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Can Unconventional Gas be a Game Changer in European Gas Markets?

Florence Gény

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Preface

Since the late 2000s, unconventional gas has become the most important new energy issue to reach public consciousness. In the United States, where gas production was in decline and imports were increasing, the revolution in (especially) shale gas production has completely transformed the outlook; production is rising and imports have fallen sharply. The prospect of a similar revolution in Europe has given rise to a huge number of conferences, op-ed articles and blogs which have created a wave of hype, but little clarity, about the subject. When Florence Gény agreed to join OIES to conduct a detailed research study of shale gas development in Europe, this provided our Programme with a major and important new avenue of study.

Europeans are generally unaware of the long history of unconventional gas development in the US, and the legal, fiscal, environmental and land use particularities which enabled the technical breakthrough in production techniques to be implemented so rapidly. This study places US unconventional gas development in its proper context in order to set the scene for an analysis of European developments. Because of the very small number of exploration wells which have been drilled it is impossible to make any definitive comment on the extent and quality of the European resource base. The major contribution of this study is that it provides detailed analysis of the specific requirements of European unconventional gas in relation to crucial issues such as drilling, land use and water use. It assembles data which are very difficult to find and applies them to the European countries which appear to have the best prospects, using a model to analyse the economics of unconventional gas development. This is the first public domain study of European unconventional gas to provide this level of detail and quality of research and analysis.

I am very grateful to Florence Gény for the huge amount of work and enthusiasm she has brought to this project. The quality of Florence's analysis makes this a highly credible and valuable study of a new and emerging area of gas research.

Jonathan Stern
Oxford, December 2010

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I would like to thank Jonathan Stern and John Elkins for their helpful comments and editorial corrections. My gratitude also goes to companies and individuals within the oil and gas industry that have provided me with useful information and insights: my colleagues from Statoil, Sarah Ladislaw from the CSIS, Vello Kuuskraa from Advance Resource International, Kamel Bennaceur from Schlumberger, Bob Moran, Mike Watts and Jerzy Wozniak from Halliburton, John Beswick, Composite Energy and Barclays Capital Commodities Research. I also thank Wood Mackenzie and IHS CERA for allowing me to use some of their data.

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SBC Energy Institute and Oxford Institute Collaboration Acknowledgement

The SBC Energy Institute and the Oxford Energy Institute for Energy Studies have formed a knowledge partnership to collaborate on joint research studies to better understand key energy themes of the 21st century. As part of this collaboration the SBC Energy Institute has provided input for this paper, in particular on European unconventional gas technologies, operational models, service sector capabilities, and E&P costs, as well as public data on unconventional gas basins. In the context of this collaboration, I would like to specially thank Jean Cristofari for his continuous and insightful feedback and Hermes Alvarez.

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Executive Summary

The rise of unconventional gas production, and in particular shale gas, has been the greatest revolution in the US energy landscape since the Second World War and has the potential to transform that country's requirement for LNG imports (and hence global LNG trade). This paper analyses the potential for European unconventional gas to be developed and transform European gas markets. The main conclusions focus on the challenges to replicate US best practices in Europe, and analyses the European response needed to make unconventional gas a success story in the continent, as well as the potential implications of unconventional gas development for European gas markets. Understanding the conditions that have made shale gas exploitation successful in North America is fundamental to an analysis of the potential of shale gas in Europe. This study identifies five catalysts, both policy and market-based, that triggered modern unconventional gas production in the US.

The development of unconventional gas in Europe is likely to be a long-term story, and is unlikely to become a sudden gas revolution as in the US. There will be no *significant* production before at least 2020 due to:

*the immaturity of the European industry in terms of geological knowledge of unconventional reservoirs;

*very few announced drilling investments over the next three years, which will translate into a long testing and play de-risking phase, and;

*lead times of about 5 years based on US shale gas projects.

In addition there are many operational, regulatory and commercial challenges to the development of unconventional gas resources which are specific to Europe.

Production levels needed to make unconventional gas an important new source of domestic supply that stabilises Europe's import dependence would have to reach about 1 Tcf/year for several decades. This would be "game-changing" at a *pan-European* level, assuming a liberalised European gas market. However, the production of unconventional gas in any single country, even at lower levels, could transform the supply mix in that country. Thus, unconventional gas production could realistically be a *national* game-changer with potential transformative effects on gas import requirements of that country and regional gas flows.

In order for operators to be able to produce unconventional gas at high levels, the two biggest challenges to overcome are land access (spatial and regulatory constraints as well as local acceptance of this new activity) and cost levels (yielding poor commercial viability compared to alternative gas supply projects).

*Land access for drilling, logistics and building infrastructure is a huge issue linked to severe spatial restrictions resulting from high levels of urbanisation in North Western Europe; extensive regulatory protection of sites and landscapes; and difficulties in accessing private land due to local hostility (although this situation varies from region to region).

*Shale gas costs in Europe are driven by geology (reservoir depths and complexity), a higher general cost of doing business compared to the US, and an oligopolistic service industry.

Drilling costs are expected to be 2 to 3 times higher than in the US. Water sourcing will also be much more expensive and constrained than in the US, with costs about 10 times higher and water shortages expected in certain regions of Central and Eastern Europe. An investment analysis performed for shale gas deposits in Poland and Northern Germany shows that breakeven prices would be in the range of $8-16/mcf (i.e €20.5 - 41/MWh), which ranks at the high end of the gas supply cost curve in Europe, but would also overlap with future expected marginal supply projects. This means the cost of shale gas projects will cap the pricing of new marginal supply projects in the next decade.

For these two reasons - land access restrictions and high costs - Europe needs to develop its own operational and business model, which will be different from that of the US. The main elements of that model will need to include the following:

- a much more R&D-based and sweet-spot focussed approach to drilling,
- new technology developments that reduce the number of wells needed, allow for the reduction and recycling of water volumes used in fraccing operations, and give the ability to drill longer laterals,
- government incentives and regulatory reforms,
- the expansion of a home-grown trained service workforce,
- financial compensation to local communities.

Introduction

In an era of declining conventional gas production and increasing demand, economically producing gas from unconventional sources represents an unavoidable alternative. Unconventional gas has thus become a topic that is increasingly being debated.

The ongoing long-term trends in the gas industry and energy policies that will shape future gas markets have indeed put unconventional gas on the energy map. Gas has become an attractive resource in many Non-OECD countries, while it is already a major energy source in the OECD. In the OECD, projected demand growth, albeit moderate, combined with declining domestic production, raises energy security concerns, while in Non-OECD countries, fast rising gas demand and increasingly limited availability of domestic supply force gas producing and consuming countries to look for new supply alternatives. Therefore, whereas international gas pipelines will keep an important role in gas supply, LNG and unconventional gas are set to become the fastest growing sources of long-term gas supply.

Furthermore, unconventional gas resources can be found in many parts of the world in abundance, including regions where net gas shortages are potentially severe. These regions are the most likely to try to develop their unconventional gas resources. The rate at which unconventional gas is developed will have a lasting impact on every aspect of the supply/demand balance, as conventional LNG projects will no longer have a near monopoly on meeting incremental demand in some of the fastest growing markets. Therefore the development of unconventional gas projects is set to significantly affect gas markets in the future; in North America this process is already under way.

The quiet unconventional gas revolution taking place in North America and its drivers have been extensively written about, and although there are challenges and uncertainties regarding the extent to which unconventional gas production in North America can continue to grow and affect global gas markets, little has been written to date about the potential for unconventional gas to change gas market trends in other regions, in particular Europe and Asia.

This study focuses on Europe, and provides an in-depth analysis of the potential for unconventional gas to alter the future European gas supply picture. The main challenge is the very small amount of research and exploration and production data that are publicly available. A literature review shows that no in-depth research paper dealing with European unconventional gas has been published to date. Only a few articles and reports from various consultancies, and one short paper published in Erdoel, Erdgas und Koehl in February 2009[1], could be found. This obviously reflects the immaturity of the unconventional gas industry in Europe, and makes the study of the potential contribution of unconventional gas in turning around the domestic production decline in Europe critical.

Because North America is the only place today that boasts substantial production from unconventional gas resources, following a long and uneven path of developments, it is

[1] H.-M. Schulz und B. Horsfield ,*Shale Gas in Europe: A New Unconventional Gas Resource as for North America?* Erdoel, Erdgas und Kohle Year 125, Heft 2 (Feb 2009) pp 50-55.

necessary to study the North American unconventional gas revolution as a starting point. This is the subject of the first part of the paper. The parallel analyses of the success factors that allowed a surge in unconventional gas production in the United States and of the European specific context will lead to conclusions on the likely scale, timeframe and necessary conditions for unconventional gas production in Europe. The final part of the paper evaluates the potential implications for natural gas supply and price dynamics at a European and national level.

What will it take for unconventional gas to be developed and become a game-changer for European gas markets? In this study we define the term "game-changer" in relation to pan-European and national levels of gas supply and demand. In our definition, unconventional gas can be considered a pan-European game-changer if its level of production will be sufficient to halt the decline of domestic gas production for several decades, thereby stabilising Europe's import dependence; or if it can supply 5% of European gas demand. However, this implies viewing Europe as a single gas market, which is not yet the case. At a national level, unconventional gas production could be a game-changer if it becomes a sufficiently large part of the national supply mix to alter the dynamics of gas trade in a single region of Europe.

Definition of unconventional gas resources

In this paper, the term 'unconventional gas resources' refers to natural gas from coal (also known as coal-bed methane (CBM)), tight gas sands and gas shales. Biogenic gas[2] is being increasingly considered as a potentially serious source of gas supply, for example in Germany, Sweden and the United Kingdom, however it is a renewable source of energy and should be assessed in the context of other renewables, supported by government subsidies. Therefore it is not included in the scope of this paper. This analysis also excludes gas hydrates[3], although this type of resource is undoubtedly unconventional, but its development is more limited and speculative at present.

Unconventional gas is methane, i.e it has the same chemical composition as "conventional" natural gas, but reservoir characteristics are unusual and more complex to understand for gas producers and service companies with the current state-of-the art technology within the industry. More details on the formation of oil and gas and the geological differences between conventional and unconventional formations can be found in Appendix A. Tight gas, CBM and shale gas have several characteristics in common but also have some fundamental differences. In common are the low permeability[4] of the reservoirs and therefore the need for a high number of production wells to extract gas. Furthermore, the well life for all three types is longer than for conventional wells; in the case of CBM there are still-producing wells in the Appalachians (United States) that are at least eighty years old. Another factor in common is the fact that, because of the low permeability in the reservoirs, the wells must be stimulated, usually by using hydraulic fracturing (aka "fraccing"[5]) of the rocks, to produce at commercial rates. For CBM, stimulation through hydraulic fracturing is not a sine qua non condition to recover methane from coal but it helps to accelerate the pace of gas recovery.

Differences occur with the tightness (permeability) of the different types of reservoirs and the way gas is stored in those reservoirs. Tight gas is natural gas found in the pore space of very

[2] See definition in the Glossary
[3] See definition in the Glossary
[4] See definition in the Glossary
[5] See definition of darcy in the Glossary and more details on the technology in Appendix B

poor reservoirs with low porosity and low permeability (generally sandstones with permeability in the order of microdarcies[6]). Basin-centred gas[7] is a particular type of tight gas and the trapping mechanism is not yet well understood. In shales, the gas is both free and adsorbed. The permeability is even lower and is measured in hundreds of nanodarcies (for details on the typical geological characteristics of gas shales see Appendix B). CBM is natural gas stored in coal's internal surface areas. The gas is adsorbed with only a negligible amount of free gas. Permeability exists in cleats (coal fractures) but these are water filled. The gas is adsorbed in the matrix between the cleats, with permeabilities measured in nanodarcies.

The type of gas storage, free or adsorbed, drives the shape of the production curve. Free gas is produced quickly at higher rates and adsorbed gas is produced slowly at low rates. This difference is particularly apparent between CBM on one hand, and tight and shale gas on the other. For both tight and shale gas, peak production is reached on day one of operations as the free gas released by fraccing is produced. The production decline of a shale gas well is rapid, typically between 70% and 90% in the first year, and as the free gas is depleted, the adsorbed gas bleeds slowly through the low permeability tight gas reservoir from beyond the fracture to give a low production rate which continues for a long period.

With CBM wells, the water held in the cleats is produced first, and, as the well is dewatered the pressure drops, the water production decreases and the gas desorbs into the cleats, and gas production increases. The length of this dewatering period before peak production varies considerably from a few months to a few years. These differences in production profiles affect the commercial viability of projects.

Another difference between the three types of unconventional gas plays is the depth at which they are found and are commercially viable. CBM is a shallow play often at depths less than 1,000m. Shale gas is usually exploited at depths of less than 3,500m, more due to well costs than for geological reasons. Tight gas plays have been found at greater depths because the increased pressure acts to give greater flow rates in these less tight reservoirs.

Overview of global unconventional resources

Industry understanding of the geographical distribution of the unconventional gas resource base and the size of the resources has improved significantly in the last decade.

Resource estimates Several estimates of combined unconventional resources worldwide have been published by various individuals, institutes and consultancies over the last few years. Among them are studies by Rogner in 1997 (which is used as the reference work), Holditch, the United States Geological Survey (USGS), the National Petroleum Council (NPC) in 2003 and 2007, Advanced Resources International (ARI), Wood Mackenzie in 2006 and IHS in 2008.[8]

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[6] Darcy is a unit of permeability. Conventional gas reservoirs typically have permeability over 0.1 mD.

[7] See definition of BCGA in the Glossary

[8] H.H Rogner, *An Assessment of World Hydrocarbon Resources*, Annual Review of Energy and Environment, 1997; National Petroleum Council, *Balancing Natural Gas Policy*, 2003 and *Topic paper #29 on Unconventional Gas, NPC Global Oil and Gas Study*, 18 July 2007; Vello A. Kuuskraa, *The Unconventional Gas Resource Base*, Oil and Gas Journal, 24 July 2007; Dr Stephen Holditch, Department of Petroleum Engineering, Texas A&M University, IHS CERA Private Report *Gas from Shale: potential outside North America?*, February 2009, Wood Mackenzie Multi-Client Study Unconventional Hydrocarbons, November 2006.

However, there is still much which is not known, in particular outside North America, such as the productive limits of the emerging gas plays and the impact of advances in well drilling and completion technologies on the productivity of wells. Therefore most of these estimates should be considered with a low level of confidence. What Rogner wrote in 1997 is still valid to a large extent: "Because of the wide availability of conventional natural gas, there has been little commercial interest in the delineation of unconventional natural gas occurrences. Consequently, resource estimates of unconventional gas are very sparse. Funds have been limited and therefore so are the data on unconventional gas occurrences. The data contained in the literature are fraught with geological uncertainty. Moreover, the technology implications for the eventual production of unconventional gas are poorly understood."[9] In summary, the data in [Rogner's] tables are speculative and should be read as such.

Furthermore, estimates of recoverable unconventional gas resources have changed and will continue to change many times over the years. As the consultancy ARI puts it, "the continuing emergence of new unconventional gas plays, the ability to more intensively develop an already discovered play, and advances in extraction technology will affect the ultimate size of the recoverable resource."[10]

In addition, due to the different nature of unconventional gas deposits from conventional gas accumulations[11], new assessment methodologies had to be developed. The traditional criteria of field size distribution, finding rates and discovery process do not apply, and creativity is required. Consequently, the new methodologies and assumptions used are quite diverse, resulting in very wide ranges of resource estimates. Moreover, since information on many source rocks is limited, even in the United States, and a lot of subsurface research still has to be carried out, developing adequate assessment methodologies is clearly still a work in progress. Another difficulty encountered in the United States is the rapid changes in the performance of unconventional gas plays, which require frequent reassessment. Finally, although numerous, only basin- and play-level appraisals of the diverse gas shale basins worldwide will build confidence on the size, quality and producibility of this type of gas resource.

The challenge of assessing the size and quality of recoverable unconventional gas is particularly acute outside North America, due to the general immature state of the industry and the limitations on access by foreign companies to resources in certain regions (e.g. FSU, China, Russia, Middle East). Detailed estimates of these resources are mainly restricted to areas that are already being developed or appraised for development, or to specific categories of resources. Therefore ongoing resource studies are mainly private and not comprehensive.

All published resource estimates of world unconventional gas gas reservoirs use Rogner's 1997 study as a starting point. Figure 1.1 below exhibits Rogner's estimates of resources in place by region, while Figures 1.2 and 1.3 compare several estimates of technically recoverable resources globally and at a regional level.

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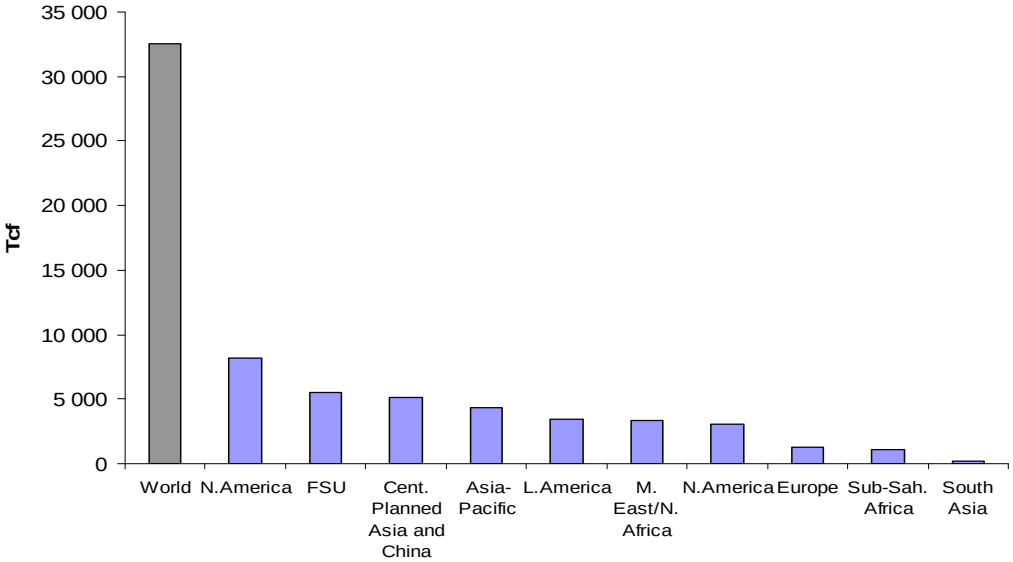
[9] Rogner, p 240.

[10] Kuuskraa, *The Unconventional Gas Resource Base*, Advanced Resources International (ARI), 24 July 2007

[11] This is particularly the case of shales. While conventional gas accumulations occur in multiple discreet accumulations, gas in shales occurs in a broadly continuous layer across a basin. Shale rocks have much lower permeabilities, which require fracture treatments to open channels for the gas to flow through the formation to the wellbore. The big issue is the diversity of shale and the key is finding the correct fracturing technique. Horizontal drilling and completions are becoming standard. Shale gas plays are referred to as "statistical" plays, as many wells are needed to understand the play and assess recoverable resources.

Figure 1.1: Estimates of unconventional gas resources in place

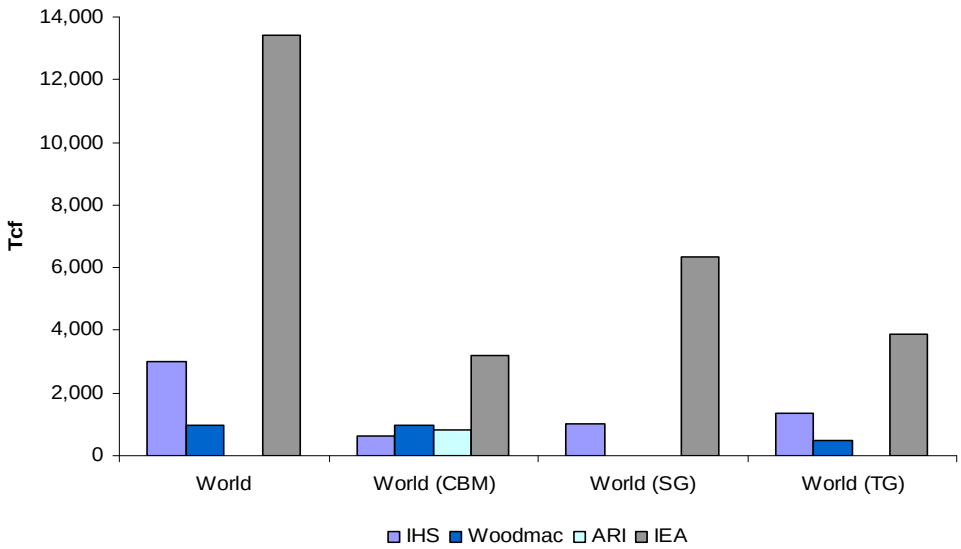


Source: Rogner 1997

Total global unconventional gas resources are estimated by Rogner to reach around 32.6 Qcf (quadrillion cubic feet[12]).

However, what really matters for producers and consumers is what quantities can be retrieved from the ground. Figures 1.2 and 1.3 exhibit some of the existing estimates for recoverable resources and, as can be seen, the ranges are wide, as mentioned previously.

Figure 1.2: Unconventional gas recoverable resources, range of estimates



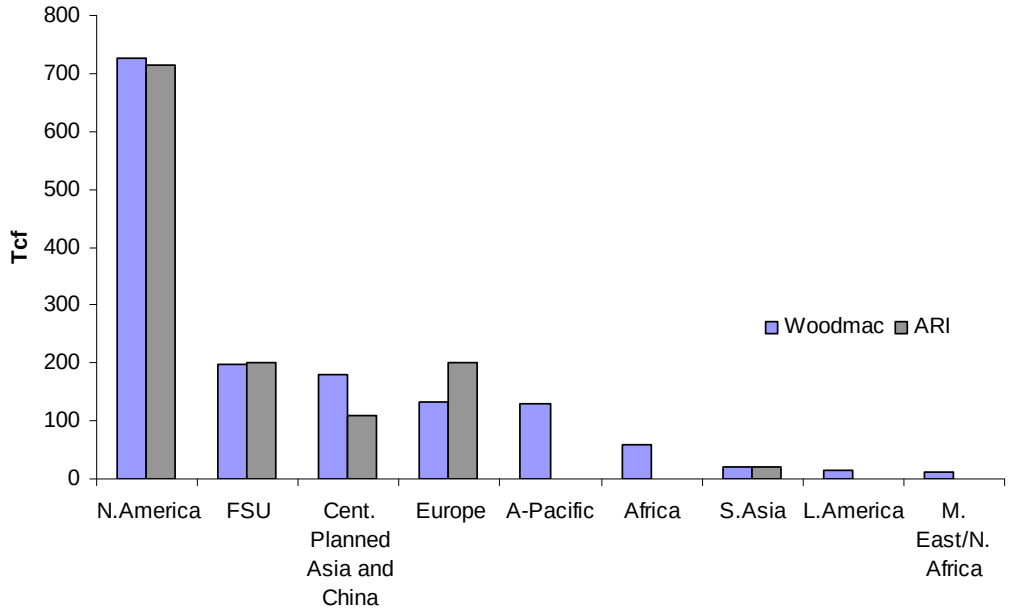
Sources: IHS, Wood Mackenzie, IEA WEO 2009

The International Energy Agency (IEA) has the most optimistic view, which assumes an overall recovery rate of 40% for shale gas worldwide at prices between $2.7 and $9/MMBTU,

[12] 32.6 Qcf is 32,600 Tcf.

while currently observed recovery rates in North America are closer to 20-30%. The three more specialised sources (i.e IHS, ARI and Wood Mackenzie) concur on the assessment of recoverable CBM resources, while the divergence is significant on the assessment of tight gas. Several reasons can explain this discrepancy: Wood Mackenzie estimates are three years older than the ones from IHS, and their definition of tight gas is probably different. Based on the IEA estimates, global recoverable unconventional gas resources would amount to 13.4 Qcf, i.e 20% less than the ultimately recoverable conventional gas resources[13].

Figure 1.3: Unconventional gas recoverable resources by region, range of estimates



Source: Wood Mackenzie 2006, Advanced Resources International

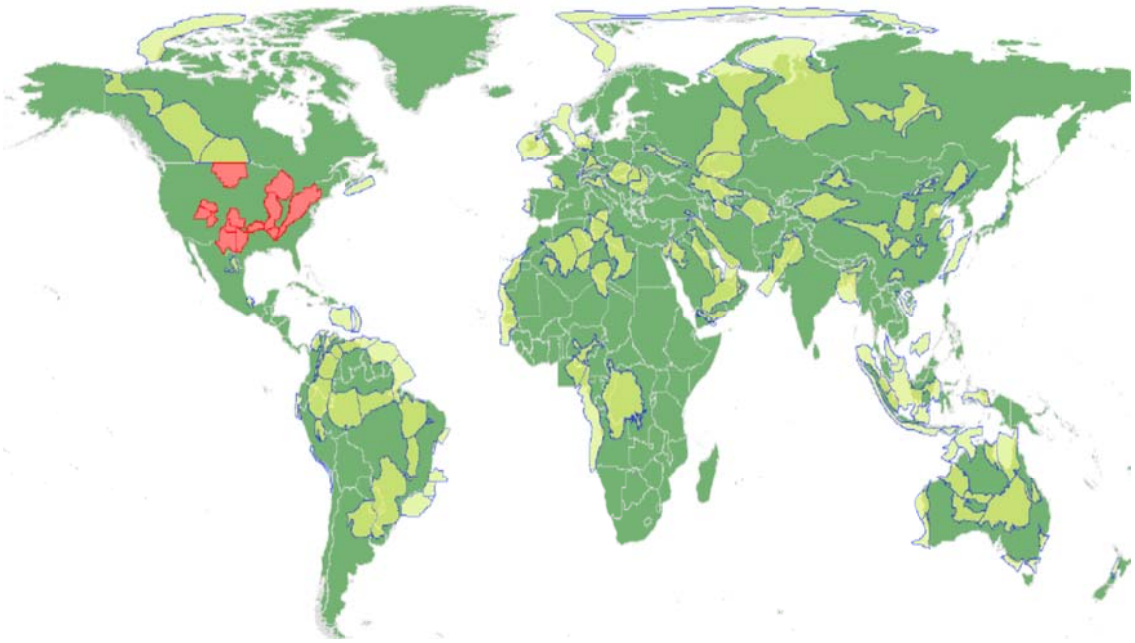
Very few estimates of recoverable resources broken down regionally are available. One challenge is to identify and delineate unconventional gas plays at a country level for the whole world. Preliminary studies have identified over 688 shales in 142 basins worldwide[14]. However, the work required to achieve this level of granularity is massive. For example, in Europe a consortium gathering many geological institutions and gas companies has just started a thorough study on shale gas plays, but it will last for no less than six years. More details on this initiative are given in Chapter 5.

Comparing ARI's and Wood Mackenzie's views, it is interesting to note that these sources concur on North America and FSU, but not on Europe and Central Asia and China.

Geography Looking at shale formations worldwide, it seems that all continents are endowed with shale gas, according to a study carried out by Schlumberger in 2007. This work ranked 688 shale formations in 142 petroleum basins. Figure 1.4 below shows the geographical distribution. However this map is now two years old, and since 2007 new basins have been identified, such as in Poland, and the Paris and Ales basins in France. A list of unconventional gas basins in Europe is available in Appendix C.

[13] IEA *World Energy Outlook 2009*. The IEA estimates that world ultimately recoverable conventional gas resources amount to 16.612 Tcf (470.6 Tcm) as of end 2008.
[14] Data presented by Schlumberger Oilfield Services at the CERA Week conference in February 2009

Figure 1.4: Global shale gas resources



Source: Schlumberger study from 2007 presented by Schlumberger Oilfield Services at CERA Week conference in February 2009

Part 1: Unconventional gas in North America: the tale of a quiet success

Chapter 1 - Context: resources and production

In less than four years, the US has moved from a significant importer into an almost self-sufficient gas producer. Net imports have declined by 17.6 % between 2004 and 2009 to 2.8 Tcf, and are projected by the US Department of Energy to be at 0.7 Tcf by 2030 in its Reference Scenario[15], a further decrease by 75%! This supply reversal took everyone by surprise. It has come as a surprise to the industry that recoverable resources were so abundant, although their existence had been known for a long time, but estimates were old and thus conservative, and did not suggest that they would be competitive in terms of cost. The reasons for the increase in supply are technological developments combined with governmental subsidies, increasing albeit volatile gas prices since 2000, and easy credit availability for most of the 2000s.

We first look at the estimated unconventional gas recoverable resource base. As explained in the introduction, many estimates have been developed independently for North America, and the divergences are very wide, with frequent revisions, in particular for shale plays, the least known type of continuous accumulations. The US Geological Survey (USGS) estimated the unconventional gas resource base at a very conservative 304 Tcf in 2006, and this figure excludes many emerging shale plays, such as East Texas and Anadarko. Advanced Resources International (ARI) estimated the technically recoverable resource base at at least 1,316 Tcf in 2009, with 230 Tcf for CBM, 371 Tcf for tight gas sands and 715 Tcf for shale gas.
In June 2009, the Potential Gas Committee (PGC), which is connected to the Colorado School of Mines, raised its estimate of gas reserves and resources in the US by 39% to 2,074 Tcf (1,836 Tcf of probable and possible resources and 238 Tcf of proven reserves estimated by the EIA), the highest number since the group started tracking the information 44 years ago. The growing importance of shale gas is substantiated by the fact that, of the 1,836 Tcf of total potential resources, shale gas accounts for 616 Tcf (33%) according to the PGC[16]. This figure is to be compared with estimated conventional gas resources of only 892 Tcf[17] in 2009.

The dramatic upward revisions of unconventional gas resource estimates contrast sharply with the severe decline of North American conventional proven gas reserves. These shrank by 16% between 1980 and 2000, from 200 Tcf to 167 Tcf[18]. They are continuing to decrease (e.g offshore Gulf of Mexico gas resources have fallen by 45%[19] since 2001), however this decline has been increasingly offset by the proving up of new gas reserves from unconventional gas deposits. As a result, in 2008 total proven gas reserves amounted to 238 Tcf, a higher level than three decades ago. Table 1.1 gives a breakdown of proved gas reserves by type.

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[15] EIA *Annual Energy Outlook 2009*
[16] http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base and see note 8 for other sources.
[17] ARI, *Paradigm Shift in domestic natural gas resources, supplies and costs*, September 2009. http://www.adv-res.com/pdf/Kuuskraa%20EFI%20Natural%20Gas%20SEP_21_09.pdf
[18] EIA *Natural gas production-Annual Energy Outlook 2009*
[19] See note 15.

Table 1.1: US proved gas reserves in 2007 and 2008 (Tcf)

Reservoir type	2007	2008	% change
Conventional and tight gas	167.5	184	9.9%
CBM	21.9	20.9	-4.6%
Shale gas	21.7	32.8	51.2%
Total	**211.1**	**237.7**	**12.6%**

Source: EIA Annual Energy Outlook 2009

In the 1990s it was CBM and tight gas that drove the growth in reserves, while over the last years shale gas has been the main growth engine. It is hard to document the growing contribution of shale gas to US gas proven reserves over time, as the EIA only started reporting shale gas reserves separately in 2007. However it is easier to observe the growing contribution of CBM, as these reserves have been reported separately by the EIA since 1990. The trend in CBM reserves has been a rapid increase in the 1990s and early 2000s, followed by a decline later in the decade. This does not change the main fact that unconventional gas reserves cannot be predicted as easily as conventional ones. The metrics for forecasting unconventional gas additions to supplies are different from those for conventional gas. Recovery is proven by drilling.

In Canada, the remaining marketable natural gas resource base is estimated at 424 Tcf, of which conventional gas represents only a third. Furthermore, conventional gas reserves dropped by 40% between 1990 and 2007 and are expected to decrease between 64 and 79% by 2030 according to the National Energy Board of Canada[20]. Conventional gas production is also falling. While the US produced 14.2 Tcf of gas from onshore and offshore conventional sources in 1995, it only provided 9.7 Tcf in 2008, i.e more than one-third less. Such a dramatic supply situation explains why the US industry and government were keen to increase efforts and investments in developing new domestic gas sources.

Chapter 2 - History of a revolution

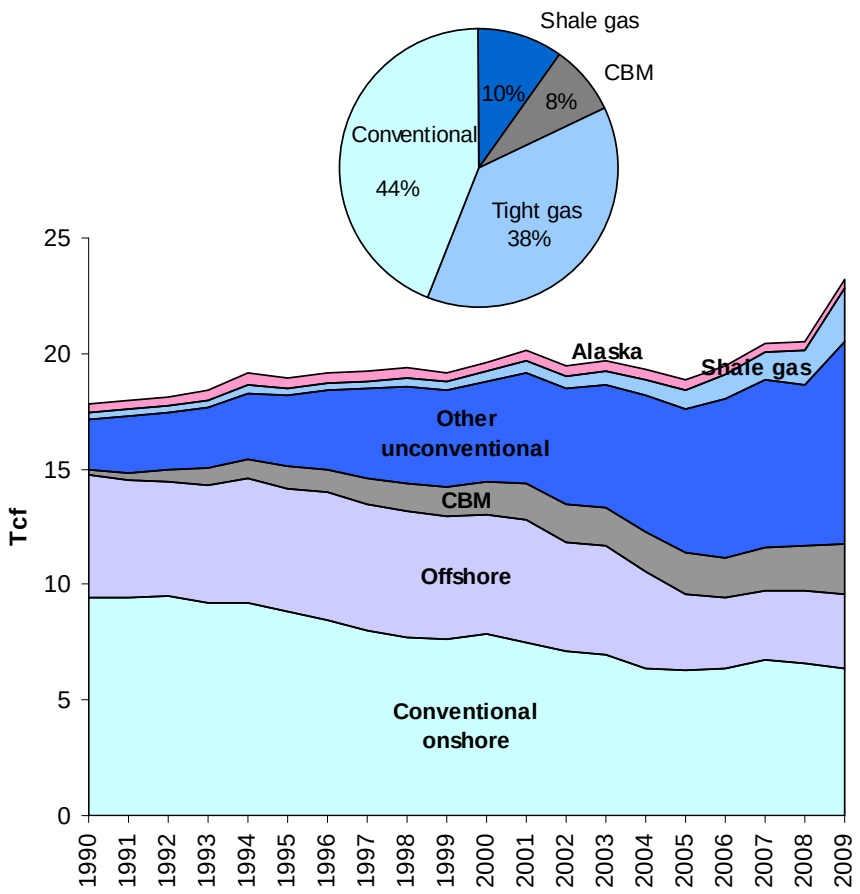
Unconventional gas as a potential source of supply in North America is far from new, but has remained marginal for decades. The first commercial well drilled in a shale reservoir dates back to the late 1820s in New York, and the first shale gas production came from the Appalachian Basin, where the Devonian shale gas fields were the world's largest known gas fields by 1926 [21].

Although commercial production was well under way in the 1980s, the pace of development of unconventional reservoirs has remained relatively slow. It is only since 2006 that the industry has been witnessing an extraordinary acceleration of unconventional gas production, driven by the exploitation of a few shale gas plays[22], in particular the Barnett Shale in North

[20] National Energy Board *Canada's Energy Future- reference case and scenarios to 2030*, November 2007
[21] K. Shirley, *Shale gas exciting again*, AAPG Explorer, March 2001
http://www.aapg.org/explorer/2001/03mar/gas_shales.cfm
[22] See definition in the Glossary

Texas. In 2010, unconventional gas accounted for more than half of US total gas production, compared with less than 40% five years previously[23], i.e a 10% jump in unconventional gas contribution to domestic production occurred since 2004. Figure 2.1 illustrates clearly that surge and the growing share of unconventional gas in US total production since 1990.

Figure 2.1: US gas production by type and 2009 gas production breakdown



Source: EIA Energy Annual Outlook 2009

Mostly structural factors have underpinned this fast and strong growth.

Vast unconventional gas reserves, large geographical space enabling the drilling of hundreds of thousands of wells[24] and declining conventional reserves, described above, have been pre-requisites for the scale of unconventional gas production in the US. However, these initial conditions alone would not have triggered any changes in domestic gas supply had not it been for other catalysts.

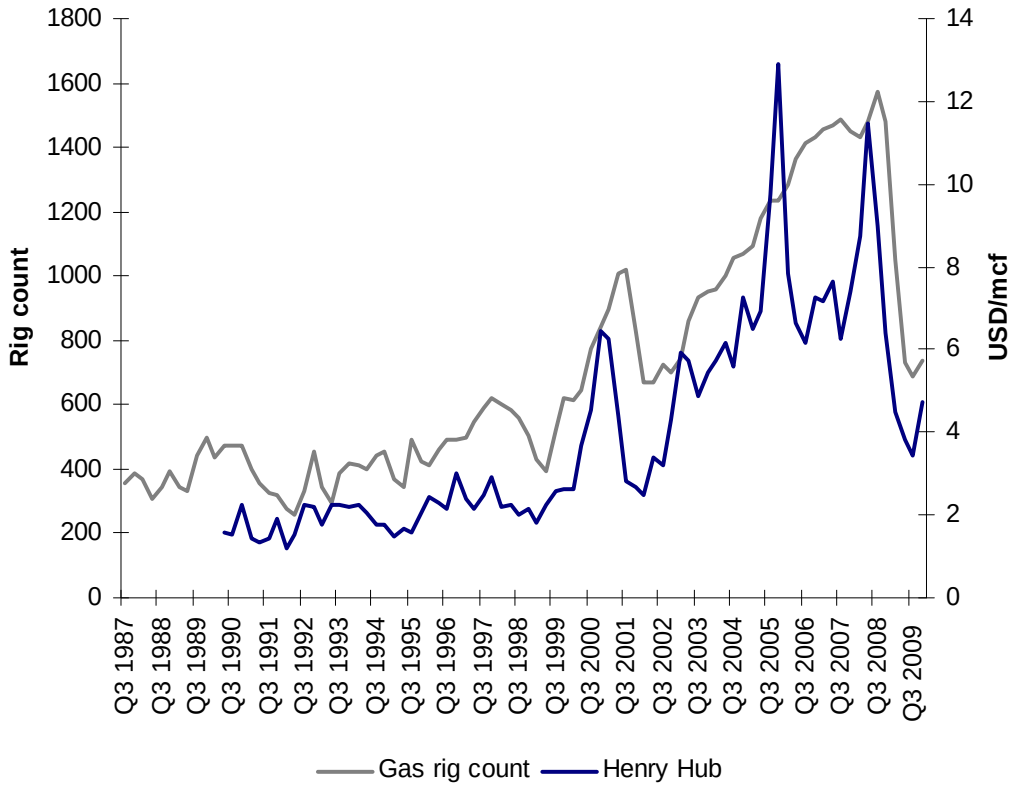
The first major incentive for modern unconventional gas production can be traced back to the implementation of the Crude Oil Windfall Profit Tax Act in 1980, which contained an Alternative Fuel Production (known as the "Section 29") tax credit of $0.5/thousand cubic

[23] IEA *World Energy Outlook 2009* and EIA *Natural gas production-Annual Energy Outlook 2009.* US natural gas production amounted to 20.9 Tcf in 2009.
[24] According to ARI, more than 124,500 wells were drilled and placed on production between 1996 and 2006. Furthermore the drilling pace has accelerated since 2007.

feet of unconventional gas production (see Part 1, Chapter 3). This spurred activity in the Antrim Shale in the Michigan Basin, and then in the New Albany Shale in Illinois, which reached its peak in 1996. It also triggered interest in the Barnett Shale in the Fort Worth Basin (North Texas) from Mitchell Energy & Development Co in 1981. Although the tax credit expired in 1992, operators continued to expand gas shale programs, as technology improvements, better understanding of mechanisms driving production, and operational efficiency gains kept the exploitation of the resource attractive.

However, large scale unconventional gas development did not get off the ground until market conditions improved in the 1990s. The sharp decline in maturing conventional gas reserves, especially in the Gulf of Mexico, and insufficient gas discoveries to replace reserves led to expectations of a gas supply gap as demand, stimulated by low prices, increased rapidly. Expectations pushed gas prices up, fostering the interest in and commerciality of unconventional gas, as figure 2.2 illustrates. It is worth highlighting that the 2004-2008 period, corresponding to the boom of shale gas, has been extraordinary in terms of price hikes and availability of credit. The United States then began its transition to unconventional resources.

Figure 2.2: Natural gas price and unconventional gas development since 1990



Source: Baker Hughes, Reuters

Looking at figure 2.2, a clear correlation between the increase in gas price and gas rig count can be observed. The number of gas-oriented rigs in use rose steadily but slowly from the second half of 1992, the year of the tax credit expiry, until early 1999. During this period, gas prices remained within a band of $1.5-2.2/mcf. It is since 1999 that an impressive surge in the number and activity of gas rigs has taken place, following the price curve, although with limited elasticity.

The San Juan CBM play was developed and tight sand capacity grew continuously. Production from tight sands rose by 58% over a decade, from 3.6 Tcf in 1996 to 5.7 Tcf in 2006.[25] However the high cost of drilling due to the lack of efficient technology and adequate rigs was limiting production growth.

It was not until 2005 that a technology breakthrough was achieved in the Barnett Shale, based on the combining of hydraulic fracturing techniques[26] with horizontal drilling (see Part 1, Chapter 3.1). The consequence of these developments was a substantial and rapid increase in US productive capacity over the last three years, as shown in Figure 2.1, driven by shale gas and underpinned by greater access to land and infrastructure, which took everyone by surprise.

Part 1, Chapter 3 contains a more detailed analysis of the drivers behind the success of unconventional gas exploitation.

