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Special issue on shale gas

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SHALE GAS

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NOTE

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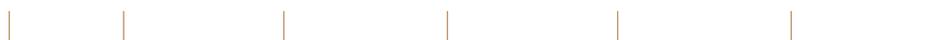
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All data sources are indicated under each table and figure.

The term “dollars” (\$) refers to United States dollars unless otherwise specified.

The term “tons” refers to metric tons.

Unless otherwise stated, all prices in this report are in nominal terms.



ABBREVIATIONS

CH₄	Methane
CO₂	Carbon dioxide
EIA	Energy Information Administration of the United States of America
GHG	Greenhouse gases
GOG	Gas-on-gas
GWP	Global warming potential
IEA	International Energy Agency
IGU	International Gas Union
LNG	Liquefied natural gas
MMBtu	Million British thermal units
TCF	Trillion cubic feet
TOC	Total organic carbon
TRR	Technically recoverable resources



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INTRODUCTION

The future of energy is among the top issues on the international agenda for sustainable development and is expected to remain as such in the years to come. This is especially true in the light of the recently adopted 2030 Agenda for Sustainable Development, in particular Sustainable Development Goal 7, which aims to ensure affordable, reliable, sustainable and modern energy for all by 2030. Moreover, the recent Paris Agreement under the United Nations Framework Convention on Climate Change has galvanized international mobilization towards tackling the effects of climate change at a time when Governments have reaffirmed their intention to ensure energy access for all by 2030. The combination of these international instruments raises the need to decide which strategy should be adopted with regard to the issue of unconventional energy sources.

Individual States and local and regional institutions display different and sometimes contradictory views with regard to the issue of unconventional energy sources and of shale gas and shale oil in particular. Shale gas is the focus of the current edition of the *Commodities at a Glance series*. Conflicting views have emerged concerning, for example, its potential contributions to the economy, its impact on job creation and its negative effects on the environment. The main challenge of this report has been to offer a dispassionate perspective on these aspects in order to make informed decisions about issues related to shale gas activities. In this regard, important developments have occurred in the United States of America since the mid-2000s. This period has been mainly referred to as the “shale gas boom or revolution” and the growth of natural gas production in the United States through shale gas extraction has led to a sharp drop in domestic natural gas prices. At the same time, in Europe, some countries have decided to ban the production of shale oil and shale gas in their territories or to prohibit the use of its main production technique, namely hydraulic fracturing.

In view of these developments, it is relevant to analyse to what extent shale gas can contribute to the future of the energy landscape and highlight the challenges this may involve. The aim of this report is to set out the facts, analyse them and draw conclusions independently of the passion that is generally associated with discussions on this issue. This is important in order to inform decisions on whether or not the exploration and development of shale

gas deposits should be undertaken, and what the framework for such activities should be, irrespective of the fact that shale gas is already extracted in some countries and planned in others.

In 2016, more than 85 per cent of world energy demand was met through the use of fossil fuels, with natural gas ranking third and providing about 24 per cent, after oil (33 per cent) and coal (28 per cent). According to the International Energy Agency (IEA), fossil fuels are expected to remain the main source of energy to 2040. However, a transition to a more diversified and environmentally friendly energy mix is under way. The future role played by renewable energies in the global energy mix will largely rely upon investments made in this area and policies undertaken to encourage them. According to the current policies and the new policies scenarios,¹ the share of renewables in the global energy mix is expected to range from 16.1 to 19.3 per cent in 2040. Under the most optimistic scenario – the *450 scenario*² – IEA forecasts renewable energies to approach 31 per cent by 2040. This scenario is particularly optimistic compared with the two others published by IEA, as well as with regard to the latest literature concerning climate change and the limitation of the global average temperature increase to below 2°C above pre-industrial levels.³ However, even under this scenario, longer time period and more significant investment levels are required for renewable energies to reach the current share of hydrocarbons in the global energy mix. By 2040, IEA expects the share of investments in fossil fuels to decline to 60 per cent

¹ The “new policies scenario of the World Energy Outlook broadly serves as the IEA baseline scenario. It takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse gas emissions and plans to phase out fossil energy subsidies, even if the measures to implement these commitments have yet to be identified or announced. The current policies scenario assumes no changes in policies from the midpoint of the year of publication (previously called the reference scenario)”. IEA. (accessed on 4 December 2017). World Energy Outlook, scenarios and projections. <https://www.iea.org/publications/scenariosandprojections/>.

² The “450 scenario sets out an energy pathway consistent with the goal of limiting the global increase in temperature to 2°C by limiting concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO₂”. IEA, World Energy Outlook, scenarios and projections.

³ United Nations Framework Convention on Climate Change (2015). Historic Paris Agreement on climate change: 195 nations set path to keep temperature rise well below 2 degrees Celsius. <http://newsroom.unfccc.int/unfccc-newsroom/finale-cop21/>.

of total investments in energy supply projects, from about 70 per cent over the last 15 years.

Before discussing recent developments in shale gas, natural gas pricing mechanisms and the role of shale gas and, more largely, natural gas in the global energy mix, it is essential to clearly understand where this natural gas resource comes from, as well as what differentiates it from what is commonly known as conventional natural gas.

The formation of hydrocarbons

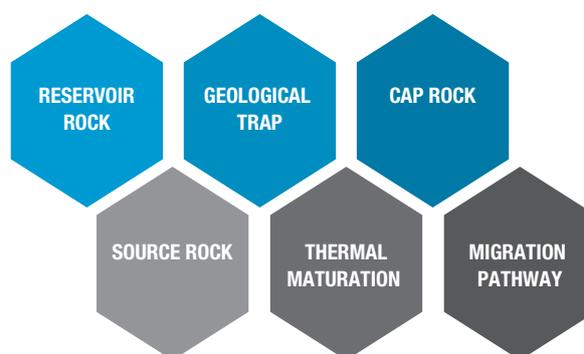
Crude oil and natural gas result from the decomposition of sediments containing rich organic matters. They gradually deposit on the seabed and progressively sink into the ground through the process of sedimentation. As burial goes on, temperature and pressure intensify, leading to the production of kerogen, the intermediary substance between organic materials and hydrocarbons. Thereafter, the liquid form of hydrocarbons (oil) appears from kerogen at between 2,000 and 3,000 m, when the temperature reaches 60–120°C. These conditions are known as the *oil window*. Deeper, between approximately 3,000 and 6,000 m, with temperatures of 100–200°C, kerogen turns to natural gas (i.e., *gas window*). The volumes of oil and gas present in the source rock vary according to the time the kerogen spends in each *window*.

As a result of the gradual process of hydrocarbon formation, both oil and natural gas can be found in the same sedimentary deposits, at different depths and with a progressive transformation from one state to the other.

Most hydrocarbons present in *source rocks* are progressively released and migrate to the surface along permeable rocks and natural fractures (*migration pathway*). The move continues until an overlying layer of impermeable rock stops them (*cap rock*). Trapped into a geological structure (*geological trap*), hydrocarbons accumulate and give birth to *conventional reservoirs* (figure 1). The share of hydrocarbons that remains trapped in source rocks is known as *unconventional oil and gas*, in general, and *shale oil and shale gas* in particular.

The distinction between conventional and unconventional gas is not based on their composition. Both are natural gas essentially made of methane (CH₄) at 70–90 per cent and some other heavier hydrocarbons (e.g. butane, ethane or propane). Their main differences pertain to the characteristics of the reservoir they are contained in and the production techniques used to extract them.

Figure 1 Hydrocarbon system building blocks



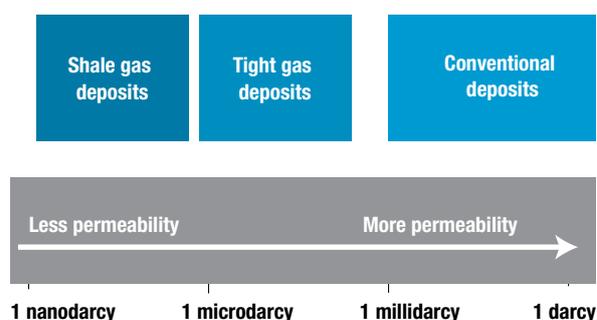
Source: UNCTAD secretariat, based on Pratson, University of Duke, United States (accessed on 4 December 2017).

It should be highlighted that while the current issue of the *Commodities at a Glance series* concentrates on shale gas, two other types of unconventional natural gas exist. First, tight gas, which results from natural gas that has migrated into a reservoir rock with high porosity and low permeability. Like shale gas, tight gas is generally produced using directional drilling and hydraulic fracturing. Second, coal bed methane, which is the form of natural gas extracted from coal deposits.

Characteristics of source rock deposits

Given the geological structure of shale gas formations – generally long but thin – the technique traditionally used to extract natural gas from conventional reservoirs, namely vertical drilling, is not appropriate for shale gas extraction. To have access to a wider surface of the source rock layer, drilling needs to be performed horizontally, in order to follow the deposit along its length and thereby maximize the quantities of natural gas that can be recovered. This operation is described as *directional drilling* or *horizontal drilling*. Moreover, shale gas deposits present two characteristics that differentiate

Figure 2 Scale of rock permeability



Source: UNCTAD secretariat, based on Bauquis, 2014.

them from conventional natural gas reservoirs, namely, their low porosity⁴ and low permeability⁵ (figure 2). These elements make shale gas more difficult to extract than conventional gas, as it does not naturally flow through source rocks to the surface. Production requires increasing the permeability of the rock through the use of *hydraulic fracturing* that contributes to extending existing cracks and creating new ones. Neither horizontal drilling nor hydraulic fracturing were new at the beginning of the 2000s. However, their prohibitive costs made their large-scale use uneconomical at the time. Moreover, the idea of combining both horizontal

drilling and hydraulic fracturing to stimulate shale gas deposits – which supports the economic feasibility of shale gas operations – is much more recent than the techniques themselves.

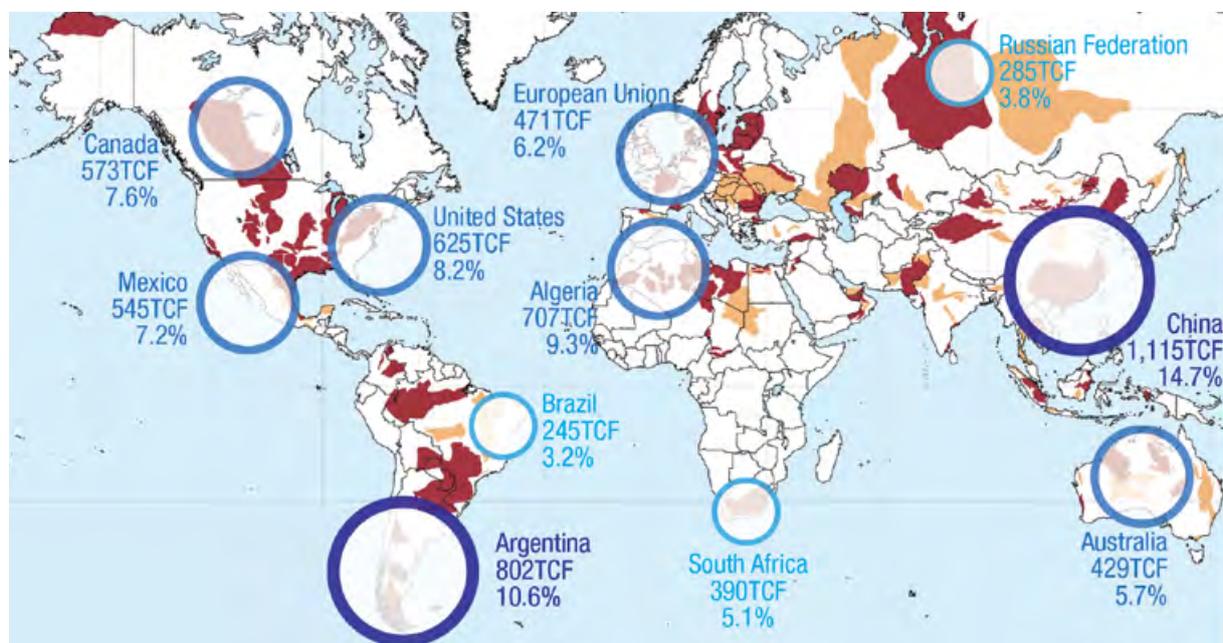
Worldwide Technically Recoverable Resources

In response to the continuous depletion of relatively easy to access and cheap conventional natural gas reserves worldwide, interest has turned to more expensive sources of natural gas, and to shale gas production, in particular. The existence of these resources has been known for a long time, yet until recently, the production of shale gas was uneconomical. Moreover, the systematic use of horizontal drilling and hydraulic fracturing since the beginning of the 2000s has allowed oil and gas companies to access the large volumes of shale gas contained in source rocks. All regions that currently produce conventional natural gas are considered to hold source rocks. As a consequence, shale gas resources are considered to be widely distributed worldwide (figure 3). However, their commercial exploration and production is currently essentially limited to the United States and Canada.

⁴ Porosity is defined as “a measure of the water-bearing capacity of subsurface rock. With respect to water movement, it is not just the total magnitude of porosity that is important, but the size of the voids and the extent to which they are interconnected, as the pores in a formation may be open, or interconnected or closed and isolated”. United States Geological Survey (accessed 5 December 2017). Water Science Glossary of Terms. <https://water.usgs.gov/edu/dictionary.html>.

⁵ Permeability is defined as “the ability of a material to allow the passage of a liquid, such as water, through rocks. Permeable materials, such as gravel and sand, allow water to move quickly through them, whereas unpermeable materials, such as clay, does not allow water to flow freely”. USGS. (Accessed 5 December 2017). United States Geological Survey, Water Science Glossary of Terms. <https://water.usgs.gov/edu/dictionary.html>.

Figure 3 Ten leading national technically recoverable resources worldwide, September 2015
(trillion cubic feet and percentage of world technically recoverable resources)



Source: UNCTAD secretariat, based on EIA. (accessed 30 August 2017). World Shale Resource Assessments. <https://www.eia.gov/analysis/studies/worldshalegas/>.

Note: Data were computed by EIA using estimates of the volume of resources in place for a prospective formation within a basin factored by (1) the formation's success factor, which is the probability that a portion of the formation is expected to have attractive natural gas flow rates, and (2) the recovery factor, which is the capability of current technology to produce natural gas from formations with similar geophysical characteristics.

- Assessed basins with resource estimate
- Assessed basins without resource estimate
- TRR higher than 10 per cent of world total TRR
- TRR between 5 per cent and 10 per cent of world total TRR
- TRR lower than 5 per cent of world total TRR

In this issue of *Commodities at a Glance*, data produced by the Energy Information Administration of the United States (EIA) is used, given the country's extensive experience in shale gas exploration and production, as well as the wide scope of data related to world resources published by this institution. EIA defines resources as estimated volumes that are expected to be produced in the future. They may fluctuate depending on technical developments, the quantities of natural gas produced and market changes. Given the nascent state of the shale gas sector outside North America, technically recoverable resources (TRR) appear to be the most relevant and almost only available indicator to evaluate shale gas potential, as "data include all gas that can be produced based on current technology, industry practice and geologic knowledge" (EIA, 2014). However, it should be highlighted that resource estimates are made "regardless of oil and natural gas prices and production costs" (EIA, 2017e:9; box 1).

Globally, as at 24 September 2015, technically recoverable resources of shale gas were estimated at around 7,576.6 TCF (about 214.5 trillion cubic metres) by EIA. This represented approximately 61 years of world natural gas consumption, considering 2016 as the reference year for natural gas consumption. According to the data, the 10 leading countries with the highest

TRR were China, Argentina, Algeria, the United States, Canada, Mexico, Australia, South Africa, the Russian Federation and Brazil. Together, they accounted for three quarters of world TRR (table 1).

Box 1 Data on technically recoverable resources must be considered as estimates and interpreted with caution

Each source rock displays different characteristics, implying that the hydraulic fracturing process must be adapted to each. Moreover, fracturing rock is at present the unique method available to obtain concrete and precise information on the quantities of resources and reserves effectively available. However, fracturing is banned in many countries, resulting in limited national information on reserves. For example, France imposed a moratorium on hydraulic fracturing in 2011, which means that no exploration has been undertaken since that date to evaluate national potential with regard to shale gas resources. In addition, where drilling tests are allowed, estimates are sometimes dramatically revised. For example, EIA highlighted that it "lowered its estimate [for South Africa] from 485 [trillion cubic feet (TCF)] to 390 TCF in the most recent report because the prospective area for the three shale formations in the Karoo Basin was reduced by 15 per cent. The Whitehill Shale's recovery rate and resource estimates were also reduced because of the geologic complexity, according to the report".

Source: EIA (2017e:9).

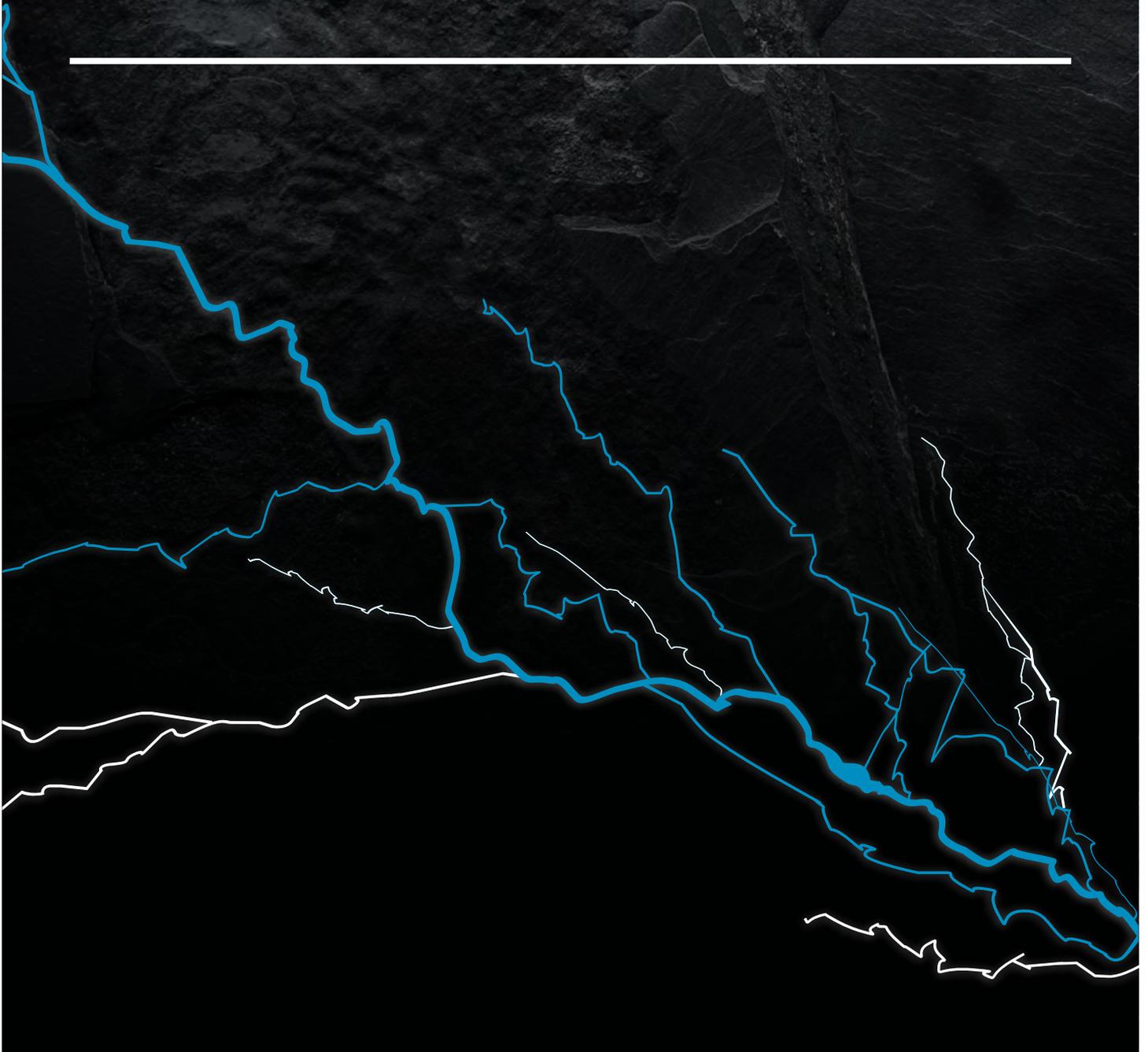
Table 1 Regional distribution of technically recoverable resources

<p>1 Asia and Oceania Share of world TRR: 28 per cent Number of countries under review: 11 Comment: Together, China and Australia, accounted for three quarters of TRR in the region.</p>	<p>2 North America Share of world TRR: 23 per cent Number of countries under review: 3 Comment: The United States and Canada are commercial shale gas producing countries and respectively accounted for 36 and 33 per cent of regional TRR. Mexico represented 31 per cent of regional TRR, with nascent exploration activities.</p>
<p>3 Latin America and the Caribbean Share of world TRR: 19 per cent Number of countries under review: 8 Comment: Argentina is the main shale gas reservoir in the region, with 56 per cent of regional TRR, followed by Brazil (17 per cent) and the Bolivarian Republic of Venezuela (12 per cent).</p>	<p>4 Africa Share of world TRR: 19 per cent Number of countries under review: 7 Comment: With 69 per cent of TRR in Africa, North Africa appears to hold the largest share of TRR on the continent. Algeria accounts for more than half of TRR in Africa. South Africa also holds large resources, with 28 per cent of regional TRR. Countries in sub-Saharan Africa are almost excluded from the sample, with the exception of Chad, with 3.2 per cent of regional TRR.</p>
<p>5 European Union Share of world TRR: 6 per cent Number of countries under review: 11 Comment: France and Poland appear to hold most shares of regional TRR, with 30 per cent each. Poland and the United Kingdom of Great Britain and Northern Ireland (5.5 per cent) have taken steps towards the future production of shale gas. France decided to ban hydraulic fracturing in July 2011 (law No. 2011-835).</p>	<p>6 Eastern Europe Share of world TRR: 6 per cent Number of countries under review: 3 Comment: The Russian Federation ranks first within the group, with a share of about two thirds of regional TRR, followed by Ukraine (29 per cent).</p>

Source: UNCTAD secretariat, based on EIA.

