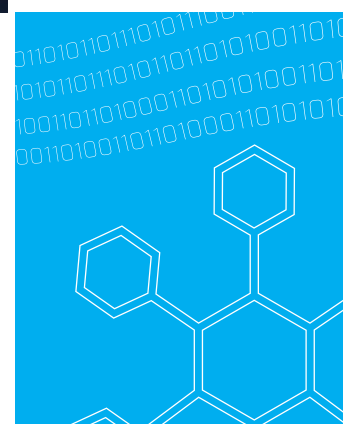




Shale gas production – its trade as LNG and prospects for Finland and its industries

Veli-Pekka Heiskanen | John Yilin Wang



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Veli-Pekka Heiskanen

VTT Technical Research Centre of Finland Ltd

John Yilin Wang

Pennsylvania State University



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Teknologian tutkimuskeskus VTT Oy

PL 1000 (Tekniikantie 4 A, Espoo)

02044 VTT

Puh. 020 722 111, faksi 020 722 7001

Teknologiska forskningscentralen VTT Ab

PB 1000 (Teknikvägen 4 A, Esbo)

FI-02044 VTT

Tfn +358 20 722 111, telefax +358 20 722 7001

VTT Technical Research Centre of Finland Ltd

P.O. Box 1000 (Tekniikantie 4 A, Espoo)

FI-02044 VTT, Finland

Tel. +358 20 722 111, fax +358 20 722 7001

Preface

VTT Technical Research Centre of Finland Ltd, with nine industrial partners, has carried out the project *Implications of solar and wind on the CHPC systems operating in international energy markets – opportunities and challenges for energy storages and hybrid concepts* (SANDWISH). The project was implemented between 1 May 2013 and 30 June 2014. This literature review is a contribution to one of the project's seven work packages (WP3).

The SANDWISH project's main focus was on energy storages and hybrid concepts, which are required when connecting solar and wind power to existing or new power, heat and cooling systems. Solar and wind energy production fluctuates on a seasonal, monthly and daily basis and therefore needs a back-up. Liquefied methane storage was studied as the primary option to back up solar and wind energy systems. Shale gas can be liquefied to LNG and exported to countries where shale gas is not available like in Finland, and can be used as the required back-up for solar and wind energy systems. Therefore the work for this report focused on shale gas production and its trade as LNG, and especially on the emerging opportunities and benefits for Finland and its industries. Processing, transportation, storage and use of LNG are existing and proven technologies and LNG provides therefore an easy-to-use option in conjunction with solar and wind power production but also for other purposes.

Finland's energy consumption per capita is one of the highest in the world due to its energy-intensive industry and cold climate, among other things. Availability of energy at a reasonable price and energy security are therefore important to Finland. These were the focal reasons, besides what was mentioned in the previous paragraph, for including the work in this report in the SANDWISH project. Additionally, since the increasing shale gas supply affects the price and availability of energy in the global market as well as LNG from shale gas, perhaps this energy source could be used in Finland in the future, thus increasing energy security and availability.

The report aims to inform VTT's co-operation partners, other interested parties and the public about shale gas utilisation-related issues, since there is so far a rather limited amount of information on shale gas utilisation including Finnish perspective and interest in it. On the other hand, Finland and its industries may benefit from increasing global shale gas utilisation and this report aims to provide background information for any companies or organisations, which are currently or will be in the

future somehow involved in shale gas businesses or other relevant activities. This report is, as far as it is known, the most comprehensive shale gas study carried out in Finland so far and will therefore supplement the previous studies.

VTT has participated in close co-operation in this particular task of the SANDWISH project with Pennsylvania State University's Department of Energy and Mineral Engineering that is one of the leading shale gas research institutes.

Funding for the project was granted by Tekes – the Finnish Funding Agency for Innovation and by the nine project partners: Foster Wheeler Energia Oy, Gasum Oy, Rautaruukki Oyj, Fennotecon Oy, Energiakolmio Oy, Jyväskylän Energia Oy, Neo-Codex Oy, LVI-Insinööritoimisto Pirttinen Oy, Rakennuspalvelu P&P Heikkinen Oy.

Jyväskylä, Finland, 6.2.2015

Authors

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Abbreviations

Abbreviations are listed in order of appearance in the report.

tcm	Trillion cubic metres
EU	European Union
EIA	U.S. Energy Information Administration
PGNiG	Polskie Górnictwo Naftowe i Gazownictwo SA
ARI	Advanced Resources International
CAPP	Canadian Association of Petroleum Producers
GHG	Greenhouse gas
DECC	Department of Energy & Climate Change (United Kingdom)
tcf	Trillion cubic feet
BGS	British Geological Survey
EPA	US Environmental Protection Agency
EUR	Estimated ultimate recovery
LNG	Liquefied natural gas
EPA	United States Environmental Protection Agency
USGS	U.S. Geological Survey
MMBtu	One million British thermal unit (~ 1055 MJ)
gal	US gallon (~ 3.79 litres)
IEA	International Energy Agency
bcm	Billion cubic metres
tpa	Ton per annum
SHIP	Shale Gas Information Platform
MEE	Finnish Ministry of Employment and the Economy

1. Introduction

Natural gas production from oil and gas bearing organic-rich mudstone formations, known as “shale gas,” is a rapidly expanding trend in onshore oil and gas exploration and production today, even though so far shale gas production has been started only in the U.S. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Three factors during the last decade have made shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last years as a result of significant supply and demand pressures (Website of U.S. Energy Department's Fossil Energy Organisation).

The development of large-scale shale gas production started when Mitchell Energy and Development Corporation experimented during the 1980s and 1990s to make deep shale gas production a commercial reality in the Barnett Shale in North-Central Texas. As the technical success of Mitchell Energy and Development became apparent, other companies entered the play and by 2005, the Barnett Shale alone was producing about 14 billion cubic metres of natural gas per year. As producers gained confidence in the ability to produce natural gas profitably in the Barnett Shale, with confirmation provided by results from the Fayetteville Shale in Arkansas, they began pursuing other shale plays, including Haynesville, Marcellus, Woodford, Eagle Ford, and others (EIA, July 2011).

Shale gas producers in the United States would like to start export of liquefied shale gas even though U.S. industry opposes this. It is however anticipated that the export may start even in next few years.

Utilisation of shale gas has been forecast to grow 400 million tonnes a year (~ 5 600 TWh/year) at least until 2020. LNG from shale or natural gas is one im-

portant option for Europe to secure adequate availability of energy. For Japan LNG may be even more crucial since demand for gas increased rapidly after the Fukushima accident when nuclear power plants were closed. Additionally, China wants to replace coal with more environmentally-friendly gas (Tekniikka&Talous, 2014).

2. Shale gas resources and reserves

2.1 Background and overview

A surge in oil and gas production from shale rock has transformed energy in the United States, helping reverse declines in oil production and prompting a massive shift from coal to natural gas electricity production that has led to a drop in carbon dioxide emissions (since burning coal releases more carbon dioxide than burning natural gas). A new report (EIA, 10 June 2013) from the U.S. Energy Information Administration lends support to the idea that a similar transformation could take place outside the United States (Bullis, 10 June 2013). Figure 2.1.1 is a map from that report, showing global shale gas and oil resources. The map gives a sense of just how wide-spread shale gas and oil resources are. Three countries have more shale gas than the United States: China, Argentina, and Algeria. Figure 2.1.2 shows a map of shale gas plays in the U.S. showing the geographically wide-spread nature of global shale gas resources. While other countries may have more of these resources than the United States, the impact in some of them may not be as great, or happen as quickly. It could take many years to develop resources in other countries because the geology is somewhat different: the techniques that work in the United States might not work elsewhere. What's more, many countries don't have the needed technological expertise.

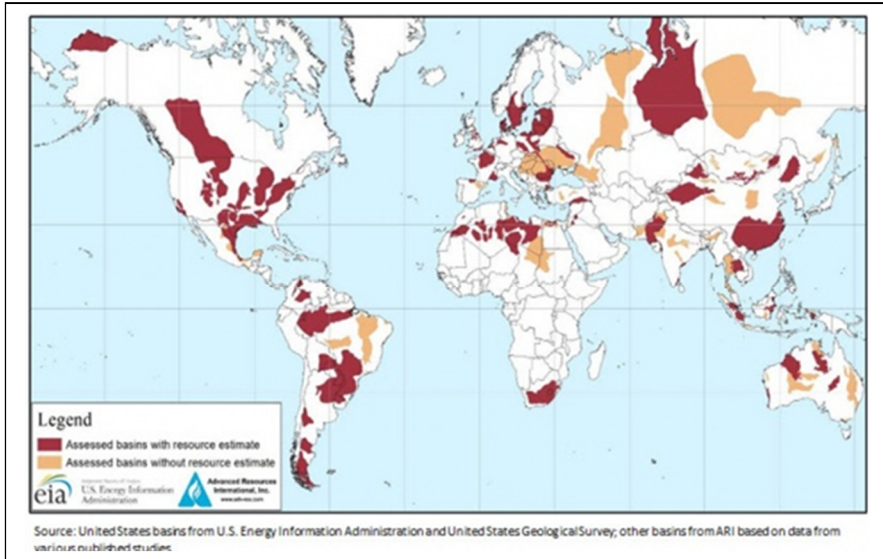


Figure 2.1.1. Assessed shale oil and shale gas formations (EIA, 10 June 2013).

Furthermore, the United States had a lot of spare natural gas generating capacity, which made it easy to switch from coal to natural gas. In a country like China, where energy demand is quickly growing, there is little spare capacity. Natural gas production might only serve to slightly slow the growth of electricity from coal plants, not reverse it.

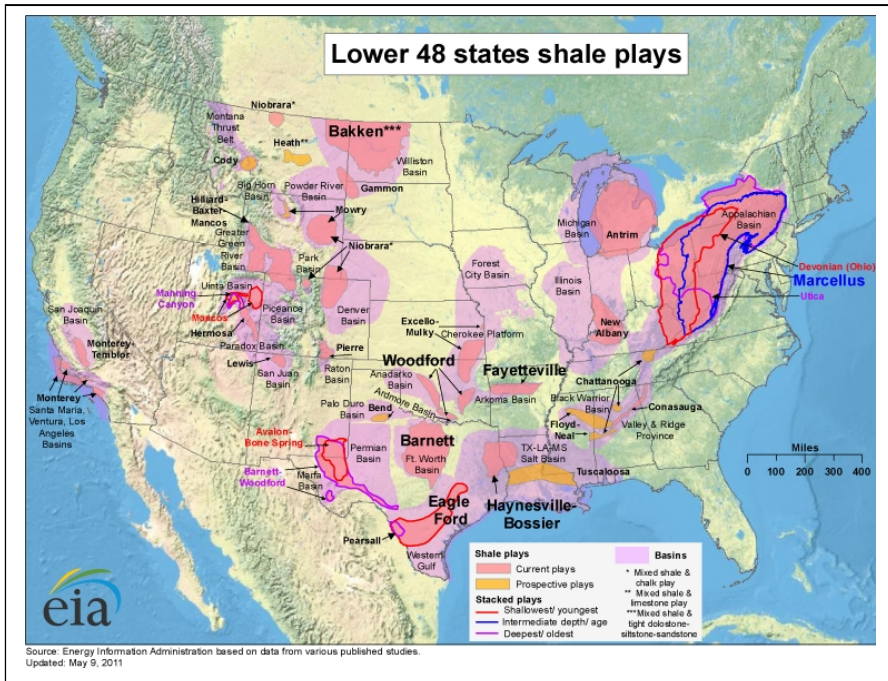


Figure 2.1.2. U.S. shale gas plays 2011 (EIA, 2011).

So far, the impact of increased shale gas production has been limited outside the United States. Because natural gas is relatively expensive to export and requires the construction of specialised infrastructure, natural gas prices have fallen sharply inside the United States, but not outside the country. But it has had one impact: increased natural gas production in the U.S. has led to increases in coal consumption elsewhere. When demand for coal dropped in the U.S., it was shipped abroad, lowering coal prices.

2.2 Geology of gas resources

With the growth of natural gas from shale, there is renewed interest in natural gas resources. Figure 2.2.1 shows the geologic nature of most major sources of natural gas in schematic form:

- Conventional gas accumulations occur when gas migrates from gas-rich shale into an overlying sandstone formation, and then becomes trapped by an overlying impermeable formation, called the seal. Associated gas accumulates in conjunction with oil, while non-associated gas does not accumulate with oil;
- Tight sand gas accumulations occur in a variety of geologic settings where gas migrates from a source rock into a sandstone formation;

- Coalbed methane is generated during the transformation of organic material to coal;

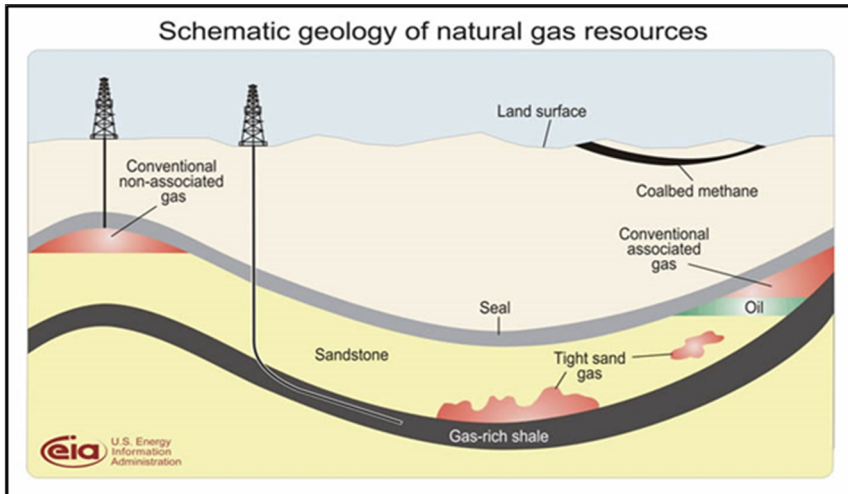


Figure 2.2.1. Geology of natural gas sources (EIA, 2010).

- Because shales ordinarily have insufficient permeability to allow significant fluid flow to a wellbore, most shales are not commercial sources of natural gas. Therefore production in commercial quantities requires fractures to provide higher permeability. Shale gas has been produced for years from shales with natural fractures; the shale gas boom in recent years has been due to modern technology in hydraulic fracturing (fracking) to create extensive artificial fractures around wellbores. Horizontal drilling is often used with shale gas wells, with lateral lengths up to 10 000 feet (3 000 m) within the shale, to create the maximum borehole surface area in contact with the shale. Shales that host economic quantities of gas have a number of common properties. They are rich in organic material (0.5% to 25%), and are usually mature petroleum source rocks (source rock refers to rocks from which hydrocarbons have been generated or are capable of being generated) in the thermogenic gas window, where high heat and pressure have converted organic matter to natural gas. They are sufficiently brittle and rigid enough to maintain open fractures.

Some of the gas produced is held in natural fractures, some in pore spaces, and some is adsorbed into organic material. The gas in the fractures is produced immediately; the gas adsorbed into organic material is released as the formation pressure is drawn down by the well.

2.3 Worldwide shale gas potential

2.3.1 Countries with extensive resources

The volume of gas bound within a specific shale (gas-in-place) is known as the gas resource. The reserves are the volume of gas that can be technically and economically produced. Reserves are therefore often much smaller than the resource. The ratio of reserves to resource varies widely between shale formations, with formations at higher pressure having a higher estimated ultimate recovery. The U.S. Energy Information Administration estimates that 22 per cent of shale resources are technically recoverable. The economically recoverable fraction may be much smaller as it depends on gas prices and production costs. The factors affecting the ratio of reserve to resource are mainly geological. However, there are also non-geological factors that could affect the size of the reserve. These factors include: engineering design (such as the number of horizontal wells per pad and the techniques used for fracking); the effect of the new protocols for earthquake mitigation and monitoring; land access; environmental permit constraints; well costs; and the prices of gas and competing fuels (MacKay et al., 2013).

Table 2.3.1.1. Top 10 countries with technically recoverable shale gas resources (EIA, 2013).

Rank	Country	Shale gas resources	
		trillion cubic feet	TWh
1	China	1,115	310 000
2	Argentina	802	228 000
3	Algeria	707	201 000
4	U.S. ¹	665	189 000
5	Canada	573	165 000
6	Mexico	545	155 000
7	Australia	437	124 000
8	South Africa	390	111 000
9	Russia	285	81 000
10	Brazil	245	70 000
World Total		7 299 (7 795)	2 070 000 (2 210 000)
¹ EIA estimates used for ranking order. ARI estimates in parentheses.			

The assessment from the EIA (EIA, 2013) updates a prior assessment of shale gas resources issued in April 2011. It assesses 137 shale formations in 41 countries outside the United States, expanding on the 69 shale formations within 32 countries considered in the prior report. The earlier assessment was released as part of an EIA report titled World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States (EIA, April 2011). Geologic research and well drilling results not available for use in the 2011 report allow for a more informed evaluation of the shale formations covered in that report as well as other shale formations that it did not assess. In addition, recent developments in the U.S. highlight the role of shale formations and other tight plays as sources of crude oil, lease condensates, and a variety of liquids processed from wet natural gas. Estimates indicate technically recoverable resources of 7 300 tcf (~ 210 tcm) of global shale gas resources (~ 2.1 million TWh). This is 14 times the annual global primary energy consumption that is ~ 150 000 TWh (Enerdata, 2014). The new global shale gas resource estimate is 10 percent higher than the estimate in the 2011 report. The shale resource estimates will likely change over time as additional information becomes available. Globally, 32 per cent of the total estimated natural gas resources are in shale formations.

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource and an economically recoverable resource. Technically recoverable resources represent the volumes that could be produced with current technology, regardless of production costs and global energy market conditions. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of shale gas resources depends mainly on three factors: the costs of drilling and completing wells, the amount of gas produced from an average well over its lifetime, and the gas price. Recent experience with shale gas in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include (EIA, 2013):

- Private ownership of subsurface rights that provide a strong incentive for development;
- Availability of many independent operators and supporting contractors with critical expertise;
- Suitable drilling rigs;
- Pre-existing gathering and pipeline infrastructure;
- The availability of water resources for use in hydraulic fracturing.

At a country level, there are two country groupings where shale gas development appears most attractive. The first group consists of countries like China and Mexico, which are currently highly dependent upon natural gas imports, have at least some gas production infrastructure, and their estimated shale gas resources are substantial relative to their current gas consumption. For these countries, shale gas development could significantly alter their future gas balance, which may

motivate development. The second group consists of those countries like Algeria and Russia where the shale gas resource estimate is large (> 5 tcm) and there already exists a significant natural gas production infrastructure for internal use or for export. Existing infrastructure would aid in the timely conversion of the resource into production, but could also lead to competition with other natural gas supply sources. For an individual country, the situation could be more complex (Speight, 2013).

2.3.2 Overall global shale gas resources

Probably the best estimates of global shale gas resources can be found in the EIA report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States (EIA, 2013) that has been referred to several times in this report. These estimates are presented in Table 2.3.3.1. The figures for total resources 35 782 and 7 795 tcf are in terms of energy 10.1 and 2.2 million TWh, respectively.

Table 2.3.2.1. Risked shale gas in-place and technically recoverable: seven continents (EIA, 2013).

Continent	Risked Gas In-Place (Tcf)	Risked Technically Recoverable (Tcf)
North America (Ex. U.S.)	4,647	1,118
Australia	2,046	437
South America	6,390	1,431
Europe	4,895	883
Africa	6,664	1,361
Asia	6,495	1,403
Sub-Total	31,138	6,634
U.S.	4,644	1,161
Total	35,782	7,795

Comparing Tables 2.3.1.1 and 2.3.2.1, it indicates that ten countries with the largest resources of shale gas have almost 75% of the worldwide resources.

2.3.3 China

Since China has the world's vastest shale gas resources, and on the other hand it presently uses energy more than any other country in the world and the energy

use is increasing rapidly and continuously, some key issues related to its shale gas development are outlined in this sub-chapter.

If China will start to produce shale gas in similar quantities as the U.S., it will affect substantially the global energy market. Even though this gas will probably be used mainly in China, it will have an effect on the market since that amount of energy in some form (natural gas, coal, etc.) will be available on the global market because China consequently would need less energy from the global market.