2.1 Main plays by type of resource

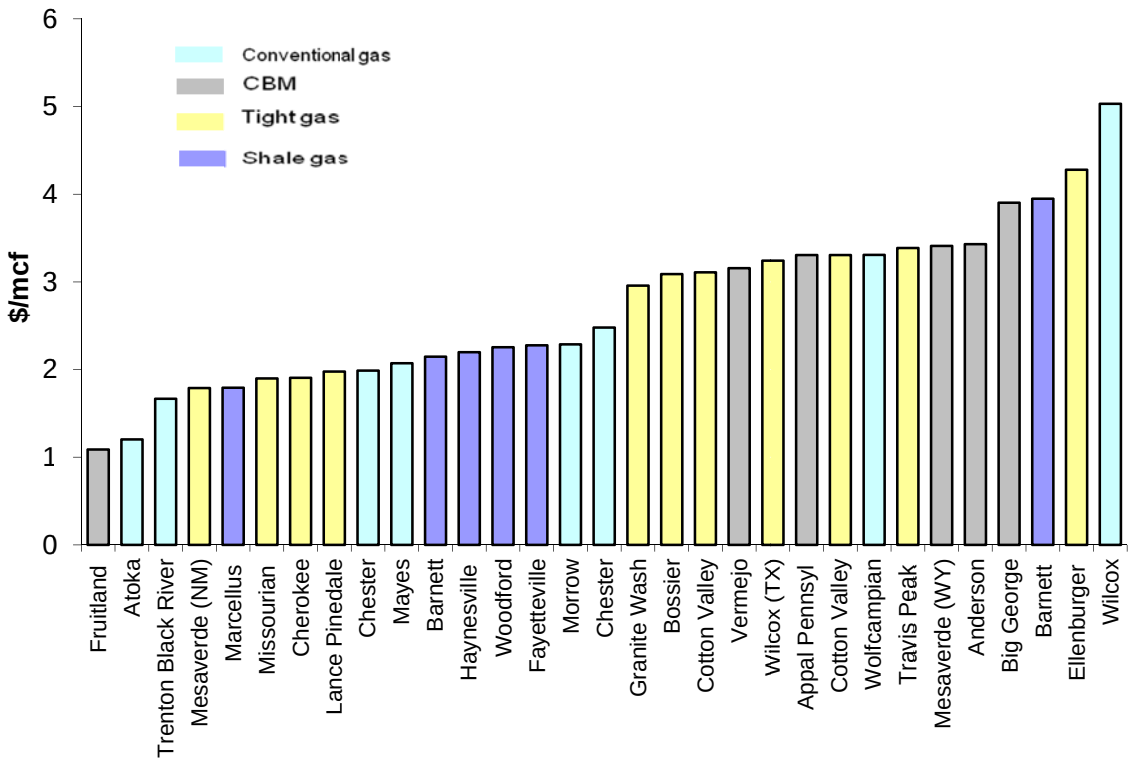
Tight gas, CBM and shale gas resources have followed different development paths. Both CBM and tight gas have required subsidies in the form of tax credits to be developed, while the only real incentive for shale gas development has been and continues to be price signals, supported by revolutionary technology developments in the form of combined horizontal drilling and hydraulic fracturing. Shale gas has been operating on a profit and loss basis, which means it plays the role of swing production depending on price signals. It is worth noting, however, that shale gas has also indirectly benefited from tax credits, as shale oil was included as an eligible fuel for tax breaks, prompting the industry to gain knowledge of shales in the 1980s and 1990s.

These three types of unconventional gas share the technological need for stimulation[27] to produce, balanced with low exploration risk and long production lives. Despite having been subject to different economic triggers (subsidies vs price), all types of unconventional gas resources can now be competitively produced compared to conventional gas, as shown in figure 2.3.

Thanks to the resource cost competitiveness compared to conventional production, and assuming that technological progress will continue to drive down costs and increase recovery rates, it is safe to say that the unconventional gas revolution only started around the mid 2000s, offsetting the gradual decline of conventional production. Unconventional gas production will continue to grow in the coming years, from current and future emerging plays. Furthermore, the production growth engine is set to be shale gas plays, while tight gas will continue to have a dominating but shrinking market share, in line with the depletion of the best resource plays. In support of that point is the natural gas production forecast to 2030 made by the US DoE in April 2009 in its Annual Energy Outlook (Reference scenario), shown in figure 2.4.

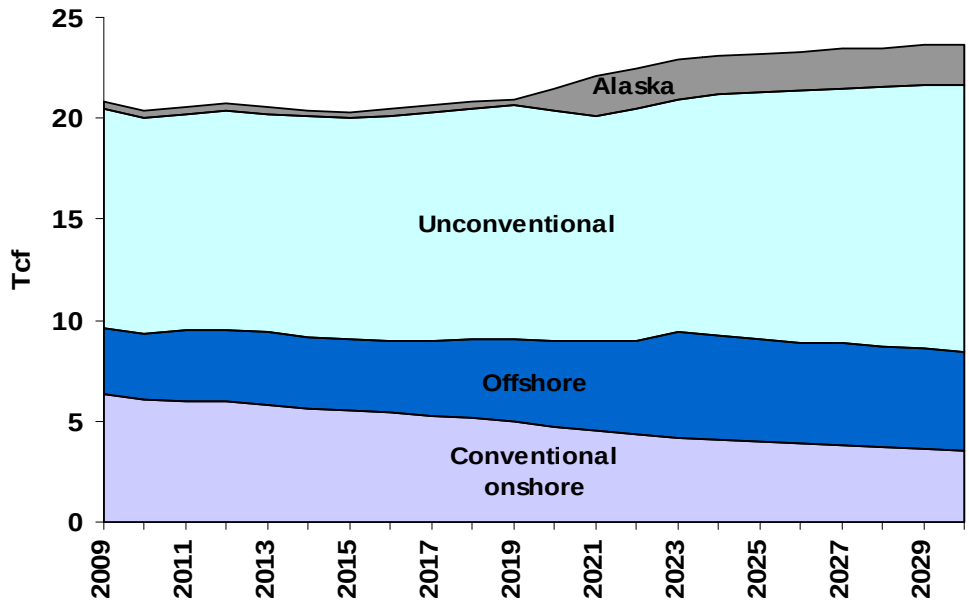
[25] Advanced Resources International, *Unconventional Gas progress*, Oil and Gas Journal 24 July 2007.
[26] See definition in the Glossary
[27] See definition in the Glossary

Figure 2.3: US long-run costs for conventional and unconventional basins (based on a sample of existing projects)



Source: Cost and price assumptions from Wood Mackenzie Upstream Services - June 2009

Figure 2.4: US natural gas production forecasts



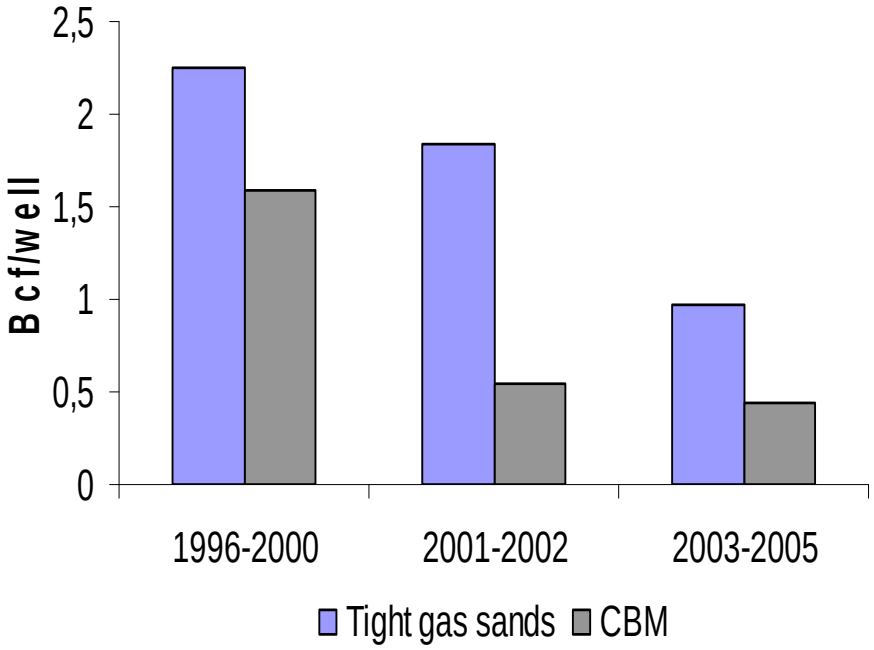
Source: EIA AEO 2009

Tight gas Tight gas sands have now been producing for more than 40 years in the US. Today production amounts to around 6.7 Tcf, i.e almost 40% of the US unconventional gas output. Development of these resources was spurred by the depletion of areas producing mature and higher grade resources. However, the overall volume of reserves per well has declined (see figure 2.5), which shows that much of the higher quality reserves has already been developed. Looking at two of the most prolific tight gas sands in the US, Pinedale and Jonah (Wyoming), illustrates this statement. An analysis[28] of more than 2,300 wells shows that both plays have passed their peaks in terms of productivity since 2007 and 2009 respectively, as average initial production rates per fracturing stage fall, and as the best parts of the plays have been exhausted.

This declining trend in tight gas productivity, and the likely consequence that the marginal cost of production from tight gas plays will continue to rise over time, has contributed to a shift in drilling activity towards the less developed shale gas plays. As a result, tight gas drilling could fall sharply over the coming decade. This is already the case in the Piceance, Uinta and Green River Basins.

Canadian tight gas production has been rising rapidly and is expected to exceed 1,9 Tcf[29] in 2009.

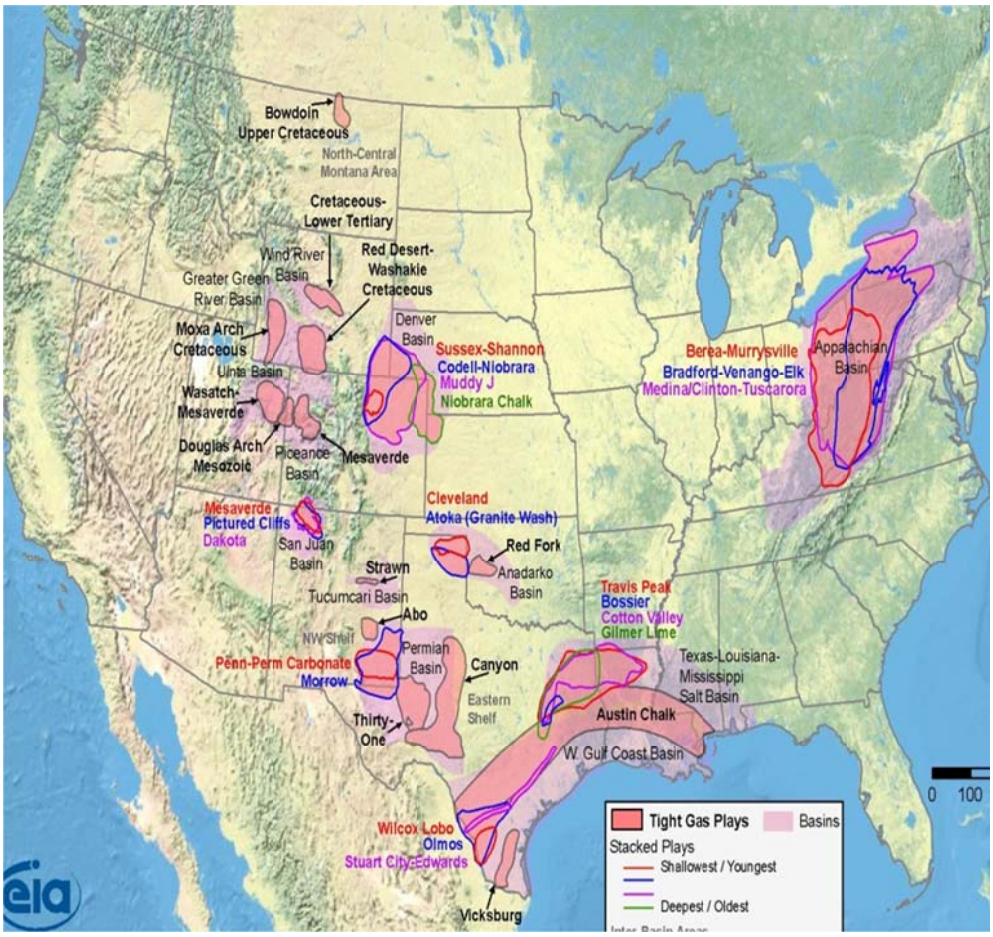
Figure 2.5: Declines in US unconventional gas well productivity



Source: ARI July 24, 2007- Only includes successful wells

[28] Bernstein Research, *Are the Wyoming Tight Sands in decline?*, 5 January 2010
[29] International Energy Agency *World Energy Outlook 2009* p 398

Figure 2.6: Major tight gas plays in the US



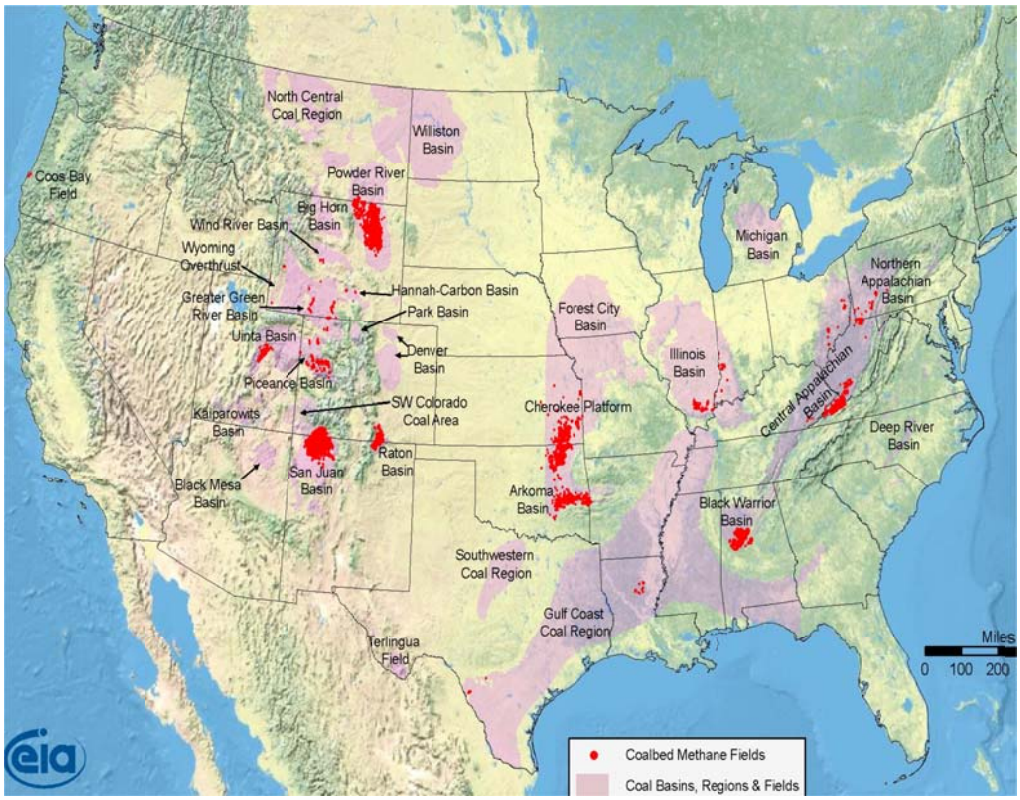
Source: EIA

CBM CBM production has been under way on a limited scale since the 1930s, in the Northern Appalachian basin, and since the 1950s in the San Juan Basin in the south-western US. Commercial production of CBM started only in the late 1980s and reached a plateau in 2004 at 1.8 Tcf, which accounts for 8.6% of the country's total natural gas production today. As with tight gas sands, CBM well productivity is on the decline, as shown in figure 2.5. Production and reserves come from 17 basins located across the country (see figure 2.7), such as the Powder River Basin (Colorado), San Juan (New Mexico), and the Black Warrior Basin (Alabama). However they are strongly dominated by the San Juan Basin (2/3 of the production and 44% of proven reserves as of 2006[30]).

Although the composition of CBM varies play by play, a common feature is that it is typically a dry gas high in methane content. Furthermore, there is no typical production profile for a CBM well, as each play varies significantly. Some CBM plays require de-watering before they reach peak production rates, while other CBM plays are dry and produce long-life gas as soon as wells are completed.

[30] EIA- http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

Figure 2.7: Major CBM fields in the US



Source: EIA

Canada also has vast CBM resources, which it started to produce commercially in 2003. Today, production from CBM accounts for 4%[31] of Canada's total gas production.

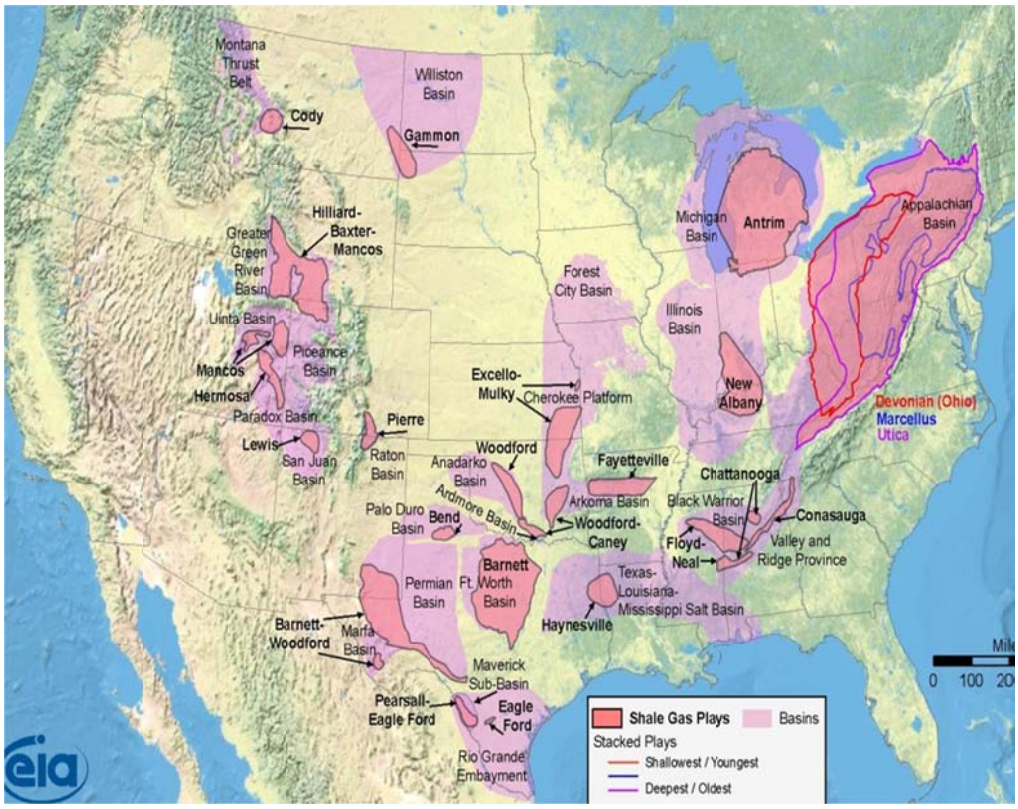
Shale gas Gas shales are currently amongst the hottest plays in the United States as a result of robust economics, gas prices in the range of $6-14/mcf in the period 2004-09, and the remarkable technological successes of exploiting the Barnett Shale of the Fort Worth Basin underpinned by a combination of horizontal drilling and hydraulic fracturing technologies. The surge in shale gas production began indeed in a group of shale plays including the giant Barnett in Texas (the second largest "field" in the country with over 1 Tcf of production in 2007), Fayetteville in Arkansas and Woodford in Oklahoma. It then spread northward in 2008 to larger and seemingly more prospective shales, such as the Marcellus in West Virginia, Pennsylvania and New York, and the Haynesville in Louisiana. Figure 2.8 shows the location of the major shale plays, as well as their larger size in the North-East of the US.

Production from US shales has grown by ten-fold during the 2000s and reached 3.1 Tcf in 2009, of which Barnett accounts for 54% (1.7 Tcf) and Fayetteville 16.5% (0.5 Tcf)[32].

The viability of these developments required an existing but underutilized distribution infrastructure and readily accessible markets. In 2010, gas production from shale gas reservoirs in the US comes from more than 40,000 wells.

[31] International Energy Agency *World Energy Outlook 2009*, p 399
[32] ARI *Worldwide Gas Shales and Unconventional Gas: A status report*, December 12 2009, Copenhagen

Figure 2.8: Major shale gas plays in the US



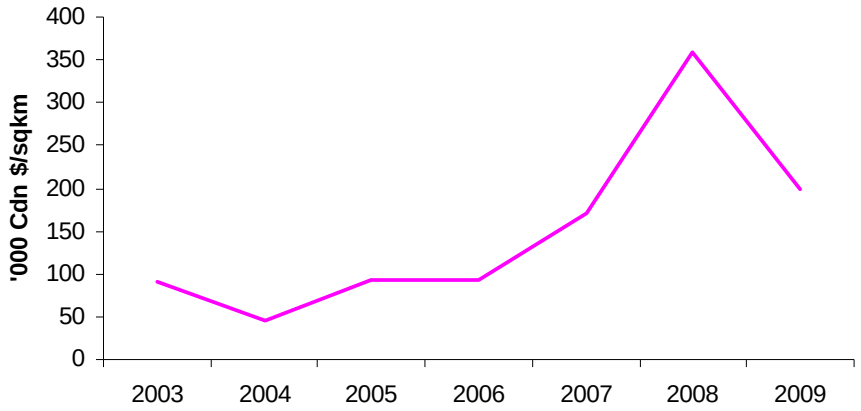
Source: EIA

Shale gas developments also spread to Canada, i.e to the Utica Shale in Quebec and the Horn River Basin and Montney region in British Columbia. The Horn River Basin initially attracted industry attention because a study carried out in 2004 by CBM Solutions showed that the shale has attributes similar to the Barnett and is even larger and thicker. This would mean that the Horn River Basin is even more prospective than the Barnett. The coming years will show whether that is the case. Today however, natural gas production from shales in Canada, which amounted to around 255 bcf in 2009[33], comes mostly from Montney (86% of the total).

As a result of the perceived prospectivity of the Horn River Basin, many of the major companies operating in the Barnett rushed to grab land in this area, which is reflected in the astonishing rise in land prices since 2006. Figure 2.9 exhibits the increase in lease prices in British Columbia. The same trend has been taking place in the US since 2006. For example, in the Eagle Ford play, lease bonuses have increased 10 times over a period of 3 years in certain areas, from $100 to $ 1,500/acre. Average lease bonuses paid in 2008 in the Barnett and Haynesville reached $20,000-30,000. However, land acquisition costs vary widely play by play and by company, reflecting the diversity of shale gas plays and of sections within these plays, in terms of subsurface, production performance and proximity to the markets. The wide differences encountered within a play add substantial complexity to geological understanding, development planning, and drilling and completion operations, making production forecasts very challenging until the inventory of wells drilled increases.

[33] ibid

Figure 2.9: Prices of unconventional gas leases in British Columbia



Source: British Columbia government

As mentioned earlier, despite the current lack of subsurface understanding and optimisation of operations and logistics, the shale gas play boom is far from over. Shale gas production will continue to grow in the coming years, from current and future emerging plays. This belief is based on the fact that technology still has substantial room to increase recovery factors and reduce drilling costs. In the newer plays, such as Haynesville and Marcellus, operators continue to report increased Initial Production (IP) rates and unit cost reductions in the drilling activity. This would indicate increasing well productivities in many shale gas plays. The questions are how long this trend will continue and how the overall shale gas well productivity picture will look like if more "mature" plays are taken into account, like the Barnett. According to a study of Barnett wells in the Denton and Tarrant counties by Bernstein Research[34], the decline in well productivity occurred early in the life of the Barnett, as early as mid-2003, while the number of fracs has surged from 2005 to mitigate well performance deterioration and keep volumes flat. This drives capital investments up. The report concludes that "from a macro perspective, the data appears to support the view that as shales grow their costs increase and they become more marginal".

In our opinion, it is too early to conclude at a macro-level on the sustainability of production from shale plays as well as on the future cost level of the shale gas resource base in the next decades, because of the ramp-up of very big plays, and because factors affecting productivity and well economics are still poorly understood.

What we know is that this new supply and its currently improving economics could challenge a large part of tight gas activity, causing drilling in tight reservoirs to decline and the share of gas produced from shale to increase significantly in the gas supply mix. Indeed, a continuation of the 2006-2008 production growth rate (around 5%/year), which would add 27 Tcf of gas supply by 2016, of which at least 70%[35] would come from shale and tight gas

[34] Bernstein Research, *The Decline in Shale Well Productivity and the "Technology" Myth - A Look at the Barnett*, 12 October 2009.
[35] Barclays Capital *100 Years of Gas-Part I: Shale Gas*, September 02 2009

drilling, is unlikely to be sustainable given the projected slow growth of demand for gas[36]. Therefore, many drilling programs will likely need to be cancelled, and this will affect the

least economic formations and new wells, i.e primarily conventional and tight gas drilling, with the distribution of the cuts depending on the future level of the Henry Hub price.

2.2 Main players: the role of independents

History The development of unconventional gas is first and foremost the result of investments by small independents. By the end of the 1970s, the Majors had decided that the onshore hydrocarbon resource base in the US was mature, and divested large parts of their domestic acreage to refocus on offshore and international exploration. Smaller Exploration & Production (E&P) companies, excluded from large-scale conventional gas projects, had no other option than to pursue what was left. Attracted by tax credits from the 1980s and 1990s, they applied themselves to the production of "non conventional" fuels.

Technical interest from small producers in tight sands and shale plays started to grow around 1996, while larger oil and gas producers shifted their focus from maturing conventional gas fields to offshore prospects in the Gulf of Mexico. The first movers started acquiring land at the end of the 1990s in the Rockies and the Gulf Coast, with the aim to develop CBM, tight sands and shale plays. Thus, although they had limited access to capital, these companies built good and contiguous land positions in fairly well-developed and understood plays, and benefited from low capital costs until 2004, making them successful.

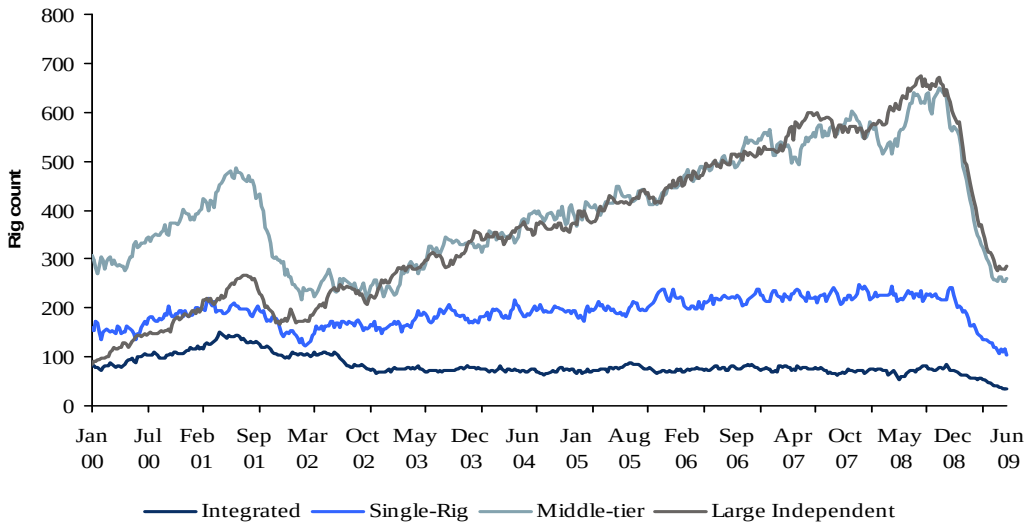
These are the players behind the development of specialised and adequate drilling technologies for exploiting shales. They started to develop shallow (500-2,500 ft) shale plays with conventional vertical wells and small hydraulic stimulations, generating modest levels of production (about 100 Mcfd/well[37]). Then Mitchell Energy & Development Corp., an operator in the Barnett Shale, developed an innovative fracturing technique using slick-water[38] instead of gel, to increase gas recovery. It is however Devon Energy, which acquired Mitchell in 2002, that achieved a technological breakthrough in the Barnett in 2005 by combining horizontal drilling and large slick-water-based fracs. Devon increased the number of fracs in the Woodford and Barnett Shale plays by nearly 500% from 2005 to 2008, compared with a rig count growth of 52%[39]. In 2006, Southwestern Energy and Newfield Energy achieved similar breakthroughs in the Fayetteville and Woodford Shales respectively. Many independents managed to get hold of capital to invest in these shales thanks to a very favourable credit market in the 2000s, until the end of 2007.

Following this series of successes reflecting improved understanding of the geology and drilling technologies, a new class of shale operators, mostly larger independents, assumed the leadership of the industry. These players have stronger financial capacity thanks to better

[36] Historical demand growth averaged 0.4%/year over the 10-year period ending in 2008. Most experts do not expect any dramatic rise in demand over 2010-2030 despite long-term growth drivers such as efficiency improvements, carbon policies and the increase in gas-fired power generation.
[37] Vello A. Kuuskraa, *Gas shale: Seven plays dominate North America activity*, Oil & Gas Journal 28 September 2009
[38] See definition in the Glossary
[39] Bernstein Research, *The Decline in Shale Well Productivity and the "Technology" Myth - A Look at the Barnett*, 12 October 2009

access to capital and the use of price hedging. Through high investments and technologically competent teams, they have contributed greatly to the acceleration of gas drilling and production since the middle of the 2000s. This trend is well illustrated by figure 2.10.

Figure 2.10: Onshore gas rig count by producer since 2000



Source: Barclays Capital report *"Who is drilling?"* 14 July 2009, SmithBits

Top natural gas leaseholders in the US at the end of 2009 are listed in table 2.1. A split between conventional and unconventional gas production and reserves is not available.

Table 2.1: Top natural gas lease holders

	Producer	Production (mmcfd)	Reserves (Tcfe)
1	XTO*	2,421	11,803
2	Chesapeake	2,286	11,327
3	BP	2,278	14,532
4	Anadarko	2,144	8,105
5	ConocoPhillips	2,043	10,920
6	Devon	1,999	8,369
7	EnCana	1,524	5,831
8	Chevron	1,420	2,709
9	ExxonMobil	1,260	11,778
10	Williams	1,148	4,339

Source: 3Q 2009 Company reports
*XTO was acquired by ExxonMobil early in 2010

In another step change since 2008, Majors such as BG Group, BP, ExxonMobil, Shell Statoil, Eni and Total have been returning to the unconventional gas sector, through leasing and acquisitions. A summary of the main transactions involving Majors can be found in Table 2.2. This return to North American domestic production by many Majors is an important indicator of evolving gas strategies within that group of producers. Majors had been busy investing heavily in international LNG projects since the end of the 1990s, and they sought to catch up with the long-term unconventional gas supply trend in North America, which they had failed to foresee, and diversify their gas supply options. Their strategic choice to acquire leases in shale gas plays is indicative of their belief in strong long-term gas fundamentals, i.e the long-term growth potential of unconventional gas and robust gas prices.

Table 2.2: Unconventional gas transactions involving Majors 2008-10

Announced date	Deal type	Buyer	Seller	Key asset/region
08/11/2010	Acquisition	Chevron	Atlas Energy	Marcellus shale, Utica shale
08/10/2010	Joint Venture	Statoil	Talisman, Enduring Resources	Eagle Ford shale
16/06/2010	Asset purchase	BG Group/Exco	Southwestern Energy	Haynesville shale
28/05/2010	Asset purchase	Shell	N/A	Eagle Ford shale
28/05/2010	Asset purchase	Shell	East Resources	Marcellus shale
10/05/2010	Joint Venture	BG Group	Exco Resources	Marcellus shale
21/04/2010	Acquisition	BG Group/Exco	Common Resources	Haynesville shale
02/03/2010	Joint Venture	BP	Lewis Energy	Eagle Ford shale
04/01/2010	Joint Venture	Total	Chesapeake	Barnett shale
14/12/2009	Acquisition	ExxonMobil	XTO	San Juan, Barnett, Fayetteville, Woodford, Bakken, Haynesville, Marcellus
30/06/2009	Joint Venture	BG Group	Exco Resources	Haynesville shale
18/05/2009	Joint Venture	ENI	Quicksilver	Barnett shale
25/11/2008	Joint Venture	Statoil	Chesapeake	Marcellus shale
02/09/2008	Joint Venture	BP	Chesapeake	Fayetteville shale
07/05/2008	Joint Venture	ExxonMobil	Newfield Exploration	South Texas

Source: press reports

Outlook The re-entry of Majors into the unconventional gas business will have some positive implications for current operating models developed by small companies. Indeed, small producers' investment and drilling decisions are only driven by their financial bottom line, as they operate on a cash basis only. Therefore they tend to only act with a short-term horizon, and improvements in their operations are constrained by their lack of capital. Majors are cash-rich, can afford to take more risk, invest in technology improvements, and have long-term planning horizons. Thus, under the influence of Majors, current short-term oriented business models, based on trial and error, may evolve in a way that makes shale gas operations more sustainable.

However, large independents and "middle-tier" producers (i.e companies that operate more than one rig but are not among the top 50 producers) are set to continue to dominate unconventional gas activity, and thus will have the largest influence on future US production growth. For example, independent producers have drilled approximately 90% of the total number of natural gas wells (35,692 wells) in 2008 according to the EIA, and they contributed 82% of total American natural gas production[40].

The share of integrated companies[41] in the overall gas-oriented rig count is likely to continue to drop as these companies remain less involved in shale gas than independents. This is so even if Majors have been shifting their US upstream operations to natural gas since the early 1990s. According to the EIA[42], despite the fact that between 1986 and 1999 Majors increased the share of natural gas in their upstream operations from 38% to 52%, their share of total US natural gas production remained flat at around 56% on a net ownership basis[43]. Consequently, even as the Majors continue to shift to natural gas, "there appears to be no compelling evidence" that their share of total U.S. natural gas production might grow, unless they acquire gas producing companies. This is for example what ExxonMobil, BG and Chevron did by acquiring respectively XTO in December 2009, Common Resources in April 2010 and Atlas Energy in November 2010.

Chapter 3 - Analysis of success factors

Understanding the conditions that have made shale gas exploitation successful in North America is fundamental to a study of the potential of shale gas to be developed in Europe. Indeed, nowhere else in the world than in North America are shale gas operations cheaper and more efficient.

Vast reserves, large geographical space enabling the drilling of hundreds of thousands of wells and declining conventional reserves were key favourable conditions for large-scale development of unconventional gas resources, but were not the catalysts. This paper identifies five catalysts that triggered modern unconventional gas production. On the policy side, these are tax credits and the lack of restrictive regulations on land access, permitting and

[40] Oklahoma Marginal Well Commission survey 2009 in Bernstein Research report *US marginal economics-Despite the Recovery in Prices the Small Producer has already been hurt*, 12 June 2009
[41] See definition in the Glossary
[42] EIA, *The Majors' Shift to Natural Gas*, 27 August 2001 http://www.eia.doe.gov/emeu/finance/sptopics/majors/
[43] The EIA defines Majors as the companies that report to the EIA FRS. At the date of the report, this category encompassed 29 companies, including some large caps **(**see definition in the Glossary**)** like Anadarko, Hess, Oxy Burlington Resources and Unocal, and smaller companies. Therefore the statistics for Majors reported by the EIA cannot be directly compared to the statistics on "independents". However the trend described remains valid.

environmental aspects. Increasing profitability of gas operations, technological developments leading to breakthroughs, availability of credit and a very competitive service industry are the other success factors, which are market-based (although technology development has been initiated and supported by both the US government and the private sector). The paper does not intend to assess the relative importance of these factors. However, while it is clear that favourable policies, prices, credit markets and support services provided the right framework for the unconventional gas revolution, it is the technological breakthroughs that provided the immediate surge in production, against all expectations. Technological progress was thus the main catalyst.

3.1 Technology and R&D

This section has two main objectives**:** the first part briefly reviews the key technology breakthroughs that have unlocked the vast gas potential of shale plays, reflects on how fast innovation in gas recovery has taken place in a historical perspective and analyses the reasons behind this fast innovation cycle. The second part analyses the positive and negative implications of the way technology is being applied, thus leading us to conclude on the challenges and opportunities facing technology development in a context of declining R&D investments, and the improvements needed to create a sustainable shale gas business.

Let us emphasize again the importance of studying the nature and challenges of technological progress in shale gas in the US, as it is this technology and the way it is applied that will be the starting point for European (and other) operators. North America provides indeed the current "best practices" in the shale gas industry in terms of operational efficiency, although its claim to best practice can be challenged and will be discussed in chapter 4**.**

Qualifying the technological breakthroughs Efficiently pursuing the exploitation of gas shales is a high-tech undertaking. The industry traditionally viewed shales as an essentially impermeable source or cap rocks. Technological progress in two areas has reversed this conception.

As mentioned above, the technological breakthrough that "cracked the technological code" was the introduction of horizontal drilling combined with intensive hydraulic stimulation. In themselves, none of these technologies were new. In the Barnett, water fracture stimulation was applied from 1997 and horizontal drilling from 2003. It was the combination of the two that represented the technological leap that has propelled gas production from shales to a major and growing source of domestic gas supply. Mitchell Energy & Development Corp. laid the groundwork by developing an innovative fracturing technique based on slick-water instead of gel, increasing gas recovery. Devon Energy refined the technology and expertise developed by Mitchell and achieved the breakthrough in the Barnett. However the significance of the outcome had not been anticipated, as there was little prior understanding of the potential results that could come from this new experiment. A further technological advancement has been multi-stage fraccing.

To give an idea of what the drilling and stimulation technology progress has achieved, let us look at the requirements of shale gas drilling: extracting shale gas at economically attractive flow rates requires drilling as deep as 7,000 ft (ca 2,100 m), with horizontal wells - as long as 10,000 ft (3,000 m) in the Woodford Shale, and the length will continue to increase - in extensively fractured rocks. Today's common practices for effective hydraulic stimulation of

gas shale formations involve a dozen or more frac stages. For example, in the Woodford play, a record of 20 frac stages was established in January 2010, and this level will likely increase over time.

The combined horizontal drilling and hydraulic stimulation innovation came in addition to what we believe is the other huge step in technological progress: an improved understanding of subsurface characteristics of shale rocks. This is less mentioned than the other two factors perhaps because it is the result of a continuous process rather than of a high-impact new technique. The prediction of gas concentration, partition behaviour and rock properties ahead of drilling is really of paramount importance for reducing risk and identifying "sweet spots"[44].

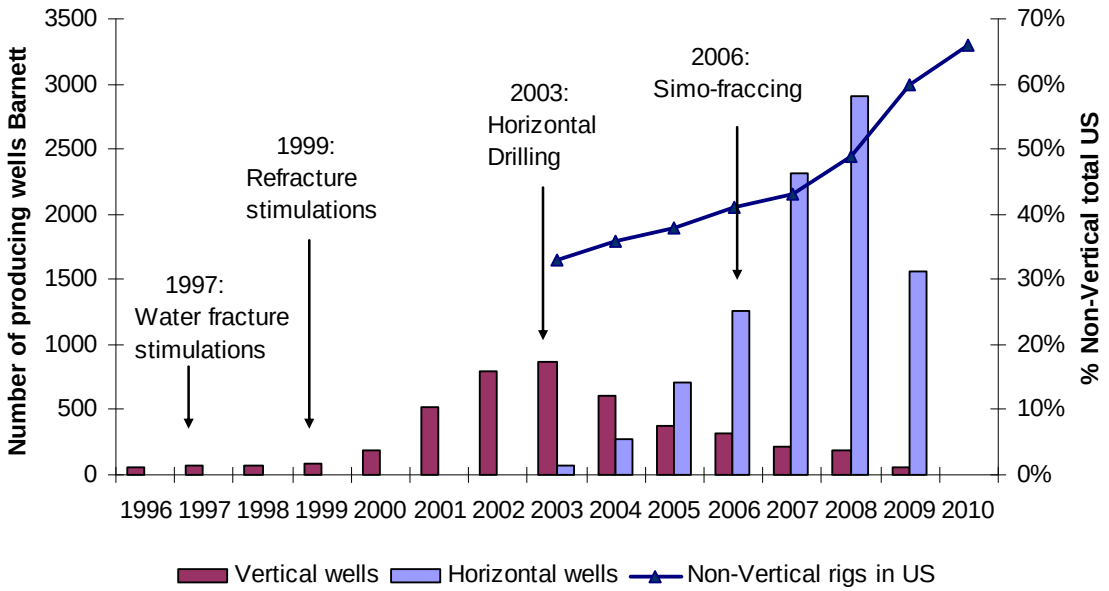
An incredibly quick innovation cycle The pace of the technological progress described above lies at the heart of the surprise effect created by the rapid surge in shale gas production since 2005. Innovation lead time typically goes through four phases from idea to commercialisation (defined as 50% Market Penetration[45]), and in the E&P industry the average lead time ranges from 30 to 35 years. For example, Chris Friedemann of ION Geophysical said in a panel at the 2009 Offshore Europe Conference that it takes an average of 35 years for a new technology to be adopted by the oil and gas industry.[46] This comment is supported by research from the management consultancy McKinsey performed for clients. According to this research, 3D seismic and horizontal drilling took about 30 years from concept development to commercialisation.

In the case of shale gas, the new drilling and stimulation technology was adopted by the industry in less than 10 years from the development of the concept in the late 1990s to its widespread application after 2006. This is an incredibly fast cycle by historical standards. According to Steve Jacobs, president of petroleum market consultancy RMI, there are three factors that determine how quickly technology is accepted by oil and gas operators: the immediacy and magnitude of the benefit that the technology promises, the reliability of the technology, and the comparative cost and benefit relative to current practices. These three elements became obvious to US independents extremely quickly, supporting the fast implementation of horizontal drilling and hydraulic stimulation. Regarding the first condition, data show that drilling horizontally and applying waterslick-based fracs in the Barnett improved well flow rates in the first years. The average first month initial production rate for the Barnett increased indeed from 0.5 mmcfd in 2004 to 0.65 in 2005 and 0.82 in 2007, i.e a 64% rise in less than four years[47]. The continuity in productivity improvements in the Barnett and Woodford over the years 2005-2007 and thereafter in emerging plays such as Fayetteville, supported by faster learning curves[48], demonstrated the reliability of the new technology. Finally, as recovery factors increased and better understanding of the play led to more customised well designs, as illustrated in figure 3.1, unit costs of production decreased, enhancing the relative cost competitiveness of horizontal drilling and hydraulic fracturing compared to previous practices based on vertical drilling and the use of gel as fracturing fluid.

