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Unconventional Gas: Potential Energy Market Impacts in the European Union

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UNCONVENTIONAL GAS:
POTENTIAL ENERGY MARKET IMPACTS IN THE EUROPEAN UNION

A REPORT BY THE ENERGY SECURITY UNIT
OF THE
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Executive summary

Background

This report investigates the potential impact of unconventional gas, most notably shale gas, on European Union (EU) energy markets.

It should be noted that Commission services are currently examining whether the environmental challenges of unconventional gas production can be effectively managed through existing regulation, monitoring and the application of industry best practices. In this vein, the Joint Research Centre (JRC) has prepared a report reviewing the literature on environmental impacts. The present report examines only the potential benefits of shale gas exploitation and should be seen together with the associated JRC report addressing environmental issues.

In February 2011, the European Council stated that: "In order to further enhance its security of supply, Europe's potential for sustainable extraction and use of conventional and unconventional (shale gas and oil shale) fossil fuel resources should be assessed." This report is a preliminary attempt to respond in part to this call by providing reliable facts for EU policy-makers.

Fossil fuels, such as oil, natural gas and coal are by far the largest sources of energy in the EU and are widely projected to dominate the European energy mix through to at least 2030. The European Commissions Energy Roadmap 2050 identifies gas as a critical fuel for the transformation of the energy system. The substitution of coal and oil with gas in the short to medium term could help to reduce emissions with existing technologies until at least 2030-2035.

Conventional gas currently dominates worldwide natural gas production, accounting for over 85% of total marketed output today. In recent years, however, two key developments have shifted the focus to so-called 'unconventionals'. The first has been mounting concern that growing demand for energy worldwide would outstrip supply. The second factor has been a dramatic increase in unconventional gas production in North America, to roughly 50% of domestic production.

The International Energy Agency (IEA) has estimated that - under the right conditions - unconventional gas may meet more than 40% of the increased global demand for gas by the year 2035. However, many questions still remain about how easily unconventional gas resources can be developed outside North America.

Unconventional gas resources are thought to be, geographically, broadly distributed across all continents, including Europe. Their potential development may therefore offer a number of security-of-supply benefits for the Union: lower natural gas prices; more readily available gas on the European market; easing tightness in global energy markets; and adding diversity to the EU's gas supplies.

However, the growing focus on unconventional gas has not come without controversy. Notably, it has been argued that there may be several negative environmental and climatic aspects to its production. In addition, more and cheaper (unconventional) gas may challenge investment in coal, nuclear and renewables, as well as the established gas business model. And, of course, questions have been raised about the size of the recoverable resource base.

Conventional and unconventional gas

Generally speaking, conventional natural gas is gas extracted from discrete, well-defined reservoirs and can usually be developed using only vertical wells, with recovery rates of over 80% of the original gas in place.

Unconventional natural gas resources are generally found in less permeable rock formations, where resource accumulations may be distributed over a much larger area than conventional gas. Unconventional gas resources typically require well-stimulation measures in order to be made productive, but recovery rates are much lower than in conventional gas – typically of the order of 15-30% of original gas in place.

There are three main types of unconventional natural gas produced today, which are considered in this report:

- **Tight gas:** this is natural gas trapped in relatively impermeable hard rock, limestone or sandstone;
- **Coal-bed methane (CBM):** this is natural gas trapped in coal seams, adsorbed in the solid matrix of the coal; and
- **Shale gas:** this is natural gas trapped in fine-grained sedimentary rock called shale that has a characteristic 'flaky' quality.

Objectives, scope and limitations

The objective of this report is to investigate the impact of unconventional gas, notably shale gas, on EU energy markets. This report seeks to clarify certain controversies and identify key gaps in the evidence-base relating to unconventional gas. The scope of this report is restricted to the economic impact of unconventional gas on energy markets. As such, it principally addresses such issues as the energy mix, energy prices, supplies, consumption, and trade flows. But it also covers resource estimates and the advancement of technologies for shale gas extraction.

Whilst this study touches on coal-bed methane and tight gas, its predominant focus is on shale gas, which the evidence at this time suggests will be the form of unconventional gas with the most growth potential in the short to medium term.

This report considers the prospects for the indigenous production of shale gas within the EU's 27 Member States. It evaluates the available evidence on unconventional gas resource size, extraction technology (past and possible future), resource access and market access.

This report also considers the implications for the EU of large-scale unconventional gas production in other parts of the world. This acknowledges the fact that many changes in the dynamics of energy supply can only be understood in the broader global context. Specifically, it reviews effects of the rapid development of shale gas production in the United States of America (USA) and its effect on European gas markets, in combination with a growing liquefied natural gas (LNG) trade worldwide. An energy model is used to elaborate possible future scenarios that illustrate the potential impact of unconventional gas on the European energy system.

Methodology

This report consists of two main components, namely:

- A close examination of the unconventional gas literature covering both Europe and the rest of the world.
- Energy system modelling of possible scenarios of future global shale gas development that illustrate the conditions under which shale gas might be integrated into the energy system in the coming 30 years.

Mindful of the fact that the unconventional gas knowledge-base is highly polarised and currently incomplete, this report identifies and describes select points of controversy in the literature that may have a bearing on the impact of unconventional gas in Europe. It then assesses the existing evidence around these points and evaluates the degree of uncertainty that currently exists.

In doing so, the report draws upon a range of techniques referred to as *evidence-based policy and practice* that aims at giving greater weight to scientific research evidence in policy-making. Specifically, as in this report, it includes the synthesis of existing evidence through a process known as a *systematic review*.

Simulations in this report are based on ETSAP-TIAM, a multiregional partial equilibrium model of the energy systems of the entire world that is divided into 15 regions. ETSAP-TIAM is developed and maintained by the Energy Technology Systems Analysis Programme under the aegis of the IEA.

Remarks

Regarding regional and global estimates of unconventional gas:

- There are multiple and substantial uncertainties in assessing the recoverable volumes of shale gas, both at regional and global level. Even in areas where production is currently taking place, notably North America, there remains significant uncertainty over the size of the resource and considerable variation in the available estimates. For several regions of the world there are no estimates at all, but some may well contain significant resources. Given the absence of production experience in most regions of the world and the number and magnitude of uncertainties described below, current resource estimates should be treated with considerable caution.
- Based on an assessment of the existing literature, this report expresses the estimates of unconventional gas as technically recoverable resources (TRR). While resource estimates based on production experience are likely to be more robust, with very limited production experience it is more appropriate to incorporate estimates from studies that use a range of methodologies (expert judgement; literature review; bottom-up assessment of geological parameters and extrapolation of production experience). Thus, this report focuses on TRR and takes no account of economic viability or any other constraints on resource recovery. The review is focused on literature with original estimates of unconventional gas and provides an overview of current estimates of TRR for tight gas and coal-bed methane in four regions (USA, Canada, Europe and China) as well as globally. An estimate is given for shale gas for 15 regions worldwide.
- Current estimates for the TRR of shale gas suggest there may be just above over 200 trillion cubic metres (Tcm) globally. Similarly, the mean of current estimates for the global TRR of tight gas is 45 Tcm and the mean estimate of CBM is 25 Tcm. For comparison, the global TRR of conventional gas is estimated at 425 Tcm of which

around 190 Tcm are currently classified as proved reserves (i.e. resources that can be easily recovered with the highest degree of confidence).

- For some regions, it was possible to obtain high, best and low TRR estimates for shale gas. In the USA, the high/best/low estimates are 47/20/13 Tcm and for China the estimates are 40/21/1.6 Tcm. As an illustration of the uncertainty in the estimates, the high and low estimates in the USA are 230% and 64% of the best estimate respectively. There is even greater uncertainty in the unconventional gas resource estimates for the rest of the world. Organisations that have provided multiple estimates for single regions have consistently, and often significantly, increased their estimates over time. The best estimate for Western Europe is 12 Tcm and for Eastern Europe it is 4Tcm.
- The variability and uncertainty in the reviewed estimates have a variety of sources. Studies use different methodologies for the resource estimates, often using imprecise or ambiguous terminology. For estimates based upon geological appraisals, significant source of uncertainty stems from the assumed recovery factor – the fraction of the original gas in place that is estimated to be recoverable – which may vary substantially (15-40%) for shale gas. For estimates based upon the extrapolation of production experience, a key source of uncertainty is the appropriate application of 'decline curve analysis', with no consensus on how quickly the rate of production from currently producing wells will slow in the future. Future technological progress, even if only leading to a small increase in recovery factors, could have a significant impact on the estimated ultimately recoverable resources.

Regarding technological development:

- The successful development of shale gas in the last decade is due to the combination of progress in two key technologies, namely horizontal (or directional) drilling and hydraulic fracturing. Progress has also been made in other stages of shale gas exploration and production, from well pad design, to water management and infrastructure planning, to microseismic monitoring.
- Environmental concerns have accompanied the growth in shale gas exploration and production. Some significant risks can have similar causes to those associated with conventional onshore gas. These include: gas migration and groundwater contamination due for instance to faulty well construction; blowouts; and above ground leaks and spills of wastewater and chemicals. Significant risks that arise from shale gas development require additional consideration and dedicated analysis. Factors to take into account include, for example, the larger number of wells when compared to conventional practices, and the high volume of water and fracturing fluids used.
- As the horizontal section of wells gets longer, multi-stage hydraulic fracturing with 10 to 20 stages per well has developed. Further improved understanding of the fracturing process may improve precision; improve the network of fractures created; reduce the number of fracturing stages per well; reduce the time needed to drill and fracture; and reduce the consumption of water. Such improvement may lead to a significant reduction in fracturing cost. Advancements in microseismic monitoring allow for the mapping and visualisation of how fracturing is progressing. It also provides information for the early detection of geo-hazards.

- Alternative fracturing fluids are being researched to allow the use of non-fresh water and flowback water. Water treatment processes are being investigated that could potentially be used on a large scale, with the ultimate goal of achieving a closed-loop system.
- Multiple horizontal wells drilled from a single pad will increase the operational efficiency of gas production and reduce infrastructure costs, land use and environmental impact.
- A larger number of wells per pad and longer wells will lead to a corresponding increase in time spent on drilling and well completion operations on each well pad. This would favour a new, more 'industrialised' concept for site and rig design, including highly automated drilling rigs with higher efficiency. Drilling cost reduction in the order of 30-60% is judged feasible. Additional savings can be expected from the specialisation of well design and well construction.
- Based on the historical development of the different components making up the process of exploration and production of shale gas, as well as judgement on potential future gains, a model for potential shale gas development in Europe is outlined, covering minimum, most likely and maximum scenarios of the key variables contributing to the cost of shale gas production.

Regarding land and resource access:

- There is a tight interrelationship between the regulatory, environmental, technical, social and economic challenges associated with land access for shale gas development. A series of obstacles to accessing land for unconventional gas development have been revealed: water management; protected areas; mineral right and royalties; surface disturbance; noise and visual impact; community impact; waste management; as well as the need to engage multiple small land owners and communities.
- Land is required to find, develop, produce and transport gas, which includes well pads, access roads, utility corridors (water and electricity lines, etc.), space for gas gathering lines, water management facilities, etc.
- It has become common to use a single pad for multiple horizontal wells (typically four to eight wells at present in the USA) in order to develop as much subsurface area as possible from one spot. Such pads require some one to four hectares of land. However, the effective surface area usage per well is significantly lower when constructing horizontal multi-well pads.
- Well density or well spacing will depend on geological and other factors. The number of well pads per square mile typically varies from 16 for single vertical wells, down to one, for horizontal multi-well configurations with six to eight wells on each pad.
- In addition to direct land use, there are disturbances caused by the duration and intensity of all the activities related to exploration, e.g. truck trips, noise levels and visual impacts. The duration of activities (including the construction of well pads and access roads, drilling, well completion and clean up) depend on multiple factors (number of wells per pad, and geological, logistical and regulatory factors). The

duration of the complete operation typically vary from 5 to 36 months (for horizontal single and multi-well pads respectively).

- It is necessary to consider the *cumulative impact* of several horizontal wells being drilled annually over a longer period of development. The potential impacts must be balanced with other land usage, such as wildlife, agriculture and tourism, and the overall quality of life in a community.

Regarding the regulatory framework:

- A successful regulatory regime governing the exploitation of sub-surface minerals must reconcile the objectives of three main sets of actors: governments, with their desire to maximise rents while achieving socioeconomic and environmental objectives; market players and their desire for a return on investment that is consistent with the risk associated with the project; and finally, the needs of societal actors to preserve or improve welfare in social, monetary or environmental terms. Key regulatory issues reported can be categorised according to their technical/logistical, legal and socioeconomic dimensions.
- With farm plots smaller and land ownership more diffuse in Europe, a key regulatory consideration is how to manage multiple landowners and their varying claims and concerns. In the USA, this is addressed by what is known as pooling and unitisation (the combination of several small tracts of land needed to support a well or well pad, up to the field-wide operation of a producing reservoir), which allow for managing concession areas fairly and effectively. Such an approach, whereby the development of a 'complex' of multiple well pads is managed centrally, helps to avoid duplication of infrastructure, as well as goods and service procurement. It speeds up permitting procedures and reduces environmental impact.
- It is often argued that because the landowners own both surface and mineral rights in the USA, this favours shale gas development (financially benefitting the landowner), whereas because the sub-surface rights would generally be owned by the state in the EU, landowners have no incentive to support development. However, the situation is more complicated in both the USA and the EU, as well as being variable between different EU Member States. The real distinction is the degree to which surface landowners have a say in granting permission to develop an area.
- In the USA, the law tends to favour the owner of the mineral estate, whilst often granting the right to compensation for the use of the surface. In the EU, on the other hand, there is variation between Member States in the extent to which surface landowners can restrict the development of shale gas. France, the United Kingdom and Poland all have different regimes in place.

Regarding market access:

- There are two principle determinants of whether new gas resources are able to reach markets: 1) their physical proximity to suitable gas transportation infrastructure; and 2) the regulatory structure of the natural gas market. Whilst the distance between the wellhead and pipelines drives up the capital and operating costs required to deliver gas to consumers, the structure of the natural gas market has important implications for how easily new supplies are able compete with established supplies.

- The US and EU gas transportation systems are broadly analogous in terms of gas transmission pipeline density if we take into account the dense infrastructure in certain parts of the USA that is the legacy of many years of hydrocarbon development. There are 53km of transmission pipeline for every 1000 km² in the USA, compared with 29km in the EU.
- A liberalised and competitive market formed an important part of the regulatory backdrop to the unconventional gas revolution in the USA. The increased investor risk in this liberalised market has not prevented the completion of major infrastructure investments intended to bring unconventional gas to market. This is in spite of the narrower profit margins and greater uncertainty commonly ascribed to unconventional gas production.
- As large-scale shale gas production has so far not been observed outside of liberalised energy markets, questions remain about whether the phenomenon can be replicated in differently structured markets and, if so, how this might look.
- Whereas the USA has a fully liberalised market for natural gas, reforms to the EU's internal gas market are still ongoing. There have been encouraging recent developments indicating that EU market liberalisation is gathering pace. However, a recent European Commission report on market progress concedes that 'a truly single energy market is far from complete'. Questions thus remain as to whether the EU's internal market rules can be practically applied in the context of possible unconventional gas development and be clear, non-discriminatory, timely and repeatable across large operations.

Regarding the impact of shale gas in the USA:

- Unconventional gas production in the USA has increased markedly in the last decade. It accounted for 58% of domestic production in 2010, causing the USA to surpass Russia as the largest gas producer in the world. Much of the expansion has been due to shale gas, which accounted for 23% of total US natural gas production in 2010. Consequently, projections for future US production have been continuously revised upwards.
- It was initially expected that the USA would need to import substantial quantities of LNG, which led to massive investments in the LNG infrastructure in the last decade. The reality, however, is that the USA has ended up requiring less than 10% out of its current 150 bcm re-gasification capacity. Instead there are now plans to add export capabilities.
- Most of the growth in demand for gas in the USA is expected to occur in the power generation sector, followed by transportation (natural gas vehicles) and in the petrochemical industries. Gas-fired power plants have cost, timing and emission advantages compared to coal-fired plants, and incremental increases in gas-fired electricity capacity have been observed since 2005, which is backed up by reported plans for the coming years. The extent to which these advantages are capitalised upon depends partly on the extent to which US producers decide to export natural gas via LNG.
- Cost estimates for shale gas production and the break-even price that is necessary to recoup expenditures per well vary considerably and are subject to much contestation. Break-even price estimates in the USA have been reduced lately and

range between \$3-7/MBtu. Estimates for Europe vary between \$5-12/MBtu. However, the production of natural gas liquids from shale wells is reportedly having a significantly positive effect on shale well economics in the USA, and technological learning, which has contributed to reducing total drilling and completion costs by half in the last five years, is expected to lower costs even more.

- Estimates of future natural gas prices in both the USA and for Europe have been repeatedly revised downwards in recent years, supported by the increase in shale gas developments. The spot price for natural gas in the USA (Henry Hub) has fallen from a peak at \$13/MBtu in mid-2008 down towards \$2/MBtu in 2012.

Regarding the impact in Europe to date:

- Global LNG trade volumes increased two-fold between 2000 and 2010, and increasing LNG liquefaction and regasification capacity looks set to continue to drive this trend for the foreseeable future. As a major consumer of natural gas, Europe is robustly contributing to this trend: the EU's current regasification capacity of 150 bcm looks set to double by 2020.
- There is ample evidence that LNG is changing the characteristics of global gas markets. Whereas the high cost of transporting gas had previously restricted trade to specific regions, fluctuations in supply, demand and prices are increasingly being transmitted throughout the globe.
- Rapidly increasing LNG capacity in receiving terminals in North-West Europe strengthened the link between UK and US gas hub prices between 2009 and 2010, enabling many EU Member States to benefit from the cheap spot-traded gas partially resulting from increased unconventional gas production in the USA. US net imports of natural gas fell 30% between 2007 and 2010.
- With legal and technical barriers to growing volumes of spot-traded gas disappearing as EU market reforms take effect, the sharp fall in spot prices witnessed in 2009 and 2010 occasioned widespread dissatisfaction amongst the utilities, which were locked into buying gas on oil-indexed terms as they were gradually priced out of the market. Spot gas prices were some 25% lower than oil-indexed gas during this period.
- The close correlation between US and EU gas hub prices came to an end around April 2010 as a result of unforeseen demand-side events, including the Fukushima disaster. However, the current balance of expert opinion suggests that the EU will continue to move slowly away from oil indexation because of the persisting risk of future exposure to discount hub prices.

Regarding potential impacts on the global energy system:

- To explore the uncertainty surrounding the reserve size and production costs of shale gas, a scenario analysis has been carried out with a global energy system model, ETSAP-TIAM, which is able to capture the complex and interrelated factors driving future gas supply and demand developments. Some preliminary conclusions as to what can be expected from shale gas development are summarised in the following points.

- Overall, the scenario analysis highlights that shale gas does have the potential to extensively impact global gas markets, but only under strongly optimistic assumptions about its production costs and reserves.
- In a scenario favourable to shale gas development, natural gas as a whole has the potential to capture 30% of the world's total primary energy supply by 2025, rising further to 35% by 2040. This would make it surpass oil as the world's foremost source of energy.
- Relative to a scenario that is not carbon constrained, strict CO₂ emissions targets reduce the production of natural gas, including shale gas. However, the strict CO₂ emissions targets modelled do not preclude a significant absolute growth in natural gas use. The modelling results therefore support the potential role of natural gas as a bridge fuel.
- Shale gas is relatively evenly dispersed around the world and the majority of regions will likely witness at least some level of production in the future. The USA and China are well placed to become the top producers of shale gas, although significant production also takes place in most of the other regions. The scenario analysis suggests that shale gas will tend to be used within the regions where it is produced. No single region will produce enough shale gas so as to move from being a net importer to a net exporter.
- The global trade in natural gas, driven by conventional gas, will increase in any scenario. Shale gas development, however, has the potential to moderate the degree of growth, particularly for interregional LNG flows. Low LNG costs would mitigate the reduction in trade resulting from widespread shale gas development.
- Significant shale gas production has the potential to lower natural gas prices, although the extent of this reduction strongly depends on the way natural gas will be priced in the future. In particular, oil indexation has the potential to reduce the fall in gas prices resulting from shale gas development.
- The degree of penetration of gas in transport strongly depends on the oil-gas price link. A weaker link implies greater potential for shale gas to induce a significant growth of gas use in transportation.
- The impact on demand in an optimistic shale gas scenario is not equal across all regions. Much depends on the relative competitiveness of fuels and technologies in each region. This is particularly apparent for electricity generation. While shale gas can induce a dramatic change in the USA's electricity generation mix, its impact on China's mix is more limited.
- Shale gas production will not make Europe self-sufficient in natural gas. The best case scenario for shale gas development in Europe is one in which declining conventional production can be replaced and import dependence maintained at a level around 60%. Regarding trade flows, the structure of EU gas imports is very sensitive to the LNG cost assumptions.

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Acronyms

1P – Proved reserves

2P – Proved and probable reserves

3P – Proved, probable and possible reserves

ACER – Agency for the Cooperation of Energy Regulators

AEO – Annual Energy Outlook report by the EIA

BAU – Business-as-usual

bcm – Billion cubic metres

bbl – Barrel

BGR – Bundesanstalt für Geowissenschaften und Rohstoffe

boe – Barrel of oil equivalent

CBM – Coal-bed methane

CCGT – Combined cycle gas turbine

CCS – Carbon capture and storage

DCA – Decline curve analysis

DECC – United Kingdom's Department of Energy and Climate Change

DG ENER – European Commission Directorate-General for Energy

DG ENV - European Commission Directorate-General for the Environment

DTS – Distributed temperature sensing

E&P – Exploration and production

EBPP – Evidence-based policy and practice

EIA – United States of America's Energy Information Administration

ENTSO – European Network of Transmission System Operators

EPA – USA's Environmental Protection Agency

ERR – Economically recoverable resources

ETSAP – Energy Technology Systems Analysis Programme

ETSAP-TIAM – ETSAP-TIMES Integrated Assessment Model

EU – European Union

EUR – Estimated ultimate recovery

EV – Electric vehicle

F&D – Finding and development

FERC – USA's Federal Energy Regulatory Commission

FRS – EIA's Financial Reporting System

FSU – Former Soviet Union

FT – Flat time
FTE – Full-time employment
GDP – Gross Domestic Product
GHG – Greenhouse gas
GJ – Gigajoules
Gt – Gigatonne
GTL – Gas-to-liquids
Gtoe – Gigatonnes of oil equivalent
ha - Hectares
HHV – High heating values
ICE – Intercontinental Exchange
IEA – International Energy Agency
ILT – Invisible lost time
IP – Initial production
KOP – Kick-off point
kPa – Kilopascal
LEL – Lower explosive level
LDC – Local distribution companies
LHS – Left-hand side
LNG – Liquefied natural gas
LOE – Lease operating expenditures
LPG – Liquefied petroleum gas
MBtu – Million British thermal units
mcm – Million cubic metres
Mcf – 1 000 cubic feet
Mcfe – 1 000 cubic feet equivalent
mD – Millidarcy
MIT – Massachusetts Institute of Technology
MMBtu – Million British thermal units (alternative convention to MBtu)
MMcf – Million cubic feet
MSM – Microseismic Mapping
Mtoe – Million tonnes of oil equivalent
mtpa – Million-tonne-per-annum
MWD – Measurement while drilling
MWh - Megawatt hour

NBP – National Balancing Point
NIMBY – Not in my backyard
NGL – Natural gas liquid
NGV – Natural gas-powered vehicle
NPC – National Petroleum Council
NPT – Non-productive time
NYMEX – New York Mercantile Exchange
NYSDEC – New York State Department of Environmental Conservation
NYSERDA – New York State Energy Research and Development Authority
OECD – Organisation for Economic Co-operation and Development
OGIP – Original gas in place
PJ – Petajoules
ppm – Parts per million
PPRTVs – Provisional peer-reviewed toxicity values
PRMS – Petroleum Resources Management System
PT – Productive time
PV – Photovoltaic
RHS – Right-hand side
RSS – Rotary steerable systems
RTRR – Remaining technically recoverable resources
R&D – Research and development
SEC – US Securities and Exchange Commission
SGEIS – Supplemental Generic Environmental Impact Assessment
SPE – Society of Petroleum Engineers
Tcf – Trillion cubic feet
Tcm – Trillion cubic metres
TDS – Total dissolved solids
TPA – Third party access
TRR – Technically recoverable resources
TSO – Transmission system operators
TWh – Terawatt hours
UK – United Kingdom
UKERC – United Kingdom Energy Research Centre
URR – Ultimately recoverable resource
USA – United States of America

USGS – United States Geological Survey

WEC – World Energy Council

WEO – World Energy Outlook report by the IEA

1 Introduction

I. Pearson (European Commission, JRC F.3)

1.1 What is this report about?

This report investigates the impact of unconventional gas on European Union (EU) energy markets.

Natural gas resources can be coarsely classified as being either conventional or unconventional. Conventional gas dominates worldwide production, accounting for over 85% of total marketed output today.¹ Generally speaking, conventional gas is gas extracted from discrete, well-defined, high-permeability reservoirs. The fact that gas can easily migrate to the wellbore and up to the surface in these reservoirs means that they can usually be developed using vertical wells only and often yield economic recovery rates of more than 80% of the original gas in place (OGIP).

Unconventional gas is gas produced using additional processes beyond the standard drilling techniques deployed widely in conventional reservoirs. Unconventional gas resources are generally found in less permeable rock formations and for this reason they are more complex to extract. These resource accumulations may be distributed over a much larger area than conventional accumulations and typically require well-stimulation measures in order to be made economically productive. Recovery rates are much lower than in conventional gas — typically of the order of 15-30% of OGIP.²

There are three main types of unconventional gas produced today; shale gas, tight gas and coal-bed methane.³ Shale gas is natural gas produced from commonly occurring shale rock formations, a kind of sedimentary rock that is rich in organic matter. Tight gas refers to gas deposits found in low permeability rock formations, like sandstone.⁴ And coal-bed methane, as the name implies, is natural gas contained in coal beds.

1.2 Why is this report needed?

Fossil fuels, such as oil, gas and coal, are by far the largest sources of energy in Europe, comprising just over 75% of gross inland consumption in 2010.⁵ While governmental support will ensure that alternative energy sources such as renewables will increasingly

¹ IEA, 'Are we entering a golden age of gas?', in *World Energy Outlook* (Paris: Organisation for Economic Co-operation and Development 2011), 50.

² E.J. Moniz, H.D. Jacoby and A.J.M. Meggs, 'The future of natural gas', (Cambridge, Massachusetts: Massachusetts Institute of Technology, 2010), 6.

³ Other kinds of unconventional gas, such as methane hydrates, are at a much earlier stage of development.

⁴ Tight gas is sometimes considered to be a continuation of conventional gas because tight gas sandstone and limestone are simply reservoir rocks, whereas coal and shale are considered to be both the source and the reservoir rock.

⁵ Source: Eurostat.

contribute to total energy supply, hydrocarbons are widely projected to dominate the European energy mix through to at least 2030.⁶

It has long been known that global unconventional gas resources may be significant – they are roughly equal to conventional gas resources, according to one widely cited estimate.⁷ In spite of their abundance, however, it was traditionally thought that the vast majority of the resource base was too difficult or costly to be commercially extracted. For this reason, virtually all estimates of the global oil and gas endowment up to the 1990s focused on conventional reserves and resources.⁸ In recent years, however, two key developments have shifted the focus to so-called 'unconventionals'.

The first has been mounting concern that growing demand for energy worldwide would outstrip supply. Whilst uncertainty over access to fossil fuel reserves persists, global population growth and rising standards of living in the developing world have pushed energy demand up considerably. These two factors have resulted in significant increases in the market prices of oil and natural gas over the last decade.