CHAPTER I

ENERGY MARKETS AND NATURAL GAS PRICE FORMATION



Box 2 Natural gas transportation

The difficulty of moving natural gas from the point of production to the point of consumption (or distribution) relative to other fossil fuels explains why the natural gas trade is concentrated within producing regions and the existence of regionally segmented markets for the commodity. Transporting natural gas requires dedicated containers, making its transportation cost about five times higher than that of crude oil. This situation may change owing to recent developments in the shale gas sector and, more specifically, the fact that the United States may become a large LNG exporting country in the coming years, which may lead to a more globalized natural gas market.

The two major ways of moving natural gas are: (1) pipelines and (2) LNG.

Pipelines

Pipelines are the main mode of natural gas transportation from producing areas to the regions where it is expected to be stored or directly consumed. A specificity of natural gas is that its pressure tends to decrease with the distance from point of production. For this reason, pipelines must be hermetic and resistant to pressure. Compressor stations must also be regularly installed along pipelines in order to ensure that pressure is maintained along the way to the final destination.

Despite the high investment costs of building pipelines, natural gas exported by pipelines accounted for the largest share of world natural gas trade flows in 2016 (at about 70 per cent of total world exports). Although infrastructure is developing worldwide, currently it remains largely available and concentrated in Europe and North America. Trade movements in both of these regions accounted for more than three quarters of world pipeline flows in 2016.

Liquefied natural gas trade flows

Liquefied natural gas is the preferred form of natural gas transportation when it must be shipped overseas. Liquefaction reduces its volume (by up to 600 times lower than in gaseous form). The LNG chain is composed of a pipeline network to transport natural gas in gaseous form from the deposit to liquefaction facilities on the coast. The natural gas is then cooled to around -162°C at atmospheric pressure to produce LNG, which is then transported by tankers to terminals at the destination. Natural gas is returned to its gaseous form in regasification plants and sent to end users.

About 30 per cent of world natural gas exports in 2016 was LNG. The development of shale gas production in the United States and the potential emergence of the country as a large LNG exporter in the coming years could have an impact on this form of transportation and contribute to increasing its share in world natural gas trade flows.

Source: UNCTAD Secretariat.

1. INTRODUCTION

Owing to the specificities related to natural gas transportation (box 2), the natural gas market is fragmented into three main regional markets, namely North America, Europe and Asia and Oceania, with specific price formation mechanisms and different benchmark prices in each region. The reference prices are, respectively: (1) the spot price at Henry Hub (Louisiana, United States) for North America; (2) the average import border price in Europe; and (3) the liquefied natural gas (LNG), import price in Japan, mainly used throughout Asia and Oceania.

2. NATURAL GAS PRICE FORMATION

a. North America: The example of the United States

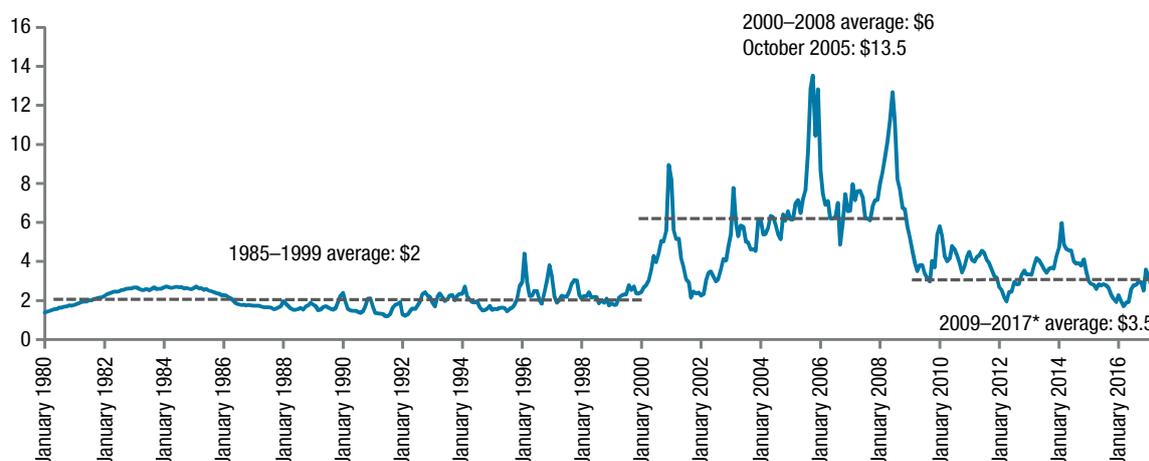
In North America, natural gas prices are freely quoted on the market. The benchmark price is that at the *Henry Hub* in Louisiana. It is expressed in dollars per million British thermal units (MMBtu), a measure of energy heat. As a result of the way natural gas prices are formed in the United States, the transmission of changes in market fundamentals, namely supply and demand, to prices is almost automatic. This implies that natural gas prices in the United States are more volatile than in some other regions in which natural gas prices are fixed through long-term contracts. According to the International Gas Union (IGU, 2017b), natural gas is almost exclusively traded on a gas-on-gas (GOG)⁶ competitive basis in the United States.

In 2016, natural gas accounted for 29 per cent of the global energy mix in the United States and was 25 per cent in 2010. The increase is largely explained by the rise of natural gas cost competitiveness in the United States. In 2016, natural gas was mainly used for power generation (36 per cent), in industrial applications (34 per cent) and for residential and commercial uses (27 per cent).⁷

⁶ The price is determined by the interplay of supply and demand and trade over a variety of different periods (daily, monthly, annually or other). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. the national balancing point in the United Kingdom). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short-term fixed-price basis and there may be longer term contracts, although these use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category is spot LNG, any pricing linked to hub or spot prices and bilateral agreements in markets in which there are multiple buyers and sellers.

⁷ EIA. (accessed 4 December 2017). Natural gas explained – the use of natural gas. https://www.eia.gov/energyexplained/index.cfm?page=natural_gas_use.

Figure 4 Natural gas prices in the United States: Spot prices at Henry Hub, Louisiana, January 1980–June 2017 (dollars per MMBtu)



* 2017 covers the period January–June 2017.

Source: UNCTAD secretariat, based on data from the World Bank Global Economic Monitor Commodities database (accessed 6 September 2017).

Evolution of natural gas prices prior to the 2000s

Between 1985 and 1999, Henry Hub natural gas prices fluctuated within a range of \$1 per MMBtu to \$3 per MMBtu, with a simple average of \$2 over the period (figure 4). Marginal moves above and below price limits were small. However, in 1996, prices reached \$4.4 per MMBtu in February, due to exceptional weather conditions and low inventories. This specific event highlights the seasonal aspect of natural gas demand and prices (box 3). Apart from this specific case, natural gas prices remained relatively stable over the period.

2000–2009: The boom of natural gas prices

Natural gas prices started to rise at the end of the 1990s. They reached an initial peak in December 2000, with a monthly average of \$9 per MMBtu, or about 2.8 times their level in December 1999. Prices continued to follow on an upward trend in the next 58 months, to reach a historical record in October 2005, at \$13.5 per MMBtu. Prices subsequently fell, yet remained high compared with historical levels, averaging \$6 per MMBtu between 2000 and 2008, about three times the level during the previous period,⁸ and peak prices in June and July 2008 of, respectively \$12.7 per MMBtu and \$11.2 per MMBtu.

⁸ In 1960–1984, the average price of natural gas in the United States was less than \$1 per MMBtu.

Box 3 Seasonality of natural gas prices

The price of natural gas is subject to the seasonality of demand, in particular in regions with great differences between high and low temperatures. Prices are usually higher during winter periods, as demand for heating rises. The seasonality of residential demand in the United States between summer and winter periods is between 1 and 8. For example, Henry Hub natural gas spot prices jumped to \$18.5 per MMBtu on 25 February 2003, compared with \$6.1 per MMBtu the week before, mainly as a result of cold weather conditions and low inventories. Price differentials may also be significant between producing and consuming regions as a result of more limited regional physical delivery capacities. For example, in February 2003, prices for New York City momentarily reached \$40 per MMBtu. In the winter of 2003–2004, pipeline constraints in delivering natural gas into New England led to spot prices as high as \$74 per MMBtu on the Intercontinental Exchange.

Sources: Charon, 2014, Federal Energy Regulatory Commission, 2003, 2; US Department of Energy, 2014, 3.

The historical high prices of natural gas in 2000–2008 created an opportunity for the development of the large-scale production of shale gas in the United States. Natural gas gross extraction from shale gas wells almost tripled in 2007–2010. However, the combination of large quantities of natural gas becoming available and declining demand owing to the financial and economic crisis in 2008 led to an oversupply situation and a significant fall in natural gas

prices starting from mid-2008. Despite this downward trend, natural gas prices remained high until the end of the year, in comparison to historical levels. This recent development initiated a decoupling of prices in the United States and references in other regions, as well as compared with crude oil prices.

2009–2017⁹: A sharp fall in natural gas prices in the United States

From July 2008 to September 2009, natural gas prices fell sharply. Prices dropped by about 73 per cent in 15 months. Over the rest of the period, prices fluctuated around \$3.5 per MMBtu, reaching their lowest level in March 2016, at \$1.7 per MMBtu. However, the sharp downward trend in natural gas prices in the United States did not lead to a significant and immediate reaction with regard to production. The disconnect between market signals and changes in production levels may be explained by various factors. Most producers expected the declining trend of natural gas prices to be temporary. Anticipating a recovery of prices, they were not encouraged to immediately reduce their production. This behaviour was exacerbated by the use of forward and futures contracts, which tended to create an artificial delay between timely information delivered by spot markets and producers' response to this stimulus. Moreover, due to long-term engagements of shale gas producers with drilling and fracturing companies, as well as conditions of minimum production enshrined in exploration and production permits in the United States, shale gas producing companies had to continue to drill, whatever the price on the market. The combination of these elements also explained the increasing number of drilled but uncompleted wells throughout the United States; as producers expected higher prices to complete these operations. Finally, at the start of shale gas activities in the United States, a large number of wells were not connected to the distribution network, which also tended to generate some delays in the transmission of supply-related information to the market.

The drop in natural gas prices led to a decrease in the corporate profits of shale gas companies, which were often low capital base and in many cases to write-down or write-off in their assets. This also led to a move towards the creation of joint ventures following the financial and economic crisis in 2008 and, more recently, to a series of asset and corporate

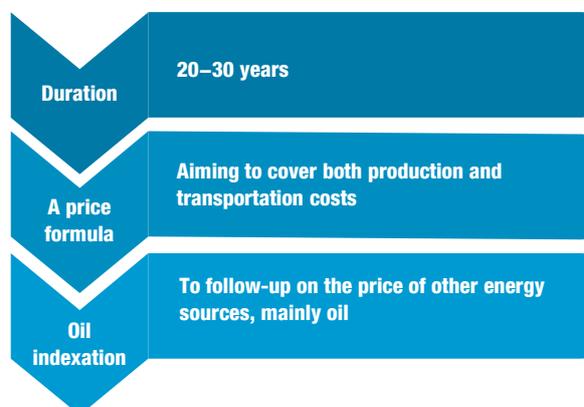
acquisitions. This move allowed major oil companies to enter the shale gas market mainly after 2011, as they had not previously been predominant in the industry. According to KPMG Global Energy Institute (2012), the number of deals in the United States shale gas industry reached 88 in 2011, with a total value of \$46.5 billion, compared with 32 deals and a total value of \$3.9 billion in 2005.

Despite some signs of recovery in natural gas prices in the United States, they have remained too low to encourage producers to significantly return to production. In June 2017, the monthly Henry Hub price averaged \$2.9 per MMBtu, while the marginal cost of shale gas production in the United States was considered to be around \$4 per MMBtu (Forbes, 2017). Moreover, the stock of drilled but uncompleted wells continued to rise, with 6,851 wells in June 2017, compared with 5,877 in May 2017, which also appeared to be a sign that United States producers expected further price increases before returning to production.

b. Europe: Special highlight on the European Union

Until recently, natural gas in Europe used to be essentially traded through long-term contracts; a legacy from the 1960s, when Europe had to invest massively in order to develop its natural gas infrastructure. The key characteristics of these contracts were their duration, a specific price formula and an indexation of the price of natural gas to competing energy sources (figure 5).

Figure 5 Key elements of long-term natural gas contracts



Source: UNCTAD secretariat.

⁹ The period under review in this report includes June 2017.

Long-term arrangements made price developments considerably less flexible in Europe than in the United States. However, they also limited natural gas price volatility.

Detailed pricing patterns and negotiations are confidential, yet some broad inferences may be made concerning the recent evolution of natural gas pricing in Europe. Starting in the mid-2000s, the situation appears to have gradually changed as a result of developments occurring in the shale gas industry in the United States, as well as due to larger quantities of LNG becoming available from traditional suppliers, such as Qatar. Combined with a contraction in demand owing to the financial and economic crisis in 2008 and the development of other sources of energy (e.g. renewables), this has resulted in an increasing role played by hub pricing and hub indexation contracts and encouraged traditional European suppliers to accept more flexible conditions (e.g. the introduction of a partial indexation on hub prices). Franza (2014: 12) highlights that Gazprom, one of the predominant natural gas suppliers in continental Europe, “introduced hub indexation for the first time in 2010”. The round of negotiations with traditional suppliers also resulted in a commitment to reduce the minimum quantities buyers are contractually obliged to purchase through a take or pay clause, although this provision may prove to be temporary. Finally, the extensive liberalization of the energy market undertaken by the European Union

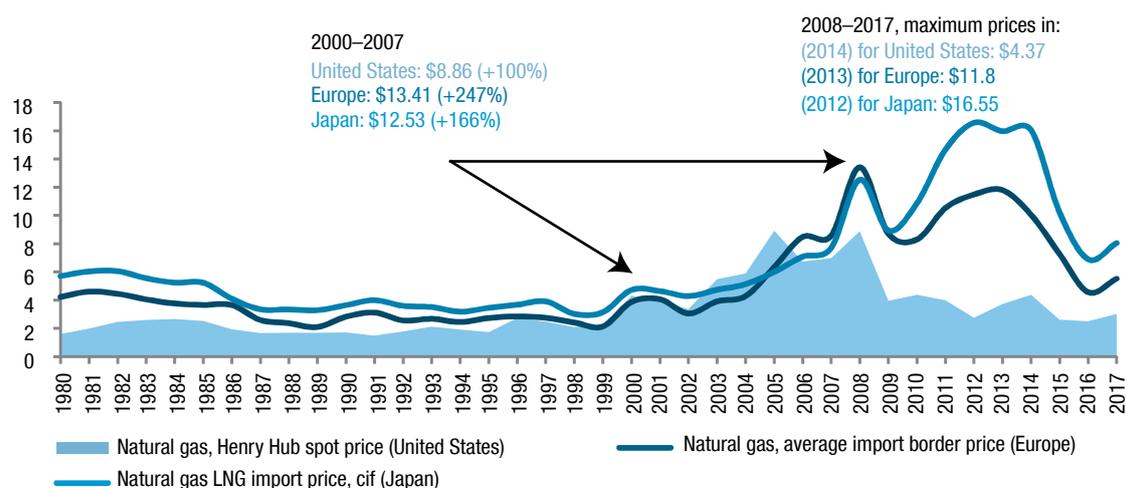
since the end of the 1990s also contributed to creating a favourable context for these changes.

In 2016, more than 88 per cent of natural gas imports in Europe were made via pipelines, the rest being LNG. Among the eight types of price formation mechanisms defined by IGU (2017b), two have proven predominant in Europe, namely oil price escalation.¹⁰ IGU highlights that, in 2016, about two thirds of imports in Europe (pipelines and LNG) were made on a GOG basis, and the rest through oil price escalation contracts. IGU also notes that the most important change has been with regard to pipeline imports. Oil price escalation accounted for 91 per cent of total pipeline imports in 2005, yet this share fell to about one third in 2016. Natural gas virtual trading has been developing in Europe mainly through the national balancing point in the United Kingdom and the title transfer facility in the Netherlands, resulting in natural gas being increasingly traded on a supply and demand basis, without any reference to competing fuels.

From 1980 to 1999, natural gas prices mainly declined in Asia and Europe (figure 6), dropping by 45 and 49.5 per cent, respectively, over the period. Despite this fall, natural gas prices remained about 1.5 to 2 times higher than in the United States.

¹⁰ Oil price escalation: The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices can be used, as well as electricity prices.

Figure 6 Natural gas prices in Japan, the United States and Europe, 1980–2017
(dollars per MMBtu)



* 2017 covers the period January–June 2017.

Source: UNCTAD secretariat, based on data from the World Bank Global Economic Monitor Commodities database (accessed on 4 September 2017).

Natural gas consumption fell in the European Union due to the financial and economic crisis in 2008. Despite a 7.6 per cent rebound in 2009–2010, consumption declined by about 23 per cent in 2008–2014. Consumption levels have risen since then, yet continued to remain below pre-crisis levels, at -13 per cent in 2016 compared with the level in 2010. The recovery of the global demand for natural gas in the European Union can be largely explained by the fall in natural gas prices, which halved between 2014 and 2016. With the recent recovery of consumption in Europe, natural gas prices have returned to growth, starting in October 2016, rising by +26 per cent between October 2016 and June 2017.

c. Asia: China and Japan, two major natural gas market players

With 29.1 and 15.4 per cent, respectively, of the natural gas consumption in Asia and Oceania, China and Japan were the two leading natural gas consuming countries in the region in 2016. Moreover, China and Japan also ranked among the top five world natural gas consuming countries, with about one tenth of world consumption in 2016.

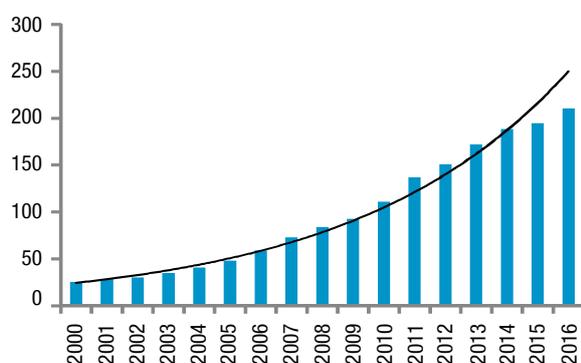
Consumption of natural gas in China has been increasing exponentially since the start of the 2000s (figure 7). Notwithstanding the slowdown recorded in 2015 and 2016, the compound annual growth rate of consumption in China averaged 13.4 per cent in 2000–2016. Higher annual growth rates were recorded in 2010 and 2011, with an increase per year of more than 20 per cent. According to Wainberg et al. (2017: 20), « the primary drivers of gas demand growth were the large expansions in manufacturing

and power sector gas demand, which grew at 16 per cent and 22 per cent, respectively, between 2005 and 2015. The growth of natural gas consumption in China has been supported by the expansion of import projects such as long-distance pipelines from Central Asia and Myanmar, and LNG import terminals ». China produced about two thirds of its domestic consumption in 2016, and the rest was mainly imported by pipeline (18 per cent of domestic consumption), mainly from Turkmenistan (77 per cent of pipeline imports) and Uzbekistan (11 per cent); and by LNG, mainly from Australia (46 per cent), Qatar (19 per cent), Indonesia (11 per cent), Malaysia (10 per cent) and Papua New Guinea (8.5 per cent). The share of natural gas in the energy mix in China is increasing (from 5 per cent in 2012 to 6.2 per cent in 2016), coal remained predominant in 2016, with 61.8 per cent of the energy mix.

According to EIA, China may hold the most important world shale gas resources as at September 2015, and the country has invested great efforts in the development of such resources, alongside with continuous development of its traditional natural gas reserves. This strategy could contribute to increasing the share of natural gas in the national energy mix and help the country to meet its objective of reaching a minimum of 10 per cent of natural gas in its mix by 2020. Simultaneously, cutting the share of coal would contribute to reducing carbon dioxide (CO₂) emissions in the country, the first country with regard to CO₂ emissions in 2013.¹¹ In 2014, the industrial sector accounted for more than half of natural gas consumption (50.5 per cent) in China, followed by the residential and commercial sector (18.3 per cent) and power generation (14.5 per cent). Finally, in 2014, the share of natural gas used in transportation exceeded the threshold of 10 per cent (11.3 per cent).

