeria



nian government's interest in expanding the use of natural gas to address the country's power shortages. With a national electrification rate as low as 24 percent (compared to 32 percent for Sub-Saharan Africa as a whole), Tanzania's population is still reliant on costly individual diesel-fired generators as well as traditional biomass (wood, charcoal, etc.) for household heating and cooking.<sup>95</sup>

Accounting for 30 percent of the electricity generation, hydropower remains the base of Tanzania's long-term power generation planning. However, the country is highly exposed to delays and cost overruns in construction of its hydropower projects and to rain shortfalls once the projects are in operation. To mitigate these risks, Tanzanian energy policy emphasizes gas-fired generation projects in the short term, and prioritises the domestic market over the export market in gas supply, as stipulated in the Draft Natural Gas Policy issued in May 2013. Under the terms of the contracts with the offshore license-holders, a portion of the production from the LNG projects is reserved for the domestic market, where over 1,000 MW of new gas-fired generation capacity is planned.<sup>96</sup>

In Mozambique, where about only 40 percent of the population has access to electricity, hydropower, which currently accounts for virtually all the electricity production, remains the cheapest option for power generation. However, for the same reasons as in Tanzania, the Mozambican government has planned the construction of gas-fired power plants for domestic consumption. Given the size of its resources, Mozambique can afford to allocate gas to domestic supply without compromising its capacity to export, unlike Tanzania. Even if all the gas needed for 10 LNG trains were set aside today, Mozambique would still hold at least 850 Bcm of uncommitted gas, far more than the existing and projected thermal energy demand in the domestic market.<sup>97</sup> Therefore, the gas resource base is not a constraint on almost any commercialisation options Mozambique would wish to consider: LNG exports, domestic power generation, but also petrochemical and industrial applications and pipeline exports to South Africa.

As Africa's second largest economy, South Africa accounts for about 30 percent of total

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and between 2.5 and 3.5 dollars in East Africa (yet domestic gas prices in Nigeria were, until recently, held at roughly 0.50 dollar per mmBtu, much lower than the minimum price needed to incentivise gas investment). In Tanzania, without increasing domestic gas prices to LNG netback parity levels of 4-6 dollars per mmBtu, the incentives for gas producers with access to a viable LNG outlet will still favour export over domestic supply. Gas sales at prices less than the LNG netback price represent a subsidy to the power sector. If domestic gas is priced lower than LNG netbacks, there will be a cost in terms of reduced royalties and taxes from production. In the extreme case, low gas prices can result in upstream gas development projects not going forward at all. See David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. ix. For a good description and analysis of the various monetisation options, see Luca Franza, "Gas in East Africa", cit.

<sup>95</sup> IEA, *Africa Energy Outlook 2014*, cit. (figures for 2012).

<sup>96</sup> David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 8.

<sup>97</sup> *Ibid.*, p. vii.

primary energy consumption in the continent. The country relies heavily on its large-scale, energy-intensive coal mining industry (about 90 percent of South Africa's electricity is generated in coal-fired power stations<sup>98</sup>). Given its rapid economic growth since the end of the apartheid era in 1994, South Africa's future requirements are estimated at over 40,000 MW of new generation capacity by 2025.<sup>99</sup> As the government has decided to impose a hard cap on CO<sub>2</sub> emissions from the electricity sector, and to decrease its reliance on coal, South Africa could strongly increase its purchases of natural gas from Mozambique, which would justify the building of new pipelines between the two countries.<sup>100</sup> South Africa has nevertheless other potential gas supply options including LNG imports and even shale gas, although supply from the last must be considered only a very long-term possibility.<sup>101</sup>

## Conclusions

Although data must be used with a high degree of caution, the natural gas resources<sup>102</sup> discovered in Sub-Saharan Africa are estimated at more than 10 Tcm, with East Africa having the potential to emerge as the second Sub-Saharan key region for the gas industry after the already developed West Africa.

<sup>98</sup> See the website of the South African Department of Energy: <http://www.energy.gov.za>

<sup>99</sup> Nelisiwe Magubane, *Our Journey Towards 2030*, Presentation at the KPMG Global Power & Utilities Conference, Paris, 28-29 September 2011, <http://www.energy.gov.za/files/media/presentations/2011/DG%20presentation%20at%20KPMG%20Energy%20Conference%20in%20Paris.pdf>.

<sup>100</sup> The most advanced project is the African Renaissance Gas Pipeline, which is intended to connect Mozambique's reserves from the Rovuma basin to South Africa's industrial heartland of Gauteng, while delivering gas to key towns in all provinces of Mozambique along the way. This project is led by South Africa's SacOil, in partnership with Mozambican public oil and gas company ENH and private sector consortium Profin Consulting, as well as CNPC-owned China Petroleum Pipeline Bureau. An agreement between the partners was signed in February 2016, but no indications of capacity or precise schedule have been officially given; it is also unknown whether it would connect with existing southern Mozambique to South Africa pipelines. Also, as of mid-March, resource holder Eni told the authors it had held no talks with the project. See Mark Smedley, "Chinese Join Planned \$6bn Mozambique Gas Pipe", in *Natural Gas Africa*, 1 March 2016, <http://www.naturalgasafrika.com/chinese-join-planned-6bn-mozambique-gas-pipe-project-1760>.

<sup>101</sup> A 2013 study by EIA estimates that South Africa would hold nearly 12 Tcm of shale gas resources. It is however still much too early to make any projection about a future shale gas boom in South Africa, as testing of these resources is just starting and any potential large-scale development would face numerous technical, economic and environmental barriers. Nevertheless, if South Africa's shale gas resources are eventually proven to be economic on a wide scale, its gas and energy balances would be profoundly altered. David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 10; Wendell Roelf, "South Africa to start shale gas exploration in next year", in *Reuters*, 8 March 2016, <http://reut.rs/1U1RNZQ>.

<sup>102</sup> Discovered gas resources are the sum of 2P commercial reserves plus contingent resources. David Santley, Robert Schlotterer and Anton Eberhard, "Harnessing African Natural Gas", cit., p. 6.

The existing LNG capacities (exclusively located in West Africa) amount to 43 Bcm/year, and the likely first phase of LNG projects in East Africa will take total capacity in Sub-Saharan Africa to 84 Bcm/year over the next decade. Estimates vary but suggest that East Africa's reserve base could theoretically support up to 16-20 LNG trains with a capacity of 7 Bcm/year each, equivalent to an output of 110-140 Bcm/year – even if the actual number of proposed trains is about half as many.<sup>103</sup>

Developing LNG on such a scale, however, could take 20 years or more to accomplish, and a number of issues might complicate the future, including growing competition on the global LNG market, uncertainty about the share of gas production that African governments will want to keep for the local development, and security threats (including piracy<sup>104</sup>).

Growth of global liquefaction capacity and demand will depend on many factors, including the shale gas supply growth in North America and (possibly) China, regional LNG demand growth (particularly in Asia) and growth in liquefaction capacity outside Africa (Australia, Middle East, North America, etc.). This remains true for East Africa even if consultants are particularly positive about the profitability and competitiveness of its LNG, relatively to other greenfield projects targeting Asia.<sup>105</sup> Therefore, securing big clients to justify the colossal investment sums required (at least 50 billion dollars in Mozambique, and 20 billion dollars in Tanzania) is the current priority for the operators, which explains why they recently brought new Asian shareholders on their licenses.

A more austere investment climate for the oil and gas sector in Sub-Saharan Africa may lead to great efficiencies, and less money squandered on vain or even corrupt schemes. Mid-sized independent operators are demanding more favourable fiscal terms, and have portfolios of projects that give them leverage over which countries they invest in. Firms which are keen to develop LNG in Mozambique, like Eni, will need convincing that any trans-national gas pipeline project to South Africa has a hard-headed

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<sup>103</sup> Luca Franza, "Gas in East Africa", cit., p. 17: original figures: 6.9 Bcm per year per train, equivalent to 110-138 Bcm per year.

<sup>104</sup> Piracy has been a problem in East Africa (including offshore Tanzania) since the collapse of the State of Somalia in 1991, although the international military operation Atalanta launched in 2008 has led to a decrease in the number of attacks. In the same time, piracy has developed in the Gulf of Guinea, especially offshore Nigeria as a consequence of the weakness of the Nigerian State and its inability to ensure security in its territorial waters. See International Crisis Group, "The Gulf of Guinea, the New Danger Zone", in *ICG Africa Reports*, No. 195 (December 2012), <http://www.crisisgroup.org/en/regions/africa/west-africa/195-the-gulf-of-guinea-the-new-danger-zone.aspx>.

<sup>105</sup> According to a study by Wood Mackenzie, the cost of supplying northeast Asia with Mozambican LNG would be close to 5.3 dollars per mmBtu (and slightly above 6 dollars for Tanzanian LNG), compared to 10-13 dollars for Australian LNG. It is nevertheless still twice the price of Qatar's LNG. See Luca Franza, "Gas in East Africa", cit., p. 20.

business rationale. Low oil prices have spurred operators to pioneer lower-cost offshore LNG technology and projects with some success – especially in Cameroon and Equatorial Guinea – and it is positive that this is happening in Sub-Saharan Africa. Similarly, modular construction may help keep costs low, if Mozambique’s up to 10 “cookie cutter” onshore trains go to plan – thus achieving economies of scale that the expensive Angola LNG and Escravos GTL projects failed to realise.

The issue of local consumption, though, remains crucial. While international investors tend to prioritise LNG, local governments aim to diversify the use of their gas reserves and to develop gas-fired generation capacities that could address power deficits without having to rely exclusively on hydropower. In the long term, this is probably desirable to ensure that people of gas-producing countries fully enjoy the benefits of gas production.<sup>106</sup> This requires infrastructure that can sustain markets, such as regional gas pipeline systems and clusters of LNG regasification terminals (FSRUs) near coastal cities, plus new gas-fired power plants. For companies, this could also be desirable as it could help maintain a climate of political stability, as (negatively) illustrated by the case of Nigeria, a country particularly affected by the so-called “resource curse.”<sup>107</sup>

In this contest, despite its huge oil and gas resources, Nigeria remains one of the poorest countries in Africa (and in the world), profoundly afflicted by social and political instability and plagued with deep corruption. Given the carelessness of local as well as federal authorities, the local population in the oil-producing Niger Delta region tends to turn straight to oil companies to obtain the fruits of indigenous production. Regularly and in a violent way, they demonstrate their hostility to the energy companies through sabotage of pipelines, kidnapping of employees, occupation of installations (including shallow water platforms), etc. These actions seriously complicate and sometimes even prevent companies’ activities.

Stabilising the political and social situation in Nigeria and avoiding repeating the same mistakes in Mozambique and Tanzania are probably the biggest challenges facing the gas industry in Sub-Saharan Africa, as well as the main conditions for the development of the full potential of the region.

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<sup>106</sup> *Ibid.*, p. 39.

<sup>107</sup> The resource curse refers to the paradoxical situation in which countries with abundant natural resources experience stagnant economic growth or even economic contraction, see the decline of all activities not linked to the resource exploitation (including manufacturing industry, agriculture, etc.), and the development of wide-scale corruption amongst the public institutions. See Richard M. Auty, “How Natural Resources Affect Economic Development”, in *Development Policy Review*, Vol. 18, No. 4 (December 2000), p. 347-364; CIEP, “FAQ ‘Dutch Disease’”, in *CIEP Papers*, No. 2013|02 (May 2013), <http://www.clingendaelenergy.com/publications/publication/faq-dutch-disease>.



## 10. Asia's Natural Gas and LNG Market Trends

Wenran Jiang

Asia has been the major driver for the growing world market for natural gas and liquefied natural gas (LNG) in recent years. China's economic growth, Japan's shutdown of its nuclear facilities following the Fukushima disaster in 2011, and steady increase in demand from South Korea, India and other Asian economies led to the Asian market being responsible for about 75 percent of global LNG imports, and pushed Asian LNG import prices to record levels in early 2014.<sup>1</sup>

But the past 18 months have witnessed rapid decline in energy prices, which has brought volatility and uncertainty to the global gas and LNG markets. At the same time, China's economic slowdown, the possible restart of Japan's nuclear power plants, and continuous capacity increase in LNG exports from Australia and other countries are factors contributing to the decrease in LNG prices.