The second factor has been a dramatic increase in unconventional gas production in North America. Against the backdrop of stiffer international competition for resources, unconventional gas production in the USA has robustly increased, more than offsetting the steady decline in domestic conventional gas production. Unconventional gas accounted for around 60% of all gas produced in the USA in 2010 – shale gas was 23%.⁹ This has had a dramatic supply impact, turning the relatively tight US gas markets of 2006-07 into a buyers' market with depressed natural gas prices now forecast to continue for some years to come.¹⁰ The sharp increase in shale gas production is particularly striking in light of the significant OGIP estimates of the resource not only in the USA, but globally.

⁶ European Commission, 'Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network', ed. Directorate-General for Energy (Luxembourg: Office for Official Publications of the European Communities, 2010).

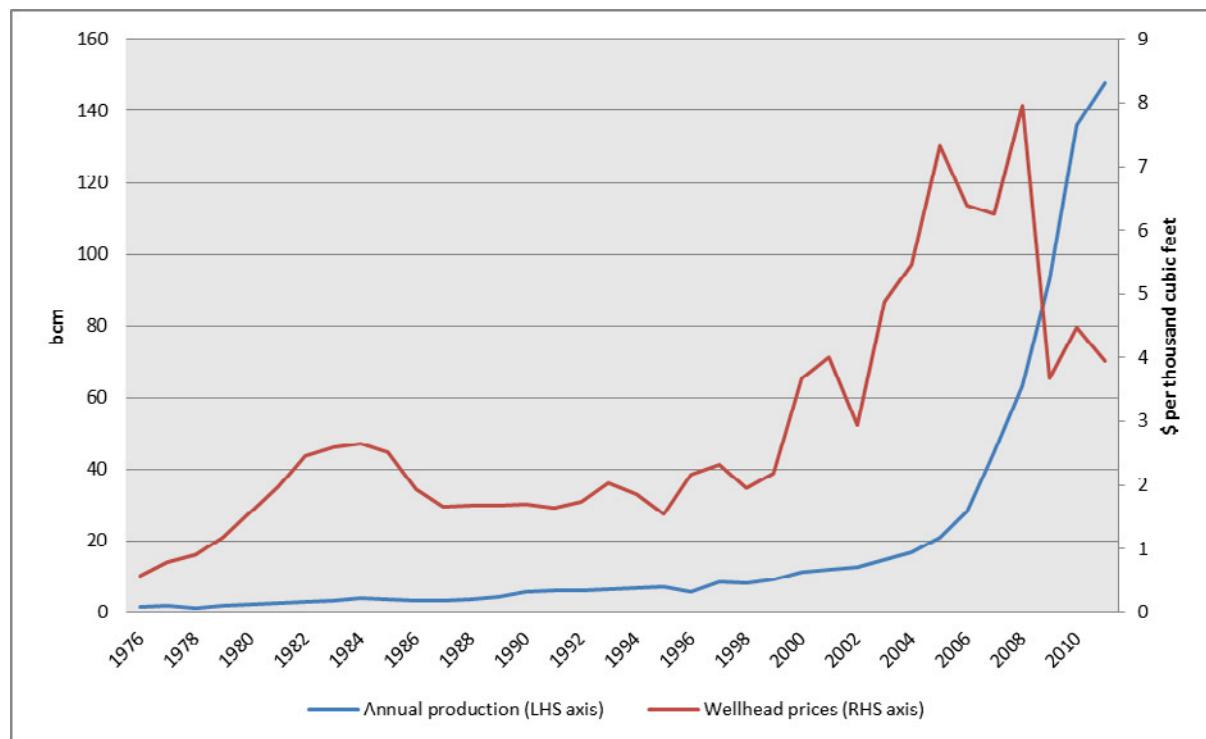
⁷ H.H. Rogner, 'An Assessment of World Hydrocarbon Resources', *Annual Review of Energy and the Environment* 22 (1997).

⁸ NPC, 'Facing the Hard Truths about Energy: A comprehensive View to 2030 of Global Oil and Natural Gas', (Washington DC: National Petroleum Council, 2007), 96-97.

⁹ Source: EIA.

¹⁰ EIA, 'Annual Energy Outlook 2011 with Projections to 2035', (Washington, DC: US Energy Information Administration, 2011).

Figure 1-1: Shale gas production and wellhead gas prices in the United States of America¹¹



The recent increase in unconventional gas production in the USA has been underpinned by technological advancements in hydraulic fracturing and horizontal drilling. These have been essential in reducing the per-unit production cost of process-intensive unconventional gas operations, making them progressively more price competitive with conventional gas. They have also unlocked access to resources previously beyond technical reach, increasing estimates of the size of the recoverable resource. These advances have been so noteworthy that they are covered in greater detail in Chapter 3 of this report.

Besides the technological aspects, however, market forces are also relevant to our understanding of the US case. Higher market prices made previously marginal or uneconomic resources profitable to extract because they compensated for the higher costs involved in producing these resources. Price signals provided important incentives for switching to different fuel sources and they encouraged exploration, which led to the discovery of resources that were previously unknown. Most significantly in the case of US unconventional gas, rising prices incentivised the development and deployment of new technologies. In this way, the recent increase in US unconventional gas production can be understood within the fundamental economics of the price mechanism.¹²

Many questions still remain about how easily unconventional gas resources can be developed elsewhere. However, at the time of writing there are growing expectations

¹¹ Source: Production data from 1982-1989 taken from J.A. Slutz, 'Unconventional gas resources: well completions and production challenges' (paper presented at the Methane to Markets Partnership Expo, Beijing, China, 2007). Production data from 1990 onwards taken from EIA, 'AEO 2011'. Price data from EIA.

¹² It is also important to note the effect of US Government initiatives, such as the Section 29 Non-Conventional Gas Tax Credits introduced in 1980. This provided a \$0.50/Mcf incentive for gas produced from tight gas sands, coal-bed methane and Devonian shale.

that 'potential barriers to further unconventional gas production will be largely overcome and that increased supplies become available in other regions at costs comparable to those in North America'.¹³ In light of the fact that rock formations potentially yielding unconventional gas can be found in abundance in many parts of the world, this has sent ripples through the energy research community. Rock that was previously considered to be of little value suddenly held the promise of changing some long-held assumptions about natural gas as an energy carrier.

Although proven reserves¹⁴ of conventional gas have increased steadily since the 1970s, the distance of much of these from markets¹⁵ has prevented a greater role for natural gas in the global energy mix. This is because natural gas has much less flexibility in terms of transmission and storage when compared with, say, oil or coal, owing to its gaseous form and low energy density. Considerable capital expenditure is necessary to bring it to market, whether by pipeline or as liquefied natural gas (LNG), making natural gas relatively expensive to transport. The inflexibility and high cost of gas transit infrastructure also tends to lock buyers and sellers into long-term relationships and makes it difficult to replace lost gas supplies.

Being highly import-dependent for gas and other energy products, the EU is especially affected by these concerns. The EU currently brings in well over half of the energy it consumes,¹⁶ and it estimates that, in the next 20-30 years, falling indigenous production levels will mean that up to 70% of its energy demand will have to be met through imports.¹⁷ Due to questions remaining about how quickly extraction capacity can be expanded by some of Europe's most important suppliers, it is little wonder that the focus on unconventional gas has been intense, in spite of the fact that the continent itself is only at the earliest stages of exploration for shale gas – the one that could be the most significant form of unconventional gas.

¹³ IEA, 'Golden age', 17-18.

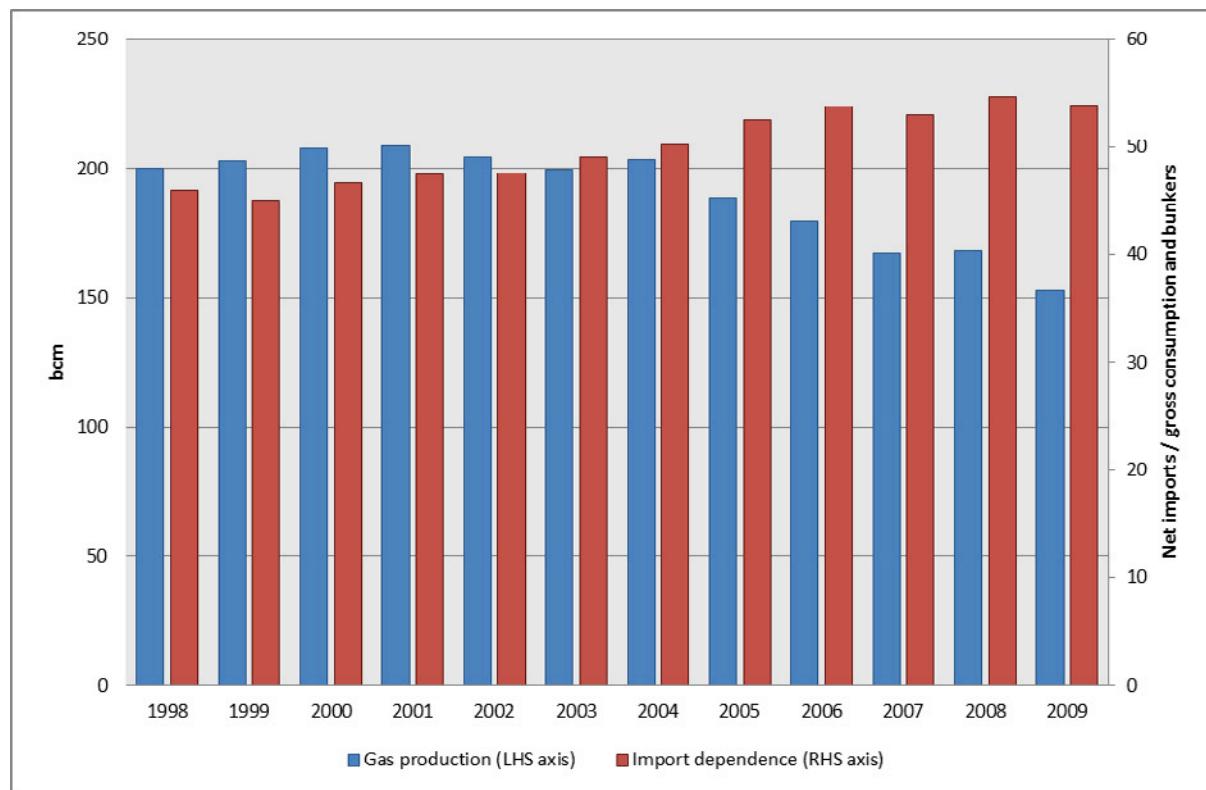
¹⁴ An industry term for reserves that can be easily recovered with the highest degree of confidence.

¹⁵ Two-thirds of global proven reserves of natural gas are located in Russia, Iran, Qatar, Saudi Arabia, the UAE, Venezuela and Nigeria. BP, 'Statistical review of world energy', ed. BP (2011).

¹⁶ Source: Eurostat.

¹⁷ European Commission, 'Towards a European strategy for the security of energy supply', ed. Directorate-General for Energy and Transport (Luxembourg: Office for Official Publications of the European Communities, 2000).

Figure 1-2: Primary production of natural gas and energy import dependence in the EU-27¹⁸



Unconventional gas may offer a number of security-of-supply benefits for the Union, helping natural gas to become cheaper and more readily available on the European market. Unconventional gas may make it easier for the EU to meet its future energy needs, either through increasing indigenous production levels, or by reducing demand for gas elsewhere in the world, thus freeing up more supplies that can be imported. Easing tightness in global energy markets has recently been given added importance in light of waning public support for nuclear power following the Fukushima disaster.

Given the concentrated nature of conventional gas supplies and the high costs and risks associated with long-distance transportation, there may also be considerable economic and strategic value in the development of unconventional resources closer to the European market. Such supplies would add diversity to the EU's gas supplies – a key goal of EU energy policy.¹⁹ Many Southern and Eastern European states were severely affected by a disruption of Russian gas through Ukraine in 2009, and the continued instability in other supplier states as a result of the 'Arab Spring'²⁰ is a compelling reminder of the dangers of over-dependence on any one gas source or supply route.

Better diversification of supplies could also improve the EU's bargaining position as a gas consumer. High prices for piped gas in those EU Member States with only a single

¹⁸ Source: Eurostat. Dry marketable gas production measured after purification and extraction of NGLs (Natural Gas Liquids) and sulphur. Energy dependency shows the extent to which an economy relies upon imports in order to meet its energy needs. The indicator is calculated as net imports divided by the sum of gross inland energy consumption plus bunkers.

¹⁹ European Commission, 'The EU energy policy: Engaging with partners beyond our borders', ed. Directorate-General for Energy (Luxembourg: Office for Official Publications of the European Communities, 2011), 5.

²⁰ In particular, Italian supplies of crude oil and natural gas were strongly affected by the unrest in Libya in 2011.

supplier suggest that greater economic efficiency can be achieved through the introduction of alternative supply options. Theoretically speaking, the broad geographical distribution of unconventional gas reserves could also reduce any nascent gas cartel's power to control the scarcity, and hence price, of global natural gas supplies.

Increased unconventional gas production may also have climatic and environmental benefits. When burned, natural gas emits less CO₂ and local pollutants²¹ than other fossil fuels. As a result of this, some have argued that the use of natural gas for power generation is among the cheapest and fastest ways to reduce CO₂ emissions, and that additional unconventional production may help natural gas play a role as a 'bridging fuel' until a permanent transition can be made to renewable sources of energy. Gas may also have an important function as lower carbon-backup generation to help balance the intermittency of many renewable energy sources. Finally, substituting imports of gas extracted far away with unconventional gas produced closer to markets may reduce the carbon cost associated with the transportation of that gas and hence its life-cycle carbon footprint.

Whilst the benefits listed above are notable, unconventional gas carries a host of potential negative impacts and risks. Environmental concerns include the risk of induced seismicity, as well as the strain on land use in areas developing shale gas. Concerns centre, however, on the large volume of water required for the hydraulic fracturing process; the disposal of this water once it has been used; and the potential contamination of fresh water aquifers as a result of drilling and well stimulation processes. The latter point is especially of concern because the treatment of contaminated groundwater can be a long and costly process and may even be impossible in some cases. As such, moratoria on the hydraulic fracturing process have been sought while further investigation is carried out in certain US states, Quebec, South Africa, Bulgaria and France.

With regard to climate policy, at the time of writing there is growing concern over the life-cycle emissions from unconventional gas; particularly shale gas. Whilst gas that is sourced from unconventional shale or sandstone formations emits the same amount of CO₂ when burned, the additional processes necessary to extract it mean that more greenhouse gas is generally emitted at the mining stage. The extent of these additional emissions may diminish, and in the worst case even negate, any life-cycle emissions advantage natural gas has over competing fuels, such as coal.

Finally, the International Energy Agency (IEA) has estimated that – under the right conditions – unconventional gas may meet more than 40% of the increased global demand for gas to the year 2035.²² This raises two investment-related questions. First, if projections such as these come to pass, then natural gas will probably gain a greater share of the global energy mix. But what will it displace? Some have suggested that cheaper gas may challenge the political commitment to certain kinds of renewable energy that still require government support in order to be price competitive. Given that a shift to gas alone will not be sufficient to meet agreed CO₂ emission targets, this may have significant implications for climate change. Secondly, if the actual volume of future unconventional gas supplies does not meet expectations, large infrastructure investments could be diverted from viable alternatives, with related supply-side

²¹ Sulphur dioxide (SO₂), nitrogen oxides (NO_x) and particulate matter (PM_{2.5}), for example.

²² IEA, 'Golden age', 29.

consequences.²³ In both cases, too zealous a commitment to developing gas resources could lock the EU into an energy mix that fulfils neither its security of supply nor its climate requirements.

In light of the possibilities outlined above, questions have been asked about if and how European policy-makers should respond to the opportunities and challenges posed by unconventional gas. The European Council itself has stated: "In order to further enhance its security of supply, Europe's potential for sustainable extraction and use of conventional and unconventional (shale gas and oil shale) fossil fuel resources should be assessed."²⁴ The difficulty faced by policy-makers is that the literature is highly polarised, with no clear consensus within the expert community on a number of issues that are critical to understanding both the modalities and the extent of the impact of unconventional gas.

One explanation for this polarisation is the broad assortment of stakeholders who either stand to gain or lose as a result of increased unconventional gas production. As unconventional gas may take market share from coal, nuclear or renewable energy – as well as 'traditional' gas suppliers – commentators have suggested that the phenomenon has mobilised the commercial, political and academic advocates of each of these industries. By this view, both the proponents and opponents of unconventional gas are embellishing its potential benefits and risks in order to generate sufficient public concern to either advance or prevent its expansion.²⁵

Another, more tangible explanation for this polarisation is that the shale gas industry is still in its infancy and that this immaturity is reflected in the inconsistent quality of the evidence that has, until now, been available. In the USA, much of the gas produced thus far has come from the most fruitful 'sweet spots' that may not be representative of the productivity of entire formations. There is a lack of comprehensive and independently corroborated data on geology, the results of exploration drilling and the long-term production levels of wells.²⁶ Industry practice is evolving so rapidly that ultimate recovery rates and unit costs of produced unconventional gas are moving targets, with some forecasts predicated on the anticipation of future technological progress. And estimating the break-even costs for shale gas production is made more difficult because of the possible production of quantities of natural gas liquids (NGLs), which fetch a high market price, from certain shale plays.

The knowledge deficit is even more acute outside the United States of America, where other key variables such as drilling service costs, environmental regulation, pricing mechanisms and the structure of markets are largely untested. And finally, one-off events, like the global economic crisis and the slew of long-planned LNG projects coming online between 2009 and 2010, have so far made it difficult to assess the economic and trade effects of shale gas in isolation.

²³ It should be noted that improvements to Europe's natural gas infrastructure are needed regardless of the future contribution of unconventional gas.

²⁴ European Council, 'Conclusions on Energy - 4 February', (Brussels: 2011).

²⁵ Matt Ridley, 'The Shale Gas Shock', (London: The Global Warming Policy Foundation, 2011).

²⁶ In France drilling data is available immediately – production data after ten years. The UK and the Netherlands have a four-year confidentiality period for drilling data. In Sweden there is a five-year waiting period – 20 years for offshore wells. In Denmark the confidentiality period is five years. In Germany data is never made publicly available.

1.3 Objectives and scope of this report

In the interest of effective policy-making, this report seeks to clarify certain controversies and identify key gaps in the evidence-base relating to unconventional gas. The scope of this report is restricted to the economic impact of unconventional gas on energy markets. As such, it principally addresses such issues as the energy mix, energy prices, supplies, consumption and trade flows.

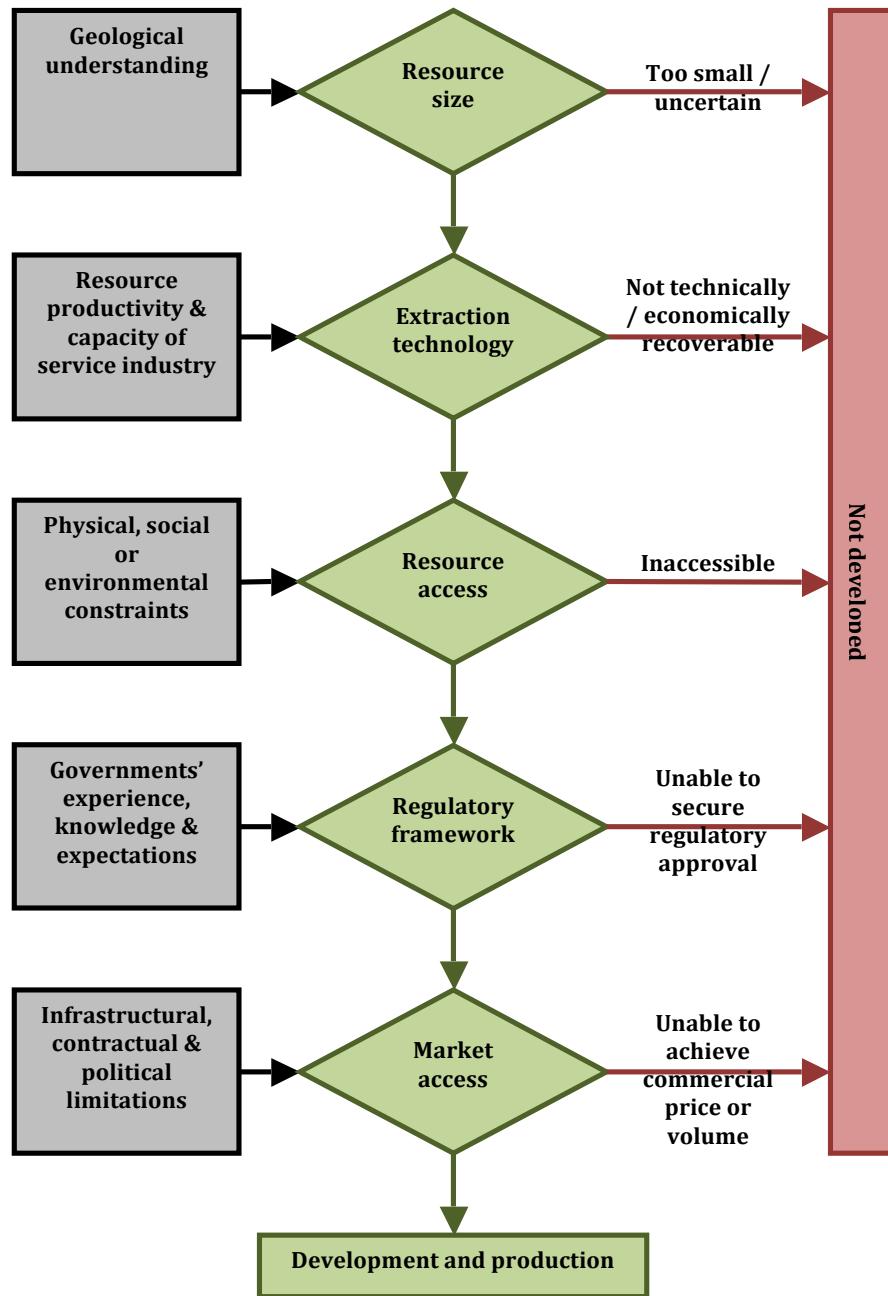
A selection of other topics that have a direct bearing on the economic impact of unconventional gas are also tackled, albeit to a less detailed extent. For instance, whilst local pollution and climate change considerations increasingly influence our energy choices, this report only touches on these aspects to the extent to which they impact unconventional gas production or consumption patterns. It should be noted that other Commission services are currently examining whether the environmental challenges of unconventional gas production can be effectively managed through regulation, monitoring and the application of industry best practices. In this vein, the JRC Institute for Environment and Sustainability is in the process of preparing a report reviewing the literature on environmental impacts. Regarding the direct greenhouse gas emissions stemming from unconventional gas mining, this report touches on notable sources. However, it does not engage in a thorough examination of the methodological merits and weaknesses of these sources.

Whilst this study touches on coal-bed methane and tight gas, its predominant focus is on shale gas, which the evidence at this time suggests will be the form of unconventional gas with the most growth potential in the short to medium term. It should be noted that, despite this focus, the processes used in shale gas extraction – particularly hydraulic fracturing and horizontal drilling – are to a degree shared by tight gas and coal-bed methane, as well as conventional gas. Technological gains in these areas are therefore likely to also result in improvements in the extraction of natural gas from other sources.

This report considers the prospects for the indigenous production of shale gas within the EU's 27 Member States. Informed by the factors identified in Figure 1-3 below, it evaluates the available evidence on resource size, extractive technology, resource access and market access. With regards to the regulatory framework, this report uses as an input the analysis provided by the legal study commissioned by the European Commission and delivered by the law firm Phillippe and Partners in November 2011.²⁷ The two reports are thus complementary in their scope.

²⁷ Philippe & Partners, 'Final Report on Unconventional Gas in Europe', (Brussels: European Commission, 2011).

Figure 1-3: Factors determining the viability of natural gas developments²⁸



This report also considers the implications for the EU of large-scale unconventional gas production in other parts of the world. This acknowledges the fact that many changes in the dynamics of energy supply can only be understood in the broader global context. It also acknowledges that the EU is a major importer of energy and that it is therefore heavily affected by developments in global energy markets that are largely out of its control. For example, whilst the current world gas trade is concentrated in three regional markets (Europe, Asia and North America), an anticipated growth in global LNG flows is likely to lead to increased price and supply interaction between regions. In spite of the fact that any significant shale gas production in the EU is not expected before 2020, the first licensing rounds for shale gas in other major energy consuming countries, such as China, have already taken place. Given the large estimated

²⁸ Adapted from IEA, 'Golden age', 47.

unconventional resource base in these countries,²⁹ their successful development may lead to supply effects on the EU market, independent of the course of any EU production.

In terms of the time horizon, this report aims to cover the impact of unconventional gas observed to date, as well as scenario analysis up to the year 2040.

Geopolitical considerations are outside the scope of this study. Many commentators have written about the possibility of unconventional gas limiting the ability of major energy exporters to use their resources as an instrument to advance political objectives;³⁰ however this report focuses on the energy market-related factors.

The economic benefits to local economies and national authorities in terms of jobs and tax revenues are also excluded from this study. Experience shows that there may be a large demand for labourers at both the gas fields and support businesses, such as drilling contractors, hydraulic fracturing companies and trucking companies. Although estimations of the economic value-added of such service sector developments are often addressed in the literature, they can be viewed as being outside the field of energy economics in a strict sense, and they require a distinct knowledge-set to evaluate in detail.

1.4 The European energy policy context

On 15 December 2011, the European Commission adopted its Energy Roadmap 2050.³¹ This Communication aims at exploring how the EU's energy system could become more sustainable and less carbon-intensive – in line with the EU's commitment to reduce greenhouse gas emissions by 80-95% in comparison to 1990 levels by 2050³² – while at the same time ensuring security of energy supply and competitiveness. The Roadmap will help to increase the long-term predictability of the regulatory framework for energy and thereby reduce uncertainty for investment by identifying initiatives that will be crucial for the decarbonisation process up to 2050. The Energy Roadmap 2050 is the start of an iterative discussion and dialogue with Member States, EU institutions and stakeholders at large.

Although forecasting the long-term future is not possible, the Energy Roadmap 2050 includes scenarios aiming at exploring possible routes towards decarbonisation. Based on this analysis, the Roadmap identifies key conclusions on 'no regrets' options (namely renewable energy, energy efficiency and infrastructure) in the European energy system, and outlines other key features for a transition to a low-carbon energy system.

The Roadmap also identifies gas as a critical fuel for the transformation of the energy system. The substitution of coal and oil with gas in the short to medium term could help to reduce emissions with existing technologies until at least 2030-2035, as well as in the longer term with the commercially availability of carbon capture and storage (CCS). Hence, in the future, Europe might need more gas in the transition towards an energy

²⁹ EIA, 'World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States', (Washington, DC: US Energy Information Administration, 2011).

³⁰ See, for example, Kenneth B. Medlock, Amy Myers Jaffe and Peter R. Hartley, 'Shale Gas and U.S. National Security', (Houston, TX: The James A. Baker III Institute Energy Forum of Rice University, 2011).

³¹ European Commission, 'Communication from the Commission to the Council and the European Parliament – Energy Roadmap 2050', ed. Directorate-General for Energy (2011).

³² In the context of necessary reductions by developed countries as a group.

system based largely on renewable energies. This gas will need to come from either domestic production or from imports – but most likely from both.

In this context, this report aims at providing reliable facts for European policy-makers and stakeholders on unconventional sources of natural gas which can, as the US example shows, have profound impacts on the assumptions and context of their work.