In Japan, natural gas consumption increased in 2000–2012 by a compound annual growth rate of + 3.8 per cent. However, since then, consumption of natural gas in Japan has been more bearish, plateauing up to 2014 and then declining to 111.2 billion cubic metres in 2016, a reduction of 5.8 per cent in 2014–2016 (figure 8). This decrease may be largely explained by the high level of natural gas prices in Japan, which jumped by 85 per cent in 2009–2012, to reach a

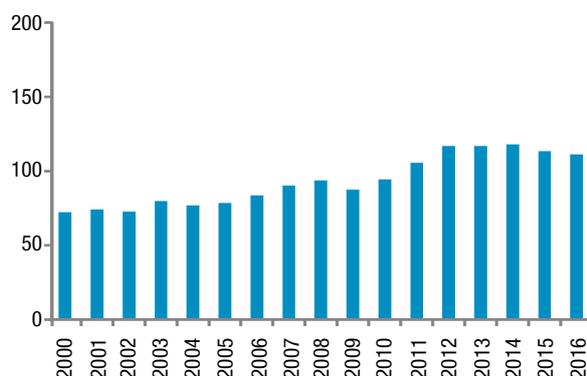
Figure 7 Natural gas consumption in China, 2000–2016 (billion cubic metres)



Source: UNCTAD secretariat, based on BP, 2017b.

¹¹ World Bank, World Development Indicators database. (accessed 8 September 2017). CO₂ emissions. <http://databank.worldbank.org/data/reports.aspx?source=world-development-indicators>. 2013 is the latest year available.

Figure 8 Natural gas consumption in Japan, 2000–2016
(billion cubic metres)



Source: UNCTAD secretariat, based on BP, 2017b.

record level of \$16.6 per MMBtu. Prices remained high until 2014, at around \$16 per MMBtu. The Fukushima accident in 2011 contributed to fuelling natural gas import prices in 2012 (+35 per cent, compared with 2011), as natural gas was required to partly balance unavailable nuclear capacity. The share of natural gas in the energy mix in Japan rose from 17.3 per cent in 2010 to 23.3 per cent in 2015. The sector with the highest consumption levels is power generation (63 per cent of total natural gas consumption in 2015), followed by industrial applications (21 per cent) and residential and commercial uses (9 per cent).

Due to the gradual contraction of domestic natural gas production in Japan for more than a decade, the latter only contributed less than 3 per cent of domestic consumption in 2015. As a result, Japan predominantly relied on imports, in particular, LNG imports. Japan was the main LNG importing country

in 2016, with about 31 per cent of world imports, at 108.5 billion cubic metres.

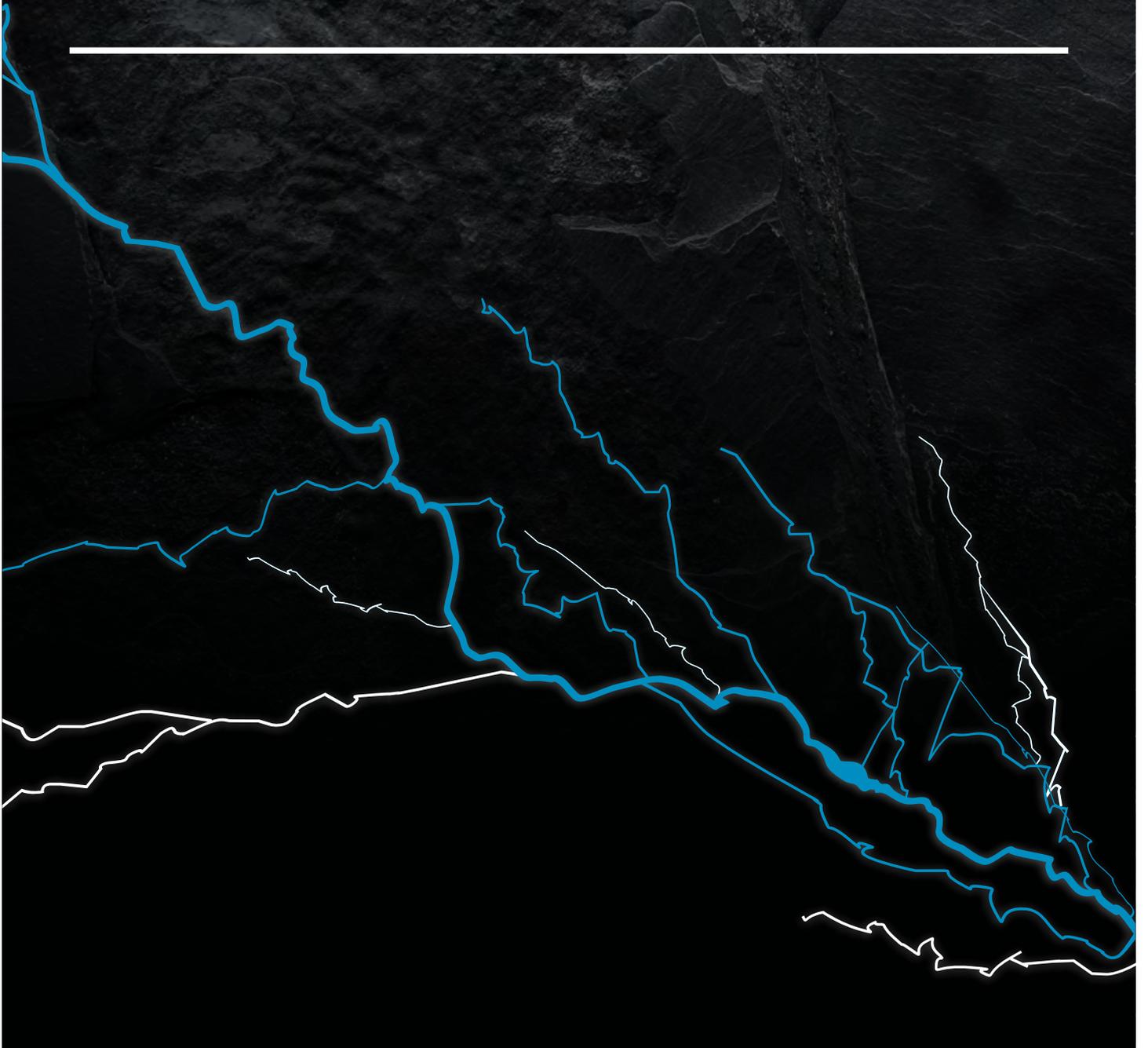
In 2016, in Asia, and in China and Japan in particular, natural gas imports continued to be mainly negotiated on an oil price escalation basis (88 per cent of total imports). According to IGU, this explains the high level of natural gas prices in the region. However, “short-term and spot LNG trade in the Asia [and] Pacific market almost tripled from 2010 to 2014, when it represented 21 per cent of global LNG trade and 7 per cent of natural gas trade [and] several Asian countries – including China, Japan, China and Singapore – are developing regional trading hubs with the goal of increasing price formation transparency” (EIA, 2016a: 54).

Except in the United States, natural gas has long been priced in comparison with other fossil fuels, in particular, crude oil, due to the fact that crude oil is traded on well-established and more liquid markets, and its price discovery mechanism is more transparent than that of natural gas. Moreover, the possibility of rapidly switching from natural gas to petroleum, considering specific conditions (e.g. infrastructure and technology), explains the traditional indexation of long-term natural gas contracts to crude oil prices.

An integrated market for natural gas does not yet exist. However, recent developments in the United States with regard to shale gas production and increasing liquefaction capacities could lead to its increasing globalization. The creation of trading hubs in Asia and Europe, allowing for the pricing of natural gas based on supply and demand fundamentals, have contributed to developing spot and short-term contracts for this commodity.

CHAPTER II

MAJOR POTENTIAL THREATS ASSOCIATED WITH SHALE GAS PRODUCTION



Large-scale shale gas operations started in the mid-2000s in the United States, when the conjunction of the long-term depletion of conventional natural gas reservoirs and high natural gas prices made the combination of horizontal drilling and hydraulic fracturing economically profitable.

Horizontal drilling dates to the 1980s. As in conventional operations, the drilling of unconventional wells is initiated vertically in the upper part of a well. Horizontal drilling occurs when the bit crosses the source rock (figure 9). Horizontal drilling accounted for about 80 per cent of total drilling in the United States in 2016, compared with 13 per cent in 2005.¹² Moreover, while horizontal (and directional) drilling is particularly associated with shale gas operations, it is also increasingly used in conventional extraction.

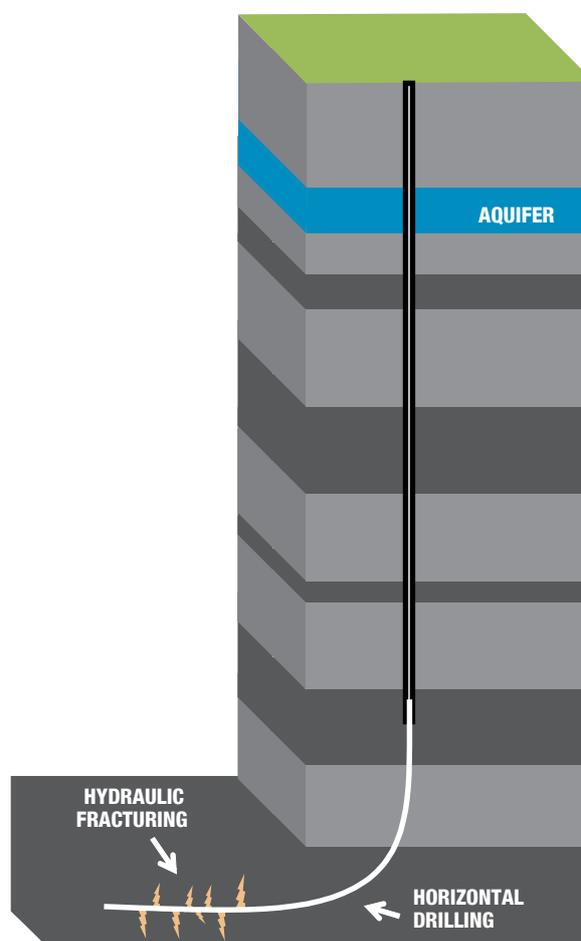
Hydraulic fracturing was developed in the late 1940s and initially used to stimulate conventional deposits. However, this process is currently essentially associated with its use in shale gas production, where it is combined with horizontal drilling. Hydraulic fracturing involves the high-pressure injection into a well of a fluid made of water (90 per cent), sand or other proppant agents (9.5 per cent) and additives (0.5 per cent).¹³ The composition of the fluid is tailored to geological conditions and the characteristics of the water used, among other factors. The share of additives may reach 2 per cent of the mix. The injection of the fracturing fluid exercises a mechanical pressure on the rock, widening existing fractures and creating new ones. Fractures can extend from tens to hundreds of metres; with few over 350 m. Davies et al. (2012) note that they do not exceed 588 m. Sand is generally used as a proppant, to keep fractures propped open while the pressure is progressively reduced within the well. The proppant is intended to stay in place, creating a more porous environment than the one in place before fracturing, allowing natural gas to flow through the fractures and migrate upward through a pipe to the surface.

A large range of additives may be added to the fluid to serve various purposes (table 2). For example, gelling

¹² Baker Hughes. (accessed 19 October 2017). North America rotary rig count (January 2000–current), United States Count by trajectory. <http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother>.

¹³ In the fracturing of a gas well, considering 10 hydraulic fracturing stimulations, the quantity of water, sand and chemicals used will be approximately as follows: 15 million litres of water; 1,400 tons to 1,500 tons of sand (or another proppant); and 70–80 tons of chemical products.

Figure 9 Horizontal drilling and hydraulic fracturing



Source: UNCTAD secretariat.

agents aim to facilitate the transport of the proppant, while biocides may be used to avoid the development of bacteria in the pipe, which may cause the equipment to deteriorate. United States EPA (2016: 40) identified “1,084 chemicals that were reported to have been used in hydraulic fracturing fluids between 2005 and 2013 [and] that between 4 and 28 chemicals were used per well between January 2011 and February 2013”. Traditionally, hydraulic fracturing stimulation takes one hour to several hours and a dozen operations are necessary per well.

While the use of additives has continued to be pivotal in hydraulic fracturing operations, industries have increasingly sought innovative processes and more environmentally friendly substances, in order to ensure that their operations are more “green” and to limit their potential impact on the environment and local populations.

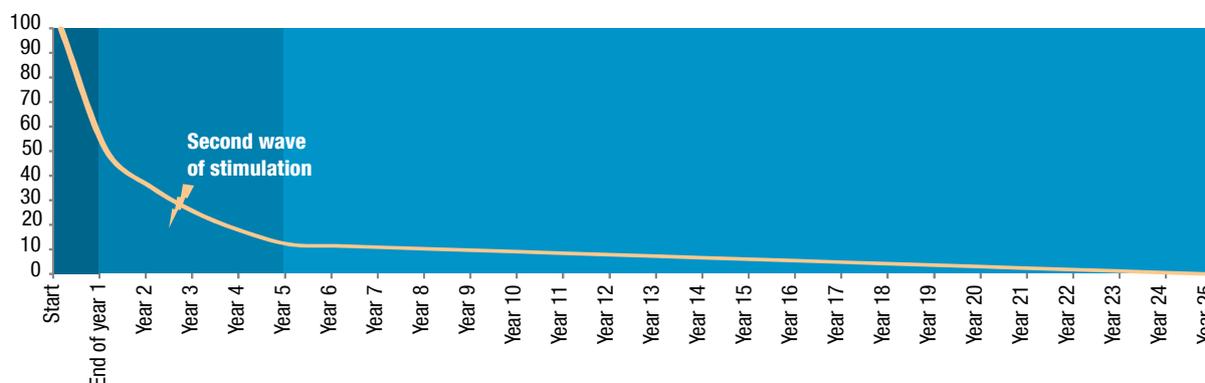
Table 2 Examples of additives commonly used in hydraulic fracturing

Function	Purpose	Names of chemicals used
Acid	Helps dissolve minerals and initiate cracks in rock	Hydrochloric acid
Biocide	Eliminates bacteria in water that produces corrosive by-products	Glutaraldehyde, quaternary ammonium chloride, tetrakis hydroxymethyl-phosphonium sulfate
Breaker	Allows delayed breakdown in gel Product stabilizer	Ammonium persulfate, magnesium peroxide, magnesium oxide Sodium chloride, calcium chloride
Clay stabilizer	Prevents clays from swelling or shifting	Choline Chloride, tetramethyl ammonium chloride, sodium chloride
Corrosion inhibitor	Product stabilizer and/or winterizing agent Prevents corrosion of pipe	Isopropanol, methanol Formic acid, acetaldehyde
Cross-linker	Carrier fluid for borate or zirconate cross-linker Maintains fluid viscosity as temperature increases Product stabilizer and/or winterizing agent	Petroleum distillate, hydrotreated light Potassium metaborate, triethanolamine zirconate, sodium tetraborate, boric acid, zirconium complex, borate salts Ethylene glycol, methanol
Friction reducer	Slicks water to minimize friction Carrier fluid for polyacrylamide friction reducer Product stabilizer and/or winterizing agent	Polyacrylamide Petroleum distillate, hydrotreated light Methanol, ethylene glycol
Gelling agent	Thickens water to suspend sand Carrier fluid for guar gum in liquid gels Product stabilizer and/or winterizing agent	Guar gum, polysaccharide blend Petroleum distillate, hydrotreated light Methanol, ethylene glycol
Iron control	Prevents precipitation of metal oxides	Citric acid, acetic acid, thioglycolic acid, sodium erythorbate
Non-emulsifier	Prevents formation of emulsions in fracture fluid Product stabilizer and/or winterizing agent	Lauryl sulfate Isopropanol, ethylene glycol
pH adjusting agent	Adjusts pH of fluid to maintain effectiveness of other components, such as cross-linkers	Sodium hydroxide, potassium hydroxide, acetic acid, sodium carbonate, potassium carbonate
Scale inhibitor	Prevents scale deposits in pipe	Copolymer of acrylamide and sodium acrylate, sodium polycarboxylate, phosphonic acid salt
Surfactant	Increases the viscosity of fracture fluid Product stabilizer and/or winterizing agent Carrier fluid for active surfactant ingredients Product stabilizer	Lauryl sulfate Ethanol, methanol, isopropyl alcohol Naphthalene 2-butoxyethanol

Source: UNCTAD secretariat, based on FracFocus, <https://fracfocus.org/chemical-use/what-chemicals-are-used> (accessed 13 September 2017).

Note: Further information about the chemicals used in hydraulic fracturing can be found on the following websites: <http://fracfocus.org/> (United States); <http://fracfocus.ca/> (Canada); and <https://echa.europa.eu/home> (regulation on the registration, evaluation, authorization and restriction of chemicals in Europe).

Figure 10 Shale gas well theoretical depletion trends over 25 years (percentage)



Source: UNCTAD secretariat.

From the 1950s to 2008, more than 180,000 oil and gas wells were dug in Alberta, Canada, using hydraulic fracturing¹⁴ and in 2013, more than 70 per cent of natural gas production in British Columbia – the leading shale and tight gas producing region in Canada – used hydraulic fracturing. According to United States EPA (2016), more than 300,000 wells used hydraulic fracturing in the United States in 2000–2015, and about 1 million have used hydraulic fracturing since the late 1940s.

One of the main characteristics of shale gas deposits is their sharp depletion rate (figure 10) starting from as early as the first months of activity. Maximum

production is generally reached relatively early following the beginning of operations, and production tends to decline rapidly thereafter, dropping by some 50 per cent by the end of the first year. In some deposits, this drop may be as high as 60–90 per cent. An additional gradual decrease occurs over the following four years, leading to low production levels after the fifth year. The remainder of shale gas contained in the reservoir may feed the well for about 20 years. The potential production of shale gas plays¹⁵ strongly relies upon the presence of particularly highly productive, but scattered, areas known as *sweet spots*. These are

¹⁴ Natural Resources Canada. (accessed 6 November 2017). Alberta's shale and tight resources. <http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17679>.

¹⁵ A play is a group of oil or natural gas areas presenting similar geological conditions. Examples of plays are, in the United States, Barnett, Eagle Ford, Fayetteville and Marcellus and, in Canada, Montney.

Table 3 Overview of preliminary risk assessment induced by hydraulic fracturing as an isolated operation and across all project phases

Environmental aspect	Individual production site			Cumulative production sites	
	Fracturing	Overall project		Fracturing	Overall project
Groundwater contamination	Moderate–High	High	→	Moderate–High	High
Surface water contamination	Moderate–High	High	→	Moderate–High	High
Water resources	Moderate	Moderate	↗	High	High
Release to air	Moderate	Moderate	↗	High	High
Land use	<i>Not applicable</i>	Moderate	↗	<i>Not applicable</i>	High
Risk to biodiversity	Low	Moderate	↗	Moderate	High
Noise-related impact	Moderate	Moderate–High	↗	Moderate	High
Visual impact	Low	Low–Moderate	↗	Moderate	Moderate
Seismicity	Low	Low	↗	Low	Low
Traffic	Moderate	Moderate	↗	High	High

Source: European Commission Directorate General on Environment (2012). Support to the identification of potential risks for the environment and human health arising from hydrocarbons operations involving hydraulic fracturing in Europe. <http://ec.europa.eu/environment/integration/energy/pdf/fracking%20study.pdf>.

defined by source-rock thickness and their presence or absence directly affects the profitability of shale gas operations. According to Bauquis (2014), the most productive areas of shale gas deposits account for about one fifth of total wells, representing 60 per cent of total revenues.

The fast depletion rate of shale gas deposits implies that to increase or even maintain production levels, companies must drill continuously. Companies may also decide to restimulate old sites through hydraulic fracturing, in order to reach new areas or reopen fractures that may have closed due to the lowering of pressure within the well. Such operations seem to be optimal after two to three years of production and to take place in an increasing number of locations in the United States.

The potential negative impacts induced by hydraulic fracturing (table 3) have dominated discussions on shale gas exploration and production. Moreover, the development of this sector in recent years has raised more global issues with regard to the impact of the use of hydrocarbons in the global energy mix, as well as on global warming. Given their relevance in the current debate on climate change, the following sections discuss some of these aspects.

1. WATER-RELATED ISSUES

Concern has been expressed with regard to the large quantities of water used by hydraulic fracturing, as well as the potential risks generated by shale gas operations, on the quality of such resources through groundwater or surface water contamination. This concern is further exacerbated in rural areas, where agriculture is the main source of water withdrawal¹⁶ and where the development of competing activities, such as shale gas production, is likely to increase competition for water with other activities such as agriculture and may affect production costs. This concern should be taken into consideration in particular in areas where food security is or can easily become an issue. Water management – with regard to both quantity and quality – is of the highest importance, especially in areas affected by water stress. Necessary steps should be taken in accordance with the precautionary principle to avoid the waste and/or deterioration of this precious

¹⁶ Water withdrawal “refers to water that has been removed from its source for a specific use. The major sectors that withdraw water are irrigated agriculture, industries and municipalities”. Food and Agriculture Organization of the United Nations. (accessed 5 December 2017). Did you know...? Facts and figures about. <http://www.fao.org/nr/water/aquastat/didyouknow/index2.stm>.

resource. The United States EPA (2016: 6) indicates that in 2000–2013 in the United States, “approximately 3,900 public water systems were estimated to have had at least one hydraulically fractured well within a mile [1.6 km] of their water source”.

a. Groundwater contamination

As mentioned earlier, additives used in hydraulic fracturing fluids are generally made up of specific chemicals. While they account for the smallest share of the mix, they may nevertheless constitute the most damaging component for the environment and living beings. This issue has attracted the attention of the public, as any potential contamination of aquifers by such chemicals is likely to have dramatic impacts on drinking water, among other concerns.

According to many studies, the risk of aquifers being contaminated by hydraulic fracturing operations appear to be low in comparison with the number of operations carried out.