Yet from a medium to long-term perspective, the appetite for more gas and LNG in Asian countries remains strong. Key players such as China and Japan are taking active steps in securing stable supply for gas and LNG. China and Russia signed two historic gas deals in 2014 alone, moving the two countries closer in energy cooperation. China has also been aggressively pursuing gas and LNG projects in Central Asia, Australia, the Middle East, South East Asia and North America. Increasing tensions in the East China Sea and South China Sea between China, Japan, Vietnam and the Philippines are partly due to the fact that both areas are considered rich in oil and natural gas deposits.

This chapter will look at Asia's thirst for gas and LNG in the global and historical context; analyse the impact of the global economic downturn and the decline of oil prices on the Asian gas market; identify the key players and newcomers in both the import and export spectrum and their strategies for "supply security" and "demand security;" and draw policy implications for the prospects of Asian gas and LNG markets in the coming years.<sup>2</sup>

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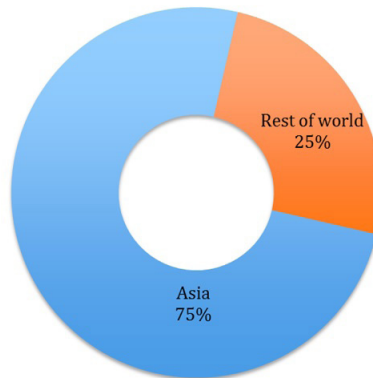
<sup>1</sup> BG, *Global LNG Market Outlook 2014/15*, 4 March 2015, [http://www.bg-group.com/~/\\_tiles/?tile-type=news&id=771](http://www.bg-group.com/~/_tiles/?tile-type=news&id=771).

<sup>2</sup> Given the fact that there is a separate chapter specifically devoted to Japan in this volume, China will

## 10.1 Asia's Thirst for Natural Gas and LNG

For much of the past decades, Asia has led the world in economic growth. Japan, South Korea, Taiwan, Southeast Asian countries, and then China have successively gone through rapid industrialisation and urbanisation process. The economic boom and the export-driven development model known as the “East Asian Miracle” have sustained the global demand for energy and resources. In this process, Asian economies have become the world's largest LNG importers. Today, as the third and eleventh largest economies (nominal GDP) in the world, Japan and South Korea are the largest and the second largest LNG importers respectively, mainly due to the fact that both countries are island or peninsular, and have very limited gas reserves and production.

Figure 1 | Global LNG imports



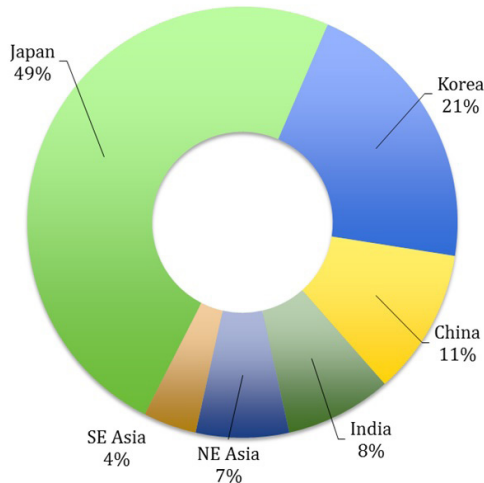
Source: BG, Global LNG Market Outlook 2014/15.

Japan, for example, produced 4.6 billion cubic metres (Bcm) in 2013, down from an average of 5.2 Bcm over the past decade (2003-12). Japan alone took 37 percent of total LNG imports worldwide during 2012-14, up from 31 percent in 2011.<sup>3</sup> Alongside Japan's declining domestic supply and the continued demand for natural gas due to its scale of the economy, the 2011 Fukushima nuclear plant disaster after the Tsunami led to the government decision to shut down most of Japan's nuclear facilities (which were responsible for producing 30 percent of Japan's total electricity), thus creating a short-term spike demand for more gas consumption.

be the focus among the Asian players in this chapter.

<sup>3</sup> “Japan Diversifies LNG Import Portfolio”, in *The Maritime Executive*, 1 February 2015, <http://www.maritime-executive.com/article/japan-diversifies-lng-import-portfolio>

Figure 2 | Asian LNG imports



Source: BG, Global LNG Market Outlook 2014/15.

In the following months, the future of nuclear power remained undefined, and intense policy debates developed in the country. This contributed to Japan's increased LNG imports. In this context, Asian LNG spot prices climbed from around 10 dollars per million British thermal units (mmBtu) to 18 dollars per mmBtu in mid-2012, and stayed around 15 dollars per mmBtu until last year. It also encouraged large Japanese corporations such as Mitsui and Mitsubishi to invest heavily in Australia and other locations, partly in expectation of an upward demand trend for Japan's gas consumption. As a result, Australia and Qatar overtook Japan's more traditional LNG suppliers, such as Malaysia and Indonesia to become the top suppliers of LNG to Japan.<sup>4</sup>

South Korea, just like Japan, is a key player in the global gas and LNG importing business. As an indication of the government's continued emphasis on the use of gas and LNG, South Korea will invest 6.1 billion dollars to expand domestic gas infrastructure, such as pipelines and storage tanks, through 2029. The residential use of gas and LNG is expected to continue to rise in the coming years. But the country is also planning to use more nuclear energy to generate power due to emission-related considerations. This means less import of LNG for power generation, a shift that already had an impact on the LNG import volume in 2015.<sup>5</sup>

<sup>4</sup> World Nuclear Association, *Nuclear Power in Japan*, updated 29 March 2016, <http://www.world-nuclear.org/info/Country-Profiles/Countries-G-N/Japan/>

<sup>5</sup> Meeyoung Cho, "S.Korea sees gas demand falling 5 percent by 2029", in *Reuters*, 28 December 2015, <http://reut.rs/1QVxwDT>.



China, although producing a good part of its own fossil fuel consumption, has been steadily increasing the share of its imported oil, gas and LNG since the mid-1990s. Since China became a WTO member in the early 2000s, its economy has gone through another round of robust growth, with GDP growth averaging around 10 percent. China's demand for energy and other raw materials in this period was dubbed the "commodity super cycle," meaning the demand from China was so strong that prices of oil, gas, coal, major metals and other key resources would sustain their high prices for a prolonged period of time. Even after the 2008 world financial crisis, the Chinese government's stimulus package was so strong that the country underwent a V-shaped recovery primarily due to infrastructure spending.

Such unprecedented growth put enormous pressure on China's energy supply. The country depends on coal for close to 70 percent of its total energy consumption, which translates into China alone using over 50 percent of global coal supply. It surpassed the United States last year as the largest importer of crude oil, with 60 percent of its oil coming from foreign countries, and despite its efforts to increase production of domestic natural gas, it could not keep up with the double-digit growth it had been experiencing in natural gas consumption, averaging a 17.3 percent increase per year between 2002 and 2013.<sup>6</sup>

To meet demand, Beijing has pursued both land-based gas pipelines from Central Asia, Russia and Burma while adding more LNG receiving terminals along the eastern coastal ports. China's LNG imports, although serving only 15 percent of China's overall gas demand in 2014, have grown rapidly, with 20 percent increase from 2011-12, 23 percent from 2012-13 and 10 percent from 2013-14.<sup>7</sup> Such a surge in demand, similar to the case of Japan, pushed Chinese energy giants such as CNPC, Sinopec and CNOOC (known as China's "Big Three" national oil companies), to invest in overseas oil and gas assets in countries across Africa and the Middle East in the past two decades, and in Australia, Canada and the United States in recent years.

Also, another rising Asian economic power, India, is not far behind China in terms of its demand for imported LNG. As the EIA data indicates, India's share of global LNG imports was about 6 percent last year, buying a record 14.3 Bcm in 2014.<sup>8</sup> In recent years, the economic development of India – second only to China in terms of population – has picked up speed. A long-time follower of its eastern neighbour, India's GDP grew by 7.5 percent in 2015, outperforming Beijing's 6.9 percent increase.<sup>9</sup> The IMF

<sup>6</sup> Colin Shek, "China's gas-import slowdown threatens LNG producers", in *Al Jazeera*, 2 June 2015, <http://aje.io/amld>.

<sup>7</sup> *Ibid.*

<sup>8</sup> Gaurav Agnihotri, "Growing India Becomes Major LNG Player", in *OilPrice.com*, 21 June 2015, <http://oilprice.com/Energy/Natural-Gas/Growing-India-Becomes-Major-LNG-Player.html>.

<sup>9</sup> "India outpaces China in 2015 economic growth", in *BBC News*, 8 February 2016, <http://www.bbc>.

has forecast that India will continue to grow at 7.5 percent in 2016, an economic surge expected to continue leading India's LNG demand to double by 2019-20.<sup>10</sup> In a longer-term perspective, EIA predicted that by 2040 India's oil and gas demand is set to rival that of the United States.<sup>11</sup>

Overall, the demand and supply picture for Asia's natural gas and LNG markets has been rosy for a considerable period, up until the beginning of the worldwide decline of oil prices last year, a factor that could possibly alter the energy trends in the region.

## 10.2 Impact of the Oil Price Decline on Asian Gas Dynamics

Global oil prices began to decline in mid-2014, leading to the currently prolonged and uncertain future for all the energy sources. Unlike crude oil prices, which are globally defined through benchmarks such as the Brent and the West Texas Index (WTI), global gas prices are determined on a more regional level. The National Balancing Point (NBP) – the UK's delivery point – is one of various gas hubs active in Europe, while in North America, Henry Hub sets the price at the pipeline hub located in Louisiana. Asia does not have a comparable regional hub or pricing mechanism for gas and LNG: most Asian countries index the LNG price with the crude oil price, normally with a three to six month lag period for gas spot prices to reflect oil prices in the market place. Thus, global crude oil price decline has a more immediate impact on the region. Asian LNG prices, for example, have dropped dramatically from the first quarter of last year: LNG was 6.60 dollars per mmBtu in the week of October 2, down from 10.10 dollars at the beginning of this year, and less than a third of the record high of 20.50 dollars from February 2014.<sup>12</sup>

Aside from the gas price setting mechanism in Asia, the fundamentals are still demand and supply. Just like crude oil, where the growth of demand has been slowing down while the supply has been increasing, the natural gas and LNG markets have followed a similar path.

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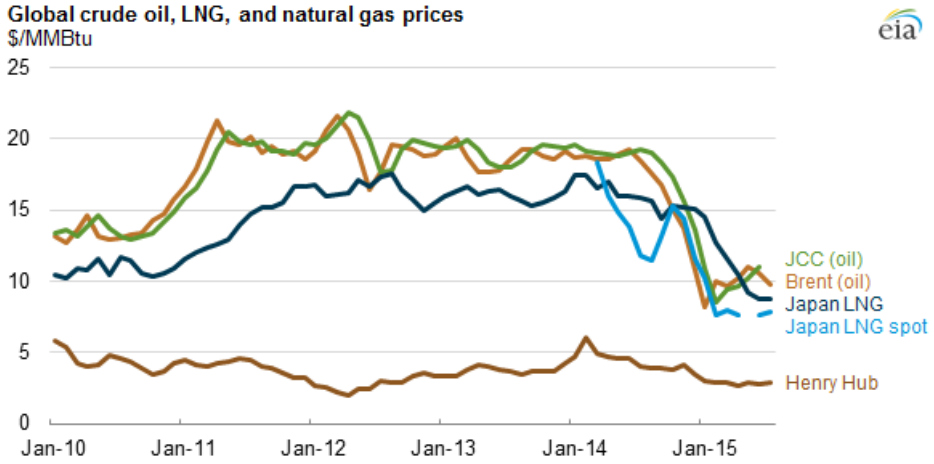
com/news/business-35519671

<sup>10</sup> Esmanie Wanepoel, "Asian demand to benefit Australia gas exports – govt report", in *Mining Weekly*, 4 March 2016, <http://www.miningweekly.com/article/asian-demand-to-benefit-australia-gas-exports-govt-report-2016-03-04>.