1.5 Methodology

This report consists of two main components. Firstly, it closely examines the unconventional gas literature covering both Europe and the rest of the world. As a second component, this report will use an energy model to elaborate possible future scenarios that illustrate the potential impact of unconventional gas on the European energy system. It will carry out this analysis based on the best, current, estimated parameters as identified in the systematic literature review.

1.5.1 Evidence-based policy and practice

Mindful of the fact that the unconventional gas knowledge-base is highly polarised and currently incomplete, this report will identify select points of controversy in the literature that may have a bearing on the impact of unconventional gas in Europe. It will simply and clearly explain why these points of controversy are important to the debate and then describe the current prevailing views. The report will then assess the existing evidence around these key points; evaluate the degree of uncertainty that currently exists; and explain how possible future developments in these areas may impact our broader understanding of the impact of unconventional gas.

In carrying out the above, Chapter 2 of this report draws upon a range of techniques referred to as *evidence-based policy and practice* (EBPP). From relatively small beginnings within the medical field, the concept of EBPP has gained increasing prominence in the UK over the last 15 years and now plays a dominant role in a number of policy areas, including education, social work, criminal justice and urban regeneration.³³ Although the UK Energy Research Centre (UKERC) has successfully applied the methodology to the energy field for a number of years, the concept remains largely unknown to policy-makers, researchers and practitioners outside the UK.

Generally speaking, EBPP implies giving greater weight to scientific research evidence in policy-making than has conventionally been the case in the past. EBPP spans a range of practices, such as a strategic approach to the creation of evidence and the effective dissemination of evidence to where it is most needed. However, the area that has received the greatest attention is the synthesis of existing evidence through a process known as a *systematic review*.

Traditional, narrative literature reviews are commonly dogged by shortcomings such as poor specification of the review topic, leading to excessively wide-ranging discussion and inconclusive results; the selective and opportunistic use of evidence, leading to selection bias and the neglect of relevant studies; inadequate specification of the criteria for including or excluding studies; limited attention to the methodological quality of different studies; and a lack of transparency, encouraging subjectivity and bias in the reporting of results.

³³ Steve Sorrel, 'Improving the evidence base for energy policy: The role of systematic reviews', *Energy Policy* 35 (2007).

Systematic reviews seek to address each of the above limitations through the use of explicit and transparent methodologies that are replicable and updateable. They involve clear specification of both the research question(s) to be addressed and the process that is to be followed; systematic and exhaustive searching of the available literature; explicit criteria for the inclusion or exclusion of studies; quality appraisal of the included studies using transparent and standardised criteria; objective summaries of the results, including the meta-analysis of quantitative data; effective dissemination of the results to the appropriate audience; and regular updating of the review results.³⁴

Table 1-1: Differences between systematic and narrative reviews³⁵

Stage	Good quality systematic reviews	Traditional narrative reviews
Deciding on review questions	Start with clear questions to be answered and/or hypotheses to be tested	May start with a clear question to be answered, but more often involve general discussion of subject with no stated hypotheses
Searching for relevant studies	Strive to locate all relevant published and unpublished studies to limit impact of selection bias	Do not usually attempt to locate all the relevant literature
Deciding which studies to include or exclude	Include explicit description of what types of studies are to be included to limit selection bias	Usually do not describe why some studies are included and others excluded
Assessing study quality	Examine in systematic manner the methods used and investigate potential biases and sources of heterogeneity between study results	Often do not consider differences in study methods or study quality
Synthesising results	Base conclusions on the studies that are considered to be most methodologically sound	Often do not differentiate between methodologically sound and unsound studies
Replicating and updating	Use protocols and explicit criteria to ensure that others would reach the same conclusions if they adopted the same methods, so the results may easily be updated	Use methodologies and criteria that lack transparency, leaving the interpretation of results open to subjectivity and bias

1.5.2 The ETSAP-TIAM model

This report will also use the ETSAP-TIAM energy model to elaborate possible future scenarios that illustrate the potential impact of unconventional gas on the energy mix, based on the best, current, estimated parameters as identified in the literature review. ETSAP-TIAM is the global multiregional incarnation of the well-known TIMES model generator that was developed and is maintained by the Energy Technology Systems Analysis Programme (ETSAP) under the aegis of the IEA.³⁶

³⁴ Ibid.

³⁵ Source: M. Petticrew, 'Systematic reviews from astronomy to zoology: myths and misconceptions', *British Medical Journal* 322 (2001). As quoted in Sorrel, 'Improving the evidence base for energy policy'.

³⁶ For more information, see The Energy Technology Systems Analysis Program, <http://www.iea-etsap.org/web/index.asp> (cited 10/10/2011).

ETSAP-TIAM is a partial equilibrium model of the energy systems of the entire world, divided into 15 regions. The regional modules are linked by trade variables of the main energy forms (coal, oil, gas) and by emission permits. For each region, the model comprises explicit descriptions of more than 1 000 technologies and 100 commodities (energy forms, materials, emissions), covering extraction, processing, conversion, trading and end-uses of all energy forms. Such technological detail allows precise tracking of capital turnover and provides a precise description of technological competition.

The model constructs a coherent image of the future energy system by choosing a mix of technologies to invest in and operate at each future period, with the objective of maximising total surplus, while respecting the many constraints of the model. The model's variables include the investments, capacities and activity levels of all technologies at each period of time, plus the amounts of energy and material flows in and out of each technology. Endogenous trade of crude oil, petroleum products, gas, liquefied natural gas and coal, as well as greenhouse gas permits, is represented in ETSAP-TIAM.³⁷

Key factors affecting future gas supply and demand are rendered into a set of workable assumptions about what can be considered as the primary determinants of future shale gas development. In particular, this report focuses on the size and production costs of shale gas resources, as well as global gross domestic product (GDP) growth. The model is then used to construct five possible scenarios of future shale gas development. The different trajectories borne out by these scenarios will be analysed and compared, with a particular focus on three main outputs: production, interregional trade and final use. In doing so, this report aims to shed light on the conditions under which shale gas can be integrated into the global energy system.³⁸

One note of caution, however. Current developments suggest that NGLs may significantly lower the effective production costs of natural gas from shale wells. As a result of a lack of reliable geological data on the NGL content of shale plays outside the USA, the modelling section of this study does not address this potentially significant factor in global shale gas development.

1.6 Report structure

Chapter 2 of this report, prepared by members of UKERC, provides a systematic review of evidence around the unconventional gas resource base – the starting point for any examination of its economic impact. By examining the methods and data sources that have been used to produce various estimates of the size and characteristics of the unconventional gas resources worldwide, this chapter teases out the main controversies and uncertainties for policy-makers, and attempts to provide a best estimate of the resource base.

Chapter 3 of this report addresses existing techniques for the extraction of unconventional gas, including an assessment of costs for different stages of exploration and production, as well as the prospects for future learning. The technological

³⁷ Richard Loulou and Maryse Labriet, 'ETSAP-TIAM: the TIMES integrated assessment model Part I: Model structure', *Computational Management Science* 5, no 1 (2008).

³⁸ Despite striving for a systemic point of view, it is invariably the case that not all factors affecting shale gas development can be considered. Aspects such as environmental impacts or legal and regulatory issues are not considered in the present analysis.

dimension of the problem is key to understanding how much of the resource base can be viably exploited and at what price. The chapter has been prepared by Prof. Gerhard Thonhauser of the University of Loeben (Austria) and although the subject material does not lend itself to a systematic review, the chapter provides a useful reference to policy-makers.

Chapter 4 of the report addresses key 'above-ground' factors that may play a role in determining the viability of indigenous unconventional gas production in Europe. In particular, it singles out two key areas of controversy in the European context – land access and market access. The chapter also provides background information for policy-makers on the complex relationship between energy independence and energy security.

Chapter 5 of this report provides an overview of evidence around the impact of unconventional gas on gas supplies, gas prices, the energy mix, transnational trade flows and gas pricing regimes. To this end, the chapter reviews empirical data on the effects of unconventional gas observed so far in both the USA and Europe, as well as modelling studies covering its possible future impact.

Finally, given the paucity of the existing data on shale gas production outside the United States of America, Chapter 6 aims to use an energy model to illustrate the potential impacts of unconventional gas in the future in order to aid policy-makers in identifying potential challenges and benefits. Key uncertainties are selected and tested, and scenarios are defined, based on the best, current, estimated parameters as identified in the literature review.

2 A review of regional and global estimates of unconventional gas resources

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J. Speirs (Imperial Centre for Energy Policy and Technology, Imperial College London, UK)

The development of unconventional gas resources is having an increasing influence on regional and global gas markets, most notably in the USA. But the future potential for unconventional gas production remains contentious, with questions over the size and recoverability of the physical resource being central to the debate. Whilst estimates of unconventional gas resources in the USA remain very uncertain, this is eclipsed by the much greater uncertainty surrounding unconventional gas resources in the rest of the world. This chapter assesses the available evidence on the size of unconventional gas resources at a global and regional level, including the estimates made to date; the methods by which they have been produced; the range of uncertainty in these estimates; and the factors that are relevant to their interpretation. Key messages include the very wide range of uncertainty that exists at this early stage of development of the resource; the confusion created by competing resource definitions; and the existence of several notable controversies in unconventional gas resource assessments.

Three separate types of unconventional gas are considered:

- **Tight gas:** this is gas trapped in relatively impermeable hard rock, limestone or sandstone, sometimes with quantified limits of permeability;
- **Coal-bed methane (CBM):** this is gas trapped in coal seams, adsorbed¹ in the solid matrix of the coal; and
- **Shale gas:** this is gas trapped in fine grained sedimentary rock called shale, which has a characteristic 'flaky' quality.

Shale gas and CBM are clearly defined, based on the nature of their occurrence in either coal seams or shale. The case of tight gas is more ambiguous since it exists in very similar geological formations to conventional gas, but exhibits relatively slow flow rates. (For a more detailed description of these forms of unconventional gas, see Section 3.1.2.) The recent interest in unconventional gas has been spurred mainly by the rapid emergence of shale gas in the USA and so this chapter, while discussing all of the unconventional gases, will focus in particular on shale gas resources.

This chapter provides a comprehensive review² of the available evidence on the size of unconventional gas resources, based upon an exhaustive search of the available literature. Greater reliance is placed upon the more rigorous studies when drawing conclusions. The chapter addresses the following four questions:

¹ Adsorbed gas refers to gas molecules which have formed some adhesion to the solid surface of the medium in which it is contained.

² M. Petticrew and H. Roberts, *Systematic Reviews in the Social Sciences: a practical guide* (Oxford: Blackwell Publishing, 2005).

- 1) What estimates have been made of unconventional gas resources? Section 2.1 examines the range of literature on all three types of unconventional gas resources in both Europe and the rest of the world, with a particular focus on shale gas resources. It also discusses the different classifications and definitions of resource estimates, indicating where these are comparable, where they differ and in which reports these definitions are used.
- 2) How do we explain the variability in shale gas resource estimates? Section 2.2 explores the differing methods used to derive shale gas resource estimates and provides an assessment of their relative strengths and weaknesses.
- 3) What does experience in the United States of America tell us about the resource estimation? Section 2.3 examines the relevance of production decline rates from individual wells, summarises some of the recent controversies over this issue in the USA, and assesses the implications for the robustness of resource estimates.
- 4) What is the range of uncertainty over the size of unconventional gas resources? Section 2.4 draws together the evidence in preceding chapters and attempts to characterise the uncertainty surrounding estimates of global unconventional gas, and particularly shale gas, resources.

2.1 Estimates: The global unconventional gas resource base

This section provides an overview of the literature providing resource estimates for the three unconventional gases. These estimates are presented in a variety of ways that are not always comparable, so it is first important to establish the meaning of the various terms and definitions that are employed. These definitional issues are discussed in detail in Section 2.1.1.

Section 2.1.2 provides a breakdown of the various types of literature that exist, categorising studies by date, region, unconventional gases covered and whether they have been peer reviewed. This is followed by a closer examination of the upward trend in shale gas resource estimates over the last two decades, which serves to demonstrate how rapidly knowledge is growing in this area. Section 2.1.3 examines the various regional and global estimates of shale gas resources, focusing in particular on those made in the last three years, while Section 2.1.4 puts these into context by comparing them with global estimates of conventional, tight and CBM resources. Using the mean of recoverable resource estimates, it is shown that shale gas may comprise some 30% of the global technically recoverable resource of natural gas. However, the main lesson is the wide variability and large uncertainty in unconventional gas resource estimates.

2.1.1 Definitions

Resource definitions

Estimates for unconventional gas resources may be provided for different levels of spatial aggregation (e.g. country, region, 'geological play',³ fields, well) and may either refer to quantities of gas that are estimated to be present or quantities of gas that are

³ A geological play is defined as "A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type." United States Geological Survey, 'Chapter GL Glossary', in *World petroleum assessment 2000: new estimates of undiscovered oil and natural gas, including reserve growth, outside the United States* (Reston, VA: US Department of the Interior, 2000).

estimated to be technically or economically recoverable. In the latter case, these estimates may be expressed probabilistically and/or given to different levels of confidence (e.g. 'probable' or 'possible'). Clear definitions and appropriate interpretation of the figures stated is important as confusion or problems frequently arise when different estimates are incorrectly compared. Within this chapter, the specific definitions given below will be used. However, the wide-ranging nature of the evidence means that not all of the reports use the same definitions. In some cases, the definition being used is not stated explicitly or at all; in others, similar terms are used but with slightly different interpretations; while in further reports, ambiguous terms that could refer to any of the definitions are employed (e.g. 'recoverable resources'). This often compounds the problem mentioned above of comparing different estimates. Wherever possible, definitions have been compared only when they are equivalent or are judged to be effectively equivalent.

A problem that frequently occurs is the use of terms applicable to conventional gas resources when referring to unconventional gas resources, where it would be clearer and less ambiguous to use alternative terms. An example of this is the use of the terms 'discovered' and 'undiscovered'. In contrast to conventional oil and gas resources, the location of the petroleum source for unconventional gas is usually known and so they are not 'undiscovered' in the traditional sense: a well drilled into an area holding unconventional gases will probably yield some volumes of gas. However, if these regions have not been extensively drilled, the precise characteristics of the geology may not be well known and there may be corresponding uncertainty regarding the technical and economic feasibility of gas production.

The Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS) indicates that 'discovered' shale gas resources require 'collected data [that] establish[es] the existence of a significant quantity of potentially moveable hydrocarbons'.⁴ To meet this criterion, the SPE indicates that there must be sufficient evidence of the existence of hydrocarbons from well tests, core and log data, together with evidence that areas which are similar to that under investigation ('analogues') can support commercially viable gas production. This appears to be a reasonable requirement, especially given the heterogeneity found in many unconventional gas plays (see Section 2.1.3). However it does not allow one to distinguish between geological areas that contain 'Resources postulated from geologic information and theory to exist outside of known oil and gas fields' (the 'traditional' definition of undiscovered conventional hydrocarbons used by the United States Geological Survey, USGS⁵) and those areas that are known but do not meet the above requirement. Unless otherwise stated, use of the term 'undiscovered' in this chapter refers only to the traditional definition – i.e. gas that is estimated to exist outside of known formations.

When reporting unconventional gas volumes, the largest figure that can be given is the initial or *original gas in place* (OGIP); this is the total volume of natural gas that is estimated to be present in a given field, play or region. This figure only conveys part of the necessary information to estimate recoverable resources, however. The fraction of the OGIP that is estimated to be recoverable – the *recovery factor* – is equally important

⁴ Society of Petroleum Engineers, 'Guidelines for Application of the Petroleum Resources Management System', (London: Society of Petroleum Engineers, 2011).

⁵ United States Geological Survey, 'Chapter GL Glossary'.

and can vary substantially depending on the geological conditions, technology used and prevailing gas prices.

The *ultimately recoverable resource* (URR) of a field or region is the sum of all gas that is expected to be recovered from that field or region over all time. This figure includes any gas that is estimated to be undiscovered (using both of the above interpretations), is not recoverable with current technology, and/or is not currently economic but which is expected to become so before production ceases. The fraction of the gas in place that can be classified as URR therefore takes into account anticipated technological developments, changes in market conditions and/or exploration efforts. Estimates of URR will therefore be sensitive to the assumptions used and are likely to be particularly uncertain during the early stages of a region's development. The industry-standard term for discussing the ultimate recovery from an individual well is the *estimated ultimate recovery* (EUR) usually denoted as EUR/well and also sometimes referred to as the 'productivity'. EUR is essentially identical to URR, although URR is usually preferred when referring to areas or regions larger than a well, and so the notation of URR/well has been used throughout this report instead of EUR/well to avoid confusion. A more detailed description of the relationship between URR and EUR is provided in Annex B.

An alternative estimate that can be given is the *technically recoverable resources* (TRR). TRR is the resource figure most frequently provided by the literature; however, complete and clear definitions of TRR are rarely provided. Sources reviewed in this chapter agree that TRR is the fraction of the gas in place that is estimated to be recoverable only with current technology; however, ambiguity remains over whether sources include undiscovered volumes of gas from their definitions and what they mean by the term 'undiscovered'. The majority of the sources that provide explicit definitions do appear to include undiscovered volumes of gas within their estimates of TRR. The report authors have therefore employed a definition whereby TRR is gas that is estimated to be recoverable with current technology in: a) discovered formations that are considered to meet the SPE/PRMS requirements; b) discovered formations that are not considered to meet the SPE/PRMS requirements; and c) undiscovered formations.

If cumulative production to date is subtracted from the estimated TRR, the residual is referred to as the *remaining technically recoverable resources* (RTRR). In practice, given the infancy of unconventional gas production outside a few areas in North America, these two terms are effectively equivalent in the majority of regions. Where relevant and possible, estimates can be converted to the definition stated (TRR, URR, etc.) using the cumulative production data shown in Figure 2-5.

Since not all of the technically recoverable resources will be economic to recover, for example in fields with low production rates and high costs, a further subset of the technically recoverable resources is often given: the *economically recoverable resources* (ERR). Similar to TRR, this estimate typically includes any gas that is in: a) discovered formations that are considered to meet the SPE/PRMS requirements; b) discovered formations that are not considered to meet the SPE/PRMS requirements; and c) undiscovered formations. However, unlike TRR, the ERR must be considered to be both technically and economically recoverable. In principle, if the market price was to increase or the production costs decrease, the estimated volume of economically recoverable resources would be expected to increase (and vice versa).

The concept of economically recoverable resources of unconventional gas in undiscovered areas is strange: there appears to be little basis for assumptions about the

economic viability of resources within regions which have not yet been found, have not been drilled and about which very little information is available. However, a number of sources⁶ report the economically recoverable resources for conventional oil and gas in undiscovered areas. So in order to provide consistency, gas in undiscovered areas within the report's definition of ERR for unconventional gas has also been included here, although it could equally be argued that it should be excluded.

Reserve definitions

The final subset of resources is *reserves*. The exact definition of reserves varies from one source to another, but they are generally those portions of the economically recoverable resources that have been discovered (i.e. fulfil the SPE/PRMS criterion described above) and are estimated to have a specified probability of being produced. Reserve estimates are frequently given to three levels of confidence, namely: *proved reserves* (1P); *proved and probable reserves* (2P); and *proved, probable and possible reserves* (3P). In principle, an estimate of economically recoverable resources includes both reserves and the estimated volumes of undiscovered gas that is considered to be economically recoverable. However, estimates of ERR are rarely given a probabilistic interpretation, so typically it is not clear whether they are based upon 1P, 2P or 3P reserve estimates.

Definitions of the 1P, 2P and 3P reserves vary widely from one country to another and from one company to another, with some employing a deterministic definition (certain qualitative criteria must be satisfied) and others using a probabilistic definition (reserve estimates are based upon a probability distribution of resource recovery). For example, the SPE/PRMS allows one to associate 1P, 2P and 3P with either deterministic or probabilistic definitions. Descriptions of the deterministic definitions are given with, for example, 1P reserves: 'those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable'.

Under the SPE/PRMS probabilistic definitions 1P, 2P and 3P, reserve estimates are commonly expressed as P90, P50 and P10 respectively. P90 (1P) estimates are then interpreted as the volume of gas production that is estimated to have a 90% probability of being exceeded by the time production ceases. Similarly, P50 (2P) and P10 (3P) estimates refer to volumes of gas production that are estimated to have a 50% and 10% probability respectively of being exceeded. Under this interpretation, 2P (P50) is equivalent to a *median* estimate of reserves. This leads to two additional problems, however. The first is whether available reserve estimates actually correspond to these precise statistical definitions.⁷ The second relates to the aggregation of reserve estimates: for example, in deriving regional reserve estimates by summing the reserve estimates of individual fields.

Statistically, it is only valid to arithmetically sum reserve estimates if these correspond to *mean* estimates of recoverable resources. If, instead, 1P (P90) reserve estimates are

⁶ E.D. Attanasi and P.A. Freeman, 'Economic analysis of the 2010 U.S. Geological Survey assessment of undiscovered oil and gas in the National Petroleum Reserve in Alaska', (Reston, VA: United States Geological Survey, 2011); Minerals Management Service, 'Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf', (Washington, DC: US Department of the Interior, 2006).

⁷ Steve Sorrell et al., 'Global oil depletion: An assessment of the evidence for a near-term peak in global oil production', (London: UK Energy Research Centre, 2009).

arithmetically summed, the aggregate figure will *underestimate* the total reserves. Similarly, if 3P (P10) reserve estimates are arithmetically summed, the aggregate figure will *overestimate* the total reserves.⁸ Aggregation of 2P reserve estimates should lead to smaller errors, but the magnitude and sign of these errors will depend upon the difference between *mean* and *median* estimates and hence the precise shape of the underlying probability distribution (which is rarely available). In practice, aggregation of 1P estimates is more common, thereby leading to underestimation of regional reserves.

A comparison of the different resource definitions is presented in Table 2-1 and in the form of a modified 'McKelvey box' in Figure 2-1.⁹ It should be clear from the above, however, that the use of resource and reserve terminology is inconsistent, imprecise and in need of standardisation. Given the early-stage production of this resource and the very large uncertainty in all resource estimates, considerable overlap is anticipated between URR, TRR and ERR estimates – despite the conceptual distinction between them.

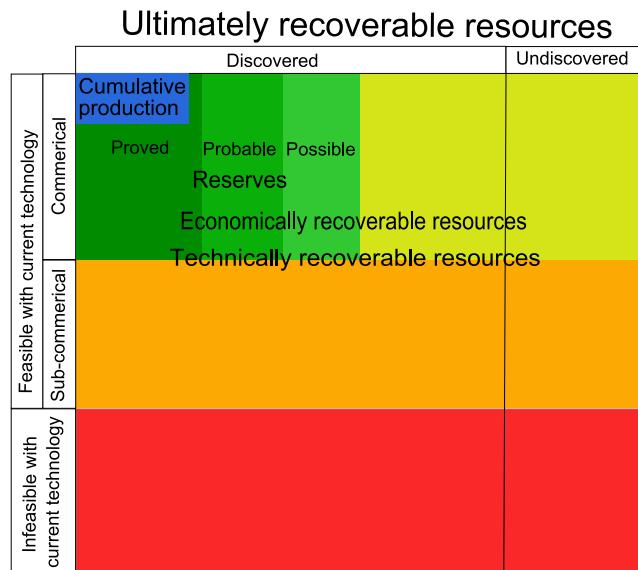
Table 2-1: Interpreting the terminology used for unconventional gas resource estimates

Name	Short description	Includes gas in undiscovered formations	Includes gas not economically recoverable with current technology	Includes gas that is not recoverable with current technology	Includes gas that is not expected to become recoverable
Original gas in place	Total volume present	✓	✓	✓	✓
Ultimately recoverable resources	Total volume recoverable over all time	✓	✓	✓	
Technically recoverable resources	Recoverable with current technology	✓	✓		
Economically recoverable resources	Economically recoverable with current technology	✓			
1P/2P/3P reserves	Specific probability of being produced				

⁸ R. Pike, 'Have we underestimated the environmental challenge?', *Petroleum review* (2006): 26-27, Sorrell et al., 'Oil depletion'.

⁹ V.E. McKelvey, 'Mineral resource estimates and public policy', *American Scientist* 60 (1972): 32-40.

Figure 2-1: Resources and reserves¹⁰



Natural gas is generally reported on a volumetric basis in either imperial (cubic feet) or metric (cubic metres) units. In the imperial system, a prefix of 'M' usually denotes a thousand (so MMcf is a million cubic feet), while in the metric system 'm' corresponds to a million (so mcm is a million cubic metres). For resource estimates, the most common prefixes are 'B' for a billion and 'T' for a trillion, both of which are commonly used with cubic metres and feet. At 60°F (15.56°C) and 14.73 psi (1 atmosphere or 101.325kPa), cubic feet can be derived by multiplying cubic metres by 35.3, i.e. 1 Tcm = 35.3 Tcf.

Although the majority of existing literature uses one or more of the above categories of resources, there is one important exception: the United States Geological Service. The USGS states that it provides estimates of "undiscovered" volumes of unconventional gases in different geological areas of the United States of America. The USGS reports do not provide a clear definition of the term 'undiscovered', but information contained in two USGS methodological papers¹¹ indicates that these figures should be interpreted as "potential additions to reserves". The authors conclude that an estimate of the remaining technically recoverable resources for the whole of the USA may be derived by summing the available estimates of the following.

- US proved reserves;
- US inferred reserves;¹²

¹⁰ Source: Modified from Ibid.

¹¹ R.R. Charpentier and T.A. Cook, 'Improved USGS methodology for assessing continuous petroleum resources', (Reston, VA: United States Geological Service, 2010), 22; J.W. Schmoker, 'US Geological Survey Assessment Concepts for Continuous Petroleum Accumulations, in Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah.', (Denver, CO: United States Geological Survey, 2005).

¹² The definition of the term 'inferred reserves' is unclear as it is used by different organisations to mean different things. The USGS in 1995, for example, used it to refer to reserve growth in conventional fields, while the EIA indicated that it most likely corresponds to 'probable reserves'. The authors prefer this later definition since it is more recent and more applicable to unconventional gas resources. 'Probable reserves' appear to be equivalent to 2P minus 1P reserves. EIA, 'Estimation of reserves and resources - appendix G', in *US Crude Oil, Natural Gas, and Natural Gas Liquids reserves report* (Washington, DC: 2009), D.L. Gautier and United States Geological Survey, '1995 national assessment of United States oil and gas

- the USGS mean estimates of potential additions to reserves in known formations; and
- mean estimates of undiscovered technically recoverable resources.

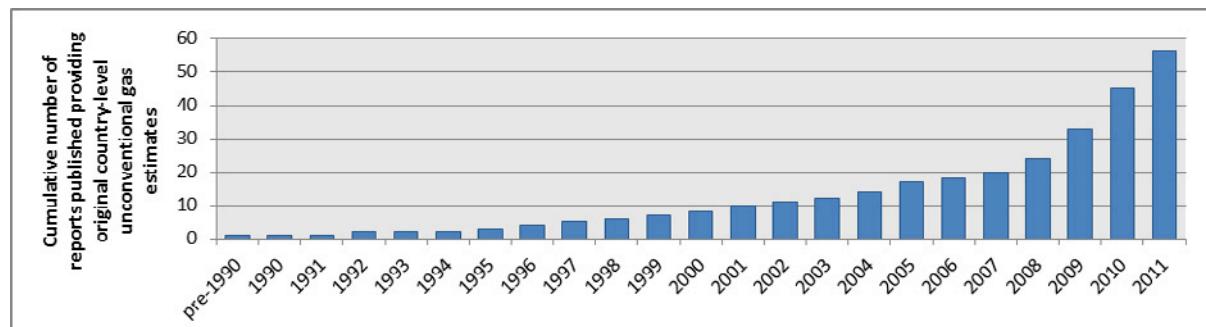
The addition of contemporaneous estimates of total cumulative production gives an estimate of the total technically recoverable resource of the USA.