The reason for this is that hydraulic fracturing generally takes place at several kilometres in depth, while aquifers are generally located at a much closer distance to the surface

Spills by flowback and produced water represented 48 per cent of the 464 reported spills accounting for 85 per cent of total reported spilled volumes between 2006 and 2012 (US EPA, 2015)

(between 100 and 500 m maximum). Moreover, fractures generated by the stimulation of source rock are generally a few hundred metres long (table 4). Andlauer and Hecker (2015) give the example of the Barnett and Marcellus plays in Pennsylvania, United States, highlighting that shale gas is extracted at a depth of between 1,300 and 4,000 m, while aquifers are located at a depth of between 120 and 360 m.

Table 4 Distance between gas shales and shallow freshwater aquifers in major United States plays (metres)

Basin	Depth to shale	Depth to aquifer
Barnett	1 981–2 590	366
Fayetteville	305–2 134	152
Haynesville	3 200–4 115	122
Marcellus	1 220–2 590	259
Woodford	1 829–3 353	122

Source: MIT (2011).

Note: Data have been converted from the original document and rounded.

However, according to United States EPA (2016), in some instances, no vertical distance may exist between the top of the formation and the bottom of the underground water reservoir, involving a higher risk of water contamination. This conclusion is supported by Jackson et al. (2014). Such differences from one site to another support the necessity of developing extensive knowledge with regard to local geology, especially with regard to the location of aquifers and other water resources that could be potentially affected by shale gas operations.

To date, most aquifer contamination reported in the United States has resulted from accidental contamination owing to human errors on the surface or to the poor mechanical integrity of wells, leading them to leak. According to Jackson (2014), “analyses of state records for the Marcellus shale from 2010 to 2013 revealed that [the] Pennsylvania well failed at rates of 3–6 per cent in the first three years of well life”. Defects in the construction of wells may lead hydraulic fracturing fluid injected from the surface, flowback water or CH₄ to rise to the surface and leak to the ground and potentially reach underground water resources. United States EPA (2016) highlights that the presence of other wells, whether active or not, in proximity to fractured wells could be an aggravating factor as it could affect the integrity of the nearby well or its network of fractures. In addition, Jackson (2014) specifies that a somewhat more plausible scenario of underground water contamination is for human-made fractures to connect to a natural fault or fracture. Again, this underlines the necessity of a thorough understanding of the local geology.

Given the importance of this issue, all necessary measures should be taken to guarantee and regularly monitor the integrity of wells during their lifespan, as well as their capacity to withstand recurrent high pressures of injected fluids and thermal changes occurring during hydraulic fracturing operations. Moreover, questions may be raised about the potential threats generated by the current large-scale development of multipad drilling operations, as well as the already existing underground pathways in countries where hydrocarbon production activities already exist, and their potential impacts on underground water resources.

b. Surface water contamination

Following fracturing of a deposit, a large proportion of the injected fluid flows up to the surface. This

wastewater is generally known as *flowback*. It may be salty and loaded with hazardous elements originating from the source rock, such as hydrocarbon residues, metals (e.g. arsenic, cadmium, cobalt and/or mercury) and, at times, naturally occurring radioactive materials. Its composition and volume may vary from one site to another. For example, while flowback may represent only 10 per cent of the injected fluid in some stimulations, it may sometimes reach 100 per cent during the first three years of activity, as indicated by United States EPA (2016).

Flowback water must be collected and handled carefully. Several solutions may be adopted to deal with this wastewater. It can be recycled and reused in ensuing fracturing operations or other industrial purposes. It may also receive further treatment, to be used in agriculture, for example, or discharged into neighbouring streams. Finally, wastewater may also be reinjected into deep underground formations. This solution has been largely used throughout the United States and has been indicated as one of the main sources of earth tremors in the country. All activities must receive particular attention as they can be the source of potential pollution of the environment and of water resources in particular.

Surface water contamination is considered to be the main source of potential pollution of water by hydraulic fracturing activities. Flowback may spill into surface water (e.g. streams) or return to the soil, where it may percolate into groundwater. According to United States EPA (2015), two thirds of spills investigated between 2006 and 2012 reached at least one of

In 2006–2012, spills of fracturing fluid represented one fifth of the 464 reported spills, accounting for 6 per cent of total reported spilled volumes (United States EPA, 2015).

these receptors. The impacts of spills are expected to be more significant and longer term if they reach underground water sources, as the reduction of chemical concentration will naturally take more time, compared with reduction in surface water. Moreover, no direct action may be taken to reduce pollution when groundwater resources are contaminated. In addition, impacts on water resources may vary depending on the composition of the flowback.

Precise conclusions are difficult to reach in this regard, as information is given by companies on a volunteer basis. The reporting system is not systematized or standardized, which does not allow

for any comparisons or for a global picture of the real impacts of hydraulic fracturing as a global activity on water resources and on drinking water in particular. For example, according to United States EPA (2015), information received is not sufficient to determine whether or not hydraulic fracturing was responsible for 12,000 spills out of 36,000 under review. Moreover, too little information is made available to estimate whether necessary actions have been taken to respond to spills and to what extent such actions have proven successful.

The implementation of monitoring measures would help to evaluate the real impact of hydraulic fracturing activities on water resources, which is a public health issue. This would also help companies to demonstrate the real impact of their activities on the environment and, if any, to develop and implement the necessary measures to protect water resources from contamination.

c. The use of water resources

Water consumption is estimated to be around 15 million litres for a 10-segment well, equivalent to 15,000 cubic metres or approximately five Olympic-size swimming pools. With regard to the total number of wells fractured in 2000–2015 in the United States, not taking into account refracturing operations, which are considered to be more water-intensive than the initial set of fracturing – total water consumption was equivalent to about one fifth of New York City water consumption in 2000–2015.¹⁷ For this reason, analysis of the issue of water consumption should not be dealt with in the context of a single well or a single fracturing operation, but should be considered on a large-scale basis, taking into account in particular the development of multipad drilling, which involves the fracturing of 10–15 wells from the same platform. At the same time, United States EPA (2016: 15) indicates that “average annual water volumes reported in FracFocus 1.0 were 10 per cent or more of total water use in 26 of the 401 counties studied, 30 per cent or more in nine counties and 50 per cent or more in four counties”. Another example is also given by the North Dakota State Water Commission (2016:5), as follows: “in 2014, records indicate that 31,632 acre-

feet [39 billion litres] of surface and groundwater were used for fracking purposes. That amounts to 9.6 per cent of North Dakota’s 2013 consumptive water use.”

As hydraulic fracturing activities may impact the quantity and/or quality of water made available to other local stakeholders, special attention should be given to the state of local water consumption before any operation begins. An evaluation of potential competitors for water use should also be made (e.g. drinking water, agricultural production, and other industrial activities), as well as of the risks of potential scarcity that hydraulic fracturing activities may cause to local water resources, both surface and underground. Moreover, activities should be adapted to the local context, especially in already sensitive areas, such as those experiencing water stress.

In conclusion, it is interesting to compare the quantities of water necessary to produce the same quantity of energy from unconventional natural gas and from other potential competitive sources of energy. According to data in Jackson et al. (2014), the production of natural gas through a conventional channel consumes far less water than the production of unconventional natural gas (table 5). However, producing the same quantity of energy through the nuclear channel would require more than threefold the volume of water necessary for the production of the same quantity of energy from unconventional natural gas. The energy source with a less favourable footprint on water resources is ethanol produced from irrigated corn, as it consumes about 1,000 times more water than the production of unconventional natural gas. Renewables are the energy sources with the most positive performance, as no water is needed to produce them.

Table 5 Water intensity in extraction and processing of different energy sources (litres per MMBtu)

Energy source	Water for extraction and processing
Natural gas, conventional	7.2
Natural gas, unconventional	15.5
Pulverized coal (once through)	28.4
Saudi Arabia crude	121.1
Nuclear (once through)	49.2
Corn ethanol (unirrigated)	450.5
Corn ethanol (irrigated)	14 384.6
Solar photovoltaic	0
Wind	0

Source: Jackson et al. (2014).

¹⁷ Proxy estimated using the following data: 300,000 wells fractured in 2000–2015; 15 million litres per well; New York City water consumption official data available on: <https://data.cityofnewyork.us/Environment/Water-Consumption-In-The-New-York-City/ia2d-e54m> and the conversion rate from United States gallons to litres used (3.79).

Concerns with regard to potentially large withdrawals of water for hydraulic fracturing purposes have led the industry to investigate alternatives to the use of fresh water. Provided that water sources are compatible with the other components incorporated in the fracturing fluid, a large range of water sources may be used to replace fresh water (e.g. saline water, brackish water extracted from deep aquifers and wastewater produced from previous fracturing operations or from other industries). With regard to wastewater reuse for hydraulic fracturing, United States EPA (2016:13) states as follows: “the proportion of water used in hydraulic fracturing that comes from reused hydraulic fracturing wastewater appears to be low. The median percentage was 5 per cent between approximately 2008 and 2014.” Local water sources are generally used as a priority. However, when such a solution cannot be implemented, water is transported to the deposit by specifically devoted pipes or, more usually, by trucks and stored on site. This increased activity is likely to cause additional impacts on local infrastructure (e.g. roads), local populations and the environment. These aspects are analysed later in this report. In addition, as a response to threats related to the potential contamination of water resources by chemicals, oil and gas companies have also developed water-free fracturing solutions. However, the use of these alternatives is still limited; non-water substances were used in less than 3 per cent of wells (United States EPA, 2016).

2. POTENTIAL SEISMICITY LINKED TO SHALE GAS ACTIVITIES

An earthquake is a sudden and sometimes violent vibration of the ground arising from the energy released from tectonic plates moving relative to one another. Most earthquakes are natural, yet some may be generated by human activities.

a. On the direct impacts of hydraulic fracturing activities on seismicity

Hydraulic fracturing is a technology that triggers seismic activity and can sometimes cause perceptible vibrations at the surface. This seismicity is usually of low intensity. Microseismic monitoring is a commonly used technology that aims to monitor and optimize the fracturing process. According to States First (2015:121), “thousands of microearthquakes may be detected during a single stage of a hydraulic

fracturing operation. It is important to understand that microearthquakes are routine and normal occurrences during hydraulic fracturing and are associated with the fracture propagation and the normal subsurface rock fracturing process”. Moreover, fracturing operations usually take place within the gas window. As a consequence, effects produced on the surface are considered to be limited, as vibrations occur deep in the ground. However, this is not always the case and some may be located closer to the surface.

Until recently, the general assessment of hydraulic fracturing and seismicity was that stimulations did not cause any identified hazard in normal conditions. For example, Warpinski (2013) indicates that the largest monitored microseism found in several thousand stages in the United States had not exceeded M1.0. Moreover, after reporting by Natural Resources Canada of 38 anomalous seismic events of low magnitude in the Horn River Basin – with one felt at the surface – between April 2009 and December 2011, the British Columbia Oil and Gas Commission reviewed more than 8,000 hydraulic fracturing completions in the region. Its conclusion was that there was “no associated anomalous seismicity” with hydraulic fracturing activities (British Columbia Oil and Gas Commission, 2012: 3). However, the Commission also pointed out that seismic activity was due to the proximity of fluid injection with pre-existing faults. As a consequence, the possibility of hydraulic fracturing activities reaching pre-existing natural faults, as well as the reinjection of wastewater in disposal wells, can be considered responsible for most of the cases of measurable and felt seismicity in North America.

b. The reinjection of wastewater from hydraulic fracturing operations in disposal wells

This operation consists of reinjecting large volumes (millions of cubic metres) of flowback water arising from hundreds to thousands of producing wells into a common permeable underground formation, typically located at between 3,000–5,000 m depth. In the United States, such wells are known as class II. According to the Centre hydrocarbures non conventionnels, about 30,000 disposal wells for industrial effluents¹⁸ exist throughout the United States. Most studies on the

¹⁸ Disposal wells are not only dedicated to effluents from the oil and gas industry (especially from hydraulic fracturing operations), but also for storing salt water and waste produced by other industries.

United States shale gas sector consider the reinjection of wastewater as the main source of increased seismicity. In addition, the United States Geological Survey indicates that “wastewater disposal is the primary cause of the recent increase in earthquakes in the central United States.”¹⁹ Hand (2014) notes that more than 2,500 small earthquakes in Oklahoma may be attributed to the injection of wastewater from oil and gas operations in disposal wells.

StatesFirst (2015:15) summarizes the potential impact of oil and gas activities on induced seismicity as follows: “recently, the frequency of earthquakes has increased, particularly in the mid-continental United States. Some of these events are occurring in areas that previously have not experienced felt seismic activity... The increase in seismic activity, particularly in the mid-continental United States, shares a temporal and spatial correlation with increased oil and gas activity, and studies have indicated a connection with class II disposal wells. However, detection of some of these events may be the result of increased seismic monitoring.”

c. On seismic risks owing to the reactivation of a pre-existing natural fault by hydraulic fracturing operations

The second scenario in which shale gas operations are likely to influence local seismicity is if hydraulic cracks interact with already existing and pre-stressed natural faults. In practice, this means that human activity has caused the event to take place before its natural possible date. For example, in 2011 in the United Kingdom, near Blackpool, two successive earthquakes of magnitude 2.3 and 1.5 occurred close to the Preese Hall site, leading to the temporary suspension of drilling activities in the region. Similar events were reported in Montney, Canada, in July 2014. Most earthquakes usually do not occur on site but several kilometres away. Atkinson et al. (2016:2) provide new insights, specifically focusing on the Western Canada Sedimentary Basin, noting a high level of correlation between hydraulic fracturing operations and seismicity “in both time and space, which is very unlikely to be coincidental... in most cases, the correlation is unlikely to be related to

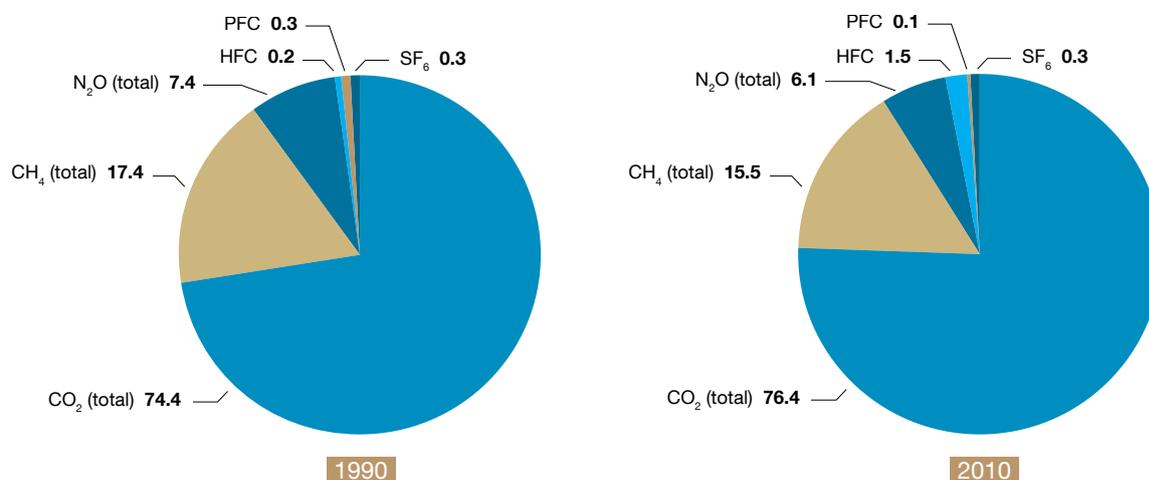
any nearby disposal wells”. The study adds that in 2010–2015, “more than half of all $M \geq 3$ seismicity has occurred in close proximity to hydraulic fracturing operations” (Atkinson et al. (2016:13). The occurrence of associated seismicity is limited compared with the number of hydraulic fracturing operations, by about 0.3 per cent, yet “implications for hazard are nevertheless significant, particularly if multiple operations are located in close proximity to critical infrastructure” (Atkinson et al. (2016:13).

The number of earthquakes generated by the reinjection of wastewater underground and by hydraulic fracturing activities have drawn the attention of the public, as well as local and national authorities in producing countries, leading to the implementation of more stringent regulations and the requirement of more frequent data reporting on hydraulic fracturing operations. For example, on 11 April 2014, the Ohio Department of Natural Resources announced the reinforcement of permit conditions for drilling near faults or areas of past seismic activity. Within this framework, the Ohio Department of Natural Resources (2014) states as follows: “[new permits issued] for horizontal drilling within 3 miles of a known fault or area of seismic activity greater than a 2.0 magnitude would require companies to install sensitive seismic monitors. If those monitors detect a seismic event in excess of 1.0 magnitude, activities would pause while the cause is investigated. If the investigation reveals a probable connection to the hydraulic fracturing process, all well completion operations will be suspended.” In comparison, the British Geological Survey has suggested that operations be temporarily suspended when earthquake magnitude exceeds $M0.5$.

It may be highlighted that prior to 2017, most shale gas developments on a commercial basis occurred only in developed countries, mainly Canada and the United States, where infrastructure is considered solid and resistant. It is thus essential to clearly assess the risks of such developments in developing countries, where infrastructure may prove less resistant. Atkinson et al. (2016:13) state as follows: “many developing countries have high exposure due to their population density, coupled with very vulnerable infrastructure. A significant increase in the number of moderate earthquakes in developing countries would almost certainly increase the incidence of earthquake damage and fatalities.”

¹⁹ United States Geological Survey (accessed 6 November 2017). Induced earthquakes – myths and misconceptions. What you do and don’t know about induced seismicity. <https://earthquake.usgs.gov/research/induced/myths.php>.

Figure 11 Emissions of carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFC), perfluorocarbons (PFC) and sulfur hexafluoride (SF₆), as a share of total GHG emissions, 1990 and 2010 (percentage)



Source: UNCTAD secretariat based on IEA (accessed 2 October 2017).

3. GREENHOUSE GAS EMISSIONS

The greenhouse effect is a natural process that contributes to an increase in the global average temperature of the Earth, making it habitable. Without it, the average temperature would be around -18°C. However, since the industrial revolution, emissions of greenhouse gases (GHG) into the atmosphere have dramatically increased, leading to a modification of the balance between incoming and outgoing heat and thereby to global warming and climate change. Since 1990, CO₂ emissions have been responsible for the bulk of GHG emissions, accounting for more than three quarters of such emissions (figure 11). Together with CH₄, CO₂ emissions accounted for more than 90 per cent of total GHG emissions in 1990–2010.

GHG are generally differentiated according to their lifespan in the atmosphere and their global warming potential (GWP). The latter allows estimations of the capacity of a gas to affect global warming over a predefined period of time. GWP for each gas is assessed according to CO₂. For example, GWP for CH₄ is 28 over a 100-year period, meaning that CH₄ is estimated to absorb 28 times more energy than CO₂ over this period, making it a more potent gas than CO₂ along this time horizon. Moreover, as the period of time shortens, the effect on the environment increases. For example, if the reference period is shortened to 20 years, GWP for CH₄ rises to 84. However, while CH₄

is considered a more potent gas, it also remains for a shorter time in the atmosphere than CO₂, at 12.4 years, compared with more than 150 years for CO₂.

With regard to CO₂ emissions, the Intergovernmental Panel on Climate Change (2014:7) suggests that “GHG emissions from energy supply can be reduced significantly by replacing current world average coal-fired power plants with modern, highly efficient natural gas combined-cycle power plants or combined heat and power plants, provided that natural gas is available, and the fugitive emissions associated with its extraction and supply are low or mitigated”. Hirst N. (2013:2) notes that statement that “properly regulated and managed shale gas can have a lifecycle footprint of approximately half that of coal”. United States EPA (2017:33) states that “within the United States, fossil fuel combustion accounted for 93.3 per cent of CO₂ emissions in 2015” and that “natural gas systems were the second largest anthropogenic source category of CH₄ emissions” (United States EPA, 2017:39).

Table 6 presents an example of typical sources of CH₄ emissions along the natural gas value chain. The main source of CH₄ emissions from shale gas production is released into the atmosphere before commercial production begins. Venting natural gas directly into the atmosphere or flaring it from flowback operations during the completion phase account for a significant share of, respectively, total CH₄ and CO₂ emissions

Table 6 Methane and carbon dioxide emissions from natural gas systems in the United States, 2015

PRODUCTION	PROCESSING
<ul style="list-style-type: none"> - CH₄: 66 per cent of total CH₄ emissions (+51 per cent over 1990–2015). Mainly from gathering stations, pneumatic controllers, liquids unloading. Mainly explained by an increase in the number of equipment and venting. - CO₂: 44 per cent of total CO₂ emissions (+88 per cent over 1990–2015). Mainly from flaring. 	<ul style="list-style-type: none"> - CH₄: 7 per cent of total CH₄ emissions (-48 per cent over 1990–2015). Mainly from compressors. - CO₂: 56 per cent of total CO₂ emissions (-15 per cent over 1990–2015). Mainly from acid gas removal.
TRANSMISSION ET STORAGE	DISTRIBUTION
<ul style="list-style-type: none"> - CH₄: 21 per cent of total CH₄ emissions (-42 per cent over 1990–2015). Mainly from fugitive emissions and venting. - CO₂: less than 1 per cent of total CO₂ emissions (-37 per cent over 1990–2015). 	<ul style="list-style-type: none"> - CH₄: 7 per cent of total CH₄ emissions (-75 per cent over 1990–2015). Mainly from fugitive emissions from pipelines and stations. - CO₂: less than 1 per cent of total CO₂ emissions (-72 per cent over 1990–2015).