[44] See definition in the Glossary
[45] Market Penetration is a measure of the adoption of a product or service compared to the total theoretical market for that product or service.
[46] Offshore Europe 2009 conference, "From Bright ideas to Implementation" panel, September 2009, http://www.spe.org/jpt/2009/09/oe-09-speeding-technology-uptake
[47] Calculation performed by Novas Consulting
[48] See definition in Glossary

Some energy executives are saying they see 20% to 35% cost reductions year on year[49], although it is unclear whether these are full-cycle costs or only operational costs. Another example of impressive unit cost reduction is reported by Talisman Energy, which estimates that its break-even level for investment in North-American shales has dropped 47% between 2008 and July 2010.[50]

Figure 3.1: Growth in the number of horizontal wells and customised technologies in the Barnett



Source: Powell Barnett Shale Newsletter 18.04.2010, Rigzone Q1 2010 Land Rig Review

Figure 3.1 illustrates the exponential growth of new horizontal wells producing in the Barnett and of rigs capable of horizontal drilling in the US over the period 2003 to 2008, as well as the increasing pace of development of new, more customised stimulation technologies since the mid-1990s. The period 2009-2010 is showing a slowdown in the number of new horizontal wells in the Barnett as new, more attractive shale plays draw new investments and the financial crisis impacts the overall onshore drilling activity in the US.

In Europe the direct adoption of the latest drilling and completion technology described above will not be influenced by the three conditions mentioned by Jacobs above. Europe has no technological expertise of its own in shale gas extraction, and this expertise is limited in the case of tight sands and CBM. The region is embracing and will have to embrace direct technology transfers from North America. However shale plays in Europe have different geological characteristics, they are generally deeper, hotter and more highly pressurised. Furthermore, the application of hydro-fraccing technology has led to the implementation of operating models that are being increasingly challenged, mostly on environmental grounds. Therefore the transfer of US drilling and stimulation technologies to Europe is likely to take place, but with adjustments. Another argument supporting this assertion is that production techniques currently used have been derived from empirical (i.e trial and error) approaches.

[49] Keith Schaefer, *Natural Gas: Costs go down as learning curve goes up*, Resource Investor 6 June 2009 http://www.resourceinvestor.com/News/2009/6/Pages/Natural-gas-Costs-go-down-as-learning-curve-goes-up.aspx

[50] Talisman Energy Corporate Presentation July 2010 p 9.

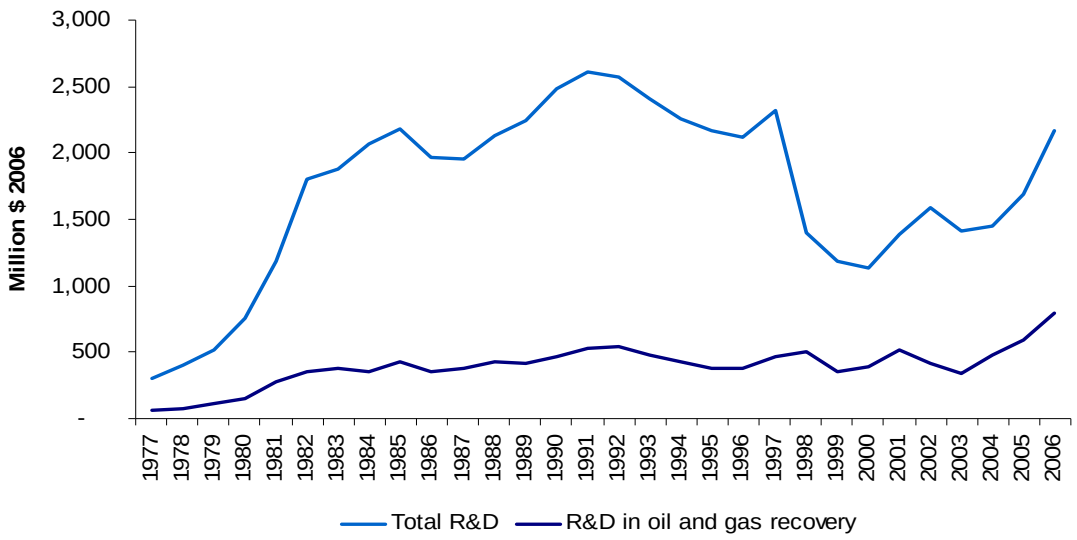
More upfront science is likely to be deployed in Europe, not only because the European culture tends to require more scientific investigations before investment decisions are made, but also because R&D could lead to alternative methods of reservoir evaluation and exploitation.

Thus, the replication of the North American unconventional gas operating model in Europe, including technology transfers, will be partial and certainly not straightforward. This latter point will be discussed in depth later, in Part 1, chapter 4 and Part 2 of this paper.

Key success factors for technological progress At the heart of the technology progress bearing fruit today lie capital incentives, such as tax credits implemented in the 1980s (see chapter 3.3) and rising gas prices over time since 2000, but also targeted R&D efforts in oil and gas recovery in the 1980s and the 1990s. The lag between research and its widespread benefits is indeed long, about 16 years according to the NPC[51].

Looking at total R&D spending in petroleum-related activities in the US since the 1970s (figure 3.2), we notice a sharp increase in investments in the 1980s until 1992. These investments are mostly made by the oil and gas industry, the share of government funding remaining small, at 6% in 1977 and declining significantly over time, to only 0.5% from 1986 until today. The spike observed in total R&D financing can however not be seen to the same extent at all in R&D targeting oil and natural gas recovery, but the trend in real terms is of a more or less slow but constant increase in investments over the last 30 years. When it comes to R&D specifically directed to US onshore needs (and in particular unconventional gas), the percentage is very small (the exact percentage is not publicly available), as this resource was considered "marginal" by international producers.

Figure 3.2: US R&D investments in petroleum



Source: EIA FRS Survey 2006

[51] NPC *Global Oil and Gas Study*, 2007

So it is not so much the amount of investments as the way R&D has been conducted that has mattered. Firstly, most of the unconventional gas research programs were sponsored by the Gas Research Institute (GRI) and the Department of Energy (DoE), and those programs established the scientific foundation for CBM and the hydraulic fracturing technology. Secondly, R&D efforts were field-based due to partnerships between the GRI and DoE and onshore gas operators. This cooperation, directing R&D toward practical and value-adding concepts, has been very valuable in accelerating the commercial development of several unconventional gas basins, such as the Piceance (tight sands), Black Warrior (CBM), San Juan (CBM) and Antrim (shale gas). Different sources suggest that field-based R&D accelerates the application of technologies to commercial levels by 10 years[52].

However the situation today is different and poses some challenges to further rapid technological improvements, which are still needed to overcome environmental challenges and sustain shale gas production growth. Most of the research programs have been discontinued, due to the lack of GRI and DoE funding, and R&D is primarily left to oil and gas companies and service providers, which act on their own and have decreased their funding significantly. This is what we observe today, and the lack of cooperation is detrimental to the speed of technology application and commercialisation. As we said earlier, the large majority of unconventional gas producers are small independents that have limited financial resources, a short-term horizon, and cannot take research risks independently. They achieve technology customisation and operational efficiencies mostly through empirical processes based on trial and error. The increasing presence of Majors in unconventional gas plays could be positive in this context, as they have the financial means and long-term thinking required to invest in R&D programs.

Furthermore a large part of operational improvements is embedded in the service sector. Service companies now play a key role in technology development, and have dedicated budgets for unconventional gas research. This is the case for example of Schlumberger (which invested $150 million in 2004) and Halliburton. Fortunately, federal funding for unconventional gas R&D has not completely disappeared. Since the Energy Policy Act of 2005 the government has been allocating $14 million/year to the sector and will continue to do so until 2015, through a non-profit organisation called Research Partnership to Secure Energy for America (RPSEA). It is a good first step, but insufficient in our view to support the technology improvements required to meet the operational challenges in shale and tight sand plays in a timely manner. Improvements are needed in basin and reservoir characterisation, but also in sweet spot detection, optimal well placement, advanced well stimulation methods (design and placement), and enhanced recovery technologies. These are areas for operational improvements and optimisation.

However, the real technological frontiers are in areas that will contribute to reduce the environmental footprint of tight and shale gas operations. Environmental concerns related to these operations have been increasing since 2008-2009, parallel to the development of plays in the North-Eastern part of the US, closer to densely populated areas (e.g the Marcellus spreads into the States of Pennsylvania and New York). Other “frontier areas” are water recycling and water efficiency, increasing the number of wells that can be drilled per pad while decreasing the spacing between wells (without creating interferences between the wells), and increasing the size of fraccing.

[52] See for example Reeves, Koperna and Kuuskraa, *Nature and Importance of Technology Progress for Unconventional Gas*, Oil & Gas Journal 24 July 2007.

Mitigating hostile public opinion and regulatory risks through technology progress focussed on increasing the density of drilling, without increasing the environmental footprint is not an option if shale gas production is to continue to grow at a sustained pace and meet rising demand. Thus, technological progress has been and will remain a key distinctive success factor for production from gas shales compared to CBM and tight gas sands.

The dynamics of public opinion concerns, potential new State and local regulation constraining shale gas developments and technology improvements to come in these areas will need to be studied and monitored, as it is certain that Europe will present similar challenges to the unconventional gas industry.

Technology will be the single main driver to future production growth for three reasons: low gas prices give low incentives (but diverging views on future level of gas prices); declining productivity of wells early and high failure rates in shale plays mean increase over time in F&D costs and opex; and environmental concerns will increase, requiring new technological solutions to comply with stricter standards and regulations.

Therefore more R&D is needed. The question is whether and how can it happen, i.e who could finance it, what partnerships should be created and how R&D programs should be best implemented. We have seen that with reductions in unconventional gas R&D and technology investments, overall technology progress has slowed significantly.

3.2 Profitability

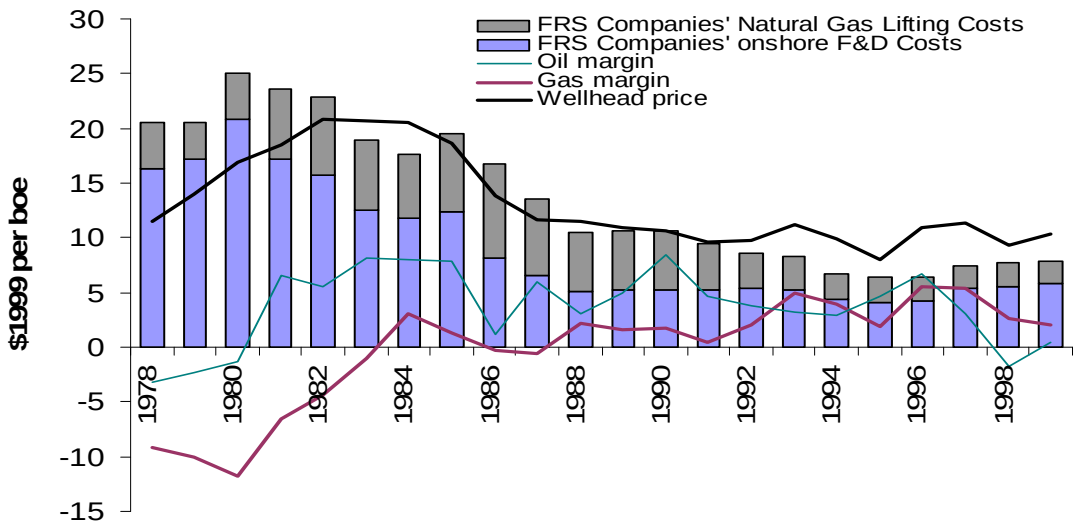
The study of the history of the unconventional gas industry in chapter 2 shows us that unconventional gas resources were not really exploited until gas prices increased after 1999, reflecting a tightening of the US gas market. The price rise enabled unconventional operations to become more profitable, in relative terms compared with oil and in absolute terms compared with conventional gas. The other side of the profitability equation, i.e production costs, also fell over time, with technological progress driving unit costs down, and better terms from service providers. These two cost reduction elements are analysed in this chapter.

Although this chapter will analyse the increasing profitability of gas operations relative to oil over time, due to a lack of detailed data, it is harder to illustrate the increasing profitability of unconventional gas operations relative to conventional gas. For that purpose, the reader is referred to figure 2.3, which demonstrates the cost competitiveness of selected CBM, shale gas and tight gas plays versus conventional fields, taking into account past Finding & Development (F&D) costs and lifting costs[53].

Looking at reported F&D and lifting costs for oil and gas and at oil and gas prices since the late 1970s, it appears that gas margins remained negative until 1984 due to very high F&D and production costs. The cost situation improved steadily from the mid-1980s, rendering gas operations increasingly profitable over time despite a sharp decrease in wellhead gas prices in real terms. Natural gas margins improved relative to oil margins “more often than not”, and started to exceed oil margins from 1993, underpinning increasing activity by Majors and independents in natural gas and a growing share of natural gas in total US oil and gas production. Figure 3.3 illustrates that trend very well.

[53] See definitions in the Glossary

Figure 3.3: Natural gas margin 1978-1999



Source: EIA *The Majors' Shift to Natural Gas*, 2001

3.3 Federal and State policies

The federal government has been instrumental in supporting US oil and gas production, and particularly unconventional gas activity from the 1980s. Policies have taken various shapes, the most important interventions being related to the fiscal regime and the funding of R&D. Another aspect to consider is where the government or States have not intervened or enacted strict regulations stifling the development of unconventional production. This is particularly the case with environmental regulations.

Tax policies: credits A key policy element triggering and supporting production from unconventional fuels which would be unprofitable if only dependent on market conditions, has been of a fiscal nature. Several tax credits have been implemented since 1980, targeting both production from "non-conventional" sources and small and marginal independent producers, who, as we have seen, were the companies most suited to the innovative and marginal nature of unconventional production. Four main fiscal measures have played a key role and are briefly reviewed below.

(i) - "Section 29": The Alternative Fuel Production Credit (known as Section 29 of the Crude Oil Windfall Profit Tax Act) was introduced in 1980, with the aim of encouraging the production of domestic energy from non conventional sources and thereby reducing dependence on energy imports. It allowed for a non refundable tax credit of US$3/boe (or $0.5/mcf of gas) for the domestic production of qualifying fuels. Among qualifying fuels were oil from shale and tar sands, and gas from coal seams, tight sands, shale, and Devonian shales. In order to qualify for the Section 29 tax credit, these fuels had to be either produced from wells that were drilled between 1980 and 1992, or produced in facilities placed in service during the same time period.

The value of the Section 29 credit was determined by a formula which varied with the price of oil and inflation. This inflation-adjusted credit was applied to all fuels except tight gas, where

the credit remained at $0.5/mcf. Furthermore, the credit was only allowed on fuels that were sold prior to the year 2003. The tax credit program expired at the end of 2002 for production from wells drilled between 1980 and the end of 1992. Thus, the Section 29 credit continued to benefit the industry for ten years after the qualifying deadline

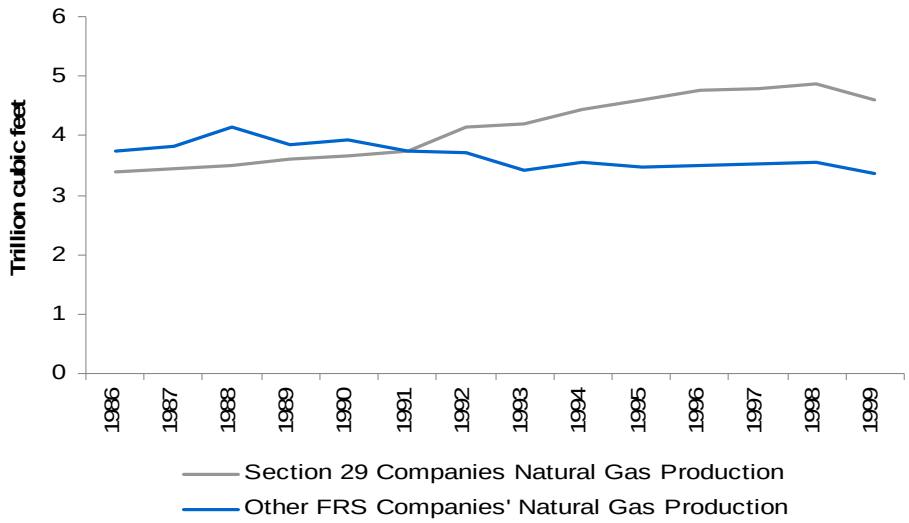
According to the EIA[54], the full value of the credit has ranged from $0.90/mcf of natural gas to $1.08 during the 1990s. The credit averaged $1.02/mcf for the decade and added 53 % to the effective price received for eligible production based on the U.S. wellhead price.

The positive effects of this tax credit on the development of the US natural gas industry, and in particular the unconventional gas activity, are clear. First, based on an analysis of FRS companies,[55] public information, all companies that reported receiving Section 29 credits were involved in CBM or tight gas production. CBM production has been affected most by the credit in recent years (prior to 1990 CBM production was negligible), although tight gas formations volumetrically account for the greatest share of US unconventional energy production (see Part 1, chapter 2).

Second, according to the EIA, nearly half the FRS companies reported reductions in their Federal income tax expense from credits available under Section 29 of the Windfall Profit Tax Act. Therefore, the incentives provided by Section 29 credits played a key role in the rise in natural gas output and in gas-related developments in general, and unconventional gas in particular, underpinned by the Majors' shift to natural gas and the rising activity of independents in the 1990s.

The first striking illustration is the difference in the pace of gas production increases between companies benefiting from Section 29 tax credits and the ones which did not, as shown in figure 3.4.

Figure 3.4: US gas production for FRS companies 1986-1999



Source: EIA, 2001 – See definition of FRS companies in footnote 54.

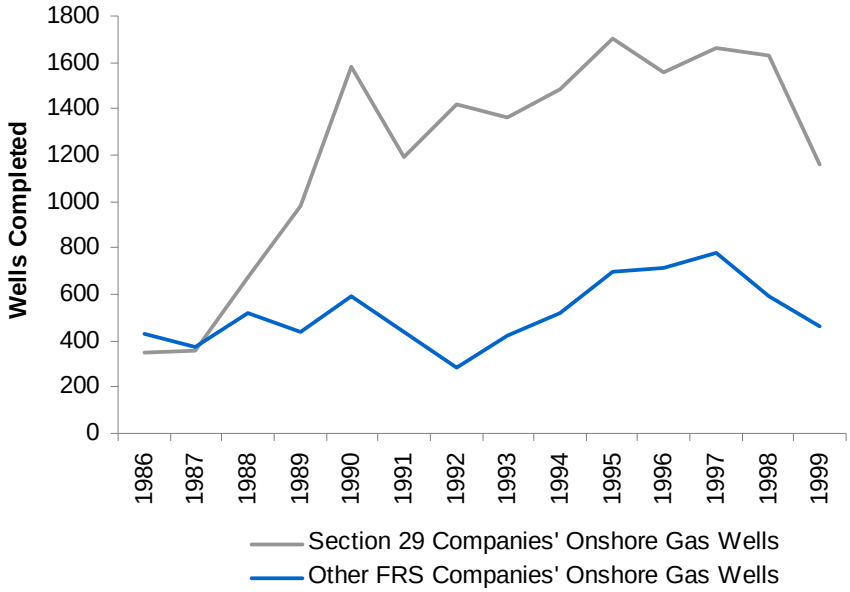
[54] EIA *The Majors' Shift to Natural Gas*, 27 August 2001

[55] "FRS companies" are major energy-producing companies based in the United States which annually report their worldwide financial and operating data to the EIA based on the EIA Financial Reporting System (FRS).

Figure 3.4 shows that the FRS companies receiving Section 29 tax credits were responsible for the growth in the Majors' U.S. natural gas production in the 1990's. Between 1990 and 1999, the Section 29 companies increased their U.S. natural gas production by 26%, while other majors reduced their production by 14%. This resulted in the former group increasing their overall share in US natural production from 39% in 1986 to almost 58% in 1999.

The contrast in natural gas-related development activity between the companies was even more dramatic than production growth. The FRS companies that reported receiving Section 29 tax credits overall quadrupled their rate of onshore natural gas drilling between 1986 and 1990, from slightly under 400 natural gas well completions per year to about 1,600, as can be seen in figure 3.5. According to the EIA, this surge in drilling activity was undoubtedly related to the originally legislated deadline of December 31, 1990, when production from wells initiated after that date would not qualify for Section 29 credits. Congress extended the deadline to December 31, 1992. By contrast, other FRS natural gas producers increased their onshore natural gas drilling activity by less than 200 well completions over the same period. After 1990, the natural gas drilling activity of the two groups of companies exhibited a roughly parallel pattern, with the Section 29 companies averaging over 900 more completions per year than the other majors.

Figure 3.5: US onshore gas wells completed by FRS companies



Source: EIA, 2001

However, the constantly higher rate of onshore drilling among Section 29 companies largely reflects the costs and geological characteristics of unconventional gas developments, such as CBM and tight gas. Indeed, as mentioned in Part 1, chapter 1, unconventional gas wells achieve marginal production rates, therefore developments require many more wells to reach a given level of production than do most onshore conventional gas fields.

This is another illustration that the Section 29 tax credit had a substantial impact on the production of alternative fuels. Initially, it stimulated the development of unconventional gas wells, but the early rates of growth were not sustained through the mid-1990s, as the 1992 deadline slipped further into the past. According to the EIA, in 1992, just before the deadline

when newly drilled wells would no longer be eligible for the tax credit, 78 % of gas wells completed were drilled for the exploitation of gas in coal seams, tight sands, and shale oil. The following year, their share had fallen to 61%.

Thus, Section 29 provided an important incentive for the development of US unconventional natural gas reserves in the 1990s and its legacy today is evident. Among Section 29 companies that reported their operational and financing data through the FRS, several large independents active in unconventional gas can be found, such as Anadarko, Marathon, El Paso Energy and Williams.

Other fiscal measures, some old and some more recent, have played a role in supporting the growth of the unconventional gas industry, although this was not the primary objective of these provisions. They are listed below.

***(ii) - Small Producers Tax Exemption*:** This is a provision included in the 1990 Tax Act, which gave some special tax advantages for small oil and gas companies and individuals. This tax incentive, known as the "Percentage Depletion Allowance", was specifically intended to encourage participation in oil and gas drilling of small producers, and is only available for the first 1,000 barrels/day of oil, or 6 million cubic feet of gas, of American production. This tax exemption allows 15% of the gross income from an oil and gas producing property to be tax-free, and as such provides capital for smaller independents and marginal well operators. The importance of this fiscal disposition as an incentive for investing is well illustrated by several calculations made by the US General Accounting Office (GAO) in 2000 and by the Texas Energy Alliance in 2009. According to the GAO[56], the percentage depletion allowance generated a total tax incentive of $8,5 billion between 1990 and 2000 in real 2000 terms (an average of $0,85 billion a year). According to the Texas Energy Alliance, removing the tax allowance would eliminate more than $8 billion that would be invested in US oil and gas production between 2010 and 2012, i.e around 3,7% of total US E&P investments in one year (estimated at $ 69 billion in 2009[57]).

***(iii) - Marginal Well Tax Credit*:** This is a countercyclical tax credit that was recommended by the NPC in 1994 to create a safety net for marginal wells during periods of low prices, and it was enacted in 2004. Marginal wells account for 12% of natural gas and 20% of oil production in the US[58], so they provide quite important contributions. These wells are the most vulnerable to permanent shut-ins when prices fall. Despite prices in the range of $3-6/mcf since the end of 2008,, it seems that the Marginal Well Tax credit has not been needed yet. However it remains a key element of support for American production.

***(iv) - Intangible Drilling and Development Costs (IDC) Expensing*:** The expensing of IDC for tax purposes has been part of the tax code since 1913. IDC generally include any necessary cost incurred for the preparation or drilling of wells that have no salvage value. These costs usually account for two-thirds of total drilling costs (including seismic, rig day rates and other services). IDC can be expensed in the year the money is spent. Although applicable to all oil and gas producers, only independents can fully expense IDC on American production. Indeed, the companies benefiting the most from this fiscal measure are high-cost producers with intense drilling activity, i.e the independents exploiting unconventional gas. According to the GAO, the tax incentive has amounted to $33.3 billion between 1980 and

[56] GAO, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work* 2000
[57] Barclays Capital, *Original E&P Spending Survey*, 16 December 2009
[58] Texas Energy Alliance, www.texasalliance.org/governmentrelations_2008_presidential_candidates

2000 (i.e an annual average of $1.7 billion). The Texas Energy Alliance estimated in 2009 that this tax indirectly supports $3 billion of new E&P investments, i.e 4.3% of total US E&P investments in one year.

Funding of various R&D initiatives This policy aspect was described in chapter 3.1.

Friendly Regulatory Framework for Oil and Gas Exploration and Production This has been a major policy component instrumental in fostering the development of unconventional gas exploitation across the US. Understanding how the regulatory framework for unconventional gas development is set up and enforced in the US is a pre-requisite for assessing its contribution to gas E&P activity.

Overview of the US Energy and Environmental Regulatory Framework The development and production of oil and gas in the U.S, including shale gas, is regulated under a complex set of federal, State, and local laws that address every aspect of exploration and exploitation. All the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The US Environmental Protection Agency (EPA) administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the US Forest Service (part of the Department of Agriculture).

However, most oil and gas development regulations are currently left to States, where regulatory bodies[59] are responsible for designing and enforcing regulations specific to oil and gas production as well environmental laws. E&P regulations primarily encompass obtaining well permits, well spacing, the application of given operational standards and practices during well construction, hydraulic fracturing, waste handling and well plugging. They also deal with tanks and pits[60], as well as any chemical or waste water spills.

In addition to these State rules and regulations, some federal environmental regulations also apply to unconventional gas. Most environmental aspects of shale gas development are regulated at a federal level by the EPA. This is a feature common to European regulatory arrangements, as we will see in Part 2. Thus, the US example is directly relevant to the assessment of unconventional gas regulatory frameworks in Europe.

The main regulations involved are the 1972 Clean Water Act, the 1986 Emergency Planning and Community Right to Know Act (EPCRA), the 2005 Safe Drinking Water Act (SDWA), the National Environmental Policy Act (NEPA) and the 1990 Clean Air Act[61]. A key mechanism is that these federal laws have provisions for granting "primacy" to the States (i.e., State agencies implement the programs with federal oversight). The idea behind it was that States can more effectively address the regional and State-specific characteristics of E&P

[59]Examples of the most important agencies are the Texas Railroad Commission, the Colorado Oil and Gas Conservation Commission, the Pennsylvania Department of Environmental Protection and the New York Department of Environmental Conservation..

[60] See definition in the Glossary

61 The Clean Water Act regulates contaminated storm water runoff and surface discharges of water from drilling sites. The EPCRA requires companies to post material safety data sheets describing the properties and health effects of any chemicals stored in quantities in excess of 10,000 pounds weight. The SDWA regulates the underground injection of waste water from gas wells. The NEPA requires that E&P activies on federal land be thoroughly analysed for environmental impacts. The Clean Air Act aims at protecting and improving the nation's air quality and the stratospheric ozone layer. Therefore it limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. See http://www.epa.gov/air/caa.

activities. Furthermore, it is important to emphasise again that the regulation of drilling and of hydro-fraccing has been under State authority since 2005[62].

Therefore, State regulatory agencies form the backbone of the design and enforcement of E&P and environmental regulations in the US. The fact that hydro-fraccing is at the centre of environmental debates gives an even bigger responsibility to State agencies to enforce regulations.

The result of these legal/regulatory arrangements is a delegation of regulatory authority to the State level, and the co-existence of heterogeneous regulations and degrees of enforcement, varying from state to state[63]. The merit of this system is that it has allowed States to tailor regulations to local investment conditions (e.g geology, topography, population density, local economics, etc.) and the needs of local operators, thereby fostering the exploitation of unconventional gas at a relatively unconstrained pace. The lack of regulatory restrictions, be it through the non-enactement of constraining requirements, their application by operators on a voluntary basis only, or their non-enforcement, has allowed the exploitation of the Barnett Shale and other emerging plays to take place at a rapid pace. US energy regulations and policies have been an important component of the success of unconventional gas.

However, a significant drawback has been the development of many differing practices among operators, which has increased the complexity for new entrants and federal regulators in understanding particular local legal requirements, and delayed the development of industry best practices. Indeed the emphasis on developing "best practices" is not strong in all States, and as a result many companies have received a licence to operate at lower operational, environmental and safety standards in some places. Less stringent standards can be found in hydrocarbon-friendly States such as Texas, Wyoming, Michigan and Pennsylvania. By contrast, tougher regulations are to be found in States where land access is under federal regulations, such as Colorado and Louisiana or States with no history of oil and gas production, such as New York.

Less stringent standards may possibly be connected to the increasing number of incidents on operational sites and growing public concern about shale gas. However the relative benevolence observed on the part of State agencies toward independent gas producers has not always been intentional. Given the scope of their legal competence, and the fact that unconventional gas development relies on the drilling and fraccing of thousands of wells every year, oversight and enforcement capability and capacity are being stretched to the limit in certain States. Some agencies have simply been overwhelmed by the scale and the rapid pace of activity growth, and this situation supports the arguments of those who are in favour of increased federal regulation and oversight of unconventional gas development.

Increasing environmental concerns about large-scale shale gas exploitation from a whole range of stakeholders at local, State and federal levels, make it more and more obvious that the trend of flexible and heterogeneous regulations cannot be sustained and could become a

[62] The 2005 Energy Policy Act exempted hydraulic fracturing from the SDWA regulation.

[63] A good example of these significant variations is found in a 2009 survey of the 27 largest gas-producing states,conducted by the Ground Water Protection Council. Results showed that 25 states required surface casing to be below the deepest groundwater, while only 10 states required companies to list chemicals or pressures used during hydro-fraccing, and none required them to list the estimated percentage of fluid flowback. Worldwatch Institute, Natural Gas And Sustainable Energy Initiative, *Addressing the Environmental Risks from Shale Gas Development*, Briefing paper 1, July 2010.

failure factor for the unconventional gas industry. The question of the level of legal authority and delegation of regulatory power to the States could also be revised. The content and the high involvement of the federal government in ongoing debates, mainly related to environmental risks, could point towards a future centralisation of regulatory arrangements.

The Environmental Debate Environmental risks linked to unconventional gas operations, real or perceived, have indeed become a major topic for debate in the US. This debate is getting strongly politicised, which in our view threatens the continued growth of the sector in the US. Concerns focus on four main sets of issues, which are risks also embedded in conventional onshore gas activities:

1. Gas migration and subsurface contamination of groundwater The concern is that hydraulic fracturing might create fractures that extend well beyond the target formation to water aquifers, allowing methane and fracturing fluids to migrate from the formation into drinking water supplies. From a geological point of view, such contamination is very unlikely to occur in deep shale formations, as several thousands of feet of rock separate most gas-bearing formations from the base of aquifers[64]. Furthermore, drinking water is very rarely tested prior to hydro-fraccing operations in the US, so it is hard to identify with certainty the potential link between fraccing and contamination. In Europe, such testing is consistently performed.

However, leaks could occur as a result of faulty well construction, i.e a failure of the cement casing surrounding the wellbore. Several examples of water contamination by fraccing fluids have been reported, in particular the series of incidents in Dimock, Pennsylvania, in 2009 involving Cabot Oil and Gas[65]. In 2007 an improperly sealed well in a tight sand formation in Bainbridge, Ohio caused methane contamination of water[66]. These incidents have led the debate on environmental risks of shale gas to become central in the media, and the making of movies such as Gasland and Haynesville, broadcast quite widely, reflects the intensity of the ongoing communication campaign on these issues.

The regulatory response has been very strong and has taken different forms. At the federal level, the EPA was asked in 2009 to conduct a study examining the links between hydraulic fracturing and drinking water, in order to inform potential new regulations. The conclusions are due in 2012. In the meantime draft legislation, called the FRAC Act, has been proposed to Congress, which calls for more federal oversight in addition to existing State regulation, and in particular would require operators to disclose chemicals used during the fraccing process (although chemical disclosure is already taking place on a voluntary basis). At the State level, similar disclosure requirements are being made mandatory, as in Wyoming since June 2010, and measures which make it mandatory for companies to disclose where they intend to source the water and how to dispose of it are being discussed in Pennsylvania. (This rule already exists in Europe.) Other measures such as implementing a moratorium on new drilling close

[64] For example, the top of the Marcellus Shale lies from 4,000 to 8,500 feet below the surface while the deepest underground sources of drinking water in this region lie about 850 feet below the surface. Worldwatch Institute, *Addressing the Environmental Risks from Shale Gas Development*, July 2010 p8.

[65]Early in 2009 drinking water in several homes was found to contain metals and methane gas that state officials determined had leaked underground from Cabot wells. Later, the company was fined for several other spills, including an 800-gallon diesel spill from a truck that overturned. In September 2009, 8,000 gallons of dangerous drilling fluids spilled and entered into the area water system, following faulty piping.

66 Ohio Department of Natural Resources, Division of Mineral Resources Management, *Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio*, September 2008.

to the watershed in NY State, or on leasing of State forest land in Pennsylvania are also under consideration.

2. Well blowouts Two recent and consecutive gas well blowouts in the Marcellus during completion operations, involving Cabot Oil and Gas and EOG[67], set against the backdrop of the recent offshore blowout and oil spill from the Macondo well in the Gulf of Mexico, have increased public concerns about risks associated with drilling in high pressurised zones. Among causes identified were the use of untrained personnel and the failure to use proper well control procedures.

3. Seismic risks Another subsurface risk that is receiving attention is the possibility that drilling and hydro-fraccing might cause low-magnitude earthquakes. Some incidents were reported in Texas in 2008 and 2009[68]. While the hydraulic fracturing process does create a large number of microseismic events, the magnitude of these is generally too small to be detected at the surface. Furthermore, underground fluid injection is an integral part not only of hydro-fraccing, but also of waste water disposal in injection wells, some geothermal energy projects and CO_2 sequestration.

4. Surface water and soil contamination Shale gas development requires massive quantities of water and, to a much lesser extent, chemicals[69]. In order to maintain sufficient volumes of fluids onsite during drilling and fraccing operations, operators typically use open pits and tanks to store make-up water and chemicals used as part of the drilling fluids. In addition, significant volumes of flowback fluids and solid waste are produced, that need to be stored before being transported, re-treated and disposed of. As a result, storage pits are becoming an important tool in the shale gas industry and more generally, because of the large quantities of waste to be handled, the risks of contaminating surface water and soil during storage, transport and disposal are very high. The problematic aspect of using open pits is the risk of fluids seeping into the soil, or in case of heavy rain, of pits overflowing and creating contaminated runoff. Storing water in enclosed steel tanks and using tanks in a closed-loop drilling system that allows for more flowback water to be re-used would help reduce these risks.

3.4 Access to land and infrastructure

In 2007, the US produced 18.8 Tcf of gas, of which 14.2% came from federal minerals/lands, managed by the Bureau of Land Management (BLM) in the Department of Interior[70], and the rest from State-owned or privately owned land. This number simply illustrates the fact that the large majority of domestic natural gas production comes from State and privately-owned lands, and as a result access to land for shale gas exploitation purposes is relatively unconstrained in the US, for the following reasons. First, uniquely to the US, private landowners also own or part-own mineral rights. Such landowners may lease their land for the development of the minerals or sell the surface or mineral rights. Therefore accessing private

[67] http://www.businessweek.com/news/2010-06-07/eog-well-in-pennsylvania-had-blowout-state-says-correct-.html
[68] Worldwatch Institute, Natural Gas And Sustainable Energy Initiative, *Addressing the Environmental Risks from Shale Gas Development*, Briefing paper 1, July 2010
[69] Fluids used for slickwater hydraulic fracturing contain typically more than 98% fresh water and sand with the remainder made up of chemicals.
[70] BLM Energy Policy team 18 Nov 2008, http://dels.nas.edu/besr/docs/Brady.pdf

land is only a matter of contractual negotiations between operators and private individuals, which have a financial incentive to lease their estate property. Common features of gas leases include signature bonuses, royalties (up to 25% depending on the States), rents, primary lease terms and conditions for lease renewals. The lives of many ordinary citizens (especially in the farming community) have been financially transformed as a result of the shale gas boom.
Second, access to State-owned land primarily takes place through lease auctions organised by States. States are already set up to manage oil and gas operations within their jurisdiction, so no special permitting or enforcement systems are required. For example in Texas, State regulations allow for drilling in many types of areas, including residential locations.

In conclusion, the ownership nature of the land where shales are located has been making land rapidly and quite freely accessible for operators. However, one should not underestimate the complexity of the process of leasing hundreds of private lots more or less simultaneously.

Furthermore, access to transmission and distribution pipelines to evacuate produced gas is a straightforward process in the US, as the market is fully deregulated with gas-to-gas competition. An operator can simply negotiate with the pipeline company a connection with the main trunkline, regardless of how much capacity is available or booked. The main problem currently in the US is the reduced availability of transportation capacity, in particular for gas from the Marcellus. In Europe, the midstream situation is very different, with many countries still maintaining restrictions on third party access, thereby preventing system and flow optimisation, and uncertainties on pipeline capacity availability. However, this will be required to change as the EU 3rd Package of gas regulations becomes law in early 2011.

3.5 Intense competition within the service sector

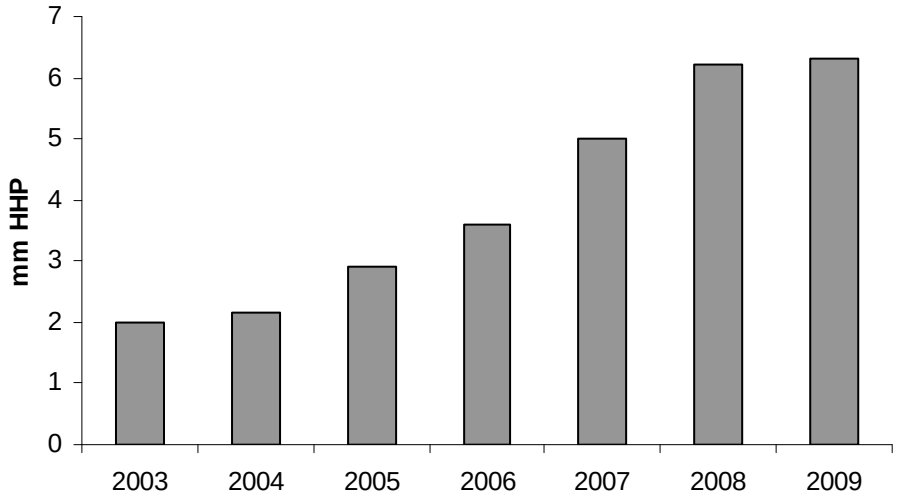
As gas operators stepped up their activity in tight gas and shale gas plays, the demand for adequate drilling and completion equipment and services increased. Tight sands and shale gas plays are highly service-intensive, as they require far more drilling and fracturing than conventional fields. Therefore they require significant drilling and pressure-pumping capacity, as well as more rigs and equipment for fracturing, in addition to staff. Raymond James Ltd, a Canadian investment boutique, estimates that unconventional wells in the US demand 14 times more horse power than conventional wells, and 20 times more in Canada[71]. Thus, the development of tight sands and thereafter shale plays at an accelerated pace since 2005 could not have taken place if the service industry, in particular land drillers and completion[72] service providers, had not been able to increase significantly their investments in new and more powerful equipment, and mobilise their resources quickly. For example, the share of US onshore rigs having a horizontal drilling capability increased fivefold in 10 years, from 6% in 1998 to close to 30% in 2008[73]. To mitigate rising service and equipment costs that resulted from a tightening market when demand for drilling and stimulation rose, some companies, such as Chesapeake, Southwestern Energy and Williams even decided to build in-house service capabilities. For example, Chesapeake owns a subsidiary specialising in geological interpretation of shales and a drilling company (Nomac Drilling), which gives it a secured access to equipment and freedom to plan, and facilitate the alignment of interests between the

[71] Raymond James Insight, *How much fraccing horsepower do these shales need anyway?* Weekly Oilfield Bulletin, 13 November 2009
[72] See definition in the Glossary
[73] Statistics given by Novas Consulting in April 2010
http://www.findingpetroleum.com/event/Unconventional_Gas_the_Shale_Gale/6f9.aspx

operator and the service provider. This is a model we need to keep in mind when studying the service company position in Europe in part 2.

An illustration of the fast response from the service industry to growing demand for stimulation services from E&P companies can be seen in Figure 3.6.

Figure 3.6: US pressure pumping capacity



Source: Spears and associates

Pressure pumping capacity is designate as the total capacity of the US pump fleet used for fraccing, thus giving an indirect measure of fraccing activity in the country.

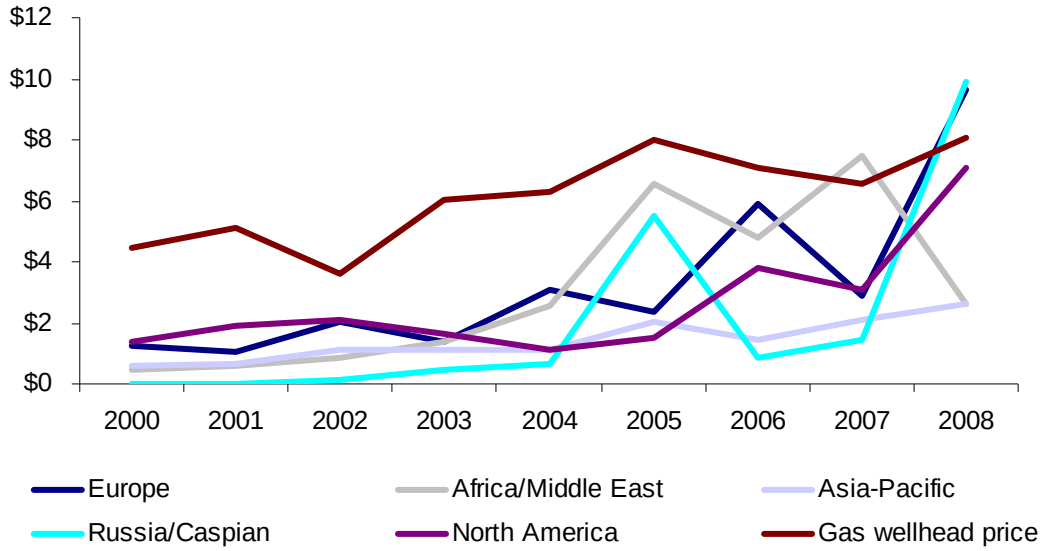
This step change could take place thanks to the favourable structure of the service sector supplying the gas industry in North America. The pressure pumping market, which is one of the most important within the service sector for shale gas exploitation, is indeed dense. It is both fragmented and largely dominated by a few companies (Halliburton, Schlumberger and Baker Hughes/BJ Services), which collectively hold a 75% market share in the US. In Canada, Trican and Calfrac dominate the market, followed by the three companies mentioned previously. Other important players are Cameron, Smith International, FMC and National Oilwell-Varco. The directional drilling market, the second key service sub-segment for shale gas, has a similar structure, with four companies controlling 75% of the market, among which Patterson-UTI[74], Helmerich & Paye and Nabors Industries.