<sup>11</sup> "India's oil and gas demand to equal US", in *Deccan Herald*, 16 February 2016, <http://www.deccanherald.com/content/529115/indias-oil-gas-demand-equal.html>

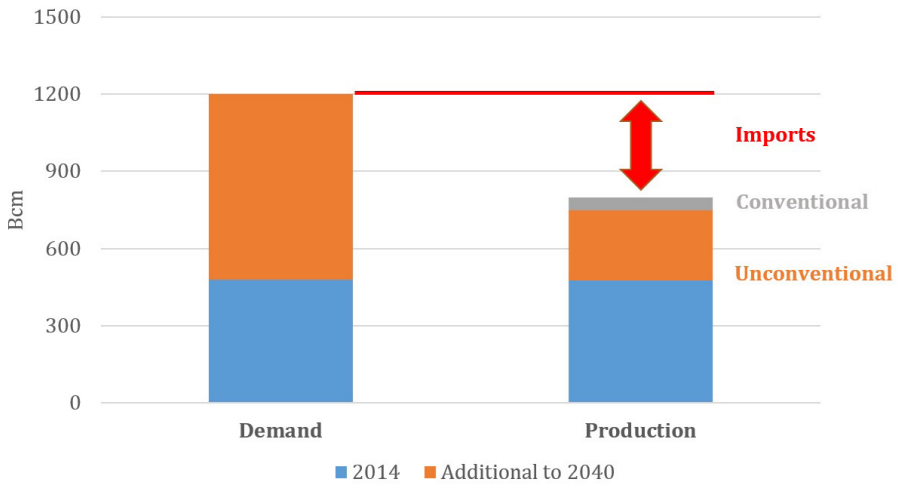
<sup>12</sup> Clyde Sussell, "Six bears, zero bulls point to lower Asia LNG price: Russell", in *Reuters*, 5 October 2015, <http://reut.rs/1MbZCDz>.

Figure 3 | Gas and LNG prices, 2010-2015



Source: EIA, "Natural gas prices in Asia mainly linked to crude oil, but use of spot indexes increases", in *Today in Energy*, 29 September 2015, <https://www.eia.gov/todayinenergy/detail.cfm?id=23132>.

Figure 4 | Natural gas demand and supply in developing Asia, 2040



Source: Data from IEA, *World Energy Outlook 2015*.<sup>13</sup>

<sup>13</sup> IEA, *World Energy Outlook 2015. Presentation to the Press*, 10 November 2015, p. 7, [http://www.worldenergyoutlook.org/media/weowebbsite/2015/151110\\_WEO2015\\_presentation.pdf](http://www.worldenergyoutlook.org/media/weowebbsite/2015/151110_WEO2015_presentation.pdf).

On the demand side, Japan's boost of LNG imports after the Fukushima nuclear accident levelled off last year. The debate on pros and cons of the future of nuclear power in Japan continues, but the push for resuming the use of nuclear power generation seems to have had an upper hand recently. The active measures by the Japanese government to restart the country's nuclear power plants will reduce the need for gas-generated electricity, thus decreasing demand for LNG imports. South Korea, the second largest LNG importer in the world, had seen the use of coal increasing since 2014, which will likely result in decreased LNG import.<sup>14</sup> In 2015, for example, South Korean state-owned Korea Gas Corp., the largest LNG buyer in the world, recorded a 13.5 percent decline in its LNG import to South Korea, as the country's LNG demand decreased by 10.6 percent.<sup>15</sup>

China, although expected to be a major gas and LNG importer via both pipelines and ports in the medium term, and the largest gas consumer in the long term, has experienced short-term economic slowdowns since last year, leading to reduced growth projections. Instead of the double-digit growth experienced in many years, China's LNG import dropped 3 percent year-on-year in the first half of 2015.<sup>16</sup>

On the supply side, widely available reports have indicated an increasing amount of natural gas and LNG coming to the global market from 2015 onward. Australia, for example, has been building up its LNG export capacities over recent years in expectation of a continuous strong demand from Asia. Platts estimates that Australia will begin to add about 45 Bcm of LNG this year; BG Group predicts that the country will add a total of 80 Bcm of LNG per year by 2019, bring Australia's total LNG producing capacity to 110 Bcm.<sup>17</sup> But the existing exporters are not doing that well. Woodside Petroleum, Australia's largest energy firm, reported a 40 percent drop in its profits for the first half of this year, and the ratings agency Moody's expects the company's credit metrics to deteriorate further.<sup>18</sup>

In North America, LNG exports have become a major energy expansion priority in both the United States and Canada in recent years. Despite the fact that gas prices have remained lowest in this part of the world in the past 2-3 years, the much higher long-term and spot prices of LNG in Asia have encouraged many projects to rush forward, all targeting the Asian market potential. Canadian LNG initiatives, currently 20 in total, have

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<sup>14</sup> Gary Ashton, "Analyzing Prices for Asian LNG Markets", in *Investopedia*, 20 March 2015, <http://www.investopedia.com/articles/investing/032015/analyzing-prices-asian-lng-markets.asp>.

<sup>15</sup> Charles Lee, "South Korea's Kogas cuts 2015 LNG imports by 13.5% to 31.41 million mt on weaker demand", in *Platts News*, 15 February 2016, <http://www.platts.com/latest-news/natural-gas/seoul/s-korea-s-kogas-cuts-2015-lng-imports-by-135-to-26368637>.

<sup>16</sup> "Asian LNG price faces steep fall as perfect storm brews", in *Reuters*, 31 August 2015, <http://reut.rs/1ieaxoQ>.

<sup>17</sup> Gary Ashton, "Analyzing Prices for Asian LNG Markets", cit.

<sup>18</sup> "Asian LNG price faces steep fall as perfect storm brews", cit.

been moving very slowly, with the government of British Columbia hoping to get three built by 2020.<sup>19</sup> In contrast, US LNG exports are moving much faster, with 29 Bcm capacity in place for this year, and another 56 Bcm capacity production facilities under active construction.<sup>20</sup> But the price drop in both oil and gas in the past year have changed the economics of exporting LNG from North America to Asia dramatically. Given the current LNG spot price in Asia, planned Canadian LNG projects are unlikely to be profitable, and betting on the price to go back up again in a few years' time is not a convincing economic rationale to launch multi-billion projects. So what we witness now is hesitation from Canadian LNG project planners, and some of their American counterparts, while waiting for a volatile energy market to recover from the current low price cycle.

However Russia, another giant gas producer, is planning to push forward its multiple gas and LNG projects. The Yamal LNG project, a joint venture between Russia's Novatek (50.1 percent), France's Total and China's CNPC (20 percent each), has targeted going into production by 2017. Yamal's CEO has expressed confidence that the Russia-led LNG project will be profitable.<sup>21</sup> The 27 billion dollars Arctic mega-project has a total capacity of more than 19 Bcm per year, although there have been reported funding problems lately.<sup>22</sup>

Furthermore, IEA has recently released its global energy outlook up to 2040, cautioning that global oil prices may remain low in the next few years, and may stay in the 50-60 dollar range into the next decade.<sup>23</sup> The continued low oil prices in early 2016 have shown that even recovering to 50 dollars may take some time. Now the question is how the key Asian players will respond to such developments in their energy security strategies.

### 10.3 China's Gas and LNG Strategies

While key importers of gas and LNG in Asia are all actively pursuing stable supply sources, often accompanied by overseas investments by large corporations of the respective

<sup>19</sup> British Columbia Gov't: *Explore B.C.'s LNG Projects*, <http://engage.gov.bc.ca/Inginbc/Lng-projects>.

<sup>20</sup> Gary Ashton, "Analyzing Prices for Asian LNG Markets", cit.

<sup>21</sup> David Rowlands, "Sberbank Chief Executive expects Yamal LNG profits, despite low oil and gas prices", in *LNG Industry*, 11 November 2015, <http://www.lngindustry.com/liquefaction/11112015/Sberbank-Chief-Executive-expects-Yamal-LNG-profits-despite-low-oil-and-gas-prices-1610>.

<sup>22</sup> "Financing for Russia's Yamal LNG plant stalls - sources", in *Reuters*, 19 October 2015, <http://reut.rs/1Mz1kPs>.

<sup>23</sup> IEA, *World Energy Outlook 2015. Factsheets*, 10 November 2015, [http://www.worldenergyoutlook.org/media/weowebbsite/2015/WEO2015\\_Factsheets.pdf](http://www.worldenergyoutlook.org/media/weowebbsite/2015/WEO2015_Factsheets.pdf).

countries, China is by far the most strategic and long-term player. China's projected gas demand in the coming years and decades by far outpaces all other players.

Given China's status as the world's largest comprehensive energy consumer, its energy security concerns have been heightened in recent years. In the gas and LNG sectors, China faces increasing dependence on imports. The share of gas and LNG in China's energy mix is just over 5 percent today, which is already a significant growth over the past 10 years. With coal taking up close to 70 percent of China's energy mix and the high CO<sub>2</sub> emission levels and pollution associated with coal use, the Chinese government is under pressure to replace coal with more gas and other sources of energy. In order to increase the share of gas in China's energy consumption, Beijing has implemented a number of domestic and international strategies in the past few years.

First, the Chinese leadership calls for more domestic gas exploration and production in order to reduce vulnerability from import dependence. According to official figures, China added 943 Bcm to the country's total gas reserve in 2014, increasing 53 percent over the year before.<sup>24</sup> In both conventional and unconventional areas, domestic production has been prioritised. In the official 12th Five Year Plan (2011-15), the Chinese government set the goal of producing 6.5 Bcm of shale gas per year total capacity, but latest reports indicate that this goal is unlikely to be met by the end of the year, as the total production will be around 5 Bcm per year at that point. This is partly due to the very challenging nature of China's shale reserve locations and the complexities involving development.<sup>25</sup> But shale exploration in China has accelerated, with the Chinese government estimating 106.8 Bcm of total shale reserve in 2014, and producing 6 Bcm of shale, which makes China the third largest shale producer after the United States and Canada.<sup>26</sup>

Second, China is speeding up the infrastructure building for gas and LNG transportation. As the Deputy Minister of the National Energy Administration Zhang Yuqing pointed out in late 2015, by international comparison, China's per capita gas consumption is only 29 percent of the global average; its gas pipelines are only one ninth those of the United States; and its peak gas storage capacity is only 2 percent of total annual consumption, much lower than the world's average of 10 percent.<sup>27</sup> And the Chinese

<sup>24</sup> "China proved reserves of natural gas" (in Chinese), in *Sogou.com*, 16 April 2015, <http://business.sohu.com/20150416/n411397436.shtml>.

<sup>25</sup> "Shale gas development" (in Chinese), in *China Business News*, 7 November 2015, <http://finance.sina.com.cn/chanjing/cyxw/20151107/065223704560.shtml>.

<sup>26</sup> "China-third countries commercial development of shale gas production capacity more than 6 Bcm" (in Chinese), in *SINA News*, 28 October 2015, <http://mil.news.sina.com.cn/2015-10-28/1427842448.html>.

<sup>27</sup> "Energy consumption reduction or shift to natural gas urgent" (in Chinese), in *SINA News*, 16 November 2015, <http://finance.sina.com.cn/money/future/futuresnyzx/20151116/103723776198.shtml>.

government is eager to change the situation, as set out in the 13th Five Year Plan (2016-2020): there will be a fourth line added to the existing West-East gas pipeline; a fourth line added to the existing Shanxi-Beijing gas pipeline; and construction of the China-Russia Eastern gas pipeline plus multiple other gas pipelines from Xinjiang and Inner Mongolia regions. China plans to expand LNG terminals along its Eastern coastal lines, forming five major regional gas reserve groups, designed to reach a capacity of 20 Bcm by 2020. All these measures are in anticipation that China will consume up to 400 Bcm of gas per year at the end of the decade.<sup>28</sup>

Third, the government has launched new policies to encourage more gas consumption. About 80 percent of China's electricity comes from coal power plants, most of them burning without any pollution control. The Chinese government has been trying hard to either shut down the more polluting ones (most of them run by local private operators), or to make them cleaner. China has made remarkable progress in making coal burning more efficient and less polluting. But coal, with the market price very low, is still responsible for well over 85 percent of China's CO<sub>2</sub> emissions. In an effort to use market incentive to displace coal with gas for electricity generation, the central government released a policy directive at the end of 2014 establishing a gas-electricity price linkage mechanism. According to the National Development and Reform Commission's new document, effective on the first day of 2015, local governments can provide as much as 0.35 yuan subsidy per kilowatt-hour generated from gas sources over the same amount produced by coal.<sup>29</sup>

Fourth, Beijing is pursuing an active go-out strategy for security of gas and LNG supply. While expanding domestic pipeline and storage infrastructure, China has also enhanced pipeline delivery capacities from Central Asia, Burma and Russia. In terms of LNG import, China has signed long-term contracts with countries such as Australia, Qatar, Malaysia, Indonesia and Russia. China's three largest national oil companies (NOCs), CNPC, Sinopec and CNOOC, are all working on West Coast LNG projects in Canada (although the pace has slowed down in the past year given the drop in LNG prices in Asia). Both land-based gas pipelines and port-based LNG terminals are each expected to import 70 Bcm of gas in 2020.<sup>30</sup>

<sup>28</sup> "China's natural gas consumption will amount to 400 Bcm in 2020" (in Chinese), in *SINA News*, 24 August 2015, <http://finance.sina.com.cn/money/future/futuresnyzx/20150824/100123046034.shtml>.