Source: UNCTAD secretariat, based on United States EPA, 2017.

attributable to this sector. According to IEA (2012: 40), “in the case of flaring, total well-to-burner emissions are estimated to be 3.5 per cent higher than for conventional gas, but this figure rises to 12 per cent if gas is vented”. This explains why IEA has underlined the importance of eliminating venting operations, as well as minimizing the flaring of natural gas. The British Columbia Oil and Gas Commission (2016:54) has published a series of guidelines supporting the reduction of flaring and venting, which state as follows: “venting is not an acceptable alternative to conservation or flaring. Venting is the least preferred option and gas should be flared under all except the most exceptional circumstances.” Venting and flaring are being progressively abandoned and replaced by, for example, reduced emissions completions. This innovative approach aims to capture natural gas and separate it from liquids and solids that are generally present in flowback, limiting the emission into the

atmosphere of large quantities of CH₄ and CO₂ as well as of other hazardous air pollutants, and enabling companies to recover and sell natural gas, instead of wasting a valuable non-renewable resource. Reduced emissions completions can also be used for workover activities when, for example, a well is refractured. According to IPIECA (2014), green completions can capture up to 90 per cent of gas. O’Sullivan (2012) provides an example of CH₄ and CO₂ emissions in the specific context of natural gas venting, flaring and capture (table 7).

The second largest source of pollution by CH₄ is through fugitive emissions, mainly due to defaults in sealing and leaks from pipelines and compressor stations, mainly attributable to the obsolescence of some installations as well as to the types of material used. For example, cast iron and unprotected steel pipes are more likely to leak than plastic pipes.

Table 7 Calculation of emission factors for gas handling techniques that can be deployed during shale well flowback operations, assuming both 100-year and 20-year global warming potentials

	Venting	Flaring	Gas capture
CH ₄ emitted – kg/1*10 ³ m ³ of natural gas	535.7	10.8	53.8
CO ₂ emitted – kg/1*10 ³ m ³ of natural gas	–	1 445.1	–
Total emission factor (100-yr global warming potential) – kg CO₂e/1*10³ m³ of natural gas	13 438	1 714	1 344
Total emission factor (20-yr global warming potential) – kg CO₂e/1*10³ m³ of natural gas	38 701	2 219	3 870

Source: O’Sullivan and Paltsev (2012).

Notes: M³, cubic metres. Factors calculated assuming that natural gas is composed of 78.8 per cent CH₄ by volume.

Bipartisan Policy Centre (2014:10) notes with regard to the United States that “approximately 7.4 per cent of distribution mains (by length) and about 6.8 per cent of distribution services (by count) are made of the ‘most susceptible’ materials” to corrosion and leaks.

An additional source of CO₂ emissions of particular importance, especially at the local level is air pollution generated by increasing traffic from heavy-duty vehicles used to transport drilling equipment and all inputs used during the hydraulic fracturing phase (e.g. water, sand and chemicals). The impact of increasing heavy-duty vehicle traffic is expected to vary from one site to another, according to, among others, geological specificities and the distance between a site and water disposals. AEA (2012:11–12) notes as follows: “total truck movements during the construction and development phases of a well are estimated at between 7,000 and 11,000 for a single 10-well pad... During the most intensive phases of development, it is estimated that there could be around 250 truck trips per day onto an individual site – noticeable by local residents – but sustained at these levels for a few days. The effects may include increased traffic on public roadways (affecting traffic flows and causing congestion), road safety issues, damage to roads, bridges and other infrastructure and increased risk of spillages and accidents involving hazardous materials. The risk is considered to be moderate for an individual installation and high for multiple installations”. However, temporary mitigation measures exist, such as temporary pipes to transport water, and may be applied to limit traffic loads and associated pollution, as well as damage to local infrastructure. During the drilling, fracturing and completion phases, pollution may also largely be generated by diesel engines powering equipment.

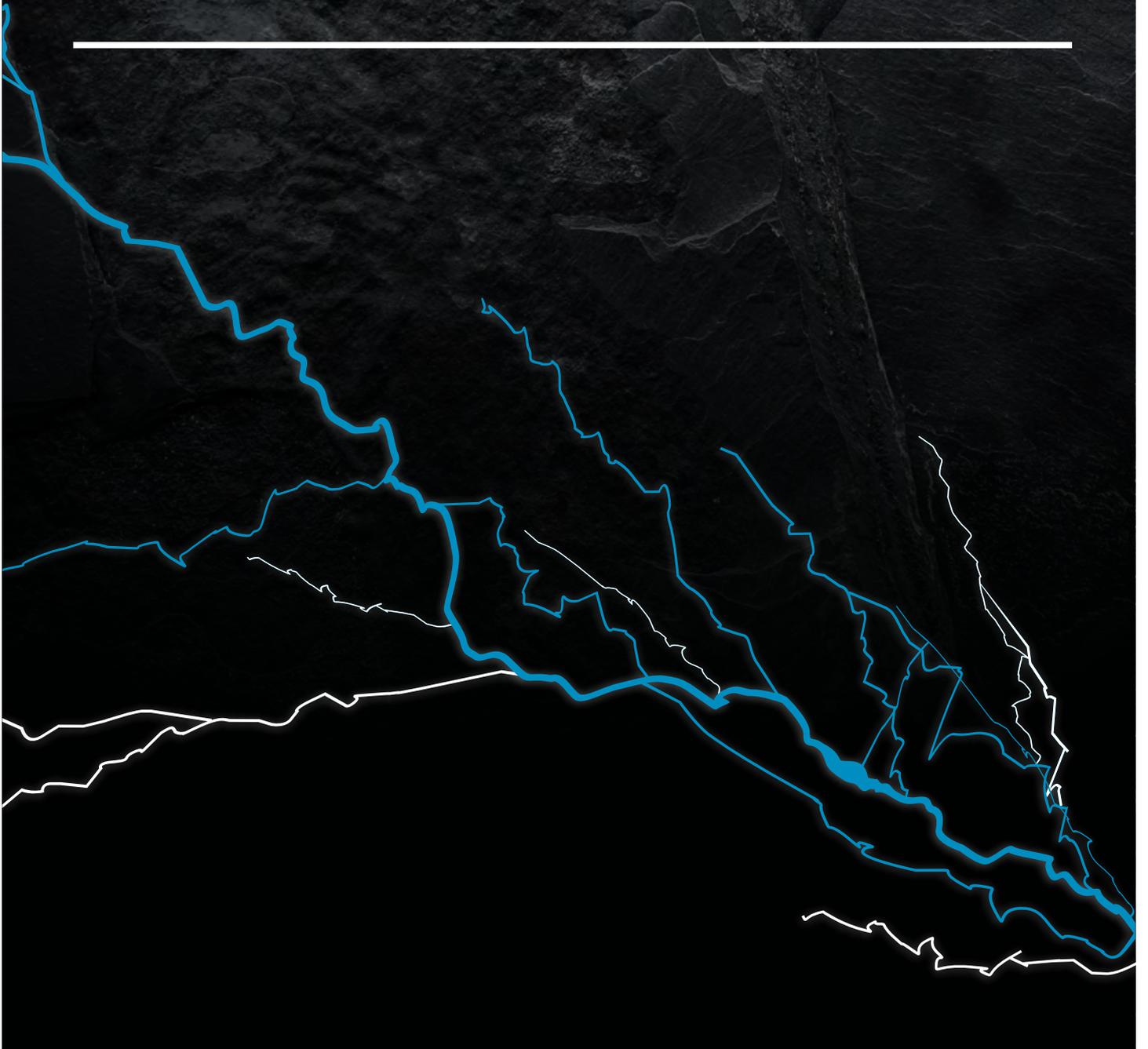
Most of these pollution sources can also be present in conventional natural gas extraction, yet it is generally accepted that the specificities of shale gas production

are likely to generate more emissions than conventional production. In addition, unless recycled on site, wastewater from flowback also must be transported to be retreated, which generates an additional source of pollution. This analysis does not take into consideration the practice of well refracturing, which requires larger quantities of water and proppants.

Continuous monitoring, increased data reporting and support for research work on the potential environmental impacts of shale gas development with regard to CH₄ and CO₂ emissions, among others, along the value chain from well to burner to users are of critical importance in order to enable national authorities to take fully informed decisions and ensure that natural gas is effectively the bridge fuel it has been touted as. Researchers do not speak with one voice on this issue. A highly debated paper by Howard (2011) is a good example. It presents a particularly negative carbon footprint for shale gas, compared with conventional natural gas, but also with other fossil fuels, including coal. Moreover, the parameters remain vague, given disagreement among experts with regard to, among others, the selection of time horizons, GWP factors and the quantities of fugitive CH₄ emissions effectively released into the atmosphere. Dealing with this important issue necessitates enhancing collaborative work among the various stakeholders, mainly in the private sector, as well as local, national and international authorities, in order to improve data collection and access to reliable and objective information. Moreover, the sharing of experiences and of know-how is pivotal, in order that past experiences may be used to minimize negative impacts on local and global environments. Taking into consideration the challenging problem of the reduction of CH₄ emissions, initiatives have been taken worldwide to tackle this issue. For example, Canada, Mexico and the United States have engaged to reduce by 40–45 per cent of their 1992 CH₄ levels emissions in the oil and gas industry by 2025.

CHAPTER III

THE DEVELOPMENT OF SHALE GAS PRODUCTION IN THE UNITED STATES

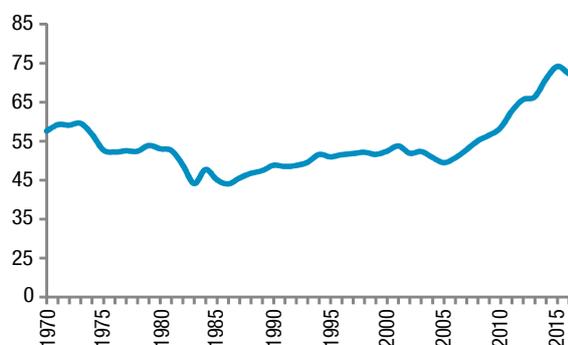


In 2015, shale gas commercial production was essentially limited to two countries, namely the United States and Canada with, respectively 87 and 13 per cent of world production. However, large projects have been implemented in other countries such as Argentina and China, while some other countries have banned the development of such resources either directly or through the prohibition of its main production technique, hydraulic fracturing, for example in France. The division of countries into groups in favour of or against the exploration and production of unconventional natural gas from shale gas deposits has been one of the main features characterizing this sector for a decade.

1. A DECADE OF SHALE GAS DEVELOPMENTS

Historically, the United States has ranked first with regard to natural gas consumption, with 30 per cent of the world total in 1980–2015. In the United States, natural gas is the second most consumed source of energy after petroleum, and its role has been strengthening since the beginning of the 2000s, increasing by 5 percentage points in 2000–2016 to reach 29.2 per cent of the United States energy mix in 2016. This has largely been made possible due to large quantities of natural gas made available through the development of domestic shale gas resources since the mid-2000s. Conventional natural gas production declined between the beginning of the 1970s and 2005, at an average rate of –0.4 per cent per annum, yet started to rise after 2007, recording an average compound average growth rate of 2.8 per cent per annum in 2007–2016 period (figure 12). Over the latter

Figure 12 United States natural gas production, 1970–2016
(billions of cubic feet per day)



Source: UNCTAD secretariat, based on BP, 2017b.

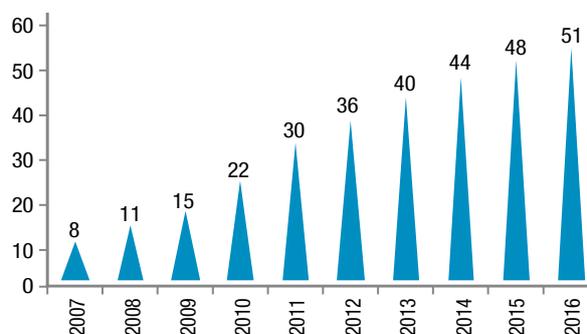
decade, natural gas gross withdrawals from shale gas wells grew from 1,990 billion cubic feet (around 8 per cent of total natural gas gross withdrawals) to more than 16,582 billion cubic feet, which represented more than half of total natural gas gross withdrawals in 2016 (figure 13).²⁰ This has significantly changed the United States gas sector landscape in recent years, and this trend is forecast to continue in future. According to EIA (2017a), shale gas and associated gas from tight oil plays may contribute two thirds of total United States natural gas production by 2040.

The development of unconventional natural gas resources in the United States, and of shale gas in particular, has led the country to become the leading global natural gas producing country since 2009. In 2016, the United States accounted for about 21 per cent of world natural gas production, ahead of the Russian Federation (16.3 per cent).

Natural gas production has shifted from traditional producing regions in the United States (e.g. the Gulf of Mexico) to onshore shale gas plays. With about 38 per cent of United States shale gas production in 2015, Marcellus is the largest of these plays (table 8). Together with Eagle Ford, the two plays accounted for more than half of United States total production and proven reserves in 2015. Including the Woodford, Barnett and Haynesville/Bossier plays, the first five United States shale gas plays accounted for about 80 per cent of total United States shale gas proven reserves and production in 2015. Despite a 12 per cent decline in United States shale gas reserves in

²⁰ EIA (accessed 12 October 2017). Dry shale gas production estimates. <https://www.eia.gov/tools/faqs/faq.php?id=907&t=8>.

Figure 13 United States natural gas gross withdrawals from shale gas, 2007–2016
(percentage of United States natural gas gross withdrawals)



Source: UNCTAD secretariat, based on EIA (accessed 19 October 2017).

Table 8 United States: Main shale gas reserves and production, 2015

All United States shale gas	PRODUCTION, 2015 15 214 TCF	RESERVES, 2015 175 601 TCF
<i>Individual shale plays as a percentage of all United States shale gas</i>		
Marcellus	37.9	41.4
Eagle Ford	14.5	11.2
Woodford	6.3	10.6
Barnett	10.7	9.7
Haynesville/Bossier	9.1	7.3
Utica/Point pleasant	6.3	7.1
Fayetteville	6.1	4.1
Others	9.1	8.7

Source: UNCTAD secretariat, based on EIA, Accessed 6 November 2017.

2015, stabilizing at around 175.6 TCF, United States domestic shale gas reserves have continuously increased since 2007, recording an increase of about 30 per cent per annum in 2007–2015.²¹

In 1985–2013, natural gas production deficit²² in the United States averaged about 1,650 billion cubic

²¹ Compound annual growth rate in 2007–2015 based on EIA (various editions). [United States] crude oil and natural gas proved reserves. <https://www.eia.gov/naturalgas/crudeoilreserves/>.

²² Computed from EIA statistics. United States natural gas marketed production minus United States natural gas total consumption. Data extracted from <https://www.eia.gov/dnav/ng/hist/n9140us2A.htm> for United States natural gas total consumption and from <https://www.eia.gov/dnav/ng/hist/n9050us2a.htm> for United States natural gas marketed production.

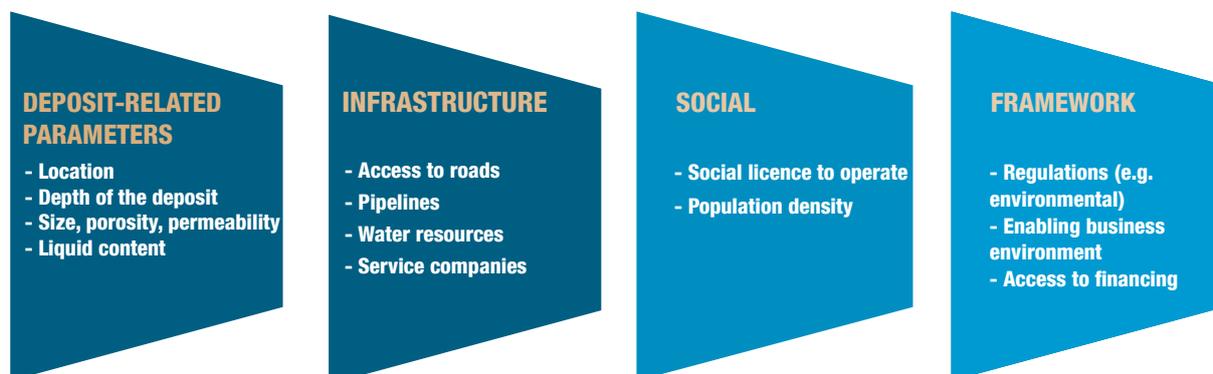
feet (8 per cent of United States annual consumption over the period), leading to increasing imports of natural gas. Net imports of natural gas were around 2,438 billion cubic feet per year over the period, with a record level of 3,785 billion cubic feet in 2007. The year 2007 marked a turning point in the recent history of natural gas consumption and production in the United States. Net imports of natural gas started to contract after this date, progressively dropping to 670 billion cubic feet in 2016, despite a simultaneous increase in natural gas consumption by +19 per cent. The United States became a net exporter of natural gas in July 2017 and, according to EIA, this situation is expected to persist in 2018. Due to the lack of facilities to export LNG, 93 per cent of United States natural gas exports in 2016 were made by pipelines, mainly to Mexico (two thirds) and Canada (one third). However, the recent evolution in the shale gas sector has led to drastic changes in domestic infrastructure. For example, large developments are planned with regard to liquefaction capacity (table 9). In concrete terms, the United States may add an extra 61.45 million tons per annum of liquefaction capacity in 2016–2020 to already existing capacity and begin to export large quantities of LNG abroad. According to EIA (2017f), “by 2020, the United States will have the third largest LNG export capacity in the world after Australia and Qatar”. This projection is supported by IGU (2017a). It is a dramatic change compared with the pre-boom period in shale gas, when “developers were building 10 new LNG import terminals and had proposed

Table 9 Global liquefaction plants in the United States by 2019
(millions of tons per annum)

Start year	Project name	Capacity	Owner
1969	Kenai LNG	1.50	Conoco Phillips
2016	Sabine Pass T2	4.50	Cheniere Energy, Blackstone
2016	Sabine Pass T1	4.50	Cheniere Energy, Blackstone
2017	Sabine Pass LNG T3-4	9.00	Cheniere Energy, Blackstone
2017	Cove Point LNG	5.25	Dominion
2018	Elba Island LNG T1-6	1.50	Kinder Morgan
2018	Cameron LNG T1	4.00	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
2018	Cameron LNG T2	4.00	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
2018	Freeport LNG T1	5.10	Freeport LNG, JERA, Osaka Gas
2019	Corpus Christi LNG T1	4.50	Cheniere Energy
2019	Elba Island LNG T7-10	1.00	Kinder Morgan
2019	Freeport LNG T2	5.10	Freeport LNG, IFM Investors
2019	Corpus Christi LNG T2	4.50	Cheniere Energy
2019	Cameron LNG T3	4.00	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
2019	Sabine Pass LNG T5	4.50	Cheniere Energy, Blackstone
2020	Total in the United States	62.95	

Source: IGU (2017a).

Figure 14 Main factors supporting the development of the shale gas sector



Source: UNCTAD secretariat.

33 additional [import] terminals” in 2004 (United States Department of Energy, 2014:3). Moreover, EIA (2015h) highlights that “almost 80 per cent of United States LNG export volumes for projects currently under construction have been contracted on pricing terms directly linked to the Henry Hub price, or under a hybrid pricing mechanism with links to Henry Hub”.

The expansion of the shale gas value chain in the United States has been supported by a combination of various factors (figure 14). The most pivotal factors are individually considered in this section, and some comments are made in the profiles of other producing or potentially producing countries in this report and used as a way to assess whether the development of a shale gas sector would be possible in these countries in light of what is known about the United States experience.

The United States has a long-standing history as a significant oil and natural gas producing country. This background contributed to providing the shale gas sector with an already dense domestic industrial base, with numerous support service companies and infrastructure already in place. Significant investments to both develop shale gas resources and adapt the existing infrastructure to new industrial needs were made possible by a strong capital market. In this regard, the United States Department of Energy (2015b:5) notes the following: “infrastructure has been built up substantially over the past decade. From 2004 to 2014, companies made \$10 billion in average annual investments in midstream natural gas infrastructure, including major pipeline projects. Investment in natural gas processing in the United States was \$7.5 billion in 2013.” According to the United States Department of Energy (2015b), a high-pressure pipeline network covered 315,000 miles of transmission pipelines and

the country had 516 natural gas processing plants with a total capacity of 64,659 million cubic feet per day. EIA (2016b) reports a processing capacity of 77,206 million cubic feet per day, 60 per cent of which is located in large shale oil and gas producing states, namely Texas (including the Gulf of Mexico), Louisiana, Oklahoma, West Virginia and Pennsylvania, and most investments were made in these new producing areas. Moreover, with 835 drilling rigs in 2014, United States capacity accounted for about 42 per cent of the world total. While the number of rigs largely decreased in 2007–2017 by -53 per cent, the rise in productivity per rig contributed to improving natural gas production in the United States during this period, helping to expand United States shale gas production.

This 10-year experience, combined with the massive development of shale gas production, as well as technological advances, progressively led to a drastic contraction in the costs of production per well in the United States. The rapid development of multipad drilling, for example, contributed to creating large economies of scale by reducing the number of rigs necessary to drill a similar number of wells, as several wells could be drilled from the same platform without moving the rig. The total number of wells drilled using this technique rose from 5 per cent of total wells in 2006 to 60 per cent in 2013, and the number of drilling operators reached 2,000 in 2013.