Large companies had the financial muscle and reach to increase the size of their workforce and equipment stocks to meet fast rising demand from unconventional gas operators. In addition, many small specialised companies, in particular drilling contractors but also technology developers, were created across the continent thanks to the spirit of entrepreneurship prevailing in North America, and provided the flexibility required in the customised planning of services and logistics for the various shale plays**.** The competitive climate resulting from the dense service sector dedicated to unconventional gas has helped mitigate the rapid rise in the costs of services from 2004, which has been taking place at a faster pace than wellhead prices. An illustration of this trend can be found in the evolution of F&D costs, displayed in Figure 3.7, which partially reflect service cost inflation. Another

[74] Patterson-UTI sold its Drilling & Completion Fluids unit to National Oilwell-Varco in January 2009.

interesting observation is the fact that the increase in the cost of services has been more moderate than in other parts of the world. It would be too simplistic to conclude that this moderation is entirely linked to the higher competition in oilfield services in North America than elsewhere, however it certainly played its part.

Figure 3.7: Finding & Development costs per mcf of gas



Source: Herold Lovegrove Global Upstream Performance Reviews 2001 to 2009 – F&D costs include oil and gas.

Chapter 4 - Limits and challenges to the shale gas business model

Unconventional gas production continued to increase despite a period of low prices in a $3.5-$5 band during 2009-10. Many believed that the increase was driven by lower breakeven costs thanks to continuous increases in drilling and fraccing performance, but one should not underestimate the size of the challenges to future shale gas exploitation, which is set to be the growth engine of future US gas production. These challenges in our view relate primarily to the sustainability of the current operating model, and the gas price environment.[75]

- Operating model:

There is some uncertainty about the ability of American gas producers to produce and deliver unconventional gas due to several "above ground" issues. Production is more sensitive to gas prices and availability of credit than conventional gas production. As mentioned earlier, many producers are independent companies which operate on a cash basis and are thus more vulnerable to price volatility. Moreover, among producers there is a constant hunt for acreage with very limited prior knowledge of the quality of the subsurface, which leads to sharp increases in lease levels and a continuous time-consuming process of optimisation of land estate portfolios by companies. Major consequences are a messy, fragmented and changing land ownership structure, and increasing complexity in operational management, which is

[75] Here we do not discuss the issues processing and transportation capacity availability.

detrimental to the development of gas resources in an economic manner. In addition, leases usually have short duration and operators have to drill wells rapidly in order to retain them.

This situation hinders the development and application of the best drilling and fraccing techniques for the play in question, and a proportion of these wells turns out to be unproductive. Thus, it is common to see sub-optimal drilling plans and a lack of efficiency in logistics management (e.g location and availability of rigs), higher costs than necessary to build gathering systems and trunklines, and a lot of negotiations required to gain access to State transportation infrastructure. The risk of making mistakes that can have a damaging impact on the environment is also increased. The need to drill more efficiently and do more research prior to fraccing is clear.

Although gas production has continued to increase in 2009 and 2010 despite lower prices than in the previous years, there is a big question mark about current well economics. Many public sources estimate that the average price required for shale gas wells to be economic is around $6/mcf. Averages are a very poor measure to use in the case of shale plays, as every play is different, and within plays, core areas and non-core areas yield very different results, but the fact that by late 2010, gas prices had not reached $6/mcf for two years suggests that the commercial viability of many wells drilled, and so the financial solidity of many independents, could be very weak. We believe it is only a question of time before costs drive up prices, or drilling slows downs significantly and production falls. However many independents get financial protection against low gas prices through hedging strategies, so the cash impact of non commercial drilling is mitigated.

Moreover, more and more data seem to indicate a trend of rising unit costs of exploiting shales in the long-term, due to factors that will prevent further cost reductions or lead to costs increases, and due to declining well productivity over time.

In the short term, costs reported by operators continue to decrease, thanks to a reduction in drilling times, improved recoveries compared to costs, and other supply chain optimisation. This reflects the dynamism typical of a young industry. However companies usually report data only for their best wells, so these cost reductions do not always apply across their portfolios, and it is uncertain how long these unit cost reductions can continue. Shale gas production growth (measured by well IP rates) relies increasingly on the “frac count” rather than the rig count. Fraccing stages per well are increasing, and the fracs are becoming more water- and sand-intensive with longer laterals. However, increasing the number of fracs, which is capital intensive, does not always seem to translate into higher IP rates, whereas it does translate into higher F&D costs. A good example of this trend can be found in the Barnett, where recent frac data show a play in severe decline, with operators spending more and more capital to recover less gas per well. In addition, many wells will need to be re-fracced and the deterioration of re-fraccing performance points toward higher unit costs. The last cost driver is the rate of well failure. According to an analysis by Bernstein Research on the Barnett, “after 3 years operators can expect around 12% of wells to have failed and the failure rate shows no sign of flattening yet.”[76].

As regards productivity over time, the same analysis of the production history from Barnett wells as mentioned above shows that the average well is producing less gas over time. This is partly due to the fact that the best wells are drilled in the first years in the core areas, and

[76] Bernstein Research, *The Death Throes of the Barnett Shale?* 13 May 2010

subsequently companies need to target increasingly marginal wells outside the core areas. According to Bernstein Research, the rate of decline in well quality is significant, up to 29% annually, and occurred very early in the life of the play. Barnett production and profitability have already peaked after 6 years of modern exploitation, raising the question of the life expectancy of other shale plays. When it comes to tight sands deposits, the same phenomenon of declining productivity can be observed as mentioned in Chapter 2. Two of the most prolific tight gas sands in the US, Pinedale and Jonah (Wyoming), illustrate this statement. An analysis[77] of more than 2,300 wells shows that both plays passed their peak productivity in 2007 and 2009 respectively, as average initial production rates per fracturing stage are falling, and as the core areas of the plays have been exhausted.

Only new technology developments which achieve improved drilling and completion efficiencies can mitigate the trend of increasing unit costs over time.

- Environmental concerns and regulatory threats:

As mentioned in the previous chapter, rapidly growing public concerns about environmental risks of shale gas operations and their impact on local communities is one of the biggest threats to further growth of that resource. Hostility is stemming mainly from heavily populated states in the North-East, where the Marcellus Shale is located. We outlined the main areas of concerns about water management, in particular the risks of drinking water contamination by hydraulic fracturing fluids, and the risks of surface water and soil contamination. Other areas are land footprint and disturbance and potentially higher lifecycle GHG emissions than conventional gas due to more energy-intensive production.[78]

The threat takes the form of increased regulation that could limit land access for new drilling, limit hydraulic fracturing and the construction of transportation infrastructure, and hence increasing costs of production. There is strong public pressure for stricter oversight of the oil and gas industry, and both Federal and State regulators will strengthen regulations and ensure that best practices are applied consistently across the industry. The States of Colorado and Wyoming have already passed new rules to protect the local environment in June and July 2010. Another good illustration is a bill passed by New York legislators to block drilling inside or within five miles of the New York City watershed, on fears that chemicals may contaminate this vital source of water supply to the city. As a result, to avoid future legislative trouble, Chesapeake Energy announced in October 2009 that it will not drill any wells in the New York watershed[79]. The US Congress is also examining several bill proposals aiming at increasing control over fraccing operations, through for example chemical disclosure requirements, increased taxes or even bans. Although a ban on hydraulic fracturing is very unlikely, since this technique has been in use in the US since the late 1940s and is used in close to 90% of all oil and gas wells, environmental and compliance costs will increase. For example, potential federal legislation following the release of the ongoing study by the EPA on the effects of hydraulic fracturing could increase costs by $125,000 to $250,000 per well. And even without federal regulations, the added bill could range from $200,000 to $500,000

[77] Bernstein Research, *Are the Wyoming Tight Sands in decline?*, 5 January 2010
[78] CSIS, *Crossing the Natural Gas Bridge*, May 2009. The GHG footprint of unconventional gas compared with conventional gas is not well documented and is an important subject for future research.
[79] http://www.nytimes.com/2009/10/28/business/energy-environment/28drill.html?_r=1&adxnnl=1&adxnnlx=1287918518-wvqf84b5X2WT983YOdU5EA

per well, on top of current well costs (ranging between $2.5 million and $10 million)[80]. We could therefore see a total cost increase of 5-7%.

To mitigate these threats, companies need to invest more in developing greener fraccing fluids and treatment technologies that allow for increasing the amount of flowback water and the re-usage of these fluids for subsequent fraccing jobs. More disposal wells and adequate water treatment facilities are also urgently needed.

- Midstream bottlenecks:

There is currently insufficient gas transportation capacity by pipelines, in particular to the North-east of the country. Building new pipeline capacity is a requirement, as it currently constrains the growth of the Marcellus production. This paper is not covering this issue in more detail.

Conclusion The rise of unconventional gas production, and in particular shale gas, has been the greatest revolution in the US energy landscape since the Second World War. Given the huge resource base - some say it could supply the US for 100 years ie a scenario of unconstrained supply - the unconventional gas revolution has the potential to transform the US, and potentially also global, LNG trade . It could force LNG exporters to re-direct their cargos to Europe and Asia. (this has already been taking place since 2009), and potentially turn the US into an LNG exporter.[81]

However, we have shown that there are significant threats to the US unconventional gas growth model, of which the politicisation of the debate about its impact on the environment and local communities is likely to intensify. Long-term unit costs, although very uncertain, also suggest a need for caution about future projections. These limits create uncertainties about the potential cost and availability of gas supply from North American shales after 2015, which add to uncertainties about future gas prices and raises difficult questions about the allocation of investment between domestic and international gas projects - conventional and unconventional.

The success of the unconventional gas revolution in the US has sparked great interest in Europe, which is becoming increasingly familiar with the US unconventional gas experience and thus aware of the E&P and market-related challenges. In addition, the increased number of constraints and challenges faced by independents in the populated States of the North-East, and particular New York State, gives some indications of the types of challenges European gas players can expect to encounter, beside uncertainties on the extent and commerciality of its subsurface potential. The ongoing environmental debate on risks, in particular on water quality[82], as well as solutions and regulations adopted in the US will be closely monitored in Europe. But these are indications only of what may happen in Europe. The gas E&P reality in Europe is actually far more complex, as the continent is a mosaic of countries with very

[80] Tudor Pickering report of July 2010, quoted in Energy Intelligence Natural Gas Week, *Fracturing Ban not likely, but Compliance Costs likely to rise*, 19 July 2010.
[81] See for example Cheniere Energy, which received an authorisation from the DoE in September 2010 to export LNG from its Sabine Pass regasification terminal.
[82] The EPA commissioned an extensive study of the effects of hydraulic fracturing and water disposal from shale gas operations in late 2009 which will report in 2012.

different socio-economic situations, and this heterogeneity is even greater when delving into local situations within countries.

Thus, while the US and European unconventional gas stories clearly have links that we will emphasise throughout our European analysis, assessing the potential for developing and producing unconventional gas in Europe requires the identification of the specific hurdles and opportunities in each country. This is the purpose of Part 2.

Part 2: Unconventional gas in Europe

In this study Europe is defined as the European Union 27 (EU) and Norway. The Ukraine is briefly mentioned when analysing the unconventional gas resource potential.

The context surrounding European gas markets seems particularly well-suited to unconventional gas resource development, for many reasons. First, it remains the second largest regional gas market in the world, with demand of 16.7 Tcf[83] in 2009, and the domestic gas supply situation is characterised by reserves and production declines in all producing countries, except Norway (where output is expected to plateau from 2012)[84]. It is worth noting that this context of decline is similar to that of the US in the mid 2000s. Second, gas demand is expected to continue to grow, albeit at an overall slow pace but with differences between countries[85], leading to increasing import dependence. In fact, Europe is expected to experience a very large increase in gas imports in absolute terms[86]. Thus, in the light of security of supply concerns prevailing in some countries and EU energy policy objectives, the development of new indigenous gas resources is an attractive proposition. Furthermore, European gas markets are attractive because of the existence of an established pipeline and gas processing infrastructure. Finally, relatively high natural gas prices, mostly linked to those of oil products (except in the UK), add to the attractiveness of developing new gas resources.

In addition to this favourable macro context, Europe is expected to possess a significant amount of unconventional gas resources which, according to Rogner's work mentioned in Part 1[87], would amount to 1,255 Tcf, of which 549 Tcf would come from shales and 431 Tcf from tight sands. The remainder would be in coal deposits. So the size of the resource base is immense at a European scale, if not at a global one.[88]

However, despite these positive macro features, the ability of producers to extract unconventional gas in Europe is constrained by many factors. This is the subject of Chapters 5 and 6, although it should be noted that the analysis encountered many difficulties due to the lack of data at the time of writing, and the diversity of geographical, economic, social, legal and operational situations across European countries.

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[83] BP Statistical Review of World Energy 2010.
However Asia-Pacific is set to overtake Europe as the second largest gas market in 2009 or 2010.

[84] Europe produced 6.7 Tcf of gas in 2008 and 5 Tcf in 2009, and proven gas reserves fell 19% between 1997 and 2009 according to the BP Statistical Review of Energy 2010.

[85] For example, gas demand is expected to grow on average 0,16% to 2020 in Germany and 2% in Poland according to Honore A, *European Gas Demand, supply and pricing: cycles, seasons and the impact of LNG price arbitrage*, forthcoming publication OUP 2010

[86] Energy Information Administration, *The Evolution of Global gas markets*, 28 October 2009. http://csis.org/event/evolution-global-gas-markets. The EIA forecasts that OECD Europe will import 35 bcfd of gas by 2035. It imported 18.7 bcfd in 2009 according to the IEA.

[87] Rogner H, An Assessment of World Hydrocarbon Resources

[88] According to Rogner, European unconventional gas in place accounts for 4% of worldwide unconventional gas resources, compared to 25% in North America and 30% in Asia.

Chapter 5 - Setting the scene: overview of resources, exploration and production activity and competitive landscape in Europe

5.1 An industry in its infancy

Let us emphasise again that unconventional gas in Europe is in its infancy. Europe has little knowledge about the potential, quality, precise location, and location of sweet spots of its unconventional gas resources.

As of 2010, Rogner's assessment for Europe remained the only public solid reference, and this was 13 years old and based on the technology and understanding of tight reservoirs and shales at that time. For these reasons, and also because Rogner did not include Poland, Hungary or Romania, its estimate of 1,255 Tcf is likely to be low.

This lack of information is the first of several major challenges facing operators in Europe. Collecting and analysing relevant geological data is the first major hurdle operators have to overcome. The poor availability of geological information is mainly due to the fact that there was little commercial interest in analysing this type of rock and gas resource in the past, leading to very few corings of potentially prospective areas. For example, in Poland, only 5 deep wells were drilled in the Baltic Basin north west of the country, and only around 35 are relevant for studying the potential of Central and East Poland.

Furthermore the quality of existing cores can also be problematic. Most of the available core samples were extracted with old equipment, which did not always allow sufficient depths to be reached. For example in Poland, well results that can be analysed for assessing the prospectivity of Silurian shales date back to the 1970s and 1980s, but these data do not allow reliable estimation of organic content and thermal maturity, two important geological characteristics.

This situation is very different in the US, which started mapping its own resources in the 1980s, largely thanks to the Alternative Fuel Credit tax incentives. This means that it took more or less 20 years for the US to explore, appraise and unlock shale gas resources in a commercial manner (and a decade less to produce tight gas and CBM); thousands of wells providing feedback information were drilled in that long process.

Europe needs to go through a similar learning and geological de-risking process, and based on the US experience, there is no reason to expect it can substantially accelerate that process. This is particularly true because shales are heterogeneous across the world, so that data from the US are not directly applicable to Europe, and each play in Europe has to be explored and appraised individually. A few operators have started drilling or announced drilling programmes. An important issue will be whether current unconventional gas acreage holders, including large ones like Majors, will be willing to allocate investments for such a long-term perspective without any help from governments on the data acquisition front.

This question is even more relevant as secrecy around data is a prevalent practice among operators, and this will slow down the speed of data interpretation and understanding, potentially leading to delays in development decisions and sub-optimal operational practices. The state of secrecy is bolstered by the fact that many concessions only have one or two holders, and by a limited number of service companies. In the US, most plays are exploited by

numerous players and information is shared via the usage of common operating crews. It would be useful to see governments across Europe foster data collection and sharing as resource holders, but there is no such culture in the upstream energy sector.

A relatively positive factor, though, is that a precise mapping of unconventional resources is ongoing through a handful of public projects, such as GeoEn[89] in Germany, and in particular a European initiative (the GASH project[90]). These projects have a six-year timeframe, which reflects the difficulty of collecting and analysing data. As operators pursue their own assessments, their conclusions risk being overtaken by events.

Another aspect illustrating the immaturity of unconventional gas in Europe is the insignificant level of production, both at national and European level. Production comes mainly from Coal Mine Methane (CMM) and tight gas. CBM/CMM and tight gas are more mature technologies in Europe than shale gas, but there are currently no commercial projects. There are are only a few small-scale CMM projects, such as in the United Kingdom and France[91]. For tight gas, an important milestone was reached in 2005 with the drilling and start-up of Leer Z4, a horizontal well with hydraulic fracturing, located in the tight sands of the Rotliegendes in Germany. Production from that reservoir reached 10.2 MMcfd in 2007 and 6.7 MMcfd[92] in 2008.

5.2 Overview of unconventional gas resources in Europe

Geography We now look at the geographical distribution of the rocks containing unconventional gas, based on the most recent geological evaluations, and whether there are overlaps with conventional gas and coal deposits. (Once again, we refer readers to Appendix A for a brief explanation of the formation of oil and gas and the geological differences between conventional and unconventional formations.) Figure 5.1 displays conventional fields, wells and unconventional gas basins across Europe.

As can be seen on the map, many parts of Europe, with few remaining conventional fossil fuel prospects, are prime targets for shale gas exploration. Europe has appeal given the age and maturity of the gas shale targets.

Shales are present in three major continuous plays across Europe. The first is a Lower Paleozoic play, spreading from Eastern Denmark and Southern Sweden to Northern and Eastern Poland. This play includes Alum shales in Sweden and Denmark, and Silurian shales in Poland (Gdansk Depression and Danish-Polish Marginal Trough). The second is the Carboniferous marine basin, spreading from North West England, through the Netherlands and North West Germany to South West Poland. The third major regional play encompasses Lower Jurassic bituminous shales (i.e Posidonia) that can be found in South England, the

89 The GeoEn project is funded by the German ministry for research and education, with a long deadline of six years. This project will look at three areas of energy, one of which is German shales. (See www.geoen.de)

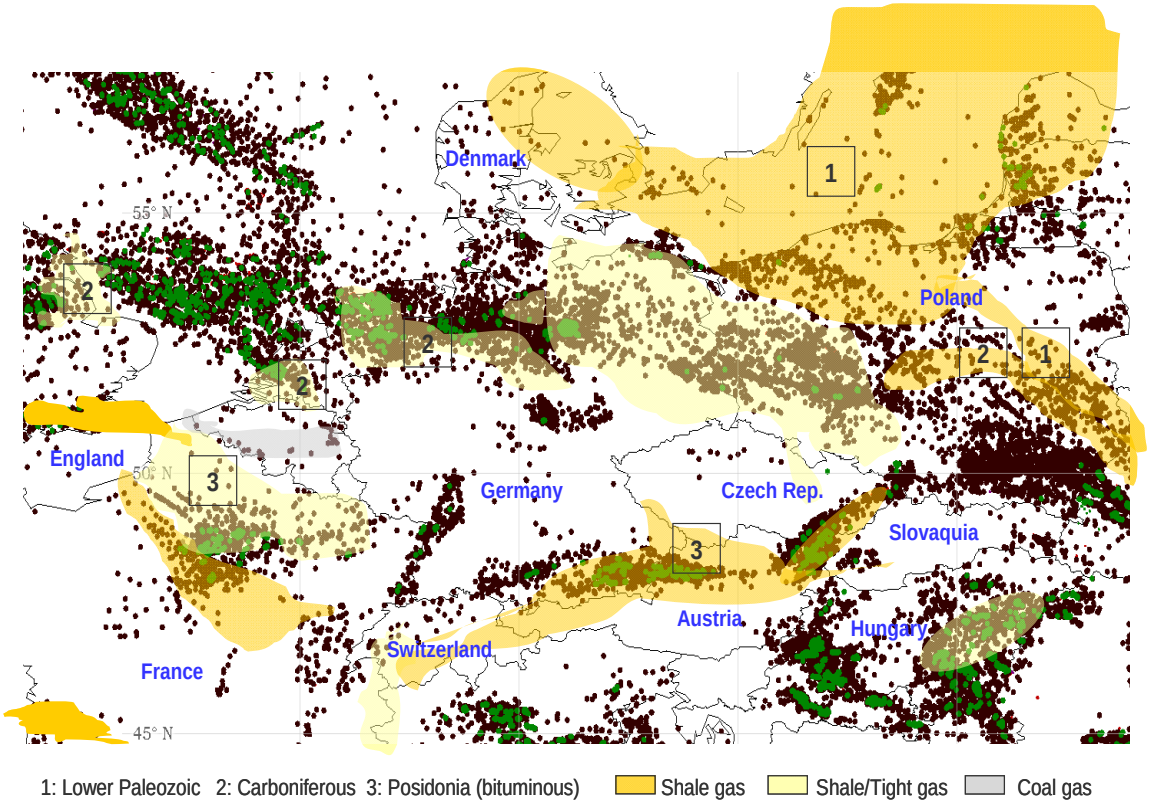
90 The so-called GASH project is exclusively funded by the industry. Sponsors sign on for three-year commitments. http://www.geos4.com/media/GeoS4_GASH.pdf. Sponsors to date include Marathon Oil Corp., StatoilHydro, Total, ExxonMobil, Gaz de France, and Vermilion Energy. The project has two main tasks: compiling a database of potential shale gas areas in Europe, excluding Russia, based on existing work done by national geological surveys; and conducting new scientific research from specific shale gas regions.

91 In France European Gas Ltd operates the Gazonor plant, which produces circa 7 MMcfd.

92 Wood Mackenzie Upstream Service, August 2009. No production data available for 2009.

Paris Basin in France, the Netherlands, Northern Germany (Lower Saxony) and Switzerland[93]. A list of the main shale basins in Europe can be found in Appendix C.

Figure 5.1: Map of conventional basins, wells and unconventional deposits



Sources: IHS EDIN-GIS May 2010, Schlumberger 2009 – Green dots represent active wells.

Three main observations can be derived from the geographical analysis of unconventional gas basins. The first is that the geographical distribution of unconventional resources is uneven, which means that not all countries within Europe have unconventional gas-related potential, and within countries which do, certain regions only will be affected by the development of this resource. Second, most shales spread across primarily industrial and relatively urbanised areas in Europe, in particular in northern continental Europe, which will potentially constrain large-scale developments. It is therefore important to take our study deeper and examine the question of unconventional gas development conditions at a local level, in the regions where the basins are located (see Chapter 6). Finally, the overlap between unconventional basins with conventional development and production wells is quite significant, in particular in the Netherlands, North West Germany, and South Hungary. These are regions with a history of gas production, which could hence be more supportive of new unconventional gas developments than other regions. The same assumption should in principle apply to regions with coal mining history, such as Northern France, Belgium and Poland. In these regions, accessing land and securing local support for the deployment of new gas operations on a large scale should prove less challenging than elsewhere, but it is hard to generalise this statement because of location specificities. It is only when they have drilled that operators will be able

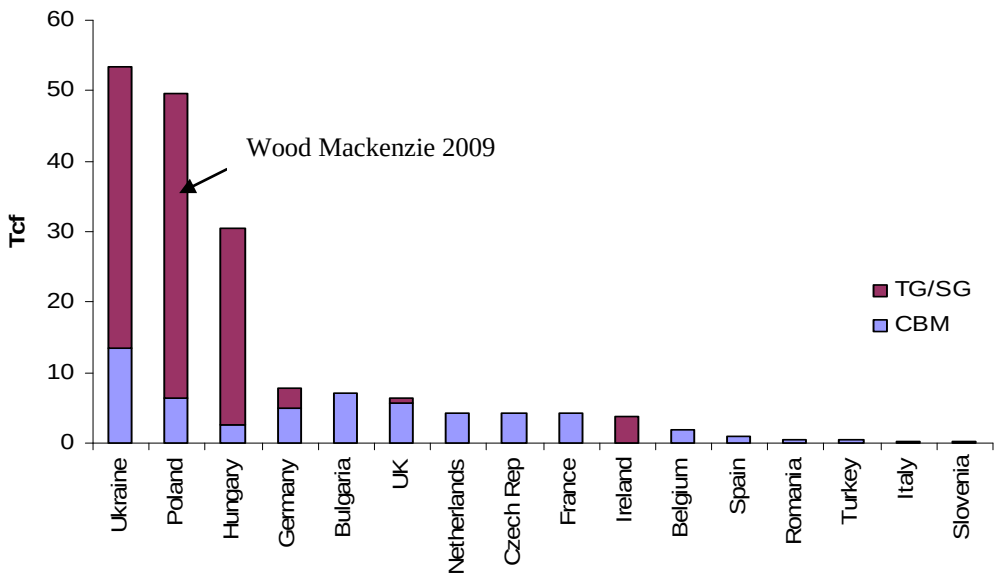
[93] Dr Ken Chew, *The shale frenzy comes to Europe*, E&P magazine, 1 March 2010 http://www.epmag.com/Magazine/2010/3/item53280.php

to assess the reality of the local challenges. We will analyse the challenges to the transfer of the US experience to Europe in Chapter 6.

An interesting observation from the distribution of resources is that a few countries could potentially develop natural gas production on a scale which would change their political relationship with neighbouring European countries and their current gas suppliers. This could be the case in Germany, Poland, France, Hungary and Romania. We will revert to that point in the last chapter of this section.

Resource estimates We indicated above the countries in which unconventional gas basins are located. The next question relates to quantities in place and recoverable in these countries. Unfortunately, due to the general lack of subsurface data on unconventional reservoirs, and of information sharing in the gas industry, there are currently no publicly available estimates of shale and tight gas resources for each European country, and only a handful for CBM resources. Wood Mackenzie attempted to make an independent assessment of tight gas and CBM resources in Europe in 2006, the result of which is exhibited below in figure 5.2, and developed estimates for selected shale plays worldwide in 2009-2010.

Figure 5.2: Estimates of European CBM and tight sands recoverable resources by country



Source: Wood Mackenzie 2006 and 2009- Russia excluded. Tight gas includes gas from shales.

Although the accuracy of these estimates can clearly be challenged in the light of new data for countries such as Poland, it reveals how countries compare relative to each other. Ukraine and Hungary have the largest endowment of tight gas resources, while for CBM it is the Ukraine and Poland. So interestingly, it appears that the largest unconventional gas resource potential for CBM and tight gas lies in Central and Eastern Europe.

A similar conclusion seems to emerge if we add shale gas resources. Although no extensive country-level estimates for shale gas are publicly accessible[94], it is possible to get an idea of

[94] In Poland Wood Mackenzie and ARI estimated in 2010 that recoverable unconventional gas resources amounted to respectively. 49.5 and 106 Tcf.

country resource endowment thanks to available assessments by basin. IHS CERA carried out such an assessment for Europe in early 2009. Their estimates of recoverable shale gas reserves (i.e proven and probable reserves) for the continent range between 106 and 423[95] Tcf. They have also attempted to refine estimates at a basin level, through a study of thirteen basins across Europe, adapting a methodology developed by Dr Stephen Holditch. From this study[96] it appears that the largest reserves would be found primarily in the Northwest German Basin, stretching into Northern Germany and the Netherlands, with an estimated range of 82 to 258 Tcf of recoverable gas reserves. The Northeast German-Polish Basin, the Aquitaine Basin in France, the Anglo-Dutch Basin and the Danish-Polish Marginal Trough in Northern Poland are also perceived as prolific. Other countries with identified shale gas formations are Austria (Vienna Basin), Hungary (Pannonean Basin), Spain, the UK and Bulgaria.

To conclude, the findings from quantitative resource assessments are in line with those from our geographical analysis of unconventional gas basins described in the previous paragraph. To simplify the picture, there seem to be two major resource clusters in Europe, in the Netherlands/North Western Germany and Central and Eastern Europe. In these provinces, shale and tight gas resources are getting most of the attention because of their contribution to domestic supply in the US. However this does not mean CBM does not have a role to play. As noted above, CBM pilot projects are already underway in France and the UK.

Geological characteristics of shale plays and comparison with US shales This section is intended to give the reader some idea of how the geology of European unconventional reservoirs, in particular shales, compares with that in the US, in order to give a first level assessment of the potential implications of the differences for surface issues, in particular US technology transferability and F&D costs (see chapter 3). Without the presence of intrinsically good quality source rocks and intervals that may be hydraulically fractured, there will indeed be no development of unconventional gas, Hence further analysis will be irrelevant.
However bearing in mind that information is limited, and the degree of uncertainty about its quality is high, the first assumption of this paper is that subsurface conditions will allow commercial development of unconventional gas.

The methodology adopted is based on a comparison of the most important geological characteristics of European and US shales.

There are several critical mineralogical, petrophysical and geomechanical properties that underpin the quality of a source rock for gas (Figure 5.3). Most importantly, the organic richness (measured by the total organic carbon), and thermal maturity necessary to generate gas need to exist. These depend on the depositional setting, burial process, the current depth of the source rock below the surface of the earth as well as the local heat flow in that part of the basin. Without these two parameters in place, organic richness and thermal maturity, gas cannot be present in the shale rock. The type of organic content in the shale also needs to be gas prone upon heating, therefore the type of kerogen is of importance. Furthermore, the thickness of the reservoir correlates with the degree of production potential.

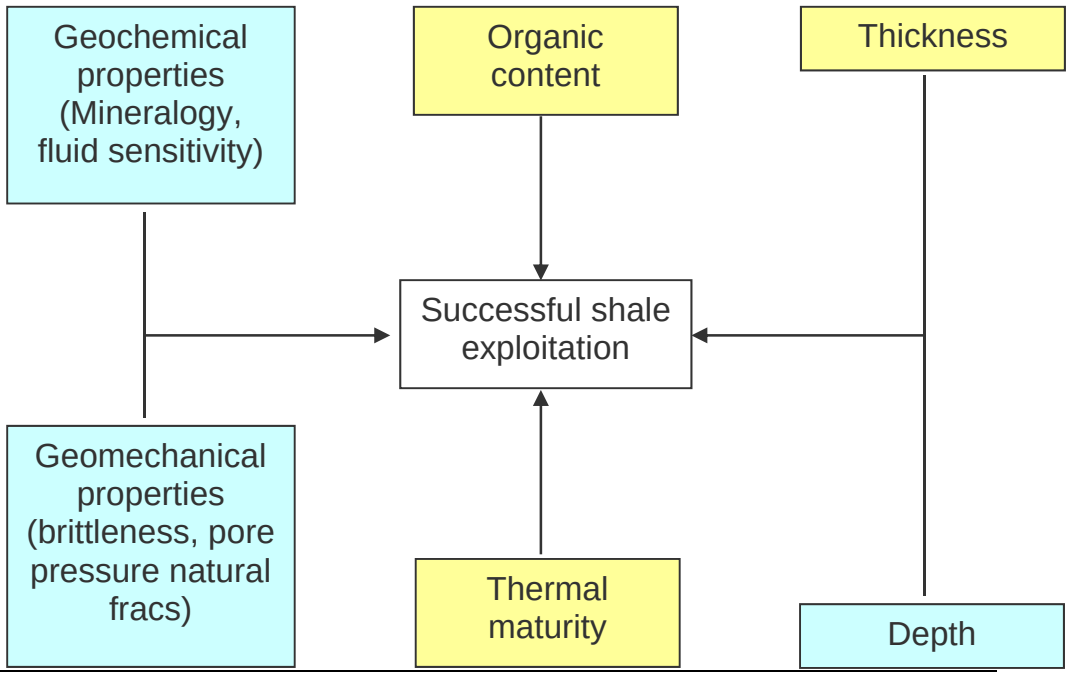
When it comes to favourable properties for exploitation through a stimulation process, the presence of silty layers, which are more permeable, and of natural fractures, which allow gas

[95] See IHS Cambridge Energy Research Associates (CERA) presentation at the Gas Infrastructure Europe conference in May 2009, Stoppard..
[96] See IHS CERA Private report *Gas from Shale-Potential outside North America?* February 2009

to flow naturally to the wellbore, are important elements. They ultimately favour the size of the stimulated rock volumes, hence of gas flows. Maturation is loosely a function of the depth of the gas prone organic shales and drives the pressure level in the reservoir, and thus flow rates. Often, the deeper the shale, the higher the pressure and flow rates. This is a positive feature, however stresses are higher at greater depths and therefore fraccing more challenging, as the pressure applied to fracture the rock will have to be higher than the reservoir pressure. Finally, the brittleness of the rock, influenced by its silica and carbonate content, is the last crucial property that needs to be present, as opposed to clay content. It can be a key factor for successful fracture stimulation and thus mineralogy is a crucial element to look for.

The success factors for shale gas exploitation mentioned above are summarised in Figure 5.3. The properties in yellow drive the existence and quantity of gas in the reservoir, while those in blue are required for the use of reservoir stimulation based on fraccing. Depth is a key consideration as it influences both.

Figure 5.3: Key factors for successful shale exploitation



Source: Author

Keeping this in mind, let us analyse how the most important European shales compare with their US counterparts on these criteria in order to get a first impression on their potential prospectivity and exploitability.

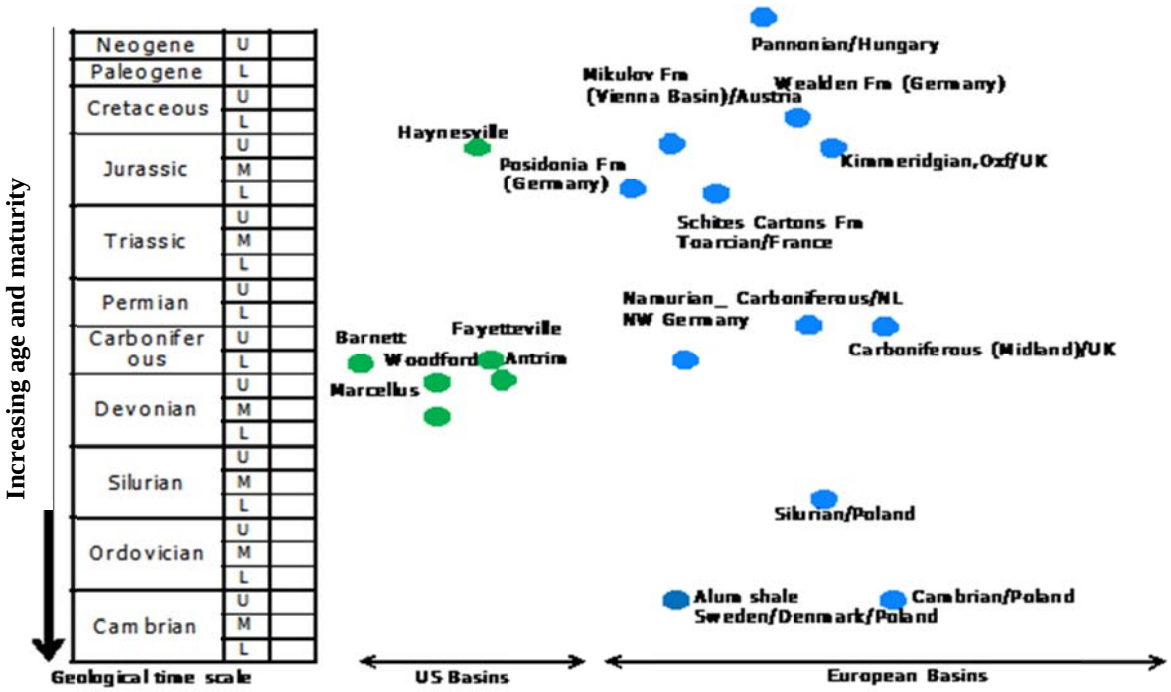
Table 5.1: Shale plays in Europe vs the US: main geological parameters

Country	Play	Thickness (ft)	Depth (ft)	Ro (%)	TOC (%)	US analogue
US	Barnett (core)	100 - 600	6,500 - 9,000	2.1 - 2.3	3.5 - 8.0	-
US	Barnett (SW)	100 - 250	6,500 - 9,000	2.1 - 2.3	3.5 - 5.0	-
US	Woodford	120 - 345	6,000 - 13,000	1.1 - 3.0	3.0 - 10.0	-
US	Fayetteville	20 - 200	1,000 - 7,000	1.5 - 4.0	4.0 - 9.5	-
US	Haynesville	200 - 300	10,500 - 13,500	0.9 - 2.6	3.0 - 5.0	-
US	Marcellus	50 - 200	4,000 - 8,500	1.0 - 2.5	2.0 - 10.0	-
US	Antrim	70 - 160	600 - 2,200	0.4 - 0.6	1.0 - 20.0	-
Germany	NW German Posidonia	50 - 200 ft	6,500	0.48-4.8	2-15%, av 11	Woodford
Netherlands	West Netherlands Epen	50 - 82 ft	4900 - 21325	1.65-1.85	8%	Woodford
Poland	Polish Baltic Depression	> 328 ft	8,200	1.5	around 7, max >15	Fayetteville
Poland	Lublin Trough	325 - 650 ft	7,545	1.4	0.5–1.2%	Fayetteville

Sources: US Department of Energy, Fort Worth Geological Society, Deutsche Bank, Touchstone Resources, American Oil & Gas Reporter, Polish Geological Institute, R.T. van Balen & al, 1999.
See definitions of TOC and Ro in the Glossary.

Given that each shale play has its own specific characteristics, it would be inaccurate to draw general conclusions on the geological differences between US and European plays. However, there are some emerging trends. Compared to North America, European unconventional gas basins tend to be smaller, and tectonically more complex, and geological units seem to be more compartmentalized (Table 5.1). Furthermore, shales tend to be deeper, hotter, and more pressurised. The quality of the shales is also different, with generally more clay content in Europe. Noticeably, there is a large span in formation ages in European shales compared to US shales, as shown in Figure 5.4.

Figure 5.4: Formation ages, US and European shales



Source: diagram provided by Schlumberger Business Consulting

The young sediments have more propensity to be rich in clay and less dewatered, so they may present challenges for exploitation.

Furthermore, in Northern Germany and Poland, there are several instances of gas contaminated with nitrogen. High nitrogen content in methane could be an issue affecting the quality, and thus the value, of the gas.

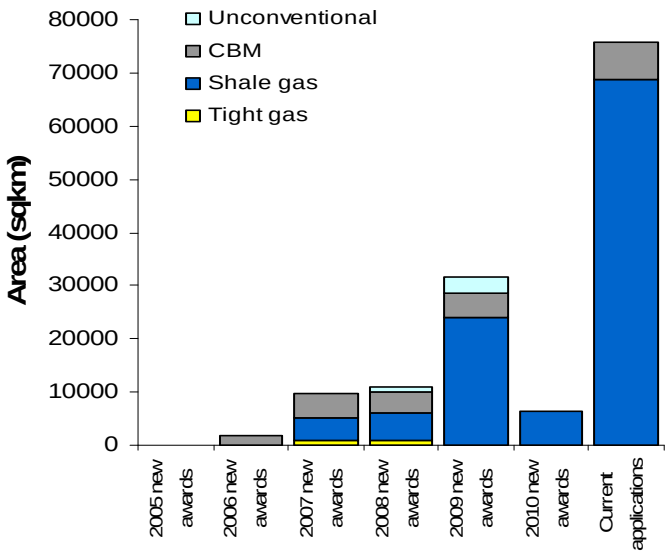
The implications of all these observations are numerous in terms of US technology application and the economics of the plays. It is clear that technological solutions developed in the US will have to be customised to European conditions. For example less brittle rocks makes the use of hydraulic fracturing more challenging, possibly requiring different fraccing techniques and potentially affecting the materiality of production. Moreover, greater depths will increase the complexity of drilling and stimulation operations as well as frac designs, and drive the level of F&D costs up. We return to this latter point on costs in Chapter 6.

Finally, due to uneven prospectivity among shales, not all countries will be able to leverage their resources despite the presence of E&P companies. It is hard to predict which basins will deliver the highest recovery rates. The increased level of applications and concession awards across Europe and the targeted countries give an indication however of the industry perception of play prospectivity, and we now turn to the competitive landscape and industry activities in European unconventional gas.

5.3 Players and activities

An intensive `land grabbing' phase that is nearing conclusion As a result of the American success, it is clear that since 2007-2008, the industry has increasingly been seduced by the prospects of potentially large unconventional gas resources in Europe, in particular. A trend of increasing and intense land grabbing has emerged since 2007, illustrated in Figures 5.5 and 5.6.