<sup>29</sup> National Development and Reform Commission, *Regulating natural gas* (in Chinese), 31 December 2014, [http://www.sdpc.gov.cn/zcfb/zcfbtz/201501/t20150114\\_660176.html](http://www.sdpc.gov.cn/zcfb/zcfbtz/201501/t20150114_660176.html).

<sup>30</sup> "China's natural gas consumption will amount to 400 Bcm in 2020", cit.

## 10.4 China-Russia Cooperation

China has particularly emphasized its gas and LNG cooperation with Russia.<sup>31</sup> In May 2014, Chinese President Xi Jinping and Russian President Vladimir Putin signed a 400 billion dollar agreement, with Russia supplying China 38 Bcm a year by 2018. Later in the year, the two countries signed another non-binding memorandum that will see top Russian gas producer Gazprom ship 30 Bcm of gas annually to China over 30 years. The two gas deals, sealed only six months apart, have profound implications on China's quest for energy security, the volatile global energy market, China-Russia relations and broader geopolitical movements worldwide.

While the world media and expert opinions at the time focused mainly on the significance of these deals for Russian President Vladimir Putin and his confrontation with the West over the Ukrainian crisis, Beijing saw them primarily as a part of its long-term search for energy security and diversification of supply sources. China's attempt to diversify its primary energy sources from its heavy dependence on coal, thanks to Russian gas, clearly responds to a renewed emphasis attached by Beijing to the global climate change agenda. This is an effort witnessed also by the historic US-China Joint Announcement on Climate Change that President Barack Obama and President Xi Jinping signed during the APEC summit, and by the encouraging results achieved by the COP21 Paris Agreement.<sup>32</sup>

The large volume movement of gas from Russia to China in the near future will have a number of impacts on global energy markets. The first is an emerging, more integrated Euro-Asian gas distribution infrastructure. While the global transportation of crude oil is well developed via land and sea, natural gas is still constrained by the lack of delivery choices. If the two countries move ahead with planned pipelines on both Eastern and Western fronts, plus China's push for the fourth gas pipeline from Central Asia, a Euro-Asian continental gas transportation infrastructure will shape future worldwide gas shipping, as well as pricing.

The second related trend is the emerging shifts in regional distribution of natural gas trade. If the China-Russia gas deals are successful, China will overtake Germany as the largest single-country market for Russian gas exports. Russia's western Siberian export

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<sup>31</sup> This section is based on Wenran Jiang, "Energy Security, Geopolitics and the China-Russia Gas Deals", in *China Brief*, Vol. 15, No. 2 (23 January 2015), p. 13-16, [http://www.jamestown.org/single/?tx\\_ttnews\[backPid\]=7&tx\\_ttnews\[tt\\_news\]=43434](http://www.jamestown.org/single/?tx_ttnews[backPid]=7&tx_ttnews[tt_news]=43434).

<sup>32</sup> White House, *U.S.-China Joint Announcement on Climate Change*, Beijing, 12 November 2014, <http://go.wh.gov/mUaW6M>.



pipeline to China draws from the same gas fields that supply the EU markets.<sup>33</sup> Gazprom has even indicated that it might shelve its Vladivostok liquefied natural gas project, designed to supply Japan, in order to focus on supplying more gas to China by pipeline.<sup>34</sup>

The third is the downturn pressure for global gas and LNG prices due to increased competition in the Chinese and other Asian markets. In recent years, China's natural gas and LNG imports have grown rapidly. With the forecast that China will consume as much gas as EU countries combined by 2035, there is a worldwide race to export gas and LNG to China. So this development may put further pressure on multiple projects in North America, Australia and the Middle East.

The mere prospect of large volumes of Russian gas coming to China in the near future has created a more competitive environment for LNG producers from North America, Australia and the Middle East. But the decline of global energy prices this year has proven to be challenging for China and Russia to move forward such large projects. Many people even doubt if the two mega deals will be implemented according to the original design, although China seems effectively determined to push the gas deals to success.<sup>35</sup>

These gas deals also have geopolitical implications. Such mega deals always go beyond simple market interactions between buyers and sellers. For Russia, a country with oil and gas exports accounting for 68 percent of the country's total export revenue in 2013, these huge export contracts are instrumental to ensure socio-economic and political stability.<sup>36</sup> China, while formally neutral towards US/EU confrontation with Russia, is willing to express its open support for Putin's ongoing fight with the West. In fact, President Xi and the new leadership core came to power amid the US "Pivot to Asia" and are alarmed by what they view as a worsening international security environment. In particular, they see Japan in the East China Sea, and the Philippines and Vietnam in the South China Sea, as "challenging" China's territorial claims with the backing of the

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<sup>33</sup> Nick Cunningam, "Russia in Weak Position for New Gas Deal with China", in *OilPrice.com*, 11 November 2014, <http://oilprice.com/Energy/Natural-Gas/Russia-In-Weak-Position-For-New-Gas-Deal-With-China.html>. Further development of the East Siberia gas field will primarily depend on capital and a long-term buyer, which the Chinese have promised, meaning Russia does not need the West to develop the field. This extends to technical expertise, as the Russians, together with the Chinese, are quite good at handling gas exploration and development.

<sup>34</sup> Jack Farhy, "Gazprom considers shelving Vladivostok LNG project", in *Financial Times*, 10 October 2014.

<sup>35</sup> See, for example, Edward C. Chow and Michael Lelyveld, "Russia-China Gas Deal and Red Deal", in *CSIS Commentaries*, 11 May 2015, <http://csis.org/node/55622>; Dalan McEndree, "Putin is Taking a Big Risk with China Gas Deals", in *OilPrice.com*, 1 November 2015, <http://oilprice.com/Energy/Natural-Gas/Putin-Is-Taking-A-Big-Risk-With-China-Gas-Deals.html>.

<sup>36</sup> EIA, "Oil and natural gas sales accounted for 68% of Russia's total export revenues in 2013", in *Today in Energy*, 23 July 2014, <http://www.eia.gov/todayinenergy/detail.cfm?id=17231>.

United States.<sup>37</sup> Such strategic concerns prompted President Xi to seek closer Russian ties as a balance against Washington.

In any case, it is premature to conclude that China and Russia share the same objectives in their geopolitical games against the West. Beijing, indeed, does not want to return to the 1950s-style military alliance with Russia, while Moscow does not want to become too dependent on China, which is already its largest trading partner.

## 10.5 Other Regional Dynamics

While big players will have a major impact on setting the trends for gas and LNG movement in Asia, it is also worth investigating major trends in Southeast Asian countries such as Malaysia and Indonesia, which are in a very good position to be gas and LNG suppliers and exporters to Japan, South Korea, China and India. And, a factor not to be underestimated, these countries are also emerging as key gas and LNG consumers themselves.

Malaysia depends heavily on its domestic oil and gas industry, which provides 22 percent of government revenues.<sup>38</sup> Aspiring to lift itself into the upper income countries by 2020, Malaysia has been strengthening its energy sector to achieve this goal. Petronas, Malaysia's state-owned energy company, is one of the largest integrated oil and gas companies in the world. In 2015, Petronas dividends accounted for almost 10 percent of the government's budget,<sup>39</sup> but the oil and gas sector has produced mixed results in recent years. While Petronas has expanded into the global market, including gas and LNG ventures in Australia and Canada, both crude exports and LNG exports declined in 2015. In order to boost its oil and gas production, the company has entered multi-billion dollar joint venture projects with large international oil companies such as ExxonMobil.<sup>40</sup>

In the gas and LNG supply domain, Petronas has built up a major portfolio. Malaysia is the world's third largest LNG exporter, and despite the recent decline in exports, the

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<sup>37</sup> "Vietnam to resolve territorial sovereignty dispute", in *China News*, 2 January 2013, [http://opinion.china.com.cn/opinion\\_27\\_62127.html](http://opinion.china.com.cn/opinion_27_62127.html).

<sup>38</sup> "Malaysian oil and gas sector to account for 22 % of government revenue", in *EOG-Asia*, 13 February 2015, <http://www.eog-asia.com/?p=431>.

<sup>39</sup> Malaysia Prime Minister, *Budget Speech 2015*, 10 October 2014, <http://www.treasury.gov.my/pdf/budget/speech/bs15.pdf>; Emily Chow, "Malaysia's Petronas cuts state dividend as profit plunges on oil drop", in *Reuters*, 11 November 2015, <http://reut.rs/1ODQYUM>.

<sup>40</sup> PennEnergy, *New report released on the ins and outs of Malaysia's oil and gas sector*, 20 July 2015, <http://www.pennenergy.com/articles/pennenergy/2015/07/new-report-released-on-the-ins-and-outs-of-malaysia-s-oil-and-gas-sector.html>.

company will increase its LNG capacity from the current 31 Bcm to 48 Bcm by 2020. It has upstream gas exploration and production in Australia and Canada and supplying Korea, Japan and Taiwan.<sup>41</sup> In support of its position as a global leader in LNG, Petronas also put in operation the world's first floating LNG facility (FLNG) early in 2016. Unlike the traditional process where gas is produced in a fixed location, transported to a processing facility via pipelines, and then liquefied and stored before it is sold on the market, an FLNG facility will do all these processes in one place and in a mobile manner. This means that the facility can be moved from location to location with better economics. Petronas's first FLNG will produce 1.65 Bcm of LNG per year at its Kanowit gas field.<sup>42</sup> This will also allow Petronas to reach remote and isolated locations for developing Malaysia's gas reserves.

Indonesia, another major energy player in Southeast Asia, has both a large population and a large reserve of natural gas. It used to be the largest LNG exporter in the world, but its market share has declined due to government policy changes in the mid-2000s, and insufficient investment in the exploration of gas fields. Today, it has the third largest gas reserves in the Asia Pacific region (after Australia and China) according to *BP Statistical Review of World Energy 2015*. Indonesia also ranks as the fourth largest LNG exporter after Qatar, Malaysia and Australia. The country produces twice as much gas as it consumes.

At a first glance, this is just another large LNG supplier in the making. But the reality is that Indonesia suffers from a domestic gas shortage. This situation is primarily caused by the fact that major foreign investors have been exploring and producing in Indonesia's gas fields under the condition that they can export their output. The Indonesian subsidiaries of Total, Conoco Philips, BP, ExxonMobil and CNOOC together produce 87 percent of the country's natural gas. So in order to attract foreign investments and earn foreign currency, paradoxically Indonesia has to import LNG to meet the domestic needs while keeping its export commitments.<sup>43</sup> In the years to come, Indonesia will have to balance its domestic consumption needs while trying to be a major international player in the gas and LNG sectors.

From a broader regional perspective, the Association of Southeast Asian Nations (ASEAN), set up to promote better economic coordination and integration in the area, operates also in the energy-related policy domain. In this context, the ASEAN Vision

<sup>41</sup> "Petronas to stay focused on 'cool and sexy' LNG business", in *Hellenic Shipping News*, 15 June 2015, <http://www.hellenicshippingnews.com/?p=224576>.

<sup>42</sup> "Petronas floating LNG unit to tap into Kanowit field off Sarawak", in *The Star Online*, 7 March 2016, <http://fw.to/Cb5CuVF>.

<sup>43</sup> See the Indonesia Investments website: *Natural Gas*, updated 10 October 2015, [http://www.indonesia-investments.com/zh\\_cn/business/commodities/natural-gas/item184](http://www.indonesia-investments.com/zh_cn/business/commodities/natural-gas/item184)

2020 puts energy security and long-term supply reliability as its core policy considerations, through the creation of two energy networks: the Trans-ASEAN Gas Pipeline (TAGP) and the ASEAN Power Grid (APG). TAGP in particular is intended to enhance and connect the gas pipeline infrastructure of all ASEAN member states.<sup>44</sup>

## 10.6 Prospects for Market and Policy

While the short-term market for oil and gas is volatile and unpredictable, the medium to long-term trends for Asia's gas demand are clear. Japan, South Korea and Taiwan will continue to sustain high levels of gas and LNG imports, while China and India will experience sharp rise in demand for gas and LNG.