According to the Chinese Ministry of Land and Resources, preliminary surveys estimate exploitable shale gas reserves to be 25 tcm (~ 250 000 TWh), a volume sufficient to satisfy China's gas needs for the next two centuries (Evans-Pritchard, 2012). These figures differ from the estimate in Table 2.3.1 to some extent but not significantly, taking into account that both figures are estimates. In the national SINOPEC demonstration area, 27 shale gas wells have been drilled in Fuling, Chongqing. So far, 10 horizontal wells are undergoing trial production. The cumulative commercial gas production in the Fuling area alone already has reached 73 million m³ (730 GWh) in 2013. For a total of 39 appraisal wells of shale gas in two national demonstration areas in Changning-Weiyuan and Zhaotong in two China National Petroleum Corporation foreign corporation areas and the completed appraisal wells of shale gas in the Fushun-Yongchuan foreign co-operation zone, the production of shale gas has reached a total of 70 million m³ (700 GWh) in 2013. China's total shale gas production in 2013 has exceeded 200 million m³ (2 TWh), an increase of nearly seven times compared with 2012 production. However, the target for the production of shale gas set by the Chinese government in 2015 is 6.5 billion m³ (65 TWh), which is 2% of the total production of natural gas in China (Chang et al., 2012). Current trends indicate that it will be difficult to achieve this target (Wan et al., 2014).

In addition to physical conditions (i.e., geographical complexity, water scarcity, or lack of related infrastructure) that limit shale gas development in China, there are several man-made barriers such as:

- Large state-run companies have monopoly over exploration rights;
- Monopoly over pipeline access;
- The major natural gas pipeline network amounts to only about 50 000 km (2012);
- China, as well as other countries excluding the U.S., has not yet mastered the technologies required for gas exploration and exploitation;
- Uncertainty in water management systems.

Regardless of the many barriers that will slow down shale gas production in China, it is expected that the production and use of shale gas will be increasing substantially in China during the next decade(s).

2.4 Shale gas potential in Europe

As Table 2.3.1.1 indicates, there are no European countries among the top 10 countries with technically recoverable shale gas resources. However, there are

significant resources in some European countries like Poland, France and the United Kingdom, for instance.

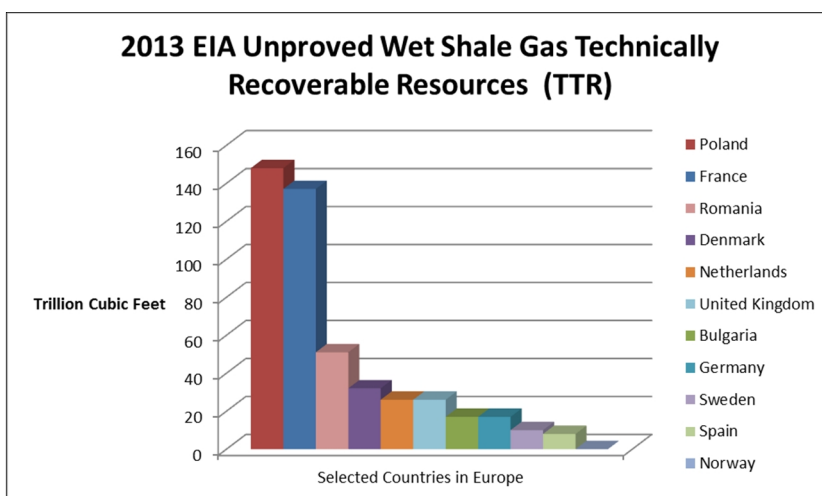


Figure 2.4.1. Estimated wet shale gas technically recoverable resources in Europe.

Figure 2.4.1 shows the estimated wet shale gas technically recoverable resources. Besides the aforementioned three countries there are significant resources in seven other European countries. The three next sub-chapters outline the shale gas resources and related issues in the three mentioned countries, since in these countries the resources are the most abundant and/or there are notable shale gas-related activities going on.

2.4.1 Poland

Estimates of shale gas resources in Poland made in recent years have shown a very wide range of results from 1 000 bcm to as much as 5 300 bcm (EIA, 2013). The Polish Geological Institute and National Research Institute presented a study in March 2012 (Polish Geological Institute, 2012) stating that the shale gas resources can reach a maximum of 1920 bcm, while the estimated resources are most likely to be 346–768 bcm (~ 3 500–7 700 TWh). To put this into context, Poland’s annual primary energy consumption in 2010 was 1 160 TWh (Website of Energy Delta Institute, 2014). In comparison with conventional gas, those estimates are 2.5–5.5 times greater than the proved reserves of natural gas from conventional deposits (about 145 bcm).

Poland is currently considered as one of the most promising areas of occurrence of shale gas in Europe. International oil companies including ExxonMobil, Chevron, Talisman and Marathon have shown interest in the prospects of the

resources. The first licenses for exploration and documentation of shale gas deposits were issued in 2007, while in February 2013, oil companies had 115 licenses for exploration and documentation of hydrocarbon deposits including 16 concessions for unconventional deposits. The total area for all issued licenses (shale gas deposits) is more than 91 thousand km², which accounts for about 29% of Polish territory. The highest number of licenses – 16 – belongs to PGNiG SA. Between 2010 and 2011, the first exploratory drillings were carried out in the Baltic Basin (3 wells) and Lublin Basin (7 wells). The wells drilled in the Baltic Basin, including Lubocino-1 (PGNiG SA), Łebień (Lane Energy Poland/ConocoPhillips) and Wylotowo S-1 (BNK Petroleum Inc.) allowed extraction of gas from Lower Palaeozoic shale. However, some exploration wells in the Lublin Basin produced negative results. This applies to the first exploration well, Markowola (PGNiG SA), as well as to the wells drilled by ExxonMobil.

Most companies are currently at the stage of laboratory evaluation of rocks, accompanied by the interpretation of the research results and borehole measurements. Shale gas reserves are at an initial stage of exploration. To assess the size of unconventional gas resources, it is necessary to drill additional wells, while there is an urgent need for additional geological, physical, chemical and geochemical analysis. According to data published by the Ministry of Environment, 40 exploration wells have been drilled in Poland as of February 4, 2013. 309 exploration wells are planned by 2021 (128 wells accompanied by an additional 181, depending on the capabilities and the results of work).

Even though the exploration of shale gas resources is ongoing, there are still two types of barriers to exploitation of shale gas in Poland. The first includes regulations related to the extraction, transport and distribution of gas, the second includes broadly defined environmental and social aspects. These barriers increase production costs and adversely affect the profitability of gas production. (Uliasz-Misiaka et al., 2014).

2.4.2 France

France has also significant shale gas resources, 3 900 bcm (39 000 TWh) according to EIA (EIA, 2013). This could fuel gas consumption in France for 9 years assuming recovery of only 10% of these resources. Currently, natural gas consumption accounts for roughly 15% of the annual energy consumption in France, 98.5% of that being imported. France's shale gas resources are located in several regions including the Southwest, the Paris Basin and in certain west-central regions.

However, at present French law bans any use of hydraulic fracturing techniques to explore for or develop gas reserves in France (Loi No. 140). The Ministry of Ecology abrogated three permits preventing companies from exploring shale gas reserves. The prospects for developing shale gas in France seem remote until the law in question is amended or repealed or an alternative to fracking is developed to produce shale gas reserves (Website of Vinson&Elkins, 2014).

In general, the opposition against shale gas extraction with hydraulic fracturing in France is strong, probably stronger than in any other country with shale gas resources. However, recently there has been some support for its extraction especially if fracking would be carried out using fluoropropane, rather than a mix of water and chemical additives. Proponents say that this new method, being developed by the Texas company EcorpStim, is more environmentally-friendly than hydraulic fracturing. The other method being employed in the United States is to use propane, which eliminates the need for chemicals. However, there are risks of explosions and these risks are assumed to be greater in France, where the population is much denser than in the United States, and each well would have to be put in the highest category in terms of industrial risk (Business News, 2014).

In addition, shale gas resources are mainly in densely populated and/or touristic areas, partly explaining the current reluctance for producing gas. For instance, the Paris basin is roughly circular in shape, and the city of Paris is in the centre of it (Chungkham, 2013).

2.4.3 United Kingdom

The Secretary of State announced in December 2012 that exploratory hydraulic fracturing for shale gas can resume in the UK, subject to new controls to mitigate the risk of seismic activity (Davey, 2012). The Department of Energy & Climate Change (DECC) commissioned more detailed work on the shale gas resources of Great Britain from the British Geological Survey which was published on 27 June 2013 (Andrews, 2013). The study evaluated the total volume of potentially productive Carboniferous Bowland-Hodder shale in central Britain using a three-dimensional geological model generated using seismic mapping, integrated with outcrop and deep borehole information. The evaluation was further refined to identify which parts of the volume had been buried to a sufficient depth for the organic material to generate gas. The BGS report estimates that the resource in the Bowland-Hodder Shale Formation could be even 38 000 bcm (380 000 TWh); the resource is an estimate of the gas in the ground; the BGS report did not estimate the reserves, the amount of gas which could in practice be produced economically from that resource. The volume 38 000 bcm sounds so huge that there may be orders of magnitude mixed in the BGS report (this report's author's comment). Until more exploration work has been performed in the Bowland-Hodder shale and in other geologically different shale gas prospects beneath the UK, it will not be possible to make any meaningful estimate of the likely shale gas reserves in the UK. Cuadrilla, which is exploring a resource in Lancashire, has estimated the resource gas-in-place in shales within the scope of its licence to be 5.7 bcm (57 TWh). However, more drilling and testing is needed to make a reliable estimate of the reserve in this location. There are other shale resources in the UK and in British overseas territories (Mackay et al., 2013). EIA's estimate of unproved wet shale gas technically recoverable resources in the UK are 740 bcm (7 400 TWh), see Figure 2.4.1 (EIA, June 10, 2013).

Some estimates state that if Britain can extract 10% of all of its shale gas reserves it could supply the entire country for almost 50 years. In December 2013, a report commissioned by the Department of Energy and Climate Change, said more than half of the UK could be suitable for fracking (BBC Business News, 13 January 2014). The present government supports fracking, saying it is safe if properly regulated and could create thousands of jobs and reduce energy bills.

To date, there has been no commercial exploitation of shale gas in the UK. The French oil and gas company, Total, will invest at least \$21 million in the UK's shale gas industry. The UK energy firm, IGas Energy, had agreed to a deal to hand Total a 40% interest in two shale gas exploration licences in Lincolnshire. The investment makes Total the first of the big oil and gas companies to invest in shale gas in the UK. Total will pay \$1.6 million in back costs and fund a work programme of up to \$46.5 million, with a \$19.5 million minimum commitment.

According to Reuters (Reuters, May 23, 2014), Britain plans to ease rules on accessing shale oil and gas, including drilling without landowners' permission, a move that coincides with a government report suggesting billions of barrels of shale oil may lie underneath southern England. As the country's North Sea reserves dwindle, hopes are that shale oil and gas will take its place and reduce dependence on imported fuel. The government's proposal is to allow companies to drill below 300 metres without permission from landowners, although. As the law stands, companies have to negotiate rights of access with every landowner living above where they are drilling and that process can take many months or more. If Britain's reserves are economically recoverable, the shale oil would add to a small shale gas boom, in which companies such as Alkane, Egdon, Cuadrilla, Dart and Island Gas are seeking to capitalise on large reserves found in northern England.

2.5 Present use and prospects

So far shale gas has been utilised mainly just in the U.S. Shale gas resources have substantially changed U.S. natural gas production, providing already 40 percent of total U.S. natural gas production in 2012 (EIA, 2014). However, given the variation across the world's shale formations in both geology and above-the-ground conditions, the extent to which global technically recoverable shale gas resources will prove to be economically recoverable is not yet clear.

While large-scale commercial production of shale gas has not yet been started in Canada, many companies are now exploring and developing shale gas resources in Alberta, British Columbia, Quebec, and New Brunswick. Development of shale gas, and other unconventional resources, will help ensure supplies of natural gas are available to the growing North American natural gas market for many decades (Website of CAPP, 2014).

Because markets for natural gas are much less globally integrated than world oil markets for instance, the rapid growth in shale gas production since 2006 has significantly lowered natural gas prices in the United States and Canada compared to prices elsewhere and to prices that would likely have prevailed without the shale boom, as indicated in Figure 2.5.1.

In addition to increases in domestic consumption in the industrial and electric power sectors, U.S. exports of natural gas also increase in the AEO2014 Reference case (Figure 2.5.2). U.S. annual exports of liquefied natural gas are predicted to increase to around 100 bcm (1000 TWh) in 2029 and remain at that level through 2040. Pipeline exports of U.S. natural gas to Mexico will grow by 6% per year, from 17 bcm in 2012 to almost 90 bcm by 2040, and pipeline exports to Canada are predicted to grow by 1.2% per year, from 28 bcm in 2012 to almost 40 bcm by 2040. Over the same period, U.S. pipeline imports from Canada will fall by 30%, from 85 bcm in 2012 to 60 bcm by 2040, as more U.S. demand is met by domestic production. Projected exports are sensitive to assumptions regarding conditions in U.S. and global natural gas markets.

In addition to activities in the U.S., wells have been drilled in shale formations in countries such as Argentina, China, Mexico, and Poland during the last years and have helped to clarify their geologic properties and productive potential. In addition, there has been interest expressed in shale formations in a number of other countries, including Algeria, Australia, India, Romania, Russia, Saudi Arabia, Turkey, Ukraine, and the United Kingdom.

In China, better information regarding the total organic content and geologic complexity resulted in a reduction of the shale gas resource and the shale gas resource estimate was reduced from 36 000 bcm in the 2011 report to 32 000 bcm in the report from June 2013 (EIA, June 10, 2013).

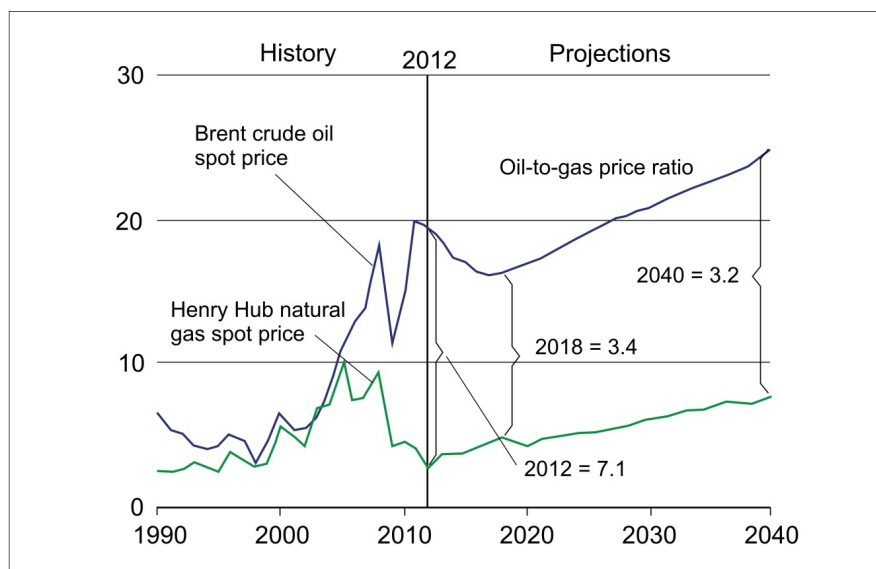


Figure 2.5.1. Development of gas and oil price in the U.S. (EIA, Annual Energy Outlook, 2014).

Technically recoverable resources are determined by multiplying the risked-in-place natural gas by a recovery factor. Based on U.S. shale production experience, the recovery factors for shale gas generally range from 20 to 30 per cent, with values as low as 15 per cent and as high as 35 per cent being applied in exceptional cases. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery.

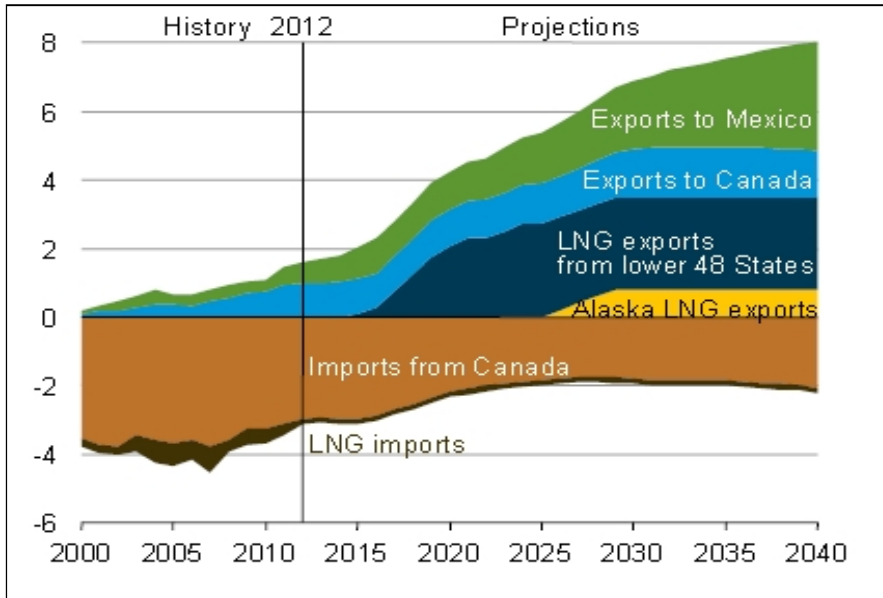


Figure 2.5.2. U.S. natural gas imports and exports in trillion cubic feet, 2000-2040 (EIA, 16 December, 2013).

3. Shale gas extraction technology

3.1 Overview of shale gas extraction process

3.1.1 Productivity of shale formations

Because of shale rock heterogeneity, neighbouring well productivity may vary significantly, and well productivity across a formation varies even more. Shale formation productivity also varies by depth. For example, Upper Bakken Member shale wells are less productive than Lower Bakken Member shale wells.

Shale heterogeneity also means that some areas across the shale formation can have wells with relatively high productivity (sweet spots), while wells in other regions have substantially lower productivities. Because productivity also varies significantly for wells located in the same neighbourhood, a single well test cannot establish a formation's productivity or even the productivity within its immediate neighbourhood. This complicates the exploration because the cost of drilling a sufficient number of wells to determine the local variation in well productivity is high (EIA, 10 June, 2013).

For those shales that are expected to have both natural gas-prone and oil-prone portions, formation heterogeneity means that there could be an extended transition zone across a shale formation from being all or mostly natural gas to being mostly oil. The best example of this gradual and extended transition from natural gas to oil is found in the Eagle Ford Shale in Texas, where the distance between the natural gas-only and mostly-oil portions of the formation are separated by 20 to 30 miles, depending on the location. This transition zone is important for two reasons. First, a well's production mix of oil, natural gas, and natural gas liquids can have a substantial impact on that well's profitability both because of the different prices associated with each component and because liquids have multiple transportation options (truck, rail, barge, pipeline), whereas large volumes of natural gas are only economic to transport by pipeline. Because many countries have large natural gas deposits that well exceed the indigenous market's ability to consume that natural gas (e.g., Qatar), the shale gas is of no value to the producer and is effectively stranded until a lengthy pipeline or LNG export terminal has been built to transport the natural gas to a country with a larger established consumption market.

Shale formation heterogeneity also somewhat confounds the process of testing alternative well completion approaches to determine which approach maximises profits. Because of the potential variation in neighbouring well productivity, it is not always clear whether a change in the completion design is responsible for the change in well productivity.

Shale formation heterogeneity also bears on the issue of determining a formation's ultimate resource potential. Because companies attempt to identify and produce from the high productivity areas first, the tendency is for producers to concentrate their efforts in those portions of the formation that appear to be highly productive, to the exclusion of much of the rest of the formation. For example, only about 1 per cent of the Marcellus Shale Formation has been explored and developed. Therefore, large portions of a shale formation could remain untested for several decades or more.

3.1.2 Stages of extraction process

Horizontal drilling and hydraulic fracturing are among the practices that have become more widely used over the past two decades. During hydraulic fracturing, materials that typically consist of water, sand and additives, are injected at high pressure into low-permeability formations. The injection of the hydraulic fracturing fluids creates channels for flow in the formations (often shale formations), allowing methane and other hydrocarbon gases and liquids in the formation to flow to the production well. The well and formation is partially cleared of liquids in a process referred to as a completion flowback, after which the well is placed into production (Allen et al., 2013).

In order to ensure the optimal development of shale gas resources it is necessary to build a comprehensive understanding of geochemistry, geological history, multiphase flow characteristics, fracture properties (including an understanding of the fracture network), and production behaviour across a variety of shale plays. It is also important to develop knowledge that can enable the scaling up of pore-level physics to reservoir-scale performance prediction, and make efforts to improve formation evaluation techniques to allow accurate determination of the recoverable resource (Speight, 2013).