Figure 5.5: Acreage awards and applications in Europe



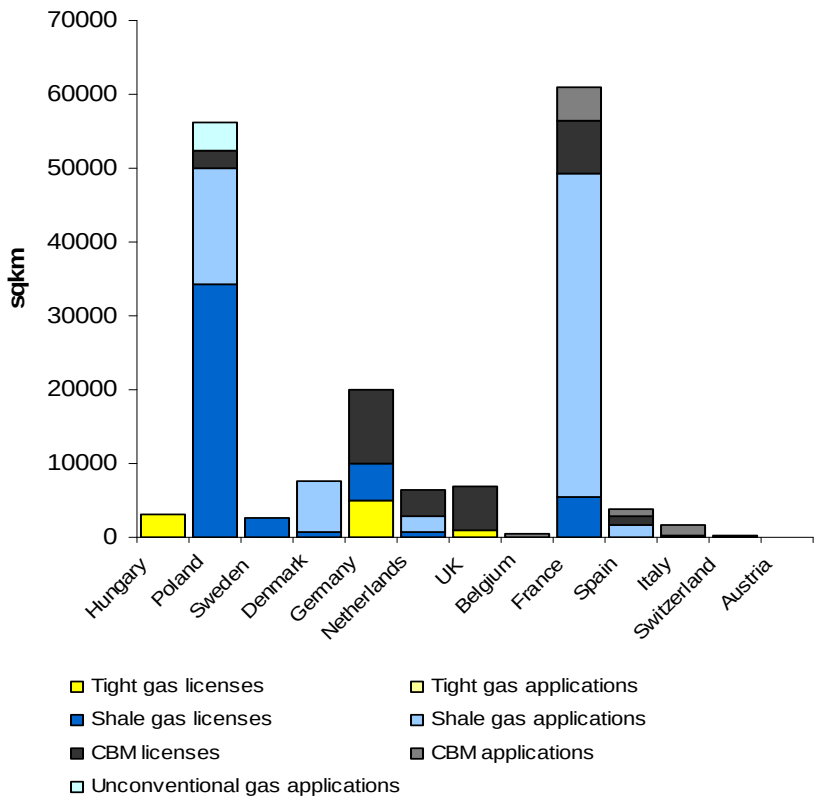
Source: IHS

Figure 5.5 shows that since 2007 the total size of acreage awarded has been increasing exponentially. This obviously reflects the higher number of applications for concessions year after year, but also in our view the fact that companies have understood the need for securing a lot of land in order to be able to identify the core shales areas. Therefore it is likely that in a few years, active acreage will be much smaller as companies will relinquish parts of their least productive assets. Relinquishment rules in Europe generally allow operators to exit parts of the concessions after 4 to 6 years. As a result the question of land access and usage could become less crucial over time.

The speed at which the land acquisition trend has been taking place is quite remarkable, particularly in the context of scarce hard data. This suggests the need for caution about how much of the acreage acquired will actually prove to be prospective. It is important to be realistic about the level of potential recoverability.

Analysis of countries that have been licensing the largest acreages for unconventional gas exploitation, and the type of resources that have been in demand in applications, reveals that Poland, France and Germany have been "hot spots" (Figure 5.6). Poland has a very strong focus on shale gas and has already licensed large acreage. Since 2008, the country has approved 70 exploration licenses for shale gas and is considering additional ones. Interest has been demonstrated in French shale gas licenses, although most of the applications are still pending, with awards expected by end-2010. Germany has been licensing its acreage for some time, mostly in areas containing tight sands and coal. However data for this country are far from transparent so the total size of acreage awarded is probably higher, and awards probably also include shale.

Figure 5.6: Acreage by country



Source: IHS

We mentioned that Germany and Poland stand out in terms of unconventional gas licensing. As these will be the first prospects to be drilled, we will look at them in more detail in Chapter 6. We will also include the Netherlands, as it is the most densely populated country in Europe, therefore surface conditions there will reflect many challenges to be met in other countries.

Who has acquired acreage? The analysis of the unconventional gas industry structure in Europe in 2010, illustrated in figure 5.7, shows that the competitive landscape is crowded, geographically concentrated, but very fragmented in terms of players.

Around fifty companies are involved in exploration activities, and the whole spectrum of the industry is represented. Five are Majors (ExxonMobil, Shell, Total, ConocoPhillips and Chevron), four are large caps (Marathon, Nexen, Talisman and BG (via QGC)), three are National Oil Companies (PGNiG, OMV, MOL) and two are European utilities (GdFSuez, RWE).

The bigger players have shown interest in European unconventional gas acreage only since 2006-2007[97], and are concentrated in Poland, with the particular case of ExxonMobil which has also deepened its historical presence in Northern Germany. Poland will act as an important test case for the development of unconventional gas, and success or failure in that country will be very important for the early development elsewhere in Europe. The industry (i.e ExxonMobil/Falcon/MOL) has already attempted to appraise the Mako Trough in Hungary in 2009 but results were very disappointing as large amounts of water were found. This raises a question about future attempts to prove up and develop resources in that country but it has not stopped initiatives in other countries.

From the above it is clear the unconventional gas game remains unconsolidated, as it is dominated by small companies which comprise more than 60% of the players. Part of the reason for the presence of so many small players are low entry and exit barriers[98].

Small companies fall into two broad categories. The first is composed of private and North American based entities, either E&P companies eager to export the knowledge they have gained in their US operations or private equity and venture capital fund; the second is mainly composed of national companies.

The heterogeneous nature of the competitive landscape means that strategies of partnerships prevail along two dichotomies, big/small and international/national[99]. The rationale is straightforward: large companies bring financing means and the ability to take on risk, while small companies bring unconventional gas expertise and speed in decision-making processes. National companies bring the knowledge of local conditions.

[97] Within the Major category, Shell and ExxonMobil have been the first to enter the unconventional gas business, since 2005-2006.

[98] For example, in the Netherlands there are no bonuses attached to concession awards. Payments are only due by production license holders, and consist of a one-off payment to municipalities based on the size of the land occupied by production facilities (€4.50/sqm in 2003), and annual surface rentals (€600/sqkm in 2003).These costs are clearly very low compared to lease bonuses in North America (see Chapter 2).

[99] Some examples of these partnerships are ConocoPhillips/Lane Energy in Poland, GdFSuez/Scuepbach in France, BG/Composite Energy in the UK and Poland, and the former ExxonMobil/Falcon/MOL JV in Hungary.

The map below tries to illustrate these observations and give a comprehensive picture of the competitive landscape in late 2010. However the competitive landscape in Europe is relatively dynamic and readers should be aware that data may become quickly outdated.

Figure 5.7: Unconventional gas competitive landscape in Europe

Taking a look at the potential future of the competitive landscape, three assumptions can be made. First, remaining unconventional gas acreage available for applications in Europe seems to be concentrated in Romania, Bulgaria and the Ukraine. Indeed, most of the acreage in prospective areas for shale gas has already been licensed. In the Netherlands, Lower Saxony (Germany) and Lorraine (France), acreage is fully licensed. In Poland, most of the attractive acreage in the North East, the Lublin Trough and the Podlasie Basin is licensed. However the location of prospective acreage may evolve as more subsurface knowledge is gained and opportunities change. The Ukraine, Romania and Bulgaria remain under-licensed[100], one major reason being that conventional gas extraction in the two first countries is still an important activity. This gives an indication of where we could expect to see new entrants in the coming years, parallel to potential farm-in deals in already licensed acreage. It also means that land access could be a big challenge for new entrants, depending on existing acreage holders' ambitions in unconventional gas, relinquishment obligations and well test results.

Second, it is likely that more gas and power utilities will join the game in Germany, Central and Eastern Europe. Many of them are indeed thought to be holding acreage containing black shales below the shallower conventional layers of gas. But ultimately this will depend on their strategic and commercial interest in developing this resource.

Finally, consolidation is to be expected. Several bankruptcies have already taken place in 2009-2010 due to a lack of cash liquidity[101].Despite improvement in credit market conditions,

[100] IHS Energy - EDIN GIS, October 2009

[101] This is the case of Gold Point Energy and Galaxy Energy. Galaxy Energy was taken over by San Leon Energy in 2009. Island Gas was also bought up by San Leon in 2010.

some companies may not be able to develop their acreage, for example in Poland. In 2010, activities are limited and exploratory, corresponding to the entry of the sector into a new phase of data acquisition and commerciality appraisal (Table 5.2).

Table 5.2: Activity chart by company and country

Operator	Country	Type of unconventional	Status
Ascent Resources	Hungary	TG	Exploration JV with MOL
Ascent Resources	Switzerland	SG	Appraisal
Aurelian Oil and Gas	Romania	TG	Appraisal
Benelux JV	Belgium	CBM	?
BNK	Poland	SG	Exploration/Appraisal
Chevron	Poland	SG	Exploration
Composite	UK, Poland	CBM	Exploration/Appraisal
ConocoPhillips	Poland	SG	Exploration
Cuadrilla	Netherlands	SG	Appraisal
Cuadrilla	Spain	SG	Exploration
Cuadrilla	UK	SG	Appraisal
Cuadrilla	Poland	SG	Exploration
EurEnergy	France	SG	Exploration
EurEnergy	Poland	SG	Exploration
European Gas Ltd	Italy	CBM	Exploration
European Gas Ltd	France	CBM/CMM	Production
ExxonMobil	Poland	SG	Exploration/Appraisal
ExxonMobil	Germany	SG, CBM, TG	Exploration/Appraisal
Falcon	Hungary	TG	Exploration/Appraisal
Falcon	Romania	CBM	Exploration
FX Energy	Poland	SG	Exploration
GdFSuez	France	SG	Exploration
GdFSuez	Germany	TG	Production
Greenpark	Spain	CBM	Exploration
Greenpark	UK	CBM	Exploration
Heritage	Spain	CBM	?
Hidrocarburos del Cantabrico	Spain	CBM	Exploration
Hulleras del Norte	Spain	CBM	Exploration
Island Gas	UK	CBM	Exploration
Lane/3 Legs O&G	Poland	SG	Exploration/Appraisal
Lane/3 Legs O&G	France	SG	Exploration
Marathon	UK	CBM	Exploration
Marathon	Poland	SG	Exploration
MOL	Hungary	TG, SG	Exploration/Appraisal
Nexen	UK	CBM	Exploration
Northern Petroleum	UK	CBM	Exploration
Northern Petroleum	Netherlands	SG	Exploration
OMV	Austria	TG, SG	Studies
Parkyn	Germany	SG	Exploration
PGNiG	Poland	SG	Exploration
Queensland Gas (BG)	Netherlands, Germany	CBM, SG	Exploration
Queensland Gas (BG)	France	SG	Exploration
Realm	France	SG	Exploration
Realm	Poland	SG	Exploration
Roc Oil	UK	CBM	Exploration
Rohol Aufsuchung	Poland	SG	Exploration
RWE	Germany	SG	Studies
San Leon	Poland	SG	Exploration
San Leon	Germany, Romania	TG, CBM	Exploration
Schuepbach	Denmark	SG	Exploration
Schuepbach	Switzerland	SG	Exploration
Schuepbach	Spain	SG	Exploration
Schuepbach	France	SG	Exploration
Shell	Sweden	SG	Exploration
Shell	Ukraine	TG	Exploration
Smart	Netherlands	SG	Exploration
Talisman	Poland	SG	Exploration
Total	France	SG	Exploration
Total	Denmark	SG	Exploration
Wintershall	Germany	TG	Production

Sources: Press and company reports, Bernstein Research

A few exploration and appraisal wells were already drilled a decade ago in CBM and tight gas prospects, in particular in North Western Europe, but results at the time proved disappointing. Over the last two years, activity has been growing again, but at a moderate pace, with a marked focus on shale gas. In 2010, wells were being spudded in Poland (e.g Lane Energy, ConocoPhillips, ExxonMobil, BNK Petroleum), Germany (e.g ExxonMobil), Netherlands and the UK (e.g Cuadrilla) and several additional testing wells are planned for 2011.

As mentioned earlier, it took at least two decades in the US to develop and produce CBM, tight gas and shale gas on a commercial scale. The catalysts for successful unconventional gas production have been of diverse nature but predominantly technological, as explained in chapter 3. Technology is now available and thus in Europe catalysts are mainly commercial.
We are likely to see a long and painful testing phase in Europe similar to the US, but primarily for commercial reasons. Constraints on the size of concessions, land access, regulations and cost issues are important hurdles, and the investment exposure required for exploring the unconventional gas potential is significant. Using the US emerging shales such as the Haynesville and Marcellus as a benchmark, and taking into account that plays in Europe are smaller, investment in seismic and at least 10-20 pilot project wells would be required to prove a play. A rough calculation suggests that this would mean an investment in the range of $100-150 million, comparable to the cost of an offshore well.

To fund this kind of investment, large players with financial muscle and long-term decision horizons are needed. This is why the presence of Majors is a welcome factor. Majors have a different way of making decisions and operating compared to US independents, and this, together with the specific challenges to unconventional gas development in Europe, will likely define a new development and business model, different from the US. We expand on this conclusion below.

5.4 Implications for the development path of unconventional gas in Europe

In addition to fundamental factors such as geology and surface conditions, future production will be greatly influenced by operators' strategies, as these will dictate the speed and scale of development of the unconventional gas resource. The resulting degree of corporate willingness to invest in exploratory activities and drilling that will not deliver certainty in the short term, and the allocation of investments, are factors that are as important as the investment climate and policies applied by European governments.

The Majors missed out on the initial stages in the development of the U.S. unconventional gas sector, which took off due to the efforts of smaller independent developers. They do not want to take the chance of making a similar mistake in Europe and appear determined to be present from the very beginning, in a gas region which is attractive in terms of demand potential, price and perceived gas resource base. However, in the light of challenges to unconventional gas development that are increasingly unveiling themselves, their ultimate strategic objectives are less clear. Furthermore, not all Majors (for example BP) have chosen to become involved in unconventional gas in Europe.

Benefits and drawbacks of the Majors' presence - which development model for Europe? Each group of players brings positive and negative factors to the exploitation of unconventional gas in Europe. While Majors bring financial guarantees and long-term horizon for decisions, small companies bring speed and a more entrepreneurial mindset. By contrast,

Majors have a higher cost structure, less appetite for risk and a longer-term perspective. The following paragraphs discuss how these benefits and drawbacks will likely affect the development model of unconventional gas in Europe.

The first positive element brought by Majors to the unconventional gas outlook is their financial capacity, investments in R&D and long-term horizon when making decisions. This fits well with the fact that unconventional gas in Europe is still in a de-risking phase and will likely be a longer-term story in Europe, as we have already started to explain and will continue to do so in Chapter 6. Furthermore they have a much stronger lobbying power with governments and the European Commission to push for more favourable investment conditions.

The key implication of the Majors' presence, though, will be on the way unconventional gas operations, i.e exploration and appraisal drilling, stimulation, logistics, and development planning, are conducted.

In the US, the operating model developed by independents is based on a statistical and "factory" approach, relying on the drilling of numerous wells in order to develop resources, rather than try to identify the best targets (sweet spots) and drill these prospects only. There is however a growing trend in the use of technology, in particular for the evaluation of well results, through a continuous learning process helping increase performance. Independents embraced aggressive appraisal drilling based on trial and error straight away without much advance investment in understanding subsurface characteristics, because they did not see the economic added value of doing so. In some mature plays, the result of this drilling frenzy in the 2000s has been a concentration of production within a small amount of wells and land, parallel to a huge number of failed wells[102]. This was made possible by the large scale area of leases and improvement in drilling and stimulation techniques making well costs per unit cheaper. The necessity to drill in order to keep leases before they expire also drove the high pace of drilling.

In Europe, however, the situation is different due to different rules on land ownership, and smaller concession sizes linked to high levels of population density. This has two implications: first, the scale and use of drilling for appraisal and development purposes will be constrained by space and land access. Second, significant exploratory, appraisal and pilot investments are currently needed using more characterisation technology such as 3D seismic, reservoir modelling, and monitoring technology such as microseismic hydraulic fracture monitoring[103]. Consequently, operators in Europe will have to conduct more efficient operations by continuing to invest more in R&D and understanding well results continuously in order to alleviate the problem of land footprint. Understanding better the subsurface, in particular fracture characteristics, helps choose the optimal placement for wellbores, and optimise well stimulation and completion designs.

Holding concession blocks that are bigger than single leases provides some stability. In that respect, the mindset of Majors seems suited to "conventional" operations and upfront risk reduction. However the ultimate questions are whether this approach would prove more expensive than empirical US practices, and whether Majors have the necessary cost structure

[102] This is the case of the San Juan CBM basin, where around 75% of the production comes from 30% of the wells, concentrated on 10% of the land.

[103] Main technologies being developed deserving more usage are for example surface seismic mapping, borehole seismic, natural fracture detection.

and speed to make fast and efficient drilling decisions, and continuously adjust their well and fraccing designs and investment plans .

The optimal model for developing unconventional gas in the US and in Europe is still a matter of debate. The costs of adopting an R&D-focussed sweetspot approach versus drilling more wells remains an unresolved issue, and this aspect is worsened by the fact that Majors and large companies tend to have a higher cost structure than smaller independent companies. For example, ExxonMobil's structure cost per unit amounts to about $4.3 /mcfe, eleven times more than Chesapeake's at $0.38/mcfe[104]. Given that the economics of unconventional gas are primarily based on efficient operations and minimising F&D costs, this data suggests that scepticism surrounding the ability of Majors to develop unconventional gas in a viable manner may be justified. Linked to this is a much less risk-taking mindset, and less speed in making decisions than small companies. A conservative mindset is not suited to the dynamic nature of the unconventional gas business, which relies on extensive operational experimentation in an iterative manner, and fast efficient drilling to reduce costs and improve optimisation.

To conclude, the stage of maturity of unconventional gas in Europe, combined with unique space and cost challenges, calls for investments focussing on decreasing geological risks ahead of drilling in all phases, exploratory, appraisal and development. These types of investments are costly and fit into the Majors' corporate cultures. From that point of view, the presence of Majors in Europe is expected to be beneficial to the exploitation of unconventional gas and the development of an operating model different from the North American one. However, the mindset and internal inertia in these big companies are not suited to the nature of the unconventional business. Therefore, it is fair to say that operators in Europe have a lot to learn from the North American experience, from companies and from their success factors. This is the topic of Chapter 6.

Chapter 6 -To what extent can Europe replicate the US unconventional gas model?

The title of this chapter implies two questions. The first is the transferability to Europe of the US catalysts and operating model identified in Part 1 of this paper. The second relates to the potential scale of European unconventional gas production, and whether the market share of these new resources can be expected to reach US levels (i.e around 55% of indigenous output, taking the 2010 US gas production level). We analyse these two questions in the following two sections, and start by outlining the operational and market requirements from producing a given amount of unconventional gas according to three scenarios developed below.

[104] Calculation based on sales, general and administrative costs per unit of production- Sources are ExxonMobil annual report 2009 pp 28, 66-67 http://media.corporate-ir.net/media_files/irol/11/115024/XOM_2009F&O.pdf and Chesapeake 10-K SEC filing March 2010 p8 http://phx.corporateir.net/External.File?item=UGFyZW50SUQ9MzcxMzU4fENoaWxkSUQ9MzY4Mzk4fFR5cGU9MQ==&t=1

6.1 Unconventional gas as a game-changer: production scenarios and operational requirements

Definition of production scenarios In this section we set out three scenarios in which unconventional gas could be deemed a pan-European "game-changer". The purpose of this exercise is to understand the order of magnitude in terms of volumes and timeframe. The next section will then identify the operational requirements to produce such quantities and the extent to which this is realistic.

In 2009, Europe (including Norway) produced 7.7 Tcf of gas and imported 11 Tcf[105]. The scenarios are:

- Scenario 1: Unconventional gas production slowly ramps up and reaches 1 Tcf/year after 2020 and 2 Tcf/year by 2030. In that scenario unconventional production flattens out the projected European production decline.
- Scenario 2: Unconventional gas production is steady at 1 Tcf/year from 2020 to 2030. This level corresponds to a share of 5% of European gas demand during this period.
- Scenario 3: Unconventional gas accounts for 30% of total domestic gas output by 2030, following a steep ramp-up accelerating over time to take into account learning curve effects and production optimisation by the industry. Production would reach 1 Tcf/year by 2020 and 3.5 Tcf/year by 2030. In our view this would be a very high but not totally unrealistic production level.

In our view the idea that unconventional gas could account for 50% of European production, similar to the US in 2009, would be totally unrealistic. This would require production of more than 1 Tcf in 2020 rising to 8 Tcf in 2030. Achieving this level of output within two decades would require a technological breakthrough with effects similar to the US in 2005. Given the current state of technology development, this seems quite unlikely.

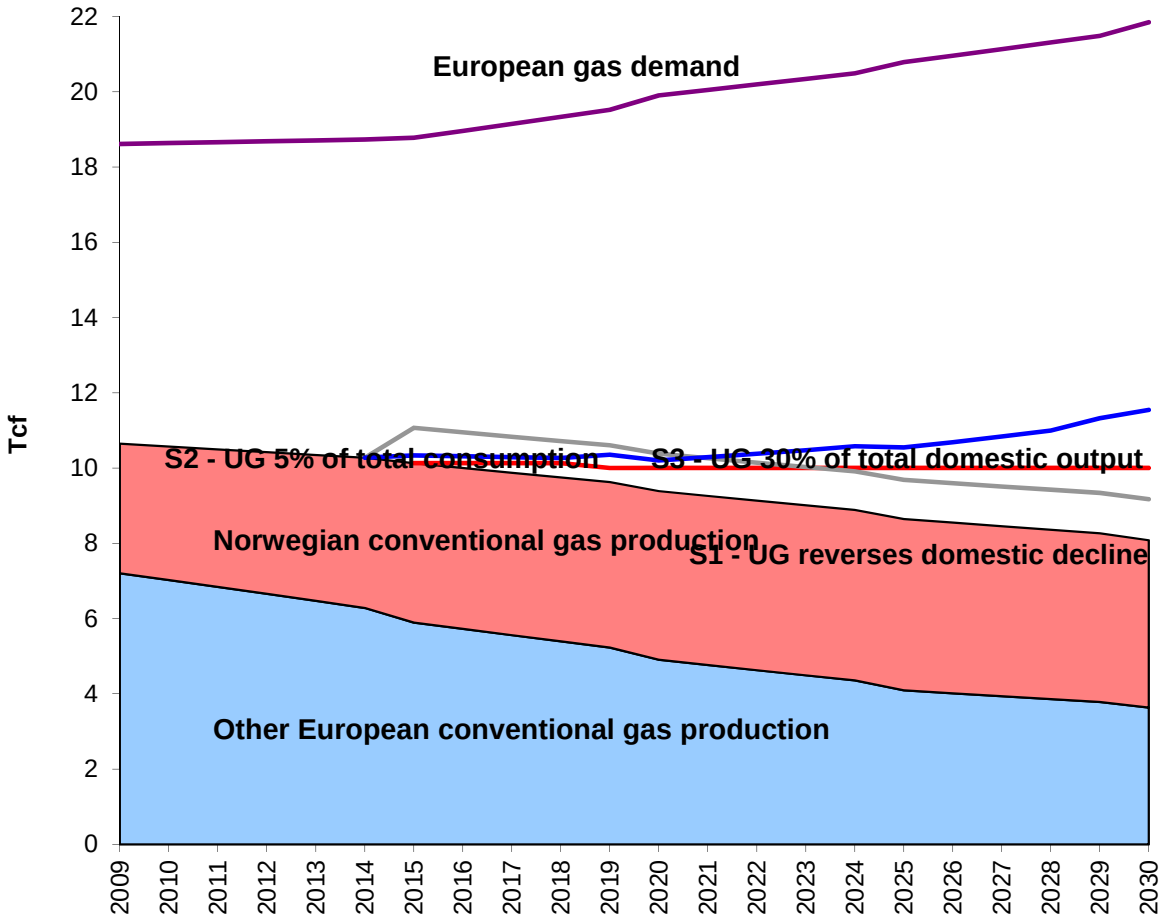
We assumed a start of production in 2015 for all three scenarios, albeit at a very low level. We do not expect pan-European unconventional gas production to exceed 0.15 Tcf/year before 2020, the main reason being the time needed by the industry to improve its subsurface knowledge of shale reservoirs. This judgement is based on the state of immaturity of the unconventional gas industry, and the small scale of drilling efforts announced for the period 2010-2012 as described in the previous chapter. This implies that the testing phase will last several years, without taking into account all the challenges of a technological, socio-economic or regulatory nature to be encountered by the industry. Furthermore, assuming that material reserves are found, the lead time from development drilling to production still means we will have to wait 4-5 years from the start-up date, based on US lead times to peak production[106], before we see significant unconventional gas volumes.

[105] BP Statistical Review of World Energy, June 2010. In this scenario exercise we have included gas production from Norway in European domestic production. Norwegian gas production accounts for around 40% of that total and quantities are not set to decline before 2012, based on the conventional wisdom that production and exports plateau in 2012 and decline after 2020. The definition of game-changer would be different if we were excluding Norway.

[106] It took about four years in the Fayetteville to reach 5 Bcm of gas production while it took the Barnett 20 years (IEA WEO 2009).

For the purpose of assessing operational requirements linked to various production scenarios, the choice of the start-up date is not critical. What matters in this exercise are the level of production that can be reached and the shape of the ramp-up curve. Production profiles corresponding to the different scenarios are illustrated in Figure 6.1 below.

Figure 6.1: Scenarios for unconventional gas development and production 2015-2030



Source: IEA WEO 2009, BP Statistical Review of World Energy, Author

The production of 1 Tcf/year of gas is a cornerstone of all three scenarios, even if the timing of that target is different in each one. We will analyse the operational conditions needed to produce that level over a certain period of time, and make a judgement as to whether this is realistic, as well as outlining which conditions are the most critical to achieving this outcome. To put this level of production into context, producing 1 Tcf/year of gas after a 5 year ramp-up would correspond to having one and a half times the Barnett Shale play in Europe starting in 2015 with the same performance observed in the US since 2005[107].

From where will the production come? Unconventional gas production in Europe could potentially come from all three types of resources included in the scope of the study, i.e tight gas, shale gas and CBM. We have chosen to exclude CBM production from our analysis, for the following reasons: first, CBM is mainly to be found in the Ukraine, which provides

[107] Calculation based on State data and forecasts for 2010 by ARI. Barnett production roughly increased by 0.7 Tcf between 2005 and 2010.

extremely challenging business conditions. Despite its vast resource potential, there are too many challenges weighing on investments in this country. Second, a few companies have tried to extract that resource in Europe since the late 1990s, for example in Poland and the UK, without much success. Technological innovation may help make that activity more profitable, but the quality of the coal endowed with CBM in those countries is uncertain. Furthermore, compared to the industry interest in shales and tight sands, CBM remains marginal.

Countries In terms of tight and shale gas, it is uncertain where the production will come from, even if there are rough resource estimates for many basins across Europe, because geological structures are extremely complex in some. Sweden, Poland and Northern Germany are the first in line for test drilling, but in late 2010, results were unavailable. Furthermore, some failures are to be expected on the way, such as in Hungary's Mako Trough in 2009. In our view, this does not necessarily doom the viability of unconventional gas development but rather reflects the need for improving the application of subsurface tools and extraction techniques. A positive piece of news at the time of the writing comes from well tests performed by PGNiG in the Lublin Trough in Poland (Makrowola-1)[108].

We have assumed that production of 1 Tcf/year of unconventional gas is needed to start being a game-changer in Europe. If we look back at our production scenarios, this threshold would represent more than 50% of total annual gas production for any country. In 2009 indeed, only two countries in Europe (excluding Norway), i.e the UK and the Netherlands, had conventional gas production above 2 Tcf, and in both countries this was in decline. 50% of domestic production is the level achieved in the US but it seems unrealistic at a country level in Europe, due to numerous surface challenges we analyse in detail below. Over 40 years, the scenarios require minimum production of 40 Tcf. With the exception of Poland, which is estimated to hold resources of between 49.5 and 106 Tcf, we do not have reliable national resource estimates to assess the realism of such a scenario.[109] However available proven conventional gas reserves data reveal that the three largest natural gas reserves holders barely reported more than 70 Tcf each in 2009[110]. There is of course no direct correlation between the amounts of conventional and unconventional gas reserves, but this number is a useful reference.

Therefore from a resource endowment point of view and given the above-ground constraints in Europe, it is likely that the production of 1 Tcf/year of unconventional gas in Europe may not come from a single basin or country, with the possible exception of Poland, but will rather result from aggregate production across Europe. This finding could change as country resource estimates become more accurate and available to the public.

Defining operational requirements – Polish case study methodology for calculation:

Selection of the play To identify the operational requirements for producing 1 Tcf of gas flat on an annual basis, we selected the Silurian shale in the Baltic Depression in Poland as the basis for a case study. The choice of this play was based on the availability of information on the subsurface, the density of concession holders and the fact that Poland is in one of our three case study countries. The methodology used to determine the number of wells, the size of the

[108] http://oilprice.com/Energy/Natural-Gas/Is-European-Shale-Gas-the-Real-Deal.html
[109] Polish estimates from Wood Mackenzie and ARI respectively.
[110] BP Statistical Review of World Energy 2010

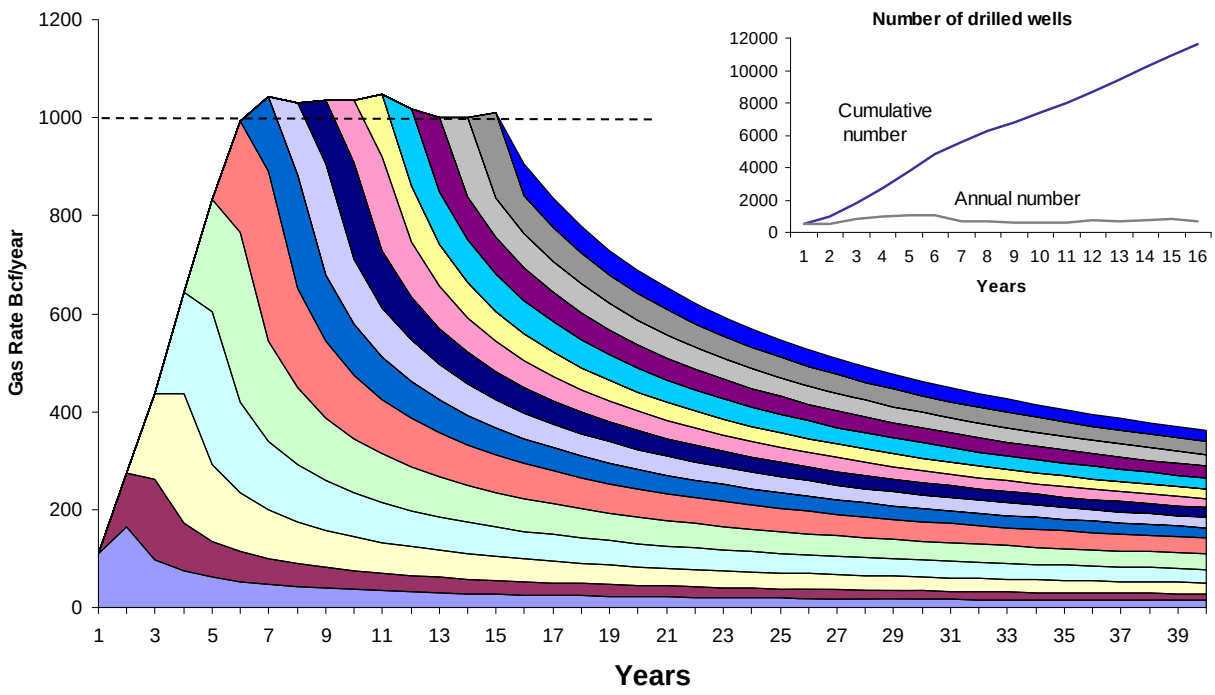
acreage and the potential production curve of the shale relies on a comparison of production performance with a shale play in the U.S sharing similar geological characteristics.

Choice of US analogue An analysis of the geological characteristics of the Baltic Depression Basin, based on table 5.1, shows that it could be compared to the Fayetteville Shale in the US on the criteria of thermal maturity and reservoir pressure. However there are several caveats. First, given the lack of geological data on the Silurian reservoirs, choosing an analogue play in the US is very speculative. Second, geological similarities are not necessarily correlated with shale play performance, as can be observed in many instances in the US. Subsurface mechanisms governing well productivity are still poorly understood. However, for this exact reason the only possible parameter for a comparison between US and European shale gas plays is geological.

The Fayetteville has an Initial Production rate (first day rate) of about 2.3 MMcfd[111], which gives us the production decline curve for the area over time. Over 40 years one well would produce about 2.4 to 2.7 bcf, assuming it is fully successful, which (as mentioned above) is not the case for all wells in an unconventional gas play[112] in the US.

Assuming that the Polish shale has similar production performance to the Fayetteville, the modelling of a drilling development plan designed to achieve annual production of 1 Tcf after 5 years (i.e 2020), over a period of 10 years, shows that close to 11,700 wells over 15 years would be needed to achieve this target, with the annual phasing illustrated in Figure 6.2.

Figure 6.2: How to produce 1 Tcf of gas/year for 10 years



Source: Author

[111] Statistics taken from U.S producers' investor presentations as of end 2009.

[112]For example in the Barnett, operators can expect that around 12% of the wells drilled fail after three years according to Bernstein Research.

A 10-year period was chosen because, assuming a start-up of production between 2015 and 2020, this gives us production extending to 2025-2030, sufficient to demonstrate the operational challenges linked to achieving this target.

Results The first observation is that the ramp-up of production to 1 Tcf over 5 years would require the drilling of many more wells in the first 5-6 years, around 800 to 1000 /year, than subsequently. Once the level of 1 Tcf is achieved, maintaining it for 10 years would require the drilling of more than 700 wells/year on average. However, if production of 1 Tcf is to be maintained beyond 10 years, i.e over the long-term, this means that far more wells per year, in the range of 600-1000/year, would then have to be drilled. Wells in the US are commonly drilled in pads (i.e clusters), which limits the land footprint of intensive drilling. A pad can include 10 wells. Applying the same operational assumption for Europe, this means that around 70 to 100 new pads would be created every year. The total acreage size awarded for shale gas E&P purposes in the Baltic Depression is estimated to amount to circa 20,000 sqkm (i.e 4,942 000 acres). Assuming that a well spacing requirement of 100 acre/well is applied, this means that in theory more than 49,000 wells could be drilled in that area. Thus, drilling more than 700 wells/year over a sustained period of time could take place in the Baltic Depression concessions alone. However the surface available is smaller due to restrictions on drilling locations. There are no data available that allow for estimating what proportion of acreage would be accessible. Therefore the operational requirements described and the assessment of their fulfilment assumes that production of 1 Tcf/year will come from several regions across Europe. This conclusion is in line with our earlier conclusion derived from looking at national outputs and proven reserves.

What would this level of drilling require in terms of acreage sizes, i.e land surface needed to accommodate all these wells? In the US, States regulate the spacing of wells. A spacing of 80 acres between wells is common, although many States allow for closer spacing. In Poland, Germany and the Netherlands, there is no such restriction in mining laws and regulations. However this could change when large-scale unconventional gas drilling becomes a reality. Assuming an 80-acre well spacing rule, the surface needed for drilling 1,000 wells would be 80,000 acres (i.e 324 sqkm), and 56,000 (i.e 226 sqkm) for 700 wells. Over 20 years, this means the required land surface could be close to 10,000 sqkm and over 40 years 20,000 sqkm. This is small when compared to the (around) 60,000 sqkm of acreage awarded by governments since 2007 (see chapter 5).

So at first sight the problem of land access for drilling does not seem to be about the overall size of acreage. But the data given above are for the development phase, once sweet spots have been identified. The problem is that in order to arrive at a development phase, a great deal of land will need to be explored. Whereas this is not a problem in the US, Australia or South Africa, there are severe limitations in Europe due to the limited surface area of certain countries, population densities and regulations protecting environmentally sensitive areas. For example the total surface area in the Netherlands amounts to 41,530 sqkm, so the drilling surface needed to produce 1 Tcf would cover way more than 50% of the country…which is unrealistic[113]. Another example is Hungary, with a surface area of 91,030 sqkm but the surface area above the prospective tight gas deposits is much smaller.

[113] One implication of this conclusion is that we have to exclude the Netherlands as a case study from the analysis below.

As a result, concessions granted by European governments are small (one block is generally 2.6 sqkm), which many operators believe is too small to allow for efficient exploration activities. In addition, within these concessions there can be many spatial constraints on the placement of wells. Under these circumstances, the size of the challenge of having to drill more than 700 additional wells/year becomes clear.

On top of this challenge, land will also be needed to build new roads to drilling sites, pits and gathering and transportation infrastructure. So the question of land availability is not just for drilling, it is also crucial for undertaking supply chain operations and gas transportation. We will go into more detail on land challenges in section 6.2 below.

How many rigs would be required for this level of drilling? In the Barnett, a rig drills on average 12 wells per year. In Europe, we should assume a lower efficiency, for example 6 wells/year. This means between 100 and 200 rigs would be needed to produce 1 Tcf, and more for more volumes. We will see that the service industry in Europe is currently not equipped to supply that level of equipment and related staff, and will need to ramp up its capacity and capabilities.

How much water would be needed for drilling and fraccing all these wells? Fraccing shale rocks requires immense amounts of fresh water to be pumped down the well. The use of saline water (for example from the sea) could be envisaged provided elements in the fraccing fluid mix are modified to allow for compatibility with the geochemical properties of the reservoir. This is not a common practice though. Looking at practices in the US, a 6-stage deep shale gas well consumes on average 120,000 barrels of freshwater for drilling and fraccing according to Chesapeake. In Europe, standard fraccing designs will include 8 or 9 stages based on the US experience. This implies that each well would use on average 180,000 barrels of water. Most of the water would have to be supplied from natural sources. However there is always some water flow-back, in variable proportions. Ranges quoted by service companies amount to 10-25%. Looking at the drilling programme again for producing 1 Tcf/year over 10 years, and taking into account recycling possibilities, annual water consumption would amount to 100-200 million barrels of water/year, i.e 16 to 32 million cu m (Table 6.1).

Table 6.1: Annual water needs for the production of 1 Tcf/year of gas

Year	Number of wells	Water need (million barrels)	Water recycling (25%)	Net water need (million barrels)
1	1500	270	68	203
2	1500	270	68	203
3	900	162	41	122
4	800	144	36	108
5	700	126	32	95
6	650	117	29	88
7	600	108	27	81
8	550	99	25	74
9	500	90	23	68
10	450	81	20	61
Total	**8150**	**1467**	**367**	**1100**

Source: Author

The amount of water needed on an annual basis to produce 1 Tcf seems large but Europe is generally well endowed with water resources (as we will show below). Furthermore, compared to other energy production activities the amounts in question are smaller, as shown in Table 6.2. Finally, it is important to keep in mind that hydraulic fracturing is a technology only applied for the extraction of shale gas. Fracturing tight sands does not use water, but other fluids (e.g foam). So concerns about intensive water consumption are only related to shale exploitation.

The question of water usage is about its general availability, but mostly about its geographical distribution within Europe and the allocation of it to new unconventional gas operations without disturbing the existing economic order in countries and communes. Therefore it needs to be put into context, at a country and basin level, and compared to other industrial activities. We will do so in Section 6.2.1.

Conclusions Based on our scenario analysis and assuming US operating practices are applied in Europe, we can conclude that operational challenges to producing only 1 Tcf/year of gas look very significant as of 2010, in particular in terms of land availability and logistics for drilling more than 100 well pads/year. The European service industry will need to acquire and supply an adequate number of rigs and fraccing equipment and develop a skilled labour force. Water availability may be an issue at a local level in countries such as Poland and Germany. The challenges will be more acute in certain countries than others and solutions will also take different forms. So we posit that producing 1 Tcf/year of gas will be a challenging target to reach, unless a more efficient operational model is developed.

These findings support the need to find a different development model for Europe, along the principles outlined in the previous chapter.

How do these findings fit with the enablers of the unconventional gas "revolution" in the US identified in Part 1? What can we learn and transfer from the US to achieve material production, and develop a specific European model and what are the biggest hurdles ultimately?

This is the purpose of section 6.2, which tries to put our preliminary findings into a wider context by highlighting which conditions favourable to unconventional gas development are already in place, which ones need adjustment, for selected European countries, and the challenges to unconventional gas production that will be hard to overcome.

6.2 European challenges and the transferability of the US experience - the question of the European response

Our analysis relies on the framework of the 5 categories of drivers behind the US unconventional gas revolution explained in chapter 3 and the extent to which these apply within Europe.

The drivers of unconventional gas success in the US have emerged as part of that country's unique history, geological and socio-economic conditions. Therefore whereas the five generic success factors identified in chapter 3 can be considered best practices in the North American context, for Europe and its historical and cultural specificities they can only be considered as reference practices. Europe will need its own best practices, even more so as it is a

heterogeneous mix of countries with different national priorities and policies. However, to develop an informed view it is important to first analyse how and to which extent the five broad US drivers can apply to Europe. For each point we will therefore try to explain conditions in our three selected countries, and compare them to the US.

What we can say already is that cost levels and a general negative perception of the impact of unconventional gas operations from local communities (and therefore politicians) are the two major differences in the general surface conditions compared with the US.

A vast resource potential was of course, as said before, a pre-requisite to the UCG revolution in the US. We demonstrated in the previous section that uncertainties about the resource potential in Europe prevail. But this is not the major focus of this study; in what follows we assume the geology will support commercial development of the resource, and focus on surface conditions only.

6.2.1 Technology and operating practices

Technology transfer is defined in a broad sense, including not only the techniques used to extract unconventional gas, but also the logistics and overall operational model entailed, including human skills. The export of drilling, completion and project management techniques and principles from the US is already ongoing. With the US as a proving ground, Europe is gaining years of knowledge-building on the technology side, but it is mostly about the broad principles. Their application to the specific subsurface and regulations of Europe in a cost- and environmentally-efficient manner will require field-based R&D, extensive experimentation and customisation of well and fraccing designs, especially as every shale is different.

Furthermore service companies raise concerns about their ability to manage the complex and intense logistics required to build pads, transport and store water, and all other necessary components of unconventional gas operations. Transport takes place mostly by trucks, and local regulations on e.g road traffic or widths of vehicles are seen as being constraints.

Finally, we have already outlined that it is the US operating model that is really challenging to replicate. High drilling and water usage intensities are unlikely to be able to be accommodated in certain countries in the light of physical and environmental constraints. New or more efficient techniques and operational approaches will be required.