In two decades, China's gas consumption will reach close to the level of EU countries combined. The share of oil and gas in China's energy mix will continue to grow, with both having an equal share in China's energy mix by 2025.<sup>45</sup>

India, the most watched major economic powerhouse as China's growth pace is slowing down, has by far the most expansive prospects for using a large amount of energy, including natural gas and LNG. Given the fact that India's foreign dependence on both oil and gas is high, and that its foreign reserve position is not as strong as China, cheap energy prices since late 2014 have provided India with some great opportunities. India's Power Minister Piyush Goyal saw the 75 percent drop in LNG prices since 2004 as good for the country's supply security. From the Indian perspective, indeed, the current historic low price of energy offers significant opportunities to control the entire value chain right from gas production to liquefaction, shipping, regasification and power generation.<sup>46</sup> In this context, in early 2016 the Indian government approved two LNG joint venture projects, aiming at strengthening the country's LNG infrastructure.<sup>47</sup>

The ASEAN group differs from Asia's large gas and LNG consuming states, since it has increasing both production/export and consumption/import potentials. This heterogeneous group is relatively small individually but, as a region, its demand for gas and LNG will continue to rise. And ASEAN will reach the level of Japan in terms of overall

<sup>44</sup> See the ASEAN Centre for Energy website: <http://www.aseanenergy.org/?p=79>.

<sup>45</sup> "Gasification of China" (in Chinese), in *hc360.com*, 28 October 2015, <http://info.chem.hc360.com/2015/10/280930498478.shtml>.

<sup>46</sup> Debjit Chakraborty and Dhvani Pandya, "India Eyes More LNG Purchases from Australia in Cheap Energy Age", in *Bloomberg*, 9 February 2016, <http://bloom.bg/1PyXpnP>.

<sup>47</sup> "Competition Commission of India approves two JVs to set up LNG terminal in Andhra Pradesh", in *The Economic Times*, 16 February 2016, <http://ecoti.in/rcL7ib>.

energy consumption. While currently only Singapore imports LNG, both the Philippines and Vietnam have built LNG receiving terminals that are expected to be in operation this year and next year.<sup>48</sup>

These trends offer an opportunity to push for a more Asia-centred gas/LNG price indexing mechanism. Japan launched an over-the-counter LNG futures market in 2014, and is actively seeking a leadership position in setting up an Asian LNG price index. South Korea is reportedly seeking a memorandum of understanding with Japan and China to coordinate over LNG contracts, pricing and supplies.<sup>49</sup> Singapore is also a leading member given its large LNG porting and storage capacity. On the infrastructure side, the country put in operation the open access, multi-user Singapore LNG (SLNG) terminal at Jurong Island in 2013 with a capacity of 4.8 Bcm per year, then expanded to 8.3 Bcm in 2014. The country is also developing additional regasification facilities to boost SLNG to 12.4 Bcm capacity by 2017. On the financial side, Singapore is currently working with Singapore Exchange and other stakeholders to develop an Asian LNG price marker.<sup>50</sup>

In conclusion, the challenge for global gas and LNG producers, given the optimistic future demand scenario, remains the price range of these commodities in the coming years. Asian markets will play a key role in this context as, in the past years, the high price for LNG in the region pushed multiple LNG projects to be planned and implemented. Today, however, the declining price is affecting the strategies of emerging producers. This is, for instance, the case for Canada: unless LNG price driven by Asian demand returns to the 12-15 dollars per mmBtu range, it would be difficult for the 20 planned LNG projects to be profitable.

There is a likelihood that in order to better coordinate the demand and supply situation of the gas and LNG markets, governments of both gas producing and consuming states may adjust their policies. While not interfering with private sector investment decisions, Western producers such as the United States, Canada and Australia may take a page from the China-Russia gas deals by facilitating medium to long-term supply agreements with large Asian importers, especially China. While Russia enjoys geographical proximity to, and shares geostrategic interests with, China, it faces financial and technologic challenges in its partnership projects with China. Western countries, on the other hand, have a much better and more open operational environment, and it remains to be seen if they will implement strategies that better promote their market access to Asia's huge gas and LNG potential.

<sup>48</sup> Catriona Scott, "Southeast Asian LNG – strength in numbers", in *Interfax Europe*, 18 February 2016, <http://interfaxenergy.com/analytics/article/514>.

<sup>49</sup> Meeyoung Cho, "S.Korea sees gas demand falling 5 percent by 2029", cit.

<sup>50</sup> Michael Lawson, "Asian LNG: where to from here and what role for Singapore?", in *Lexology*, 27 May 2015, <http://www.lexology.com/library/detail.aspx?g=32719267-f75e-495f-b204-f5d23e0ada11>.

## 11. The Evolution of Japan's LNG Strategies and Their Geopolitical Implications

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The role of natural gas in Japan's energy system, and the country's role in the global gas markets have been undergoing a major transition since the Fukushima nuclear accident that followed the Great East Japan Earthquake of March 2011. Japan's response to the Fukushima-induced energy supply challenge and to the subsequent macroeconomic stress heralds the prospect of transforming the global liquefied natural gas (LNG) business. The success of Japan's LNG strategies depends on geopolitical developments in the region. Also, the future of natural gas in the Japanese energy system depends on domestic policy developments. How did the Fukushima accident affect Japan's LNG strategies? What actions have Japanese stakeholders taken in accordance with strategic adjustments? What are the major exogenous and indigenous factors that affect the future role of natural gas in Japan's energy mix and Japan's gas diplomacy?

### 11.1 The Growth of Natural Gas in the Japanese Energy System

The dearth of indigenous hydrocarbon resources, including natural gas, has meant that Japan is highly dependent on fossil fuel imports to meet its primary energy supply needs. Japan, which was about 90 percent dependent on fossil energy imports in the early 1970s, took the experience of the Arab oil embargos to heart, and launched concerted efforts to reduce its oil import dependence and to diversify the sources of both the primary energy and electricity supplies. The government thus promoted nuclear energy and

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energy efficiency, and by 2010 had reduced the dependency on fossil energy imports to about 80 percent.<sup>1</sup> In fact, Japan succeeded in nearly halving its oil import dependency from 75.5 percent to 40.1 percent in the three decades following the oil embargos.<sup>2</sup>

Concurrently, Japan has emerged as the largest importer of natural gas. The share of natural gas in the country's electricity supply mix steadily grew during the same period. Between 1973 and 2000, the share of natural gas in the overall electricity supply grew from 2.4 percent to 29.3 percent.<sup>3</sup> This strong growth was driven by the national effort to address the air pollution challenge in the early 1960s. Today, Japan has over 30 regasification terminals. Japanese companies earned recognition as credit-worthy buyers meriting the confidence of banks and other investors in capital-intensive undertakings such as LNG export projects. Also, the country has played a leading role in the development of global LNG trade since Tokyo Electric Power Co. and Tokyo Gas began importing Alaskan LNG in 1969.

By the very beginning of this decade, however, growing Chinese gas demand and the country's implied future market power were beginning to capture the imagination of suppliers. Additionally, heeding the rising public awareness of the threat of global climate change, the Japanese government reaffirmed its commitment to fulfilling its carbon emission reduction target under the Kyoto Protocol and to using low-carbon-emitting energy such as nuclear and non-hydro renewables for power generation. The third Strategic Energy Plan, issued in 2010, called for the share of nuclear energy to grow from 25 percent in 2007 to 53 percent in 2030, and non-hydro renewables from 1 percent in 2007 to 10 percent in 2030. Under the same plan, the share of natural gas was to decline from 28 percent to 13 percent, and coal from 25 percent to 11 percent.<sup>4</sup>

## 11.2 The Fukushima Nuclear Accident and Natural Gas Renaissance

The nuclear accident at the Fukushima Dai-ichi Power Station in March 2011, however, voided Japan's planned transition away from fossil fuels. Public concern over nuclear safety and shattered faith in the country's nuclear sector governance meant that all of

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<sup>1</sup> Hironori Nakanishi, *Japan's Energy Situation and Policy*, presentation, 2 June 2014, p. 2, [http://www.pl.emb-japan.go.jp/keizai/documents/E0\\_2%20METI%20Nakanishi.pdf](http://www.pl.emb-japan.go.jp/keizai/documents/E0_2%20METI%20Nakanishi.pdf).

<sup>2</sup> Japan Agency for Natural Resources and Energy, *Japan's Energy Policy*, Tokyo, July 2014, p. 5.

<sup>3</sup> Japan Ministry of Economy, Trade and Industry, *Japan's Energy Situation*, Tokyo, April 2015, p. 2.

<sup>4</sup> Ryo Minami, *Revision to the Japanese Energy Policy*, presentation, 2 December 2011, p. 5, [http://www.eu-japan.eu/sites/eu-japan.eu/files/presentation\\_minami\\_02122011.pdf](http://www.eu-japan.eu/sites/eu-japan.eu/files/presentation_minami_02122011.pdf).

Japan's 48 post-accident operable commercial nuclear reactor units<sup>5</sup> had gone off-line by autumn 2013, as prefectural governments declined to give routine restart approvals to reactors under scheduled maintenance.

The nuclear outage from September 2013 to August 2015 left a 46 GW hole in Japan's installed capacity,<sup>6</sup> compelling the country to turn to fossil fuels to meet the shortfalls. In the years following the March 2011 earthquake, Japan's LNG import volumes grew by 24 percent, from 98 billion cubic metres (Bcm) per annum in Japanese Fiscal Year (JFY) 2010 to 121 Bcm in JFY 2013.<sup>7</sup> By 2013, the proportion of electricity generated by thermal power increased to nearly 90 percent, and LNG-based power generation alone accounted for nearly 43 percent of Japan's total.<sup>8</sup> This heightened reliance on LNG essentially reversed Japan's status as a mature and perhaps saturated market to that of a global centre for LNG demand. Japan's global market share of LNG demand increased from 31 percent in 2010, the lowest in four decades, to the average of 37 percent between 2012 and 2014.<sup>9</sup>

The dash to LNG procurement came with significant economic consequences. The increase in volume and in the price of oil-linked LNG imports<sup>10</sup> led the overall cost of LNG imports to Japan to increase from 35 billion dollars<sup>11</sup> in 2010 to about 70 billion dollars in 2013.<sup>12</sup> The trade deficit steadily increased in the years following the Fukushima accident – which coincidentally occurred at the end of JFY 2010 – and reached 115 billion dollars in 2013.<sup>13</sup> The high cost of fossil fuel procurement has grown into an economic security challenge. After maximizing efforts to secure additional volumes to avert electricity shortages in the immediate aftermath of Fukushima, Japan has turned its attention to the macroeconomic toll of its soaring energy import spending, and has embarked upon strategies to diversify LNG import sources as well as LNG procurement models in order to generate competition among supplier countries and to secure cheaper gas abroad.

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<sup>5</sup> Japan had 54 reactor units at the beginning of 2011. Four units were disabled following the tsunami and two units in the same plant became inaccessible due to plant contamination.

<sup>6</sup> See the webpage of the Japan Federation of Electric Power Companies: *Nuclear Power Plants in Japan*, [http://www.fepc.or.jp/english/nuclear/power\\_generation/plants/sw\\_plants\\_01](http://www.fepc.or.jp/english/nuclear/power_generation/plants/sw_plants_01).

<sup>7</sup> Japan Ministry of Economy, Trade and Industry, *Japan's Energy Situation*, cit., p. 35. Japan's fiscal year runs from April of the same year to March of the following year.

<sup>8</sup> *Ibid.*, p. 34.

<sup>9</sup> EIA, *Country Analysis: Japan*, updated 30 January 2015, p. 26, <https://www.eia.gov/beta/international/analysis.cfm?iso=JPN>.

<sup>10</sup> The weaker Japanese yen versus the US dollar increased Japan's trade deficit levels in 2012 and 2013.

<sup>11</sup> The exchange rate between the US dollar and Japanese yen is set at 1 dollar = 100 yen throughout this chapter.

<sup>12</sup> Japan Ministry of Economy, Trade and Industry, *Japan's Energy Situation*, cit., p. 36.