The major difference in shale gas production in comparison with conventional natural gas production originates from the different permeability of shale gas and natural gas reservoirs. Permeability refers to the capacity of a porous sediment, soil or rock to transmit a fluid. In a conventional reservoir, the gas is in interconnected pore spaces, much like a kitchen sponge, that allow easier flow to a well; but in an unconventional reservoir, like shale, the reservoir must be mechanically "stimulated" to create additional permeability and free the gas for collection (U.S. Department of Energy, 2013). That is the main reason why hydraulic fracking is needed in shale gas production.

There are three main phases in shale gas extraction: pre-production; production; and plug & abandonment (MacKay et al., 2013). These are described briefly in the next paragraphs.

3.1.2.1 Shale gas pre-production

Pre-production stages for shale gas include:

Exploration

Before a shale resource could be considered economic, many tests will need to be carried out which could include three-dimensional seismology and the drilling of test wells.

Site preparation

Removal of vegetation, building of access roads and the well pad, drilling rig mobilisation and demobilisation.

Drilling and casing

Shale reserves are often at depths of approximately 2 km, which is deeper than conventional reserves. A typical well consists of a vertical section and a horizontal section of up to 3 km in length. Drilling is completed in stages with the shallower section having a greater diameter to allow for the additional casing to protect the groundwater. Once the well has been lined, accurately positioned holes are made in the horizontal section to enable hydraulic fracturing.

Hydraulic fracturing

Fluids (approximately 90% water with 1–2% chemical additives such as hydrochloric acid for pH control, glutaraldehyde as a bactericide, guar gum as a gelling agent, and petroleum based surfactants (STRATERRA website, 2014) together with a 'proppant' (approximately 8% by volume, normally sand) are pumped down the well at high pressure. This pressure breaks up the shale, creating fractures which can extend a few hundred metres. The fracture growth height is dependent on the geology and treatment parameters (number and spacing of stages, fluid chemistry, and injection rates and volumes). Once the pressure is released, the proppant prevents the fractures from closing. Hydraulic fracturing is carried out in as many as 46 stages, starting from the furthest point and proceeding back towards the well head, as it is not usually possible to maintain the required down-hole pressure to stimulate the whole length of a lateral in one stage. Each interval is isolated in sequence so that only a single section of the well is hydraulically fractured at a given time.

Well completion

Once pumping has stopped and hydraulic fracturing is complete, a proportion (dependent on the geology) of the injected fracturing fluid flows back to the surface. The EPA estimates that a flowback can last one to ten days. In some cases, however, the flow may continue during the life of the well. After the flowback period, the fluids produced from the well are primarily hydrocarbons.

Waste treatment

Both drilling and well completion produce quantities of waste, which require careful disposal. The flowback fluids discharged from the well are saline and can include the fracturing fluid as well as naturally-occurring substances found within the shale, such as methane, trace metals, and naturally occurring radioactive material. The flowback of fluids, sometimes referred to as produced water, may continue during the production stage, and the liquid requires treatment before reuse or disposal. For instance, in the Marcellus Shale Formation the flowback fluids are normally reused to minimise environmental impact.

3.1.2.2 Production phase

The gas in the shale formation is likely to be a variable mixture of: methane and other gaseous hydrocarbons; acidic gases (CO₂, sulphurous compounds); inert gases (including nitrogen); water vapour; condensed higher hydrocarbons; and entrained particles. Table 3.1.2.2.1 shows how the gas composition varies between formations as well as between wells in the same formation, in several U.S. shale formations.

Table 3.1.2.2.1. Raw shale gas composition as a percentage by volume (Bullin, 2008).

	Bar- nett	Marcel- lus	Fayette- ville	New Albany	Antrim	Haynes ville	Mean
Methane (%)	87	85	97	90	62	95	86
Ethane (%)	7	11	1	1	4	0	4
Propane (%)	2	3	0	1	1	0	1
CO ₂ (%)	2	0	1	8	4	5	3
N ₂ (%)	3	0	1	-	29	0	7

The gas production rate from a well starts high and declines steeply; the decline is dependent on the shale formation (Baihly et al., 2011). Figure 3.1.2.2.1 gives examples of typical curves for the production rates as a function of time. The production rate starts to decline soon after the first month. On the other hand, the production rate after five years is still about half of that in the beginning, and the operation is obviously still profitable.

Once the gas production flow rate declines significantly, the operators may give the well a workover to extend its life. This workover may involve “re-fracking” or “liquid unloading” to remove liquids and debris that have built up in the wellbore. The U.S. Geological Survey (US Geological Survey, 2012) reported that the average EUR (estimated ultimate recovery) for basins ranged between 0.04 and 2.60 bcf per well (1–74 million m³). Due to the collapse in gas prices in the USA such small wells are now probably considered uneconomic.

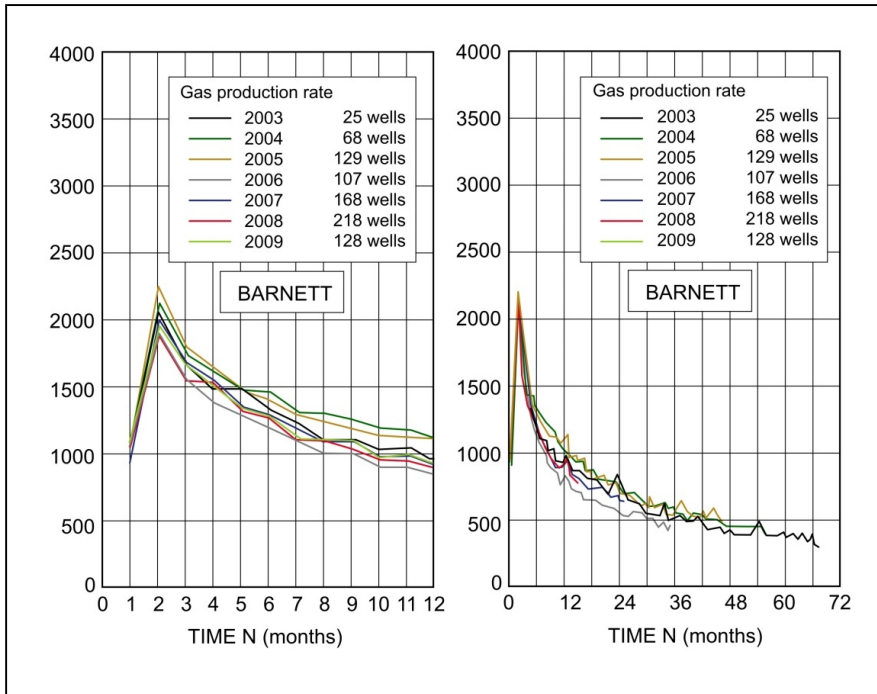


Figure 3.1.2.2.1. Barnett shale first-year and total production rates, colour-coded by year (Baihly et al., 2011).

3.1.2.3 Plug & abandonment

The plug & abandonment phase occurs once the operator deems the well uneconomic. The well is decommissioned by removing the equipment and distribution infrastructure. The well is then plugged with cement at various key points along the well to prevent fugitive emissions or future contamination.

3.2 Required infrastructure

Publication *Expanding the Shale Gas Infrastructure* (Goellner, 2012) together with websites <http://www.gie.eu/KC/gasinfrastructure.html> and http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/process.html provides a summary of required infrastructure for shale gas production, transmission, distribution, etc. The following chapters provide some key points from these sources.

The entire shale gas supply chain needs new, expanded and/or upgraded infrastructure in addition to that what exists for natural gas. These needs include:

- Bringing shale gas resources to production;
- Gathering the gas;

- Midstream processing of the gas;
- Long-distance gas transmission.

Additional facilities will be needed for processing, storing and use of increasing supplies of gas like LNG liquefaction plants and terminals, and gas-fired natural gas power plants for instance. Shale gas can be delivered to the customer through a gas network or as LNG when it is needed for logistical reasons.

3.2.1 Enabling drilling and production

Drilling increases the local demand for concrete, steel, excavation, hauling, and skilled construction. Drilling also requires large quantities of water, sand and equipment, which need to be transported into areas that are often remote. The road systems in shale plays need significant upgrading since local highways are often insufficient for supply of required goods and services. Regarding railroads, congestion has become a problem in some terminals and service yards in north-eastern Pennsylvania (Marcellus shale boom) for instance. Consequently, additional silos and storage facilities are needed to support the distribution network of sand and water.

The procurement and delivery of water for hydraulic fracturing is a complex water management and ecological issue in addition to infrastructure needs. Additionally, the disposition of produced and spent water used in the fracturing process further stresses the transportation infrastructure and requires the development of a disposition infrastructure. Facilities to treat waters associated with shale gas production are more sophisticated and more capital-intensive than municipal waste water plants.

3.2.2 Gathering and processing

After extracting the gas, it must be gathered into the transmission and distribution network. The investment for gathering lines as well as for the gas-processing facilities themselves is substantial, and in some cases may create an insurmountable barrier for profitable recovery of shale gas. The construction of gathering lines requires complex negotiations of rights of way.

The gas-processing unit is a relatively complex facility responsible for removal of acid gases (carbon dioxide, hydrogen sulfide, and organosulfur compounds), recovery of elemental sulfur, dehydration, mercury removal, and nitrogen removal occasionally. Furthermore, the gas stream goes to a demethaniser, where high-value gases (ethane, propane, butane, etc.) are separated from the gas stream, if economically feasible and/or separation is necessary, so that the remaining gas will meet pipeline gas specifications. The remaining pipeline-quality gas is injected into the transmission lines, which have to be expanded if new shale gas supply increases total gas consumption.

3.2.3 Market hubs

Market hubs are locations where pipelines intersect and flows are transferred. Market hubs have been developed to provide new natural gas shippers with many of the physical capabilities and administrative support services formally handled by the interstate pipeline company (in the U.S.) as “bundled” sales services. Two key services offered by market hubs are transportation between and interconnections with other pipelines and the physical coverage of short-term receipt/delivery balancing needs. Many of these centres also provide services that help expedite and improve the natural gas transportation process overall, such as Internet-based access to natural gas trading platforms and capacity release programs. Most also provide title transfer services between parties that buy, sell, or move their natural gas through the centre.

3.2.4 Liquefaction plants, storage terminals and export

In the countries, which will end up exporting shale gas as LNG since there is no gas network connection to the destination country, liquefaction plants and storage terminals need to be built for trading the gas on the world market (and perhaps also on the national market to some extent). In addition, for the trading of gas, new LNG carriers for gas transportation have to be built.

3.2.5 Re-gasification of LNG

Imported or domestic LNG is unloaded in LNG terminals where it is stored in special tanks before being re-gasified and injected into the transmission network.

Jetty: The LNG vessels are moored at a dock, where LNG is transferred to storage tanks using unloading arms (articulated pipes).

Storage tanks: Huge containers specially designed to store LNG at -160° C before re-gasification.

Vaporisers: Equipment where LNG is heated to about 0 °C when it returns to its gaseous form. This process increases its volume by about 600 times.

Grid connection: Connection to the transmission system where natural gas is metered.

3.2.6 Transmission

Gas is transported from the production areas to the end consumers by underground pipelines.

Pipelines: Underground gas pipelines arranged in a network for the transportation of gas between LNG terminals, upstream pipelines, storages and distribution networks and end users.

Delivery point: Pressure reduction station where gas is metered and supplied to end customers or distribution system operators.

Odourisation: Mixing odourless gas with an odourant to enable detection of gas leaks.

Metering: Measurement of gas quantity and energy flow through a pipeline.

Compressors: Engines used to increase the pressure of natural gas allowing it to flow through a pipeline. Compression stations are installed regularly in a pipeline network in order to maintain the right pressure.

3.2.7 Distribution to end users and use of shale gas

Gas needs to be distributed to residential and small industrial end consumers and other users by underground distribution networks.

Distribution pipelines: Small-diameter and low-pressure underground gas pipelines arranged in a network for the transportation of natural gas from the transmission network to end consumers.

Gas meters: Devices measuring the quantity of gas delivered to end consumers.

Higher-value gases separated from raw shale gas (see 3.2.2) need to be transported to their own markets and new assets to consume them may need to be built because of the increased supply.

Increased supply of pipeline-quality gas in addition to natural gas (see 3.2.2) implies also construction of new gas-fired power plants, and/or retrofitting of existing coal-fired plants to enable gas combustion in them. On the other hand, if a gas-fired power plant will be an option instead of construction of a new coal-fired power plant for instance, this may result in substantial savings.

Finally, use of compressed gas in vehicles, if employed in increasing quantities, implies also construction of expanded distribution and filling station networks. CNG filling stations for vehicles are being built in Pennsylvania and other states.

All in all, the whole supply chain of shale gas from the shale play to the end users is a relatively complicated and capital-intensive chain. However, depending on the market conditions it may be economically competitive in comparison with other energy production and use options.

3.3 Water consumption

The report Water Consumption of Energy Resource Extraction, Processing, and Conversion (Mielke et al., 2010) presents water consumption data gathered from several sources. According to the report, there are estimates for the water intensity of shale gas developments, from different gas producers, water regulators, and the USGS. Compared to other fossil fuels (Figure 3.3.1), the water-intensity of shale gas appears to be relatively low, at 0.6 to 1.8 gal/MMBtu. However, there are fundamental differences with coal and oil, which presents unique challenges for shale gas: the water consumption is front-loaded, during the drilling and completion stage. GTL and CTL in Figure 3.3.1 refer to gas-to-liquids and coal-to-liquids, respectively.

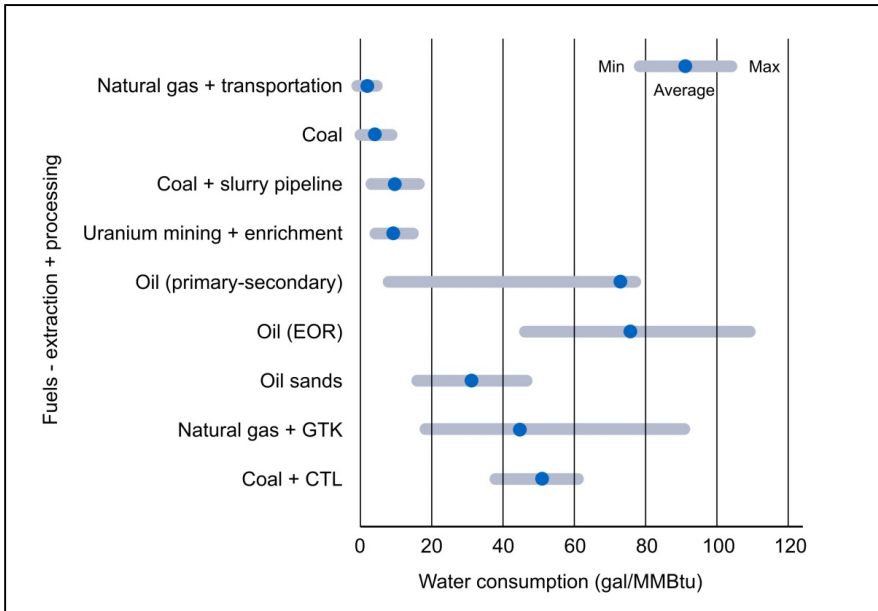


Figure 3.3.1. Water intensity in fossil fuel production (Mielke et al., 2010).

The two primary factors determining water intensity of extraction are (i) water consumed during the development (pre-production) phase, primarily for hydraulic fracturing and, to a lesser extent, drilling, and (ii) expected ultimate recovery of natural gas from the well. These factors vary by well, depending on the geology and the development decisions by the operator. Water consumption per well can be grouped into four areas: geological (maturity of shale, formation thickness); technological (horizontal vs. vertical wells, water recycling); operational (proximity of fresh-water source); and regulatory. (Bene and Harden, 2007).

Chesapeake Energy, the second-largest producer of unconventional natural gas in the U.S., has released data on its own estimates for water consumption in four plays in which it is active, detailing water consumption and reserve estimates for an average well in each play, with an average water intensity ranging from 0.8 gal/MMBtu (Haynesville) to 1.7 gal/MMBtu (Fayetteville). The company also provides a range of estimates for the company's shale gas drilling as a whole, with water consumption ranging from 3.6 to 4.5 million gal of water per well, and reserve estimates ranging from 2.1 to 6.7 million MMBtu per well, giving a range of 0.6 to 1.8 gal/MMBtu (Table 3.3.1).

Table 3.3.1. Estimates of water consumption for different shale plays (Chesapeake Energy, 2010).

Shale play	Water consumption per well (million gal)			Gas reserves per well		Water intensity
	Drilling	Hydraulic Fracturing	Total	BCF	MMBtu (million)	gal/MMBtu
Barnett	0.3	3.8	4.1	2.7	2.7	1.5
Fayetteville	0.1	4.0	4.1	2.4	2.5	1.7
Haynesville	0.6	5.0	5.6	6.5	6.7	0.8
Marcellus	0.1	5.5	5.6	4.2	4.3	1.3
<i>Typical min</i>	<i>1.0</i>	<i>3.5</i>	<i>4.5</i>	<i>6.5</i>	<i>6.7</i>	<i>0.6</i>
<i>Typical max</i>	<i>0.1</i>	<i>3.5</i>	<i>3.6</i>	<i>2.0</i>	<i>2.1</i>	<i>1.8</i>
Average						1.3

The estimates are specific to one company's operations (i.e. Chesapeake Energy) and reflect typical water intensity across its asset portfolio, not necessarily a representative range of water intensity for the industry as a whole.

Reference (Jiang et al., 2013) discusses the life cycle water consumption and wastewater generation impacts of a Marcellus shale gas well from its construction to end of life. The results show that under the current conditions, an average Marcellus shale gas well consumes 20 000 m³ (with a range from 6700 to 33 000 m³) of freshwater per well over its life cycle excluding final gas utilisation, with 65% direct water consumption at the well site and 35% indirect water consumption across the supply chain production. If assumed that reserve estimates would range from 2.1 to 6.7 million MMBtu per well like in the previous chapter, this would result in water intensity figures from 2.5 to 7.9 gal/MMBtu, clearly higher than what Table 3.3.1 gives (1.3 gal/MMBtu for Marcellus).

Jiang et al. have also evaluated direct and indirect water consumption at the well site. Direct water consumption was assessed by analysis of data from approximately 500 individual well completion reports collected in 2010 by the Pennsylvania Department of Conservation and Natural Resources. Indirect water consumption for supply chain production at each life cycle stage of the well was estimated using the economic input–output life cycle assessment (EIO-LCA) method. Figure 3.3.2 shows direct and indirect water consumption across the life cycle stages of a Marcellus shale well. Hydraulic fracturing represents 86% of the freshwater consumption during the whole life cycle (excluding gas utilisation). Most of this (76%) is direct water consumption for fracturing fluids and the rest is mainly indirect water consumption for sand and additives production. Well pad preparation accounts for 11% of the total water consumption and other process stages are practically insignificant in comparison with fracturing and preparation stages.

Jenkins has made a rough estimation on water consumption in his article How Much Water Does Fracking for Shale Consume (Jenkins, 2013). According to EIA

approximately 27 000 shale gas wells were drilled in 2011 (http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm). Shale gas wells represented virtually all of the increase in gas production from 2010 to 2011, and therefore Jenkins has assumed, for simplicity, that these were all shale wells that were hydraulically fractured (rather than any conventional wells). Furthermore, Jenkins has assumed that each well consumes 5 million gallons of water on average for the fracturing and completion of the well. Given those assumptions, all shale gas wells completed in 2011 across the United States consumed on the order of 135 billion gallons of water. On the other hand, all freshwater withdrawals (surface and groundwater) totalled about 127 750 billion gallons already in 2005. Using that as a baseline, Jenkins calculates that shale gas wells in 2011 account only for 0.1 percent of total U.S. freshwater withdrawals. As another point of comparison, Jenkins states that golf courses in the United States consume about 0.5 percent of all freshwater used in the country, according to the Professional Golf Association.

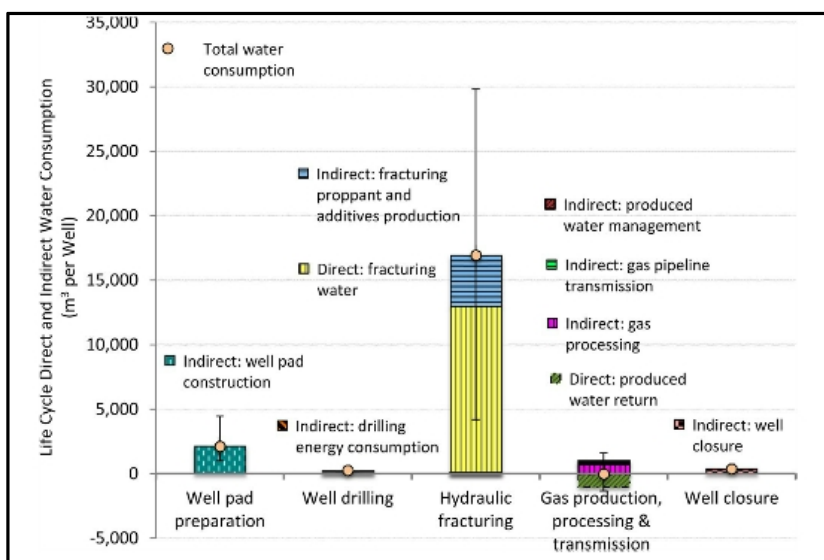


Figure 3.3.2. Estimated life cycle direct and indirect water consumption for a Marcellus shale gas well (Jiang et al., 2013).