The low population density in producing areas has also enabled the development of shale gas activities in the United States, as it tended to limit the number of households potentially affected by shale gas activities. Moreover, the general acceptance of oil and gas activities by local populations in areas with higher density and, sometimes, with past experience in conventional and unconventional natural gas production, also

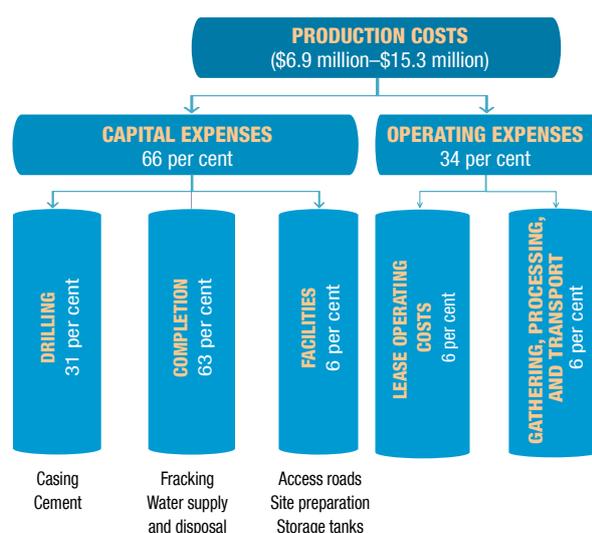
played a pivotal role. Furthermore, the specific nature of mineral rights in the United States, which give landowners ownership of resources under their land for royalties, also largely contributed to this expansion, leading households to more easily permit drilling in their backyards. In most other countries, financial rewards associated with such extraction accrue to the State, irrespective of ownership of the land.

2. PRODUCTION COSTS

The average production costs per unit for unconventional oil and natural gas wells were between \$6.9 million and \$15.3 million in 2014 (EIA, 2016d). This assessment was made from a cost analysis of the five main unconventional plays in the United States, namely Bakken, Eagle Ford, Marcellus, Delaware and Midland²³ and included both capital and operating expenses (figure 15). Production costs may vary largely from one play to another and from one well to another, as a result of, for example, specific geological conditions or the availability of water resources. Since the mid-2000s, two main periods can be identified, namely 2006–2012 and 2012–2015. In 2006–2012, production costs largely increased as a result of the progressive setting up of specific services aimed at supporting the development of the sector. However, technological advances in drilling have been key

²³ This list differs from the previous as it takes into consideration not only shale gas plays but also unconventional plays.

Figure 15 Production cost breakdown, 2014



Source: UNCTAD secretariat based on EIA, 2016d.

Note: Data in this diagram are averages.

drivers in the reduction of production costs in the United States after 2012, by means of significant economies of scale and/or productivity gains. EIA (2016d:4) underlines that “average well-drilling and completion costs in five onshore areas evaluated in 2015 were between 25 per cent and 30 per cent below their level in 2012, when costs per well were at their highest point over the past decade”.

3. EFFECTS OF SHALE GAS SECTOR DEVELOPMENT ON OTHER ECONOMIC SECTORS

A portion of natural gas is consumed along the value chain before reaching final users. Such upstream consumption accounted for about 8 per cent of total natural gas consumption in 2016 and mainly contributed to fuel lease and plant (70 per cent), with the rest consumed by pipelines and distribution.²⁴

In 2016, the two main final natural gas consuming sectors in the United States were power generation and industrial applications, accounting for 40 and 31 per cent, respectively, of total end-use consumption.

In 2000–2016, power generation was particularly buoyant, with quantities used almost doubling by +92 per cent, from 5,206 billion cubic feet in 2000 to almost 9,984 billion cubic feet in 2016. This can be largely explained by the adoption of regulations promoting the use of lower carbon footprint energies in the United States, combined with increasing quantities of low-cost natural gas being made available as a result of domestic shale gas developments. As at 22 October 2017, EIA indicates that natural gas accounted for nearly 34 per cent of all electricity generation at utility-scale facilities in the United States in 2016.²⁵

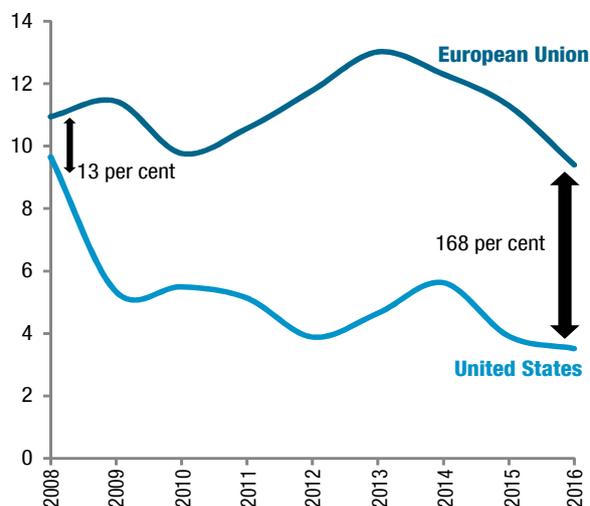
With regard to industrial uses of natural gas, the trend has been somewhat different, with consumption declining in 2000–2009 by -24 per cent, from 8,142 billion cubic feet to 6,167 billion cubic feet, mainly as a result of large upward price swings. This period was followed by significant consumption growth, by +25 per cent, in 2009–2016, up to 7,722 billion cubic feet in 2016, as a result of large quantities of low-cost natural gas becoming available from shale gas developments in the country.

²⁴ EIA (accessed 22 October 2017). [United States] Natural gas consumption by end use. https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

²⁵ EIA (accessed 22 October 2017). What is [United States] electricity generation by energy source? <https://www.eia.gov/tools/faqs/faq.php?id=427&t=3>.

With regard to industrial applications, natural gas is essentially used for power and heating purposes, as well as for feedstock. The decline of natural gas prices in the United States starting in 2008 reflected the prices paid for industrial use (figure 16) and, to a lesser extent, household use. The situation has differed in Europe, leading to large price differentials between the two regions. For example, the premium paid on natural gas by industry in Europe compared with prices paid in the United States jumped from 13 per cent in 2008 to 168 per cent in 2016. The decline of natural gas prices paid by the industrial sector in the United States compared with prices paid in other regions has likely had favourable impacts on the competitiveness of United States energy-intensive industries (e.g. petrochemicals, steel and fertilizers) through the contraction of prices paid both for inputs (e.g. ethane) and for energy burned. For example, the United States petrochemical industry faced significant difficulties in 2007, yet the large quantities of low-cost natural gas and natural gas liquids made available from shale oil and gas developments, among others, had a downward effect on ethane prices, a core raw material in the production of plastics (e.g. ethylene and propylene), and positively impacted this industry in the United States. At the same time, the large use of naphtha – a derivative of petroleum – in Asia and Europe, contributed to further widening the spread in competitiveness between the United States on the one hand and industries in Asia and Europe on the other hand. These opposing developments led to a wave of investments in the United States. The American Chemistry Council (2017:1) states as follows: “310 projects cumulatively valued at \$185 billion in capital investment have been announced... Much of the investment is geared toward export markets for chemistry and plastics products... Fully 62 per cent of the announced investment is by firms based outside the United States.”

Figure 16 Natural gas industrial prices in the European Union and the United States, 2008–2016 (dollars per 1,000 cubic feet)



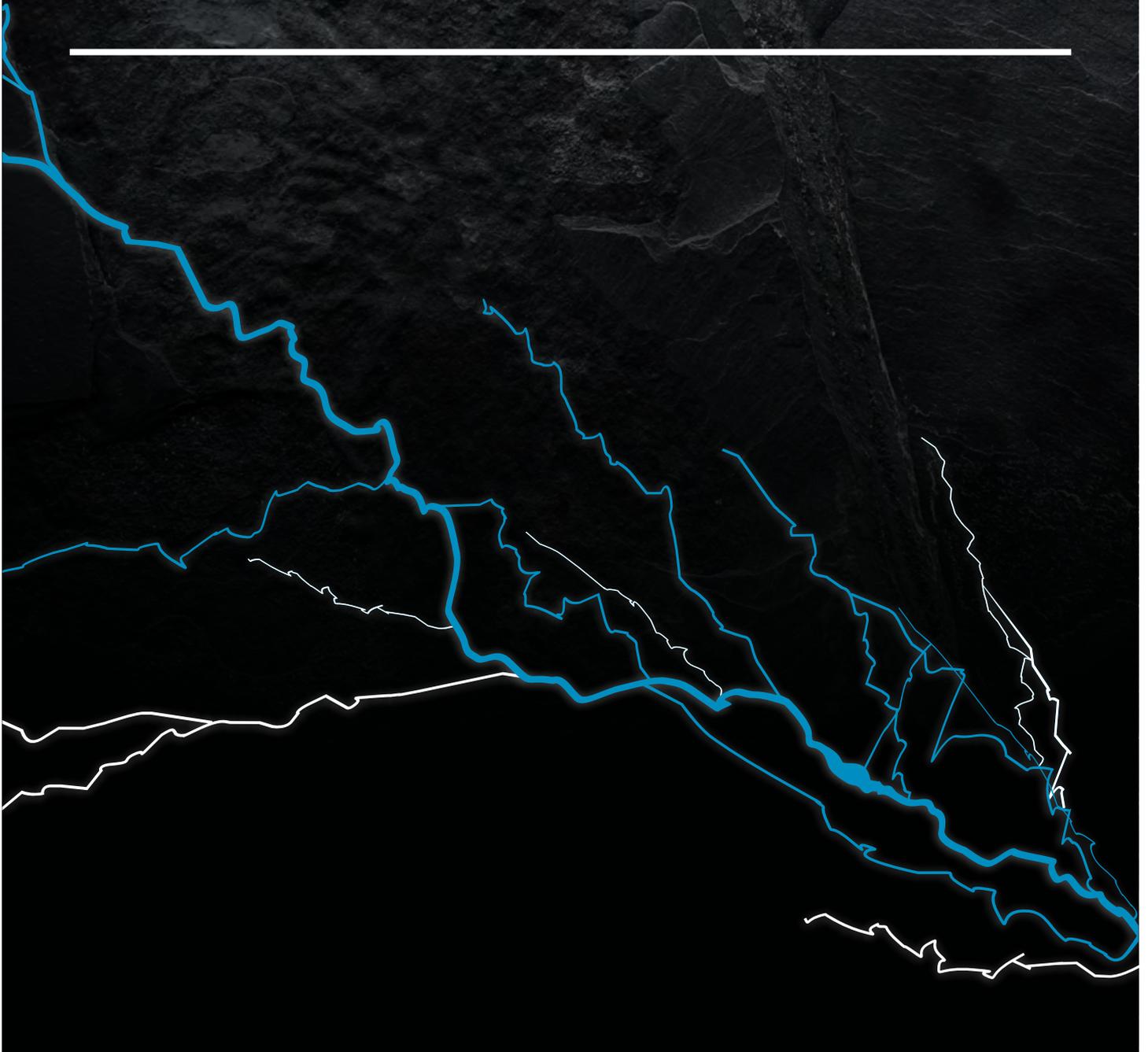
Source: UNCTAD secretariat based on EIA, 2016d.

Note: Data in this diagram are averages.

With regard to the effect of the shale gas sector on employment and macroeconomic variables, there is not sufficient hindsight to make a valid assessment. The difficulties associated with information coherence and objectivity faced during the preparation of this report have been significant in this regard. However, the United States Department of Energy (2017:350) indicated as follows in its 2017 quadrennial energy review report: “the oil and natural gas industry experienced a large net increase in jobs over the last several years, adding 80,000 jobs from 2004 to 2014, [However] employment in the natural gas extraction industry is regionally and temporally volatile; 28,000 jobs were lost between January 2015 and August 2016.”

CHAPTER IV

SHALE GAS DEVELOPMENTS OUTSIDE THE UNITED STATES



With hundreds of thousands of wells drilled since the mid-2000s, the United States has accumulated experience with regard to mastering the exploration and production of shale gas. It also has a wealth of knowledge on the potential impacts this extractive activity may have on local populations, the environment and the economy. Other countries holding shale gas resources may wish to emulate the United States model, taking into consideration only the positive aspects of the experience. The development of shale gas activities may be viewed as a way to reduce the natural gas import bill and increase energy independence. It may also be considered a vehicle for direct and indirect job creation through the expansion of support service sectors, as well as the revitalization of some stagnant sectors. Some industrial sectors have benefited from competitiveness gains owing to lower energy and input costs in the United States. Moreover, the increasing quantities of natural gas made available through shale gas deposits have also contributed to curbing coal consumption in the United States, especially in the power generation sector. However, it should be noted that the development of this industry has also led to some concerns that have resulted in shale gas exploration and production being banned, especially in high-populated areas (e.g. New York State).

Except in Canada and the United States, as well as Argentina and China to some extent, the development of shale gas resources in other countries remains marginal, and activities are mainly at the exploratory stage. From the experiences of most countries besides Canada and the United States, it may be noted that none of the models pursued in Canada and the United States are directly replicable, owing to, for example, differences in geological conditions, the availability of water resources and the development status of local infrastructure, as well as a lack of knowledge and specific skills and machinery. The learning curve is long and costly. The acceptance of extractive industries, and shale gas extraction in particular, by local populations, known as “social licence to operate” is pivotal.

Various examples from Canada, Argentina and China, the three main countries after the United States currently producing shale gas, are reviewed in this chapter, followed by an overview of the situation in Europe, where countries have adopted different policies – sometimes opposing policies – towards shale gas. For example, Bulgaria and France have

imposed a ban on the use of hydraulic fracturing in their territories, while others, such as Poland and the United Kingdom, with different levels of experience in hydrocarbon production and potential shale gas resources, have experienced different outcomes with regard to the development of their shale gas sectors. Finally, the situation of shale gas in Africa is reviewed from the perspectives of Algeria and South Africa, as these countries are considered as holding the main resources on the continent.²⁶

1. CANADA: A COMMERCIAL-LEVEL SHALE GAS PRODUCER

With 13 per cent and 1,496.5 billion cubic feet of the world’s shale gas production in 2015, Canada ranked second after the United States with regard to production. Apart from the United States, Canada is the only country that has achieved commercial-level shale gas production since 2015.

With 76.68 TCF of world natural gas reserves (about 1.2 per cent of the world total), Canada ranked fifteenth among natural gas holding countries in 2016. Known natural gas reserves dropped from about 88 TCF in 1980 to 56.5 TCF in 2005, before rising, by +36 per cent between in 2005–2016, fuelled by the development of unconventional natural gas resources in the country. However, as unconventional natural gas reserves have been simultaneously developing in other countries, and in the United States in particular, the share of Canada in world natural gas reserves has remained relatively stable since 2005, at around 1 per cent.

Canada has a long history of producing hydrocarbons. It was the fifth largest natural gas producing country in 2015, with about 14.4 billion cubic feet per day, and 4.2 per cent of world natural gas production. With 89.9 million tons of oil equivalent, Canada ranked eighth among natural gas consuming countries in 2016, with less than 3 per cent of the world total. The share of fossil fuels in the national energy mix is relatively low (63.5 per cent), compared with most developed countries, and only a handful of countries displayed a lower share than Canada in 2016.²⁷ Natural gas accounted for 27.3 per cent of the mix in 2016.

²⁶ With the exception of the United States and Canada, to some extent, data on resources are preliminary estimates. Moreover, as at 2017, the review of shale gas TRR in Africa is limited, especially with regard to sub-Saharan Africa.

²⁷ Namely Brazil, Finland, France, New Zealand, Norway, Sweden and Switzerland.

Canada produces unconventional natural gas from both shale and tight gas formations, yet the shale gas accounted for a relatively marginal share of natural gas production in 2014 (5 per cent), compared with tight gas (47 per cent). In Canada, the main shale gas basins are located in Alberta, mostly within the Montney²⁸ and Duvernay formations, and in British Columbia, including the Horn River, Liard and Montney Basins. Together, Alberta and British Columbia accounted for about 94 per cent of total shale gas TRR in Canada.

The development of unconventional natural gas resources in Canada has contributed to limiting the depletion of its natural gas reserves. However, its domestic marketable natural gas production continued to decline in 2007–2017.²⁹ Moreover, the large development of shale gas production in the United States in 2007–2016 led to a progressive contraction in United States natural gas imports, notably from Canada. Exports from Canada to the United States dropped by 23 per cent over this period.³⁰ In order to compensate for this decline, Canada has increasingly turned to LNG exports, to the point where more than 37 per cent of additional world liquefaction capacity at the end of January 2017 was to be developed in the country, mainly in British Columbia.

The National Energy Board of Canada anticipates that by 2040, both shale and tight gas production will grow substantially. Natural gas production in Canada is expected to mainly come from both of these resources, with an overwhelming share for tight natural gas, which may contribute 76 per cent of total natural gas production in 2040. Shale gas production in the Montney formation should increase more than threefold from 3 billion cubic feet per day in 2014 to 9.6 billion cubic feet per day in 2040, while shale gas production in the Duvernay formation is expected to reach 417 million cubic feet per day in 2040, compared with 65 million cubic feet per day in 2014. Despite these developments, the share of shale gas in total natural gas production in Canada is expected to remain the same as it is at present (table 10).

²⁸ The Montney Basin straddles both Alberta and British Columbia.

²⁹ National Energy Board of Canada (accessed 23 October 2017). Marketable natural gas production in Canada. <https://www.neb-one.gc.ca/nrg/ststc/ntrlg/st/mrktblntrlgspdrctn-eng.html>.

³⁰ BP (various editions). Statistical Review of World Energy. <https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/downloads.html>.

Table 10 Canada: Potential opportunities and challenges in shale gas development

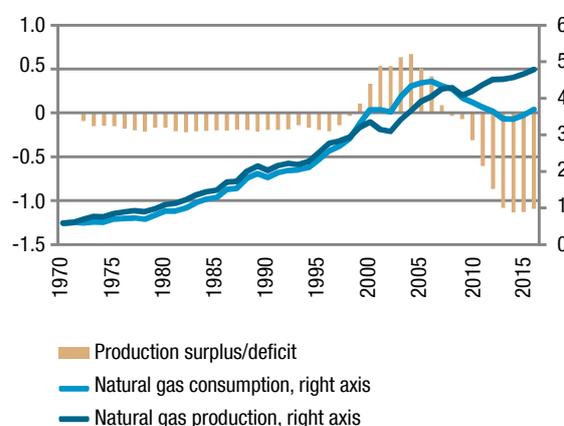
Opportunities	Challenges
- Low population density	- Decline of pipeline exports, especially to the United States
- Relative acceptability of unconventional natural gas operations by local populations	- Impact on commitments made under international agreements with regard to GHG emissions, global warming and climate change
- Potential development of LNG export infrastructure	

Source: UNCTAD secretariat.

2. ARGENTINA: EARLY PRODUCTION

With 44.6 million tons of oil equivalent consumed in 2016, natural gas is a key component of the energy mix in Argentina, covering 50 per cent of energy needs. Natural gas is mainly used for power generation (33 per cent), industrial purposes (28 per cent), household consumption (24 per cent) and transportation (7 per cent). Due to rapid growth in the production of natural gas compared with consumption, Argentina recorded a production surplus in 1999–2007. However, since then, the natural gas balance has progressively declined mainly as a result of policy decisions taken since 2003 that have largely contributed to a fall in production (figure 17). Among these policies, Mares (2013) notes the setting of price caps in the domestic market, the rise in taxes and the introduction of quotas, which contributed to a drop in exploration and production. The production deficit has been particularly significant since 2010, when it jumped

Figure 17 Argentina: Natural gas production, consumption and balance, 1970–2016
(billions cubic feet per day)



Source: UNCTAD secretariat, based on BP, 2017b.

by a factor of 4.5 compared with 2009, reaching 113.8 billion cubic feet. It continued to widen, with a record production deficit of 413 billion cubic feet in 2014 (about 25 per cent of natural gas consumption in Argentina). The situation appears to have stabilized since then. However, the large production deficits recorded since 2008 led to significant imports of natural gas. According to the United Nations International Trade Statistics Database, natural gas imports cost about \$24.4 billion over the five-year period from 2010 to 2015 and imposed an enormous burden on the national economy.

The natural gas industry in Argentina dates to the 1950s. According to EIA, Argentina holds the second-most world shale gas resources, after China, with about one tenth of the world total and an almost 30 per cent higher TRR rate than the United States (figure 3).