<sup>13</sup> *Ibid.*



### 11.3 Diversifying the Supplier Country Pool

Supplier diversification has been on the agenda for Japanese energy policymakers since before the Fukushima accident,<sup>14</sup> but the significant rise in fuel import expenses prodded Japanese companies to seek supply relations with countries outside Southeast Asia. Whereas supplies from Indonesia, Malaysia and Brunei alone accounted for nearly half of Japanese imports pre-Fukushima,<sup>15</sup> by 2012 Australia and Qatar had become the leading suppliers to Japan. Since the mid 1980s, Japanese companies have been involved in the Australian LNG export projects, including North West Shelf LNG (Mitsubishi and Mitsui), Darwin LNG (Inpex, TEPCO and Tokyo Gas), and Pluto LNG (Kansai Electric and Tokyo Gas).<sup>16</sup> Its vast hydrocarbon resources, geopolitical stability and relative geographical proximity made Australia attractive to Japan, which in 2013 was the market for 80 percent of Australian LNG exports, mostly through long-term contracts.<sup>17</sup> Imports from Australia's Pluto pushed the share of Australian imports to over one-fifth in Japanese LNG supply mix starting in 2012.

Japan's relationship with Qatar – which goes back to the 1990s – also expanded after Qatar supplied LNG to Japan on short-term contracts in the immediate aftermath of the Fukushima accident. The robust development of shale gas in the United States since the late 2000s significantly reduced the American dependence on natural gas imports, thereby rendering about one-third of Qatar's new LNG volumes (equivalent to up to 20 billion cubic metres) desperately in need of alternative markets.<sup>18</sup> The spike in Japanese LNG demand following the Fukushima accident could not have been better timed from the Qatari business perspective. Qatari imports jumped by 85 percent in 2011 year-on-year, and in 2012, Qatar became the second largest LNG supplier to Japan after Australia.

Additionally, Japan focused on developing gas projects with and in Russia, Canada and Mozambique.<sup>19</sup> For example, Russia has been supplying gas to Japan from its

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<sup>14</sup> Tomoko Hosoe, "Asia's Post-Fukushima Market for Liquefied Natural Gas: A Special Focus on Japan", in Philip Andrew-Speed et al., "Oil and Gas for Asia. Geopolitical Implications of Asia's Rising Demand", in *NBR Special Reports*, No. 41 (September 2012), p. 51.

<sup>15</sup> Japan Agency for Natural Resources and Energy, *Energy White Paper for FY 2010*, Tokyo, December 2010, p. 172.

<sup>16</sup> EIA, *Country Analysis: Australia*, updated 28 August 2014, <https://www.eia.gov/beta/international/analysis.cfm?iso=AUS>.

<sup>17</sup> *Ibid.*

<sup>18</sup> Anne-Sophie Corbeau et al., *The Asian Quest for LNG in a Globalising Market*, Paris, OECD/IEA, 2014, p. 21, <https://www.iea.org/publications/freepublications/publication/partner-country-series---the-asian-quest-for-lng-in-a-globalising-market.html>.

<sup>19</sup> Japan Ministry of Economy, Trade and Industry, *Keynote Address by Mr. Toshimitsu Motegi, Minister*

Sakhalin II project since 2009 (Mitsui and Mitsubishi), but Japan has also been pursuing additional projects with Russia, including the Sakhalin I gas production project and the Vladivostok LNG project. Furthermore, Japan has increased its involvement in Canada since 2011; but the future scope of Canadian market share in Japan is highly tentative as the low global oil price environment has rendered final investment decisions difficult.

## 11.4 Diversifying LNG Procurement Models

Another major strategic development was to seek more flexible terms in LNG business to secure cheaper natural gas supplies abroad. In this strategic pursuit, the robust production of shale gas and low gas prices in the United States could not have unfolded at a more opportune time. By the time of the Fukushima accident the United States was witnessing a renaissance in its domestic gas production. The gas output in March 2011 was 2.2 million cubic metres per day (mmcm/d), up from 2.08 mmcm/d a year before.

Developing an LNG export project generally takes an integrated approach in that a LNG export project must first secure a firm purchase commitment from buyers, and in that the feedgas supply is obtained from within the consortium that develops the project. Producers in this model have traditionally asked for a multi-decade contract based on oil-linked prices and with a take-or-pay provision to hedge against the risk associated with the length and scope of such an endeavour. In fact, much of LNG in Asia, including in Japan, is currently priced based on a mechanism tied to the Japan Customs-cleared Crude price (JCC, also called the "Japan Crude Cocktail"), which is an average price of customs-cleared oil imports into Japan. The oil linkage is a relic of the 1970s and 1980s, when natural gas was in direct competition with crude oil in power generation in Japan. Also, traditional Asian contracts have what is known as the "destination clause," which prohibits buyers from re-selling cargoes or taking delivery outside their home country without seller's agreement and thus competing with the original seller. This restriction has also inhibited trading opportunities in Asia and kept the regional spot markets relatively illiquid.

In contrast, US LNG projects and their export contracts offer many flexibilities. Gas markets in the United States are highly liquid and transparent, and US LNG export projects do not require oil-linkage or natural gas production by LNG plan owners to be able to recoup requisite investment for developing upstream or infrastructure. Instead, most

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*of Economy, Trade and Industry, at the Second LNG Producer-Consumer Conference, Tokyo, 10 September 2013, <http://www.meti.go.jp/english/speeches/20130910.html>.*

of the US export projects offer LNG contracts with Henry Hub indexed pricing and no obligation to the customers to take ownership of the gas when prices are too high and thus unattractive abroad – as long as they pay a fee (or “toll”) for the contracted liquefaction capacity they did not use. This so-called tolling model shifts the risk of volatility in gas prices to the customers, but it also provides them with destination flexibility.

The combination of such contractual flexibilities in US LNG export business models and the growing price divergence between the United States – primarily the Henry Hub price – and Japan in the early 2010s raised Japanese interest in potentially importing LNG from the United States.<sup>20</sup> Major Japanese power utilities and general trading houses took a major step forward in 2012 by announcing investment decisions in US export terminals in April and July. Following US government approval, all LNG export projects with Japanese stakes have entered into the final investment decision. The Japanese take will total up to 23.5 Bcm, accounting for 20 to 25 percent of Japanese imports. In order to benefit from low North American gas prices with the ultimate aim of exporting the gas back to Japan, Japanese companies have also made upstream investments, including the Eagle Ford Shale in Texas, and the Marcellus Shale in Pennsylvania.

In addition to signing on for sourcing LNG from the United States on terms, including a free on board provision and Henry Hub price linkage, Japanese companies began exploring various types of procurement in attempts to break the rigidity that has traditionally defined LNG trade. One approach for companies has been to strike joint procurement arrangements, such as Chubu Electric’s 2013 agreement with KOGAS of South Korea to relocate 2.4 Bcm (or 28 cargoes) of LNG supplies from Eni among themselves over 2013-17,<sup>21</sup> and Kansai Electric’s 2015 agreement with Engie (formerly GDF Suez) of France.<sup>22</sup> These buyers appear motivated to gain a better bargaining position or the ability to relocate supplies among themselves to meet fluctuating demand levels. Joint LNG procurement efforts may also be on rise between Japanese companies, again in hopes of gaining a better bargaining position although there is no clear correlation between such aggregation of purchasing activities and price reduction. The most prominent case is the April 2015 launch of a new joint venture called JERA,<sup>23</sup> by Chubu Electric and

<sup>20</sup> Eric Yep, “Asia’s LNG Buyers Get Sweeter Deals”, in *The Wall Street Journal*, 15 June 2015, <http://on.wsj.com/1fdnxcB>.

<sup>21</sup> Eni, *Eni signs mid-term agreement for the sale of LNG to Japan and South Korea*, 1 November 2013, <http://bit.ly/1pbsUxN>.

<sup>22</sup> Tsuyoshi Inajima and Emi Urabe, “Kansai Electric Seeks ‘Loose’ Alliances Amid Uncertainties”, in *Bloomberg*, 27 October 2015, <http://bloom.bg/103VjAx>.

<sup>23</sup> In addition to the merger of the new business developments of Chubu and TEPCO in April 2015, the fuel transportation and fuel trading businesses of the two companies were merged in October 2015. JERA is scheduled to further merge the existing fuel business (i.e., upstream, SPAs, fuel receipt and storage, gas transportation facilities), overseas IPPs and energy infrastructure businesses by summer 2016.

TEPCO, whose purchasing power will account for about 40 percent of Japan's LNG imports (or the total LNG purchasing volume of 40mta). JERA has publicly stated that it will not sign LNG contracts with destination clauses and will eventually halve its share of long-term LNG contracts.<sup>24</sup> Additionally, there have been several deals by Japanese companies where the US Henry Hub natural gas price is used for supplies from BP Singapore's global portfolio. These include Kansai Electric's 2015 agreement to purchase 18 Bcm over 23 years, starting in 2015,<sup>25</sup> and Tokyo Electric's 2014 agreement to purchase 1.6 Bcm for 17 years, starting in 2017.<sup>26</sup>

In fact, initiatives to secure cheaper LNG were not left to the private sector. The Japanese government decided to pursue cheap LNG supplies through what its policy-makers termed the "top runner" approach in determining whether to approve individual electric utility applications for an electricity rate increase submitted during JFY 2013 and JFY 2014 as the post-Fukushima switch to fossil fuels hurt utilities balance sheets. Specifically, the average power price rose by about 20 percent for households and about 30 percent for industry between 2011 and 2013.<sup>27</sup> As a means of urging electric utilities to procure LNG as cheaply as possible, the government set a ceiling on long-term LNG procurement costs whereby the lowest revised price among all long-term LNG contracts (thus the "top runner") becomes a benchmark against which all electric power companies must revise their LNG procurement costs. Starting in 2015, the ceiling will partly reflect natural-gas-linked procurement prices.<sup>28</sup>

Also, the Japanese government intensified its support for private sector investment in upstream and gas export projects around the world through its financial institutions. For example, Japan Oil, Gas and Metals National Corporation (JOGMEC) established the debt-guarantee level at 10,000 dollars for projects aimed to procure cheap LNG supplies post-Fukushima.<sup>29</sup> Also, Japan Bank for International Cooperation (JBIC) supported Japanese private sector efforts to secure cheaper supplies abroad by providing long-term loans to complement private-sector financing. While there is no official account

<sup>24</sup> Stephen Stapczynski, Tsuyoshi Inajima and Emi Urabe, "Buyers Market for LNG Turns Tables on Producers Amid Supply Glut", in *Bloomberg*, 5 October 2015, <http://bloom.bg/1VBLh8u>.

<sup>25</sup> Kansai Electric Power Co., *LNG Sale and Purchase Agreement and Cooperation Agreement with BP Singapore Pte. Limited*, 28 May 2015, [http://www.kepcoco.jp/english/corporate/pr/2015/\\_\\_\\_icsFiles/afiedfile/2015/06/01/2015\\_may\\_28.pdf](http://www.kepcoco.jp/english/corporate/pr/2015/___icsFiles/afiedfile/2015/06/01/2015_may_28.pdf).

<sup>26</sup> TEPCO, *Sale and Purchase Agreement for LNG from BP Singapore*, 12 September 2014, [http://www.tepcoco.jp/en/press/corp-com/release/2014/1241741\\_5892.html](http://www.tepcoco.jp/en/press/corp-com/release/2014/1241741_5892.html).

<sup>27</sup> Japan Ministry of Economy, Trade and Industry, *Japan's Energy Situation*, cit., p. 10.

<sup>28</sup> Japan Ministry of Economy, Trade and Industry, *Kansaidenryoku to Kyūshūdenryoku no denki ryōkin no neage* (Power Price Increases by Kansai and Kyushu Electric Power Companies), Minister's press conference, Tokyo, 27 March 2015, [http://www.meti.go.jp/speeches/data\\_ed/ed130327j.html](http://www.meti.go.jp/speeches/data_ed/ed130327j.html).

<sup>29</sup> Japan Ministry of Economy, Trade and Industry, *Keynote Address by Mr. Toshimitsu Motegi...*, cit.

of how much JBIC provided to meet the additional gas demand that has arisen due to the Fukushima accident, many of their loans since 2011 have clearly been provided in recognition of their importance for Japan's effort to diversify LNG procurement sources and pricing formulas.<sup>30</sup>

Moreover, seeing the lack of transparency in regional LNG markets as a major cause of high LNG prices, the Japanese government initiated the creation of an LNG futures market in April 2014, when they began publishing a price index based on spot cargos. The Japanese contract has thus far gained limited traction, as LNG is usually bought on long-term contracts, while the spot market is illiquid. In order to increase liquidity, the Japan OTC Exchange (JOE) engaged the Chicago Mercantile Exchange in fall 2015 whereby CME will begin clearing the non-deliverable forward Japanese LNG contract.<sup>31</sup> The success of this endeavour is a crucial test in Japanese capacity to become a regional hub, which is among the government visions under the 2014 Strategic Energy Plan. Additionally, aiming to identify a scope for mutual benefit between suppliers and importer economies while promoting greater flexibility in LNG procurement models, the Japanese government launched multilateral discussions, such as the LNG Producer and Consumer Conference.