2.1.2 Sources of data

The focus of this chapter is *original* estimates of OGIP, TRR or ERR for any of the unconventional gases – although with a particular focus on shale gas. An original estimate for any country or region is one from a source that has either *developed* the estimate itself using recognised methodologies, or *adapted* the estimate from existing sources. Original estimates do not need to come from independent or distinct organisations – indeed, several individuals and organisations have produced multiple estimates. However, the estimates must be *different* in order to be counted as original.

As can be seen in Figure 2-2, there are 56 reports providing original country-level estimates of unconventional gas resources, with 38 of these (~70%) published since the beginning of 2007. The primary motivation for these studies has been the rapid development of US shale gas resources (Figure 2-5), with 52 of the 56 reports providing resource estimates for the USA and/or Canada. Figure 2-4 provides a breakdown of estimates by gas type and region, indicating whether the reports have been peer reviewed.

Figure 2-2: Cumulative number of reports published providing original country-level estimates of any of the unconventional gases



Relatively few organisations or individuals provide periodic resource estimates for all three of the unconventional gases on a consistent basis. One notable exception is the EIA, whose Annual Energy Outlooks (AEO) have provided estimates of the remaining, technically recoverable, unconventional gas resources in the USA since 1997. Each AEO reports the remaining recoverable resources from two years prior to publication, so the first estimate of remaining recoverable resources is for 1995. Figure 2-3 demonstrates that the estimates of the remaining technically recoverable tight gas and CBM have increased by 25% and 134% respectively since 1995, while the estimates for shale gas have increased by a factor of 15. The majority of the increase in tight gas and CBM resource estimates has occurred since 2007, with estimated volumes increasing by around 50% and 100% respectively. Shale gas estimates have increased by 200% in the same timeframe.

resources results, methodology, and supporting data', (Reston, VA: United States Geological Survey, 1995).

Figure 2-3: Estimates of remaining recoverable resources for unconventional gases in the USA in successive Annual Energy Outlooks from the EIA¹³

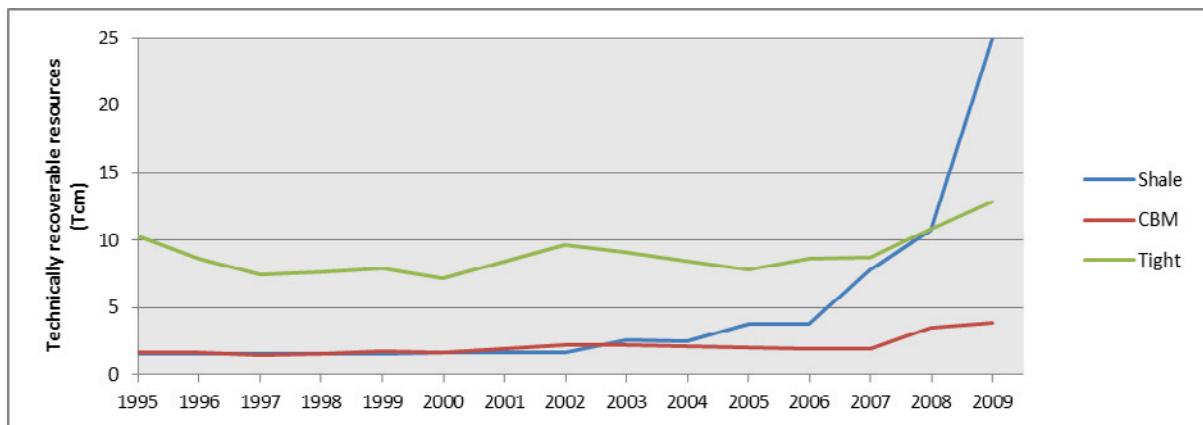
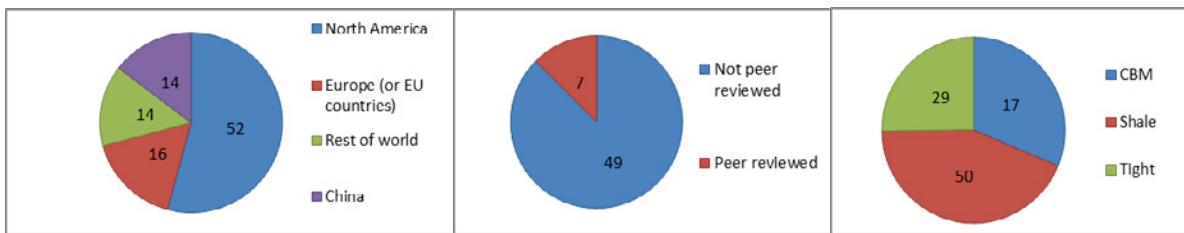


Figure 2-4: Distribution of literature providing original resource estimates by region, source and gas type¹⁴

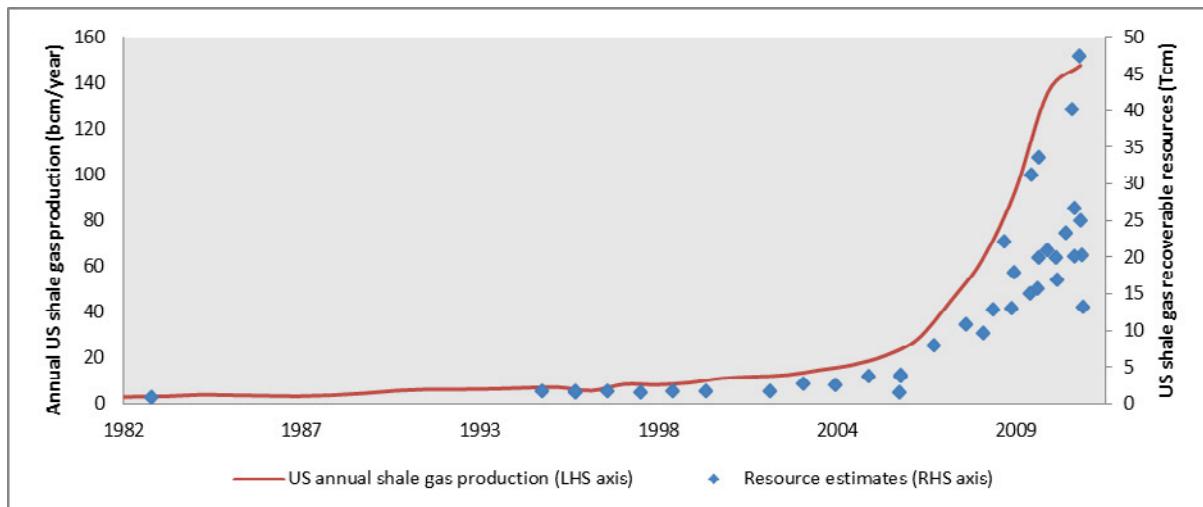


As indicated in Figure 2-4, a great number of reports have provided estimates for shale gas resources in North America. There is, however, a huge variation between these estimates and US estimates have risen dramatically in the past six years. Figure 2-5 illustrates the trend in US shale gas resource estimates since 1982. These increased from an average of 1.8 Tcm between 1983 and 2005 to an average of 18.4 Tcm between 2006 and 2010. This rise coincided with a roughly tenfold increase in annual shale gas production over the same period. Since the rapid increase in the estimated volume of recoverable resources has coincided with a dramatic increase in drilling across the USA and therefore provided a greater knowledge and understanding of the resource base, the more recent estimates are likely to prove more accurate.

¹³ Source: EIA, 'Annual Energy Outlook', (Washington, DC: US Energy Information Administration, Various). The 1998 and 1997 AEOs provided estimates of the remaining ERR while all the others provided estimates of the remaining TRR.

¹⁴ Note: A number of reports provide estimates for more than one country or gas type. These are reported separately in each category and so the absolute numbers within each chart will not be identical.

Figure 2-5: US shale gas resource estimates and annual production¹⁵



2.1.3 Estimates of shale gas resource

Global estimates

This section provides a more detailed examination of the estimates made for shale gas resources or shale gas-in-place. It begins with those reports that have considered either global shale gas resources or the shale gas potential in a number of regions worldwide. This is followed by an examination of the estimates that have been made in North America, Europe and in China. For all other regions it was found that only one or two, if any, resource estimates were available and so it was not possible to provide any meaningful comparisons of these.

A total of 50 sources provide original country or regional-level estimates of shale gas resources (see Table B-1). As indicated previously, a number of sources do not indicate whether they have included estimates of undiscovered volumes of shale gas in their estimates of TRR. We can deduce whether this is likely, however, by examining whether they only consider individual, discovered shale plays and/or make any reference to the potential for shale gas to be found outside these plays. INTEK¹⁶ estimates that there are 1.6 Tcm of undiscovered shale gas resources in the USA. Hence, it is possible to convert estimates of 'discovered TRR' in the USA to estimates of 'full TRR' by adding in the INTEK figure. There are no estimates of undiscovered shale gas outside the USA since the focus to date has been on those shale plays that are known to exist.

On a global scale, the estimate made by Rogner¹⁷ formed the basis of nearly all estimates of the shale gas resource base outside North America until around 2009. As discussed in more detail in Section 2.2, Rogner estimated the original gas in place for each of the unconventional gases within 11 continental regions, as shown in Table 2-2. Rogner's

¹⁵ Source: Production data from 1982-1989 taken from Slutz, 'Well completions and production challenges'; data from 1990 onwards taken from EIA, 'AEO 2011'. Graph includes both TRR and ERR resource estimates from all sources. The USGS figure combines all of its latest resource assessments for shale plays of various dates but is plotted at August 2011, the date of the most recent USGS assessment of the Marcellus shale. J.L. Coleman et al., 'Assessment of undiscovered oil and gas resources of the Devonian Marcellus shale of the Appalachian basin province', (Reston, VA: United States Geological Survey, 2011).

¹⁶ INTEK, 'Review of emerging resources: U.S. shale gas and shale oil plays', (Washington, DC: 2011).

¹⁷ Rogner, 'Assessment of World Resources'.

estimate of the global OGIP for unconventional gas was 920 Tcm, of which 50% was shale gas. Rogner neither provided a breakdown of OGIP in any individual countries, nor did he indicate the fraction of these values that were likely to be recoverable. However, numerous organisations have derived technically recoverable resource estimates by applying percentage recovery factors to Rogner's figures. Some values suggested or used include 15% by Mohr and Evans,¹⁸ 10-35% by the Massachusetts Institute of Technology (MIT)¹⁹ and 40% by both ARI²⁰ and the IEA²¹. To put these recovery factors in context, ARI²² uses a range of 15-35% for the recovery of shale gas from each geological area analysed, while recovery from conventional gas wells is often around 70-80%.²³

Table 2-2: Estimates of original shale gas in place by Rogner²⁴

Region	Original shale gas in place (Tcm)
North America	108.3
Latin America and the Caribbean	59.7
Western Europe	14.4
Central and Eastern Europe	1.1
Former Soviet Union	17.7
Middle East & North Africa	71.8
Sub-Saharan Africa	7.7
Centrally Planned Asia & China	99.4
South Asia	65.2
Other Pacific Asia	8.8
Pacific OECD	0
Total	454.1

Using Rogner's OGIP estimates, a 15% recovery factor would give a global estimate of 68 Tcm for the TRR of shale gas, while a 40% recovery factor would increase this to 181.3 Tcm. Hence, the range of 15-40% in the recoverable fraction of Rogner's OGIP corresponds to an uncertainty of around 113.3 Tcm on a global scale. This approximates to one-third of the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR)'s estimate of the remaining global, technically recoverable resource of conventional gas (~425 Tcm).²⁵

¹⁸ S.H. Mohr and G.M. Evans, 'Shale gas changes N. American gas production projections', *Oil and Gas Journal* 108, no 27 (2010).

¹⁹ Q. Ejaz, 'The Future of Natural Gas Supplementary paper SP2.2: Background material on natural gas resource assessments, with major resource country reviews', (Cambridge, MT: Massachusetts Institute of Technology, 2010).

²⁰ V.A. Kuuskraa, 'Worldwide gas shales and unconventional gas: a status report', (Arlington, VA: Advanced Resources International Inc., 2009).

²¹ The IEA does not explicitly state the recovery factor used for each of the three unconventional gases, but provides figures from which it can be calculated. IEA, 'World Energy Outlook 2009', in *World Energy Outlook* (Paris: Organisation for Economic Co-operation and Development, 2009).

²² Advanced Resources International, 'World shale gas resources: an initial assessment of 14 regions outside the United States', (Washington, DC: Advanced Resources International Inc., 2011).

²³ C. Besson, 'Resources to reserves: oil & gas technologies for the energy markets of the future', (Paris: International Energy Agency, 2005).

²⁴ Rogner, 'Assessment of World Resources'.

²⁵ H.J. Kümpel, 'Energy Resources 2009: Reserves, Resources, Availability', (Hannover, Germany: Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) Federal Institute for Geosciences and Natural Resources, 2009). 187 Tcm, or 44% of the total remaining technically recoverable resources of

A more recent report by the World Energy Council (WEC) in 2010 also provided OGIP figures for regions similar to those used by Rogner,²⁶ although it combined South Asia, Other Pacific Asia and OECD Pacific into one region. Some of the estimates provided are significantly different to Rogner's, with the estimated OGIP for Latin America and Centrally Planned Asia & China decreasing to 10.6 Tcm and 10.5 Tcm (a reduction of around 80% and 90% respectively from Rogner's figures) while the OGIP estimated for the Former Soviet Union is 153 Tcm (an increase greater than eightfold). Regarding recovery factors, it is mentioned that "nearly 40% of this endowment would be economically recoverable", corresponding to a global ERR of around 170 Tcm. Given that the costs of extraction and market conditions at the time when the resource will be extracted is highly uncertain, particularly in areas where there is currently no shale gas production, it is likely that the WEC's estimate actually corresponds more closely to TRR rather than to ERR.

Two other recent independent reports have been undertaken that estimate technically recoverable shale gas resources on a global scale.²⁷ Nevertheless, even these do not attempt to assess all shale plays and indicate that there is limited geological information available for a number of plays anticipated to hold shale gas.

ARI, for example, ignores regions where there are large quantities of conventional gas reserves (Russia and the Middle East) or where there is insufficient information to carry out an assessment.²⁸ Similarly, Medlock et al. only assess the shale gas potential in six countries²⁹ outside North America and justify the exclusion of unassessed shales by suggesting that they are unlikely to be economically recoverable.³⁰ Hence, neither review provides a global estimate of technically recoverable shale gas resources.

ARI produced an earlier and much smaller estimate in 2009. It noted that a number of other shale plays were likely to contain resources but had not been quantitatively assessed, so its estimate was therefore anticipated to "grow with time and new data".³¹ The majority of the increase between ARI's estimate in 2009 and 2011 comes from this increase in the geographical coverage of the later survey (see Figure 2-6). Finally, three other estimates of global shale resources have been made, but these were produced some time before the recent increase in US production and are predominantly based upon expert judgment.³²

conventional gas, is classified as proved reserves in BP, 'Statistical review 2011'. Note, however, that this 'proved' figure covers all four types of gas (conventional, tight, CBM and shale) to differing degrees in different countries, depending upon the state of development of the resource.

²⁶ WEC, 'Survey of Energy Resources: Focus on Shale Gas', (London, UK: World Energy Council, 2010).

²⁷ Advanced Resources International, 'World shale gas resources', Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

²⁸ Advanced Resources International, 'World shale gas resources'.

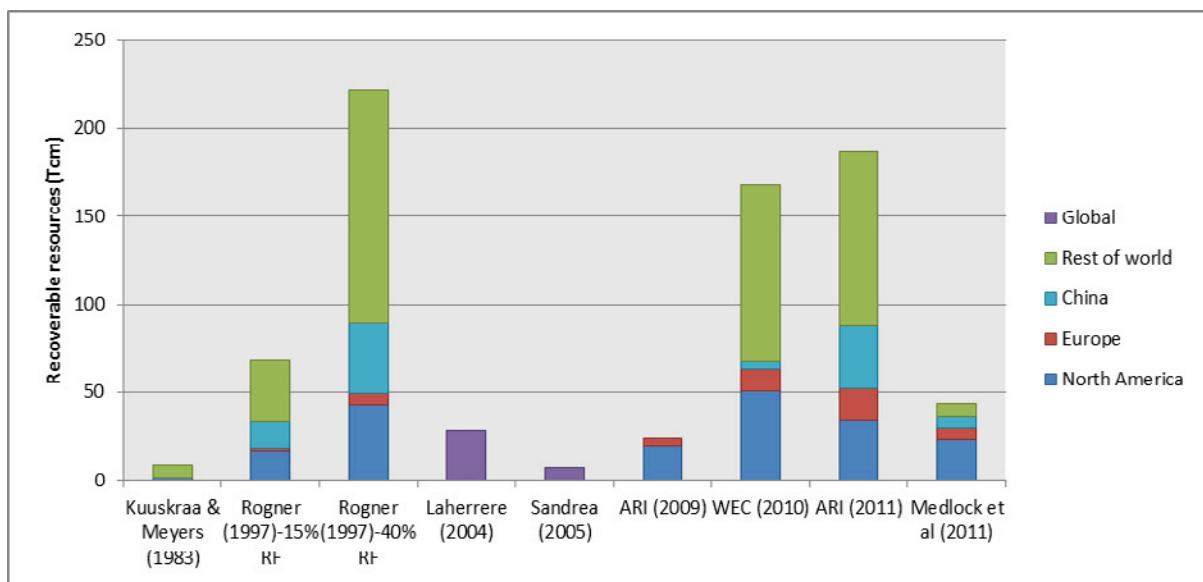
²⁹ The nine countries analysed are: the United States of America, Canada, Mexico, Austria, Germany, Poland, Sweden, China and Australia.

³⁰ Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

³¹ Ibid.

³² V.A. Kuuskraa and R.F. Meyers, 'Review of world resources of unconventional gas' (paper presented at the fifth IIASA conference on energy resources: Conventional and unconventional world natural gas resources, Laxenburg, Austria, 1980); J. Laherrère, 'Natural gas future supply', in *IIASA-IEW* (Paris, France: 2004); R. Sandrea, 'Global natural gas reserves - a heuristic viewpoint', (Tulsa, OK: IPC Petroleum Consultants, Inc., 2005).

Figure 2-6: Estimates of global shale gas resources by sources considering regions outside North America³³



North America

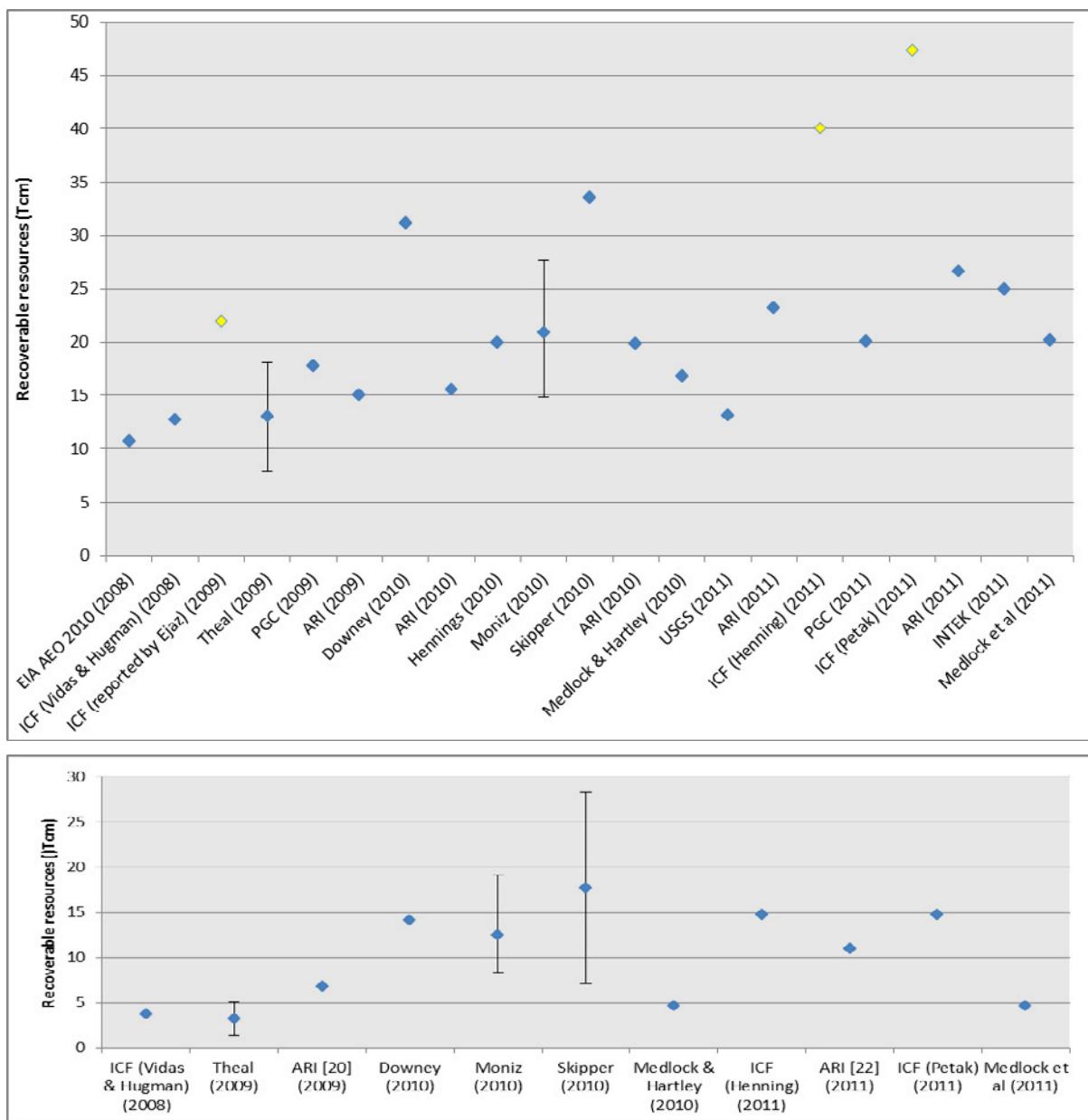
As can be seen from Figure 2-5, estimates of the recoverable resources of shale gas within the USA have been increasing rapidly, with the more recent reports likely to provide more accurate estimates. Figure 2-7 therefore presents the more recent reports, chosen here to be those produced since 2008, which provide estimates of the recoverable resources of shale gas within the USA and Canada. There have been a total of 18 reports providing estimates for the USA and 12 for Canada over this period. Some of these, for example those by ICF³⁴ or ARI,³⁵ are updates of older reports but are reported here separately. It is noticeable that despite the variation in resource estimates between these reports (even those of similar dates), only three of these give a range of uncertainty in the values quoted. Even within this short timeframe, the estimates made in the past year are higher on average than those made in 2008.

³³ Note: Different studies cover different countries and regions and none provide a truly global estimate. Laherrere's estimate is URR, while Medlock et al.'s estimates are likely to be closer to ERR. The OGIP estimate by Rogner is converted to TRR using 15% and 40% recovery factors and the WEC's estimate is converted to ERR using a 40% recovery factor.

³⁴ K.R. Petak, 'Impact of natural gas supply on CHP development' (paper presented at the US Clean Heat & Power Association's (USCHPA) Spring CHP Forum, Washington, DC, 2011).

³⁵ V.A. Kuuskraa, 'Unconventional gas: an exportable North American revolution?', in *The changing fundamentals of global gas markets – Europe as the battleground?* (Washington, DC: Advanced Resources International Inc., 2010).

Figure 2-7: Estimates made since 2008 of the technically recoverable shale gas resources in the United States of America (above) and Canada (below)³⁶



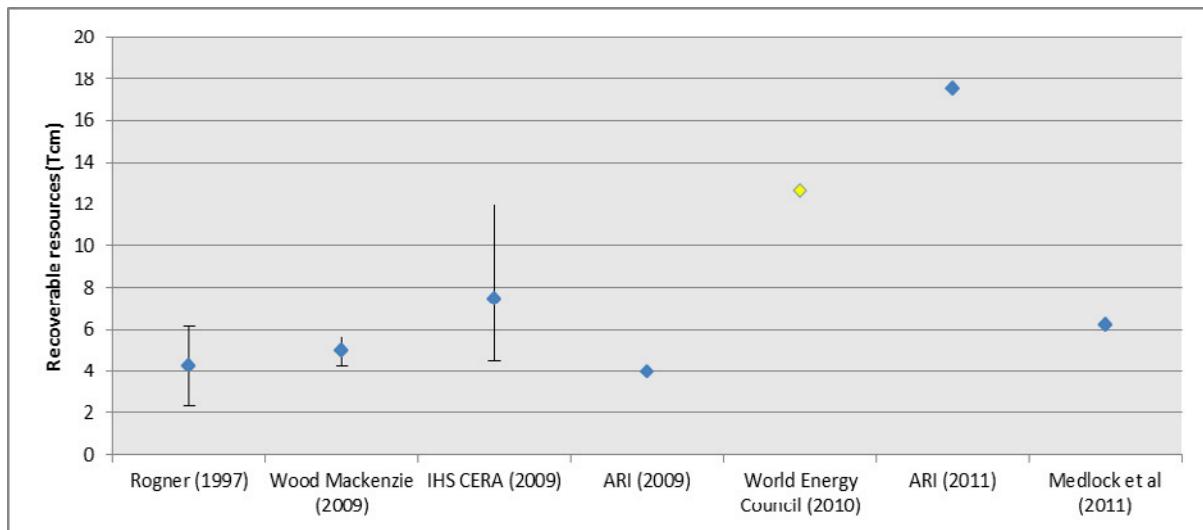
Europe

In contrast to the USA, very few estimates are available of the recoverable resource of shale gas within Europe. However, since 2009, a number of reports have been published that provide estimates of technically recoverable resources within Europe. These are presented in Figure 2-8 and range from 2.3 Tcm to 17.6 Tcm, with a mean of 7.1 Tcm. Note that ARI's estimate from 2009 ignored a number of plays.³⁷

³⁶ Points in yellow correspond to estimates that were stated as referring to economically recoverable resources.