3.4 Latest developments

In the debate over hydraulic fracturing for natural gas, especially water consumption and additives used in hydraulic fracking fluid seem to raise concern. An emerging technology developed in Canada, just making its way to the U.S., does away with the need for water. Instead, it relies on a thick gel made from propane, a widely-available gas used in households for barbecue grills, for instance. Called

liquefied propane gas fracturing, or simply "gas fracking," the waterless method was developed by GasFrac, based in Calgary, Alberta. Still awaiting a patent in the U.S., the technique has been used about 1000 times since 2008, mainly in gas wells in the Canadian provinces of Alberta, British Columbia and New Brunswick and a smaller handful of test wells in states that include Texas, Pennsylvania, Colorado, Oklahoma and New Mexico (BioFuels and Energy/Environment, 11 August, 2011).

Like water, propane gel is pumped into deep shale formations a mile or more underground, creating high pressure that cracks rocks to free trapped natural gas bubbles. Like water, the gel also carries small particles of sand or man-made material that are forced into cracks to hold them open allowing the gas to flow out. After the pumping the gel reverts to vapour due to pressure and heat, then returns to the surface – along with the natural gas – for collection, possible reuse and ultimate resale. According to GasFrac, propane does not carry back to the surface drilling chemicals, ancient seabed salts and underground radioactivity.

According to GasFrac, propane fracking has significant benefits in comparison with slick-water fracturing:

- It is more efficient, because it allows more gas to flow from wells than water-based fracturing. All the propane leaves the fractured rocks, unlike water, part of which remains behind and can be absorbed into rock to partially block the pathways for gas to escape;
- The propane method uses only about one-quarter of the number of truck trips compared to water-based fracking and consequently the impact on local roads, the noise and dust annoyance to neighbours, and the trucking costs for drillers are reduced.

However, propane costs more initially to use, even though it can be resold once recovered. It is also explosive, and requires special equipment to be handled properly and reduce risk.

The American company eCORP Stimulation Technologies describes their technology called "propane stimulation" on their website <http://www.ecorstim.com/propane-stimulation/>. However, the website does not clearly demonstrate how this technology differs from GasFrac's technology.

The company Halliburton has developed the OmegaFrac™ additive. Halliburton explains on their website that it is the first fracturing fluid that eliminates the need to use potable water without compromising the necessary fluid qualities. While most fluids used in fracturing today are blended from fresh water and natural polymers, according to Halliburton their additive is based on a proprietary biopolymer and uses field-produced brine water to suspend and deliver proppant into the fracture, providing easy clean-up to maximise sustained conductivity (<http://www.halliburton.com/public/solutions/contents/Shale/Brochures/H06377.pdf>).

General Electric says it has developed a technology that could cut the cost of water treatment in half. The new technology would make it unnecessary to dilute the wastewater, or transport it for treatment or disposal. It is based on a desalination technology known as membrane distillation, which combines heat and de-

creased pressure to vaporise water using membranes to separate pure water vapour from salt water. Ordinarily, membrane distillation works by applying heat to the water at one end of the process, while at the other side cooling off the water vapour to make it condense. The heating and cooling systems have been replaced with one device, a vapour compressor borrowed from industrial refrigerators in order to make the process more efficient (Bullis, 24 September 2013). Based on pilot-scale tests of a machine that can process about 2 500 gallons of water per day, General Electric researchers say they are on track to cut the costs of treating salty fracking wastewater in half. The system needs to be scaled up for commercial use, but a full-sized system could treat about 40 000 gallons per day.

Another benefit that the water-free fracking offers is that it could be used in regions with scarce water resources. As a matter of fact, some of the world's largest sources of shale gas are found in deserts. For instance, in China the best shale gas deposits are in arid areas such as the Tarim Basin in northeast China, located beneath the Taklamakan Desert with nearly 300 000 square kilometres of shifting dunes. Piping in water would strain already tight supplies (Bullis, 22 March 2013).

4. Environmental impacts

The extraction and use of shale gas can affect the environment through the leaking of extraction chemicals and waste into water supplies, the leaking of greenhouse gases during extraction, and the pollution caused by the improper processing of natural gas. A challenge to preventing pollution is that shale gas extraction varies widely in this regard, even between different wells in the same project; the processes that reduce pollution sufficiently in one extraction area may not be enough in another (Bahadori, 2013).

4.1 Greenhouse gas emissions

GHG emissions resulting directly from shale gas operations are usually categorised as follows (MacKay et al., 2013):

- Vented emissions of methane and CO₂. Vented emissions are intentional. Many processes associated with shale gas exploration and production can cause gases to be vented, where permitted. Examples include: release of gases during flowback, and release for safety reasons and during certain maintenance operations;
- Emissions from combustion of fossil fuels on site. These emissions come from engines (such as diesel engines used for drilling, hydraulic fracturing and natural gas compression) and from flaring of shale gas. It is assumed that the combustion emissions would be mainly CO₂. However, incomplete combustion could result in other emissions such as methane, volatile organic compounds and carbon black, all of which would have global warming and air pollution impacts;
- Fugitive emissions. These emissions are unintentional gas leaks and are difficult to quantify and control. There are various potential sources of fugitive emissions, including leaks from valves, well heads and onsite accidents or accidental releases from the well casing into groundwater. It has also been suggested that it may be possible for gas in the shale formation to escape into groundwater due to fracking activities. The likelihood of wide-spread significant releases by this mechanism has been widely questioned in literature. No incidents of direct invasion of shallow water zones by fracture fluids during the fracturing process have been recorded. There

are also indirect emissions, which result from product/processes used in the exploitation of shale gas. These emissions include the emissions from the energy used to treat and transport the water and wastewater, and to manufacture the chemicals and materials of construction.

Jiang et al. (2011) have estimated the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compared its emissions with national average U.S. natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. They estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide-equivalent emissions or about 1.8 g CO₂e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO₂e/MJ of gas produced with an average of 68 g CO₂e/MJ (Jiang et al., 2011). These studies on GHG emissions are based on present practices of drilling, completions, flowback and production. These practices are being developed, which may have an effect on the GHG emissions also in the future.

Howarth et al. (2011) have evaluated the GHG footprint of natural gas obtained by high volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and according to Howarth et al. 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured – as methane escapes from flowback return fluids – and during drill out following the fracturing. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years (Howarth et al., 2011).

Cathles et al. (2012) argue that the analysis in the previous paragraph (Howarth et al., 2011) is seriously flawed in that they, among other things, significantly overestimate the fugitive emissions associated with unconventional gas extraction and undervalue the contribution of “green technologies” to reducing those emissions. In addition, Cathles et al. state that Howarth et al.’s high-end (7.9%) estimate of methane leakage from well drilling to gas delivery exceeds a reasonable estimate by about a factor of three and they document nothing that indicates that shale wells vent significantly more gas than conventional wells.

Howarth’s et al. high-end 7.9% for methane emissions indeed seems to be overestimated. Their estimate for methane flow rate during the flow-back period (in m³/day, data in Table 1 of their paper) corresponds to methane flow rates in the range 0.5–7.9 m³/s (Barnett 0.5 and Haynesville 7.9 m³/s. Those would be 17–283

MW in terms of energy flow rate. The high-end would correspond to the fuel feed to a relatively large power plant. It would be obviously impossible to stay in the vicinity of the sites if the rates would be that high and the probability for large-scale fires would be very high too. No such problems have been reported so far from the shale gas production sites.

The University of Texas at Austin has published a study (Allen et al., 2013) entitled “*Measurements of Methane Emissions at Natural Gas Production Sites in the United States*”. The study is the first to be based on direct on-site measurements of methane emissions at the well pad. It concludes that emissions during the completion stage of the well are significantly lower than previous national emissions estimates. The study over methane emissions from natural gas production, was based on the measurements of 190 natural gas production sites in the U.S. spread over several shale gas plays. According to the report, methane emissions from natural gas production are 0.42% of produced natural gas, similar to the most recent estimates of the U.S. Environmental Protection Agency. The authors found that at the majority of hydraulically fractured well completions sampled, industry has proactively imposed green completion technology which effectively reduced methane emissions by 99 per cent. As a result, methane emissions from well completions are 97 per cent lower than 2011 national emission estimates published by the EPA in April 2013.

The report *Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use* (MacKay et al., 2013) discusses the potential GHG emissions from the production of shale gas in the UK. Their main conclusions are:

- The carbon footprint (emissions intensity, Figure 4.1.1) of shale gas extraction and use is likely to be in the range 200–253 g CO₂ per kWh of chemical energy, which makes shale gas’s overall carbon footprint comparable to gas extracted from conventional sources (199–207 g CO₂ per kWh), and lower than the carbon footprint of liquefied natural gas (233–270 g CO₂ per kWh). When shale gas is used for power generation, its footprint is likely to be 423–535 g CO₂ per kWh, which is significantly lower than the carbon footprint of coal, 837–1130 g CO₂ per kWh;
- If adequately regulated, local GHG emissions from shale gas operations should represent only a small proportion of the total carbon footprint of shale gas, which is likely to be dominated by CO₂ emissions associated with its combustion;
- If shale gas extraction is demonstrated by industry to be economic in the UK, some of the UK’s reserve may be used nationally. Because the UK is well-connected to the Western European gas market, the effect of UK shale gas production on gas prices is likely to be small, and the principal effect of UK shale gas production and use will be that it displaces imported LNG, or possibly piped gas from outside Europe. The net effect on total UK GHG emissions rates is likely to be small.

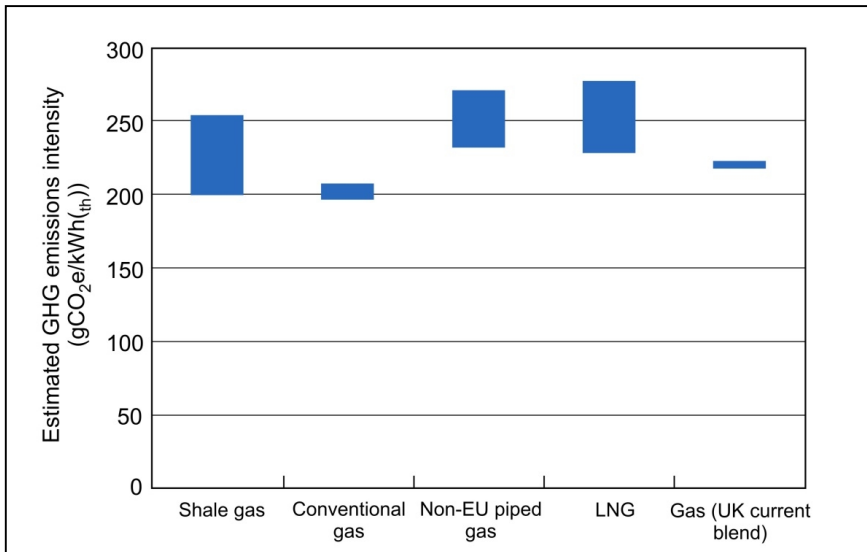


Figure 4.1.1. Estimated GHG emission intensity for various sources of gas. For shale gas the emissions intensity depends on the assumed completion method; here it has been assumed that methane released during completion would be 90% captured and flared (Mackay et al., 2013).

Many shale gas play regions have seen a marked increase in diesel emissions due to increased truck traffic and drilling activity. The industry should reduce the use of diesel fuel by converting engines to run off of natural gas. This conversion is underway in many areas, like South Texas in the Eagle Ford development (Holditch, 2013).

4.2 Impact on water resources

4.2.1 Process water cycle

Water consumption in shale gas production was discussed in subchapter 3.3. The process water cycle of hydraulic fracturing is presented schematically in Figure 4.2.1.1.

Figure 4.2.1.2 is a schematic depiction of the water pumping and mixing unit. Concentrated gel and fracturing fluid additives are first mixed with water. Proppant is then mixed with this fluid and pumped through the wellhead to the well.

The EPA's report *The Hydraulic Fracturing Water Cycle* (EPA, 2014) lists the stages and possible environmental impacts of the hydraulic fracturing water cycle:

Stage 1: Water Acquisition

Large volumes of water are withdrawn from ground water and surface water resources to be used in the hydraulic fracturing process. However, many companies have begun recycling wastewater from previous hydraulic fracturing activities, rather than acquiring water from ground or surface resources. Potential impacts on drinking water resources are according to EPA:

- Change in the quantity of water available for drinking
- Change in drinking water quality

Stage 2: Chemical Mixing

Once delivered to the well site, the acquired water is combined with chemical additives and proppant to make the hydraulic fracturing fluid. Chemical additives found in hydraulic fracturing fluids are discussed in sub-chapter 4.2.2. Proppant is a granular substance such as sand that is used to keep the underground cracks open once the hydraulic fracturing fluid is withdrawn. The potential impact on drinking water resources in this stage is the release of the mixture to surface and ground water through on-site spills and/or leaks.

Stage 3: Well Injection

Pressurised hydraulic fracturing fluid is injected into the well, creating cracks in the geological formation that allow oil or gas to escape through the well to be collected at the surface. The EPA lists possible mechanisms, which could have an effect on drinking water resources, such as:

- Release of hydraulic fracturing fluids into groundwater due to inadequate well construction or operation;
- Movement of hydraulic fracturing fluids from the target formation to drinking water aquifers through local man-made or natural features (e.g., abandoned wells and existing faults);
- Movement into drinking water aquifers of natural substances found underground, such as metals or radioactive materials, which are mobilised during hydraulic fracturing activities.

These mechanisms are considered possible, but not likely, taking into account the recent developments in regulations and technology. There are no reported cases where drinking water resources would have been affected through these mechanisms.

Stage 4: Flowback and Produced Water (Hydraulic Fracturing Wastewaters)

After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses, and water and excess proppant flow up through the wellbore to the surface. This combination of fluids, containing hydraulic fracturing chemical additives and naturally occurring substances (called flowback), must be stored on-site – typically in tanks or pits – before treatment, recycling, or disposal. Furthermore, after the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracturing fluid

and some is natural formation water. These waters (called produced water) move back through the wellhead with the gas. The potential environmental impact is the release of these fluids into surface or ground water through spills or leakage from on-site storage.

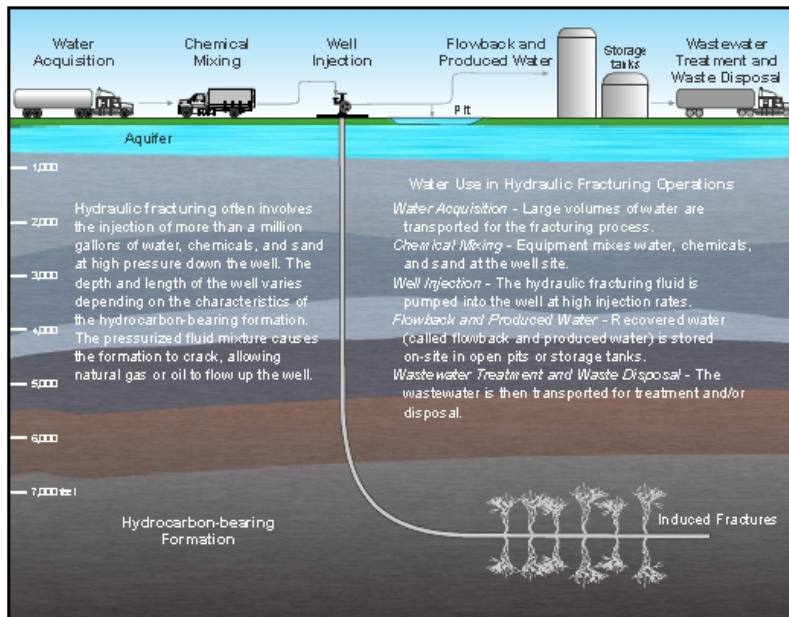


Figure 4.2.1.1. Illustration of a horizontal well showing the water lifecycle in hydraulic fracturing (EPA, 2011).

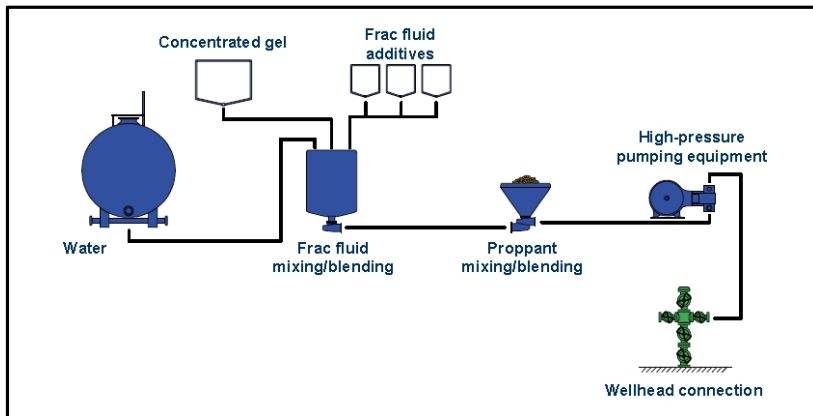


Figure 4.2.1.2. Water pumping and mixing unit for a shale gas well, (<http://www.slb.com>).

Stage 5: Wastewater Treatment and Waste Disposal

Wastewater is dealt with in one of several ways, including but not limited to: disposal by underground injection, treatment followed by disposal to surface water bodies, or recycling (with or without treatment) for use in future hydraulic fracturing operations. According to the EPA, potential impacts on drinking water resources in this stage are:

- Contaminants reaching drinking water due to surface water discharge and inadequate treatment of wastewater;
- Byproducts formed at drinking water treatment facilities by reaction of hydraulic fracturing contaminants with disinfectants.

4.2.2 Additives used in the extraction process

Use of additives in the shale gas extraction process and possible environmental effects that it may have, is a highly controversial and complex issue. The authors do not endorse any opinions or information referred to in this sub-chapter and cannot guarantee accuracy, or completeness of that information.

The complexity of this issue is, among other things, due to the high number of chemicals used (several hundreds), as well as quite complicated mechanisms, which may be involved. Proponents of shale gas utilisation say that practically all additives and their compounds are substances, which are used in households or for other commonly accepted purposes. Most of the complaints against hydraulic fracturing are because of possible groundwater contamination (Directorate General for Internal Policies, 2011). Besides specific spills and accidents, the intrusion of fracturing fluids or methane from the deeper structures is a main focus. Some mechanisms, which could contaminate water according to the previous reference are:

- Spills of drilling mud, flowback and brine, from tailings or storage tanks causing water contamination and salinisation;
- Leaks or accidents from surface activities, e.g. leaking fluid or waste water pipes or ponds, unprofessional handling or old equipment;
- Leaks from inadequate cementing of the wells;
- Leaks through geological structures, either through natural or through artificial cracks or pathways.

Additives are used during the extraction process for a variety of purposes, like those listed below (Shale Gas Explained, 2014):

- Reducing friction between the water and the pipe or casing in the well;
- Stopping the growth of bacteria in the well and reservoir;
- Preventing corrosion of the casing; and
- Carrying the proppant.

The U.S. Department of Energy's web page Shale Gas Development Challenges – A Closer Look has a figure that shows the average hydraulic fracturing fluid composition for U.S. shale plays (Figure 4.2.2.1).

The original source of Figure 4.2.2.1 is FracFocus (<http://fracfocus.org/>). FracFocus is a joint effort by the Ground Water Protection Council (<http://www.gwpc.org/>) and the Interstate Oil and Gas Compact Commission (<http://iogcc.publishpath.com/about-us>). It is sponsored by the U.S. Department of Energy. It is an online registry for companies to publicly disclose the chemicals used in hydraulic fracturing. For the U.S. and Canada, fracturing fluid compositions and other data can be accessed on a well-to-well basis on the website *FracFocus Chemical Disclosure Registry* (<http://fracfocus.org/>). FracFocus has been criticised for being incomplete and for allowing operators to claim trade secrets and thus circumvent full disclosure. As of November 2012, more than 30 000 well sites and 200 companies were registered on the FracFocus site, and eight states were using it for regulatory reporting. Regardless, according to Figure 4.2.2.1 fracturing fluid consists mainly of water and sand (99.7%) and of nine groups of additives.