## 11.5 Domestic Factors Influencing the Future of Gas in Japan

At home, the Japanese government also examined major changes in energy supply and demand surrounding Japan since the last version of the Strategic Energy Plan was issued in 2010. The undertaking culminated in the issuance of a new Strategic Energy Plan in April 2014, on the basis of which the Japanese government announced the new energy supply outlook for 2030,<sup>32</sup> in spring 2015 (see figure 1). The new electricity supply mix suggests continued promotion of renewable energy while significantly reducing the role of oil; the latter, however, is in line with the pre-Fukushima government vision despite a temporary spike following the Fukushima disaster. Mostly notable are LNG and nuclear. The share of LNG is to decline from the current high of 43.2 percent (in JFY 2013) and return to the pre-Fukushima 10-year average of 27 percent in 2030. Also, the 20-22 percent nuclear share in 2030 is targeted to be lower than the pre-Fukushima

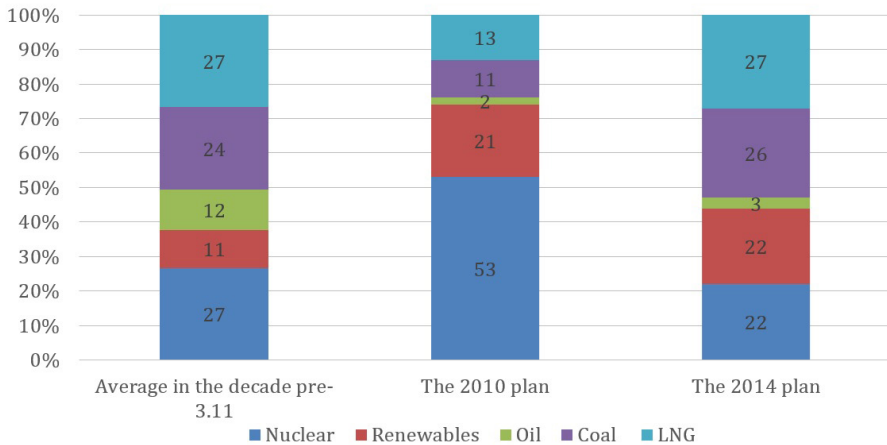
<sup>30</sup> Japan Bank for International Cooperation (JBIC), *Project Financing for Cameron LNG Project in U.S.*, 7 August 2014, <http://www.jbic.go.jp/en/information/press/press-2014/0807-26775>.

<sup>31</sup> Jacob Gronholt-Pedersen, "Japan teams up with CME to develop LNG index, break oil-link", in *Reuters*, 10 September 2015, <http://uk.reuters.com/article/2015/09/10/cme-lng-idUKL4N11G18F20150910>.

<sup>32</sup> Japan Ministry of Economy, Trade and Industry, *Japan's Energy Situation*, cit., p. 22.

average and significantly lower than the pre-Fukushima (2010) vision of 53 percent in 2030. It is also notable that the 2030 target shares of LNG and of coal per the 2014 plan are roughly double the 2010 plan.

Figure 1 | Japan's electricity supply mix outlook for 2030 per the 2010 and 2014 strategic energy plans



Source: Author's elaboration, with data from the Agency for Natural Resources and Energy of Japan.

Striking this balance is predicated upon the outcomes of three important domestic policy debates. First, the scope of nuclear power generation is a key uncertainty. Until the Fukushima accident, nuclear energy was a cornerstone of Japan's energy policy. The Fukushima accident and subsequent public concern over nuclear safety and governance forced the Japanese government to scratch the vision. The post-Fukushima nuclear supply target of 20-22 percent in 2030 is more modest in relation to the pre-Fukushima goal, but it may still not be an easy target. There are currently 43 operable units left in Japan after several power companies decided against making retrofits to some older reactors that would be needed if they were to meet the more stringent, post-Fukushima nuclear safety standards that entered into effect in July 2013. The successful restart of the Sendai Reactor in August 2015 brought an end to the two-year absence of nuclear power generation in Japan. But this milestone neither guarantees the new nuclear share in 2030 nor the full restoration of nuclear power generation in Japan. About one-fourth to one-third of the country's reactors will need to have their operational licenses renewed beyond 40 years, or in the absence of new builds, nuclear energy will only account for about 15 percent in 2030<sup>33</sup> – a prospect of great uncertainty given the continued public

<sup>33</sup> Takeo Kikkawa, *Electricity Power Mix in 2030: Nuclear Power Generation Would Account for about*

concern. By 2040, Japan's nuclear fleet could become nearly extinct without new construction or wide-scale license extensions.

The second debate concerns the role of coal. Japan does not have significant coal reserves but coal, as a relatively cheap fossil fuel, has re-kindled Japanese interest. Between 2010 and 2014, the country's coal consumption increased by 19 percent,<sup>34</sup> primarily to fill the gap left by nuclear outage. In August 2015, monthly coal consumption for power generation was the highest in 40 years.<sup>35</sup> Of 15.2 GW installed capacity that is planned to come online in the next 10 years, over 95 percent is thermal, including 30 percent coal and 60 percent natural gas.<sup>36</sup> Some of the 70-plus entities registered as new power suppliers<sup>37</sup> in preparation for further retail liberalization from April 2016 are planning to acquire a low-cost electricity source in the form of coal to compete with current power utilities. Such a robust expansion of coal has not gone unnoticed. For example, in summer 2015 the environmental minister refused to support several new coal power projects as part of the ministry's effort to control GHG emissions. The continued approvals could jeopardize Japanese ability to fulfil its Intended Nationally Determined Contribution (INDC) of 26 percent by 2030 against 2013 (or a 25.4 percent reduction compared to JFY 2005). While the ingenuity of Japanese manufacturers has advanced technologies in boilers and turbines, debate continues on the propriety of expanding coal usage vis-à-vis Japanese commitment to climate change.

Third, the future power supply mix as outlined above may come under significant pressure, as deregulation efforts in the power and gas sectors will heighten competition among electric power companies, gas companies and new entrants. The Japanese government approved the Policy on Electricity System Reform in 2013, to help facilitate electricity sector deregulation, which dates back to 1995. One of the aims is to create competition among the power utilities by weakening their regional monopolies and thus loosening their control on power prices. The further retail competition in the power sector from April 2016 and in the gas sector from 2017 will likely present a period of

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15%, Tokyo, Research Institute of Economy, Trade & Industry (RIETI), 15 April 2015, <http://www.rieti.go.jp/en/papers/contribution/kikkawa/02.html>.

<sup>34</sup> Stephen Stapczynski, "Japan Utilities Burn Record Coal amid Minister's Call for Cuts", in *Bloomberg*, 11 September 2015, <http://bloom.bg/1J1Lz10>.

<sup>35</sup> *Ibid.*

<sup>36</sup> Masaya Ishida, "Hatsudensho-no Shinsetsu Keikaku-ga 10nende 1520-man kW, Karyoku-ga 97% wo Shimeru" (About 15.2 million kW of new power generation facility under plan for the next 10 years; 97% will come from thermal power sources), in *ITmedia*, 2 July 2015, <http://www.itmedia.co.jp/smartjapan/articles/1507/02/news035.html>.

<sup>37</sup> Kazutaka Mishima, "Kouri Denki-jigyosha ha Itochu-nadoga Jizentourokushi 73-shahe" (The number of retail power generating companies will total 73, including Itochu), in *ITmedia*, 8 December 2015, <http://www.itmedia.co.jp/smartjapan/articles/1512/08/news038.html>.

uncertainty for companies, leading to some deferred decision-making on infrastructure build-out. The economic pressure resulting from deregulation may therefore challenge and possibly negate the supply mix envisioned by the government policymakers.

## 11.6 Blessing and Curse of Low Oil Prices

Japan's LNG strategies are subject not only to forces such as the above-mentioned developments in the regulatory and public policy domains. The price decline in the global energy markets since summer 2014 is affecting the competitiveness of different LNG projects and sources differently. Specifically, the low oil price environment has advantaged the oil-linked LNG supplies to Japan although the Henry Hub prices have remained under 3 dollars/mmBtu since the beginning of 2015. Also, the relative abundance of global supply has led spot LNG prices to come down significantly for Japanese buyers since last fall: what had gone for over 18 dollars per million British thermal units (mmBtu) in March 2014,<sup>38</sup> went for 7.10 dollars/mmBtu for delivery in January 2016.<sup>39</sup>

The market development has also illuminated the fact that the competitiveness of Henry Hub-based contracts is predicated upon North American gas prices being low enough or global oil prices being high enough to present an arbitrage opportunity even after cost is incurred for liquefaction and transportation. Simply put, the current low oil price environment disabuses any illusion that oil de-linkage lowers the prices of LNG. The clarification helps manage the Japanese expectation for what economic and security benefits US gas supplies can and cannot deliver. Another caveat is that its export volume may be naturally limited as the United States will likely remain the leading gas consumer in the world and the dominant consumer of its indigenous output.

Otherwise, for the time being, US gas production has been resilient owing mainly to improved well productivity, despite the decline in upstream spending and rig counts. For example, the US dry gas production of 63.1 billion cubic metres in November 2015 was the highest since the US Energy Information Administration began reporting such production data in 1973. This output level was 1.7 percent higher than the level of the previous year.<sup>40</sup> Also, the US technically recoverable resource base continues to increase, standing at 75.45 trillion cubic metres as of year-end 2014 – the highest in 50

<sup>38</sup> The Japanese government began publishing LNG spot prices for delivery to Japan in March 2014.

<sup>39</sup> Osamu Tsukimori, "Japan Jan average LNG spot price falls to \$7.10/mmBtu", in *Reuters*, 8 February 2016, <http://www.reuters.com/article/lng-japan-spot-idUSL3N1500GX>.

<sup>40</sup> EIA, *Natural Gas Monthly*, 29 January 2016, [http://www.eia.gov/naturalgas/monthly/archive/2016/2016\\_01/ngm\\_2016\\_01.cfm](http://www.eia.gov/naturalgas/monthly/archive/2016/2016_01/ngm_2016_01.cfm).



years.<sup>41</sup> Moreover, nearly 90 percent of the approved volume has taken final investment decision (FID) and most projects are under construction albeit at varying stages. How long the global oil price level remains low will affect the pace of construction as well as the competitiveness of the first wave of US LNG exports, which is expected to come online in the next few years.

## 11.7 Geopolitical Developments Affecting Japanese LNG Strategies

Notwithstanding the fact that their economic attractiveness is highly subject to various market forces, the geopolitical uncertainty surrounding Japan renders US LNG exports still attractive. First, LNG imports from the United States will diversify not only Japan's pool of supplier countries, but also supply routes. The security of Japanese LNG imports has been heavily dependent on stability in the South China Sea, through which roughly three-quarters<sup>42</sup> of Japanese imports – including those from Qatar, Australia, Malaysia and Indonesia – travel. LNG supplies from the United States, however, will presumably travel on the open sea to Japan – after transiting through the Panama Canal for those originating in the US Gulf or East Coast.

Transit security in the South China Sea is a growing concern to Japanese policymakers as the area has seen rising instability since the beginning of this decade. In addition to territorial disputes in the South China Sea, which led to several collisions between Vietnamese naval ships and Chinese vessels over a Chinese oil rig in spring 2014, China's growing challenge to the international law that regulates the activities of foreign military forces operating within China's exclusive economic zones has led to multiple incidents between US and Chinese ships and aircraft since 2001.<sup>43</sup> The tensions in the South China Sea appear to be intensifying as China has been undertaking extensive reclamation and construction in the Spratly Island chain since the fall of 2013<sup>44</sup> and has

<sup>41</sup> Potential Gas Committee, *Potential Gas Committee Reports Increase in Magnitude of U.S. Natural Gas Resource Base*, 8 April 2015, <http://potentialgas.org/download/pgc-press-release-april-2015.pdf>.

<sup>42</sup> Based on the author's calculation with statistical inputs from the EIA and Japanese government.

<sup>43</sup> Ronald O'Rourke, "Maritime Territorial and Exclusive Economic Zone (EEZ) Disputes Involving China: Issues for Congress", in *CRS Reports for Congress*, No. R42784 (22 December 2015), p. 14, <https://www.fas.org/sgp/crs/row/R42784.pdf>.