³⁷ Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

Figure 2-8: All estimates of the technically recoverable resources of shale gas within Europe³⁸



China

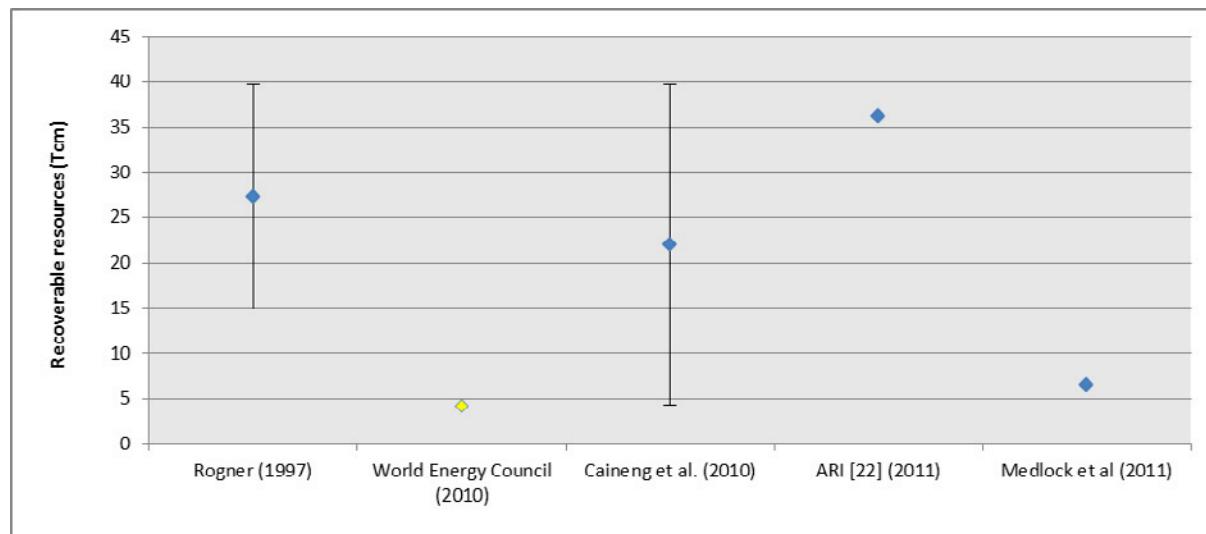
Relatively few estimates of the Chinese shale gas resource are available and even fewer provide an estimate of the TRR or ERR, preferring instead to estimate the OGIP. ARI³⁹ estimates an OGIP of 144.5 Tcm and a TRR of 36.0 Tcm, which suggests a recovery factor of around 25%. Since there is little agreement on this factor, the authors have again converted any estimates of OGIP into TRR using a range of recovery factors between 15% and 40%. The range in the estimate of Zou et al. results from applying this variation in recovery factor to the range of OGIP provided by the authors (28.3-99.1 Tcm).⁴⁰ The World Energy Council's estimate is for 'Centrally Planned Asia' (which includes Cambodia, Hong Kong, PDR Korea, Laos, Mongolia and Vietnam) as well as China, but for illustrative purposes all of the resource was assigned to China. The variation in currently available estimates for TRR in China is therefore even larger than that in Europe and North America.

³⁸ The point in yellow corresponds to an estimate that was stated as referring to economically recoverable resources. The range for Rogner's estimate is derived using a 15-40% recovery factor within Western and Eastern Europe. Values for Wood Mackenzie and IHS CERA come from Ruud Weijermars et al., 'Unconventional gas research initiative for clean energy transition in Europe', *Journal of Natural Gas Science and Engineering* 3, no 2 (2011).

³⁹ Advanced Resources International, 'World shale gas resources'.

⁴⁰ Caineng Zou et al., 'Geological characteristics and resource potential of shale gas in China', *Petroleum exploration and development* 37, no 6 (2010).

Figure 2-9: All estimates of the technically recoverable resources of shale gas within China⁴¹



2.1.4 Shale gas estimates in context

Table 2-3 summarises the ranges and mean estimates of the technically recoverable shale gas in the above regions and globally. Within each region, the shale gas estimates are derived using the sources shown in Figure 2-7 to Figure 2-9. As explained previously, it is considered that the estimates of shale gas ERR given by ICF⁴² and WEC⁴³ are better described as TRR and so their figures are included in the calculation of the mean resource estimates. In addition, when sources have provided multiple estimates (e.g. ARI/Kuuskraa), only the latest update is included in the calculation of the mean resource estimate.

This table also includes estimates of the remaining technically recoverable resources of conventional gas, CBM and tight gas held by each of the regions. The conventional estimates come from BGR,⁴⁴ while the tight and CBM estimates come from a variety of sources with a different number of reports or articles available for each of the regions.

As mentioned in Section 2.1.3, given the focus on the resource potential of those shale plays that are known to exist, there have been no estimates of shale gas resources from shale plays outside the USA that are estimated, but not known, to exist. It is therefore difficult to determine what the relative magnitude of shale gas in undiscovered shale plays worldwide is likely to be compared to those in known shale plays. Stevens⁴⁵ indicates that shale gas plays tend to overlie conventional oil and gas wells. He therefore concludes that countries with a history of onshore oil and gas production (e.g. the USA) will have a higher degree of knowledge of the shale gas resource and hence less potential for undiscovered shale plays compared to countries with relatively little history of onshore production (e.g. most European countries). This can be

⁴¹ The point in yellow corresponds to an estimate that was stated as referring to economically recoverable resources.

⁴² Petak, 'Impact of natural gas on CHP'.

⁴³ WEC, 'Survey of Energy Resources'.

⁴⁴ BGR, 'Reserves, resources and availability of energy resources: 2010', (Hannover, Germany: Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) Federal Institute for Geosciences and Natural Resources, 2010).

⁴⁵ Paul Stevens, 'The "Shale Gas Revolution": Hype and Reality', (London: Chatham House (The Royal Institute of International Affairs), 2011).

demonstrated by observing that, within the USA, estimated volumes of technically recoverable resources of undiscovered shale gas only make up 7% of the total shale gas TRR.

Nevertheless, there has been extensive geological mapping of the rocks underlying many countries worldwide. Despite limited onshore drilling in the UK, for example, various geological studies provide a complete cross section of the rocks throughout the UK.⁴⁶ There is therefore unlikely to be any undiscovered shale gas plays in the UK. While this may not be the case for all countries, it suggests that the volumes of gas in currently undiscovered shale plays will likely be overshadowed by volumes in discovered but undeveloped plays.

Table 2-3: Mean estimates of remaining technically recoverable resources of conventional gas, CBM, tight gas and shale gas provided by the evidence base (Tcm)⁴⁷

Region	Conventional	Tight	CBM	Shale		
				Lowest estimate	Mean of estimates	Highest estimate
United States of America	27.2	12.7	3.7	8.0	23.5	47.4
Canada	8.8	6.7	2.0	1.4	11.1	28.3
Europe	11.6	1.4	1.4	2.3	8.9	17.6
China	12.5	9.9	2.8	4.2	19.2	39.8
(Implied rest of world)	(364.9)	(14.6)	(15.6)		(34.7)	
Global	424.9	45.4	25.5	7.1	97.4	186.4

As noted previously, the global estimates do not all cover the same regions, do not use the same definitions and are based on a number of different methodologies and assumptions (e.g. for the recovery factor), which helps to explain the significant variation in estimates. The mean estimate for shale gas is also skewed by the low estimates of Sandrea⁴⁸ and Laherrere,⁴⁹ which are both relatively old and based on expert judgment alone. If these are excluded, the mean estimate increases to 130 Tcm

⁴⁶ T. Harvey and J. Gray, 'The unconventional hydrocarbon resources of Britain's onshore basins – shale gas', (London, UK: Department of Energy and Climate Change, 2011).

⁴⁷ Sources: Shale gas reports in Figure 2-7, Figure 2-8 and Figure 2-9 as well as the following: BGR, 'Reserves, resources and availability'; F.M. Dawson, 'Cross Canada check up unconventional gas emerging opportunities and status of activity' (paper presented at the CSUG Technical Luncheon, Calgary, AB, 2010); EIA, 'Annual Energy Outlook 2010 with Projections to 2035', (Washington, DC: US Energy Information Administration, 2010); V.A. Kuuskraa, 'Economic and market impacts of abundant international shale gas resources', in *Worldwide Shale Gas Resource Assessment* (Washington, DC: Advanced Resources International 2011); Kuuskraa, 'Status report'; S.H. Mohr and G.M. Evans, 'Long term forecasting of natural gas production', *Energy Policy* 39, no 9 (2011); Moniz, Jacoby and Meggs, 'Future of natural gas'; Potential Gas Committee, 'Potential Gas Committee reports substantial increase in magnitude of US natural gas resource base', (Golden: CO: Colorado School of Mines, 2011); Rogner, 'Assessment of World Resources'; Sandrea, 'Global natural gas reserves'; R.G. Smead and G.B. Pickering, 'North American natural gas supply assessment', (Chicago, IL: Navigant Consulting, 2008); Total, 'Tight reservoirs: Technology-intensive resources', (Paris, France: 2006); WEC, 'Survey of Energy Resources'; Weijermars et al., 'Unconventional gas research initiative'. Notes: Implied rest-of-world figures derived by subtracting each mean regional estimate from the mean global estimate.

⁴⁸ Sandrea, 'Global natural gas reserves'.

⁴⁹ Laherrere, 'Natural gas future supply'.

and the lowest global estimate then becomes that provided by Medlock et al. at 42.9 Tcm.⁵⁰

Focusing on the mean estimates within Table 2-3, the figures suggest that the USA holds around 25% of the global TRR of shale gas, while Europe holds around 10%. Similar percentages are obtained in both regions if the highest estimates are compared, but the European and USA's share may be smaller than this in practice since many regions are excluded from the global estimates.

It is also of interest to place global shale gas resources into context with the global remaining recoverable resources of conventional gas. The mean estimate given by the current literature of the global TRR for shale gas is around 23% of the remaining recoverable resources of conventional gas, which increases to 30% if Sandrea's and Laherrere's shale gas estimates are excluded.

The remaining global TRR of all natural gas consists of the sum of the mean estimates of conventional gas and the three unconventional gases. On a global scale, shale gas is estimated to make up 16% of the total figure of 593.2 Tcm. On a regional basis, however, shale gas can form a much larger proportion of the remaining TRR. For example, using the mean estimates, shale gas is estimated to represent 43% of the remaining TRR of natural gas in China, 39% in Canada, 38% in Europe and 35% in the USA. This suggests that the impact of shale gas is likely to be greater at the regional level than at the global level.

2.2 Methods for estimating the recoverable resources of shale gas

This section provides an overview and critique of the methods employed to estimate the technically recoverable resources of shale gas.

Four broad approaches have been used to estimate recoverable volumes of shale gas, namely: a) expert judgement; b) literature review/adaptation of existing literature; c) bottom-up analysis of geological parameters; and d) extrapolation of production experience. A crossover between these approaches is common, with several reports employing and combining more than one approach.

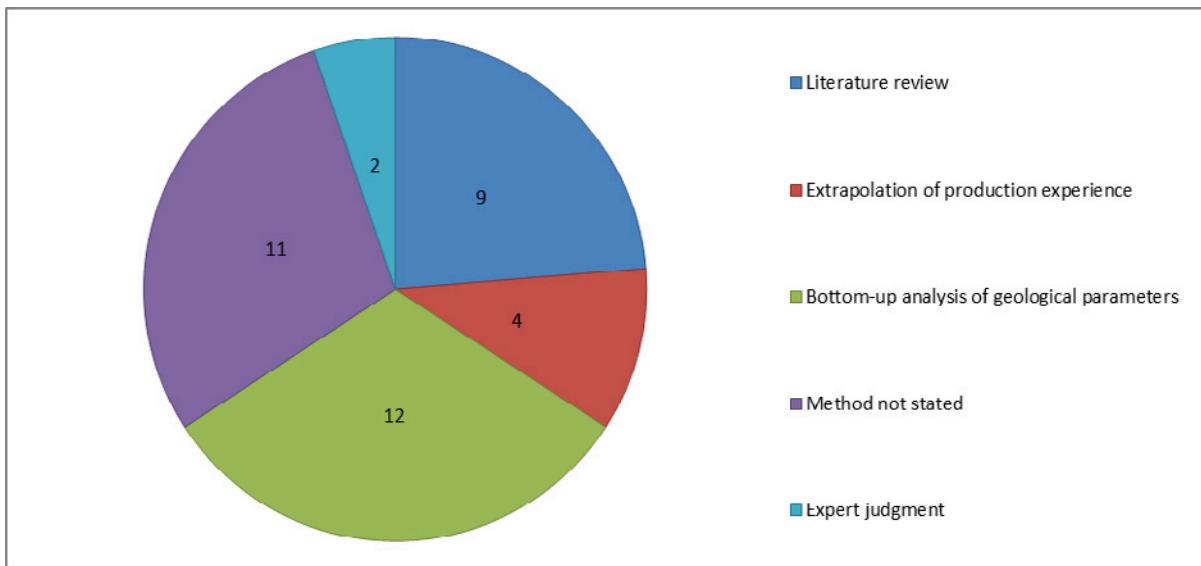
Different reports provide different degrees of explanation of the methods employed and in many cases little or no information is given – a major weakness. Hence, judgment is frequently required when identifying and classifying the approach that has been taken. Figure 2-10 classifies the approaches used by each report. Reports labelled as 'Method not stated' provide little or no description of the methods used and provide insufficient information to allow this to be identified.

Section 2.2.1 provides a brief description and explanation of each of these approaches and illustrates this by discussing the specific approach taken by three reports in more detail. Not all the reports use an identical approach, however, and differences such as the definition and terminology used for relevant variables, the inclusion or exclusion of particular parameters, the reliance upon different sources of information and values chosen for subjective parameters are common. These differences are likely in turn to have a significant influence on the results. Section 2.2.2 evaluates and compares the methodological robustness of each approach; Section 2.2.3 provides an overview of the

⁵⁰ Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

role technology could play in increasing current estimates of technically recoverable shale gas resources, while Section 2.2.4 provides the conclusion.

Figure 2-10 Approaches used by all reports providing original country-level shale gas resource estimates⁵¹



2.2.1 Description of approaches

The four approaches to estimating resource size that are used in the literature are briefly described below. The order in which they are discussed reflects the relative weight that may be given to their results, with the least robust first.

Expert judgment

The first category is used by only two authors who do not cite any other sources or indicate the method they have used to develop their resource estimate.⁵² The estimates provided therefore appear not to have been derived using any rigorous or repeatable method but are rather based upon the authors' own opinions of technology and geology, and therefore likely to be very subjective.⁵³

Literature review/adaption of existing literature

A number of report authors rely upon estimates made by others, which are then collated or adapted to determine new estimates. Some sources, for example MIT⁵⁴ and Mohr and Evans,⁵⁵ analyse a number of estimates and use the variation between these to identify a range of uncertainty for regional or country values. Others also use a literature review but augment this data with additional primary research. Navigant Consulting,⁵⁶ for example, conducted a survey of natural gas producers and used this to provide an upper bound on its estimates, which it called the "maximum reported"

⁵¹ Note: the EIA AEOs are only included once.

⁵² Laherrère, 'Natural gas future supply'; Sandrea, 'Global natural gas reserves'.

⁵³ This category differs from those reports classified as 'Method not stated', as it is thought that these estimates have been derived using one of the four broad approaches described; it is not possible to determine which approach has been used, however.

⁵⁴ Moniz, Jacoby and Meggs, 'Future of natural gas'.

⁵⁵ Mohr and Evans, 'Long term forecasting'; Mohr and Evans, 'Shale gas changes production projections'.

⁵⁶ Smead and Pickering, 'North American supply assessment'.

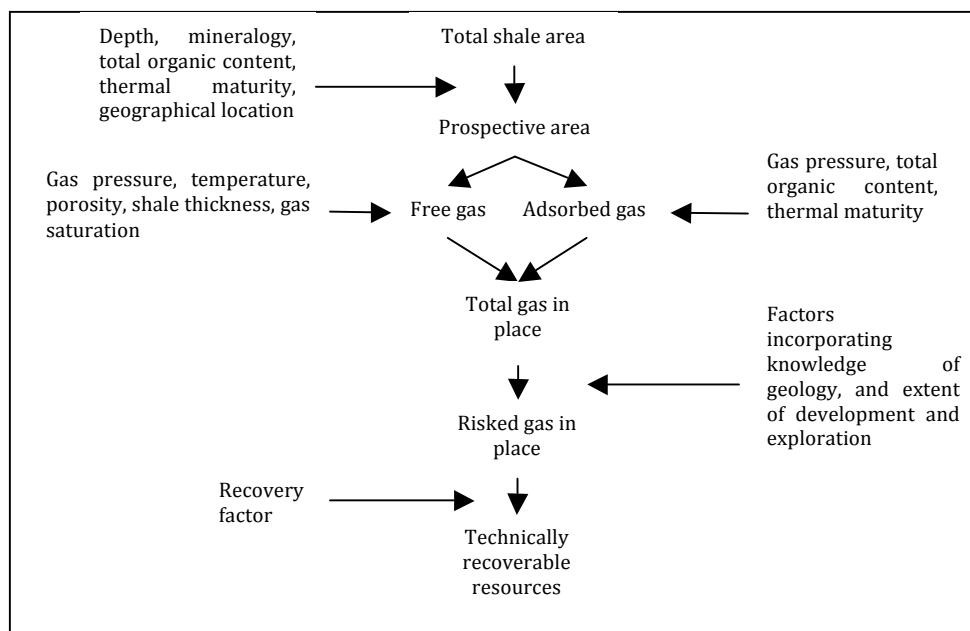
estimate for each shale play. The WEC appears to have used a literature review, but provides no description of its methodology other than noting that “most credible studies” were used. It also does not provide details of the literature referred to other than the names of the organisations that produced the estimates.⁵⁷

An alternative approach is followed by Medlock et al. who indicate that they use “peer-reviewed, scientific assessments of the properties of shales to develop technically recoverable resources”. However, Medlock et al. do not specify the precise approach used and fail to cite the relevant peer-reviewed sources. In addition, they note that: “A reduction of the technically recoverable shale gas resource base in areas with potential water constraints is primarily done because the cost of development has been deemed prohibitive.” In explaining the difference between theirs and ARI’s estimates, Medlock et al. also note that the clay content of the shale can constrain recoverability. Clay-rich shales will have lower production rates and higher costs and so are excluded from their estimates of recoverable resources. Since these constraints do not appear to be employed by other sources estimating TRR, Medlock et al.’s resource figures may correspond more closely to ERR.⁵⁸

Bottom-up analysis of geological parameters

This approach uses geological knowledge of the extent and characteristics of the shale rock to estimate the volume of shale gas that is present. A recovery factor is then applied to this estimate to produce an estimate of the technically recoverable (or ultimately recoverable) resources. ARI⁵⁹ employed this approach to determine the volumes of gas that exist in worldwide shales for which there was little, or no, drilling experience or production data. Figure 2-11 summarises the approach, indicating the geological parameters used at each step in the process.

Figure 2-11: Schematic representation of the steps used in the geological-based approach (see Table 3-1 for terminology)



⁵⁷ WEC, 'Survey of Energy Resources'.

⁵⁸ Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

⁵⁹ Advanced Resources International, 'World shale gas resources'.

The first step involves determining the total areal extent of the shale being examined. This is next reduced to the 'prospective area', which, depending on estimates or determinations of various properties of the rock, describes the area of shale that is expected to contain an appreciably high concentration of gas to make development viable. The geographic location of the shale is also taken into account at this stage, with shale in offshore regions being removed from the prospective area.

Within shale plays, natural gas can be stored either in pore spaces within the rocks ('free gas') or adsorbed⁶⁰ on to the rocks. Equations can be used to estimate the volume of this stored gas, which require estimates of various geological parameters, such as the pressure of the gas in place and the porosity of the rocks.

Two further factors are then determined that represent the confidence of the authors in their estimates, given their extent of knowledge of the geology and the prior exploration and development of the play. These factors are the 'play success probability factor', which represents the probability that suitably high flow rates will be achieved from the play to make development likely, and the 'prospective area success factor', which represents the probability that there will not be any geological complications or problems in the prospective area that would reduce the volumes of gas present. For the plays in ARI's report, the play success probability factor ranged from 100% to 30% with a mean for all of the shale plays analysed of 58%, while the prospective area success factor ranged from 75% to 20% with a mean of 50%. The application of these factors to the estimated gas in place yields an estimate of the 'risked' gas in place. Using the above mean factors of 58% and 50%, the 'risked' gas in place would therefore be 29% of the gas in place. A number of other approaches use comparable 'success factors' to reduce volumes of gas that are estimated to exist.

Finally, a recovery factor is estimated to reflect the anticipated fraction of this volume that is likely to be technically recoverable. The product of the recovery factor and the 'risked' gas in place gives an estimate of the technically recoverable resource. ARI⁶¹ indicates that the recovery factor is established on the basis of the shale mineralogy, the properties of the reservoir and the geological complexity. The values chosen typically lie in the range 20-30%, although factors of 35% and 15% are used in "a few exceptional cases".

As can be seen from Figure 2-11, there are a large number of parameters which must be estimated or calculated when using geological methods to determine recoverable volumes of gas. These parameters range from the area and geographical location (onshore/offshore) of the shale rock, to the total organic content (measured as a percentage of the total weight) of the shale, to the minerals (clay/quartz, etc.) contained within the shale. A number of these parameters are used at more than one stage of the process. There are also some factors, whose estimation, although dependent on a number of these parameters, is largely subjective. Examples are the recovery factor and the two factors for converting the OGIP estimate into a 'risked' OGIP estimate. ARI sets out which factors have been used in an appendix; however, of the 11 other sources

⁶⁰ Adsorbed gas is gas attached to the surface of the rock.

⁶¹ Advanced Resources International, 'World shale gas resources'.

using this approach, only three⁶² provide figures for both TRR and OGIP from which the assumed recovery factors can be determined.

Extrapolation of production experience

This approach relies upon analysing the production experience in shales for which there is a sufficiently long history of production and then extrapolating these results to either undeveloped areas of the same shale or to new shales. There are two general methods employed. The first, commonly applied at the play level, is to estimate shale gas volumes, either OGIP or TRR, by multiplying the estimated shale play area (or mass) by an estimated yield per square area (or mass). The yield per unit area is often called the productivity and measured in mcm/km². For undeveloped shale play areas, the values for such calculations are typically based upon measurements or estimates from geologically similar regions (analogues) where more information is available.

The second method differs in its complexity: the investigated area is split into more and less productive sectors and more precise gas yields per area are determined by using a greater number of parameters, including the URR per well and the well spacing (number of wells per unit area). Estimates of the URR per well require the extrapolation of production from currently producing wells with the help of decline curve analysis – discussed in more detail in Section 2.3.

A key issue for the extrapolation of production experience method is the validity of taking estimates of well spacing and the URR/well from one area and applying these to a second, potentially very different, area. US shale gas plays that are currently producing are very heterogeneous, with production rates between neighbouring wells varying by a factor of three and across an entire shale play by a factor of ten.⁶³ It is commonly the case that some areas within the shale have significantly higher productivity and ultimate recovery than others. These are commonly referred to as 'sweet spots'. In addition, there also appears to be significant variation in the productivity of wells within sweet-spot areas, although this distinction partly depends on how sweet spots are defined.⁶⁴ Given this heterogeneity, it is important not to assume single values for the URR/well and well spacing across the whole area of a shale play. This is particularly relevant when extrapolating historical URR/well and well spacing estimates, since these will only be available from the areas of the shale play that have been developed first and which tend to be the most productive.

Each of the above methods has been used by two reports. The first and simpler method was used by Rogner⁶⁵ and the UK's Department of Energy and Climate Change (DECC).⁶⁶ Surprisingly, given the reliance that has been placed upon his work, Rogner appears to have used a relatively crude approach on which he provided very little information. He

⁶² S. Hennings, 'Shale gas resources and development' (paper presented at the IIR inaugural shale gas briefing, Brisbane, 2010); C. Theal, 'The shale gas revolution: The bear market balancing act', (2009); H. Vidas and B. Hugman, 'Availability, economics, and production potential of North American unconventional natural gas supplies', (Fairfax, VA: ICF International, 2008).

⁶³ EIA, 'Various AEOs'.

⁶⁴ V.A. Kuuskraa, 'Case study #1. Barnett Shale: The start of the gas shale revolution', in *Gas shale development workshop* (Beijing, China: 2010); R.F. Strickland, D.C. Purvis and T.A. Blasingame, 'Practical Aspects of Reserves Determinations for Shale Gas' (paper presented at the North American Unconventional Gas Conference and Exhibition, Woodlands, TX, 2011).

⁶⁵ Rogner, 'Assessment of World Resources'.

⁶⁶ Harvey and Gray, 'Unconventional resources of Britain'.

notes simply that: 'the ratio of the US estimates for natural gas from shale formations to the in-place shale volume was used as a guide to calculate the regional natural gas resource from fractured shale resource potentials...based on the assumption that shale oil occurrences outside the United States also contain the US gas value of 17.7 Tcf/Gt (gigatonne) of shale-in-place'. Rogner therefore appears to have used only a single analogue to estimate worldwide shale gas resources.

DECC also used this simpler approach in order to estimate shale gas resources in the UK. More than one analogue was used with the Barnett, Antrim and a 'more conservative' play, identified as possible analogues for the three shale plays in the UK. The choice of analogues significantly affects the resource estimates produced, with the productivity of the most productive analogue play (the Barnett at 7.6 mcm/km²) being 13 times greater than that of the least productive analogue play (the 'more conservative' play at 0.6 mcm/km²).

The second approach requires substantially more information from areas that are already being developed, but is likely to be more reliable. As a result, this approach has been used by two of the main sources providing shale gas resource estimates for the USA, namely INTEK for the EIA⁶⁷ and the USGS.⁶⁸ The approach taken by the USGS is described in detail below and serves to illustrate the types of issues that are raised. A map of all US shale gas plays and detailed description of the INTEK method are presented in Annex C.2.

Methods used by the US Geological Survey

As indicated above in Section 2.1.1, the USGS undertakes analysis of geological areas within the USA and provides estimates of the 'potential additions to reserves' for unconventional gas from those areas. While it does not provide an estimate of TRR for the whole of the USA, such an estimate can be compiled using the following:

- USGS mean estimates of the potential additions to reserves for all individual shale plays;
- estimates of total proved US shale gas reserves;⁶⁹
- estimates of 'inferred' reserves of shale gas;⁷⁰
- estimates of technically recoverable resources in undiscovered shale gas plays;⁷¹ and
- cumulative shale gas production.

The approach taken by the USGS is described in two methodological papers,⁷² one of which is a 2010 update of the method used previously. These two methods differ slightly; the earlier method excludes any shale gas that was estimated to exist in non-sweet-spot areas from the estimates of 'potential additions to reserves' that were

⁶⁷ INTEK, 'Review of emerging resources'.

⁶⁸ For example Coleman et al., 'Assessment of undiscovered oil and gas'.

⁶⁹ Available from EIA, *Shale gas: proved reserves* (2011, cited 22/11/2011); available from http://www.eia.gov/dnav/ng/ng_enr_shalegas_a_EPG0_R5301_Bcf_a.htm

⁷⁰ Available from INTEK, 'Review of emerging resources'.

⁷¹ Also available from Ibid.

⁷² Charpentier and Cook, 'Improved USGS methodology'; Schmoker, 'Assessment concepts for continuous petroleum accumulations'.

produced. In addition, the earlier method refers to dividing the area under investigation into 'cells' with particular drainage areas (number of cells per unit area) rather than wells; however, cells and wells are essentially identical.⁷³

Nevertheless, the general approach of both methods is similar: the shale play is split into individual areas and then estimates are made of the areal extent of each area; the drainage area of wells (or cells) within those areas; and the mean URR/cell or URR/well within those areas.

A further difference between the two USGS methods is in the estimation of a 'success ratio'. In the newer method, this is estimated separately for the sweet-spot and non-sweet-spot areas and represents the percentage of wells that the USGS estimates will produce at least the minimum URR/well. It modifies the product of the above parameters, tending to reduce the volume of gas estimated to be technically recoverable. The earlier method also estimated a factor similar to the success ratio, but this was not used in the volumetric calculations.

The application of the success ratio (if used) to the above parameters yields an estimate of the discovered technically recoverable resources. The USGS removes cumulative production and an estimate of gas considered to be reserves in order to yield its estimate of the 'potential additions to reserves'.

The USGS periodically updates its resource assessments for individual US shale plays or areas of the plays and produces an end-of-year summary combining all of the latest surveys it has carried out. When estimating the overall TRR for shale gas in the USA from the USGS figures, it is important that within each shale play, the figures to be added must be contemporaneous with the date on which the USGS carried out its assessment. One cannot, for example, simply add current estimates of proved reserves to the USGS figures, since volumes of gas that were not considered reserves when the USGS made its assessment but are now included as reserves would be double counted since they have moved from the USGS 'potential additions to reserves' category into the reserves category. A similar situation exists with cumulative production. The latest resource assessments are summarised in Table 2-4. Although a number of these assessments were produced after 2010, recently released USGS data⁷⁴ suggests that the old methodology was used for all of these. As described above, the earlier assessment methodology excluded volumes of gas estimated to exist in non-sweet-spot areas and so is likely to underestimate the total play TRR.