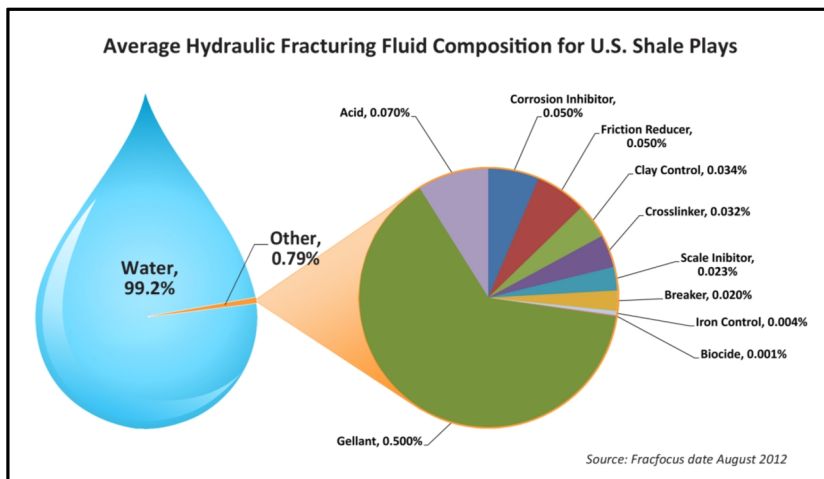


Figure 4.2.2.1. Average hydraulic fracturing fluid composition for U.S. shale plays according to FracFocus.

Table 4.2.2.1 provides a summary of the additives, their main compounds, the reason the additive is used in a hydraulic fracturing fluid, and some of the other common uses for these compounds. Hydrochloric acid (HCl) is the single largest liquid component used in a fracturing fluid aside from water; while the concentration of the acid may vary, a 15% HCl mix is a typical concentration (US Department of Energy, 2009).

According to Shale Gas Information Platform shale gas operators are continually called upon to fully disclose the composition of the fracturing fluids and to fully report the volume and the types of additives used. This has become an important issue in the public debate because some of the additives that have been and/or are still being used are hazardous or toxic in their pure form. According to SHIP's website at the present time some companies do disclose these data. Disclosure has been made mandatory in some U.S. states by law.

The U.S. Secretary of Energy authorized the establishment of the Secretary of Energy Advisory Board Subcommittee on Shale Gas Production. The Committee published two reports, one in August 2011 and the second in November 2011. Among other things, issues related to the additives used in the shale gas extraction process and other water related issues are discussed in these reports. Both reports can be found at: <http://www.shalegas.energy.gov/>.

Table 4.2.2.1. Fracturing Fluid Additives, Main Compounds, and Common Uses. (Modern Shale Gas Development in the United States: A Primer, 2009)

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make-up remover, laxatives, and candy
Gel	Guar gum or hydroxyl ethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron Control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as cross linkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and deicing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant and hair color
<p>Note: The specific compounds used in a given fracturing operation will vary depending on company preference, source water quality and site-specific characteristics on the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales.</p>			

The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

- Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process;
- Manifest all transfers of water among different locations;
- Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing;
- Additional field studies on possible methane leakage from shale gas wells to water reservoirs;
- Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity;
- Agencies should review field experience and modernise rules and enforcement practices to ensure protection of drinking and surface waters. Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

4.2.3 Groundwater and surface water

The reference (US Department of Energy, 2009) presents a comprehensive review on casing and cementing programs, and on drilling fluids and retention pits. The review is referred to below.

Protecting Groundwater: Casing and Cementing Programs

Current well construction requirements consist of installing multiple layers of protective steel casing and cement that are specifically designed and installed to protect fresh water aquifers and to ensure that the producing zone is isolated from overlying formations. During the drilling process, a conductor and surface casing string are set in the borehole and cemented in place.

In some instances, additional casing strings may be installed; these are known as intermediate casings (Figure 4.2.3.1). After each string of casing is set, and prior to drilling any deeper in the borehole, the casing is cemented to ensure a seal is provided between the casing and formation or between two strings of casing (Bellabarba et al., 2008). Figure 4.2.3.1 illustrates the casing and cement that may be installed in shale gas wells and highlights how the casing can be set to isolate different water-bearing zones from each other. The figure shows the multiple strings of casing, layers of cement and the production tubing, which are all important parts of the well completion in preventing contamination of fresh water zones and assuring that the gas resource does not flow into other, lower pressure zones around the outside of the casing rather than flowing up the well to be produced and sold (<http://www.rrc.state.tx.us/>).

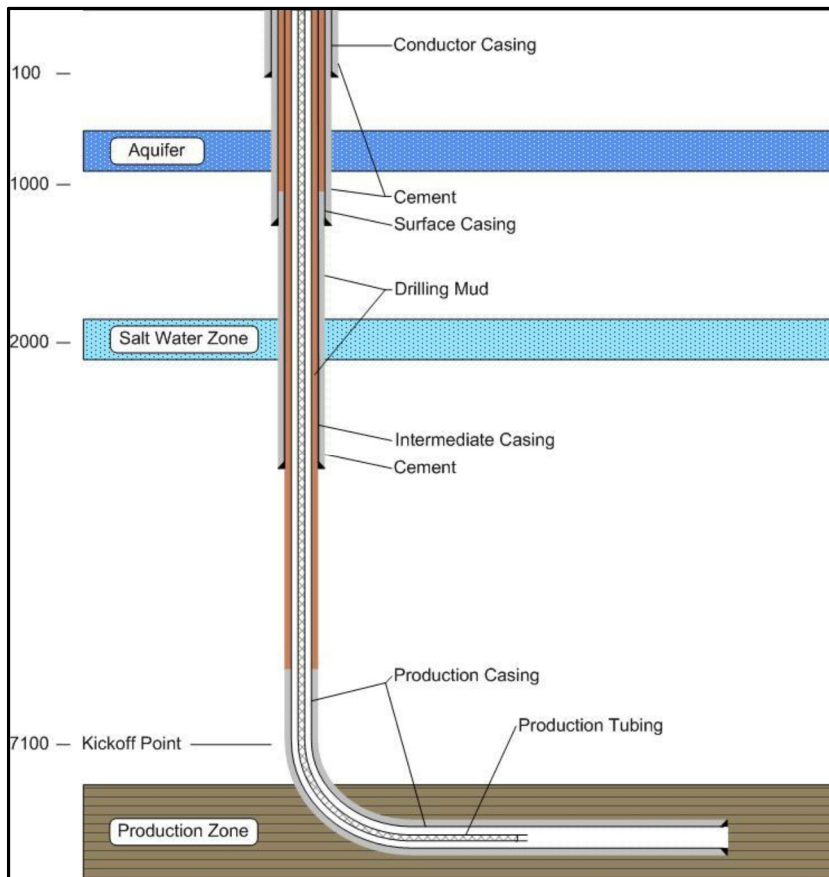


Figure 4.2.3.1. Casing and cementing of the shale gas borehole (ALL Consulting, 2008).

The conductor casing serves as a foundation for the well construction and prevents caving of surface soils. The surface casing is installed to seal off potential freshwater-bearing zones. This isolation is necessary in order to protect aquifers from drilling mud and produced fluids. As a further protection of the fresh water zones, air-rotary drilling is often used when drilling through this portion of the wellbore interval to ensure that no drilling mud comes in contact with the fresh water zone. Intermediate casings, when installed, are used to isolate non-freshwater-bearing zones from the producing wellbore. Intermediate casing may be necessary because of a naturally over-pressured zone or because of a saltwater zone located at depth. The borehole area below an intermediate casing may be uncemented until just above the kick-off point for the horizontal leg. This area of wellbore is typically filled with drilling muds.

In addition to the protections provided by multiple casings and cements, there are natural barriers in the rock strata that act as seals holding the gas in the target formation. Without such seals, gas and oil would naturally migrate to the earth's surface. A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so could never be tapped and produced in usable quantities.

In the U.S., state oil and gas regulatory agencies often specify the required depth of protective casings and regulate the time that is required for cement to set prior to additional drilling. These requirements are typically based on regional conditions. Once the casing strings are run and cemented there could be five or more layers or barriers between the inside of the production tubing and a water-bearing formation (fresh or salt).

Drilling Fluids and Retention Pits

Drilling fluids are a necessary component of the drilling process; they circulate cuttings (rock chips created as the drill bit advances through rock, much like sawdust) to the surface to clear the borehole, they lubricate and cool the drilling bit, they stabilise the wellbore (preventing cave in), and control downhole fluid pressure (Schlumberger, 2008). In order to maintain sufficient volumes of fluids onsite during drilling, operators typically use pits to store make-up water used as part of the drilling fluids. Storage pits are not used in every development situation. In the case of shale gas development, drilling operations have occurred in both urban and rural locations, requiring that drilling practices be adapted to facilitate development in both settings. Drilling with compressed air is becoming an increasingly popular alternative to drilling with fluids due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air-based drilling (Singh, 1965). The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus Shale in New York.

In rural areas, storage pits may be used to hold fresh water for drilling and hydraulic fracturing. In an urban setting, due to space limitations, steel storage tanks may be used. Tanks can also be used in a closed-loop drilling system. Closed-loop drilling allows for the re-use of drilling fluids and the use of lesser amounts of

drilling fluids (Swaco, 2006). Closed-loop drilling systems have also been used with water-based fluids in environmentally sensitive environments in combination with air-rotary drilling techniques. While closed-loop drilling has been used to address specific situations, the practice is not necessary for every well drilled.

In rural environments, storage pits may be used to hold water. They are typically excavated containment ponds that, based on the local conditions and regulatory requirements, may be lined. Pits can also be used to store additional make-up water for drilling fluids or to store water used in the hydraulic fracturing of wells.

Water storage pits used to hold water for hydraulic fracturing purposes are typically lined to minimise the loss of water from infiltration (Figure 4.2.3.2). Water storage pits are becoming an important tool in the shale gas industry because the drilling and hydraulic fracturing of these wells often requires significant volumes of water as the base fluid for both purposes (Harper, 2008).

General Electric says it has developed a technology that could cut the cost of water treatment in half, see sub-chapter 3.5. Much of the freshwater pumped underground at high pressure to fracture rock and release trapped oil and gas, flows back out. The new technology would make it unnecessary to dilute the wastewater, or transport it for treatment or disposal (Bullis, 24 September 2013).



Figure 4.2.3.2. Lined Fresh Water Supply Pit from the Marcellus Shale Development in Pennsylvania (source: ALL Consulting, 2008).

4.3 Induced seismicity

Induced seismicity results from human activity, such as 1) mining, 2) construction of large water reservoir impoundments with dams, 3) fluid injections into rock formations for waste water disposal or 4) stimulation of fluid flow using hydraulic fracturing in hydrocarbon or geothermal reservoirs. These activities involve changes in stress, pore pressure, volume and load in underground rock formations which can result in sudden shear failures in the subsurface, releasing pre-existing shear stress on weakness zones, such as fault structures or fractures (Shale Gas Information Platform's website, 8 September, 2014).

Induced seismicity in oil and gas production has been observed since the 1930s, i.e., ever since large-scale extraction of fluids occurred. The most famous early instance was in Wilmington, California, where oil production triggered a series of damaging earthquakes. In this instance, the cause of the seismicity was traced to subsidence due to rapid extraction of oil without replacement of fluids. Once this was realised, oil extraction was balanced with water injection not only to mitigate seismicity, but also to mitigate damage to the oil wells in the producing field. In the last decade, a number of examples of earthquake activity related to oil and gas production as well as injection of liquids under high pressure have been observed, although not with the serious consequences seen in Wilmington. In some recent cases, injection of produced water has produced significant seismic activity (Lawrence Berkeley National Laboratory, Earth Sciences Division's website, 8 September, 2014).

Physically there is no difference between induced and natural seismicity; both are characterised by shear slip on a fault or fracture. It can often be difficult to determine whether a given seismic event is of natural origin or induced, especially in the case of moderate to large seismic events. The reason is the pre-existing natural underground stress field and the often unknown significance of the added, human-induced contribution to the stress field. Clear rules and scientific methods to discriminate between natural and induced earthquakes are not yet well established or commonly accepted. When addressing induced seismicity in terms of operations related to shale gas production, the hydraulic fracturing process itself and the sometimes practiced injection of flowback or production water into disposal wells have to be considered. The vast majority of seismic events related to both hydraulic fracturing and waste water disposal in wells are of minor significance. In general, hydraulic fracturing induces lower maximum magnitudes than water disposal in wells. Sufficient data are available on the magnitudes of induced seismicity from short-term, high-pressure hydraulic fracturing operations carried out in geothermal and unconventional hydrocarbon production. The final conclusion that can be drawn from these reports is that hydraulic fracturing causes a large amount of small seismic events, with the vast majority of events being too small to even be detected by geophones at the surface. (SHIP's website, 8 September, 2014). An example of microseismic event distribution from a Barnett Shale hydraulic fracturing operation is shown in Figure 4.3.1. The maximum magnitude recorded was -

1.6 (negative seismic magnitudes exist since magnitude calculations are based on a logarithmic scale).

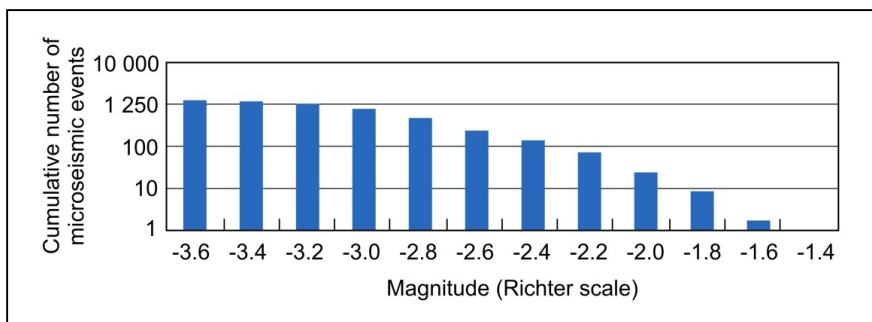


Figure 4.3.1. Cumulative frequency distribution of microseismic events of different sizes in a Barnett Shale well (Worldwatch Institute, 2010).

Higher maximum seismic magnitudes have been observed during long-term, high-pressure (waste) water injection into deep wells (Nicola et al., 2011). In the case of long-term water injection, much larger volumes of fluids are injected than in hydraulic fracturing operations. Additionally, long-term water injections cover a timespan of several months or years, whereas hydraulic fracturing operations can be completed in a matter of hours or a day at the most.

Operators generally benefit from induced seismicity since the seismic cloud is the only feature that allows characterisation of the spatial extent of the created hydrofracture. This information is important for operators since it defines the portion of the reservoir that has been fractured, thus increasing the shale's permeability and promoting the natural gas stream from the rock to the production casing (Shale Gas Information Platform's website, 8 September, 2014).

5. Implications of shale gas production on global energy market

5.1 Global implications

In terms of gas markets the shale gas revolution has already had an impact (Stevens, 2012). It has created an oversupply of LNG and a general downward pressure on gas prices. The impact of the shale gas revolution has been significant in the United States. The increased supply has led to a significant drop in U.S. domestic gas prices. Stevens lists the following effects, which shale gas revolution has had on energy markets:

- The 'shale gas revolution' in the United States created an oversupply of liquefied natural gas and downward pressure on gas prices across the globe;
- Disappointing outcomes have reduced the hype about the prospects for shale gas in Europe, and led to the realisation that, at least in western Europe, there are serious obstacles to its development;
- There has been considerable debate over the level of technically recoverable shale gas resources together with significant revisions to some estimates of those resources;
- Growing opposition to shale gas is driven by concerns over the environmental impact of hydraulic fracturing and the impact on greenhouse gas emissions;
- In the United States, energy self-sufficiency has increased in importance, making the continuation of the 'shale gas revolution' there more likely;
- There is a growing fear that shale gas may not be a substitute for coal as many originally hoped, but rather for renewables;
- Overall, levels of investor uncertainty remain as high as ever, particularly with regard to developments outside the United States.

Figure 5.1.1 shows the Henry Hub natural gas spot price from 1997 to 2014. Excluding two peaks (2006 and 2008), the price has been decreasing during the last ten years, even though it has fluctuated quite a lot.

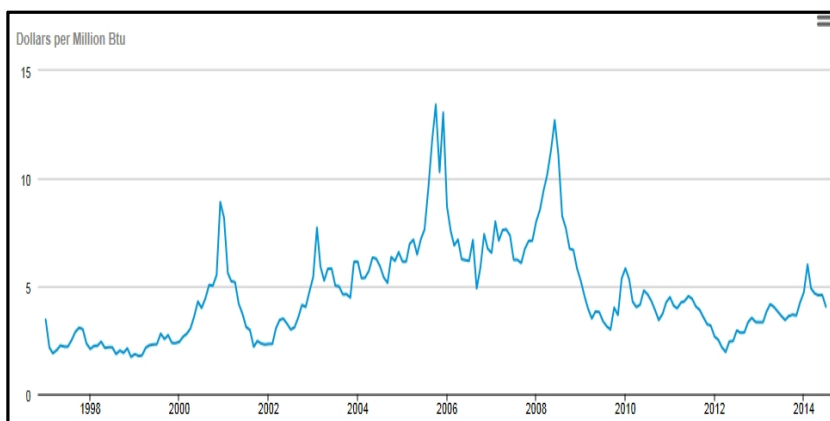


Figure 5.1.1. Henry Hub natural gas spot price (EIA, September 2014).

According to Melikoglu (2014), in 2012 the U.S. surpassed Russian natural gas production for the first time since 1982. On the same year, the annual average U.S. Henry Hub natural gas spot price decreased to \$2.75 per million Btu (\$9.4/MWh). In 2013, technically recoverable shale gas resources of the world were estimated at 7 300 trillion cubic feet (EIA, June 10, 2013). As a result, there is a global rush to develop as much of this resource as possible. However, there is concern about the accuracy of resource potential estimations due to the lack of data and specifically designed shale gas reservoir models. Nonetheless, the analysis showed (Melikoglu, 2014) that without developing global shale gas resources the world has to consume 66% of its proved natural gas reserves to supply the demand until 2040. This would make most of the world natural gas importers, and rules of economy dictate that limited supply and increasing demand would skyrocket natural gas prices.

Moryadee et al. state in their journal article (Moryadee et al., 2013) that the emergence of shale gas has shifted the U.S. from a natural gas importer to LNG exporter and U.S. natural gas companies are motivated to export for several reasons. First, natural gas prices in the U.S. are substantially lower than in other natural gas markets. The prices at Henry Hub were between \$3 and 4 per million British thermal units in 2012, which is relatively low compared with Asian prices (\$15 to 16/MMBtu) and European prices (\$9 to 11 /MMBtu), as indicated in Figure 5.1.2. Second, because natural gas is considered a key fuel source that exhibits the lowest carbon content among fossil fuels (EIA, September 2012), its demand is rapidly growing, especially in Asia due in part to current or anticipated environmental advantages over other fossil fuels (EIA, 2010). Of these markets, Japan is the largest LNG importer. An upswing in LNG imports has been driven by the Fukushima nuclear disaster in 2011 to compensate for the lost nuclear power, leading to a 12% increase in natural gas consumption between 2010 and 2011 (EIA, June 2012). Likewise, the Chinese government aims to increase the use of

natural gas as the country's primary source of energy by 8.3% by 2025 (IEA, 2011). According to forecasts from the China National Petroleum Cooperation (Zhaofang, 2010), the projected Chinese natural gas consumption based on its 12th five-year energy plan will reach 400 bcm/year by 2030. Finally, U.S. LNG import facilities can be readily converted into LNG export terminals. Construction costs for LNG terminals have increased greatly due to the high price of steel. It costs approximately \$1000 per ton per annum (tpa) in 2012 as compared to \$200 in the early 2000s to build a new liquefaction plant. However, the cost of converting an LNG import terminal to one that can export is approximately half of building a new terminal, at \$625 per tpa (The Economist, 2012).

There are twelve LNG import terminals in the United States, with a total capacity of 19.1 billion cubic feet per day (Henderson, 2012). In the recent past, most of these terminals have been used for natural gas imports. After the great increase in shale gas resources, most LNG import terminals have become redundant because of the rapid growth of U.S. domestic shale gas production. To maintain their operation, there have been a number of re-export applications filed with the U.S. Department of Energy (DOE). In these cases, natural gas companies can use LNG import terminals to receive LNG cargo from different sources; they will then wait for higher prices and sell back to the LNG spot markets (Ratner, 2011). As of March 2012, the DOE had approved a total export capacity of 84 bcm/y, accounting for approximately 15% of the total U.S. consumption in 2011. Seven export terminals will be fully operational by 2018 (Henderson, 2012). With this capacity, the U.S. will be the third largest exporter of LNG behind Qatar and Australia (Mor-yadee et al., 2013).