Shale gas resources in Argentina are mainly located in the Neuquen Basin in central-west Argentina, which may hold about three quarters of total domestic shale gas resources, specifically in the Vaca Muerta and Los Molles shale formations. Since 2009, most attention has been focused on these two areas. Other basins

may also hold some resources, such as Austral-Magallanes (16 per cent), San Jorge (11 per cent) and Chaco-Paranaense (0.3 per cent). However, few activities have taken place in these areas to date. According to the Argentinian Oil and Gas Company Yacimientos Petrolíferos Fiscales SA, a significant advantage of the Vaca Muerta formation hinges on its remoteness from urban centres. However, this may also pose a significant obstacle to the transportation of necessary machinery on site, as well as of the significant volumes of water needed to perform hydraulic fracturing operations, among others. In addition, the development of support services for shale gas activities is relatively new in Argentina, which implies that drilling equipment is imported from the United States; this may prove difficult and costly. Furthermore, the development of the sector has stalled for several years due to a business environment considered non-conducive by foreign investors. Nevertheless, the situation seems to be evolving, as the Government of Argentina has introduced several financial incentives to stimulate investment. For example, the gas plan programme has been extended to 2021, providing a minimum wellhead price for gas companies. Under this system, producers are paid

Table 11 Argentina: Potential opportunities and challenges in shale gas development

	Opportunities	Challenges
Geology	Usually compared with that in Eagle Ford in the United States. However, total organic carbon is higher in Vaca Muerta than in Eagle Ford, and formation is thicker	Low productivity rates and high production costs (1.5 times higher than average cost in Eagle Ford) Limited number of drilling rigs and other specific machinery
Political support	Political support aimed at reducing the natural gas import bill and dependency, as well as counterbalancing depletion of conventional natural gas reserves	Unexpected impacts of price changes after 2022. Longer-term enabling policies (e.g. investments) likely needed
Population	Low population density in potential producing areas, and population used to oil and gas operations	Financial benefits associated with extraction accrue to the State. Concerns over use of chemicals for hydraulic fracturing can become an issue
Background	Traditional conventional oil and gas producing country, with big players. The latter have increased their presence in shale gas activities	Shale gas specific services largely non-existent. Sector mainly consists of limited number of large-scale companies with significant bargaining power. Small and medium-sized enterprises virtually non-existent
Infrastructure	Good infrastructure, including roads, for current needs	Some infrastructure improvements needed, especially after 2020, to bring additional natural gas to the market (see Oxford Institute for Energy Studies, 2016)
Water resources	Large surface water resources available in Neuquén Province	Variable distances between water resources and producing areas generate variable transportation costs
Investor trust	Rating changed from B3 stable to positive, showing increasing investor confidence in 2017	Moody's rating remains B3, highly speculative
Labour conditions	Labour regulations revised in 2017, creating more flexibility	High labour costs compared with some other potential producing countries (see Castro Sammartino, 2016). Insufficient skilled labour, which requires training to meet specific requirements of shale gas industry. Accenture (2014b) underlines the specific need for trained engineers

Source: UNCTAD secretariat.

\$7.5 per MMBtu through 2018, after which the price gradually decreases to \$6 per MMBtu in 2021. Finally, free market conditions are expected to be applied to natural gas prices starting in 2022. In addition, a new labour-related legal framework for shale gas activities was implemented in 2017. As a result of these initiatives, several large investments were announced in 2017, mainly in the Vaca Muerta region. For example, Yacimientos Petrolíferos Fiscales SA, Total SA, Wintershall Energía SA and Pan American Energy LLC indicated on 18 July 2017 that they were ready to invest \$1.15 billion in Vaca Muerta. In March 2017, Tecpetrol, a company in Argentina, announced its decision to invest \$2.3 billion by 2019 in the Fortín de Piedra area in Vaca Muerta.

In Argentina, with one third of total shale oil and gas wells drilled in 2015, the total reached 673, with total shale gas production of 64.6 billion cubic feet at the end of 2015 (about 5 per cent of total natural gas production in Argentina in 2015). As in Canada, unconventional natural gas production in Argentina mainly comes from tight gas, at 170.9 billion cubic feet in 2015.

Natural gas production from tight sands and shales are expected to continue to grow in the country. They may account for about two thirds of total domestic natural gas production by 2030 and three quarters by 2040. This may help to limit natural gas imports in the coming years, and Argentina may begin to export a surplus if natural gas production exceeds national demand.

3. CHINA: THE LARGEST POTENTIAL WORLD SHALE GAS SOURCE

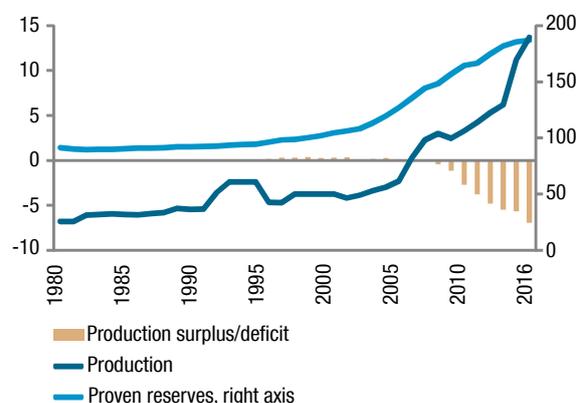
Natural gas proven reserves in China have remained below 50 TCF, except in 1993–1996, with an average of 41.7 TCF in 1980–2003. Since 2003, however natural gas proven reserves have started to build up, rapidly exceeding 60 TCF in 2006, then 100 TCF in 2009, nearing 170 TCF in 2015 and finally reaching 190 TCF in 2016.

Natural gas production in China grew rapidly in 2004–2011 with a compound annual growth rate of +12.5 per cent. In 2014–2015, BP (2017b) ranked China as the sixth natural gas producing country, with an average daily production of 13.3 billion cubic feet (about 4 per cent of world production), directly behind Canada.

Despite the expansion of natural gas production in the country, the even faster increase in natural gas

Figure 18 China: Natural gas production, production surplus/deficit and proven reserves, 1980–2016

(Production, production surplus/deficit: billion cubic feet per day and proven reserves: trillion cubic metres)

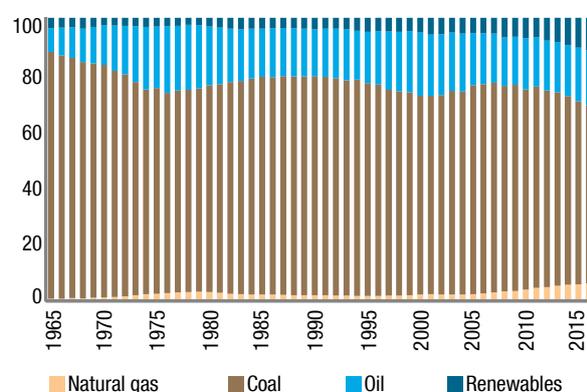


Source: UNCTAD secretariat, based on BP, 2017b.

consumption, especially since the mid-2000s with a compound annual growth rate of +16.2 per cent in 2004–2011, led to a production deficit in 2007 (figure 18). China therefore increased imports, mainly from Turkmenistan (by pipeline), Australia (by LNG) and Qatar (by LNG). These countries respectively accounted for 41, 22 and 9 per cent of total natural gas imports in 2016, and total natural gas imports represented more than one third of total natural gas consumption in China in 2016. This increasing need for imports led China to become the second largest natural gas importing country in Asia in 2016, with about 25 per cent of regional imports, following Japan (35 per cent), as well as the fourth world importing country.

With 189.3 million tons of oil equivalent, natural gas accounted for a relatively low share (7.1 per cent) of the energy mix in China in 2016. However, this represented a strong rise compared with the 2.4 per cent recorded in 2000, with 22.8 million tons of oil equivalent. The change in energy consumption has been particularly significant since 2006. While coal continues to remain the dominant source of energy in China (figure 19), natural gas and renewables, including hydroelectricity, have played an increasing role since the mid-2000s. In 2015, natural gas was predominantly used in industry (50 per cent), and consumption was also significant in residential and commercial sectors (18.3 per cent), power generation (14.5 per cent) and transportation (11.3 per cent).

Figure 19 China: Energy mix, 1965-2016
(percentage)



Source: UNCTAD secretariat, based on BP, 2017b.

Owing to the significant growth in natural gas imports and in order to diversify its energy sources, essentially from coal, the major contributor to air pollution in the country, China decided to invest in the development of domestic shale gas resources. According to EIA (2015c), China holds the most important stock of shale gas resources in the world. With 1,115.2 TCF, about 15 per cent of the world total (figure 3), shale gas resources in China are higher than total resources in the United States and Australia combined.

Of seven basins, namely Jiangnan, Junggar, Sichuan, Songliao, Subei, Tarim and the Yantze platform, two areas may hold about three quarters of technically recoverable shale gas resources, Sichuan is in the lead, with 56 per cent – especially in the southwest part of the basin – followed by Tarim, with 20 per cent. The

first shale gas well was drilled in 2010. Following a slow start, shale gas production rapidly intensified, reaching 0.7 billion cubic feet per day as of 2016, about 5.4 per cent of total domestic natural gas production.

In 2016, shale gas production was essentially limited to the Sichuan region, with some exploratory steps taken in other provinces. As in conventional oil and gas operations, shale gas exploitation is almost exclusively concentrated in national oil and gas companies, namely PetroChina, Sinopec and China National Offshore Oil Corporation. The attribution of exploration blocks is conferred through public tenders organized by the Ministry of Land and Resources of China. Foreign companies are not allowed to directly compete for mineral rights, yet are highly encouraged to create joint ventures with companies in China to develop domestic shale gas deposits.

Demand for natural gas in China is expected to continue to grow as a result of increasing population, economic development and climate change mitigation strategies leading to the gradual replacement of coal by cleaner sources of energy (e.g. electricity and natural gas) and the reduction of air pollution and CO₂ emissions in particular. The thirteenth five-year plan (2016–2020) encourages the gradual replacement of coal with natural gas in power generation, for example, as well as in factory boilers and for household heating purposes. According to the plan, natural gas is expected to reach one tenth of the energy mix in China by 2020, and this share is expected to increase to 15 per cent by 2030. In order to achieve this goal, the long-term objective of the Government is to support domestic shale gas

Table 12 China: Potential opportunities and challenges in shale gas development

	Opportunities	Challenges
Geology	<p>Large investments made in prospection. About \$1.3 billion invested in shale gas prospection in 2016</p> <p>Large deposits and highest world TRR, with 1,115.2 TCF in 2015</p> <p>Drilling and completion costs decreasing rapidly. (see Mistré et al., 2017)</p>	<p>Lack of knowledge of local geology due to low level of shale gas exploration and development</p> <p>Recoverable resources estimates largely vary from one source to another</p> <p>Deposits often located in remote areas. Structure of formations is considered complex (e.g. presence of some active tectonic faults). Local seismicity should be particularly monitored, especially in areas where seismicity is already an issue (e.g. Sichuan)</p> <p>Lower total organic carbon than in most shale gas deposits in Argentina and the United States. High levels of hydrogen sulfide (H₂S) in some areas. Shale gas formations located deeper than most deposits in the United States. (Dong et al. (2016:7) state that “Shale gas that occurred deeper than 3,500m accounts for 65 per cent in China”). This would involve developing specific equipment and adapting exploration and production techniques</p> <p>High production costs. Average drilling and completion costs are 80–100 per cent higher in Sichuan basin than in the United States. (Average computed using various sources of information)</p>

Table 12 (cont.) China: Potential opportunities and challenges in shale gas development

	Opportunities	Challenges
Political support	<p>Priority to shale gas development given in successive five-year plans</p> <p>Political incentives (e.g. subsidies): 2012–2015: ¥0.4 per cubic metre 2016–2018: ¥0.3 per cubic metre 2019–2020: ¥0.2 per cubic metre</p>	<p>Most of pipeline network owned and operated by one company (China National Petroleum Corporation) → Low levels of competition</p>
Population	<p>Scattered population in some potential producing areas</p> <p>Increasing concerns about environmental issues and pollution by coal may be an asset for development of national shale gas resources</p>	<p>High population density in some areas (e.g. Sichuan)</p> <p>Unexpected reaction from local populations with regard to shale gas developments (e.g. demonstrations)</p>
Background	<p>Some conventional and unconventional (e.g. coal bed methane) hydrocarbon production activities already in place</p> <p>Joint ventures with foreign companies and acquisition of shale gas assets in the United States (China National Offshore Oil Corporation bought one third of Chesapeake Energy, a pioneer in the sector in 2010) can give China access to specific technologies and know-how</p> <p>The thirteenth five-year plan highlights the “need to reduce government intervention in the price formation mechanism” (Ratner et al., 2016:15)</p>	<p>Mineral rights largely owned by national oil and gas companies. When such rights overlap with potential unconventional deposits, priority in exploring deposits is given to national companies. According to Accenture (2014a:8), “approximately 80 per cent of the best acreage already belongs to four national oil companies: Sinopec, China National Petroleum Corporation, China National Offshore Oil Corporation and Yan Chang Petroleum”</p> <p>Specific skills and know-how need to be developed to deal with local, sometimes complex geology</p> <p>Multidimensional and complicated price discovery mechanism</p>
Infrastructure	<p>Investments made with regard to pipeline development. Pipeline network expected to reach 123,000 km by 2025</p> <p>National Oil Companies among largest companies in the world (strong capital base)</p> <p>LNG import capacity expected to reach 100 million tons by 2025, compared with 43.8 million tons in 2015</p>	<p>Shale gas formations in Sichuan mostly located in remote mountainous areas, with low levels of access and weak infrastructure</p> <p>Lack of support services dedicated to shale gas sector</p> <p>Lack of gas storage facilities; “1.8 per cent of total consumption versus 12 per cent world average” (Accenture, 2014a:8)</p>
Water resources	<p>Water availability differs between areas</p>	<p>Water supply may be critical in some regions that already experience water scarcity or where water needs for hydraulic fracturing may compete with other requirements (e.g. agriculture and drinking water). In such instances, use of recycled water should be encouraged</p> <p>Issue of flowback water management should be properly monitored and supervised</p> <p>Local authorities should monitor composition of fluids used for hydraulic fracturing. A clear and detailed reporting scheme is a crucial asset (e.g. FracFocus)</p>
Labour conditions	<p>Large labour force</p>	<p>Specific competencies need to be developed</p>

Source: UNCTAD secretariat.

production, to reach 30 billion cubic metres in 2020 and 80 billion–100 billion cubic metres by 2030. However, it is unlikely that such developments can compensate for the growth of domestic demand, and China is expected to continue to rely on imports in the future. According to BP (2017a), natural gas imports may account for 40 per cent of total consumption in China by 2035. China National Petroleum Corporation and Gazprom (Russian Federation) signed a 30-year purchase and sale agreement on 21 May 2014, entailing the supply of 1.34 TCF per year of natural gas by pipeline from the Russian Federation. According to the supplementary agreement signed on 4 July 2017, gas delivery is expected to start in December 2019.

4. EUROPE: ONE REGION, DIVERSE EXPERIENCES

With 471 TCF of TRR, Europe may hold more than 6 per cent of world TRR as determined by EIA. On 22 January 2014, the European Commission enacted

a set of minimum principles with regard to shale gas. However, as energy policy remains the responsibility of each member State, the situation with regard to shale gas extraction must be analysed from a country-level perspective.

According to most experts, it is highly unlikely that Europe will experience the same level of shale gas development as in the United States. This is the result of geological conditions in the region, which appear to be less favourable than in the United States; higher population density compared with the United States; mineral rights that give subsoil rights to States instead of landowners, as in the United States; and stricter environmental regulations. Moreover, as most countries with shale gas resources also have limited experience in hydrocarbon exploration, support services as well as skills dedicated specifically to shale gas are not largely available. Furthermore, most potential reservoirs in Europe are located in highly populated areas that, in addition, are not accustomed to oil and gas activities.

Table 13 Indicators related to the natural gas situation and potential in selected countries in Europe, as at 31 October 2017

	France	Poland	United Kingdom
Natural gas reserves (TCF), 2016	–	3.2	7.3
Shale gas resources (TCF), 2013	136.7	145.8	25.8
Natural gas production (billions of cubic feet per day), 2016	–	0.4	4.0
Natural gas consumption (billions of cubic feet per day), 2016	4.1	1.7	7.4
Natural gas imports (billion cubic feet), 2016	1 483.2	445.0	1 575.0
Natural gas imports as share of natural gas consumption (percentage)	99.1	71.7	58.3
Pipeline imports as share of total natural gas imports (percentage)	77.0	100.0	76.5
Main trading partners	Norway (51.4) Russian Federation (32.5) Netherlands (14.2) Other (1.9)	Russian Federation (81.0) Other (19.0)	Norway (84.2) Other (15.8)
LNG imports as share of total natural gas imports (percentage)	23.0	–	23.5
Main trading partners	Algeria (63.9) Nigeria (19.6) Other (16.5)	–	Qatar (91.4) Other (8.6)
Natural gas in energy mix (percentage)	16	16	37
Situation with regard to shale gas	Ban on hydraulic fracturing	High level of resources but first test proved lower than expected	Low level of resources and growing protests from population. But political authorities supportive of shale gas exploration and development

Source: UNCTAD secretariat based on BP (2017b) and EIA.

In 2016, natural gas accounted for only 16 per cent of primary energy consumption in France, compared with 37 per cent in the United Kingdom, for example. France exclusively relied on natural gas imports to meet its 4.1 billion cubic feet per day rate of consumption in 2016, mainly used in transport. According to EIA (2015d), France may hold about 30 per cent of total shale gas resources in Europe, mainly located in the Paris (95 per cent) and South-East (5 per cent) Basins. Almost all of the resources in the Paris Basin are located at an average depth of 10,000–14,000 feet (3,050–4,270 m), that is, deeper than the formations of Los Molles and Vaca Muerta in the Neuquen Basin in Argentina, yet TOC ranges from 2 to 15 per cent, with an average of 9 per cent, considered high. As a matter of comparison, average TOC in Los Molles and Vaca Muerta in Argentina are estimated at 2–5 per cent. However, since mid-July 2011, shale gas exploration activities have been suspended in France, owing to the ban on hydraulic fracturing and the abrogation of all permits, a decision largely supported by local populations. Moreover, the concerns of the population were strengthened by the proximity of potential exploration and production sites to highly populated, urban areas. However, oil and gas companies in France have continued to explore shale gas resources and develop expertise in other potentially key markets. For example, Total has invested in operations in several shale plays in the United States (e.g. Barnett and Utica).

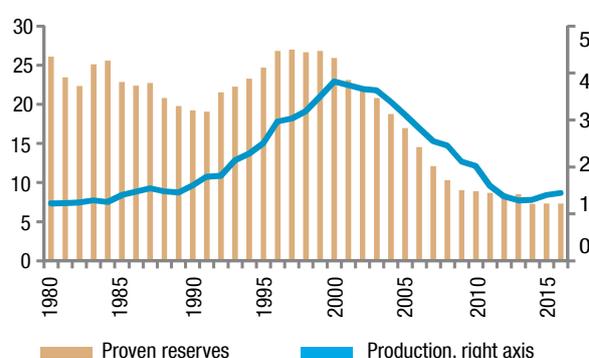
Poland relied on natural gas to meet 17 per cent of primary energy consumption in 2016. At 72 per cent, the dependency of Poland on natural gas imports is lower than that of France, yet imports are highly geographically concentrated, with the Russian Federation accounting for more than 80 per cent of total imports in 2016. The need to diversify natural gas imports, combined with high levels of estimated shale gas resources in the country and a high level of reliance on coal for power generation have prompted Poland to further investigate national shale gas potential.

Shale gas resources appear to be mainly located in the Baltic Basin (71 per cent of TRR) and the Fore-Sudetic Monocline Basin (about 15 per cent). Both potential formations are located at similar depths of 10,000–12,500 feet (3,050–3,800 m). Shale gas exploration in Poland began with high resource estimates, a significant infrastructure already in place, general acceptance by the local population and political support. However, estimates have been drastically

revised. For example, between its 2011 edition and its 2013 edition, EIA cut its estimates for the Lubin Basin in western Poland by about 80 per cent. Furthermore, due to lower than expected preliminary test results owing to the complex local geology, unfavourable regulatory framework and declining commodity prices, among others, most foreign companies decided to stop exploration activities in the country. In 2012–2017, shale gas exploration drilling fell from 24 to 0, and in June 2017, the Polish Geological Institute indicated that 20 concessions were active in Poland, compared with 115 in 2012.

The United Kingdom is a traditional hydrocarbon producing country. It reached its record natural gas production in 2000, with 3.82 TCF and 4.5 per cent of world production. However, the gradual depletion of its natural gas reserves, mainly in the North Sea in 1980–2014, by -72 per cent, led natural gas production to decline sharply to a historical low of 1.29 TCF in 2013, its lowest level since 1984 (figure 20). The sharp contraction in natural gas reserves and production in the United Kingdom, combined with increasing demand, which rose by a factor of 1.8 in two decades in 1990–2010, resulted in an overreliance on imports. From 2.2 billion cubic metres in 2000 (0.08 TCF), natural gas imports rose to 47.9 billion cubic metres in 2016 (1.69 TCF), peaking at almost 50 billion cubic metres in 2010–2013 (1.77 TCF). The situation with regard to both reserves and production seems to have reversed since 2013–2014, with natural gas reserves stabilizing at around 7.3 TCF in 2014–2016 and production rising by 12 per cent, to 1.44 TCF in 2016 (1.2 per cent of world production). In 2016, natural gas imports contributed to about 58 per cent of natural

Figure 20 United Kingdom: natural gas proven reserves and production, 1980–2016
(trillion cubic feet)



Source: UNCTAD secretariat, based on BP, 2017b.

gas consumption in the United Kingdom, a somewhat limited share compared with France and Poland. In 2016, the main trading partners of the United Kingdom with regard to natural gas imports were Norway (by pipeline) and Qatar (by LNG), accounting for 84.2 and 91.4 per cent, respectively, of total pipeline and LNG imports.

According to EIA, the United Kingdom holds 25.8 TCF of TRR of shale gas, about 5.5 per cent of the resources in the European Union and about 0.3 per cent of the world total. Shale gas potential resources in the United Kingdom are almost exclusively concentrated in the north (98 per cent), at a depth ranging from 5,000–13,000 feet (1,520–3,960 m), with an average of 3 per cent TOC. According to EIA (2015g: 11), the geology in the United Kingdom is considerably more complex than in the United States, “while drilling and completion costs for shale wells are substantially higher”. Geological structures appear to be carved, with numerous faults. As at 2017, only the Bowland Basin appears to have experienced activity since 2010.