Since a detailed breakdown of proved reserve figures is only available from 2007 and only a single aggregate estimate of 'inferred' (i.e. probable minus proved) reserves is available, it is not possible to derive a rigorous assessment of the USGS estimate of the TRR within each shale play. In the early 2000s, the potential of shale gas production was not fully realised (as can be seen from the low level of resource estimates in Figure 2-5) and so the majority of shale plays assessed at that time were unlikely to have contained any proved reserves, with the exception of the Barnett and Antrim Shales. Therefore, for those shales which were assessed prior to 2007, it is assumed that proved reserves are zero, except in the Barnett and Antrim Shales. For the Barnett Shale, historic estimates

⁷³ Charpentier and Cook, 'Improved USGS methodology'.

⁷⁴ USGS Marcellus Shale Assessment Team, 'Information relevant to the U.S. Geological Survey assessment of the Middle Devonian Shale of the Appalachian Basin Province', (Reston, VA: United States Geological Survey, 2011).

of proved reserves are available,⁷⁵ however no data is available for historically proved reserves in the Antrim Shale and so we use the earliest data available from 2007. The fifth and sixth columns of Table 2-4 therefore give an approximation of contemporaneously proved shale gas reserves and cumulative production respectively.

Summing the mean estimates of the 'potential additions to reserves', proved reserves and cumulative production for each shale play leads to an estimate of 11 Tcm for the total technically recoverable resource in these plays. To obtain an estimate for the total technically recoverable shale gas resource in the USA, estimates of undiscovered resources (1.6 Tcm) and inferred reserves (0.56 Tcm) both taken from INTEK⁷⁶ have been added in. This leads to an estimate of **13.1 Tcm**,⁷⁷ which compares to a mean estimate of 23.5 Tcm and a range of 8.0-47.4 Tcm from the review of studies presented in Section 2.2. However, since the earlier USGS methodology excluded non-sweet spots, which are now expected to contain significant volumes of shale gas, it may have underestimated the potential additions to reserves in those plays.

⁷⁵ See EIA, 'Barnett shale, Ft Worth Basin, Texas. Wells by year of first production and orientation', (Washington DC: Department of Energy, 2011).

⁷⁶ INTEK, 'Review of emerging resources'.

⁷⁷ Some, but not all, double counting is eliminated by this process.

Table 2-4: USGS estimates of shale gas resource in the United States of America⁷⁸

Report	Assessment date	Major shale plays analysed	Mean estimate provided (Tcm)	Proved reserves at time of assessment*	Cumulative production at time of assessment**
Coleman et al. (2011)	2011	Marcellus shale	2.39	0.13	0.01
Dubiel et al. (2011)	2010	Haynesville and Eagle-Ford	3.62	0.31	0.05
Higley et al. (2011)	2010	Woodford shale	0.70	0.18	0.03
Houseknecht et al. (2010)	2010	Fayetteville and Woodford-Caney	0.76	0.25	0.05
Schenk et al. (2008)	2007	Barnett-Woodford	0.99	0	0
Swezey et al. (2007)	2007	New Albany	0.11	0	0
Swezey et al. (2005)	2004	Antrim	0.21	0.09	0.04
Pollastro et al. (2004)	2003	Barnett	0.75	0.10	0.02
Higley et al. (2003)	2002	Niobrara	0.03	0	0
Milici et al. (2003)	2002	Devonian (Ohio) shale	0.11	0	0.07
Total			9.67	1.07	0.27

2.2.2 Methodological robustness of each method

This section, which identifies some of the strengths and weaknesses of the different methods, attempts to explain why differences exist between estimates, and indicates which procedures are likely to be the most robust.

Literature review/adaptation of existing literature

Studies relying upon literature reviews draw on information from a variety of sources and hence a variety of methods of resource estimation, thus removing some of the uncertainty over the choice of method. They also appear more likely to quantitatively estimate the uncertainty in their resource figure. For example, on the basis of the variation in resource estimates provided by sources for the USA, Mohr and Evans⁷⁹ indicate that the 'best' estimate of URR for shale gas in the USA is 17.7 Tcm with a 'high' value of 35.9 Tcm and a 'low' value of 9.3 Tcm.

⁷⁸ Notes: The borders of the shale plays and assessment units may not always coincide. Most reserve figures are only available at a state level and so some judgement is required to assign these to the shale plays.

* Source: EIA, 'Barnett shale wells', EIA, *Shale gas: proved reserves* (cited).

** Sources: Lippman Consulting (taken from J.B. Curtis, 'The Contribution of Shale Gas to Future U.S. Production: A View of the Resource Base' (paper presented at the AAPG Annual Convention, Denver, CO, 2009); R. Dougher, 'Natural gas and America's energy future' (paper presented at the Marcellus shale lecture series, New York, NY, 2011).)

⁷⁹ Mohr and Evans, 'Shale gas changes production projections'.

On the other hand, reports relying on literature reviews are potentially open to subjectivity over which sources are to be included and which are relied on more heavily. The extent to which, and the reasons for which, certain sources have been favoured over others is rarely made clear. It is also not always clear how the quoted literature has been used. MIT for example, cites ICF, USGS and the National Petroleum Council (NPC) as the sources used for its unconventional gas estimates.⁸⁰ The mean value chosen by MIT for US shale gas corresponds to the values used by ICF; however it is unclear how MIT's P10 and P90 estimates rely upon the USGS and NPC figures.

Bottom-up analysis of geological parameters

The geological approach employs well-known and well-understood equations to estimate the volumes of free and adsorbed gas in place. A number of problems exist, however.

The first, and perhaps the most important, is the inherent subjectivity in choosing the recovery factor to apply to the estimated gas in place. It was for this reason that the USGS chose not to use this approach stating: "the estimation of an overall recovery factor must sometimes be quite qualitative". ARI⁸¹ attempted to remove some of the subjectivity in its estimates of recovery factors, which lay between 20% and 30% in most circumstances, by linking this to the mineralogy of the source rocks; however, recovery factors of 15-40% have been used by other authors,⁸² while Strickland et al.⁸³ report that some recoveries can be as low as 1-2%. When the volumes of gas in place are so large, this corresponds to a huge range of uncertainty in the technically recoverable resources.

An additional problem relates to the estimation of the geological variables required for this method. It is important to remember that data may only be available for a subset of these, and for unexplored shale plays such estimates must necessarily have large confidence bounds. Hubbert remarked that for conventional petroleum resource estimates: "it is easy to show that no geological information exists other than that provided by drilling...that has a range of uncertainty of less than several orders of magnitude."⁸⁴ Even when exploratory drilling has taken place, the range of uncertainty may still be wide. For example, it is often difficult to estimate the gas saturation⁸⁵ from well-log data, a key parameter in the estimation of the gas in place.⁸⁶

A third problem relates to the issue of 'sweet spots'. As mentioned above, there is significant heterogeneity between sweet spots and non-sweet spots. Simply extrapolating geological values from certain areas within the sweet spot across the entire extent of the shale is likely to overestimate the resource potential; segregating the shale play area is necessary to avoid this. ARI's concept of 'prospective area' indicates an attempt to disregard areas of shale that are likely to be less productive. The next step would be to delineate the prospective area into sweet-spot and non-sweet-

⁸⁰ Ejaz, 'Background material on natural gas resource assessments'.

⁸¹ Advanced Resources International, 'World shale gas resources'.

⁸² IEA, 'WEO 2009'; Kuuskraa, 'Status report'; Mohr and Evans, 'Long term forecasting'.

⁸³ Strickland, Purvis and Blasingame, 'Reserves Determinations'.

⁸⁴ M.K. Hubbert, 'Techniques of prediction as applied to the production of oil and gas', in *Oil and gas supply modeling* (Washington, DC: 1982).

⁸⁵ The gas saturation is the fraction of the porosity of the shales filled with gas rather than water.

⁸⁶ Hubbert, 'Techniques of prediction'; W.J. Lee and R. Sidle, 'Gas-Reserves Estimation in Resource Plays' (paper presented at the SPE Unconventional Gas Conference, Pittsburgh, PA, 2010).

spot sectors, but ARI was unable to do this. The frequency and extent of sweet spots and the degree of variation between sweet spots and other areas remains uncertain, even in comparatively well-developed shales.

A fourth point is that this approach does not depend particularly upon prior production experience. Drilling is the only reliable means of assessing the extent and volumes of shale gas that exists, as can be seen by the large number of wells that have been drilled outside the sweet-spot areas within the USA. This shows that the productivity of these areas can vary enormously and, although displaying some correlation with parameters such as the shale thickness, is not really known until drilling is well under way.⁸⁷

The final and most important problem is the absence of a rigorous approach to uncertainty. While some reports mention the uncertainty in values in passing or give a range in final resource estimates, no reports placed in this category provided a thorough description of the uncertainties that had been analysed or present their results in the form of a probability distribution. There is no reason, except potentially because of an absence of relevant data, why the uncertainties in individual geological parameters (particularly those used more than once or which are especially uncertain, such as the areal extent of the shale), cannot be estimated, stated and accounted for.

Extrapolation of production experience

This approach avoids some of the above problems but unfortunately introduces some more, one of which is currently somewhat controversial. It is first interesting to note that the only source providing a detailed methodology, the USGS, chose to employ this approach.

The key general additional problem introduced regards the methods for estimating the URR from individual wells. As explained in detail in Section 2.3, these methods rely upon modelling the anticipated decline in the rate of production from individual wells. Different choices are available for the 'shape' and rate of future production decline, and the limited historical experience at present does not constrain these choices especially well – with different choices potentially leading to very different estimates of the URR. As explained in Section 2.3 there is concern that current practice may be overestimating the URR for individual wells. To the extent that these form the basis of regional resource estimates, these too could be overestimated.

An additional problem that applies to the simple analogy-based approach used by DECC⁸⁸ and Rogner⁸⁹ concerns which analogue to choose. The choice of an analogue is extremely important: as noted DECC's choices of analogues varied by a factor of ten. The USGS suggested using a probabilistic approach with more than one analogue to reduce this problem,⁹⁰ which appears to be a sensible approach given the uncertainties that exist.

A further problem, given both the complexity and heterogeneity of the geological determinants and the absence of a long history of production data, is the validity of the

⁸⁷ R.R. Charpentier and T.A. Cook, 'Applying probabilistic well-performance parameters to assessments of shale gas resources' (paper presented at the American Association of Petroleum Geologists annual convention and exhibition, New Orleans, LA, 2010); Kuuskraa, 'Case study #1. Barnett Shale: The start of the gas shale revolution'.

⁸⁸ Harvey and Gray, 'Unconventional resources of Britain'.

⁸⁹ Rogner, 'Assessment of World Resources'.

⁹⁰ Charpentier and Cook, 'Probabilistic well-performance parameters'.

assumptions made for the productivity of areas outside those currently being produced. As mentioned in Section 2.2.1, historic production has focused upon sweet spots and upon the most productive areas within those sweet spots. Extrapolating a mean URR/well from this area to the whole of the sweet spot could potentially overestimate the resource potential. If these estimates are then extended across the entire shale play, the resource potential of the region could be greatly overestimated.

The USGS attempted to mitigate this problem by mapping a range of geological factors and using these to estimate the possible productivities outside the area currently being produced, although it has not, in the assessments it has performed so far, attempted to estimate the productivity of non-sweet-spot areas. Nevertheless, its approach is relatively transparent and has the advantage that uncertainties are explicitly accounted for.

It is clear, therefore, that careful delineation of the shale play is necessary to avoid overestimating productivity in undeveloped areas, but delineation is itself challenging. This is particularly relevant when splitting the shale play into sweet-spot and non-sweet-spot areas. Given the heterogeneity even within sweet spots, it is preferable to define and isolate the shale into an even greater number of areas of differing productivity: a procedure used by the USGS through the differentiation of shale plays into smaller assessment units.

As mentioned above, INTEK also used this approach to derive estimates of the TRR in the USA for the EIA.⁹¹ Its method is described in Annex C which also provides a detailed comparison of these two methods; however, a brief examination of their assessments for the Marcellus Shale play is given in Box 2-1.

⁹¹ INTEK, 'Review of emerging resources'.

Box 2-1: Comparison of Marcellus Shale play assessments

Recently released data⁹² from the USGS allows one to attempt a 'like-with-like' comparison between the assessments carried out by the USGS⁹³ and INTEK⁹⁴ of the Marcellus Shale. The USGS estimate is of "potential additions to reserves" while INTEK's estimate is of "unproved discovered technically recoverable resources". Despite these different names, both exclude any volumes of proved reserves from their estimates and it is assumed both exclude "inferred reserves". The two estimates should therefore be comparable.

The authors include below only the mean estimates of the data provided by USGS: reproducing the estimates provided would require a rigorous handling of the ranges it provides. There are some errors introduced by this but the overall difference between the calculated value and quoted figure provided by the USGS is only 0.4%.

There are two major differences that can be seen in the table below that result in the difference between the 'headline' figures of 2.4 Tcm by the USGS and 11.6 Tcm by INTEK. First, the USGS excludes shale gas in non-sweet-spot areas, which INTEK indicates makes up 57% its estimate. INTEK's resource estimate within its sweet-spot area is still 110% larger than USGS's, however, and so the second major difference can be seen to be the values used for URR/well. INTEK's URR/well is over three times the productivity within the Interior assessment unit, the most productive of USGS's assessment units. In fact, INTEK's non-sweet-spot productivity is equivalent to the mean productivity within the sweet-spot area of the USGS's most productive assessment unit. Countering this to an extent is USGS's larger overall sweet-spot area, which is around 90% greater than that used by INTEK. The two non-sweet-spot areas are almost identical.

Assessment unit	INTEK		USGS		
	Foldbelt	Interior	Western Margin	Total	
Sweet-spot area					
Area (km ²)	27 511	2 469	42 840	7 151	52 460
Well spacing (wells/km ²)	3.1	1.7	1.7	2.1	
URR/well (mcm/well)	99.2	5.9	32.6	3.7	
Success factor	60%		Not used		
Calculated gas volume (Tcm)	5.06	0.024	2.315	0.056	2.395
Quoted gas volume (Tcm)	5.06	0.022	2.305	0.058	2.385
Non-sweet-spot area					
Area (km ²)	218 261	46 903	74 114	96 043	217 060
Well spacing (wells/km ²)	3.1				
URR/well (mcm/well)	32.6				
Success factor	30%		Not assessed		
Calculated gas volume (Tcm)	6.59				
Quoted gas volume (Tcm)	6.59				
Total (Tcm)		11.65			2.385

2.2.3 Impact of technology on resource estimates

The studies reviewed above have focused upon estimating the volume of shale gas that could be recovered using currently available technology. As indicated in Section 2.1.1, assessment methods that explicitly allow for future technological advances are likely to lead to substantially larger estimates of recoverable resources. Only three reports that attempt to quantify the effects of future technology development have been identified,

⁹² USGS Marcellus Shale Assessment Team, 'Information relevant to assessment of Appalachian Basin'.

⁹³ Coleman et al., 'Assessment of undiscovered oil and gas'.

⁹⁴ INTEK, 'Review of emerging resources'.

namely: a 2004 report by Kuuskraa,⁹⁵ a paper by the US National Petroleum Council⁹⁶ and a number of the EIA AEOs.⁹⁷ In each case, technological progress is represented by annual percentage increases in the URR/well.

It is important to note that it was not the introduction of 'new' technologies, i.e. technologies that had not been employed elsewhere and whose potential was unknown, but the adaptation and utilisation of existing technologies that has led to the large increases seen in the URR/well recently (ARI⁹⁸ for example indicates that the URR/well within the Barnett Shale between 1985 and 1990 averaged around 11.3-14.1 mcm/well, but in 2007-2008 had increased to around 65.2 mcm/well). New technological breakthroughs can never be ruled out, however.

Two technologies identified by the EIA AEOs, stimulation⁹⁹ and horizontal drilling, are now much more widely used than in 2000. It therefore seems likely that there is less potential for a step increase through switching from vertical wells without stimulation to horizontal wells with stimulation, in addition to there now being a better understanding of the current and future potential of these technologies. There has also been a significant body of work analysing the geology of individual shale plays. One would therefore expect shale geology to be now also much better understood and hence the scope for future improvements in URR/well to be better appreciated. These two factors suggest that such a step change in URR/well as witnessed between 1985 and the present is less likely to occur again in the future.

However, another way to look at the role of technology is by examining the influence of changes in shale gas recovery factors. Even a very small increase in average recovery factors can have very significant impacts on estimated global recoverable volumes of shale gas. For example, using ARI's global estimate of shale gas OGIP of around 708.2 Tcm,¹⁰⁰ a 1% increase in recovery factors globally would lead to an increase in global URR of 7.1 Tcm – over twice the global production of all natural gas in 2010.¹⁰¹

The significant impact that even a small improvement in technology can have on the URR, and the possibility of major future technological breakthroughs, means that estimates of future technological progress must always be interpreted with considerable caution.

2.2.4 Summary

Nearly all of the sources examined acknowledge that the estimates they provided are liable to change. Despite this, the majority present their results as single figures rather than a range (see for example Figure 2-7 to Figure 2-9). Given the limited production

⁹⁵ V.A. Kuuskraa, 'Natural gas resources, unconventional', in *Encyclopedia of Energy*, ed. C.J. Cleveland (London: Elsevier, 2004).

⁹⁶ S.A. Holditch, 'Unconventional gas topic paper #29', (Washington, DC: National Petroleum Council, 2007).

⁹⁷ See, for example, EIA, 'AEO 2010'.

⁹⁸ Kuuskraa, 'Case study #1. Barnett Shale: The start of the gas shale revolution'.

⁹⁹ Stimulation, also known as hydraulic fracturing, involves "pumping fluids" consisting primarily of water and sand...injected under high pressure into the producing formation, creating fissures that allow resources to move freely from rock pores where it is trapped'. American Petroleum Institute, 'Hydraulic fracturing: unlocking America's natural gas resources', (Washington, DC: American Petroleum Institute, 2010).

¹⁰⁰ Advanced Resources International, 'World shale gas resources'.

¹⁰¹ BP, 'Statistical review 2011'.

experience with shale gas, the limitations of the resource assessment methodologies, the level of uncertainty associated with many of the relevant variables, the high degree of subjectivity involved and the huge changes that have occurred in US estimates over the past few years, this greatly overemphasises the certainty with which the estimates should be interpreted.

The table below summarises some of the advantages and disadvantages of the two main resource assessment methodologies. The choice between them will depend upon the extent of development of the region, the level of access to the relevant data, and the human and financial resources available. While a high-level of uncertainty is inevitable at this stage of the development of the resource, this can be addressed, or at least mitigated, through the use of probabilistic methods. The absence of such methods is the primary weakness of the available literature.

Table 2-5: Advantages and disadvantages of geological and extrapolation approaches to estimating shale gas resources

Bottom-up analysis of geological parameters		Extrapolation of production experience	
Advantages	Disadvantages	Advantages	Disadvantages
Robust and well-established geological approach	Limited data and wide range of uncertainty in many of the geological parameters	No need to assume recovery factor	a Decline rate problem for URR/well
Reduces emphasis on the use of analogues	Difficulties in delineating sweet-spot areas		Difficulties in delineating sweet-spot areas
	Subjectivity in choice of recovery factor(s)		Subjectivity in choice of key variables such as 'success factor'
	Not directly based on actual drilling data		Estimation of productivity in undeveloped areas
			Risk of using inappropriate analogues

Within the analysis of geological parameters category, ARI's¹⁰² report is not only the most ambitious in scope but also provides the most detailed description of the methods used. It also attempts to address some of the general disadvantages of the approach discussed above. One criticism, however, is its lack of handling of uncertainty.

Within the extrapolation category, the INTEK report is widely cited and influential, but has a number of important limitations as described in Annex C, including: the inaccurate delineation of sweet-spot areas; the subjective choice of 'success factors'; the reliance upon out-of-date information; and the inadequate treatment of uncertainty. The USGS approach is significantly more transparent and robust, but there are difficulties in using the available USGS literature to estimate the overall US TRR.

All of the USGS assessments were undertaken using a methodology that excluded resources contained within non-sweet-spot areas. The absence of suitably disaggregated reserve and production data also creates the risk of double counting. These two effects could however potentially act in opposite directions, the first leading to an underestimate and the second to an overestimate of recoverable resources. The

¹⁰² Advanced Resources International, 'World shale gas resources'.

most commendable feature of the USGS approach is the explicit treatment of uncertainty, which is one reason why the results may be considered more reliable than those from INTEK. Furthermore, reliability should improve once updates using the new USGS methodology are undertaken for the shale plays that have not been assessed for some time.

One major drawback of both the geological and extrapolation methods are their sensitivity to a single parameter, namely the recovery factor with the geological approach and the assumed functional form for the production decline curve with the extrapolation approach (see Section 2.3). Both of these parameters are poorly understood with regard to shale gas production and remain controversial. It is generally accepted that estimation of the recovery factor is challenging, but little progress appears to have been made regarding its estimation in shale areas, even when the geology is relatively well understood. The controversy regarding estimation of the URR/well is more recent and the reasons behind the differing assumptions used by reporting organizations are not well understood. It is for this reason that Section 2.3 below examines the issue in more detail and attempts to find common ground between the polarised views. In principle, the reliability of the extrapolation method should improve as production experience increases. Hence, we would expect approaches based upon actual production experience to provide more reliable resource estimates in the medium term. At present, however, the level of uncertainty from these methods appears to be comparable to that from geological methods. As recommended by Lee and Sidle,¹⁰³ future studies that seek to derive mean estimates of the TRR for a region, should use as many different approaches as possible.

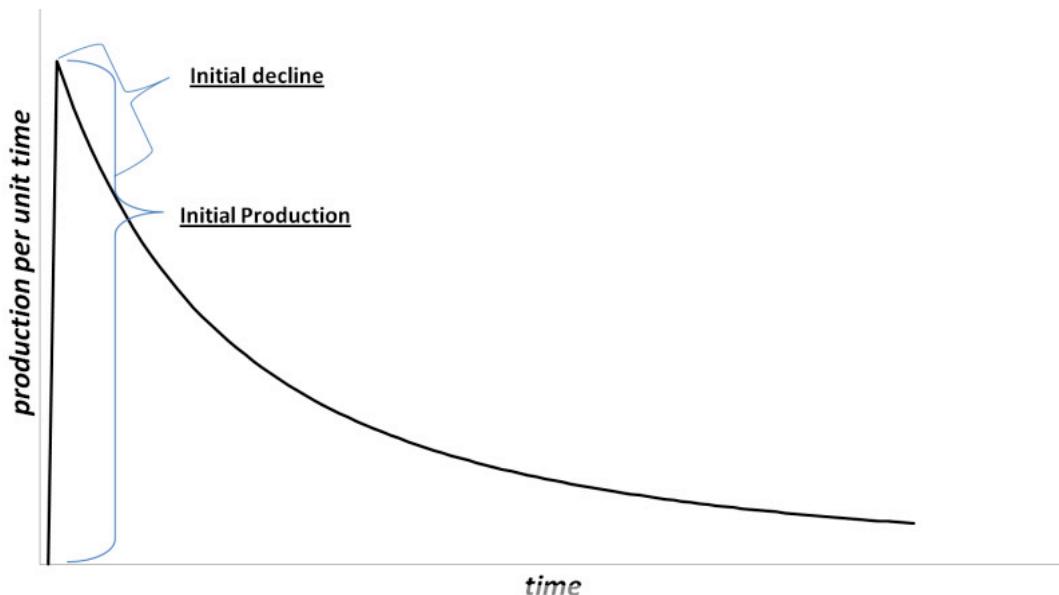
Given these multiple limitations, it is essential to address and report on the level of uncertainty in the estimates, whichever approach is adopted. The failure of the majority of the existing literature to do this is a major limitation. To date, only the USGS has handled uncertainty in a rigorous manner, but there is no reason why other studies could not do so.

2.3 Decline curve analysis and the estimation of recoverable resources

Production from shale gas wells declines continuously and rapidly within a month or two of initial production (IP) (see schematic in Figure 2-12). Estimating the future rate of production decline is therefore central, both to forecasting future production and to estimating the URR of the well – a key determinant of profitability. Appropriate methodologies for forecasting future decline rates are therefore needed to develop robust estimates of these two variables.

¹⁰³ Lee and Sidle, 'Reserves Estimation'.

Figure 2-12: Illustrative chart of typical decline in shale gas production



Such methodologies, termed *decline curve analysis* (DCA), are well-established and widely used.¹⁰⁴ However, the appropriateness of specific methodologies for shale gas plays has been questioned, with suggestions that future decline rates have been underestimated, and both well longevity and ultimate recovery overestimated.¹⁰⁵ These individual well URR estimates form a key input into the extrapolation of production experience approach for estimating the regional URR of shale gas described in Section 2.3. Hence, if the URR/well is being overestimated, there is a risk that the regional URR will be overestimated also. However, other commentators contest this interpretation and point to the impressive recent history of shale gas production as evidence that future estimates are realistic.¹⁰⁶ While the roots of this disagreement lie in the technical assumptions underpinning decline curve analysis, the economic importance of shale gas has led to a very public and politicised debate.¹⁰⁷

In brief, DCA involves statistically fitting a hyperbolically declining curve to a time series of historical production data from a well. This fitted curve can then be extrapolated to derive the future production estimate or URR for that well. The typical hyperbolic equation used involves three key terms: the initial production rate; the initial decline rate; and a constant termed b , which defines the rate at which decline rate arrests (see

¹⁰⁴ Ram G. Agarwal et al., 'Analyzing Well Production Data Using Combined-Type-Curve and Decline-Curve Analysis Concepts', in *SPE Annual Technical Conference and Exhibition* (New Orleans, LA: 1998); J.J. Arps, ed., *Analysis of Decline Curves. Petroleum Technology* (Houston, Texas: Society of Petroleum Engineers, 1945); M.J. Fetkovich, 'Decline Curve Analysis Using Type Curves', *SPE Journal of Petroleum Technology* 06 (1980); D. Ilk et al., 'Integrating Multiple Production Analysis Techniques To Assess Tight Gas Sand Reserves: Defining a New Paradigm for Industry Best Practices', in *CIPC/SPE Gas Technology Symposium 2008 Joint Conference*, ed. Society of Petroleum Engineers (Calgary, Alberta: 2008).

¹⁰⁵ A.E. Berman, 'Shale Gas-Abundance or Mirage? Why The Marcellus Shale Will Disappoint Expectations' (paper presented at the ASPO USA 2010 World Oil Conference, Washington, DC, 17/10/11 2010).

¹⁰⁶ W.A. Featherston et al., 'Energy Sector: NYT Shale Gas Allegations Seem Exaggerated', in *UBS Investment Research* (New York: UBS, 2011).

¹⁰⁷ Berman, 'Shale Gas-Abundance or Mirage? Why The Marcellus Shale Will Disappoint Expectations'; John Dizard, 'Debate over shale gas decline fires up', *Financial Times* 2010; Featherston et al., 'NYT Allegations Exaggerated'; I. Urbina, 'Insiders Sound an Alarm Amid a Natural Gas Rush', *New York Times* 2011.