The Journal article *Shale gas and oil: fundamentally changing global energy markets* by Aguilera et al.,(2013) discusses the circumstances and reasons assuring the U.S. lead in shale gas production, including the following:

- A long history of large-scale gas and oil exploitation guaranteed technological prominence of the US, and the physical infrastructure easily adapted to the needs of shale;
- The U.S. also possessed a valuable institutional infrastructure essential to promote innovative entrepreneurial activities;
- The sparse population led to reduced environmental sensitivities;
- U.S. legislation granting the landholder ownership rights to what is underground has greatly facilitated shale development;
- The U.S. tradition of small, adventurous exploration enterprises has helped to speed up the revolutionary process.

Furthermore, build-up of needed infrastructure from scratch, the most extended delaying factor, may take up to 10 years. The vanguard position is therefore likely to be taken by gas producers such as Canada, Australia, Argentina, and Poland, whose existing infrastructure can be speedily adjusted to shale. Existing infrastructure, matched with a lengthy history of oil and gas industry experience, gives Canada a strategic advantage in shale development. Canadian natural gas production currently ranks third in the world, with shale gas steadily increasing its share.

Developments in Argentina, with a technically recoverable resource ranking second in the world by size, have faced political problems. Poland's dependence on imports from Russia provides a strong political incentive to move ahead quickly. However, the high population density and environmental sensitivities in Europe constitute a deterrent to shale on most of the continent (Aguilera et al., 2013). Despite an impressive resource wealth and the authorities being very keen on developing the resource, China's gas industry does not expect much progress until after 2020 (Fan, 2012). By 2035, however, shale is projected to account for 70% of total gas output (IEA, 2012).

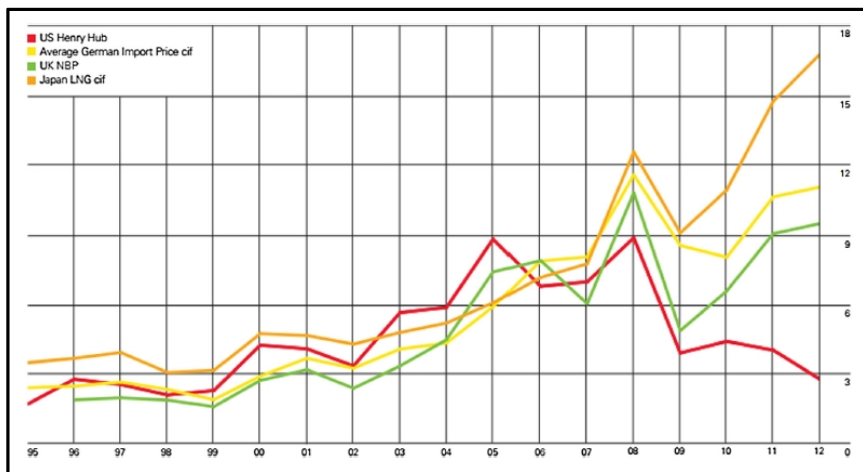


Figure 5.1.2. Comparison of prices from 1996 to 2012 in \$/MMBtu (BP, 2013).

Antto Vihma discusses global implications of increased shale gas production in his paper (Vihma, 2013) and lists the following implications:

- The shale gas boom has made the U.S. self-sufficient in natural gas and has considerable export potential;
- Gas is set to become the biggest fuel in the U.S. energy mix and has helped the U.S. to curb its greenhouse gas emissions;
- Cheap gas is also reinforcing the trend of rising industry investment in the U.S.;
- The U.S. shale gas boom is already being felt in Europe and Asia, for example via cheaper coal;
- Globally, the energy markets of the coming decades will move towards a more competitive and fragmented order, in which many energy importing countries also utilise significant domestic resources, and are able to balance their imports with regional exporters and the major global players;
- Russia may not retain its lead on the European gas market and its gas export revenues will decrease.

Furthermore, other countries are far behind the U.S. in shale gas technology, but will try to replicate the U.S. experiment according to the paper.

5.2 Implications in Europe

EIA expects an average growth of 0.7% per year for OECD European natural gas consumption and the IEO projections reaching 23.2 tcf in 2035 because of increasing demand in the power sectors of Europe. Although a small rate of demand growth is predicted, Europe will still require more imports because there is a considerable gap between the declining endogenous supply and the demand. Europe currently imports natural gas from five sources: Russia, Norway, Africa, Central Asia and overseas LNG imports. Therefore, U.S. LNG exports from the East Coast and the Gulf of Mexico would provide an alternative for Europe because of the close proximity, reliability, and political considerations (EIA, 2014).

Supply security has led the European Union to assist EU members in diversifying their natural gas suppliers by proposing a number of pipeline projects to deliver more gas to Europe (Ratner et al., 2012). In addition to the pipeline projects, numbers of large LNG import terminals are in the process of construction, such as the GATE Terminal in the Netherlands and the Polskie Terminal in Poland. The routing of LNG cargoes not only provides flexibility, but also allows for rapid responses to uncertain demands (Hayes, 2006). Proposed LNG projects enable more LNG to be distributed throughout Europe as well as an export opportunity for LNG exporters. Any volumes of LNG exported from the U.S. potentially provide an additional option for European supply diversity to mitigate Russian market power.

Stevens, in his report (Stevens, 2010), assumes that the utilisation of European shale gas resources will meet major challenges mainly because of the assumed environmental impacts. It indeed looks likely that if shale gas will be used in the future (say, within about five years), it will be imported shale gas-based LNG.

Pöyry consulting company in co-operation with Cambridge Econometrics (CE) has published a report "*Macroeconomic Effects Of European Shale Gas Production*" (Williams et al., November 2013). It aims to examine the impact of potential shale gas production on energy prices and macroeconomic indicators for the EU28 countries for the period 2020 to 2050. Pöyry and CE were commissioned to prepare the report by The International Association of Oil and Gas Producers. For calculating the effects, Pöyry's Zephyr and CE's E3ME models have been employed. Detailed information of the models and input data are described in the report. The study analysed three potential shale gas scenarios from 'No Shale' to 'Some Shale' to 'Shale Boom' production levels in the EU. The shale gas scenarios that were developed are based on information from the EIA that has been supplemented by national geological surveys, where available. The "Some Shale" scenario assumes that 15% of the resources in place are technically recoverable. However, due to some restrictions remaining in place, not all shale gas can be produced due to environmental, technical and practical barriers. The "Shale Boom" scenario is a more optimistic projection of shale gas production that assumes 20% of the resources in place are technically recoverable and is based on

the assumption that widespread public and political support can be achieved and that any barriers to production are minimised. As to the impact on energy markets, the key findings in the report are:

- Shale gas production in EU28 should result in lower gas and electricity wholesale prices when compared to a future with no shale gas production, as shown in Figure 5.2.1;
- There is an average reduction in wholesale gas prices of 6% in the “Some Shale” scenario and 14% in the “Shale Boom” scenario, when compared to the “No Shale” scenario, over the period resulting in average annual savings of €12bn and €28bn, respectively. The maximum savings is €36bn in 2050 in the “Some Shale” scenario and €51bn in 2050 in the “Shale Boom” scenario;
- There is an average reduction in wholesale electricity prices of 3% in the “Some Shale” scenario and 8% in the “Shale Boom” scenario, over the period resulting in average annual savings of €12bn and €27bn, respectively. The maximum savings is €28bn in 2050 in the “Some Shale” scenario and €42bn in 2039 in the “Shale Boom” scenario;
- Cumulatively, over the period in question the sum of wholesale energy savings would be €765bn in the “Some Shale” scenario and €1.7tn in the “Shale Boom” scenario, as compared to the “No Shale” scenario;
- Household spending on energy costs by 2050 could be lower by up to 8% in the “Some Shale” scenario and by up to 11% in the “Shale Boom” scenario and over the period 2020–2050 total cumulative savings could be €245bn and €540bn, respectively;
- According to the report, the production of shale gas in Europe does not affect the growth of renewables under either shale gas scenario, but it does reduce coal burn in electricity generation as shown in Figure 5.2.2.

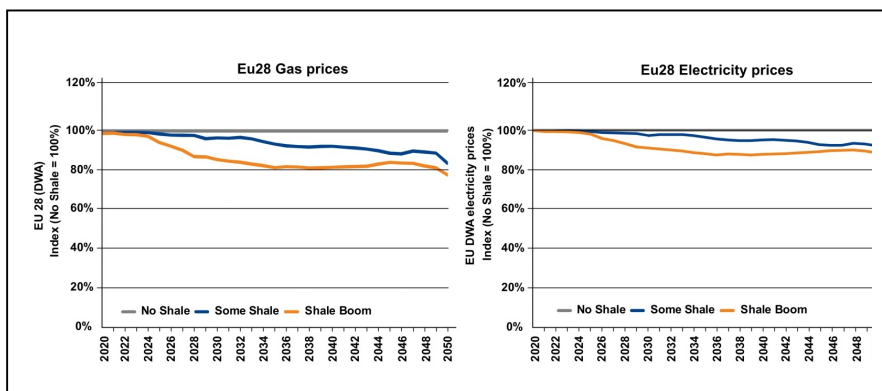


Figure 5.2.1. EU28 demand weighed average wholesale gas and electricity prices compared to the “NO Shale” scenario (NO Shale=100%), (Williams et al., November 2013).

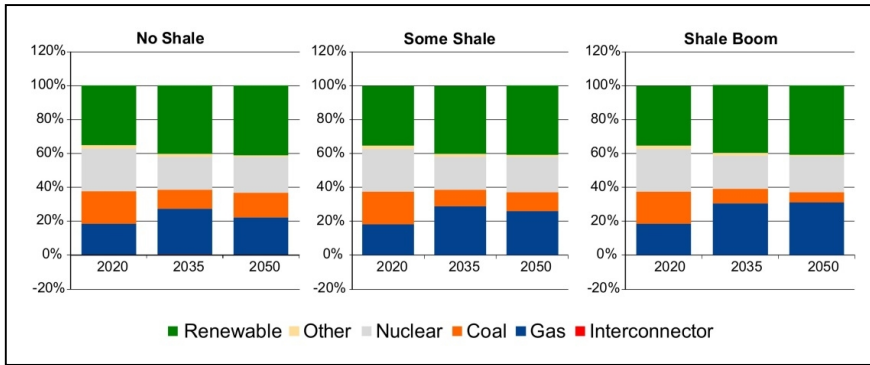


Figure 5.2.2. EU28 electrical generation mix (Williams et al., November 2013).

In addition, the report lists the following effects and benefits coming out of the shale gas utilisation in “Some Shale” and “Shale Boom” scenarios compared to “No Shale” scenario:

- Gas import dependency could reduce from 89% in 2035 to 78% in the “Some Shale” and 62% in the “Shale Boom” scenarios, respectively;
- This could result in a total balance of trade benefits of €484bn and €1.1tn;
- Cumulatively, GDP in EU28 could increase by €1.7tn and €3.8tn in the period between 2020 and 2050 according to the report;
- Correspondingly, net employment is expected to increase by 0.6 million and 1.1 million jobs by 2050.

Furthermore, the study forecasts significant increases in tax revenues as indicated in Figure 5.2.3.

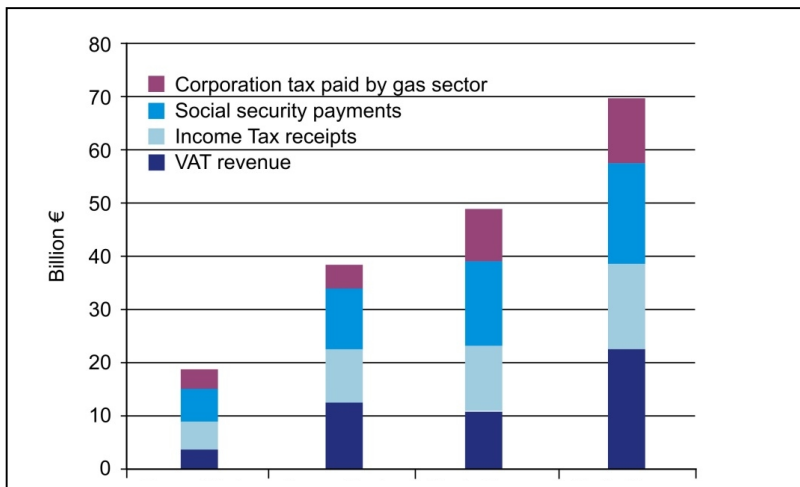


Figure 5.2.3. Increases in EU28 tax revenues (Williams et al., November 2013).

6. Emerging opportunities and benefits for Finland and its industry

6.1 Prospects for utilisation

In order to put the natural gas trade into a global perspective, Figure 6.1.1 shows its major trade movements for pipeline gas and LNG. LNG's share of global gas trade is 31.4%, being 248 bcm/year. This is about 2 500 TWh/year in terms of energy. The global gas consumption is somewhat over 3 000 bcm/year (~ 30 000 TWh), implying that the local consumption accounts for about 90% of the total consumption. In regard to Finland, its total natural gas consumption was 33.2 TWh/year in 2013. Pipeline gas from Russia accounts for almost 100% of the total. Figure 6.1.2 shows the main branches of Finland's natural gas network. It covers presently almost all large cities except Turku. It is not probable that the network will be extended substantially because other parts of the country are relatively sparsely populated and the investment for the network might not be cost-effective. It is more likely that the use of LNG will be increasing. Whether that LNG will originate from shale gas or from conventional natural gas will be seen, but it is possible that LNG from shale gas can be produced and imported to Finland at a less expensive price than LNG from conventional natural gas, and would therefore be an option. This will depend on many matters such as the costs of liquefaction and transportation, and especially on the production costs and supplier's profit margin in the country of the origin.

In the autumn of 2008, the European Commission launched the BEMIP project (Baltic Energy Market Interconnection Plan). The objectives of the project include connection of the Baltic States and Finland to the European gas network and the construction of large-scale LNG terminal(s) on the coast of the Gulf of Finland to serve the Baltic States and Finland (Website of the MEE, 2013b).

Balticconnector is a joint project between Finnish natural gas supplier Gasum and other gas supplier companies operating in the Baltic region. The project is looking into the opportunity to connect the Finnish and Estonian gas networks with a pipeline laid under the Gulf of Finland. The connection would enable gas transmission in both directions between Finland and Estonia. The project has also assessed issues such as the submarine pipeline route alternatives and possible sites where the pipeline could come ashore in Finland and Estonia (Gasum's website, 2014d).

There are several projects for LNG terminals underway. Gasum has been looking into constructing an LNG import terminal either in Inkoo or Porvoo. The terminal would focus on serving the regional markets. Final decision on its capacity has not been made yet. LNG sourced from the world market and shipped in by special-purpose vessels could be imported to Finland via the terminal. Substantial amounts of the LNG shipped to the terminal would be reloaded into ships and trucks for further transport to industrial users outside the existing gas grid and for use as transport fuel. In February 2014, on the request of the European Commission, Gasum and Estonian AS Alexela Energy signed a Memorandum of Understanding on further feasibility studies concerning the regional LNG terminal project in order to map out possible modes of collaboration by the end of May. The companies presented their plans in June 2014, but the European Commission did not find them viable for investment aid. Consequently, the parties have, at the European Commission's request, evaluated several options for the implementation of one import terminal or two terminals, one in Finland and another in Estonia. However, none of these proved to be commercially viable at the support levels indicated by the European Commission. Gasum will therefore continue to further its own terminal project independently. The final location of the terminal, the amount of investment and the schedule will be revised (Gasum's website, 2014a).

Joint venture Manga LNG Oy, a company founded by Outokumpu, SSAB, Gasum Corporation and EPV Energy, has planned to build an LNG terminal that will be located in Tornio Harbour. Its storage capacity will be 50 000 m³ and its annual energy throughput 3-4 TWh. The building phase of the terminal is during 2014–2018 and LNG deliveries will commence during 2018. The turnkey contract tendering process of the terminal was carried out during 2013 and the Finnish company Wärtsilä was chosen as the contractor for this €100 million project. The Ministry of Employment and the Economy made a positive investment support decision concerning this terminal project in September 2014 (Gasum's website, 2014b).

Skangass, a subsidiary of Gasum, has chosen Pori as the location of its first LNG import terminal. The capacity of this terminal will be 30 000 m³. In addition, Skangass intends to build a liquefied natural gas distribution logistics chain based on truck transport around the Pori terminal. Gas supply will be targeted to fit the needs of the industry as well as maritime and road traffic. When completed, the LNG import terminal will serve the entire western coast from Hanko to Kokkola. The port, which is accessible throughout the year, has an existing infrastructure, active ship traffic and many industrial clients operate in its vicinity (Gasum's website, 2014c). The expected completion of the project is autumn 2016. The MEE made a positive investment support decision for this terminal project in September 2014. The LNG terminal will be Skangass' third terminal in the Nordic countries. A terminal of the same capacity was opened by the company in Lysekil, Sweden, also in 2014. The Øra terminal in Norway is smaller in terms of its storage capacity. Skangass also has a long-term supply contract with the Norwegian Lyse Group concerning the use of the LNG production facility located in Risavika, Norway. The facility supplies LNG to industrial, shipping and heavy-duty land transport custom-

ers by road and sea. Skangass has charter parties for two LNG tankers and it operates a fleet of 20 LNG road tankers (Gasum's website, 2014d).

Aga company, also with investment support from the MEE, will build a LNG terminal with a capacity of 10 000 m³. It will be located in Rauma and serve local industry and other potential customers. The construction of this terminal will start 2015 and the plant will start commercial operation in early 2017 (LNG Industry, 2014).

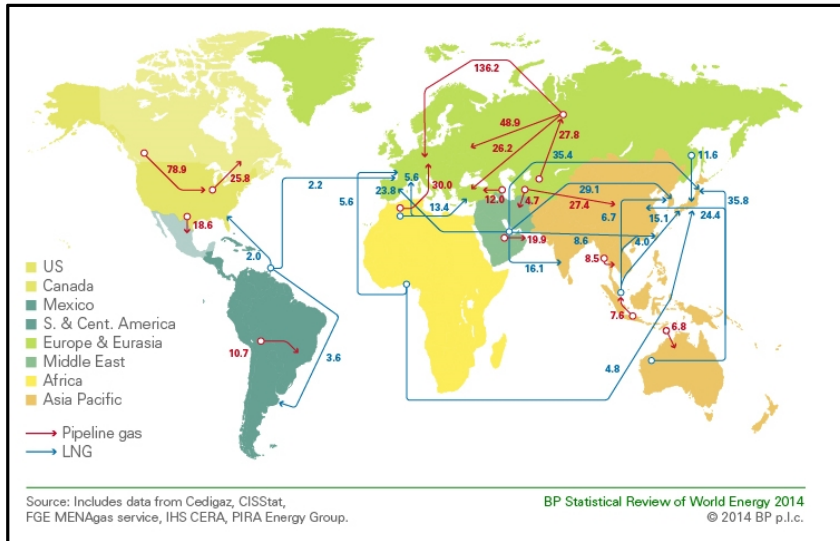


Figure 6.1.1. Natural gas major trade movements in billion cubic metres (BP, 2014).



Figure 6.1.2. Finland's natural gas pipelines (Finnish Gas Association).

Haminan Energia, a municipal energy company of Hamina city, plans to build a LNG terminal and power plant between 2015 and 2018 with a planned capacity of 30 000 m³. In addition to serving local customers, re-gasified LNG could be fed into the existing natural gas network (Yle, 2013, in Finnish).

The LNG Finland consortium plans to build a floating LNG terminal close to city of Salo. Its capacity would be up to a couple of thousand cubic metres (website of the MEE, 2013a).

Under EU rules from 1 January 2015, all ships operating in the North Sea, Baltic Sea and English Channel will have to use a fuel with a maximum sulfur content of 0.1 percent. New EU rules aim at cutting emissions coming from ship fuels used presently. Ships are typically powered by heavy fuel oil or bunker oil, both of which produce pollutants such as sulphur dioxide. Those fuels contain high amounts of sulphur, typically more than 1%. Ship owners can comply by changing fuels, such as low-sulfur marine gasoil, which can cost four times as much as high-sulphur bunker fuel. Some companies are likely to find it cheaper to pay fines than to comply. Or they can use bunker fuel and fit a "scrubber", a technology that filters out pollutant gases before they are released into the atmosphere. This costs as much as €3–12 million depending on the size of the ship and it could take up to two years for every ship to be fitted. Another option is to use LNG, but ships would require relatively expensive retrofitting (Reuters, 2014). However, the Finnish Viking Line company has been using LNG for one of its passenger ferries that began service in January 2013. It is the world's first LNG-powered passenger ship. Additionally, the Finnish Border Guard's new offshore patrol vessel, also fuelled with LNG, has recently begun service. The LNG used to propel the vessels is supplied by Skangass and AGA Finland.