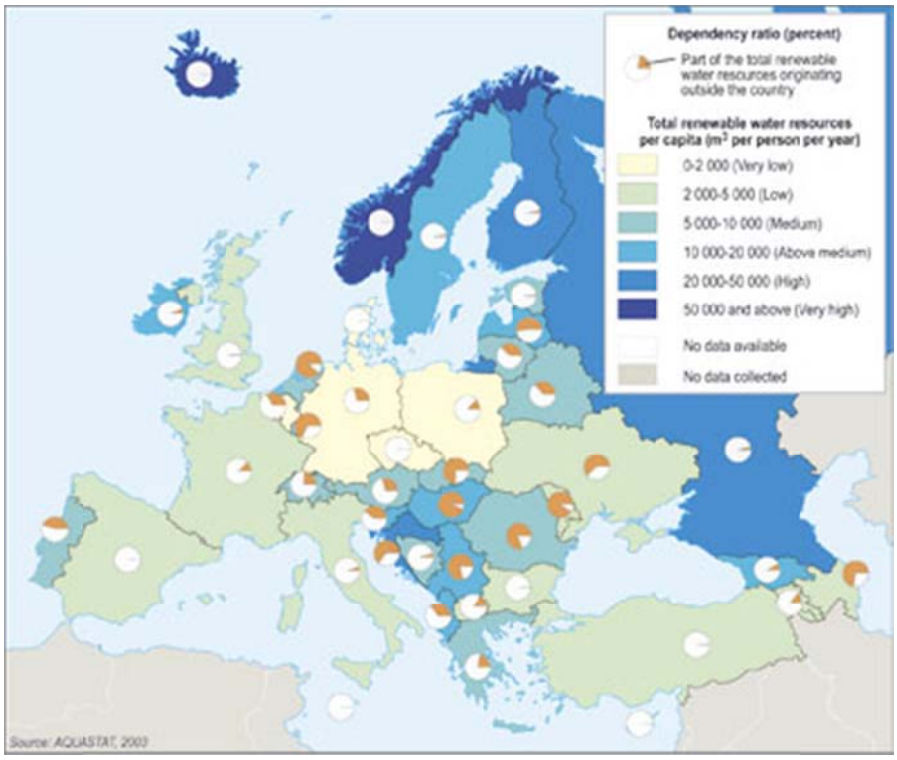
The water challenge If we look again at the scale of drilling and fraccing required to produce a minimum 1 Tcf/year of gas, and more particularly at water management, the main questions that need to be answered are: Is water sourcing a problem in Europe and where? Should it be perceived as a threat for other sectors? How much water can be re-used? Is regional infrastructure for waste water treatment and disposal adequate and close to drilling sites?

Let’s look at the first question. We showed above (Section 6.1) that producing 1 Tcf of gas flat over 10 years would require between 16 and 32 million cubic metres/year, based on a typical and quite basic well design in the US. This calculation takes into account a flow-back rate of 25%, meaning that 25% of water used can potentially be retreated and re-used.

However in Europe shales tend to be deeper than in the US, which implies that less water could flow back and therefore less could be recycled.

Let's first look at absolute quantities of renewable water in Europe and their distribution. On the continental scale, Europe appears to have abundant renewable freshwater resources, about 2,183 km^3/year.[114] So quantities involved in fraccing are negligible on that scale. However, these water resources are unevenly distributed, both between and within countries and once population density is taken into account, the inequity is even more striking (Figure 6.3).

Figure 6.3: Renewable fresh water resources and dependency ratio



Source: Aquastat 2000

Two observations can be made from this map. The first is that Germany, Denmark, the Czech Republic and Poland have the lowest renewable water resources per capita. Poland for example has average inland water resources of 1,600 m3/year. Furthermore, the United Nations Environmental Programme estimates that these countries already experience water stress due to excessive withdrawal of their resources[115]. This is linked to high population densities and the industrial or agricultural structures of the economy which add to water demand. Second, some countries have a very high water dependency rate, such as the Netherlands, Hungary and Romania. This means that these countries depend on neighbouring countries for most of the renewable water resources.

[114] The World's Water 2008-2009, FAO and Pacific Institute http://www.worldwater.org/data20082009/Table1.pdf
[115] http://maps.grida.no/go/graphic/excessive-withdrawal-of-renewable-water-resources

Unfortunately, these are countries where hopes are high in terms of unconventional gas development. So water sourcing seems to be a potential problem for these countries[116], and the acuteness of the problem will also depend on the competition for water from other economic sectors, in particular the agricultural sector, the local proximity of basins to groundwater and surface water sources, and the legal protection of areas. To illustrate this point, we examine below these intertwined issues in the Polish unconventional basins.

Thus, protecting water resources, in particular groundwater, has become an important political issue, enhanced by the 2000 EU Water Directive and the 2006 Groundwater Directive[117]. Therefore the extent to which the allocation of water for hydraulic fracturing purposes will be approved and granted to operators through water permits by national authorities is not clear.

Having said this, the lifecycle water footprint of unconventional gas exploitation is among the smallest of all energy sources, just after renewable sources but far ahead of coal, nuclear and oil (Table 6.2).

Table 6.2: Fresh water use intensity by energy type

Relative Fresh Water Use Intensity	Energy Production Type
High Water Intensity	Coal (including CCS) Biofuels Geothermal
Medium Water Intensity	Oil Nuclear Coal (without CCS) **Conventional and Unconventional Natural Gas** Solar (concentrating)
Low Water Intensity	Hydropower (net evaporation)
Very Low Water Intensity	Solar (Photovoltaic)

Source: CH2MHill analysis for the Water Business Council for Sustainable Development Water Project, based on Sandia Report on the Interdependency of Energy and Water to US Congress, 2006.

Furthermore, while the volumes of water we have quoted may seem very large, they are small by comparison to some other uses of water. For example in the US, and it is most likely the case in Europe as well, the upstream energy sector consumes much less than agriculture, electric power generation, and municipalities, and water consumed by unconventional gas will generally represent a small percentage of total water resource use in each shale gas area. Calculations made in the US indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin[118].

[116] There are many examples of water shortages in the summer, such as in the Netherlands where canals get drier, water deprivation in villages in Romania, restricted supply of water to power plants in Northern Germany, etc.
[117] http://ec.europa.eu/environment/water/water-framework/index_en.html
[118] US Department of Energy, *US Modern Shale Gas Development: a primer*, April 2009 http://www.fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf

However, because the development of unconventional gas is new in Europe, these water needs may still challenge supplies and infrastructure. In addition, the comparison with the US is to be taken with some caution as, on a per capita basis, the country has 3 times more fresh water resources than Europe[119]and interestingly, the areas where shales are present and being developed, from the South towards the North East, correspond to areas of low water scarcity. So the water challenge in the US is not one of shortages, but rather of usage and protection. As mentioned in the first part of the paper, the problem has become one of allocation of water to shale gas operations in the context of proximity of major cities, such as New York. In Europe it will ultimately be a question of allocation and competition among sectors, within a context of existing risks of water shortages.

Therefore the bigger picture described above should be taken into account by governments when making their energy policy choices. A corollary to the question of scarcity and allocation is that of water procurement cost. A study carried out by the American Water Works Association in 2007 indicates that the price per unit volume to be paid by operators in Europe will be significantly higher than in the US. According to the study, water is more than 10 times expensive in Europe than in the US, with an estimated average cost of €3.4/m^3 versus €0.4/m^3 in the US. This is one element underpinning higher unconventional gas completion costs in Europe.

All the questions handled above, i.e water scarcity, competition with other existing sectors, concerns of local communities, regulations on water protection, and high exploitation costs, bolster the need for operators to make significant improvements in the efficiency of water use in drilling and fraccing operations. This requires further technological innovations, in addition to establishing communication with local water planning agencies, state agencies, and regional water basin commissions. In many European countries there will be little or no choice. In the US, an intense debate about the risk of severe water shortages in one or two decades has already emerged.

6.2.2 Land access

Accessing land surfaces is one of the two biggest challenges unconventional gas operators will be facing in Europe, together with higher costs than in the US. (The land access question is not so much a challenge in the US.)

We showed above that once core areas of shales and tight sands have been identified, the absolute size of acreage required to drill 600+ new wells/year in not so large on a European scale. However, this is not true in the exploration phase, which is currently ongoing, and more generally it masks constraints on surface accessibility and geographical distribution of wells across Europe.

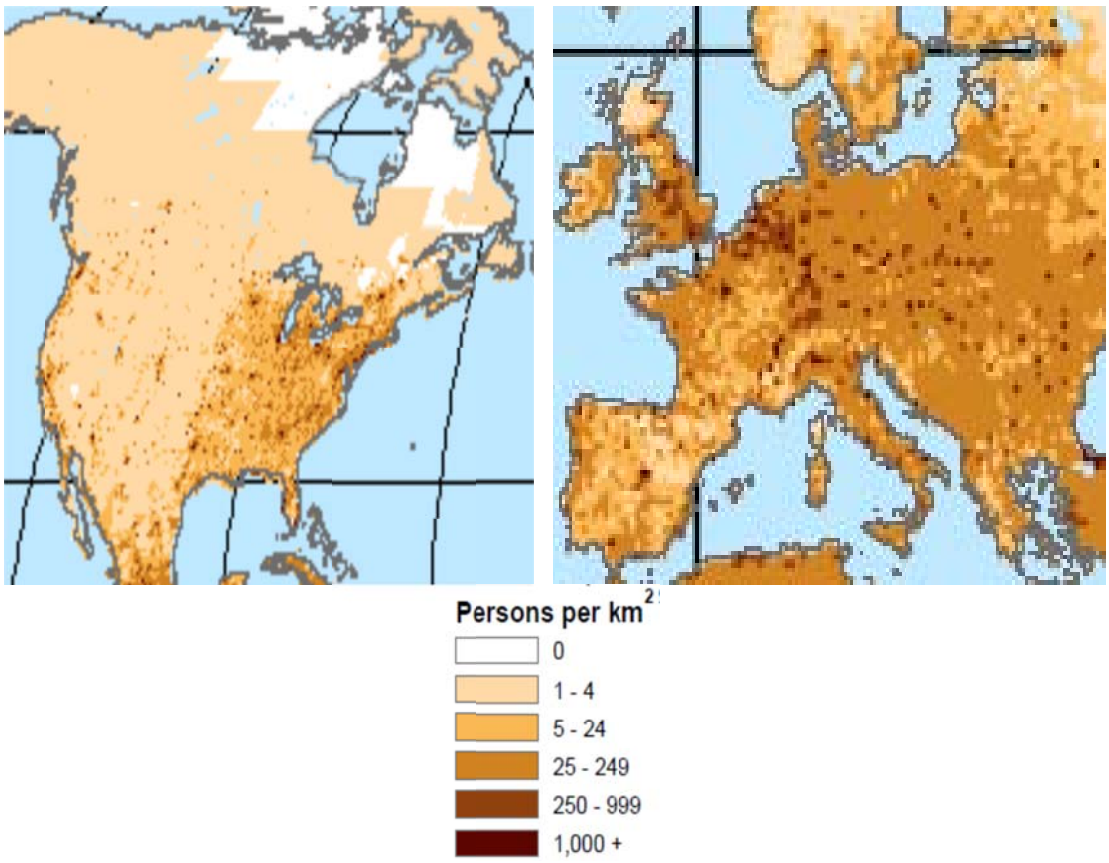
The question of land access has two major dimensions valid across Europe. The first is about spatial constraints to drilling and laying out the necessary infrastructure for unconventional gas exploitation. The second is related to accessing private land once concessions have been awarded, and this issue is embedded in local attitudes towards unconventional gas operations.

[119] Total freshwater resources amount to 4,417,003 km^3 in North America, of which 97% is groundwater. In the US freshwater resources amount to between 6,000 and 15,000 cu m per person per year, vs between 1,700 and 15,000 cu m per person per year in Europe. Source: UNEP- vital water graphics 2008.

Spatial constraints A general problem is that most operators cannot access 100% of the surface they were awarded through concessions, for physical and regulatory reasons. This increases the limitation that concessions granted in Europe are generally too small to perform the exploratory and appraisal drilling needed to identify core areas in shales and tight sands. The problem is linked to population densities, the related presence of numerous buildings and infrastructure, and the protection of many areas by law for environmental and safety reasons.

Figure 6.4 shows that many unconventional gas deposits in Europe lie beneath highly urbanised areas. Indeed, Europe is generally more densely populated than the US (Figures 6.4 and 6.5), and in particular Northern Europe (i.e the Netherlands and Northern Germany, such as Lower Saxony).

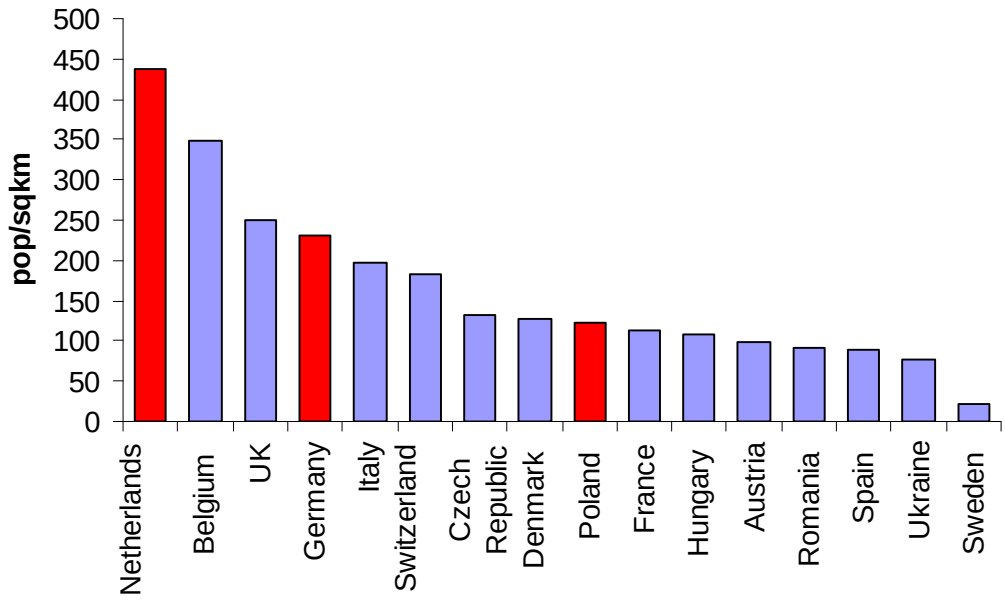
Figure 6.4: Population density in North America and Europe



Source: CIESIN

High population densities mean that there are many buildings and infrastructure scattered all across regions, and safety zones around these regions also occupy space. Thus there are numerous “no-go” areas across every region and country, and the only non-controversial areas allowing drilling are agricultural land. A non-exhaustive list of areas where drilling is not allowed is summarised in Table 6.3

Figure 6.5: Population density in Europe by country



Source: United Nations Statistics Division 2007

Table 6.3: Generally restricted areas

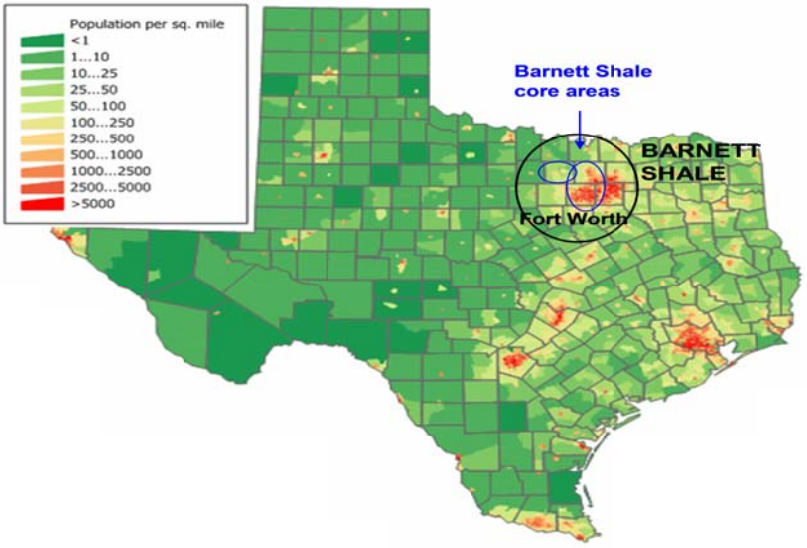
Go areas	Open agricultural areas
No go areas	Buildings Surface water Archeological monuments Roads Railways Overhead power lines Existing safety zones Buffer areas around infrastructure Drinking water production areas

Source: Author

A good illustration of this can be found in the map of the Baltic Depression Basin in Poland later in this section (Figure 6.9).

However in the US, many shales are also located in densely populated areas, such as the Barnett Shale in Texas. Figure 6.6 shows that the Barnett Shale lies beneath the fourth largest metropolitan area in the U.S, and the largest in Texas. Despite the very high density of the population in that area (706 people/km^2), the Barnett Shale has been in a full scale development phase since the early 2000s, with more than 1,000 natural gas wells already drilled as of December 2009, and in all types of zones, including residential ones.

Figure 6.6: Map of Texas, Barnett shale and population density



Source: US Census Bureau, 2000 Census, company reports

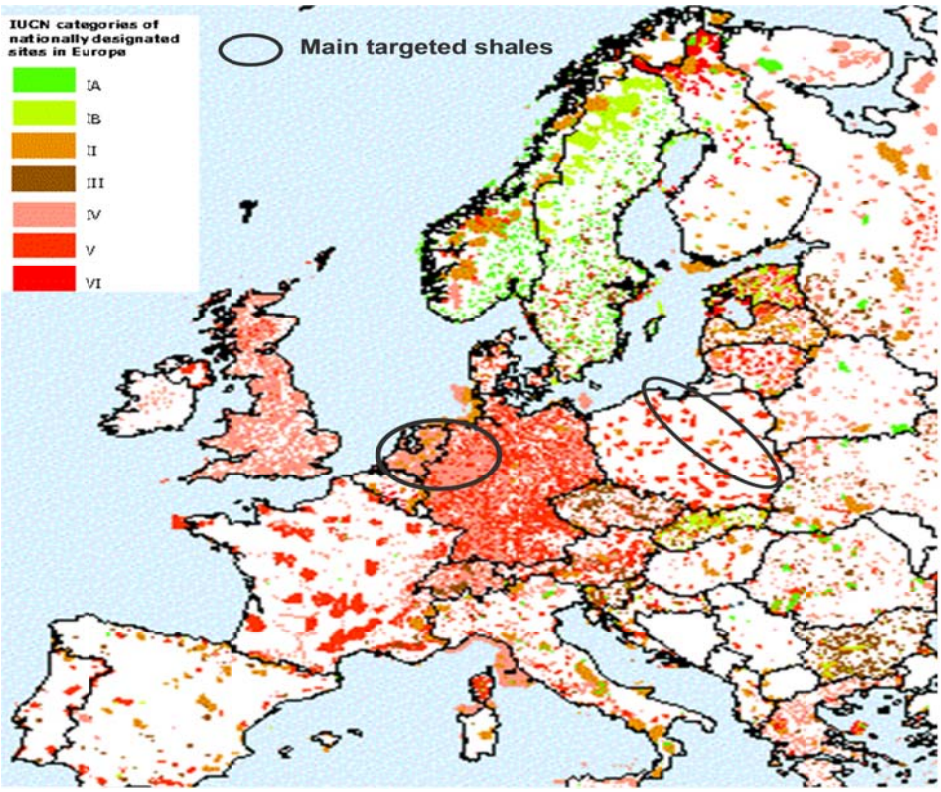
So it is possible in the US to drill in urban areas, despite the greater complexity of logistics and safety risks. The conclusion of this analysis is that the presence of large urban areas in the vicinity of shale deposits is not an absolute physical obstacle to land access and unconventional gas-related logistics and operations. The two real underlying challenges are securing acceptance by local communities, and regulations on the location of drilling, fraccing operations and safety. Both are favourable in Texas. Therefore, in fine, land access in relation to high population densities in Europe is a matter of policy and regulations. Europe has more restrictive provisions on drilling locations, and safety is a top priority.

The second constraint on spatial distribution of wells and infrastructure is related to the legal protection of many areas on environmental grounds. These protections take place at different levels. The United Nations Environment Programme compiles a list of Protected Areas that are covered in national environmental laws. The EU has implemented a biodiversity policy called Natura 2000, following two directives on habitats and bird protection[120], and enacted the Water Framework Directive, one objective of which is to protect groundwater sources. Finally, there are also national and local regulations that complement these supranational provisions. As a result, many areas within or surrounding concessions in Europe cannot be accessed for unconventional gas exploitation purposes. The existence of these "no-go" areas is a key problem.

Figures 6.7 and 6.8 give an indication of the protected areas and which basins are the most affected.

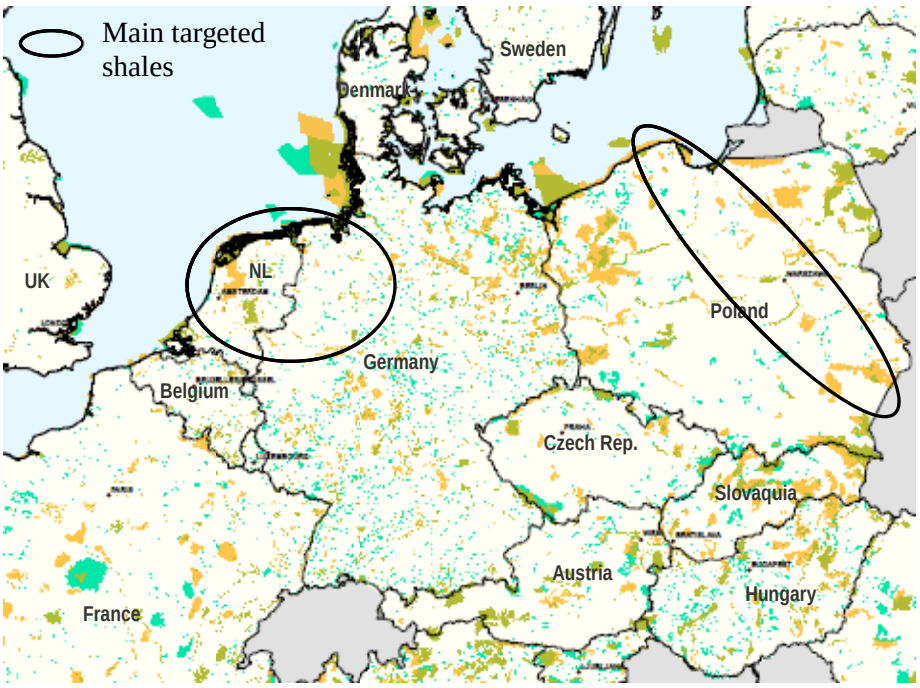
[120] http://ec.europa.eu/environment/nature/index_en.htm

Figure 6.7: Nationally protected sites according to their IUCN category classification



Source: European Environment Agency

Figure 6.8: Natura 2000 sites



Source: European Commission - Environment

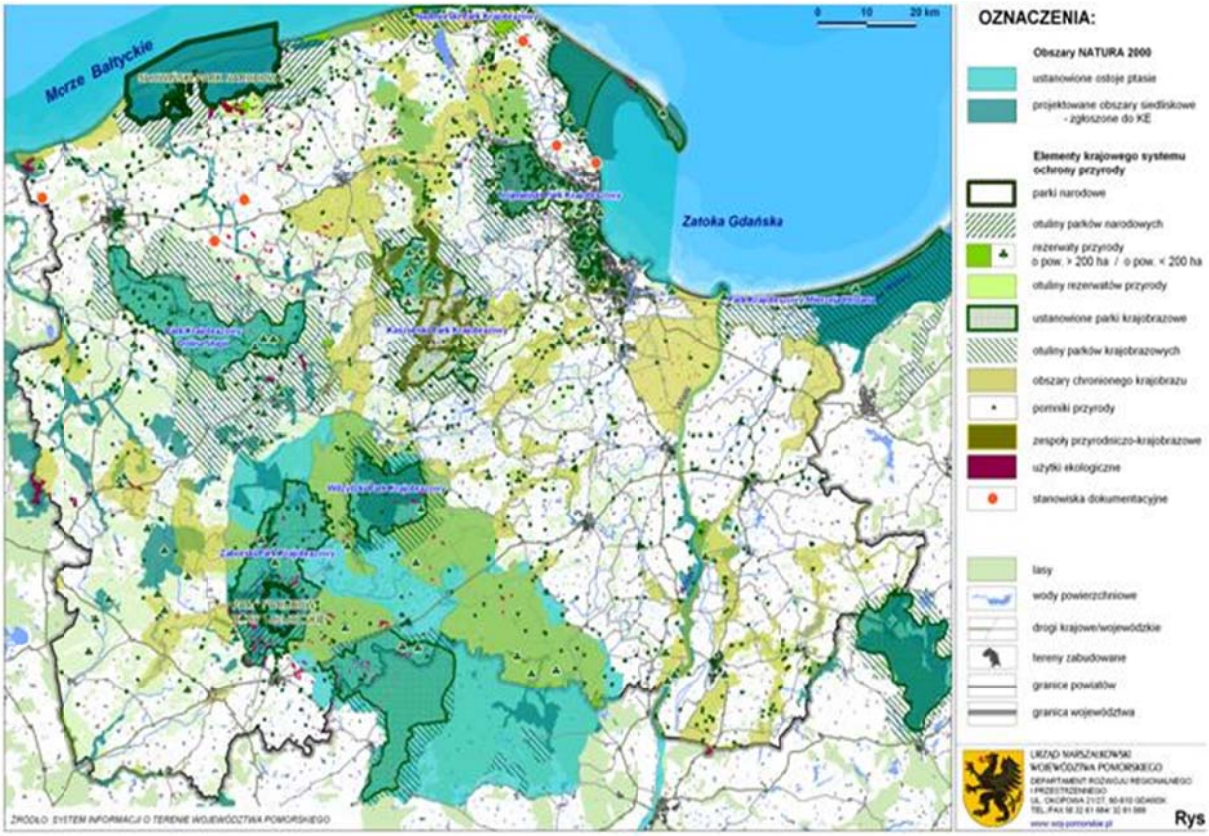
The maps show very clearly that the extent of protected areas in Germany is huge and densely distributed. Almost the whole country appears to be under the IUCN classifications, including the Lower Saxony Basin. These environmental regulations present a tremendous challenge to unconventional gas drilling and supply chain infrastructure building in these areas. The same applies to the Netherlands, in particular the western part. The two main Polish concession areas, (the Gdansk Depression and Warsaw-Lublin Trough) also include numerous protected areas, but with much less density than Germany or the Netherlands.

If we refine the analysis at a basin level, taking the Gdansk Depression as an example, the obstacles to land access due to urbanisation and environmental protection of sites are seen to be quite significant, even if they appear to be fewer at a less detailed level of analysis. This is very clearly illustrated in Figure 6.9.

This map includes Natura 2000 sites (in blue), nationally protected sites (parks, reserves, landscapes, sculptures, forests, lakes, groundwater) and urban areas. It clearly shows that the concession area is dotted with restrictions.

The conclusion is that to fully grasp the problem of surface accessibility caused by spatial constraints, it is necessary to do an analysis at the most local level possible. Only once the operator has the concession and intends to get planning permission, do these issues become clear.

Figure 6.9: Map of the Baltic (Gdansk) Depression



Source: Urzad Marszalkowski Woiewodztwa Pomorskiego

The factors constraining the choice of drilling locations and scale of operations are primarily of a regulatory nature. Therefore only reforms of the environmental and E&P frameworks allowing more operational flexibility can solve the problem of lack of space in Europe. On the market side, technological improvements enabling more efficient and commercially viable gas recovery is the only solution. A central pad location containing wells with extended reach (several kilometres laterally) and even more wells simultaneously (10 wells per pad have become common practice) can be used to overcome some restrictions and get access to a larger subsurface area. For example, in the Netherlands it is allowed to drill horizontal wells 2 kms below construction and houses. However there is an economic limit to this design.

Ability to access private surfaces and local support Once a company has been granted a concession and a right to drill by the mining authorities, it needs to get access to the land. European land ownership rules are different from those in the US. While in the US, private land owners own mineral rights, and can thus control how and when resources are developed as well as get up to 25% royalties on the production, this is not the case in Europe, where land owners only own surface property rights.

Accessing land in Europe therefore follows slightly different models than in the US. A company has three options for accessing the land:

*Negotiation of a "rental" fee for land use
*Compulsory purchase by government
*Acquisition of the land by the company

These procedures are standard across developed countries and based on negotiations with every individual land owner. What matters is the extent to which these are easy and successful in practice. Expropriation procedures are usually to be avoided as they are lengthy and can damage relationships with the local community. So is it easy to negotiate access to the land or land purchase with European private landowners? The answer to this question depends in our view on three elements. First, the number of landowners with whom negotiations must be carried out; second the degree of support from local administrations; and third the local economic, social and environmental conditions surrounding the location of the acreage, translating into the degree of local acceptance of gas operations.

In some countries, land ownership can be very fragmented, which leads to lengthy negotiations with numerous land owners and delays obtaining planning permissions. This is particularly true in Poland, where there are many small farms in the North and around Lublin[121]. Furthermore, it is important for operators to gain support for negotiations from local authorities, which often have an important say in many European countries. It is not only about complying with local policies and regulatory sytems, but also addressing the needs of local communities.

Indeed, there are many challenges to securing acceptance for unconventional gas activities from local populations. The first and biggest one is linked to the fact that landowners are not associated with revenues generated by exploration and production activities. Therefore their interests are misaligned with those of gas producers. As we mentioned in chapter 3, in the US landowners get land use fees plus royalties on gas production as they own mineral rights. Furthermore, the reluctance to make land available even at a fair fee is likely to be higher in

[121] The average farming plot size is only 12 ha in Poland, compared to 160 ha in Oklahoma and 210 ha in Texas, according to Bernstein Research *European shale gas- So will it or won't it work?* April 2010

countries which are richer and where the protection of the environment and landscapes is valued. A good example of this kind of situation can be found in Sweden, where Shell has faced local opposition to drilling. [122]

Thus we think it will be key for producers and national authorities supportive of the development of the resource to find solutions that give surface owners satisfactory financial compensation, and even incentivise them by creating a form of participation in profits. Operators also need to ensure that the economic benefits of new gas activities trickle down to local communities through revenues and job creation, and offset environmental or social costs. Some ways to meet these objectives could be the contribution to funds for local development[123] and ensuring that local workers replace "imported" ones over time through training.

6.2.3 Economic profitability (costs and breakeven prices)

In this section an investment analysis is performed for shale gas basins in Poland and Germany, with the assumption that they would individually deliver 1 Tcf/year of gas for almost 40 years following an exploration and ramp-up period of 5 years, although we saw in the previous section that this is an optimistic production forecast both from sub-surface and surface viewpoints. We exclude the Netherlands from this analysis as it is too small a country to support this approach. This does not mean the Netherlands will not produce unconventional gas, but rather that it cannot produce as high quantities as 1 Tcf/year, as we mentioned in section 6.1.

The purpose of the exercise is twofold: to link economics with our production scenarios and to use a consistent starting point across basins to identify cost and breakeven prices required for these projects to be commercially viable, and compare the results with the costs of alternative sources of gas supply and European gas prices.

Modelling methodology and general assumptions An explanation of the methodology and assumptions used in the economic model is set out below:

- *Starting date and asset life duration*: for shale gas basins we assumed an exploration and appraisal period of 3 years starting in 2012, leading to the drilling of a maximum of 20 wells within that period. We assumed a development decision is made after that period and development starts in 2015, with a steep production ramp-up of 5 years before reaching a level of 1Tcf/year from 2020. We assume an asset life of 40 years, which is in line with successful US tight gas assets and expected life expectancy of US shale plays, although the duration can be even longer (60-65 years).

- *Production curve*: We selected a US analogue for each play that gives us the best approximate production curve. We used Woodford for the German play in Lower

[122] Shell's drilling program has met with resistance from local residents and environmentalists. Neighbours to the planned drilling site appealed to the Environmental Court over an earlier approval of test drilling by the county administrative board. Concerns focus on the potential pollution of the region's groundwater supplies. Furthermore, the political centre-left opposition has vowed to stop Shell's gas E&P activities should it win elections scheduled for the end of September 2010.

[123] A comparable system is already in place in the Netherlands. The Dutch Mining Act can require license holders to make annual contributions to a Mining Damage Guarantee Fund aiming at compensating persons suffering property damage as a result of mining and hydrocarbon activities. Both Shell and ExxonMobil contribute to this fund.

Saxony, the Fayetteville for the Baltic Depression and the Marcellus for the Lublin Trough.

- *Number of wells*: For shale basins, we developed a drilling plan along the lines of the model set out above (Section 6.1, Figure 6.2) to identify the annual number of wells that need to be drilled to produce 1 Tcf/year of natural gas over a 20 year period.

- *Costs*: We made assumptions about capital and operational expenditures per well, and included cost reductions and optimisations over time resulting from the Learning Curve theory[124]. Well cost estimates for each play are based on data provided by Schlumberger and are summarised in Table 6.4. The drilling and completion (D&C) cost reduction curve is based on improvements reported by US operators like Chesapeake, Exco and Talisman since 2008[125], adjusted to the European business context. A detailed explanation of well costs in general and the backbone of the specific cost assumptions in our model can be found below.

- *Discount rate*: we used a 10% nominal discount rate and a discount date of January 2010.

Unravelling the natural gas cost structure The concept of costs is one of the most confusing aspects of the gas industry. Full-cycle costs fall into four general categories, which are valid for both conventional and unconventional gas E&P: finding and development costs, production costs (also known as Lease Operating Expenses or LOE), general and administrative and interest expense. We will focus on the two first components, i.e F&D and LOE, as they account for 80% of total full-cycle costs of producing gas on average[126].

F&D costs F&D costs are capital expenditures associated with finding and developing gas reserves, i.e acquiring land, exploring it, drilling and completing (D&C) wells. While land acquisitions amount to almost half of total F&D costs[127], D&C costs are the most monitored sub-categories and account for close to 100% of well costs. As a rule of thumb, well costs are split 50/50 between drilling and completion costs. However, a new trend in the US is the rising share of completion costs due to the increased number and intensity of fracs per well. A detailed breakdown of D&C costs for a typical Haynesville well is shown in Figure 6.10. It gives an indication of how the capex assumptions we used in our model were calculated, although the exact proportion of each cost item varies between shales, depending on location and geological characteristics.

Figure 6.10 clearly shows that directional drilling and cementing work captures the largest share of drilling expenditures, followed by rig (i.e day rates), casing and mobilisation/demobilisation costs. Stimulation (i.e fluid fracturing) work accounts for the highest share of completion investments.

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[124] The Learning Curve Theory mathematically describes the ability of organisations and individuals to improve their performance over time. The theory applies to repetitive tasks and has been shown to be applicable to drilling. SPE paper 15362, J F.Brett and K K.Millheim *The Drilling Performance Curve: A Yardstick for judging drilling performance*, 1986.

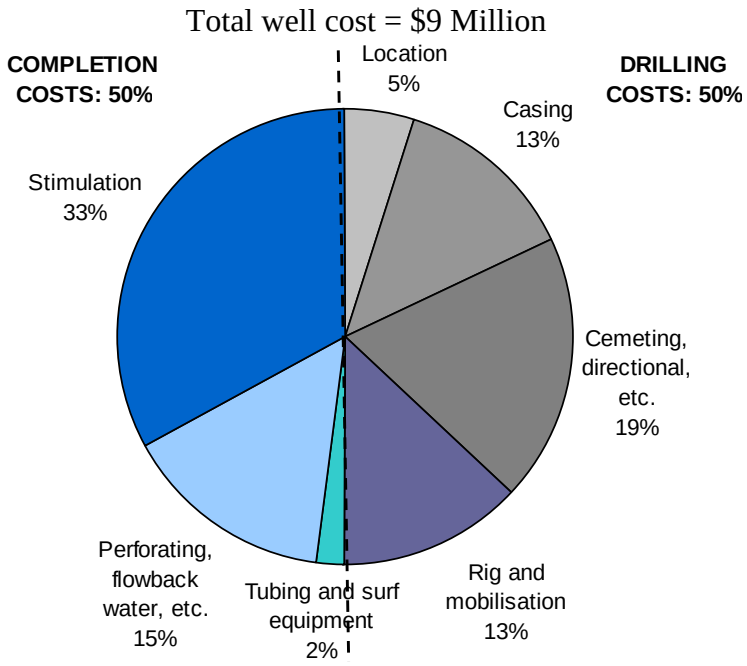
[125] Chesapeake reported D&C cost reductions of 27% between 3Q 2008 and 2Q 2009 in the Haynesville. Talisman reported D&C cost reductions of 50% between 2008 and 2009, and 15% between 2009 and Q1 2010.

[126] Barclays Capital Weekly Kaleidoscope *Understanding Gas costs*, 11 August 2009

[127] Barclays Capital Weekly Kaleidoscope *Understanding Gas costs*, 11 August 2009

Moreover, horizontal wells generally have D&C costs two to four times higher than vertical ones as they are more challenging technically and require more fracturing. Thus, drilling costs alone range from $0.5 to $10 million or more[128].

Figure 6.10: Drilling and completion cost breakdown in the Haynesville



Source: Exco

Lease Operating Expenses (LOE) LOE are costs incurred to produce gas after the well has been drilled and completed. Therefore they include costs of gathering, processing and shipping the gas to a market point, in addition to labour, overhead, maintenance and work-over costs. Operating costs vary depending on the particular characteristics of each reservoir, the chemical composition of the gas, well pressure and distance to pipelines. Furthermore, as LOE costs are ongoing cash costs incurred in operating an existing well, they act as a "floor" price, below which producers will start losing money on a cash basis, and thus curb production. In the US, this floor price amounts on average to about $2/mcf[129].

Well costs in Europe and assumptions in the economic model Unconventional gas wells in Europe are expected to be very expensive, compared to the US and conventional gas wells in Europe, especially initially. High costs, together with local acceptance, are the two biggest challenges to the European investment climate surrounding unconventional gas compared to the US. After mentioning the main cost drivers for gas exploration and production activities, we will attempt to look at whether cost reductions can be achieved and at what pace.

High well costs and levers Several factors drive well costs up in Europe, and they are structural.

F&D Cost drivers There are four main cost drivers in Europe: geological depth, regulations, cost of services and cost of building infrastructure. All these drivers are less favourable than in the US.

[128] Barclays Capital Weekly Kaleidoscope *Understanding Gas costs*, 11 August 2009.
[129] Extrapolation from data in Barclays Capital Weekly Kaleidoscope *Understanding Gas costs*, 11 August 2009

- Geological depth: we showed in chapter 1 that shale depths in Europe are on average 1.5 times greater than in the US, translating into the need for powerful rigs, more powerful pumps and more fraccing fluids (especially as less is expected to flow back and be re-used), while the cost of water is 10 times higher than in the US.
- Regulations: we are referring in particular to labour laws and environmental and safety regulations. Examples that differentiate Europe from the US relate to well design (around four casing programs are required versus only one in the US), and the higher level of wages and regulated working time which increase the size of manning crews on the rigs.
- Higher cost of services: the service industry in Europe is oligopolistic, with very few specialist companies and staff, compared to the US. This lack of competition will contribute to maintaining rates at a higher level. For example rig rates in the unconventional gas development phase in Europe would be on average 20% higher, in the order of $25,000-$30,000/day according to interviews with various service companies, compared to around $20,000/day in the US as of 2010.
- Cost of building infrastructure: we are referring to building roads, processing facilities and transportation pipelines.

Let us now enlarge the cost analysis to other unconventional gas resources, i.e CBM and tight gas.

CBM well costs Europe has adopted horizontal drilling for the exploitation of CBM, but this activity is in its infancy. In 2010, the inventory of horizontal wells amounted to 10, of which 9 were located in the UK and one in France. CBM was looked at in the 1990s by American companies[130] trying to leverage their technological success at home, which was primarily based on very cheap vertical wells with cheap fracs, such as in the Black Warrior Basin. However there was no development in Europe, due to low permeability and thus insufficient gas flow rates. In 2004 however, costs of onshore drilling decreased in Europe, and horizontal drilling technology coupled with high pressure fraccing was starting to make strides in the exploitation of CBM and tight reservoirs, for example in the Appalachian Basin. This has prompted investors such as Island Gas, Greenpark, and Composite Energy in the UK to revisit the potential of European CBM.

CBM horizontal wells are generally cheaper than shale gas wells in Europe[131], as the deposits tend to be at shallower depths and drilling and completion operations are faster. Therefore CBM is cost competitive relative to shale gas in Europe, but recovered volumes are lower, making this activity hardly profitable at 2010 prices. The future of CBM in Europe will depend more on increasing recovery rates than decreasing unit costs. A major question to solve in this respect is whether technology imported from the U.S is the right one for exploiting European coal beds.

Tight gas well costs Tight gas drilling and completion costs vary from shale gas costs depending on the depth of exploitation. There are two types of tight sand deposits in Europe, “shallow”, as in Northern Germany, and BCGA[132] (e.g the Mako Trough in Hungary), which are deep gas basins. Tight gas developments are currently underway in the Rotliegendes and

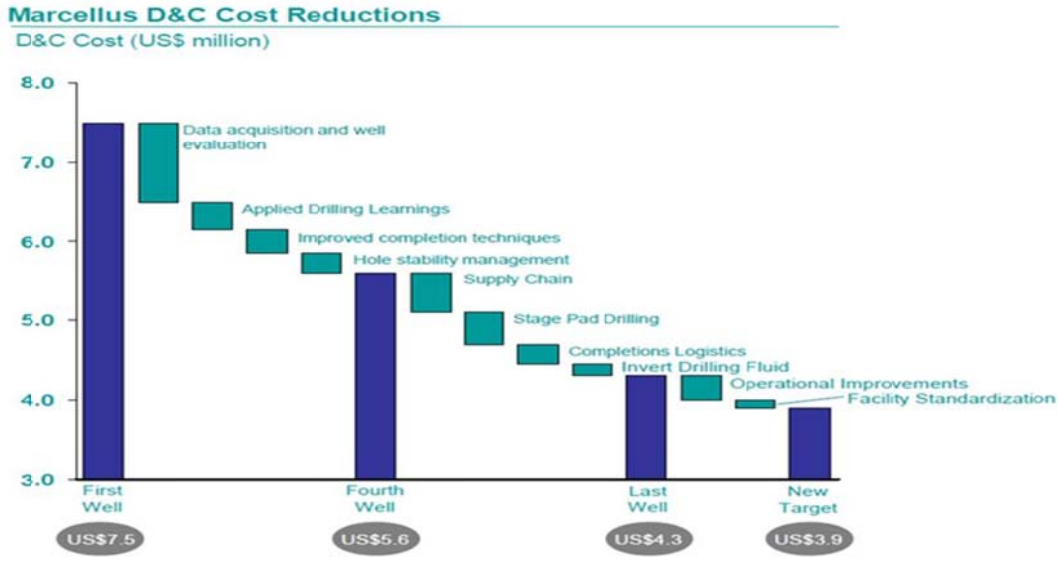
[130] This is the case of Amoco in the mid-1990s and Texaco in the late 1990s in southern Poland. The companies drilled 3 and 8 wells respectively.
[131] According to UK E&P company Composite Energy, CBM well costs in Europe amount on average to 50% of shale gas well costs, and are five times higher than CBM well costs in the US.
[132] See the Glossary.