Annex A). Both initial production and initial decline can be measured from a short production experience. The appropriate b constant, however, is significantly less certain until several years production experience is available. The impact of increasing b is to increase the production rate to which the fitted curve is asymptotically approaching. Therefore a higher b constant leads to higher estimates of URR for that well. Typically b varies between 0 and 1, but the initial production from wells with a high initial decline rate (such as shale gas) can be approximated by hyperbolic curves with b constants greater than unity. At present, it remains unclear whether subsequent production rates from these wells will remain consistent with these fitted curves. Hence, the 'correct' b constant for such wells has become a focus of controversy.

Based on both simulated and empirically observed well behaviour, some authors have suggested that assuming $b > 1$ results in resource estimates that are 2-100 times greater than the 'reasonable' values derived from completed wells or other estimation techniques.¹⁰⁸ Shale gas companies currently active in the four main US shale gas plays have used hyperbolic decline curves with b constants of between 1.4 and 1.6.¹⁰⁹ Analysis of 1957 horizontal wells in Barnett, Fayetteville, Woodford, Haynesville and Eagle Ford shale plays¹¹⁰ suggests that b constants above 1 may be appropriate for unconventional gas in some instances, though b constants such as the 1.4 to 1.6 indicated above are not supported. Guidelines from SPE identify a possible range for the b constant of between 0 and 1.5 for shale gas, but suggest that a conservative decline rate (lower b) be used to derive proved reserve estimates. A more optimistic decline rate (higher b) may be used for proved and probable (2P) reserves.¹¹¹

Critics of the use of decline rates in shale gas have suggested that operators may assume overly optimistic b constants¹¹² based upon only limited production experience. In an analysis of 44 wells with over 12-months production experience in the Haynesville shale,¹¹³ a hyperbolic curve was fit to the average production with a b constant of 1.1. This resulted in a mean URR estimate for the 44 wells of 185 mcm/well. Some have argued that this estimate is optimistic and it has been shown that curves with a range of different b constants fit the data comparably well (see Annex A). For example, a hyperbolic curve with a b constant of 0.5 would give a mean URR estimate of only 85 mcm/well. It has already been seen that, under some circumstances, a b constant of over 1 may be estimated. However, it can be shown that the sensitivity of URR estimates to b increases with the assumed value of b , suggesting that small variations in b where $b > 1$ have more impact on URR estimates than similar variations in b where $b < 1$.

Shale gas analyst Arthur Berman examined the implications of this analysis for shale gas economics and suggested that a well with an estimated URR of 85 mcm (the outcome for

¹⁰⁸ L. Mattar, 'Production Analysis and Forecasting of Shale Gas Reservoirs: Case History-Based Approach', in *SPE Shale Gas Production Conference*, ed. Society of Petroleum Engineers (Fort Worth, TX: 2008); J.A. Rushing et al., 'Estimating Reserves in Tight Gas Sands at HP/HT Reservoir Conditions: Use and Misuse of an Arps Decline Curve Methodology', in *SPE Annual Technical Conference and Exhibition*, ed. Society of Petroleum Engineers (Anaheim, CA: 2007).

¹⁰⁹ Chesapeake Energy, 'Institutional investor and analyst meeting', (2010).

¹¹⁰ Jason Baily et al., 'Shale Gas Production Decline Trend Comparison Over Time and Basins' (paper presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, 2010).

¹¹¹ Society of Petroleum Engineers, 'Guidelines for Application of the Petroleum Resources Management System'.

¹¹² Berman, 'Shale Gas-Abundance or Mirage? Why The Marcellus Shale Will Disappoint Expectations'.

¹¹³ Chesapeake Energy, 'Investor and analyst meeting'.

$b=0.5$ in the case of average Haynesville production decline) is likely to require a gas price of $\sim \$7$ per thousand cubic feet (Mcf), which compares to current US gas prices of only $\sim \$3.5$.¹¹⁴ This debate has subsequently been explored by the press, with articles in the *Financial Times* and the *New York Times* discussing the argument over b constants and the range of opinion over the economic viability of shale gas in the USA.¹¹⁵ These articles have in turn prompted response from some analysts defending the future profitability of shale production in the USA.¹¹⁶ However, even from this defensive position, it is highlighted that a gas price of between $\$5.5$ and $\$6$ per Mcf of gas is required to support shale gas production in most of the US regions.

A recent analysis of 8 700 horizontal wells in the Barnett Shale¹¹⁷ lends some support to a more optimistic position. This analysis groups wells by the number of years they have been in production and uses non-linear regression to find the best fit decline curve for each group. The results suggest hyperbolic decline with b values ranging from 1.3 to 1.6, with a mean of 1.5. This leads to a mean URR/well of 56.6 mcm when extrapolating production over an assumed 30-year lifetime. The same analysis also shows that older wells perform better (i.e. decline less rapidly) and speculates that this may be due both to newer wells targeting poor quality rock and/or to reduced spacing between wells. 'Re-stimulation' of wells leads to higher production in the short term, but it is too early to tell whether this also leads to higher ultimate recovery.

In summary, if b constants are overestimated, the US shale gas reserve is likely to be overstated by studies relying upon the extrapolation of historical production experience (e.g. the USGS). But the empirical evidence remains equivocal at present and several more years of production experience is likely to be required before any firm judgement can be made. In the interim, continued controversy can be anticipated.

2.4 Best estimates: characterising the uncertainty

2.4.1 Estimates of shale gas resources

Drawing together the above, Table 2-6 provides a range of estimates of the technically recoverable shale gas resources within 15 global regions. In some regions it was not possible to provide a central estimate due to the absence of sufficient information. It is also important to note the numerous and important caveats to these estimates, summarised in the table and in the following section. The reasons for choosing these particular estimates and/or manner in which they were derived are indicated in the table. Since all estimates refer to technically recoverable resources, they take no account of economic viability or any other constraints on resource recovery. Hence, there is no guarantee that these resources will be produced.

As discussed in Section 2.2, resource estimates based upon the extrapolation of production experience are likely to be more robust. However, with very limited production experience in the majority of the world's regions, it is more appropriate at

¹¹⁴ On 15 December 2011, Bloomberg.com stated that the NYMEX Henry Hub 1M future was $\$3.11$, the Henry Hub Spot was $\$3.08$, and the New York City Gate Spot was $\$3.33$. These prices are all per million BTU, which when converted to Mcf become $\$3.02$, $\$3.00$ and $\$3.24$ respectively.

¹¹⁵ Dizard, 'Debate'; Urbina, 'Insiders Sound Alarm'.

¹¹⁶ Featherston et al., 'NYT Allegations Exaggerated'.

¹¹⁷ Li Fan et al., 'The Bottom-Line of Horizontal Well Production Decline in the Barnett Shale' (paper presented at the SPE Production and Operations Symposium, Oklahoma City, OA, 2011).

this stage to incorporate estimates from studies that use a range of methodologies. Since experience with production and resource estimation is growing rapidly, it is also important to use the most recent estimates. Organisations that have provided multiple estimates for single regions (e.g. Kuuskraa/ARI¹¹⁸ and the EIA¹¹⁹) have consistently, and often significantly, increased their estimates over time.

As shown in Table 2-6, it was only possible to obtain high, best and low estimates of recoverable resources for four regions – namely, Canada, USA, China and Other developing Asia. For these regions, the high estimate is, on average, 250% of the best estimate, while the low estimate is 31% of the best estimate. In the USA, the corresponding figures are 230% and 64%. This serves to demonstrate that the range of uncertainty in these estimates is extremely large, even for the USA. Given the comparative absence of production experience in most other regions of the world, the resource estimates should be treated with considerable caution.

Table 2-6: Estimates of shale gas resources (Tcm)

	High	Best	Low	Notes/sources
Africa	29.5			ARI ¹²⁰
Australia	6.3			Average of Medlock et al. ¹²¹ and ARI. Cannot assume that estimate from ARI is the 'high' estimate as this is reported as a conservative assessment
Canada	28.3	12.5	4.7	Only estimates from 2010 and after have been chosen High: Highest estimate provided in Skipper ¹²² Best: mean of several studies ¹²³ (ICF estimate assumed to be TRR) Low: Medlock et al.
China	39.8	21.2	1.6	High: All of 'Centrally planned Asia' from Rogner ¹²⁴ with 40% recovery factor Best: Average of Medlock et al. and ARI Low: All of 'Centrally planned Asia' from WEC ¹²⁵ with 15% recovery factor

¹¹⁸ Advanced Resources International, 'World shale gas resources'; Kuuskraa, 'Economic and market impacts'; V.A. Kuuskraa, 'Gas shales drive the unconventional gas revolution' (paper presented at the Washington energy policy conference: the unconventional gas revolution, Washington, DC, 2010); Kuuskraa, 'Gas resources, unconventional'; Kuuskraa, 'An exportable North American revolution?'; V.A. Kuuskraa, 'Unconventional gas: Resource potential estimates likely to change', *Oil and Gas Journal* 105, no 35 (2007); Kuuskraa, 'Status report'; Kuuskraa and Meyers, 'Review of world resources'; V.A. Kuuskraa and T. Van Leeuwen, 'Economic and market impacts of abundant shale gas resources, in Global Leaders Forum: 'The natural gas revolution: U.S. and global impacts'', (Arlington, VA: Advanced Resources International Inc., 2011).

¹¹⁹ EIA, 'Annual Energy Outlook 2008 with Projections to 2030', (Washington, DC: US Energy Information Administration, 2008); EIA, 'AEO 2010'; EIA, 'AEO 2011'; S.A. Jikich and A.S. Popa, 'Hyperbolic Decline Parameter Identification Using Optimization Procedures, (paper presented at the SPE Eastern Regional Meeting, Morgantown, WV, 2000).

¹²⁰ Advanced Resources International, 'World shale gas resources'.

¹²¹ Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

¹²² K. Skipper, 'Status of global shale gas developments, with particular emphasis on North America', in *IIR inaugural shale gas briefing* (Brisbane: 2010).

¹²³ Advanced Resources International, 'World shale gas resources'; K. Downey, 'Fueling North America's energy future: The unconventional natural gas revolution and the carbon agenda - Executive summary', (Cambridge, MA: IHS CERA, 2010); Medlock, Jaffe and Hartley, 'Shale Gas and National Security'; Moniz, Jacoby and Meggs, 'Future of natural gas'; Petak, 'Impact of natural gas on CHP'; Skipper, 'Status of global shale gas developments'.

¹²⁴ Rogner, 'Assessment of World Resources'.

¹²⁵ WEC, 'Survey of Energy Resources'.

	High	Best	Low	Notes/sources
Central and South America	34.7		ARI	
Eastern Europe¹²⁶	4.3			Average of Medlock et al. and ARI for Poland
Former Soviet Union	61.2	2.7		High: WEC with 40% recovery factor Low: Rogner with 15% recovery factor
India	1.8		ARI	
Japan	0			No sources report any shale gas to be present in Japan
Middle East	28.7	2.8		High: whole of Rogner's MENA region with 40% recovery factor. Low: half of WEC MENA region (as assumed by ARI) with 15% recovery factor
Mexico	11.6			Average of Medlock et al. and ARI
Other developing Asia	22.1	1.3		WEC reported OECD Asia and 'Other Asia' collectively cannot be used High: Rogner 'Other Pacific Asia' and 'Centrally Planned Asia' regions with 40% recovery factor minus best estimate of China from above Low: 'Other Pacific Asia' only (as assume all of Rogner's 'Central Planned Asia' is China) and assuming a 15% recovery factor. This is similar to estimate for Pakistan only from ARI
South Korea	0			No sources report any shale gas to be present in South Korea
United States of America	47.4	20.0	13.1	Only estimates from 2010 and after have been chosen High: highest estimate available – ICF ¹²⁷ (assumed to be TRR) Best: mean of three estimates from each category judged to be most suitable ¹²⁸ Low: lowest estimate available – USGS
Western Europe¹²⁹	11.6			Average of Medlock et al. and ARI for Sweden and Germany, and ARI and DECC ¹³⁰ for the UK. ARI for France, the Netherlands, Norway and Denmark and Medlock et al. for Austria

2.4.2 Confidence in current estimates and conclusions

This section summarises some of the main findings from the preceding sections, and assesses whether and to what extent these resource estimates are likely to change in the future.

The focus of this chapter has been on *original* estimates of unconventional gas resources – and especially shale gas resources – for different countries and regions. Original estimates are defined as those that have been developed using recognised methodologies or derived by adapting figures from existing sources. This criterion

¹²⁶ Including Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Macedonia, Montenegro, Poland, Romania, Serbia (Kosovo), Slovenia, Slovakia

¹²⁷ Petak, 'Impact of natural gas on CHP'.

¹²⁸ Kuuskraa, 'Economic and market impacts'; Medlock, Jaffe and Hartley, 'Shale Gas and National Security'. As well as USGS.

¹²⁹ Including Austria, Belgium, Cyprus, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Malta, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, United Kingdom.

¹³⁰ Harvey and Gray, 'Unconventional resources of Britain'.

excludes the resource estimates published in an influential study by the IEA.¹³¹ The IEA takes most of its shale gas resource estimates directly from ARI,¹³² while for the Middle East the estimates are based upon the seminal study by Rogner¹³³ assuming a 20% recovery factor. Rogner is also the source of the IEA tight gas and CBM resource estimates, assuming a 40% and 25% recovery factor respectively. Whether such reliance upon Rogner is reasonable is discussed below.

Only within North America, and predominantly the USA, are any shale gas resources considered proved reserves and these comprise only a small proportion of the estimated technically recoverable resources.¹³⁴ It is thus very important not to confuse reserves with resources. As indicated above, resource estimates are inherently uncertain and all the more so for a resource that is at such an early stage of development. Moreover, this uncertainty is compounded by the use of imprecise or ambiguous terminology. This often results from employing terminology that has been derived for conventional hydrocarbons but is not necessarily appropriate for unconventional resources (e.g. 'undiscovered resources'). Hence, uncertainty could be reduced by more careful and consistent use of terms and definitions or, better still, the development of an appropriate standard such as the SPE/PRMS.

Four general methods have been used to generate resource estimates of shale gas, namely: expert judgement; literature review; bottom-up assessment of geological parameters and extrapolation of production experience. These have been described in detail and the strengths and weaknesses of each discussed. While the extrapolation of production experience is potentially the most robust methodology, it relies upon data that is unavailable for most regions of the world. While analogues can be used, the results are sensitive to the particular analogue that is chosen.

With the current state of development of the literature, the differences in resource estimates between institutions using a similar methodological approach are as significant as the differences between those using different approaches. For example, looking at estimates of the US TRR, the differences between the estimates of the USGS and INTEK¹³⁵ within the extrapolation category are as great as between Medlock et al.¹³⁶ (literature review), USGS (extrapolation) and ICF¹³⁷ (geological). A primary source of these differences is the uncertainty over the recovery factor and the URR/well. Hence, emphasis needs to be placed on constraining these parameters to a greater

¹³¹ IEA, 'Golden age'. Most of the IEA shale gas resource estimates were taken directly from ARI, while the Middle Eastern estimates were based upon Rogner assuming 20% recovery factor. The tight gas resource estimates for all regions, and the CBM resource estimates for North America and Asia/Pacific, were all taken from Rogner assuming 40% and 25% recovery factors respectively. The IEA also provides a CBM resource estimate for Eastern Europe/Eurasia, but it is not clear how this was derived. The figure of 85 Tcm would require a 75% recovery factor to correlate to Rogner's estimate of CBM OGIP. Alternatively, an OGIP of 340 Tcm would be required if a 25% recovery factor is assumed – which is significantly greater than any other estimate of global CBM OGIP. Advanced Resources International, 'World shale gas resources', Rogner, 'Assessment of World Resources'.

¹³² Advanced Resources International, 'World shale gas resources'.

¹³³ Rogner, 'Assessment of World Resources'.

¹³⁴ Proved reserves reported by the EIA for 2009 are 1.7 Tcm and so comprise only 9% of the best estimate of TRR given in Table 2-6. EIA, *Shale gas: proved reserves* (cited).

¹³⁵ INTEK, 'Review of emerging resources'.

¹³⁶ Medlock, Jaffe and Hartley, 'Shale Gas and National Security'.

¹³⁷ K.R. Petak, D. Fritsch and E.H. Vidas, 'North American Midstream Infrastructure Through 2035 - A Secure Energy Future', (ICF International, 2011).

degree than at present and on incorporating probabilistic techniques to capture their inherent uncertainty.

There is an absence of rigorous studies for a number of key regions across the world. This includes Russia and the Middle East, which are estimated to hold potentially very large resource volumes (Table 2-6). While Rogner¹³⁸ and the World Energy Council¹³⁹ provide independent estimates for these regions, they provide very little information on their methodology and their methods are potentially flawed. For example, Rogner used a single analogue from the USA to estimate recoverable resources across the whole world. But since subsequent US experience has demonstrated a wide variation, both within and between shale plays, the choice of a different analogue could have led to very different results. The WEC provides no references for the literature relied upon for its study. This makes reliance on other studies preferable whenever possible, although in many regions Rogner and the WEC are the only sources that are available.

As mentioned above, the estimates produced by bottom-up geological assessments are very sensitive to the assumed recovery factor. While it is generally accepted that estimating recovery factors is challenging, little progress appears to have been made in establishing such factors for shale, even when the geology is well understood. Uncertainty over this factor, which is currently estimated to be between 15% and 40% for shale gas production, makes an accurate estimate of TRR very difficult – even assuming the OGIP can be established with any confidence.

In a similar manner, many of the estimates produced by extrapolation methods are sensitive to the assumed URR/well and hence to the choice and parameterisation of the relevant decline curves. The application of decline curve analysis to shale gas production is contested, with no consensus on how quickly the rate of production decline will slow. Of particular concern is the fact that a small change in assumptions in these analyses may have a large effect on the estimated URR of a well and hence on the estimated URR for a region. It is therefore important to focus attention on refining these techniques and developing comprehensive assessments of their accuracy. A significant amount of work has been conducted in recent years into refining extrapolation methods, but further work is needed to prove these new methods and establish them as best practice if genuine improvement is to be achieved.

It is important to note that while bottom-up estimates are uncertain, they are informed by some level of historical experience and are often bounded at the individual well or play level. This may limit the uncertainty relative to that for top-down estimates of regions or countries where there is limited or no historical experience and where the estimates of URR or TRR may be sensitive to small changes in assumptions.

Another uncertainty influencing shale gas estimates is the practice of simply delineating shale play areas into more and less productive areas. Splitting a shale play into only these two areas implies that comparable production rates and URR/well will be experienced across the whole of these areas. This assumption belies the true heterogeneity of shale plays. In addition, production to date has focused upon areas with the highest productivity and URR/well. Assuming that comparable production rates will be experienced across the remainder of the play is likely to lead to overestimates of the TRR. The large areal extent of many shale plays means that

¹³⁸ Rogner, 'Assessment of World Resources'.

¹³⁹ WEC, 'Survey of Energy Resources'.

inadequate delineation could have a large effect on the results, although this source of uncertainty should reduce as drilling continues and the extent to which different areas can be grouped together becomes more obvious.

A related uncertainty is the validity of assumptions for URR/well and well spacing in areas outside those from which production is currently taking place. Even though assumptions for these areas are necessary to estimate the resource potential of the whole shale play, the level of confidence in these assumptions is much lower than that for developed areas.

There is also uncertainty over the impact that technology will have on increasing current estimates of TRR. Previous forecasts of the potential impact of technological improvements failed to anticipate the increase in URR/well that has occurred since the 1980s. The technologies currently being used for shale gas extraction are now better understood, having been much more widely studied and utilised than previously. In addition, shale geology is now much better understood, suggesting that potential improvements in technology can now be better characterised. Nevertheless, technological progress, even if only leading to a small increase in URR/well or recovery factor, can have a significant impact on the estimated ultimately recoverable resources and it is impossible to rule out future major technological breakthroughs.

Finally, the potential for shale gas in as yet undiscovered basins is likely to be low but probably not insignificant and requires further investigation.

In conclusion, there are multiple and substantial uncertainties in assessing the recoverable volumes of shale gas at both the regional and global level. Even in areas where production is currently taking place, there remains significant uncertainty over the size of the resource and considerable variation in the available estimates. For undeveloped regions where less research has been conducted, one estimate of resources may be all that is available and the range of uncertainty cannot be characterised. For several regions of the world there are no estimates at all, but this does not necessarily mean that such regions contain only insignificant resources. Therefore, given the absence of production experience in most regions of the world, and the number and magnitude of uncertainties described above, current resource estimates should be treated with considerable caution.

3 Shale and tight gas development for Europe

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This chapter provides a technical overview of shale gas development in Europe. The state of the art and future drilling, hydraulic fracturing and producing technologies for shale gas wells are discussed. The cost impact of some of these technologies is evaluated and future potential improvements are explained. The data generated can be used to support models to evaluate shale gas development scenarios.

3.1 Introduction to unconventional gas technology

Conventional gas and unconventional gas are two terms that are widely used in the industry. It is not the produced gas that distinguishes the categories. It is the rock that makes the difference. The most important property to mention here is the permeability of the source rock and secondly, but less important, its porosity.

Permeability is the measure of a reservoir's capacity to transmit fluids.¹

Porosity can be regarded the measure of a rock's fluid storage capacity. Porosity is dimensionless.²

3.1.1 Conventional gas

Conventional gas is typically found in reservoirs with permeabilities greater than 1 millidarcy (mD) and can be extracted via traditional techniques. A large proportion of the gas produced globally to date is conventional and is relatively easy and inexpensive to extract. By contrast, unconventional gas is found in reservoirs with relatively low permeabilities (less than 1 mD) and therefore cannot be extracted via conventional methods.

3.1.2 Definition of shale and tight gas and coal-bed methane

There are several types of unconventional gas resources that are produced today, but the three most common types are tight gas, coal-bed methane and shale gas. Given the low permeability of the reservoirs yielding such gas, the gas must be developed via special techniques, including fracture stimulation, in order to be produced commercially.³

Shale gas

A gas shale is an organically-rich shale formation, which in the classical definition can be both the source rock and cap rock of an oil or gas reservoir. The production of shale gas seemed to be impossible because gas is so tightly confined within the shale rock matrix. However, some years ago, technologies and procedures were developed that allowed industry to economically produce shale gas.

¹ Tarek Ahmed, *Reservoir Engineering Handbook*, Fourth edition ed. (Burlington, MA: Gulf Professional Publishing, 2010).

² Ibid.

³ 3 Legs Resources, 'An Introduction to Shale Gas', (Isle of Man: 2011).

Shale is a sedimentary rock that is predominantly comprised of consolidated clay and silt-sized particles. Compaction of the clay particles occurs during post-deposition as additional materials accumulate above these particles, resulting in the formation of thin, laminated layers. Laminated layers are formed because clay grains align as a result of compaction. The thin layers that make up shale result in a rock with limited horizontal and vertical permeability.⁴ Gas can be sorbed on to organic material or can exist as free gas in natural fractures and micro porosity.

Tight gas

Tight gas refers to natural gas produced from reservoirs that have very low porosity and permeability. Such reservoirs are usually sandstone, although carbonate rocks can also be tight gas producers. The standard industry definition for a tight gas reservoir is a rock with matrix porosity of 10% or less and permeability of 0.1 millidarcy or less, exclusive of fracture permeability.⁵

Coal-bed methane

Coals are sedimentary rocks containing more than 50wt% organic matter, whereas shales contain less than 50wt% organic matter. Methane is either generated by bacterial (biogenic gas) or geochemical (thermogenic gas) processes during burial. The gas can be stored by multiple mechanisms, including as free gas in micro-pores and sorbed gas on the internal surfaces of the organic matter. Nearly all coal-bed gas is considered to be sorbed gas, whereas shale gas is a combination of those two mechanisms.

Coal-bed gas reservoirs contain an orthogonal fracture set called cleats that are orientated perpendicular to the bedding and provide the primary conduit for fluid flow. Gas diffuses from the matrix into the cleats and flows to the wellbore. In shale gas reservoirs, gas is sometimes produced through more permeable sand or silt layers, interbedded with the shale through natural fractures or from the shale matrix itself.

In coal-bed reservoirs, the key parameters controlling the amount of gas in place include coal-bed thickness, coal composition, gas content and gas composition. Coal composition refers to the amount and type of organic constituents in the coal, which has a significant effect on the amount of gas that can be sorbed. Gas contents in coal seams vary widely (<1 to >25m³/ton) and are a function of composition, thermal maturity, burial and uplift history, and the addition of migrated thermal and biogenic gas. Production rates are mainly influenced by the coal-bed's permeability, which is in the order of millidarcies or tens of millidarcies.

Shale gas reservoirs typically are thicker, and have lower sorbed and free gas in the pore space. In addition, shale gas reservoirs usually have much lower permeabilities, commonly in the nanodarcy range.

Both are not density-stratified, do not contain a gas-water contact and may be spread over a very large geographic area. The challenge is not to find gas but to find areas that will produce gas commercially. See Table 3-1 for the most critical reservoir evaluation parameters.

⁴ J. Daniel Arthur et al., 'Evaluating Implications of hydraulic fracturing in Shale Gas Reservoirs', in *SPE Americas E&P Environmental and Safety Conference* (San Antonio, TX: 2009).

⁵ Leslie Haines, 'Tight Gas', *Oil and Gas Investor* 2006.

Table 3-1: Summary of critical data used to appraise coal-bed and shale gas reservoirs

Analysis	Results
Gas content	Provides volumes of desorbed gas (from coal samples placed in canisters), residual gas (from crushed coal) and lost gas (calculated). The sum of these is the <i>in-situ</i> gas content of a given coal seam.
Rock-evaluation pyrolysis	Assesses the petroleum-generative potential and thermal maturity of organic matter in a sample. Determines the fraction of organic matter already transformed to hydrocarbons and the total amount of hydrocarbons that could be generated by complete thermal conversion.
Total organic carbon	Determines the total amount of carbon in the rock including the amount of carbon present in free hydrocarbons and the amount of kerogen.
Gas composition	Determines the percentage of methane, carbon dioxide, nitrogen and ethane in the desorbed gas. Used to determine gas purity and to build composite desorption isotherms.
Core description	Visually captures coal brightness, banding, cleat spacing, mineralogy, coal thickness and other factors. Provides insights about the composition, permeability and heterogeneity of a coal seam.
Sorption isotherm	A relationship, at constant temperature, describing the volume of gas that can be sorbed to a surface as a function of pressure. Describes how much gas a coal seam is capable of storing and how quickly this gas will be liberated.
Proximate analysis	Provides the percentage of ash, moisture, fixed carbon and volatile matter. Used to correct gas contents and sorption isotherms to an ash-free basis, correct the isotherms for moisture and determine the maturity of high-rank coals.
Mineralogical analyses	Determines bulk mineralogy using petrography and/or X-ray diffraction and clay mineralogy using X-ray diffraction and/or scanning electron microscopy.
Vitrinite reflectance	A value indicating the amount of incidental light reflected by the vitrinite maceral. This technique is a fast and inexpensive means of determining coal maturity in higher rank coals.
Calorific value	The heat produced by combustion of a coal sample. Used to determine coal maturity in lower rank coals.
Maceral analysis	Captures the types, abundance and spatial relationships of various maceral types. These differences can be related to differences in gas-sorption capacity and brittleness, which affect gas content and permeability.
Bulk density	Relationships between bulk density and other parameters (such as ash content and gas content) can be used to establish a bulk-density cut-off for counting coal and shale thicknesses using a bulk-density log.
Conventional logs	Self-potential, gamma ray, shallow and deep resistivity, microlog, caliper, density, neutron and sonic logs. Used to identify coals and shales, and to determine porosity and saturation values in shales.
Special logs	Image logs to resolve fractures and wireline spectrometry logs to determine <i>in-situ</i> gas content.
Pressure-transient tests	Pressure build-up or injection fall-off tests to determine reservoir pressure, permeability, skin factor and to detect fractured reservoir behaviour.
3D seismic	Used to determine fault locations, reservoir depths, variations in thickness and lateral continuity, and coal/shale properties.