The Container Ships logistics company has acquired the first completely LNG-fuelled truck in Finland. The vehicle has factory-installed gas tanks for LNG and compressed natural gas. The truck has a range of about 600 kilometres and because there is thus far only one LNG filling station, the truck will be used only in southern Finland for the time being. On top of that, Container Ships has ordered two sea freighters and aims to order 8–10 more during the next six years. Total investments for these will be almost €300 million.

All in all, there are a lot of LNG-related activities going on in Finland and very probably many of the planned investments will be implemented. Depending on the extent of the investments, the terminals' total throughput capacity will be between 15–30 TWh. This will have a substantial effect on the Finnish gas market and even on the entire Finnish energy market (annual primary energy consumption ~ 400 TWh). The LNG terminals will enable natural gas supply to the regions which are not covered by the existing natural gas network. This increases the diversity and security of supply and can reduce emissions, in particular in industries where gas will replace other fossil energy sources. The LNG terminals will also increase competition in gas markets.

6.2 Required infrastructure for LNG deployment

As shown in Figure 6.1.2, the existing natural gas network covers only southern Finland. Construction of LNG infrastructure would enable the use of LNG elsewhere in the country as well. Figure 6.2.1 shows schematically an example of the entire LNG supply and distribution chain from gas production to the customers. With respect to LNG utilisation in Finland, the downstream end of the chain is of importance. This end is depicted in Figure 6.2.2 that shows the main components of the process from the LNG tanker to the customers. LNG is transferred from a tanker to large, heavily insulated storage tanks using cryogenic transfer pumps. The LNG is pumped at pipeline pressure by high pressure multistage cryogenic pumps and re-gasified by heating it with seawater using heat exchangers called open rack vaporisers (Website of General Electric, 2014). In addition to feeding LNG to customers through pipelines (Fig. 6.2.2), truck transportation of LNG from the terminal to the customers will be employed in Finland as well. LNG terminals, which distribute LNG regionally by trucks need unloading facilities for that. Flexible hoses are used to transfer LNG between truck and terminal. Truck capacities vary from 40 to 80 m³ of LNG.

Investment costs of LNG terminals are quite high. For example, 500 000, 50 000 and 20 000 m³ terminals would cost roughly €300, €100 and €60 million, respectively. These of course depend on the type of the terminal and what activities are included but these costs provide a good estimate for those terminals which have been planned for Finland. Table 6.2.1 shows cost calculations from a report where three LNG terminal cases have been studied (Danish Maritime Authority, 2012). The first one is a large LNG import terminal (> 100 000 m³), the other options are intermediary terminals. In the case of the import terminal the investment costs' effect on the LNG price would be about €120/tonne of LNG

(pay-back time 10 years). On the other hand, given that LNG's heat value is about 14 MWh/tonne, the cost calculated per energy unit would be €8–9/MWh. As of June 2014, the consumer prices of natural gas were €33 and €44 /MWh for power and heat production, respectively.

In addition to LNG terminal investment, investments for a distribution network will be needed too. Once received and unloaded, LNG is returned to cryogenic storage where it is kept at a temperature of -163 °C prior to regasification. Regasification consists of gradually warming the gas back up to over 0 °C. It is done under high pressures of 60 to 100 bar, usually in a series of seawater percolation heat exchangers. An alternative method is to burn some of the gas to provide heat. On its way out of the terminal, the gas undergoes treatment processes needed to bring its characteristics in line with regulatory and end-user requirements. Its heating value, for example, may be tweaked by altering nitrogen, butane or propane content or blending it with other gases. In addition to regasification, LNG can be transported to the end-user by trucks or trains. Investment costs for the distribution network may also be quite high but much less than the LNG terminal investment.

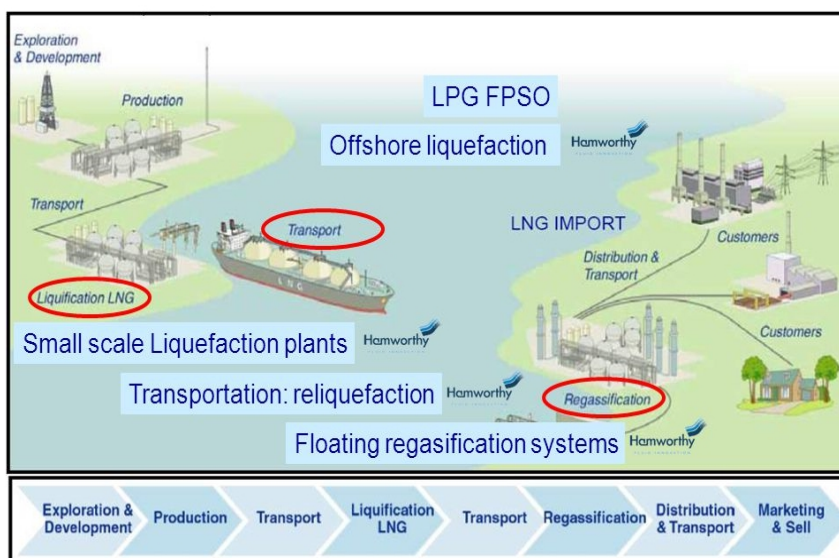


Figure 6.2.1. LNG supply and consumption chain (Wärtsilä Hamworthy).

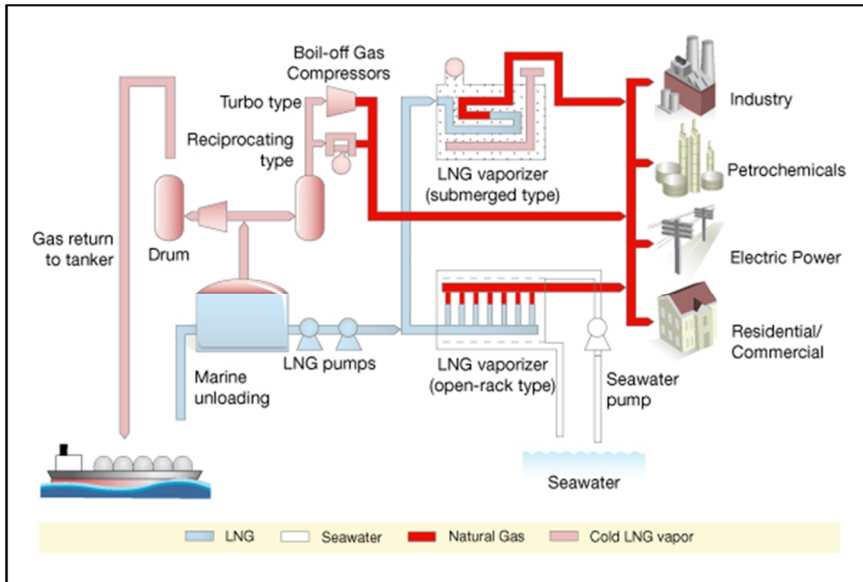


Figure 6.2.2. LNG receiving terminal and distribution (http://www.ihrdc.com/els/po-demo/module15/figures/fig_021.jpg).

Table 6.2.1. Effect of LNG terminal investment on the LNG price (Danish Maritime Authority, 2012).

	Case I	Case II	Case III
Cost per tonne LNG with 8 years pay-back (€/tonne)	136	157	211
Cost per tonne LNG with 10 years pay-back (€/tonne)	118	137	194
Cost per tonne LNG with 12 years pay-back (€/tonne)	107	125	183
Cost per tonne LNG with 15 years pay-back (€/tonne)	95	112	172

6.3 Foreseen benefits for Finland and its industry

6.3.1 Benefits for Finland

If the U.S. or other countries start to export LNG processed from shale gas, Finland and its industries may benefit from it to a considerable extent. Even though the LNG would not be processed from shale gas, increasing use of it as well as

increased production of pipeline shale gas may benefit Finnish industries. One benefit comes from the opportunity to buy it at a lower price than energy from competing sources if its price in Finland finally will be competitive. However, Asian countries such as Japan and South Korea are presently paying more than Europe for gas, and may continue to do so and consequently LNG processed from shale gas may end up mainly in Asia. Another implication comes from the fact that the increased energy supply from one source often affects the price of energy from other sources. This has actually happened already to some extent because increased gas use in the U.S. has lowered the price of coal on the world market. This is a controversial and arguable implication since even though many individual countries and energy users benefit economically because of the lower coal price, the greenhouse gas emissions increase globally as a consequence of this increasing coal use.

Finland is very dependent on Russian natural gas. Import of LNG could decrease this dependency and possibly lower the price of Russian pipeline gas. LNG import could also diversify energy supply and increase its security. Its use would also decrease greenhouse gas and other emissions where it replaces coal and oil, for example, in the power plants or in sea transportation.

LNG import could allow natural gas use outside of Finland's geographically limited natural gas network. LNG terminals and the Balticconnector would enable Finland to connect to the European natural gas network to increase energy supply options and security of supply. Finally, LNG can be used to balance the overall energy supply during the fluctuating supply from renewable energy sources.

It should be noted however that many Finnish organisations and companies involved in the gas utilisation chain in one way or another, as well as the public, are still waiting for additional information on the environmental effects of shale gas since shale gas production started less than 10 years ago and there is still controversial information on its environmental impacts. Public opinion seems to be that its potential to reduce greenhouse gas and other emissions where it replaces other energy sources, mainly coal, should outweigh its own adverse environmental impacts.

6.3.2 Benefits for Finnish industry

A great deal of Finnish industry is very energy-intensive, especially the wood-processing and metal-processing industries and the energy use accounts for a substantial part in the total costs of their products. Therefore, the availability of energy for a reasonable price is important for Finnish industry to enable it to stay competitive. As an example, the Outokumpu Group has recently invested in a new mill in Calvert in the U.S. and probably one of the reasons has been the availability of inexpensive energy. The price of energy has been historically clearly lower in the U.S. than in Europe for example, and its price has still lowered as a consequence of the shale gas boom. The United States' energy-intensive industries have therefore gained a substantial advantage for its competitiveness. This is demonstrated in Figure 6.3.2.1 that shows the gas prices in the U.S. and in Eu-

rope. The natural gas price is very high in Northern Europe compared with the U.S. and even with Central Europe.

Opportunities and benefits for industrial companies

Outokumpu, SSAB, Skangass and EPV Energy have plans for LNG use and have established the consortium Manga that plans to build an LNG import terminal close to Outokumpu's Tornio Mill. As background information for this consortium's plans, 6.3.2.1 shows gas market prices in the U.S. and in Central and Northern Europe in 2012. By building a LNG import terminal the consortium believes overall energy costs will be lower and the supply will become more secure. The main user of the natural gas from the terminal will be the Outokumpu Tornio steel mill that would replace more expensive propane with LNG. In addition, industries, mines, and other potential gas consumers in the region will also be served. The terminal may also eventually supply LNG to ships, such as the new icebreaker planned to operate in the Tornio and Bay of Bothnia regions.

Wärtsilä, the marine industry's provider, and Shell Oil Company have signed a Joint Co-operation Agreement aiming at promoting and accelerating the use of LNG as a marine fuel. The agreement was signed in August 2011 and will be valid for several years. The co-operation aims to supply LNG fuel to Wärtsilä's natural gas-powered vessel operators, and other customers by Shell. The Joint Cooperation Agreement will focus first on supplies from the U.S. Gulf Coast, and then later expand their efforts to cover a broader geographical range. Gas-fuelled marine engines are seen as being a logical means for ship owners and operators to comply with increasingly stringent environmental legislation. This agreement aims at increasing and easing the availability of natural gas for marine engine use, as well as developing the supply chain and infrastructure to facilitate the bunkering of LNG fuel. The two companies will jointly move these developments to marine markets in order to enhance its rapid introduction and use. Wärtsilä has been developing dual-fuel engine technology, allowing the same engine to be operated on both gas and diesel fuel. This dual-fuel capability means that when running in gas mode, the environmental impact is minimised since nitrogen oxides (NO_x) are reduced by some 85 percent compared to diesel operation, sulphur oxide (SO_x) emissions are eliminated as gas contains no sulfur, and emissions of CO₂ are also lowered. Natural gas has no solid matter in it and thus the particulate emissions are practically negligible (Wärtsilä's press release, 8 September 2011).

Wärtsilä Hamworthy (WH) delivers LNG production plant solutions, which are suitable for small to medium-size liquefaction capacities. WH's offering covers the following:

- Ship loading/unloading
- Optional: ship re-loading
- Liquefaction/regasification and boil-off gas handling
- Storage tanks
- Automation and control
- Optional: supply to gas pipeline

- Optional: power plant with electricity and heat supply to regasification/liquefaction

WH has already delivered a number of complete onshore LNG production facilities including the LNG production plant for Gasum in Finland, delivered in 2010 (Wärt-silä's website, 2014).

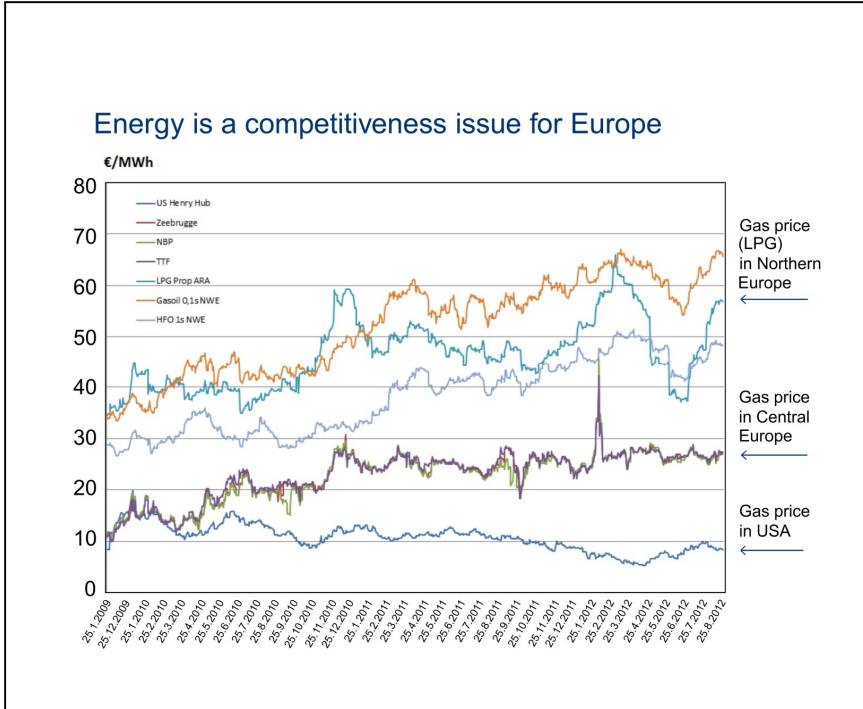


Figure 6.3.2.1. Gas prices in the U.S. and Europe (Outokumpu, 2012).

The Metso company delivers valves for industries including gas and oil industries. At the moment, more than 60% of the world's LNG flows through Metso's Neles and Mapag valves. Their ball, butterfly and control valves are designed for cryogenic, low-temperature and ambient applications. They are used for purification, dehydration, fractionation, liquefaction, LNG tanks and loading applications. Metso has delivered valves for numerous LNG installations around the world – for example, for Indonesia LNG, Malaysia LNG, Brunei LNG, Australia NWS, Abu Dhabi, QatarGas, RasGas, Oman LNG, Algeria LNG, Nigeria LNG, Sakhalin LNG and Yemen LNG. Gas-to-liquid process valves encounter demands, such as high temperatures, high pressure-differentials and impurities. Metso delivers valves practically in all sizes. The largest valves cost on order of one million € and even though Metso has factories in China, the United States, Brazil and South Korea, the biggest and most expensive valves are manufactured in its Finnish factory.

Caverion Corporation delivers LNG tanks mainly to Europe but also elsewhere in the world. Caverion has been a partner in a consortium that has constructed the biggest LNG terminal in the Baltic Sea region in Nynäshamn in Sweden. Caverion's project implementation includes design, manufacturing and installation of the LNG tanks. Caverion's LNG business includes also after sales services like maintenance (Caverion's website, 2014).

The Finnish shipbuilding industry can benefit from the increasing demand for LNG carriers due to growing LNG transportation. In April 2014 there were 365 LNG vessels and about 100 had been ordered.

It is expected that the gas consumption in energy production will increase on a global basis due to increasing supply. This will create opportunities for Finland's strong boiler and boiler plant industry because of demand for new boilers and retrofits of the existing boilers, as well as for the gas engine and power plant manufacturer Wärtsilä.

An example of how small companies can also contribute to LNG business is the Finnish company, LNGTainer, that has patented an LNG container system. According to the company, LNGTainer containers allow the use of existing global infrastructure for handling of ordinary shipping containers (see Figure 6.3.2.2). Furthermore, according to the company's website, LNGTainers, which are built inside standard shipping containers, are more cost-efficient than existing LNG storage and shipping solutions since LNGTainer containers can be handled using the existing container transportation infrastructure, i.e. container ships, harbours and rail and flatbed trucks (LNGTainer's website, 2014).

In addition to LNGTainer, there are probably several small and medium-size manufacturing companies, which can benefit from increasing utilisation of shale gas as sub-contractors of the above-mentioned larger Finnish companies or foreign enterprises.

Opportunities and benefits for design, engineering and consulting companies

Ramboll's Finnish branch has been involved in feasibility studies, concept evaluation, concept selection studies, detailed design and operational support on LNG projects. Ramboll says that it can provide engineering consultancy services within all phases of an LNG project. Ramboll's main LNG competences include according to their website (Ramboll's website, 2014):

- Market analysis and business case studies
- Site selection studies
- Separation and gas pre-treatment facilities
- LNG liquefaction facilities
- LNG transport facilities
- LNG storage and re-gasification facilities
- LNG harbour facilities
- Strategic LNG storage facilities
- Marine LNG facilities
- Risk and safety evaluations

- Environmental evaluations

Neste Jacobs, a Finnish technology, engineering and project management company has also been already involved in LNG business.

There are probably several other Finnish consulting and engineering companies, which have relevant know-how for various stages of shale gas production and its utilisation chain.



Figure 6.3.2.2. LNGTainer container (LNGTainer's website, 2014).

As a conclusion, many Finnish companies are already involved in the LNG and shale gas business directly or indirectly. They deliver components as well as design and engineering services for the LNG and shale gas industry for several stages of the production and utilisation chain. So far, obtained experience and expertise will help these companies to increase their sales in the international market. Growing shale gas production can increase global LNG supply and consequently create additional business opportunities for Finnish companies.

7. Conclusions

Natural gas production from shale gas has increased rapidly since 2005, even though so far shale gas production has been started only in the U.S. and in minor volumes in Canada. This has been possible because of advances in horizontal drilling and hydraulic fracturing technologies, which have enabled production of shale gas at lower costs than conventional natural gas.

Shale gas reserves and resources, and their utilisation

The estimate of the global technically recoverable shale gas resources is about 220 bcm, that corresponds to 2.2 million TWh in primary energy. In order to put this into perspective, global primary energy consumption is about 150 000 TWh. The shale resource estimates will likely change over time as additional information becomes available. Globally, 32 per cent of the total estimated natural gas resources are in shale formations.

The U.S. Energy Information Administration estimates that 22 per cent of shale gas resources are technically recoverable. The economically recoverable fraction may be much smaller as it depends on gas prices and production costs. The factors affecting the ratio of reserve to resource are mainly geological. Shales that host economic quantities of gas have a number of common properties. They are rich in organic material (0.5% to 25%), and are usually mature petroleum source rocks (source rock refers to rocks from which hydrocarbons have been generated or are capable of being generated) in the thermogenic gas window, where high heat and pressure have converted organic matter to natural gas. The economic recoverability of shale gas resources depends mainly on three factors: the costs of drilling and completing wells, the amount of gas produced from an average well over its lifetime, and the prices received for gas production. In addition, economic recoverability can be significantly influenced by above-the-ground factors as well as by geology among other things.

Figure 2.1.1 is a map showing global shale gas and oil resources. The map gives a sense of just how wide-spread shale gas and oil resources are. Three countries have more shale gas than the United States: China, Argentina, and Algeria. Other countries with abundant resources are Canada, Mexico, Australia, South Africa, Russia and Brazil.