The first well, known as Preese Hall–1, was drilled near Blackpool by Cuadrilla Resources Ltd. in 2010–2011. Operations were suspended as a result of the occurrence of earth tremors on 1 April and 27 May 2011, with the largest recording 2.3 on the Richter scale. A moratorium was immediately put in place extending from May 2011 to the end of 2012, and investigations were commissioned on the causes of the events. Conclusions highlighted the responsibility of hydraulic fracturing activities in both, but with no related impacts on nearby aquifers or structural damage. A set of measures related to groundwater monitoring, well integrity and seismicity were defined to limit the occurrence of such events in future and to mitigate potential effects. With regard to the current status of shale gas activities in the United Kingdom, Delabarre et al. (2017:4) states as follows: “shale gas drilling in the United Kingdom is still at an exploratory phase – no commercial operations have yet been authorised and a lengthy application process must be completed before commercial drilling could start. However, the recent approval of two planning decisions in Lancashire and North Yorkshire suggest that the United Kingdom is getting closer to commercial shale gas exploitation.” The United Kingdom has strong infrastructure, a good experience in conventional oil and gas operations, a skilled labour force and national political authorities supportive of shale gas exploration

and development (e.g. an enabling fiscal regime and a benefits package for local communities). However, high population density in some potential areas and anti-hydraulic fracturing campaigns, among others, combined with low levels of knowledge of the geology of the various shale plays, may be major impediments to further developments. According to estimates prepared by the Oil and Gas Authority of the United Kingdom, the production of natural gas is expected to continue to decline up to 2022 (-13 per cent) and 2035 (-60 per cent), compared with the level in 2016.³¹

5. AFRICA: SHALE GAS POTENTIAL, MAINLY IN THE NORTH AND SOUTH

EIA notes that two countries in Africa as potentially hold large shale gas resources, namely Algeria, with 707 TCF (9.3 per cent of world total TRR), and South Africa, with 390 TCF (5.1 per cent).

Algeria is a member State of the Organization of Petroleum Exporting Countries (OPEC) and is traditionally a large conventional natural gas producer in Africa. In 2016, Algeria accounted for about 30 per cent of natural gas reserves on the continent, 43 per cent of production and 56 per cent of exports. Natural gas exports from Algeria, which represent almost 60 per cent of national production, are mostly to the European Union (more than 80 per cent of LNG and pipeline exports). The energy mix in Algeria is particularly reliant on fossil fuels, crude oil and natural gas, accounting for 99.6 per cent of primary energy in 2016.

Owing to the gradual depletion of ageing conventional deposits, Algeria has been increasing its interest in unconventional hydrocarbon resources, which are largely distributed in three main shale basins, namely Ghadames, Timimoun and Reggane, which hold 40, 22 and 17 per cent, respectively, of total shale gas resources in Algeria. The first exploratory drilling test for shale gas was approved in 2014. However, it was suspended following large-scale protests from local populations. In October 2017, authorities considered the resuming unconventional operations by Sonatrach. However, numerous barriers remain, such as the lack of adequate infrastructure, specific

³¹ Oil and Gas Authority of the United Kingdom (accessed 2 November 2017). [United Kingdom] oil and gas production (and demand) projections. <https://www.ogauthority.co.uk/data-centre/data-downloads-and-publications/production-projections/>.

knowledge and skills, support services and equipment and machinery. The opposition of local populations to shale gas projects and security issues in the regions where the deposits are located may also continue to be substantial obstacles.

In South Africa, the production of fossil fuels is almost exclusively limited to coal (95 per cent of production in Africa) and some marginal production of natural gas. As a result, the energy mix mainly relies on domestic coal production (70 per cent in 2016) as well as on some imports of oil and natural gas (mainly from Mozambique for the latter).

According to EIA (2015f), shale gas resources in South Africa could account for more than 5 per cent of world TRR. They are essentially concentrated within the semi-arid Karoo Basin, with more than half in the Whitehill formation, and the rest almost equally split between the Prince Albert and Collingham formations. Some foreign companies have taken some steps to explore shale gas resources in South Africa. However, a moratorium put activities on hold between April 2011

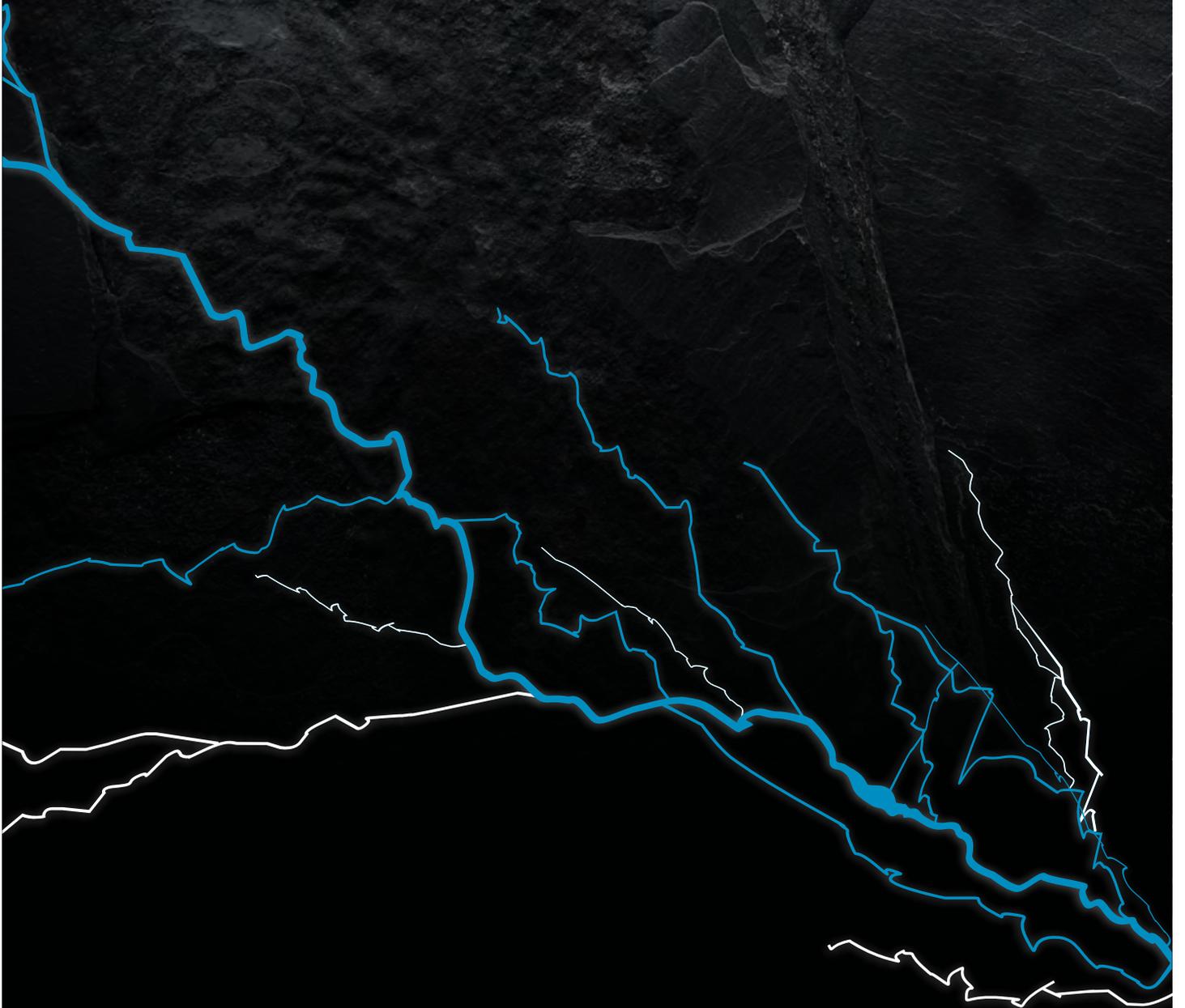
and September 2012, owing to questions of potential water shortages and concern over impacts on the environment from hydraulic fracturing. Since 2012, authorities have continuously tried to resume the exploration and assessment of shale gas resources. Natural gas is considered a potential option to meet growing domestic demand for energy and to reduce reliance on coal. However, little progress has been made owing to strong opposition from the population. Shale gas exploration may restart in 2019 at the earliest.

With regard to the necessary conditions for the development of the shale gas sector, the lack of infrastructure, both with regard to roads and distribution networks, and support services and dedicated local expertise, may be considered key among the most important constraints faced by South Africa. Moreover, the Strategic Environmental Assessment for Shale Gas Development in South Africa (2016:26) highlights that water scarcity is already an issue in the region of the Karoo Basin, as is the fragility of the local ecosystem, which “includes relatively high levels of biodiversity”.



CHAPTER V

LESSONS LEARNED



As the leading natural gas consuming country, the United States has traditionally played a pivotal role in this sector. Within the context of a regionally segmented natural gas market, the United States is among the three main hubs at which natural gas prices are determined. However, the natural gas market has been subjected to profound changes as a result of important developments in shale gas production that have taken place in the United States, mainly since 2007. Starting from the mid-2000s, shale gas production has grown rapidly, pushing the United States into a leadership position with regard to world natural gas production since 2009. Moreover, from a position of net importing country in 2007, the United States has recently become a net natural gas exporter, and this trend is expected to continue over 2018. The drastic changes occurring with regard to local infrastructure mirror this development. The United States invested significantly in developing its LNG importing capacities in 2007, with more than 40 LNG import terminals being built or proposed for construction, and it has retargeted its investments towards the development of LNG export capacity, which would make it the third largest exporting country by 2020.

The development of shale gas resources in the United States has been made possible due to the conjunction of several factors, related to favourable local geological conditions, low population density in producing areas and favourable mineral rights. Moreover, the country has among the most developed natural gas infrastructure (e.g. pipelines), as well as an extensive road network. In addition, the specific business and regulatory environment in the United States, involving a strong capital market enabling the financing of large and at times risky projects, as well as a flexible legal framework with regard to environmental issues at the start of activity, largely contributed to this rapid expansion. Supported by high natural gas prices, large investments have been made possible in the industry since 2004. This has allowed the country to gain experience and build expertise and to progressively reduce its production costs due to technological advances. In 2012–2015, average well-drilling and completion costs fell by more than 25 per cent. The long-term political support from United States authorities to the sector, dating to the mid-1970s, has also played a catalytic role. However, the rapid increase of shale gas production progressively led to oversupply, especially as export capacity was not in place to ship natural gas abroad, and this led

to a sharp decline in domestic prices. Natural gas prices in the United States progressively decoupled from other major regional references, namely Asia and Europe, leading to competitiveness gains for some United States industries, and the United States energy mix began to shift away from coal, to be progressively replaced by natural gas.

However, the unprecedented and possibly too rapid expansion of shale gas production in the United States has also led to major concerns over the potential negative impacts of hydraulic fracturing on the environment, especially with regard to water pollution, large levels of water withdrawals and induced seismicity.

Water-related issues are the basis of the main criticisms of shale gas activities. Among potential issues are the contamination of surface and groundwater by fracturing fluid, flowback wastewater or CH₄, as well as the use of the large volumes of water necessary to perform fracturing operations. Water is of paramount importance to life on Earth and this is all the more important in areas where water availability is already an issue or in regions where new activities would compete with existing activities consuming large amounts of water, such as agriculture. A more systematized, standardized and detailed reporting system of spills is needed in order to determine their sources, as well as the efficiency of mitigation measures implemented. Moreover, a review of the quality of surrounding water resources prior to the start of operations, as well as across their lifespans, is necessary to serve as a reference. Such a reporting and monitoring system is also relevant for oil and gas companies, to prove the reliability of activities or that necessary mitigation strategies have been effectively set up, should any incident arise.

Some preventive measures may be applied to limit the emergence of water pollution, including the use of best available practices for the design and construction of wells, as well as their regular monitoring during drilling and after completion. The need to regularly control production sites even after abandonment has also been highlighted, as well structures could leak as a result of ageing. Moreover, good knowledge of the local geology of shale gas plays is critical for early detection of existing faults, as well as potential migration pathways to aquifers. This issue is probably one of the most challenging, as data collection on geological information is still in its infancy in most countries that are exploring their shale gas potential.

Furthermore, it may also be interesting to investigate the potential impacts of the development of multipad drilling on water pollution, as well proximity is likely to increase risks to well structures as well as to the network of fractures.

The issue regarding the generation of small-size earthquakes by hydraulic fracturing is another topic that has attracted worldwide attention. The general view is that underground vibrations are normal occurrences during hydraulic fracturing operations and that stimulations do not cause identified hazards when operated under normal conditions. However, such induced seismicity is, in rare cases, felt on the surface. The two situations described as the most likely to generate such events are the injection of fracturing fluid in proximity to an existing pre-stressed natural fault; and the reinjection of large amounts of wastewater arising from hundreds to thousands of producing wells in a common permeable underground formation, an operation that is not limited to the shale gas industry.

Following the occurrence of earth tremors of low magnitude near Blackpool in the United Kingdom that were officially attributed to hydraulic fracturing activities, the Department of Energy and Climate Change (2012) of the United Kingdom proposed several recommendations in order to limit such events in the future. They are focused on three main lines of action, as follows:

1. Before any hydraulic fracturing operations starts:
 - i. A review of local seismicity should be conducted with the aim of identifying natural faults that could be reactivated by hydraulic fracturing operations.
 - ii. A pre-injection test, allowing water to flow back, should also be made and monitored prior to any large-scale hydraulic stimulation taking place.
2. Throughout the whole hydraulic fracturing cycle, seismic activity must be carefully monitored.
3. Hydraulic fracturing activities must be suspended as soon as seismic activity exceeds a predefined threshold. The Department of Energy and Climate Change (2012:3) proposes that this limit be fixed at M0.5, a level considered as prudent. This threshold may be revised on the basis of experience gained.

Commercial shale gas production has been mainly restricted to Canada and the United States. Some steps to scale up the production of shale gas have been taken in a few other countries, with limited success to date. Conditions that have supported the rapid development of shale gas in the United States are not necessarily available in other countries holding important shale gas resources.

In Europe, for example, the high population density, the absence of a social licence to operate, as populations are mostly not used to onshore hydrocarbon activities, combined with the nature of local mineral rights, which give ownership of underground resources to the State, have not prompted populations to welcome the development of shale gas activities. As a result, several countries have successively established a moratorium on shale gas activities or hydraulic fracturing. Poland is an exception in this regard. The consensus between the population and national authorities towards higher energy independence, combined with preliminary positive perspectives of potential shale gas resources in the country, have encouraged the launch of exploratory campaigns to estimate the domestic shale gas potential. However, despite encouraging early information, initial drilling tests have proven underwhelming, owing to the complex local geology, which has led to a drastic downward revision of earlier estimates.

Most investments outside of Canada and the United States are now taking place in Argentina and China, where resources appear to be among the largest in the world. However, challenges need to be addressed with regard to, for example, infrastructure availability, the development of support services, the creation of adapted equipment and the development of appropriate skills. The regulatory framework also needs to be adapted to ensure environmental friendly methods, safety and security, as well as an environment that attracts foreign direct investment.

The main conclusion that may be drawn from various experiences beyond North America is that the United States model is unlikely to be directly replicable in other countries. Production techniques need to be adapted to local geological conditions before commercial production may be reached. Countries will therefore need to pass through an experimental stage that may appear long and costly. Finally, general acceptance by local populations may prove highly pivotal. However, the United States experience may also help countries implement the necessary measures and

adapt regulatory frameworks to prevent the already identified negative effects of shale gas operations on the environment and local populations.

Important changes that have occurred in the natural gas market in the last decade, in particular the possibility that large quantities of LNG may become available from North America in the coming years, raise numerous questions concerning the future of the sector. Will natural gas markets in their current configurations converge into a more globalized market with one benchmark price? Will the new large-scale LNG projects contribute to increasing competition in Europe and lead to a decline of natural gas prices in the region? Or, conversely will additional volumes of natural gas contribute to meeting the growing demand from Asia, which could potentially push prices for natural gas upward in Europe? In Europe, what will be the most likely trends with regard to long-term contracts? Will increased competition lead to the gradual abolishment of the traditional business model?

Global energy consumption is expected to grow by more than 20 per cent by 2035, mainly fuelled by demand from non-OECD countries in Asia. With regard to natural gas, its share in the global energy mix may rise by 3 percentage points by 2035, owing to increasing demand from the power generation and industrial sectors. This may lead to natural gas

accounting for 24 per cent of the global energy mix by 2035. About one fifth of this demand may come from shale gas production, mainly from North America, in particular the United States, as well as from China, where shale gas may account for half of national natural gas production by 2040. In addition, as a consequence of international commitments taken by countries aimed at curbing global warming, the share of renewable energies in the global energy mix is expected to expand and may account for 19 per cent of the global energy mix by 2035. With this in mind, a key issue relating to the current trends in the shale gas sector is to evaluate the role that natural gas is expected to play in the future energy landscape.

Natural gas is pointed out as a bridge fuel by the Intergovernmental Panel on Climate Change, when it is used as a source of energy that emits less CO₂. However, although it is less carbon intensive than oil or coal, for instance, natural gas also emits CO₂ into the atmosphere and contributes to global warming. Moreover, the issue of fugitive CH₄ emissions must be particularly taken into consideration and mitigation strategies applied. In addition, irrespective of the level of future prices of natural gas, its use should contribute to fostering a smooth transition from the current economic model, mainly based on fossil fuels, to achieving a low-carbon economy, with the objective of meeting the Sustainable Development Goal 7 by 2030.



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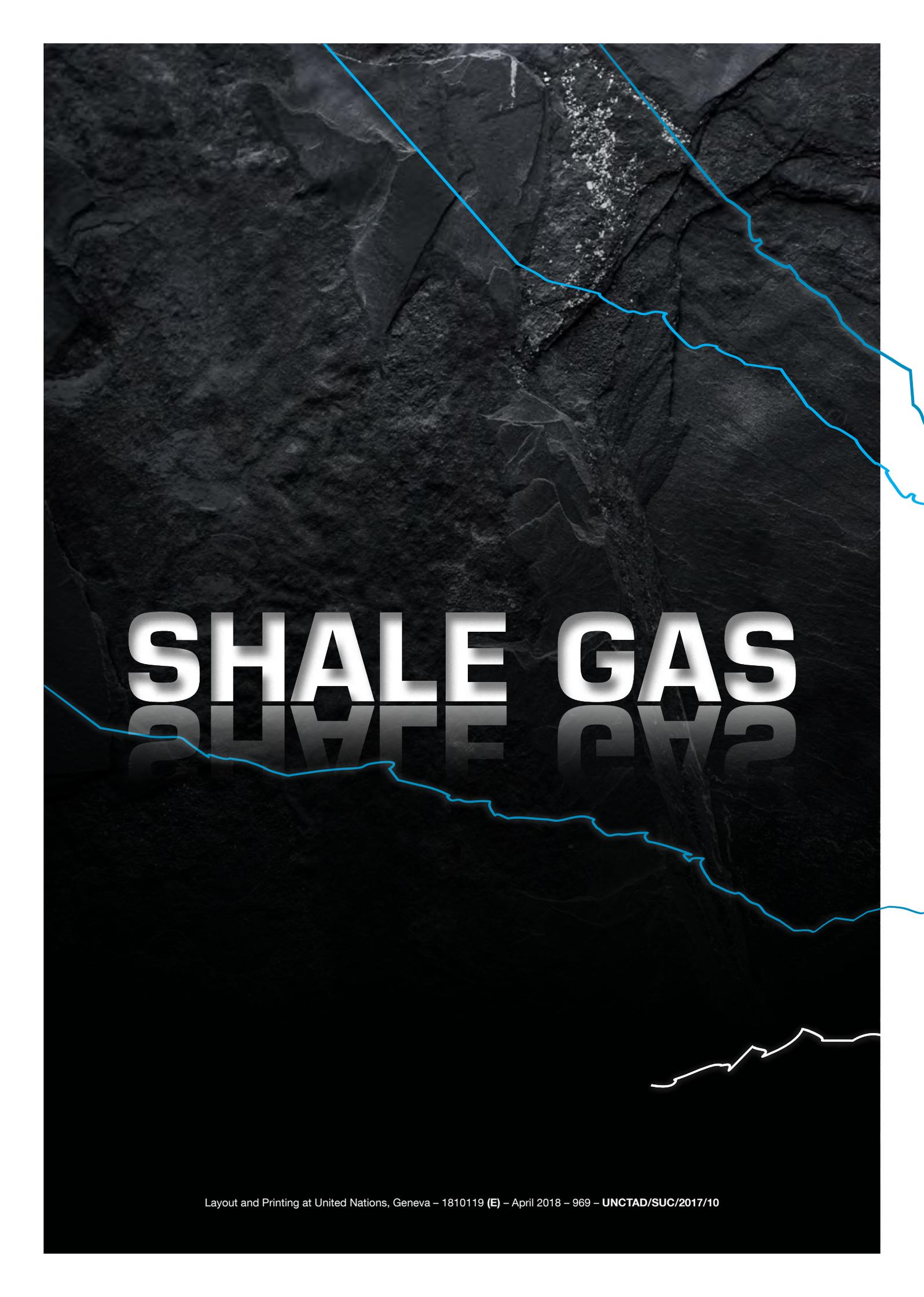
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