Carboniferous of Germany, offshore Holland and the UK, and efforts are being made to develop basin-centered gas accumulations in the Pannonian Basin of Central Europe (e.g in Hungary). Drilling in "shallow" tight gas is expected to be cheaper than shale gas drilling and the fact that it is already ongoing, for example in Germany (GdFSuez and Wintershall operations), demonstrates that it can be profitable. However the comparison is more uncertain for drilling costs in deep gas basins. According to Schlumberger, fraccing costs are comparable with shale gas since, although fraccing fluids used in tight sands are more expensive than water, the pressure needed to fracture rocks is lower.

To what extent can F&D costs be reduced in Europe? F&D Costs for unconventional gas can be and will be reduced in Europe, the question is how and to what extent. There are several factors that can contribute to cost reductions along the value chain: cost optimisation from more efficient operations during the development phase, higher competition in the European service sector, and further technological progress.

Areas for cost reduction potential Based on the US experience but in a European context, cost reduction can mostly be achieved through time saving and increasing quantities recovered, which can be achieved by faster drilling, drilling in pads, and fraccing more stages simultaneously. In the Marcellus for example, average drilling times have decreased from 40 days for the first wells to 30 days within a year[133]. Faster drilling can be achieved by knowing how and where to drill with more accuracy, and this information is collected through the feedback loop provided by drilling and fraccing more and more wells and the continuous integration of this new information in new drilling operations. The other way of improving drilling decisions and optimising well placement is by using subsurface mapping tools. We mentioned above (Section 5.4) that independents do not utilise the opportunities provided by these tools because of insufficient investment. In our view, more investment in technologies that improve reservoir characterisation and the identification of sweet spots would reduce costs further in the longer-term.
Our analysis is confirmed by Talisman Energy's experience illustrated in figure 6.11. Another area of cost reduction shown in Figure 6.11 is operational improvements in the supply chain.

Figure 6.11: Cost reductions in the Marcellus



Source: Talisman Energy

[133] Chesapeake company reports

However for the two reasons mentioned earlier, even in a successful development scenario in Europe, there will be fewer opportunities to realise operational efficiencies and optimise costs compared to the US. The first is the structurally higher cost of doing business in Europe related to regulations and a less competitive service industry in Europe. The second is a reflection of reduced possibilities to realise economies of scale, due to lower recoverable volumes, smaller surfaces to drill and a greater number of concession holders in a given area that are unlikely to cooperate on operations. Working together to plan operations in a way that ensures a continuous workload for rigs or fraccing equipment is key to driving operational costs down in Europe, but is unlikely to happen.

Interviews with experts in service companies such as Schlumberger support this point. A 50% decrease in development costs seems to be the best that could be expected for European drilling operations in the long run, versus at least 3 times in the US, using the Barnett case as a reference.

Competition in service industry as explained in section 6.2.5, the service industry in Europe has different dynamics to its American counterpart and this contributes to a high cost structure. North Western Europe is dominated by a handful of international service companies, while the Central and Eastern Europe sector is dominated by National Oil Companies (such as PGNiG in Poland) and is yet to be liberalised. We can expect these markets to open slowly over time as compliance with EU competition laws improves.

Technological innovation technological progress is driven by R&D investments and accumulation of operational experience. There are several areas where R&D by the industry is needed to decrease development costs:

- Characterisation and development of new resources, e.g improving the detection of sweet spots through better integration of seismic data with cores and logs. Optimising completions by developing stimulation software that predicts rock fracture initiation and propagation based on true 3D imaging. And improving the integration of natural fracture networks and hydraulic fractures.
- Drilling technologies: developing and using hybrid rig solutions (i.e rotary and CTD combination), increasing the number of wells that can be drilled per pad, improving extended reach and multilateral drilling technology. And developing geological steering capabilities in order to land and place wells optimally (i.e in the sweet spots) through new or more sophisticated real-time tools.
- Fraccing technologies: increasing the number of simultaneous fracs, minimising water use in fraccing, as water sourcing in Europe is so much more expensive than in the US, developing new technologies to monitor fracs (especially in the exploration phase) through single well micro-seismic, and better identification of candidate wells for re-fracturing.

Conclusions from the investment analysis: cost and breakeven price comparisons with alternative sources of natural gas

Cost assumptions As a result of an analysis of the cost drivers, we have used the following shale well cost assumptions for Poland and Germany, based on data provided by Schlumberger. The costs are in 2010 dollar terms. The estimates assume the drilling of vertical wells in the exploration phase and horizontal wells with 10 frac-stages in the development phase.

Table 6.4: Initial well cost assumptions

Play	Poland- Baltic Depression	Poland- Lublin Trough	Germany- Lower Saxony
Depth (m)	2500	2300	2000
Seismic and data acquisition ($ M)	14	14	14
Surface capex ($ M)	50	50	50
Well capex ($)			
Exploration	11,8	11	8,4
Development	13,2	12,5	9,9
Opex ($/mcf)	2,5	2,5	2,5

Source: Based on data provided by Schlumberger Business Consulting

It is important to remember that these are estimated initial cost levels for respectively the testing and development phases, without taking into account any operational performance improvements. Furthermore, the cost assumption made in the exploration phase is for vertical wells. But some operators have chosen to drill horizontal wells straight away in order to maximise the potential for results, leading to well costs in that phase that are up to twice as high, i.e around $20 Million. This is for example the case with PNGiG's well drilled and fracced in Markowola in South East Poland in August 2010[134]. Furthermore, Aurelian Oil and Gas reported in Q1 2010 a tight gas horizontal well cost of $19 Million in its Sikierki asset, in the Rotliegendes area of Poland.

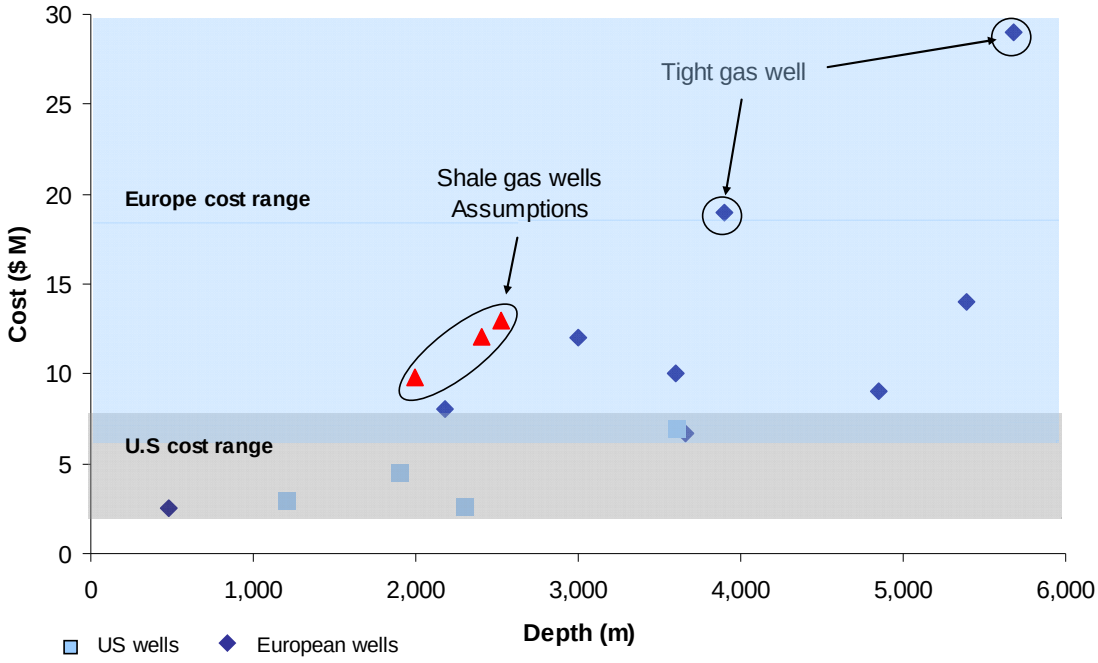
As mentioned above, in our model we have assumed cost optimisation and reductions effects as a result of increased understanding of subsurface characteristics and well behaviours, and how supply value chains function in the country. We have considered various parameters of cost reduction pace, with a 50% reduction in drilling and completion costs achieved within a range of 5 to 10 years, due to the large number (several thousands) of wells drilled in this period. The impact on project breakeven prices is significant, as we show through our range of results below.

Beside quantifying European unconventional gas well costs, it is important to understand how these costs may compare with the US context and alternative sources of gas supply to Europe , i.e domestic conventional gas E&P and imports from Russia, Algeria (Norway in included in Europe for this exercise) and LNG during 2010-2030. Will drilling the European unconventional gas plays be much more expensive and what implications would it have on their development?

Conventional gas in Europe Figure 6.12 below provides a picture of well cost ranges for conventional E&P wells across Europe and US shale gas wells, and how our range of cost assumptions fit into this picture. The sample we used for conventional gas wells in Europe includes Germany, the Netherlands, Poland and Romania.

[134] http://oilprice.com/Energy/Natural-Gas/Is-European-Shale-Gas-the-Real-Deal.html

Figure 6.12: Gas well cost ranges in Europe and the US



Source: company reports, Wood Mackenzie – US wells are shale wells only.

The conclusions from this cost analysis are clear and quite unsurprising. First, unconventional gas well costs are roughly 2 to 3 times higher than in the US, for structural reasons which we have already mentioned. Second, within Europe they are on the high end of the cost range compared to conventional wells, due to greater drilling depths, and more costly technology and designs. Tight gas wells in particular appear to be far more expensive than the assumptions for shale wells, ranging from $18-28 million, principally because these projects involve much greater drilling depths.

Imports Let us look at the relative cost level of producing unconventional gas compared to alternative investment opportunities to supply gas to Europe from new piped gas from Russia, North Africa and the Caspian region and new LNG projects. From an economic point of view, the most important benchmark is the breakeven price. In this study this is a measure of the gas price needed to achieve a 10% nominal return, and is independent of gas price forecasts. It reflects costs, fiscal terms and production profiles, as well as the return on investment required by investors to make a final investment decision. Given our assumptions on start-up date and ramp-up time, our breakeven prices give indicative cost levels for shale gas projects starting production around 2015.

The caveats attached to such an analysis are that nobody knows how much gas will actually be produced from shale wells. Therefore making an assumption on EUR (Estimated Recoverable Reserves) using US analogues is the only way currently to calculate a unit cost. Moreover, cost data for pipeline gas and LNG are averages that do not reflect the fact that actual supply costs for specific individual projects could differ significantly, depending on the detailed design of each project.

We have calculated breakeven prices for various shale plays in Poland and Germany according to different scenarios of cost reduction. For Germany we modelled shale gas

development under two fiscal regimes, the favourable Tight Gas Regime in the event shale gas becomes eligible to it, and the normal onshore regime (see the discussion on fiscal regimes below). The range of price results is shown in Table 6.5.

Table 6.5: Breakeven prices for shale gas plays in Germany and Poland ($/mcf)

GERMANY	Tight Gas Regime	Onshore Regime
No cost optimisation	$11.45 (€ 29.3/MWh)	$16.28 (€ 41.7/MWh)
Slow cost optimisation	$8.3 (€ 21.2/MWh)	$11.8 (€ 30.2/MWh)
Fast cost optimisation	$7.8 (€ 20/MWh)	$11.1 (€ 28.4/MWh)

Depending on the speed of cost optimisation and the fiscal regime that is applicable, the cost of developing shale gas in Lower Saxony, including a 10% remuneration on investments, ranges from $8-11.5 under the Tight Gas regime, compared with $11-$16 under the normal onshore regime. These prices are very sensitive to the fiscal regime as well as to increases in capital expenditures.

POLAND	Baltic Depression	Lublin Trough
No cost optimisation	$12.1 (€ 31/MWh)	$11.7 (€ 30/MWh)
Slow cost optimisation	$8.7 (€ 22.2/MWh)	$8.4 (€ 21.5/MWh)
Fast cost optimisation	$8.2 (€ 21/MWh)	$7.9 (€ 20.2/MWh)

Source: Author

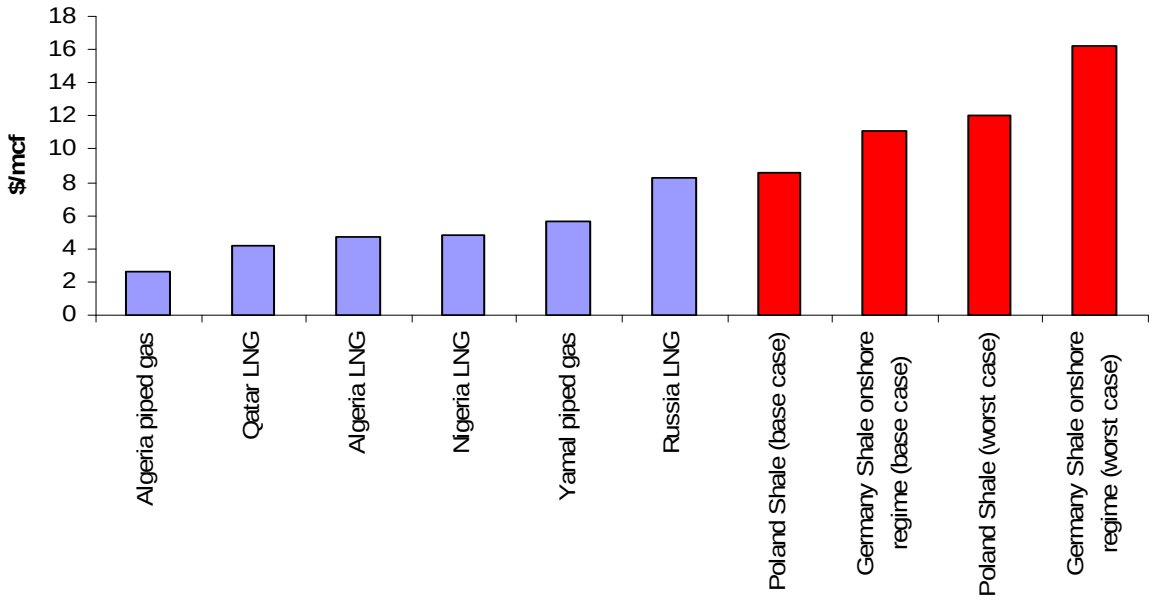
Shale gas development projects in Poland would be sanctioned at a price level ranging from $8-12. So based on our sample of plays in Germany and Poland, breakeven costs range from roughly $8 to $16, and in the event shale gas is eligible for the Tight Gas low royalty regime in Germany, then projects in both countries appear to have similar overall costs. These cost levels seem very high, but need to be compared to costs of new gas sources from Russia, Algeria and LNG projects delivering volumes to Europe around the same period, i.e post 2015.

The IEA has performed such a cost analysis for new supplies to Europe delivered in 2020. The comparison of our cost analysis with results from the IEA's work is displayed in the graph below (Figure 6.13).

From this analysis it is clear that unconventional gas economics will not be cost competitive with imports over the next decade. Furthermore, domestic gas projects will have to bear a CO_2 tax, which penalises them versus gas supply projects outside Europe. Therefore developments are unlikely to be prioritised and very little unconventional gas will be produced if market conditions do not improve, or if investments are only based on market considerations. For these reasons policies promoting unconventional gas will be needed, and are more likely to be implemented in countries that wish to reduce their import dependence (we return to this point below). The required extent of government intervention would obviously also depend on the level of natural gas prices prevailing in Europe, which will be a key determinant of the attractiveness of new unconventional gas opportunities. Therefore we now compare breakeven prices for our shale gas projects with future gas prices (including a perspective on

the past). Prices depend on market fundamentals, expectations and the Long Run Marginal Cost of Supply (LRMC)[135].

Figure 6.13: Indicative costs for potential new sources of gas delivered to Europe, including shale gas, in 2020



Source: IEA World Energy Outlook 2009 pp 481-482
Algerian LNG and pipe gas is delivered to Spain and Italy, Russian LNG (Barents) and Nigerian LNG is delivered to the UK and Yamal gas is delivered to the German border. IEA cost estimates are in 2010 real dollar terms. Qatari and Algerian LNG cost estimates seem high. Russian project cost estimates do not include the 30% export duty. There is high uncertainty on which tax regime will be applied to these new Russian projects. Not included in this analysis are new pipeline gas from Libya or from the Caspian/Middle East region.

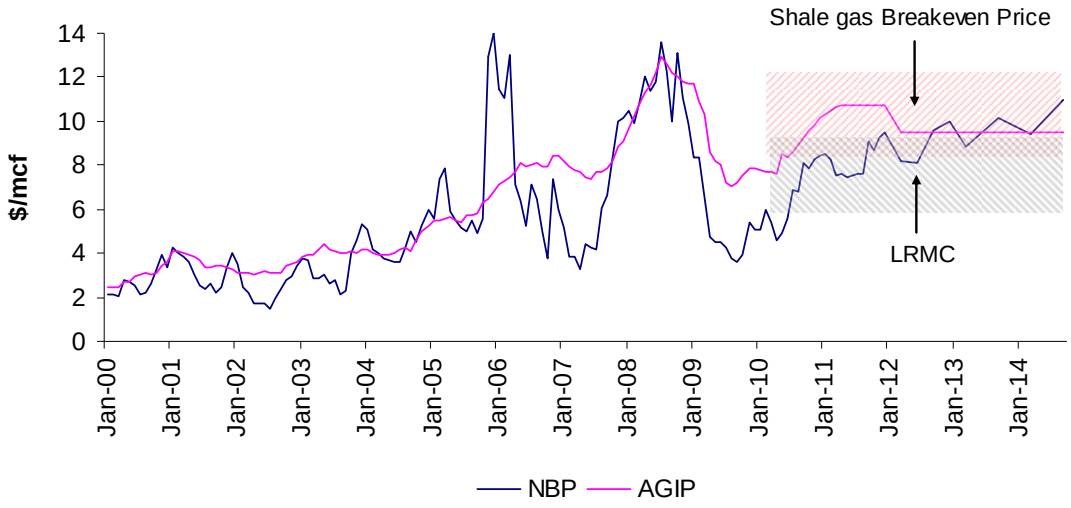
The lowest cost incremental sources of gas to Europe (including Norway) are to be found in North Africa and Qatar, while the largest volumes to be developed for the European market are those in Russia, especially in the Yamal peninsula. Therefore, in the next decade, marginal production supplying Europe will originate mainly from Russia and perhaps new LNG projects in the Atlantic Basin (Nigeria, Russia), defining a LRMC of supply in the range $6-$8,5/mcf.[136]

These are the two sources of supply that will most influence future natural gas price levels in Europe.

Natural gas prices in Europe have in the past (with the exception of 2008) been much lower than the $10 threshold for unconventional gas projects, and market expectations remain below that level as well for the coming 2-3 years (Figure 6.14).

[135] See definition in Glossary
[136] Other North African gas would be below this range; Middle East and Caspian gas will probably be competitive in the lower end of it.

Figure 6.14: European gas prices



Source: Reuters, ICIS Heren

When it comes to price forecasts, we used the most recent NBP forward curve at the time of writing, i.e the June 2010 contract. For oil-indexed prices, we chose the average oil-indexed gas price at the German border (AGIP). The forecasts are based on a generic gas price formula based on fuel oil and heating oil prices over the last 9 months. We used an oil price forecast of $85 in 2010.[137]

The conclusion of this analysis is that new Russian and LNG projects as well as shale gas projects will require prices higher than $6-7/MMBTU, and prices within a potentially overlapping range. Therefore these supply sources will compete for investments, and shale gas projects will likely influence future gas prices.

6.2.4 Energy policies and regulations

We saw that in the US the federal government has played a key role in supporting unconventional oil and gas production, through fiscal policies, R&D funding and a pragmatic approach to the enacting and application of E&P and environmental regulations, even though this is now changing rapidly.

Similarly, the role of governments and EU authorities will be crucial if unconventional gas is to take off in Europe. In the light of lack of geological data, high costs, constrained access to land and strict regulations, the investment framework is clearly not favourable currently. Energy policies improving this context for oil and gas companies are needed and would have to address the two most important areas of regulations affecting unconventional activities, i.e E&P and environmental issues.

We first analyse the legal architecture of energy policies in Europe before assessing how supportive or not these are to the development of unconventional gas.

[137] Generic oil-indexed gas price based on the formula structure described on page 18 of 'LNG Trade-flows in the Atlantic Basin: Trends and Discontinuities', H V Rogers, OIES NG41, March 2010. In the longer-term it is assumed that NBP and oil-indexed prices converge. Oil price forecast is from Barcap as of July 2010.

A complex set-up of supranational and national laws and regulations Energy policies in Europe are crafted at both the EU and national levels. So the two-tier structure of jurisdictions appears to be comparable to the US, with a federal (i.e EU) and a State (national) level. It is important to gain a more detailed understanding on which rules apply to unconventional gas activities and at which level, in order to identify constraints and areas for potential reforms.

The EU does not have an integrated energy policy, and policy-makers traditionally borrowed legal competences from the economic and environmental parts of EU treaties. However an Energy Community Treaty was signed in 2006 giving legal competence to the European Commission, and in 2007 the Treaty of Lisbon outlined the main objectives of an EU energy policy. These goals fall into three categories: the liberalisation and integration of energy markets, the improvement of security of supply and combating climate change. The Treaty of Lisbon also gave formal competence to the EU to ensure security of supply. However, it also re-stated the national sovereignty of Member States on any decision pertaining to the exploitation of its energy resources and the structure of its energy supply.

Therefore, the EU dimension in energy policies, in particular ensuring security of supply, is weaker than in traditional federal states like the US, and the EU has no power over Member States' energy mix or taxation policies on upstream production. However, the EU climate change and energy security package from March 2007 touches on the core of national prerogatives by setting national targets on the share of renewables in energy consumption, on carbon emission reductions and on energy efficiency. Thus, the legal set-up of energy policies in Europe is very complex, with some EU laws and regulations prevailing over national ones in certain areas, and some having weak effects in others.

Table 6.6: Interactions between EU and national energy and environmental laws

European Union	Liberalisation and integration of energy markets	**Water**: Drinking Water Directive (1998) Water Framework Directive (2000) Groundwater Framework Directive (2006)
	Climate change and energy package: 20-20-20 targets	**Biodiversity:** Birds Directive (1979) Habitats Directive (1992) Natura 2000 network
	Improve security of supply	**Mining Waste** Directive (2006)
		Noise Directive (2002)
States	Mining laws and decrees Permitting regulations (spatial planning, drilling, safety, noise, etc.)	Federal or National environmental laws Permitting regulations (Water, EIA, etc.)
	Local E&P regulations	Local environmental regulations (water, soils, chemical use, etc.)

Source: Author

Table 6.6 maps at a high level existing laws and regulations that are likely to affect unconventional gas, at EU and national levels. The text highlighted in blue indicates EU regulations which will have a direct impact on the unconventional gas development framework, in addition to national mining and environmental laws. The texts highlighted in shaded blue are those that will have some indirect or weak influence.

The first observation is that EU environmental laws and regulations will have far more impact on unconventional gas than their energy counterparts, and this impact is direct. We believe that none of the EU energy regulations will have a direct impact on E&P activities, because

this remains within national prerogatives. However the climate and energy package will have an indirect knock-on effect on gas investments by incentivising investments in renewable energy sources. Therefore, EU energy regulations are not central to E&P activities in European countries, and if the EU is to promote the development of indigenous gas supply, the main efforts would have to be in the environmental sphere.

As of late 2010 there was no significant EU political initiative or policy to promote the development of unconventional gas.[138]

Consequently, policy changes at the EU level to foster unconventional gas development can be expected to take time (if they happen at all), and the relevant E&P regulatory frameworks across Europe will be national and local. Their assessment in terms of suitability for unconventional gas operations is thus to be carried out at a national level.

National regulatory frameworks An assessment of the general characteristics and legal obligations in mining laws has been conducted in our selected three countries. A summary of this comparative analysis is shown in Table 6.7. From this empirical analysis we can draw several conclusions which apply across Europe.

[138] The only indirect mention of shale gas reserves can be found in the Second Strategic Energy Review, which states that the European Commission will commence discussions in the Berlin Fossil Fuel Forum "on which additional measures could be taken at Community and national level, and in particular in partnership with Norway, to further promote the increased cost-effectiveness and environmentally compatible access to indigenous EU fossil fuels"

Table 6.7: National regulations for E&P and the environment: comparative summary analysis

	Netherlands	Germany	Poland
Legislative framework	Mining Industry Act 2002 Mining Decree 2002 and 2007 Mining Regulations 2002	Federal Mining Act 1980 and 1991	1/ Geological and Mining Law 1994, 2005 and 23 decrees. 2/ Specific E&P regulations: Regulations on the Detailed Requirements for Deposit Development Plans, Regulations on the Disposal of the Right to Geological Information for Compensation and the Provision of Geological Information to be used free of charge, Regulations on Cases for the Development of Geological Documentation, 2005 3/ Other relevant regulations for E&P: Economic Activity Act 1999 and Foreign Investment Act 1991.
Awarding and administrating authorities	Ministry of Economic Affairs	.Competence of the Landesoberbergamt at States' (Laender) level. .Federal authorities approval is only a formality	.Mining authority is the Ministry of Environment .Authority: execution of mining law, certification of staff and equipment, checking of operations compliance .Approval by municipalities required --> in practice, usually a formality, but they can place additional demands.
Licensing process and terms	.Onshore licenses are awarded on an ad hoc basis, i.e no formal licensing rounds. .Duration of exploration license is up to 6 years. Duration of production licenses is up to 40 years with possible extension. .The State has an option to acquire a 40% working interest in production licenses.	.No formal licensing rounds. Companies can apply for licenses on an area by area basis. .Duration of exploration licenses is negotiable. Duration of production licenses is up to 50 years, but are rarely revoked in practice. .Exploration concession areas are usually 500 sqkm, but no formal restrictions.	.Limited competition, and "1st come - 1st served" principle for awards. .Individual concessions have a maximum size of 1,200 sqkm. .Duration of production licenses is up to 30 years. .Relinquishment is negotiable. .An amendment to the current mining law is expected to come out in 2011.
Drilling permitting	.Shale gas not covered by special legislation .Need to make separate application for each pad and each water well	.More stringent requirements than in Poland and more bureaucratic process .Lengthy process: can take up to 6 months	.Includes environmental permits .No distinction between contractor and operator--> **operators have to partner with Polish contractors and cannot build their own operating organisation** .Certification of staff and equipement by Polish authorities required. In practice, only Polish staff can be certified. **This is a major bottleneck.** **.Specification of exact location of well in the site required** .Any deviation to development plans is penalised and requires new applications. **This is not suited to the flexible nature of shale gas drilling operations**. However application for pad drilling possible. .Restrictions on length of lateral drilling .Permit valid for 6 months only .Need to comply with local laws (municipalities) .**Lengthy process: 3 to 6 months --> Not suited to intensive drilling operations** .No well-spacing regulation --> **Favourable to drilling-intensive operations.**
Water access	Regulated by the Water Act	*No information found*	**No restrictions on volumes** in mining law, but this will likely change.
Environmental regulations	.Noise permit required .Water: Groundwater Act, Act on the Pollution of Surface Water- Responsibility of the Water Board .Application of EU policy Natura 2000 for protected areas, and of Water Directive Framework. Additional country regulations.	.Noise permit required .Application of EU policy Natura 2000 for protected areas, and of Water Directive Framework on water management. .Additional local regulations.	Application of EU policy Natura 2000 for protected areas, and of Water Directive Framework on water management. Additional country regulations: Environmental Protection Act, 2001.

Source: Author

In general, hydrocarbon mining laws in Europe have been drafted for conventional E&P activities. As a result, a large number of definitions, concepts, and permitting approaches taken by these laws are unsuited to the nature of unconventional gas deposits and operations, creating legal uncertainty and operational challenges that will likely generate expected and unexpected project delays. Many examples can be listed, and we will mention a few important ones:

- In all countries, work programmes during the exploration phase are defined for blocks rather than continuous plays, which are bigger areas with no legal delineation. By contrast, in the US, land is granted by states or private owners under lease contracts. The key success factor to shale gas exploration is the identification of sweet spots, which requires location flexibility when planning for exploration activities. As a result, the obligation for each operator to fulfil given seismic and drilling commitments on strictly defined blocks with small sizes is sub-optimal and will contribute to delays in exploration activities.
- In Germany, the delineation of a field relies on gas water content. However shale gas does not have such characteristics. This makes it challenging to define limits of shale "fields" and more clarity or changes in this regulation are needed.

- Permitting processes, e.g for drilling, carrying out supply chain operations, accessing and discharging water, and building pipelines, are lengthy in all three countries studied, with the Netherlands being the slowest. Reasons are the involvement of municipalities, adding bureaucracy, and a high number of compliance and documentation requirements that burden the process. Moreover, permits are granted per well, or in the case of unconventional gas, presumably per well pad (i.e up to 10 wells simultaneously). However, the economics of unconventional gas depend on the ability to drill many wells on a continuous basis as quickly and cheaply as possible. Thus, without adjustments to mining and other E&P-related laws, current lengthy drilling permitting processes and the need to repeat the process for every pad will significantly hinder successful unconventional gas exploitation.
- In Poland, there is no legal distinction between operator and contractor. As a result, companies are forced to carry out E&P operations under the umbrella of a contractor and cannot build their own E&P organisation. In addition, the head of operations has to be certified by the Polish mining authorities, which means in practice that, due to the required language skills, this person has to be Polish. So operators are compelled to allow Polish service companies, which are owned by the NOC PGNiG[139], to lead all E&P operations in the country. This type of organisation is complex and far from being cost efficient, as operations are subject to many inefficiencies and the lack of unconventional gas competence in the country.

Heavy reliance on local contractors is not uniformly negative for operators. These companies are familiar with requirements to obtain drilling permits, environmental permits and planning permission.

Another reflection from the study of E&P and safety regulations is that such local regulations will impact unconventional gas operations not only with respect to drilling, but also logistics (e.g mud transportation and storage), fraccing (i.e transportation of water, chemicals and proppants) and well integrity (for example, including safety valves on wells and having several casing programmes are mandatory in Europe, as opposed to the US). These conclusions are based on discussions with service companies such as Schlumberger and Halliburton. The main consequence of these additional regulations on supply chain activities and well designs translates into additional F&D costs in Europe compared to the US, as discussed previously.

Fiscal policies In our analysis of the catalysts of the US unconventional gas revolution (Chapter 1), we identified that the implementation of several tax credits, and in particular the Alternative Fuel Production Credit in 1980, had been instrumental in boosting exploration and production of CBM and tight gas. In the 1990s this particular fiscal incentive added more than 50% to the effective wellhead price received by eligible gas producers. Without these tax measures, unconventional gas would never have got off the ground as it was not cost-competitive with alternative sources of gas supply. Our cost and profitability analysis (Figure 6.13) demonstrated that F&D costs of shale and tight gas projects and breakeven prices after tax are currently at the far end of the cost curve for European natural gas supplies. Furthermore, natural gas prices in Europe have in the past been much lower than the required $10 threshold, and market expectations remain below that level as well for the coming 2-3 years (Figure 6.14).

[139] The Polish Oil and Gas Company PGNiG is the national oil and gas company of Poland.

Therefore, as in the US in the 1980s and 1990s, European gas markets do not offer enough support for the development of new unconventional gas sources, especially in a higher cost environment compared with the US. Therefore we believe that additional incentives, in particular tax incentives such as tax credits, tax reductions, uplifts or accelerated depreciation, will be required for unconventional gas to be developed over the next decade.

This suggestion could encounter criticism because most European fiscal regimes and commercial terms for natural gas activities are not particularly tough compared to fiscal regimes in other gas producing regions. (But based on the results of our breakeven price analysis conducted after tax, they are not particularly favourable either.) Furthermore, frameworks in Hungary, Poland and Germany already contain specific provisions for unconventional gas E&P, especially CBM and tight gas. While Poland offers an exemption from royalty payment for CBM production, Hungary and Germany offer lower royalty rates on "unconventional" hydrocarbons and tight gas compared with conventional gas. The reduced royalty rate in Germany applies for the first five years to every new well coming into production, which is very favourable for well economics as most of the tight gas production is recovered in the first 5-7 years, and could indicate a real political appetite to boost new domestic production.

However it is worth noting that to date there is no specific provision for shale gas exploitation in any national framework. Given that companies' focus in Europe has been mainly on shales, it will be necessary to provide tax exceptions for that resource as well.

A summary of fiscal frameworks in effect in selected countries is outlined below to illustrate the argument:

Table 6.8: Fiscal regimes for gas production in four European countries

Country	Regime	Terms	Specific terms for unconventional gas
Germany	Royalty/Tax	Federal system in which individual states set the majority of tax rates. -Royalty rates vary frequently. In Lower Saxony the royalty rate on gas production reached 36% in 2008. -Effective corporate tax rate of 29,83% (includes standard rate, surtax and average municipal trade tax) -Withholding tax of up to 20%	**Yes - "Tight gas incentive"**: for tight gas production, royalty is 25% of the 'regular' onshore rate, resulting in a rate of 9%, for the five first years of production. This applies to gas produced from reservoirs with an average permeability of less than 0.6 mD.
Poland	Royalty/Tax	-Mining usufruct fee -Prospecting/Exploration Concession fee -Royalty, charged at a fixed rate on gross production. Rates amount to PLN 5.39 per thousand cubic metres for high methane gas and PLN 4.48 per thousand cubic metres for low methane gas. -Corporate tax rate of 19% -Withholding tax of maximum 19% -Regulated wholesale gas prices	**Yes** - CBM is exempt from royalty
Netherlands	Royalty/Tax	-Sliding scale royalty based on production levels. Minimum and maximum rates of resp. 0% and 7%, but rates double if there is no state participation in the license. Offshore licenses are not subject to royalty. -Profit Production Tax of 50% -Corporate Income Tax of 25,5% but deductible against the PPT -Marginal offshore fields tax incentive (uplift)	No, but very favourable tax regime in general. A tax incentive for onshore marginal reservoirs similar to provisions for offshore ones could be implemented.
Hungary	Royalty/Tax	-Sliding scale royalty based on production levels. Minimum and maximum rates of resp. 12% and 30% -Effective corporate tax rate of 28% (standard rate, solidarity surcharge and temporary "Robin Hood tax" until 2010).	**Yes** - Reduced royalty rate of 12% for "unconventional" hydrocarbons to be exploited using special methods

Source: Author

6.2.5 Service industry - a significant bottleneck?

The role of the service industry in developing unconventional gas deposits is key, as it provides equipment, staff and management of the supply chain, as well as a lot of the operational information required to obtain drilling permits. As we noted above in the case of Poland, operators cannot even have their own organisation and have to operate under the umbrella of service companies.

Thus the capacity and capabilities related to unconventional gas offered by the service industry in Europe need to be looked at to understand how this might affect the pace and cost of developing unconventional gas in the region.

From our operational analysis above, we found that producing 1 Tcf/year of gas would require around 150 rigs working simultaneously. However as of July 2010, there were only 81 active rigs in Europe, of which only 34 were onshore[140]. Furthermore, the current fleet of land rigs suited for horizontal drilling at great depths is very limited - less than 20% of the total fleet according to Schlumberger - because this type of drilling requires a lot of horsepower while almost all oil and gas wells drilled in Europe are vertical and demand far less horsepower capacity. This makes the real number of adequate rigs for tight and shale gas exploration closer to 7, and in a development scenario, the fleet would have to grow more than twenty times from the level of 2010!

The service industry is thus clearly facing an important equipment supply challenge to provide sufficient adequate rigs, but also fraccing equipment (such as pumps). It is important to note that the challenge will occur only in the event of a large-scale development phase occurring at a rapid pace. Indeed, in the exploration phase, the use of current low-specifications rigs seems to be sufficient. In the development phase, high-specification fit-for-purpose rigs with skidding capabilities[141] meeting EU specification and safety requirements will be needed.

The service sector in the US was very responsive to a surge in demand for drilling and fraccing services, thanks to intense competition and an entrepreneurial spirit. However the situation is different in Europe. Competition in the service sector, dominated by four international service companies (Schlumberger, Halliburton, Weatherford and Baker Hughes) and containing few local specialised manufacturers and service providers, is limited. Therefore, incentives for investing in the construction of new rigs, and at a competitive price, are far more limited than in the US. This situation may delay the development phase if there is high demand from operators.

There are two options to address the rig supply issue. The first is to import high-spec fit-for-purpose rigs, from major manufacturers such as China, the US and Canada. However, this is not a straightforward solution for the following reasons: equipment to be used in Europe must meet high European and country specifications in order to get the EU certification. China can currently only produce non-customised low-spec rigs. While North America could manufacture adequate units, there will be important issues of costs. Is it more economic to import high-spec rigs from North America rather than produce them in Europe, which is the

[140] Baker Hughes international rig count, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm. The total number of rigs can be higher, as some may be idle and thus fall out of the statistics.
[141] Rigs which have the ability to slide or slip sideways from one hole location to the next. This capability allows the time between successive drilling operations to be reduced.

second option? The answer to this question is unclear in 2010. The problem is that the rig manufacturing capacity in Europe is limited. There are only a few land rig builders, in Germany, Italy and Romania, and only German manufacturers could currently build high-specification rigs. Their total capacity is estimated at only 12 to 18 rigs/year. In the longer-term, the solution to meeting a high demand for sophisticated rigs would likely come from a combination of indigenous production and imports from North America.

The other aspect of equipment shortage relates to fraccing material. There is currently close to no fraccing expertise nor manufacturing capacity in Europe. Again, relying on international service providers will likely be the solution of choice. To conclude on this point, we think that the rig and pump fleet scale issue will be resolved if there is enough demand from operators, and the demand ramp-up pace will drive the growth of the fleet.

The most important bottleneck is not equipment, but rather people. In Europe there is a shortage of skilled labour able to operate sophisticated rigs and with fraccing knowledge and, most of all, the specific supply value chain management skills required in shale gas projects. In some countries, staff will have to be local, for example in Poland where workers have to get Polish certification, which requires in practice that they can speak Polish. Finding the right people in a sufficient amount, and training them, is therefore a big challenge that will take time to overcome.

Beyond the time needed to build sufficient service capacity and capability to meet large-scale developments, the other area affected by the limited competitive service sector is costs of operations. Controlling costs along the entire operational chain is the best way in Europe to keep costs down and therefore in the longer-run, it will be critical for operators to secure rigs and pumps that are customised to their play at the lowest possible cost. This will be best achieved through the creation of integrated drilling, and in some cases completion, services to be developed in-house or through JVs with specialised drilling and fraccing companies, possibly outside Europe. A handful of small operators, such as Cuadrilla, have already chosen the integrated business model.

6.2.6 Conclusions

Based on the analysis conducted in this chapter, we conclude that Europe cannot replicate much of the American model and that production of unconventional gas at a European level of 1 Tcf/year is at least a decade away, i.e post 2020. However it is possible to envisage that the timeframe could be slightly shorter at a country level. That would not make unconventional gas a pan-European game-changer, but it could have effects on the energy mix of individual countries, such as Poland, more quickly than at a European level.

Ultimately the key question is related to what the European response and model will be. We have outlined some ideas and directions for the operating model throughout this study, and emphasised that the conditions in investment frameworks would need to change, many of them requiring political intervention. Our suggestions and general conclusions can be found in Chapter 7.

The issue of which hurdles can be overcome most easily depends on whether they are of a market or policy nature. An expanded summary of the five broad conditions and challenges, categorised according to their nature can be found in Figure 6.9. The main point is that market

conditions may currently be lacking but should be considered as challenges that will be met over time if the subsurface potential is attractive. The biggest obstacles to unconventional gas developments are related to politics and policy, as changes in this area are less predictable by nature, and usually take time, if changes take place at all. Ultimately it will be political factors that will affect the two major differentiating challenges to unconventional gas development in Europe compared to the US, i.e costs and local acceptance and support. However, policy-related ingredients will be the hardest and longest to implement.