Utilisation of shale gas has been forecast to grow by 400 million tonnes a year (~ 5 600 TWh/year) at least until 2020. Besides the United States, it can take many years to develop resources in other countries because the geology is somewhat different: the techniques that works in the United States might not work elsewhere. What's more, many countries don't have the needed technological expertise. Furthermore, the United States had a lot of spare natural gas generating capacity, which made it easy to switch from coal to natural gas. In a country like China with vast shale gas resources and where energy demand is quickly growing, there is very little spare natural gas generating capacity. Natural gas production might only serve to slightly slow the growth of electricity from coal plants, probably not reverse it. For these reasons, obviously the U.S. will remain the major shale gas producer for years or even decades to come.

LNG from shale or natural gas is one option for Europe to secure adequate availability of energy. For the time being, LNG is the only logistical option to deliver shale gas to Europe since it is not probable that shale gas would be produced and delivered in the near future through the European gas network in significant quantities from Europe or from other regions which are (Russia) or perhaps will be connected (Caspian Sea area) to the European natural gas network.

Shale gas extraction technology

Shale reserves are often at depths of approximately 2 km, which is deeper than conventional reserves. A typical well consists of a vertical section and a horizontal section of up to 3 km in length. Because productivity also varies significantly for wells located in the same neighbourhood, a single well test cannot establish a formation's productivity or even the productivity within its immediate neighbourhood. This complicates the exploration phase because the cost of drilling a sufficient number of wells to determine the local variation in well productivity is high.

Fluids approximately 90% water with 0.5% chemical additives such as hydrochloric acid for pH control, glutaraldehyde as a bactericide, guar gum as a gelling agent, and petroleum-based surfactants together with a 'proppant' (approximately 8% by volume, normally sand) are pumped down the well at high pressure. This pressure breaks up the shale, creating fractures which can extend a few hundred metres. Once the pressure is released, the proppant prevents the fractures from closing. Hydraulic fracturing is carried out in as many as 46 stages, starting from the furthest point and proceeding back towards the well head, as it is not usually possible to maintain the required downhole pressure to stimulate the whole length of a lateral in one stage.

The gas production rate from a well starts high and declines steeply and the decline is dependent on the shale formation. Figure 3.1.2.2.1 gives examples of typical curves for the production rates as function of time. The production rate starts to decline soon after the first month. On the other hand, the production rate after five years is still about half of that in the beginning, and the operation is obviously still profitable.

Latest developments in shale gas technology

In the debate over hydraulic fracturing for natural gas, especially water consumption and additives used in hydraulic fracturing fluid seem to raise concern. There are emerging technologies, which could radically decrease water consumption and additives used in hydraulic fracturing. One of these relies on a thick gel made from propane and is called 'liquefied propane gas fracturing'. Like water, propane gel is pumped into deep shale formations a mile or more underground, creating high pressure that cracks rocks to free trapped natural gas bubbles. Like water, the gel also carries small particles of sand or man-made material that are forced into cracks to hold them open that the gas can flow out. After the pumping the gel reverts to vapour due to pressure and heat, then returns to the surface – along with the natural gas – for collection, possible reuse and ultimate resale. However, propane costs more initially to use, even though it can be resold once recovered. It is also explosive, and requires special equipment to be handled properly and reduce risk.

Another new technology called “propane stimulation” aims also to decrease use of water and additives. Furthermore, the American company that has developed said technology says that their fracturing fluid is the first one to eliminate the need to use potable water without compromising the necessary fluid qualities. Another American company says it has developed a technology that could cut the cost of water treatment in half. The new technology would make it unnecessary to dilute the wastewater, or transport it for treatment or disposal.

Environmental impact of shale gas utilisation

There is continuous debate and discussions about the extraction and use of shale gas and its potential to affect the environment significantly even if the best available technology would be used. The effects are quite difficult to detect and measure, making discussion about these issues very complicated. The discussion about the environmental effects has been focused mainly on greenhouse gas emissions and impacts on water resources, and to a lesser extent on induced seismicity.

GHG emissions resulting directly from shale gas operations are usually categorised as:

- Intentional vented emissions of methane and CO₂, which are associated with many shale gas exploration and production processes and can cause gases to be vented, where permitted;
- Emissions from combustion of fossil fuels on site from engines such as diesel engines used for drilling, hydraulic fracturing and natural gas compression and from flaring of shale gas;
- Fugitive emissions are unintentional gas leaks such as leaks from valves, well heads, onsite accidents and gas escaping into groundwater.

A great number of scientific and journal papers have been written about this topic giving a very wide range of greenhouse gas emissions associated with shale gas production and use. The values for the carbon footprint in these papers vary from

about 250 to over 1 000 g CO₂ per kWh. The values at the high-end do not seem to be realistic because of the reasoning discussed in the fifth paragraph of Chapter 4.1.

Use of additives in fracturing fluid and their possible environmental effects, is also a controversial and complex issue. Complexity is due to the high number of chemicals used (several hundreds), as well as complicated mechanisms, which may be involved. Proponents say that practically all additives and their compounds are substances, which are used in households or for other commonly accepted purposes. Most of the complaints against hydraulic fracturing are because of possible groundwater contamination. Possible mechanisms, which might contaminate surface or ground water according to the opponents of shale gas utilisation are:

- Spills of drilling mud, flowback and brine, from tailings or storage tanks causing water contamination and salinisation;
- Leaks or accidents from surface activities, e.g. leaking fluid or waste water pipes or ponds, unprofessional handling or old equipment;
- Leaks from inadequate cementing of the wells;
- Leaks through geological structures, either through natural or through artificial cracks or pathways.

Table 4.2.2.1 provides a summary of the additives, their main compounds, the reason the additive is used in a hydraulic fracturing fluid, and some of the other common uses for these compounds.

Implications of shale gas production on global energy market

The impact of the shale gas boom has been significant in the United States. The increased supply has led to a significant drop in U.S. domestic gas prices. Increased natural gas production in the U.S. has also led to increases in coal consumption elsewhere. Unlike natural gas, coal is relatively easy to export. When demand for coal decreased in the U.S., it was shipped abroad, lowering coal prices.

Issues and implications associated with the shale gas boom:

- There has been considerable debate over the level of technically recoverable shale gas resources together with significant revisions to some estimates of those resources;
- Growing opposition to shale gas is driven by concerns over the environmental impact of hydraulic fracturing and the impact on greenhouse gas emissions;
- In the United States, energy self-sufficiency has increased in importance, making the continuation of the 'shale gas revolution' there more likely;
- There is a growing fear that shale gas may not necessarily become a substitute for coal as many originally hoped, but rather for renewables;
- Disappointing outcomes have reduced the hype about the prospects for shale gas in Europe, and led to the realisation that, at least in western Europe, there are serious obstacles to its development;

U.S. natural gas companies are motivated to export shale gas as LNG for several reasons. First, natural gas prices in the U.S. are substantially lower than in other natural gas markets. Secondly, because natural gas is considered a key fuel source that exhibits the lowest carbon content among fossil fuels, its demand is rapidly growing, especially in Asia. Finally, U.S. LNG import facilities can be readily converted into LNG export terminals. There are twelve LNG import terminals in the United States, with a total capacity of 19.1 bcf per day. Europe currently imports natural gas from five sources: Russia, Norway, Africa, Central Asia and overseas LNG imports. Supply security has led the European Union to try to mitigate these situations and to assist EU members in diversifying their natural gas suppliers by proposing a number of projects such as pipeline and large LNG import terminal projects. Therefore, LNG imports would provide a timely alternative for Europe and as a consequence of that Russia may not retain its lead in the European gas market and its gas export revenues may decrease.

A surge in oil and gas production from shale rock has transformed energy in the United States, helping reverse declines in oil production and prompting a massive shift from coal to natural gas electricity production. Shale gas producers in the United States would like to start export of liquefied shale gas even though U.S. industry opposes this. It is however anticipated that the export may start even in next few years.

The U.S. natural gas production (conventional and unconventional together) has surpassed Russian natural gas production for the first time since 1982.

The United States will maintain its dominance in shale gas production during next years

There are several reasons assuring the U.S. lead in the shale gas production during the next years and even decades, one of the most crucial being the fact that other countries are far behind the U.S. in shale gas technology and the build-up of needed infrastructure from scratch may take up to 10 years. In addition, U.S. legislation granting the landholder ownership rights to everything that is underground has greatly facilitated deployment of shale gas wells, and the U.S. had wide conventional natural gas network already before the shale gas boom.

Foreseen benefits for Finland and its industries

Availability of energy for a reasonable price is important for Finnish energy-intensive industries to enable it to stay competitive. Shale gas delivered as LNG may offer an affordable alternative for Finnish industry.

Outokumpu and Rautaruukki Corporation have plans to build an LNG import terminal close to Outokumpu's Tornio mill. The main user of the natural gas from the terminal will be the Outokumpu Tornio Steel Mill that would replace more expensive propane with LNG.

Wärtsilä, the marine industry's provider, and Shell have signed a Joint Cooperation Agreement aiming at promoting and accelerating the use of LNG as a marine fuel. The co-operation aims to supply LNG fuel to Wärtsilä's natural gas-powered vessel operators, and other customers by Shell.

Wärtsilä Hamworthy (WH) delivers LNG production plant solutions, which are suitable for small to medium-size liquefaction capacities. WH has already delivered a number of complete onshore LNG production facilities including the LNG production plant for Gasum in Finland, delivered in 2010.

The Metso company supplies valves for industries including gas and oil industries. More than 60% of the world's LNG flows through Metso's valves. Metso delivers valves practically in all sizes and the biggest ones cost in order of one million €

The Caverion Corporation delivers LNG tanks to Europe and elsewhere in the world. Caverion's project implementation includes design, manufacturing and installation of the LNG tanks. Caverion's LNG business includes also after sales services like maintenance.

Gas consumption as a fuel for power and other energy production will increase. This will create opportunities for Finland's strong boiler industry because of demand for new boilers or retrofits of the existing boilers, as well as for gas engine manufacturer, Wärtsilä.

The Finnish shipbuilding industry can benefit from the increasing demand for LNG carriers due to growing LNG transportation. In April 2014 there were 365 LNG vessels and about 100 had been ordered.

Ramboll's Finnish branch has been involved in feasibility studies, detailed design and operational support of LNG projects among other things. Ramboll states that it can provide engineering consultancy services within all phases of an LNG project. Besides Ramboll, the Neste Jacobs engineering company has also been already involved in LNG business. Among other things, it just recently won the bidding competition of Gasum's Finngulf LNG and Balticconnector project to deliver the Project Management Office.

There are probably several other Finnish consulting and engineering companies, and small and medium-size manufacturing companies, which can benefit from increasing utilisation of shale gas as sub-contractors of the above-mentioned larger Finnish companies or foreign enterprises.

Extended abstract

Natural gas production from shale gas has increased rapidly since 2005 because of advances in horizontal drilling and hydraulic fracturing technologies, which have enabled its economic production from shale gas formations. Almost all this increase has come about in the U.S.

The estimate of the global technically recoverable shale gas resources is about 220 tcm that corresponds to 2.2 million TWh in primary energy. In order to put this into perspective, the global primary energy consumption is about 150 000 TWh/year and the consumption in Finland about 400 TWh/year.

The economic viability of shale gas utilisation depends primarily on the amount of gas extracted over the lifetime of the wells in question and associated costs, and the market price of the produced gas. On top of that, economic viability is influenced by above-the-ground factors such as the extent of required water treatment and transportation costs.

Shale gas resources are geographically wide-spread globally even though over 90% of the technically recoverable shale gas resources are in 10 countries including China, Argentina, Algeria, the United States, Canada, Mexico, Australia, South Africa, Russia and Brazil, in order of abundance.

LNG from shale or natural gas is one option for Europe to secure adequate availability of energy. For Japan LNG may be even more crucial since demand for gas increased rapidly after the Fukushima accident when nuclear power plants were closed. South Korea is also a very significant potential importer of LNG.

There is continuous debate and discussion about the extraction and use of shale gas and if it will affect the environment significantly even though the best available technology would be used. The effects are quite difficult to detect and measure, making discussion rather complicated. The discussion about the environmental effects has been focused mainly on greenhouse gas emissions and impact on water resources, and to lesser extent on induced seismicity. Use of additives in fracturing fluid and possible environmental effects that it may have, is a controversial and complex issue. The complexity is due to the high number of chemicals used (several hundred), as well as the complicated mechanisms, which may be involved. Proponents say that practically all additives and their compounds are substances, which are used in households or for other commonly accepted purposes. Most of the complaints against hydraulic fracturing are because of pos-

sible groundwater contamination. As to the water consumption and additives used in hydraulic fracking, there are emerging technologies, which could substantially decrease water and additive consumption used in hydraulic fracking like 'liquefied propane gas fracturing'.

In regard to the natural gas markets, the increased shale gas production has already had an impact. The impact of the shale gas boom has been significant, especially in the United States. The increased supply has lowered U.S. domestic gas prices. Increased gas production and use in the U.S. has also led to increases in coal consumption elsewhere. When demand for coal has decreased in the U.S., there has been a coal surplus on the global market and the price of coal has lowered. Furthermore, the recent carbon credit tariffs have been low and therefore additionally increased competitiveness of coal in Europe.

Europe imports natural gas from Russia, Norway, Africa, Central Asia and LNG from overseas. Supply security has led the European Union to encourage and support EU member countries in diversifying their imports by proposing several pipeline and LNG import terminal projects. Consequently Russia may not maintain its dominance in the European gas market. Shale gas producers in the United States would like to start LNG export and it is expected that it will start even in the near future. U.S. natural gas production (conventional and unconventional together) has surpassed Russian natural gas production for the first time since 1982.

The U.S. will probably maintain its dominance in shale gas production during the next years and even decades. The other potential countries are behind the U.S. in shale gas technology and they do not have the required infrastructure that takes several years to build. Besides, the U.S. already had an existing extensive conventional natural gas network before the shale gas boom. The landowners' rights in the U.S. have enabled easy deployment of shale gas resources because most landowners own also what is underground, and most of them have decided to sell the rights for shale gas extraction to the gas production companies.

If the U.S. or other countries start to export LNG processed from shale gas, Finland may benefit from it in several ways. Possible benefits emerge from the opportunity that shale gas may be available at a lower price than energy from competing sources and especially from the fact that a new source of energy on the market usually lowers the price of energy from other sources. This has actually happened already as described above. Furthermore, Finland is very dependent on Russian natural gas. Import of LNG could decrease this dependency. LNG imports could also diversify energy supply and increase energy security. Its use could also decrease greenhouse gas and other emissions where it replaces coal and oil like in the power plants or in sea transportation. LNG import would also enable natural gas use outside of Finland's geographically limited natural gas network. New LNG terminals and the Balticconnector would enable Finland to connect to the European natural gas network to increase energy supply options and security of supply. LNG can be used to balance the overall energy supply during the fluctuating supply of renewable energy sources.

As for the availability of shale gas-based LNG in Europe, it should be taken into account that in addition to many European countries (including Finland), Asia as

well will be a very probable market for shale gas-based LNG from the U.S. Especially since the price of LNG in Asia (main users Japan and South Korea) has been higher than the price of natural gas or LNG in Europe. However, the average prices of LNG in Japan and natural gas in Finland, in 2013 for instance, were about €42 and €38/MWh, respectively. The difference is not high given that the transportation costs of LNG from the U.S. to Asia are much higher than the costs to Europe. This depends on the fact that only small LNG vessels can use the Panama Canal and therefore most of the LNG shipped from the U.S. to Asia should be delivered around Africa making the distance about 2.5 times longer than to Europe. The expansion of the Panama Canal is underway and is expected to be finished by 2016. After the expansion its estimated capacity for LNG transportation will not be more than about 12 million tonnes a year. The capacity of the four first LNG export terminals under construction in the U.S. will be about 80 million tonnes a year and there are other terminal projects planned. This implies that only a small share of LNG from those terminals can be delivered to Asia through the Panama Canal and consequently the average LNG transportation costs to Asia, if it will be imported in high volumes, will remain clearly higher than its average import costs to Europe. This enables Europe to buy LNG from the U.S. for a lower total price at the destination and may enable its import to Europe as well as to Asia.

On top of the shale gas demand in Asia, the U.S. industry would like to maintain the competitive advantage that it has now due to inexpensive shale gas available in the U.S. On the other hand, since the mentioned four LNG terminals are already under construction and others will be constructed, it seems to be obvious that the U.S. will start to export LNG in substantial volumes already in the near future. This does not significantly decrease competitiveness of the U.S. industry since the price of the exported LNG and finally the price of the re-gasified gas from it at the final destination will be in any case much higher than the price of shale gas delivered through the gas network in the United States. This is a consequence of the additional costs due to the multi-phased delivery chain from the shale gas field to the final end user abroad. If the volumes of shale gas export would be so high that the availability of shale gas in the U.S. would decrease, it could increase the price of shale gas for U.S. industry and consequently decrease its competitiveness. However, this does not look likely given that the potential for shale gas production and already the present production in the United States is high in comparison with the planned volumes of LNG export. Finally, the recently increasing exchange rates of the U.S. dollar in 2014 will also increase the price of the U.S. LNG abroad, if the value of the dollar will remain high.

Availability of energy at a reasonable price is vital for Finnish, energy-intensive industry to continue to be competitive. Shale gas exported as LNG to Finland and to other countries may offer an affordable alternative and new business opportunities for Finnish industry, gas suppliers, and consulting and engineering companies. At least the following Finnish companies could benefit from increasing LNG use in several ways:

- Outokumpu, SSAB, Skangass and EPV Energia will build an LNG import terminal close to Outokumpu's Tornio steel mill. The main user of the LNG

will be the Tornio steel mill that would replace more expensive propane with LNG and achieve substantial savings in its overall production costs, since energy costs account for a significant share in steel production;

- Gas suppliers Skangass and AGA can extend their business activities with LNG supply for sea transportation and for the industries outside the existing natural gas network;
- Wärtsilä, a main marine industry engine provider, and Shell have signed an agreement aiming to promote the use of LNG as a marine fuel in Wärtsilä's dual-fuel engines:
- Wärtsilä Hamworthy delivers LNG production plant solutions, which are suitable for small to medium-size liquefaction plants. The company has already delivered a number of onshore LNG production facilities including the LNG production plant for the Gasum company in 2010;
- Neste Jacobs has also been already involved in LNG business and among other things won the bidding competition of Gasum's Finngulf LNG terminal and Balticconnector project to deliver the Project Management Office and will be the main partner in Gasum's 30 000 m³ LNG terminal project that is due to start soon;
- Metso company produces valves for industries including gas and oil industries and currently more than 60% of the world's LNG flows through Metso's valves;
- Ramboll's Finnish branch has been involved in LNG projects in many ways and says that it can provide engineering consultancy services within all phases of an LNG project.
- Caverion Corporation delivers LNG tanks to Europe and elsewhere in the world including design, manufacturing, installation of the LNG tanks and after sales services;
- Expecting that the gas consumption in power and other energy production will increase on a global basis, it will consequently create opportunities for Finland's boiler plant industry to deliver new boilers or retrofits for existing boilers as well as opportunities for the gas engine and power plant manufacturer Wärtsilä;
- The Finnish shipbuilding industry can benefit from the increasing demand for LNG carriers due to growing LNG transportation;
- There are several Finnish consulting and engineering companies, and small and medium-size companies, which can benefit from increasing utilisation of shale gas as sub-contractors of the above-mentioned larger Finnish companies or foreign enterprises.

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6 UTILISATION OF IMPORTED SHALE GAS IN FINLAND

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Title	Shale gas production – its trade as LNG and prospects for Finland and its industries
Author(s)	Veli-Pekka Heiskanen, John Yilin Wang
Abstract	<p>Shale gas production has increased rapidly during last years because of advances in horizontal drilling and hydraulic fracturing technologies. Almost all shale gas is produced in the U.S. but many other countries may follow suit in following years or at least in the coming decades.</p> <p>The global technically recoverable shale gas resources are about 220 tcm that corresponds to 2.2 million TWh in primary energy, being almost 15 times the global annual primary energy consumption. Shale gas resources are wide-spread globally even though over 90% of the technically recoverable shale gas resources are located in 10 countries.</p> <p>There is continuous debate on the environmental effects of shale gas production. The discussion has been focused mainly on greenhouse gas emissions and impact on water resources, and to lesser extent on induced seismicity. New technologies are being developed to decrease consumption of water and chemicals in fracking.</p> <p>The increased shale gas production since 2005 has had an impact on the natural gas markets, especially in the United States. It has also led to increases in coal consumption elsewhere.</p> <p>Shale gas delivered as LNG may offer one alternative energy source for Finland and its industry. Several Finnish companies may benefit from increasing global shale gas and LNG use such as equipment manufacturers, contractors and subcontractors for shale gas and LNG-related projects.</p>
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