<sup>44</sup> The undertaking is considered by the Chinese as "playing catch-up to rival claimants;" within the Spratlys, all the claimants except Brunei have undertaken reclamation activities. For more information, see Ben Dolven et al., "Chinese Land Reclamation in the South China Sea: Implications and Policy Options", in *CRS Reports for Congress*, No. R44072 (18 June 2015), p. 16 and 20, <https://www.fas.org/sgp/>

elicited several major responses, including the US challenge to China's territorial claims over the 12-nautical-mile region surrounding its artificial islands in the South China Sea through the first freedom of navigation patrol by the USS Lassen in October 2015. As escalation in the regional tensions could interfere with the secure transport of energy commodities, diversification of supply routes has become ever more salient.

Second, LNG trade ties with the United States reinforce the strong sense of security partnership Japan seeks from the US. The Japanese welcomed America's recognition of the strategic implication of its own new energy posture for regional affairs in Asia when the two governments issued a joint statement in April 2014 that included the wording: "The United States and Japan view energy security as vital to prosperity and stability. Both sides welcomed the prospect of U.S. LNG exports in the future since additional global supplies will benefit Japan and other strategic partners."<sup>45</sup>

Furthermore, US imports may also help prop up the relative geopolitical posture of Japan as a key regional ally by dampening China's "United States in decline" narrative that surfaced following the economic recession of 2008.<sup>46</sup> The narrative emerged in close correlation with the prevalent sentiment among Chinese elites that China has ascended as a "first-class global power," especially having managed to weather the 2008-09 global financial crisis relatively unscathed, while US financial system appeared in disorder, with its deficit and unemployment levels alarmingly high.<sup>47</sup> However, shale gas has revived the US economy by creating jobs, reducing consumer costs for natural gas and electricity as well as bolstering federal, state and local tax revenue. For example, a 2011 study by IHS concluded that shale gas development contributed over 600,000 jobs and 76.9 billion dollars to the US GDP in 2010.<sup>48</sup> Also, a 2015 study by Harvard University and Boston Consulting determined that in 2014, unconventional energy development contributed more than 430 billion dollars to annual US GDP, supported more than 2.7 million American jobs, saved each household about 800 dollars in energy spending, and generated new government revenues of approximately 110

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crs/row/R44072.pdf.

<sup>45</sup> White House, *The U.S.-Japan Joint Statement: The United States and Japan: Shaping the Future of the Asia-Pacific and Beyond*, 25 April 2014, <http://go.wh.gov/ESdxgD>.

<sup>46</sup> Sarah O. Ladislav, Maren Leed and Molly A. Walton, *New Energy, New Geopolitics. Balancing Stability and Leverage*, Washington, Center for Strategic and International Studies (CSIS), April 2014, p. 32, <https://csis.org/publication/new-energy-new-geopolitics>.

<sup>47</sup> Kenneth Lieberthal and Wang Jisi, "Addressing U.S.-China Strategic Distrust", in *China Center Monographs*, No. 4 (March 2012), p. 9, <http://brook.gs/1Ma5YnS>.

<sup>48</sup> IHS, *Shale Gas Supports More Than 600,000 American Jobs Today; By 2015, Shale Gas Predicted to Support Nearly 870,000 Jobs and Contribute \$118.2 Billion to GDP, IHS Study Finds*, 6 December 2011, <http://press.ihs.com/press-release/energy-power/shale-gas-supports-more-600000-american-jobs-today-2015-shale-gas-predict>.

billion dollars.<sup>49</sup> The new US energy and economic posture seems to be beginning to counter the view held by many Chinese elites that economic recession signalled waning US influence.<sup>50</sup> As Japan's security and prosperity are embedded in continued stability in the Asia-Pacific, developments like the shale revolution that strengthen the US economy and reinforce US capacity to maintain regional stability bolster Japan in geopolitical terms.

Japan's energy relationship with Russia also has a significant, but more difficult, geopolitical dimension. At first glance, Japan and Russia are seemingly highly complementary: Japan is a resource-poor country that is increasingly dependent on LNG imports post-Fukushima, while Russia is a close neighbour with a wealth of gas resources and the only geographically viable source of pipeline gas imports for Japan.

In fact, the idea of pipeline gas imports appears to have a strong allure among some Japanese lawmakers and companies – mostly those in construction, plant engineering and steel-making lines of business – as a means of strengthening the country's energy security through diversified import methods. But it is geopolitics, not energy needs, that is driving the bilateral relations. Japanese supporters of pipeline imports from Russia believe that launching the pipeline gas trade could help advance or resolve what it considers to be an outstanding territorial issue over what the Japanese call the Northern Territories and the Russians call the Southern Kurils.<sup>51</sup> These territories consist of four islands that Japan claims were occupied by the Soviet Union – which declared war on Japan on August 9, 1945 – even after Japan accepted the Potsdam Declaration (or the *Proclamation Defining Terms for Japanese Surrender*) on August 15 of that year.<sup>52</sup> Japan under the leadership of Prime Minister Abe appears particularly keen on resolving the issue. One avenue under consideration has been to expand energy economic cooperation with Russia – particularly between Russia's Far East and the northern part of Japan – to make it more politically palatable for the Russian leadership to come to the table. Japan is counting on the centrality of energy exports for the Russian economy as a motivation for Moscow to reconsider its stance on the territorial issue.

Moreover, the US-led western sanctions against Russia over Crimea since 2014 have significantly complicated Japan's energy diplomacy with Russia. Participation in the sanc-

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<sup>49</sup> Michael E. Porter, David S. Gee and Gregory J. Pope, *America's Unconventional Energy Opportunity*, Harvard Business School and Boston Consulting Group, June 2015, p. 7 and 22, <http://www.hbs.edu/competitiveness/Documents/america-unconventional-energy-opportunity.pdf>.

<sup>50</sup> Sarah O. Ladislaw, Maren Leed, and Molly A. Walton (2014), *New Energy, New Geopolitics*, cit., p. 32.

<sup>51</sup> Tsuyoshi Inajima and Emi Urabe, "Japanese Lawmakers to Lobby Abe for Russian Gas Pipeline", in *Bloomberg*, 28 May 2014, <http://bloom.bg/1Zth4x8>.

<sup>52</sup> See the website of the Japan Ministry for Foreign Affairs: *Northern Territories Issue*, <http://www.mofa.go.jp/region/europe/russia/territory/overview.html>.

tions has prevented Japan from being able to capitalize on its prime minister's rapport with President Putin, although the two leaders agreed in April 2013 to resume talks on a peace treaty to formally end World War II. For example, it has become diplomatically unacceptable for Japan to follow through on its February 2014 invitation to Putin to visit Japan. As for Russia, its political leadership has pointed to the sanctions as a main obstacle to advancing its relationship with Japan, including discussion on the territorial issue.<sup>53</sup>

Geopolitical tension between the United States and Russia has created another layer of complication to Japan. By significantly limiting Russian access to foreign lending, the western sanctions appear to be fuelling a closer relationship between Russia and the People's Republic of China (PRC) – the two other key powers in the Northeast Asia alongside Japan. For example, the decade-long negotiation between Russia's Gazprom and China National Petroleum Corporation (CNPC) saw a breakthrough on the issues of price and pipeline route during President Putin's visit to Shanghai in May 2014. The fact that Gazprom accepted the CNPC-preferred East Siberia route, combined with a presumed agreed-upon price lower than the figure long asked by Gazprom suggests that the deal had a stronger commercial viability for CNPC than for Gazprom. What Gazprom gained from the May 2014 agreement was geopolitical in nature in that it sent a signal to the west that Russia cannot be isolated despite the sanctions. Although its fate is much less certain,<sup>54</sup> the October 2014 Memorandum of Understanding between Gazprom and CNPC on West Siberia pipeline gas was similarly motivated by Russia under significant geopolitical pressure.

Moreover, Russia's growing economic reliance on China – its historical rival in the region – combined with China's market potential have seemingly undermined Japanese pursuit of the Vladivostok LNG project. Since June 2015, Gazprom has noted that the project is now indefinitely postponed and, moreover, has reiterated the company's interest in supplying the same gas to China. The Vladivostok LNG project scheduled to begin shipping gas to Asia (including Japan and China) in 2019 was as much a manifestation of the Russian desire to increase its market share in Asia, as of the Japanese desire to expand its gas relationship with Russia. Notwithstanding the unknown impact of slowing Chinese gas demand growth on the scope of future Russia-China gas trade, Russia's geopolitical contest with the West appears to take precedence over its historical distrust of China. Japan is keenly monitoring this new phase in the Russia-PRC relationship to determine its geopolitical implications and to consider ways to counter potentially adversarial effects on regional affairs and on Japan's national interests.

<sup>53</sup> Ko Hirano, "Abe quondary: How to court Putin and still maintain sanctions over Crimea", in *The Japan Times*, 9 June 2015, <http://www.japantimes.co.jp/news/2015/06/09/national/politics-diplomacy/abe-quondary-ensure-putin-visits-russia-sanctions-doesnt-get-close-assertive-china>.

<sup>54</sup> Signs of greater uncertainty associated with the West Siberia MoU include the absence of information on price, and China's relative indifference to the West Siberia route.

## Conclusions

The Fukushima nuclear accident ushered in a major transition in Japan's energy system. Japan responded to Fukushima-induced energy security and macroeconomic challenges by seeking cheaper gas supplies, and by increasing its efforts to diversify its mix of LNG supplier countries. Japanese stakeholders from both the public and private sectors have undertaken a number of initiatives, including contracting LNG cargos with the Henry Hub indexed pricing, as well as striking international joint procurements, in an effort to secure more competitively priced LNG volumes and to promote greater flexibility in LNG trading and contract models. Although the low energy price environment since summer 2014 may be lessening pressure on the Japanese stakeholders to seek cheaper gas supplies, greater flexibility in LNG trading, such as delinking Asian LNG prices from oil prices and eliminating destination restrictions for LNG cargos, will likely remain Japan's key agenda for years to come. These efforts will greatly benefit from US LNG exports, whose project development approaches and contractual terms are much more flexible than those of traditional suppliers, although their economic competitiveness varies depending on the price levels of competing oil-linked LNG supplies to Asia.

While Japan strongly values its gas trade ties with traditional suppliers, the country sees the advent of US LNG exports as a unique opportunity. US LNG would provide a new global route for Japan's LNG imports. Geopolitical instability in the South China Sea in recent years illustrates Japan's particular vulnerability to escalating conflicts in this body of water, transited by nearly two-thirds of Japanese LNG imports. Moreover, whatever geopolitical currency the United States has gained from its strong energy production profile helps sustain Japan's geopolitical standing in Asia, particularly concerning its relationship with China. Continued stability in the Asia-Pacific, which is underpinned by a strong US presence, is essential for Japan's security and prosperity. Yet the primacy of the alliance with the United States in Japan's foreign policymaking is also a cause of some constraint on its energy diplomacy. The US-led sanctions on Russia have hindered Japan's pursuit of stronger diplomatic ties with Russia, which geographically is the closest country and has vast hydrocarbon resources. Specifically, the western sanctions have brought Moscow and Beijing closer, complicating Japan's pursuit of additional gas import projects and higher volumes from Russia. The magnitude and nature of future challenges to Japan's energy security may change. However, the latitude Japan has in pursuing energy diplomacy and striking specific natural gas deals will likely remain defined by the geopolitical reality – which for Japan means the primacy of its alliance with the United States and the uncertainties over the path and nature of China's rise, as well as the role of Russia in regional politics.

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Energy is at the core of the remarkable current transitions in the global economy and geopolitics, and natural gas plays a crucial role in these processes. In this context of rapidly evolving trends at the market level and developing dynamics between regional and global actors, *The Future of Natural Gas* aims at analysing the role of natural gas in the future energy mix by considering several key factors: the ambitious climate policies agreed by the international community, cost issues, and the role of technological innovation in the broader global gas picture. Starting from this analysis, the volume adopts a geographical approach to take into account the significant variability in the global perspective for gas markets. Focusing on major developments in the main supplying and consuming regions and countries, it considers geological factors, the development of internal policy and regulatory frameworks, the evolution of gas consumption patterns, as well as export and import strategies elaborated by key regional and global gas players. *The Future of Natural Gas* is thus an in-depth analysis of some of the fastest moving gas markets, attempting to define the trends of a resource that will have a decisive role in shaping the global economy and modelling the geopolitical dynamics in the next decades.

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