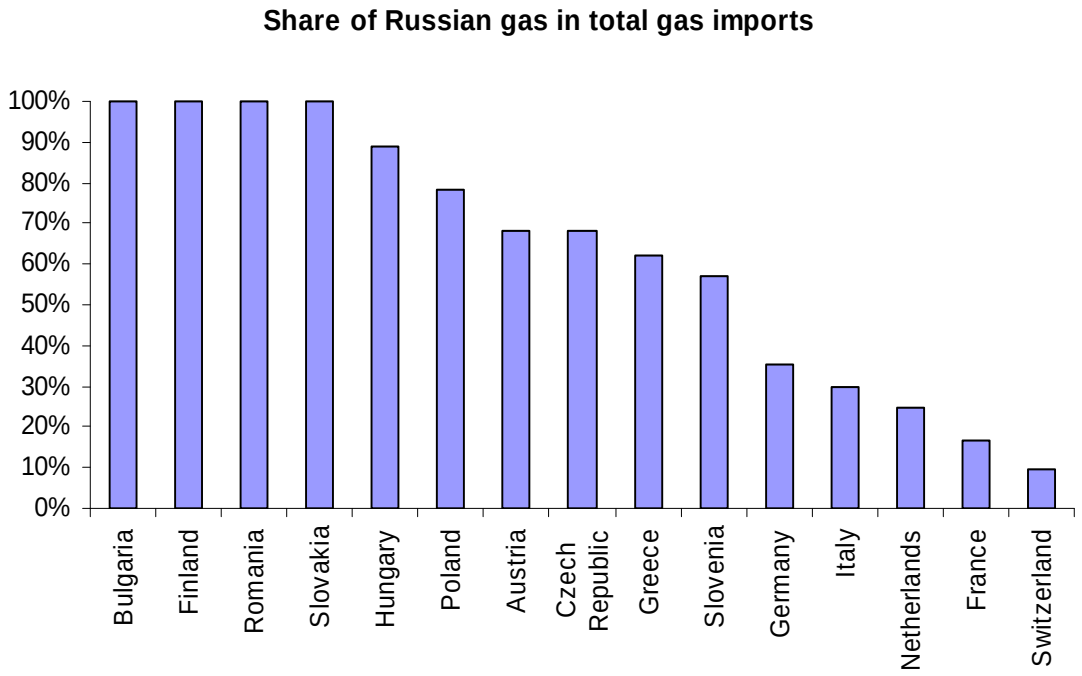
Table 6.9: Overview of market and policy conditions required to develop unconventional gas

Market	Policy
Technology innovation	Technology innovation
Application of best technology to operations	Subsidies, tax incentives
Operations and logistics efficiency	Loosening of E&P and environmental regulations
Service supply chain capacity and capability (trained staff, services, equipment)	Equipment standards and certification
Drilling and completion costs	Water access and allocation
Gas price	Ownership of mineral rights
Local acceptance	
Land access - Incentivisation of landowners	Land access - Drilling restrictions, local negotiation support to operators
Compliance to regulations in a cost-effective manner	Labour laws
Access to transportation and distribution infrastructure	Access to transportation and distribution infrastructure

Source: Author

In our view, given the significance of the challenges facing tight and shale gas E&P, policy incentives will have to be justified and explained to the population against a bigger geopolitical picture emphasising in particular energy security imperatives. Looking at the structure of gas imports for each country in Europe, it emerges that there are 3-4 countries with unconventional gas potential that have the highest share of Russian gas in total gas imports, and unsurprisingly all are located in Central and Eastern Europe, as illustrated in Figure 6.14. These countries are Romania, Hungary, Poland and Austria, and are the countries where we can expect incentives to boost indigenous gas production to be implemented more rapidly than elsewhere.

Figure 6.14: Share of Russian gas imports in total imports by country, 2009



Source: BP Statistical Review of World Energy 2010

Transportation and marketing aspects The challenges weighing on upstream activities are such that they make the study of transportation and commercialisation almost secondary when assessing the potential of unconventional gas to become a significant source of supply. However midstream and marketing issues are obviously extremely important. There are questions and challenges that need to be examined further, such as the availability of extra transportation and processing capacity for future new unconventional supply, and the adequacy of the existing network location relative to wellheads and consumption centres i.e will this infrastructure, designed to accommodate gas imports from Russia, Algeria, Norway and LNG, be suited to unconventional gas?

In the US, a huge number of pipeline debottlenecking projects have been necessary to sustain shale gas production growth, despite the fact that the main producing regions (e.g Texas, Rockies, Oklahoma) are in the vicinity of dense pipeline networks. Therefore, any production growth from Central and Eastern Europe will likely need to be met by pipeline capacity expansions to transport the gas to domestic and other European markets. This would prove costly to build, and may face hostile public opinion. Investments which might be required for such infrastructure are highly speculative.

What we can say however is that governments are likely to ensure that their domestic resources will be marketed, although the cost of and hurdles to building extra capacity inland in Europe might be higher than we think. Another obstacle is access to transportation capacity, which is currently still controlled by incumbents in many countries (Germany, France, Poland, etc.). However, with the EU 3rd package of liberalisation measures becoming law in early 2011, and substantial unconventional gas production not expected before the end of this decade, it is reasonable to expect that European gas market liberalisation will by then have made substantial progress.

Chapter 7 - General conclusions and macro-implications for European gas markets

The ongoing long-term trends in the gas industry and energy policies that will shape future gas markets have certainly put unconventional gas on the energy map. Therefore the development of unconventional gas projects is set to significantly affect gas markets in the future, and has already done so in North America. The rise of unconventional gas production, and in particular shale gas, has been the greatest revolution in the US energy landscape since the Second World War and has transformed the short to medium term outlook for LNG imports in that country[142]. This took everyone by surprise**,** especially the fact that unconventional gas became competitive in terms of cost. The main feature of this surprise is of a technological nature, combined with governmental subsidies and increasing, albeit volatile, gas prices, since 2000.

In the US, tight gas, CBM and shale gas resources have followed different development paths. Despite having been subject to different economic triggers (subsidies vs price), all types of unconventional gas resources can now be competitively produced compared to conventional gas. However a trend of declining productivity in tight sands can be observed, and the likely consequence is that the marginal cost of production from tight gas plays will continue to rise over time. Meanwhile US shale gas production will continue to grow, from current and future emerging plays. This belief is based on the fact that technology still has substantial room to increase recovery factors and reduce drilling costs. However we think it is too early to conclude at a macro-level on the sustainability of production from shale plays. We have raised many concerns about the outlook for unconventional gas growth in North America, among which are the sustainability of the current operating model, highlighted by its impact on the environment and increasingly concerned local communities, and the long-term profitability and life expectancy of shale assets. Understanding the limits and threats to the current shale gas model in North America requires a separate study.

Understanding the conditions that have made shale gas exploitation successful in North America is fundamental for a study of the potential of shale gas to be developed in Europe. This paper identified five catalysts that triggered modern unconventional gas production. Fiscal policies triggered commercial interest in unconventional gas. Friendly and decentralised energy and environmental regulatory frameworks granted freedom to operators to develop the cheapest possible practices. However, it is R&D and technological innovation that have been and will continue to be the main drivers to future production growth in the US, improving operational efficiencies, economics and mitigating the impact of operations on the environment and local communities. We noted above that these last two aspects involve major uncertainties for the US operating model and the continued growth of tight and shale gas production, as illustrated by deteriorating economics in the Barnett Shale despite increased investments in fraccing. Also an increasingly politicised national debate on the environmental consequences of shale gas operations is creating risks of increased regulations and costs.
These issues are very relevant for Europe, as it is densely populated (like in the North East of the US). Nevertheless the overall European political and socio-economic context is very different from the US, and the differences are rooted at all institutional levels: national, regional and local. Furthermore the unconventional gas industry in Europe is still in its

[142] If the US does not need LNG, flows will be redirected to Europe and Asia. If the unconventional gas revolution continues, then by the mid 2010s, the US could become an LNG exporter.

infancy. Therefore while the US and European unconventional gas stories clearly have links, Europe needs to develop its own model and investment framework conditions for unconventional gas resources. US practices are reference practices but probably not the best ones for Europe.

In Europe, while hopes are still high, the unconventional gas industry has to overcome many severe and regionally specific challenges before unconventional gas can be produced in significant quantities. European surface conditions significantly limit the transferability of the US experience to the continent. We have argued that achieving a production level of 1 Tcf/year will not happen before 2020, and maintaining this level for several decades in current conditions will be extremely challenging. The most likely countries to see early developments are Poland and Germany. In these countries as in others, production could be small at a pan-European level but still account for a very significant proportion of national gas production.

The lack of geological information on shale deposits is the first challenge to address, a situation that is similar to the US thirty years ago, when it started mapping its own resources in the 1980s. This process will take time even if these resources have attracted numerous companies, including the Majors, into a land grab process that is nearing completion. Thus we are likely to see a long and painful testing phase in Europe similar to the US, driven by commercial catalysts, as technology from the US is already available. The stage of immaturity of unconventional gas in Europe combined with unique space and cost challenges, calls for investments focussing on decreasing geological risks ahead of drilling in all phases, exploratory, appraisal and development. These types of investments are costly and fit into the Majors' corporate cultures. From that point of view, the presence of Majors in Europe could be beneficial to the exploitation of unconventional gas and the development of a distinct operating model.

This leads us to the question of the extent to which Europe can replicate the US model within European frameworks and conditions, in terms of success factors and production levels. Based on our production scenario analysis, producing 1 Tcf/year of gas, which would flatten the projected domestic production decline starting from 2020, involves very significant challenges, in particular land availability and access, logistics operations, and service sector capacity. Such production levels can probably be reached only from more than one play and more than one country across Europe. Each of the conditions behind the success of unconventional gas in the US, encounters different conditions in Europe, starting with the application of US technology and operating practices. Geological differences between US and European shales, water supply constraints and protection, and spatial constraints linked to population density and site protection all require more efficient operations and new technology-based solutions. Land access will remain challenging as long as there are no financial incentives for landowners. This is embedded in a general negative perception of the impact of unconventional gas operations by local communities.

Land access and cost levels are the two major differences in the general surface conditions between Europe and the US. Finding and development costs in Europe are expected to be 2-3 times higher than in the US, and lie in the high end of the cost range compared to conventional gas wells in Europe. Even if reductions and optimisation can be expected, these will be limited by regulations, high costs of services due to limited competition in the sector, and a potentially insufficient critical mass of operations.

From our cost analysis it is clear that unconventional gas economics, with breakeven prices of $8-12/mcf, will hardly be cost competitive with gas imports over the next decade. Therefore developments are unlikely to be prioritised and very little unconventional gas will be produced if market conditions do not improve, or if investments are only based on market considerations. For these reasons, policies promoting unconventional gas will be urgently needed if large scale development is to get underway by the end of the decade. National regulators have an important role to play and, to a lesser extent, EU authorities. Based on our case studies, it is clear that adjustments of permitting approval procedures and fiscal regimes to accommodate unconventional gas activities need to take place in most European countries, where national governments (rather than the EU) have legal competence over their hydrocarbon E&P regulations. Unlike the environmental sector, EU energy regulations currently have limited authority over European E&P activities, so little can be currently expected from EU energy policies to foster the development of unconventional gas resources. But decisions in the environmental sphere, for example on water usage, could affect the prospects of shale gas development.

The final challenge to the large-scale development of these resources is linked to the limited capacity of the service industry in terms of equipment, but mostly in terms of staff qualified to carry out this work. There will be options to source equipment from abroad, but the personnel issue remains an important uncertainty.

Due to the different nature of the operators and surface issues, the European response to all the challenges mentioned above will be based on a different model to the US model. The response has to come both from the market and governments. We think that while some hurdles can be overcome by the market if the investment climate is favourable, changes will ultimately depend on political priorities, at a national and EU level. Political changes are usually the hardest and longest to implement, and that does not work in favour of unconventional gas. However, socio-economic and political situations between countries are very diverse, and countries which have the highest import dependency on Russian gas could be expected to implement policies fostering the development of their unconventional resources before others. This will be particularly relevant in Poland and Hungary.

Some suggestions noted in this study that should be part of a successful European framework for unconventional gas production, include:

- Developing and deploying new and more efficient technologies that allow for increased recovery rates and cost reductions and help mitigate spatial constraints;
- Increasing land access and local support: involvement of operators to develop mechanisms that incentivise landowners and to integrate stakeholders in decisions impacting local socio-economic and environmental conditions;
- Better communication on environmental impacts and responses to growing public concerns arising from US operations. Environmental issues could be a killer to the nascent industry in Europe, as it could be a serious brake to US shale gas operations. We think the US needs to clear its environmental debate before Europe can fully embrace unconventional gas;
- Introducing policies to improve flexibility in the application of E&P and environmental regulations, or adjust them to the specific requirements of unconventional gas exploitation, such as drilling and water permitting procedures, multi-pad application, introducing the concept of play instead of block in the licensing process;

- Recognising that subsidies will be needed if future gas prices fail to reach a level close to $10/mcf. Early developments might be seen in shallow, tight gas exploitation in Northern Europe (e.g Germany), which could be an attractive segment from an operational and economic point of view, as the resource potential is large. It can rely on other fraccing fluids than water, offer similar economics as shale gas, and benefit from a favourable royalty rate in Germany that could be implemented in other countries. However land footprint and spatial constraints remain important challenges;
- Developing a home-grown service segment with local trained workforce and greater manufacturing capacity.

Whether unconventional gas can be a game-changer for Europe depends on the production level that is considered realistic, and conclusions at this stage remain speculative due to the very early stage of development. Going back to our three production scenarios for 2020, we argued that if Europe as a whole can produce 1 Tcf/year at a competitive price, this would have the potential to stabilise the incremental import dependence of Europe post 2020. This would represent a huge commercial and political shift in the dynamics of European gas supply and trade and would in itself be game-changing for both gas importing and exporting countries.

There will also be potential effects on European gas prices. First, to be economic, the pricing of unconventional gas volumes will have to be sustained at a level above $ 8-10/mcf, higher than historical prices and current market expectations. The contractual pricing structure will have to provide for this, taking into account possible governmental incentives, and the question is whether, by 2020, spot prices will be at these levels or whether oil-indexation will be needed. Second, whether European gas prices will be set by spot or oil-indexed prices, unconventional gas will not be a price setter at a European level, but project breakeven prices will represent a cap on the pricing of new projects. Third, the arrival of large new gas volumes could have a downward effect on prices, as it has in the US, but this seems unlikely. So unconventional gas development is not anticipated to lead to a fundamental shift in European price formation after 2020 but it could limit the scope for high cost imported gas.

The effects of new gas production from unconventional sources are likely to be the strongest within Continental Europe. Unconventional gas might not be able to transform the entire European market, but it should shift regional dynamics within the continent. It will only be a potential game-changer for countries that are endowed with such resources, and in those there might be a disproportionate effect on their energy policy. The comparison between Spain, which hardly has any unconventional gas potential but is extremely reliant on LNG, and Poland, which imports 60% of its gas needs from pipeline gas producers, mainly Russia, provides an excellent example. So even if unconventional gas proves not to be a pan-European game-changer it could still have very significant effects on regional gas dynamics.

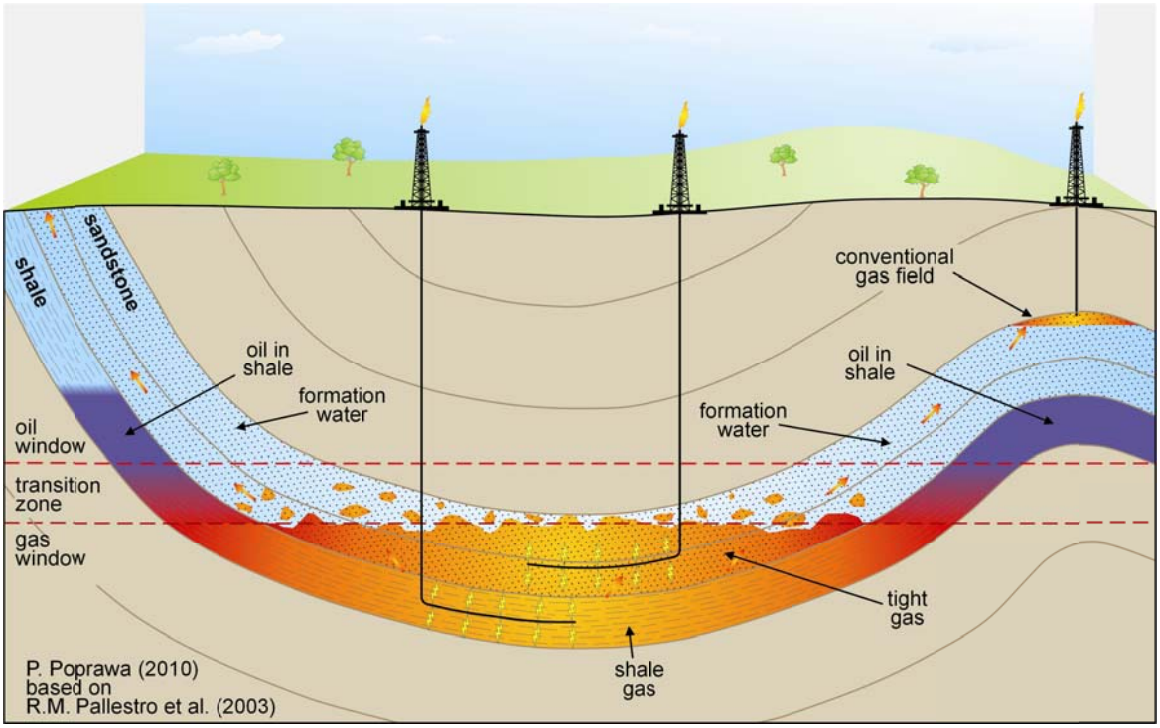
Appendix A – Conventional and unconventional gas: what are the differences?

A.1 The origin of natural gas

Oil and gas originated from the remains of pre-historic zooplankton and algal blooms which thrived in lake bottom or river delta environments. Over geological time their remains were buried with and beneath layers of sediment. As the depth of burial increased so did temperatures and pressures, transforming the sediment surrounding the organic material into shale This process caused the organic matter to change, first into a waxy material known as kerogen and then with more heat into liquid and gaseous hydrocarbons.

The rock strata in which the kerogen was formed and transformed into oil or gas is known as a 'source rock'. The oil and gas tended to migrate upwards through pores and faults in overlying rock strata ultimately reaching the earth's surface or alternatively becoming trapped within porous rocks (known as reservoirs) by impermeable rock strata above them. The process of oil and gas migration is influenced by underground water flows, causing oil and gas to migrate hundreds of kilometres horizontally or even short distances vertically before becoming trapped in a reservoir. The geological processes described above, as well as typical conventional and "unconventional" geological structures are illustrated in the following figure.

Figure A.1: Oil and gas formation



Gas, in the 'conventional' sense remains in these reservoirs as **non-associated gas** where there is no oil present, as **associated gas** where it is dissolved within oil in an oil-filled reservoir, or lastly as **gas cap gas** where there is a distinct gas layer above an oil layer within a reservoir. In all these three cases, the hydrocarbons are produced by drilling wells from the

surface into the reservoir where the pressure drive of the underlying water aquifer combined with the action of re-injecting water or a portion of the produced gas maintains well flow rates.

So, in conventional reservoirs, overall reservoir pressure is affected by the production rate from each well, and wells interfere with each other if they are drilled too closely together, as they attempt to produce from overlapping resource volumes. By contrast, in unconventional gas reservoirs, wells do not interfere with the depletion of reservoirs.

A high-level summary of the major differences between conventional and unconventional gas can be found in the table below:

Table A.1: Differences between conventional and unconventional gas

Conventional plays	Unconventional plays
Accumulations in medium to highly porous reservoir with sufficient permeability to allow gas to flow to wellbore	Deposits of natural gas found in relatively impermeable rock formations (tight sands, shale and coal beds)
Vertical or horizontal completions	Key technologies are horizontal drilling and modern fraccing techniques
Production from formation matrix, natural flow	Production from natural and induced fractures (e.g shales are the source rock)
Permeability and porosity determine production rates and estimated ultimate recoveries	Total organic carbon, thermal maturity and mineralogy determine reservoir and ultimate completion
Development plans on a field basis	Development plans on a well by well basis

Sources: Halliburton, E.ON presentation Prospects for unconventional gas in Europe 5 February 2010

A.2 Introduction to unconventional gas geological properties

Coal bed methane (CBM) CBM is natural gas contained in coal deposits. The gas is usually produced from coal which is either too deep or of too poor a quality to be mined commercially. The methane lines the inside of pores within the coal (called the matrix). The gas is mainly adsorbed[143]. The open fractures in the coal (called the cleats) can also contain free gas or can be saturated with water. When the reservoir is put into production, water in the fracture spaces is pumped off first. This leads to a reduction of pressure, enhancing de-sorption of gas from the matrix. CBM resources are usually appraised with simple vertical wells, but hydraulic fracturing is a commonly used technique to improve production in less permeable beds and, in a few cases, horizontal and even multi-lateral wells have been used to enhance productivity and optimise drainage of the reservoirs.[144]

[143] Adsorption refers to the formation of a thin film on the surface of a material..
[144] IEA World Energy Outlook 2009 p 399

Tight gas Tight Gas essentially refers to a non-associated gas reservoir which has a much lower porosity and permeability than is usual for sandstone gas reservoirs. Low permeability means there is very limited ability for the hydrocarbons trapped in the rock to flow due to a lack of natural fractures in the rock. In addition such a reservoir may have low vertical permeability because of thin horizontal layers of non-permeable rock. As a result, without additional treatment, wells have poor deliverability and low recovery factors.

A working definition might be a natural gas reservoir that cannot be developed profitably with conventional vertical wells, due to low flow rates. In the US, tight gas sands were originally defined, for fiscal purposes, as natural gas reservoirs with permeability of less than a threshold of 0.1 mD.[145]

Tight natural gas reservoirs have been developed primarily in North America for more than 40 years, and have driven the majority of technological innovation in the area. The key technology to increase gas flow rates is hydraulically fracturing the productive formation. Producers have taken the horizontal drilling and multistage fraccing technology and applied it to a large number of tight plays across North America, making previously uneconomic reservoirs very attractive.

Shale gas Shale gas is natural gas composed primarily of methane and contained in a commonly occurring, widespread rock loosely classified as shale. These formations are rich in organic matter and, unlike most hydrocarbon reservoirs, are typically both the source of the gas and its reservoir or storage medium.

Certain attributes of a good shale gas play are therefore also those of a good source rock. Good source rocks have adequate porosity, greater than 3%, and high reservoir pressure. They are organically rich, volumetrically extensive, with large thickness and lateral extent, and thermally mature at least to the point of gas generation.

Organic richness is measured by total organic carbon (TOC), and most good source rocks have concentrations that are 2% or greater. Shales with lesser TOC concentrations can still be good source rocks. What they may lack in organic richness they can make up for in sheer volume by being thicker or more laterally extensive. Thermal maturation is measured by the vitrinite reflectance (Ro) of the rock. Vitrinite is a type of woody organic matter that changes predictably and consistently through time with burial and higher subsurface temperatures. The reflectance measurement is a comparison with a material having 100% reflectance, such as a mirror. Shales with an Ro greater than 1% are considered mature for gas generation and a good risk for shale gas exploitation.

Gas can be stored in shale by different mechanisms: within the pores of the rock, within a naturally occurring system of fractures, or adsorbed onto the shale minerals and organic matter within the shale.[146]

Not all shale/tight gas plays are created equal and each requires its own learning curve. Determining an optimal completion strategy often entails a thorough analysis of the reservoir composition, porosity, permeability, saturation levels, pressure and temperature gradients. In the end, the selection of the proper wellbore orientation, stimulation equipment, frac size and

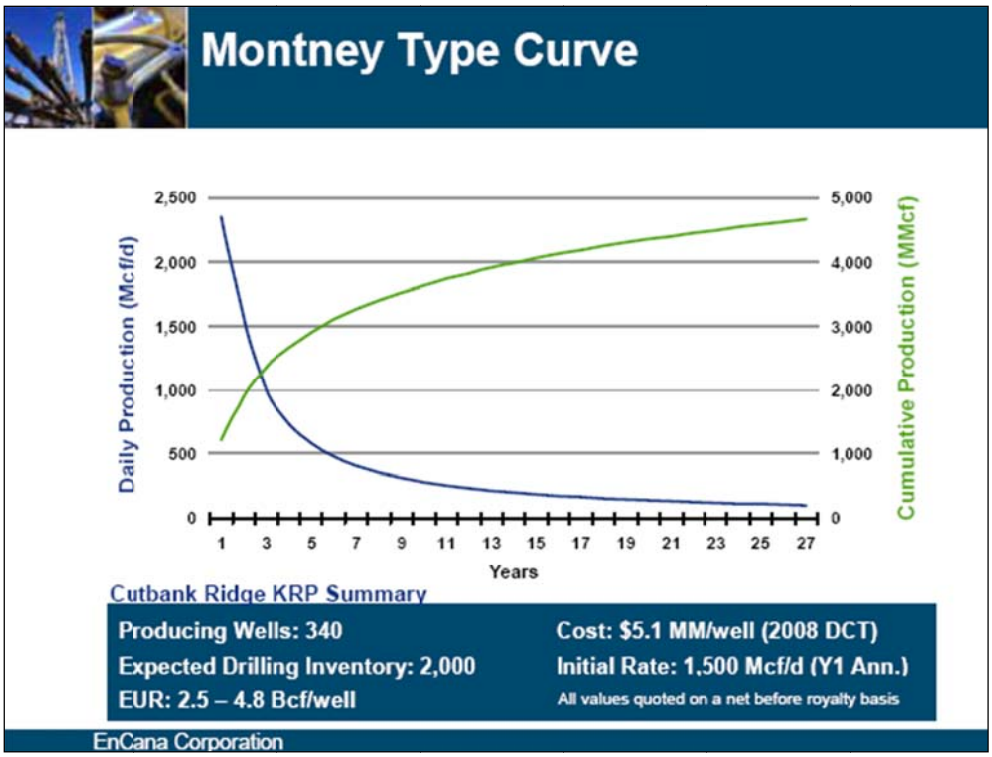
[145] See definition in the Glossary
[146] IEA World Energy Outlook 2009, p 400

frac liquids are the key variables in unlocking the huge resource potential from these reservoirs.

A.3 Production profiles

One notable characteristic of tight gas development utilizing fraccing is very high first year decline rates with a long tail of low decline, as can be seen in Figure A2. This characteristic is also shared by shale wells.

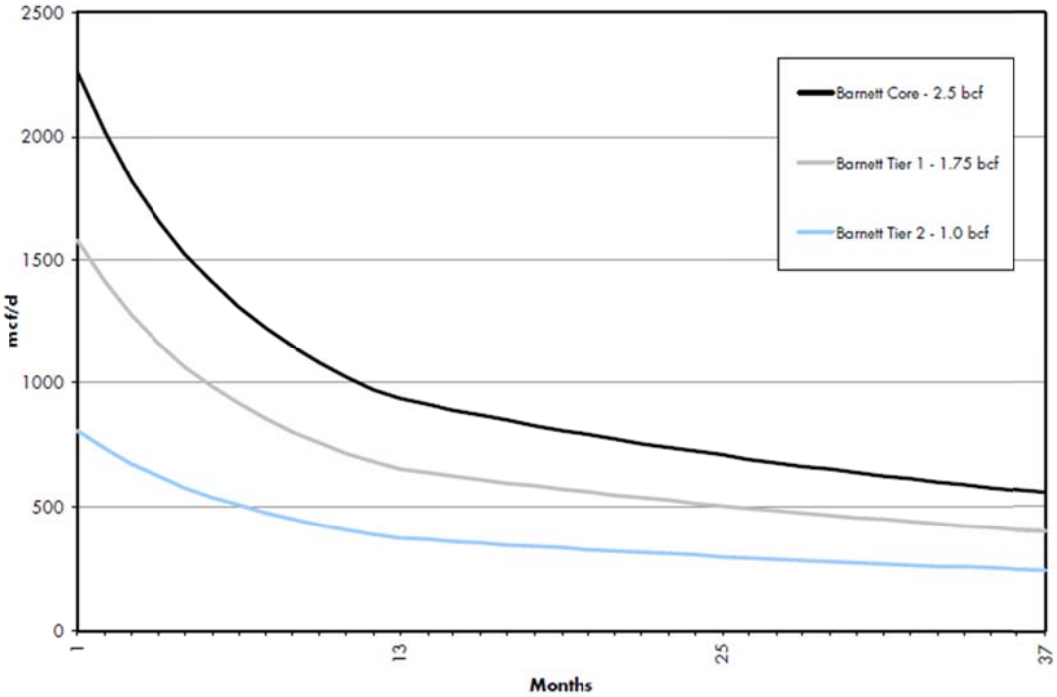
Figure A.2: Tight gas type curve



Source: EnCana company report

Based on shale gas production in several plays in North America, it seems that most wells, regardless of their productivity, exhibit an early peak of production and then a rapid decline, for both vertical and horizontal wells. For example, in the Barnett Shale, horizontal wells have on average, weighted by production, declined by 39% from the 1st to the 2nd year of production, and by 50% from the 1st to the 3rd year. Decline rates tend to slow after several years but remain high, such that most of the recoverable gas is extracted after just a few years. A typical shale well production curve is shown in Figure A3.

Figure A.3: Barnett shale type curve



Source: Tristone Capital report *Can you smell what the rocks are cookin'?* 6 October 2008

Furthermore, a wide range in well productivity, production rates and recoverable resources characterises all shale plays and types of wells, and the variation in productivity from well to well is significantly greater than that usually encountered in conventional reservoirs.

Appendix B – Fracturing technologies

B.1 Objectives of the technology

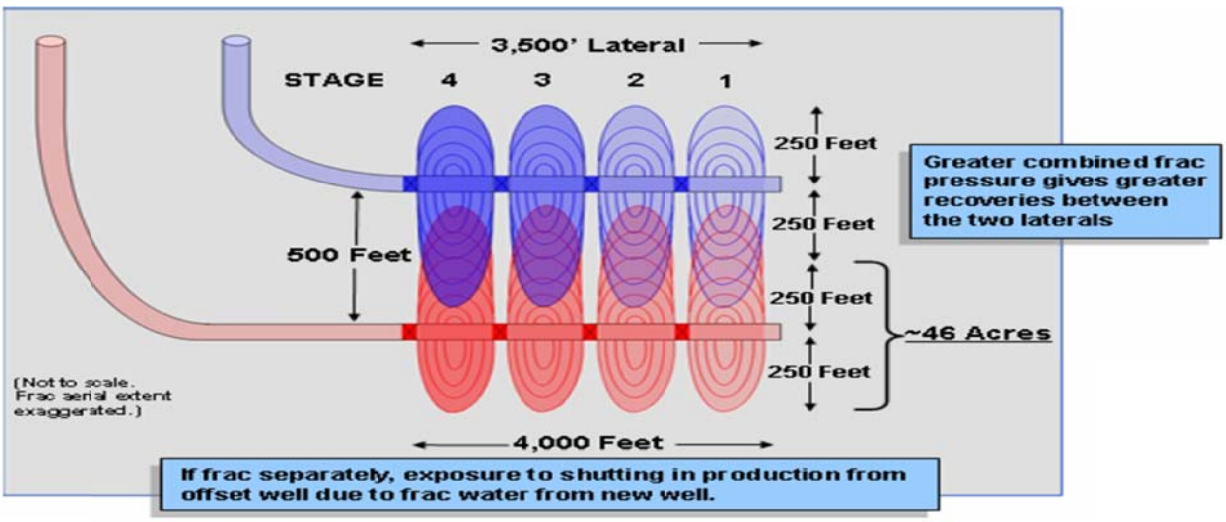
Hydraulic fracturing is a formation stimulation practice used to create additional permeability in a producing formation, thus allowing gas to flow more easily toward the wellbore.

The process is not new; it has been practiced for decades. The first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil and gas occurred at the Hugoton field in western Kansas in 1947, using war surplus napalm as the fracturing fluid. While initially unsuccessful, the addition of proppants in the 1960s allowed the industry to realise better flow rates, and the practice spread. Today a wide range of hydraulic stimulation treatments exists, targeting mainly unconventional gas reservoirs (tight sands, coal bed methane and shales)[147]and hydraulic fracturing has developed into a routine technology.

B.2 The process

Hydraulic fracturing involves the pumping of a fracturing fluid into a formation at a calculated, predetermined rate and pressure to generate fractures or cracks in the target formation, allowing oil or gas to flow through the fractures more freely to the wellbore. By creating new pathways, hydraulic fracturing can exponentially increase oil and gas flow to the well. Hydraulic fracturing of horizontal shale gas wells is performed in stages, sequentially. Figure B.1 below illustrates the process. Lateral lengths in horizontal wells for shale gas development may range from 1,000 feet to more than 5,000 feet.[148]

Figure B.1: Example of lateral fraccing



Source: Range Resources

[147] Bernstein Research, *The decline in Shale Well Productivity and the "Technology" Myth, a look at the Barnett Part 2*, 20 October 2009,

[148] Groundwater Protection Council and ALL Consulting, *Modern Shale Gas Development in the US: a primer*, April 2009

For shale gas development, fracture fluids are primarily water-based fluids mixed with additives which help the water to carry sand proppant into the fractures. The sand proppant is needed to “prop” open the fractures once the pumping of fluids has stopped.

B.3 Fracturing fluids and additives

Fracture fluids can be based on water, oil, acid, gel, foam and even liquid CO_2. Most fracturing work is conducted using water based fluid. In addition, fracture fluids can contain a wide array of additives, each with a particular function, the combination depending on the conditions of the specific well being targeted. For deep shale gas zones, the water is commonly mixed with a friction reducer (called slickwater), biocides, scale inhibitors, and proppants such as sand to hold the fracture open. It is the use of such additives that has raised concerns about hydraulic fracturing. However, overall the concentration of additives in most slickwater fracturing fluids ranges between 0.5% and 2%, with water making up 98% to 99.5%.

Geology dictates the combination of fracturing fluids and proppant used, and part of the challenge of unlocking new plays involves determining the optimal stimulation treatment.

Appendix C – Main unconventional gas basins in Europe

Table C.1: Coal bed methane

	Country	Basin
1	Italy	Northern Apeninnes
2	Spain	Asturian Basin
3	France	Northern Coal basin
4	France	Paris Basin
5	France	Vosges Greseuses Plateau
6	France	Bresse-Valence Basin
7	France	Languedoc-Provence Basin
8	UK	Midland Valley Graben
9	UK	South Wales Carboniferous Basin
10	UK	Western Cheshire Slope
11	UK	Western Audiem Sub-basin
12	UK	Market Weighton Block
13	UK	East Midlands Platform
14	UK	Solway Basin
15	UK	Pennine High
16	UK	East Irish Sea Basin
17	UK	Harrogate Basin
18	UK	Gainsborough Trough
19	UK	Lymm High
20	UK	North Wales Carboniferous Basin
21	UK	Needwood Basin
22	UK	Cheshire Basin
23	UK	Worcester Graben
24	Poland	Lublin Trough
25	Poland	Fore-Sudetic Monocline
26	Poland	Outer Carpathian Foredeep

Sources: Chew K, IHS

Table C.2: Tight gas

	Country	Basin
1	Hungary	Pannonian Basin
2	Poland	Permian Rotliegendes
3	Germany	Permian Rotliegendes
4	Netherlands	Carboniferous

Source: press articles

Table C.3: Shale gas

	Country	Basin
1	Sweden	Fennoscandian Border Zone
2	Switzerland, Austria	Molasse Basin
3	Spain	Campo de Gibraltar Zone
4	Spain	Pyrenean Foothills
5	France	Paris Basin
6	France	Bresse-Valence Basin
7	France	Western Alps Foothills
8	France	Aquitaine Basin
9	France	Languedoc-Provence Basin
10	UK	Bowland Basin
11	Poland	Baltic Depression
12	Poland	Ketzyn Terrace
13	Poland	Danish-Polish Marginal Trough
14	Poland	E European Platform Margin
15	Poland	Podlasie Basin
16	Poland	Lublin Trough
17	Germany, Netherlands	Northwest German Basin
18	Germany, Poland	Northeast German-Polish Basin
19	Netherlands, UK	Anglo-Dutch Basin

Sources: Chew K, IHS

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Glossary

AGIP: Average German Import Price of natural gas at the German border.

BCGA, Basin-centred gas accumulation: A type of tight gas, generally defined as a regionally pervasive, low-permeability sand accumulation that is gas saturated, is abnormally pressured, and lacks a down dip water contact. Similar to conventional oil and gas systems, BCGSs are often described by complex geological and petrophysical systems as well as heterogeneities at all scales.

Bcf, bcf: Billion cubic feet

Bcf/d: Billion cubic feet per day (equivalent to 10.34 billion cubic metres/year (bcma)).

Biogenic gas: One of the two types of natural gas, the other being thermogenic gas. Biogenic gas is formed at shallow depths and low temperatures by anaerobic bacterial decomposition of sedimentary organic matter, and is very dry.

BLM: Bureau Land of Management, in the US.

CBM, Coal bed methane: Methane which is held within the structure of the coal matrix by adsorption. This may be produced in commercial quantities when the coal is de-pressurised and de-watered in situ through drilling and the application of suitable well technology. See more details in Appendix A.

Cdn $: Canadian dollars

CMM, Coal mine methane: Methane emissions recovered from working mines.

Completion: A generic term used to describe the events and equipment necessary to bring a well into production once drilling operations have been concluded, including but not limited to the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well. Completion quality can significantly affect production from shale reservoirs.

Darcy: Darcy and milliDarcy (mD) are units of permeability widely used in the oil and gas industry.

D&C: Drilling and Completion costs.

E&P: Exploration & Production activities

EIA: Energy Information Administration, part of the US Department of Energy (DOE)

EPA: Environmental Protection Agency in the US

EUR: Estimated Ultimately Recoverable Reserves

F&D cost: Finding and Development cost. The cost of replacing oil and gas produced. Finding and Development costs are calculated by the ratio of exploration and development expenditures for a given period of time to oil and gas reserves added for the same period of time.

Formation: A body of rock that is sufficiently distinctive and continuous that it can be mapped.

FSU: Former Soviet Union countries

Gas hydrates: An unusual occurrence of hydrocarbon in which molecules of natural gas, typically methane, are trapped in ice molecules. Hydrates form in cold climates, such as permafrost zones and in deep water. To date, economic liberation of hydrocarbon gases from hydrates has not occurred, but hydrates contain quantities of hydrocarbons that could be of great economic significance.

GASH: Designates the Gas Shales in Europe programme.

GHG: Greenhouse gases

GRI: Gas Research Institute, in the US.

Henry Hub: The principal market hub for gas in the US, located in Erath, Louisiana. It is at a point on the US natural gas pipeline system where nine interstate and four intrastate pipelines interconnect. It is the delivery point for the largest New York Mercantile Exchange natural gas contract by volume.

Hydraulic fracturing (aka “fraccing”): A process used to create additional permeability in reservoir rocks, which allows oil or natural gas to flow out of a well-bore. The process is based on forcing a fluid into the rock at sufficient pressure to create fractures in the rock and thus a pathway for oil and natural gas to the wellbore, thereby improving deliverability and recovery rates through increased contact with the well. Over the last 5-10 years fraccing technology has progressed significantly, especially in unconventional gas reservoirs. See Appendix B for more details.

IDC: Intangible Drilling and Development costs

IEA: International Energy Agency

Independents: A term used to describe oil and gas companies which do not have a large size at a national or continental level, but this is no longer necessarily the case.

Integrated company: A company involved in all phases of the oil and/or gas business, i.e exploration, production, transportation, processing, refining and marketing.

IP rate: Initial Production rate

Large cap: A term used by the investment community to refer to companies with a market capitalization value of more than $10 billion. Large cap is an abbreviation of the term "large market capitalization".

Learning Curve: The Learning Curve Theory mathematically describes the ability of organisations and individuals to improve their performance over time.

Lifting costs: Cost of extracting oil and gas, i.e the cost of production. Lifting costs are the costs per barrel of operating and maintaining wells and related equipment and facilities, including taxes levied directly on production.

LNG: Liquefied Natural Gas

Long-Run Marginal Cost: Concept that measures the costs of increasing the production output by one additional unit or the costs saved by reducing the production output by one unit, holding the production levels of all other services constant.

Major: A term generally used to describe the group of the largest publicly owned international oil and gas companies.

Mcf, mcf: Thousand cubic feet

Mcfd, mcf/d: Thousand cubic feet per day

Md: See Darcy.

Mid cap: Business term designating companies with a certain level of market capitalization, e.g between $2 and $10 billion. Mid cap stands for “middle capitalisation”. Classifications such as large cap, mid cap and small cap are only approximations that change over time and depend on business participants.

Millidarcy: See Darcy.

MMBTU: Million British thermal units

Mm HHP: Million Horsepower

NOC, National Oil Company: An Oil and Gas company fully or majority owned by a national government.

NBP: The UK’s National Balancing Point: a virtual point (hub) in the National Transmission System where gas trades are deemed to occur. It is also used as shorthand for the UK spot gas price.

Permeability: The ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies. Formations that transmit fluids readily tend to have many large, well-connected pores.

Pit: A typically excavated containment pond that, based on the local conditions and regulatory requirements, may be lined. Pits can be used to store make-up water for the drilling and hydraulic fracturing of wells, or waste water before transportation and treatment.

Play: An area in which hydrocarbon accumulations or prospects of a given type occur. A play (or a group of interrelated plays) generally occurs in a single petroleum system.

Qcf: Quadrillion cubic feet = 1,000 Tcf.

Proppant: A material (sand) used to "prop" open the fractures once the pumping of fluids has stopped.

Rig Count: The number of rotary rigs which are actively drilling on a given date. These are essentially working on exploration or development wells and represent the activity level of new production capacity development.

Ro: The measure of the vitrinite reflectance of a sedimentary rock. The study of vitrinite reflectance is a key method for identifying the temperature history of sediments in sedimentary basins. The key attraction of vitrinite reflectance in this context is its sensitivity to temperature ranges that largely correspond to those of hydrocarbon generation (i.e. 60° to 120°C). This means that, with a suitable calibration, vitrinite reflectance can be used as an indicator of maturity in hydrocarbon source rocks. Generally, the onset of oil generation is correlated with a reflectance of 0.5-0.6% and the termination of oil generation with reflectance of 0.85-1.1%.

Slickwater: Water-based fluid containing chemicals and proppant (e.g sand) and used in hydraulic fracturing.

Small cap: Business term that refers to stocks with a relatively small market capitalization. The definition of small cap can vary among brokerages, but generally it is a company with a market capitalization of between $300 million and $2 billion.

Stimulation: A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments.
Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore.

Sqkm: Square kilometres

Sweet spot: Colloquial expression for a target location or area within a play or a reservoir that represents the best production or potential production.

Tcf, tcf: Trillion cubic feet.

TOC: Total Organic Carbon refers to the carbon concentration of an organic compound and is used to measure the organic richness of a rock. Most good shale source rocks have concentrations that are 2 percent or greater.

Conversions

	Mcm	Mcf	MMBtu	MWh	Acre	Sqkm	Square mile	$	€
Mcm	1	0.0353	3533.5689	0.011					
Mcf	28.3*10^ -6	1	1	0.3					
MMBtu	28.3*10^ -6	1	1	0.3					
MWh	94.43	3.412	3.412	1					
Acre					1	0.004	0.002		
Sqkm					247	1	0.39		
Square mile					640	2.59	1		
$								1	0.75
€								1.3	1