Drilling in shallow coal-bed methane reservoirs is often done with underbalanced percussion drilling, which has the advantage of a high drilling rate and nearly no formation damage.

For coal-bed reservoirs, coiled tubing or multiple cased-hole fracture stimulations are conducted on thin individual seams by use of gelled fluids with sand as the proppant. Water is usually flushed at rates of <5bbl/min.⁶

3.1.3 Generation of contact surface in the shale

Unfractured shales typically have permeabilities in the order of 0.01 to 0.001 microdarcies. This low natural permeability is a limiting factor in producing the gas resource; however, natural fractures are key sources of flow paths. They develop when overburdened pressure is reduced as a result of the erosion of overlying rock formations and/or other tectonic activities.⁷

The lack of sufficient permeability, or in other words the lack of a flow path, can be overcome by drilling horizontal wells and hydraulic fracturing in order to expand the contact area and increase the flow into the well.⁸

3.2 Definition of state-of-the-art shale gas technology

The combination of two technological advances, namely 'horizontal drilling' and 'hydraulic fracturing', mainly drove the breakthrough in shale gas production in the USA.⁹

3.2.1 Drilling

As already stated, horizontal drilling is one of the keys that made unconventional gas economically viable.¹⁰

Since the thickness of the pay zone is often insufficient, horizontal wells are drilled within each shale layer.¹¹ Figure 3-1 compares a vertical and a horizontal well that are producing from a shale formation.

⁶ Creties D. Jenkins and Charles M. Boyer, 'Coalbed- and Shale-Gas Reservoirs', *Journal of Petroleum Technology* February (2008).

⁷ Arthur et al., 'Evaluating Implications of hydraulic fracturing in Shale Gas Reservoirs'.

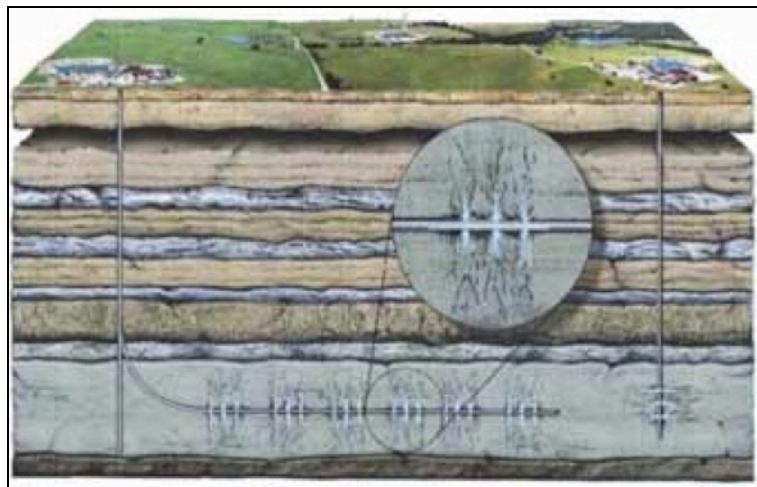
⁸ Don R. Watson et al., 'One-Trip Multistage Completion Technology for Unconventional Gas Formations', in *CIPC/SPE Gas Technology Symposium 2008 Joint Conference* (Calgary, Alberta: Society of Petroleum Engineers, 2008).

⁹ ALL Consulting, 'Modern Shale Gas development in the United States - a primer', (Tulsa, OK: ALL Consulting, 2009).

¹⁰ Ibid.

¹¹ Mark Zoback, Saya Kitasei and Brad Copithorne, 'Addressing the Environmental Risks from Shale Gas Development', in *Briefing Paper* (Washington, DC: Worldwatch Institute, 2010).

Figure 3-1: Vertical vs. horizontal well comparison¹²



In addition to horizontal drilling, drilling from pads is a field development strategy that can reduce the surface footprint, environmental disturbance, logistical issues, etc.¹³

US drilling activity highlights the importance of horizontal drilling technology. In the Barnett Shale, the number of horizontal wells drilled has increased from 76 in March 2001 to 1 810 in August 2007 (see Figure 3-3). On the other hand, vertical wells have decreased from 2 001 to 131 in the same time period.¹⁴

The latest data from the USA shows that, over the period 2005-2010, the percentage of horizontal rigs has increased from 10% to 58% of the total rig count.¹⁵

Horizontal drilling technology

In order to drill within the horizontal layers, directional drilling technology is applied. This is conventionally done by using standard down-hole motors. New developments also utilise directional drilling automation or rotary steerable systems.

As can be seen from Figure 3-2, a typical well is drilled nearly vertically (depending upon the situation) from surface down to the kick-off point (KOP). At the KOP, the trajectory starts deviating from the vertical with build rates of about 10°/30m to 20°/30m. In practice this means that the KOP is about 100m to 200m vertically above the horizontal section. In the USA the length of the horizontal section of the well is between 1 000m to 2 000m on average. Horizontal lengths of up to 6 000m have been reported.¹⁶

¹² Chief Oil and Gas, *Why Multiple Horizontal Wells from centralized well pads should be used for the Marcellus Shale* (West Virginia Surface Owner's Rights Organization, 2012, cited 04/05/2012); available from http://www.wvSORO.org/resources/marcellus/horiz_drilling.html

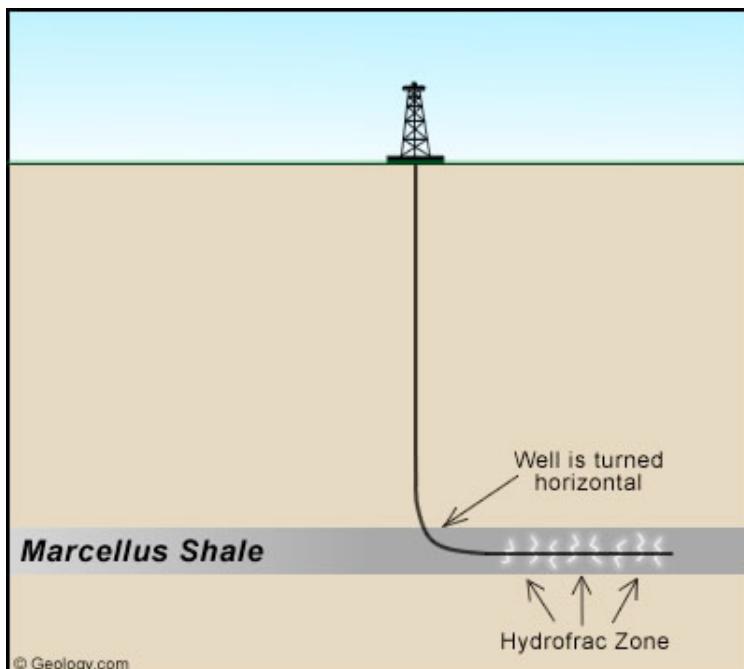
¹³ Krisanne L. Edwards et al., 'Marcellus Shale Hydraulic Fracturing and Optimal Well Spacing to Maximize Recovery and Control Costs', in *SPE Hydraulic Fracturing Technology Conference* (Woodlands, TX: Society of Petroleum Engineers, 2011); Florence Gény, 'Can Unconventional Gas be a Game Changer in European Markets?', (Oxford: Oxford Institute for Energy Studies, 2010).

¹⁴ 3 Legs Resources, 'Introduction to Shale Gas'.

¹⁵ Abu M. Sani and Efe A. Ejefodomi, 'Horizontal Wells Drilling Activity in South Texas Unconventional Gas Resources and Micro-seismic Hydraulic Fracturing Monitoring Application to Reduce Risk and Increase the Success Rate', in *SPE/DGS Saudi Arabia Section Technical Symposium and Exhibition* (Al-Khobar, Saudi Arabia: Society of Petroleum Engineers 2011).

¹⁶ Sandeep Janwadkar et al., 'Innovative Design Rotary Steerable Technologies Overcome Challenges of Complex Well Profiles in a Fast Growing Unconventional Resource—Woodford Shale', in *SPE/IADC*

Figure 3-2: Typical wellbore trajectory¹⁷



State-of-the-art technologies currently in use include down-hole motors, often utilised in conjunction with directional drilling automation or rotary steerable systems (RSS).

A downhole motor, as shown in Figure 3-3, mainly consists of two parts connected through a joint that permits the lower end to be directed by some degrees, allowing directional drilling. The rotational energy used to turn the motor, and hence the drill bit connected to it, is provided by the drilling fluid. To enable directional control, parameters such as stand pipe pressure and torque are closely and constantly monitored. Finally, to get feedback as to whether the wellbore being drilled matches the planned trajectory, measurement-while-drilling tools (MWD) are used.¹⁸

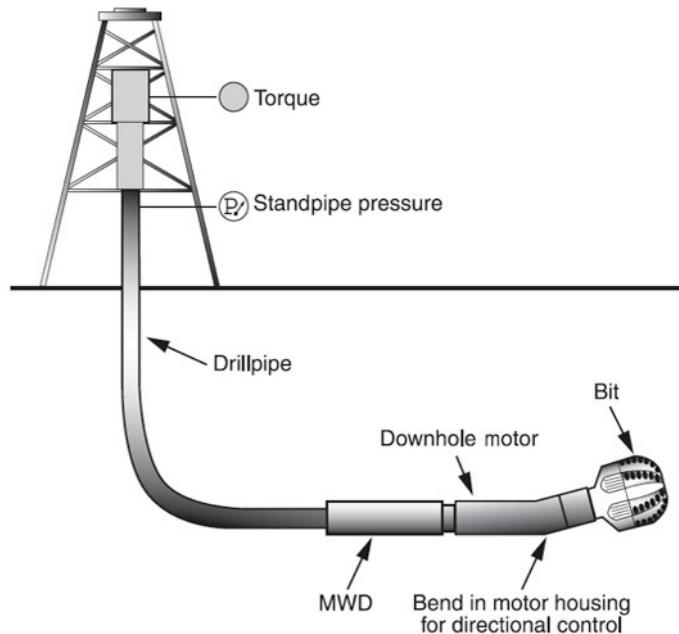
Drilling Conference and Exhibition (Amsterdam, the Netherlands: Society of Petroleum Engineers, 2009); Sandeep Janwadkar et al., 'Barnett Shale Drilling and Geological Complexities - Advanced Technologies Provide The Solution', in *IADC/SPE Drilling Conference* (Orlando, FL: Society of Petroleum Engineers, 2008); New York State Department of Environmental Conservation, 'Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program ', (Albany, NY: New York State Department of Environmental Conservation, 2009); Benny Poedjono et al., 'Case Studies in the Application of Pad Drilling Design in the Marcellus Shale', in *SPE Eastern Regional Meeting* (Morgantown, WV: Society of Petroleum Engineers, 2010); Junichi Sugiura and Steve Jones, 'Rotary Steerable System Enhances Drilling Performance on Horizontal Shale Wells', in *International Oil and Gas Conference and Exhibition in China* (Beijing: Society of Petroleum Engineers, 2010); S. Zargari and S. D. Mohaghegh, 'Field Development Strategies for Bakken Shale Formation', in *SPE Eastern Regional Meeting* (Morgantown, WV: Society of Petroleum Engineers, 2010).

¹⁷ geology.com, *Mineral Rights: Basic information about mineral, surface, oil and gas rights* (2012, cited 15 March 2012).

¹⁸ Baker Hughes INTEQ, *Drilling Engineering Workbook: A Distributed Learning Course* (Houston, TX: Baker Hughes INTEQ, 1995); William C. Lyons, *Working Guide to Drilling Equipment and Operations*, First Edition ed. (Burlington, MA: Gulf Publishing, 2010); H.R. Motahhari, G. Hareland and J.A. James, 'Improved Drilling Efficiency Technique Using Integrated PDM and PDC Bit Parameters', *Journal of Canadian petroleum Technology* 49, no 10 (2010); Schlumberger Ltd., *Oilfield Glossary*: ©Steerable Motor

One option for increasing horizontal drilling efficiency and improving directional control is utilising directional drilling automation technology. A rocking motion is applied from the top where the torque measurement is monitored, hence breaking the drag down the hole and using the torque as a feedback to control motion.¹⁹

Figure 3-3: Horizontal drilling technology²⁰



In principle, RSS provides the same control of wellbore trajectory; however, no directional drilling automation technology is required to overcome drag, and thus curved sections can be drilled faster and more accurately. Despite these significant and highly desired advantages, downhole motors are found to be more practical due to their lower cost.²¹

Drilling from pads

In shale drilling, it is becoming increasingly common to use a single pad, as in Figure 3-4, to develop as much subsurface area as possible from one spot. One surface location can be used for multiple wells. Pad drilling increases the operational efficiency of gas production and reduces infrastructure costs, land use and environmental impacts.²²

(Schlumberger Ltd, 2011, cited 27 March 2012); available from http://www.slb.com/resources/publications/oilfield_review/ori/ori002/01/01a.aspx

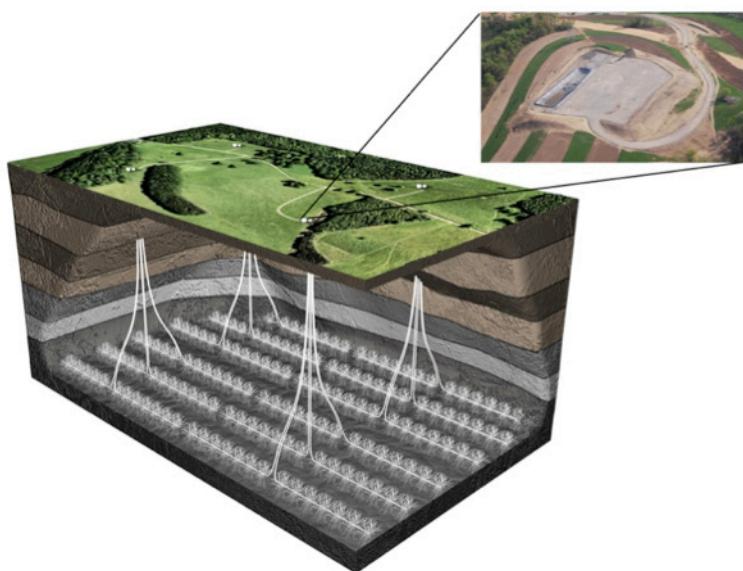
¹⁹ Eric Maidla, Marc Haci and Daniel Wright, 'Case History Summary: Horizontal Drilling Performance Improvement Due to Torque Rocking on 800 Horizontal Land Wells Drilled for Unconventional Gas Resources', in *SPE Annual Technical Conference and Exhibition* (New Orleans, LA: Society of Petroleum Engineers, 2009).

²⁰ Eric Maidla and Marc Haci, 'Understanding Torque: The Key to Slide Drilling Directional Wells', in *IADC/SPE Drilling Conference* (Dallas, TX: Society of Petroleum Engineers, 2004).

²¹ Steve Jones, Junichi Sugiura and Steve Barton, 'Finding optimal balance in rotary steerable systems', *Offshore Magazine* 68, no 9 (2008).

²² 3 Legs Resources, 'Introduction to Shale Gas'.

Figure 3-4: Multi-well pad development²³



The footprint of a pad usually ranges from 12 000m² (100m x 120m) to 20 000m². Wells are often placed next to each other at distances of between 7m and 8m. A typical pad includes upwards of 6 wells, with up to 24 being reported.²⁴

The wells are drilled parallel in the shale for a distance of about 200m to 500m, with a horizontal length of about 1 000m to 2 000m.

The difference in total surface footprint between vertical and horizontal wells is shown in Table 3-2.

Table 3-2: Ten-square-mile total surface disturbance of vertical and horizontal wells²⁵

Spacing option	Multi-well 640 acres	Single well 40 acres
Number of pads	10	160
Total disturbance- drilling phase	50 acres (5 ac. per pad)	480 acres (3 ac. per pad)
% Disturbance - drilling phase	0.78	7.5

3.2.2 Hydraulic fracturing

Hydraulic fracture stimulation, or 'fracking', is a process that is used to create a large number of fractures in the rock, in order to allow the natural gas trapped in shales to move to the wellbore. Fracking can both increase production rates and increase the total amount of gas that can be recovered. Pump pressure causes the rock to fracture and water carries sand ('proppant') into the hydraulic fracture to prop it open, allowing

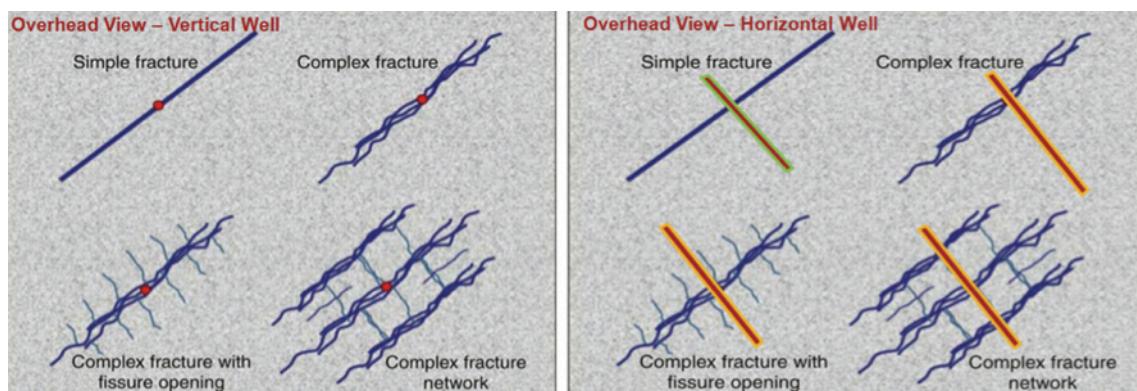
²³ Ruth Wood et al., 'Shale gas: a provisional assessment of climate change and environmental impacts', (Manchester: Tyndall Centre, University of Manchester, 2011).

²⁴ Travis Garza et al., 'Gyro Guidance Techniques and Telemetry Methods Prove Economical in Onshore Multiwell Pad Drilling Operations in the Piceance Basin', in *IADC/SPE Drilling Conference and Exhibition* (New Orleans, LA: Society of Petroleum Engineers, 2010); Géné, 'Unconventional Gas'; M.M. Reynolds and D.L. Munn, 'Development Update for an Emerging Shale Gas Giant Field - Horn River Basin, British Columbia, Canada', in *SPE Unconventional Gas Conference* (Pittsburgh, PA: Society of Petroleum Engineers, 2010).

²⁵ New York State Department of Environmental Conservation, 'Draft SGEIS'.

the flow of gas. Whilst water and sand are the main components of hydraulic fracture fluid, chemical additives are often added in small concentrations.²⁶

Figure 3-5: Vertical well and horizontal well fracture views



Conventional fracturing fluid

Table 3-3 illustrates that the chemicals used can have a range of toxicities. For instance, sand, polyacrylamide, guar gum and hydroxyethyl cellulose are relatively benign materials. Acids and bases may cause an irritant response upon dermal or inhalation exposure, but more acute responses are possible. Chronic toxicity has been associated with some identified chemicals, such as ethylene glycol, glutaraldehyde and N,N-dimethyl formamide.

Naturally occurring metals also exert various forms of toxicity even at low concentrations.²⁷

Table 3-3: An example of the volumetric composition of hydraulic fracturing fluid

Product category	Main ingredient	Purpose	Other common uses
Water	Approximately 99.5% water and sand	Expand fracture and deliver sand	Landscaping and manufacturing
Sand		Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete and brick mortar
Other	Approximately 0.5%		
Acid	Hydrochloric acid or muriatic acid	Helps dissolve minerals and initiates cracks in the rock	Swimming pool chemical and cleaner
Antibacterial agent	Glutaraldehyde	Eliminates bacteria in the water that produces corrosive by-products	Disinfectant, steriliser for medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed breakdown of the gel	Used in hair colouring, as a disinfectant and in the manufacture of common household plastics
Corrosion inhibitor	N,N-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibres and plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Used in laundry detergents, hand soaps and cosmetics

²⁶ 3 Legs Resources, 'Introduction to Shale Gas'.

²⁷ Environmental Protection Agency, 'Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources', (Washington, DC: Environmental Protection Agency, 2011).

Product category	Main ingredient	Purpose	Other common uses
Friction reducer	Petroleum distillate	'Slicks' the water to minimise friction	Used in cosmetics including hair, make-up, nail and skin products
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand	Thickener used in cosmetics, baked goods, ice cream, toothpaste, sauces and salad dressings
Iron control	Citric acid	Prevents precipitation of metal oxides	Food additive, food and beverages, lemon juice ~7% citric acid
Clay stabiliser	Potassium chloride	Creates a brine carrier fluid	Used in low-sodium table salt substitute, medicines and IV fluids
pH adjusting agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Used in laundry detergents, soap, water softener and dishwasher detergents
Scale inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Used in household cleansers, deicer, paints and caulk
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Used in glass cleaner, multi-surface cleansers, antiperspirant, deodorants and hair colour

Table 3-4: Naturally occurring substances that may be found in hydrocarbon-containing formations

Type of contaminant	Examples
Formation fluid	Brine
Gases	Natural gas (e.g. methane, ethane), carbon dioxide, hydrogen sulphide, nitrogen, helium
Trace elements	Mercury, lead, arsenic
Naturally occurring radioactive material	Radium, thorium, uranium
Organic material	Organic acids, polycyclic aromatic hydrocarbons, volatile and semi-volatile organic compounds

The US Environmental Protection Agency (EPA) anticipates that an initial database search and ranking of high, low and unknown-priority chemicals will be completed for a 2012 interim report. Additional work using high-throughput screening tools is expected to be available in a 2014 report, as well as the development of chemical-specific Provisional Peer Reviewed Toxicity Values (PPRTVs) for high-priority chemicals.²⁸

It must be pointed out that the fracturing fluid composition presented here reflects the fluids used in the USA; however, in Europe this composition could be different, with hazardous elements eliminated or their concentrations reduced.

Multi-stage fracturing

Due to the length of the lateral section, it is usually not possible to maintain sufficient downhole pressure to stimulate its entire length in a single event. Thus, in shale gas wells, stimulation is achieved by isolating portions of the lateral and performing treatments in multiple stages.

²⁸ Ibid.

Each fracture stage is performed within an isolated interval of the lateral, where a cluster of perforations is created using a perforation tool to establish communication between the formation and the wellbore. The fracture stages are isolated with packers.

In the area of Eagle Ford Shale, the range of fracturing stages is between 12 and 21 stages per horizontal well, with an average of 17 stages per well.²⁹

Alternative fracturing fluids

Fluids for fracturing operations that do not require high-purity fresh water as a base are being developed. Various components that allow for the reuse of fracturing flowback water have been developed, such as salt compatible, nano-particle friction reducers; neutral pH iron controls; blended and targeted scale controls; aqueous biomass controls; and low-toxicity clay stabilisers.³⁰

Alternative chemicals have been created to replace toxic 2-butoxyethanol, which have a far superior environmental profile and perform even better in well flowback enhancement.³¹

Apart from this, liquefied petroleum gas and foam fluids are being developed and utilised.

Liquefied petroleum gas (LPG) is a mixture of petroleum gases existing in a liquid state at ambient temperature and moderate pressure. Once the well treatment is complete, the propane and natural gas in the LPG remains in either a multi-phase or a single vapour phase at formation conditions.³²

Foam fluids are essentially two-phase fluids that consist of an inner phase, which is either liquid (N₂) or vapour/gaseous (CO₂), and an outer phase, which is primarily composed of a saline-water mixture with either a surfactant or gallant.³³

Alternative fracturing methods

Channel fracturing is claimed to provide significantly higher fracture conductivity, better fracture cleanup, lower pressure loss within the fracture and longer effective fracture half-length. The idea is basically to substitute the homogeneous proppant pack in the fracture with a heterogeneous structure containing a network of open channels (Figure 3-6). The fracture is held open by discrete conglomerations of propping

²⁹ Sergio Centurion, 'Eagle Ford Shale: A Multistage Hydraulic Fracturing, Completion Trends and Production Outcome Study Using Practical Data Mining Techniques', in *SPE Eastern Regional Meeting* (Columbus, OH: Society of Petroleum Engineers, 2011).

³⁰ M.E. Blauch, 'Developing Effective and Environmentally Suitable Fracturing Fluids Using Hydraulic Fracturing Flowback Waters', in *SPE Unconventional Gas Conference* (Pittsburgh, PA: Society of Petroleum Engineers, 2010).

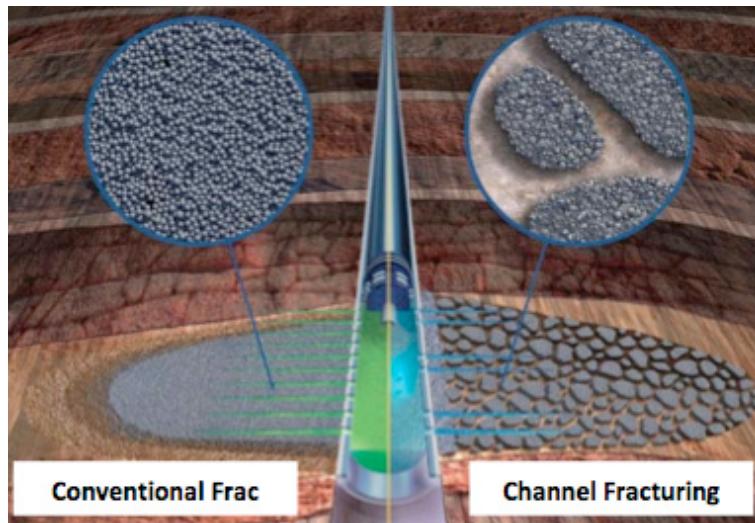
³¹ Jonathan J. Wylde and Bill O'Neil, 'Environmentally Acceptable Replacement of 2-Butoxyethanol with a High Performance Alternative for Fracturing Applications', in *SPE International Symposium on Oilfield Chemistry* (Woodlands, TX: Society of Petroleum Engineers, 2011).

³² Eric H. Tudor et al., '100% Gelled LPG Fracturing Process: An Alternative to Conventional Water-Based Fracturing Techniques', in *SPE Eastern Regional Meeting* (Charleston, WV: Society of Petroleum Engineers, 2009).

³³ A. Kumar et al., 'Prospects of Foam Stimulation in Oil and Gas Wells of India', in *Trinidad and Tobago Energy Resources Conference* (Port of Spain, Trinidad: Society of Petroleum Engineers, 2010).

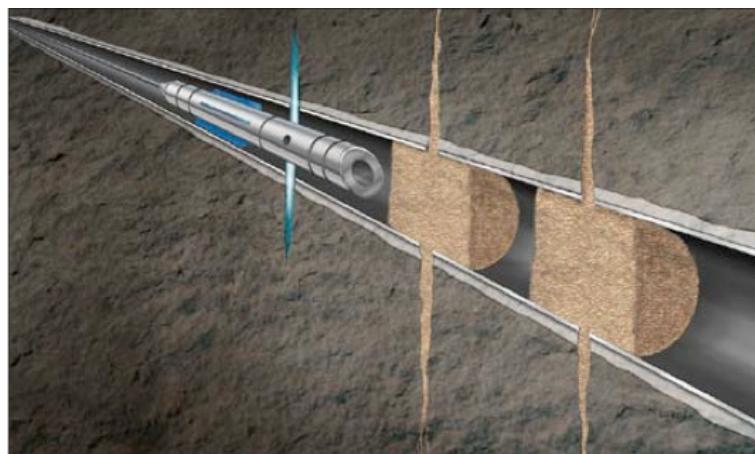
materials. The open channels act as low-resistance paths for the flow of reservoir fluids.³⁴

Figure 3-6: Representation of the new fracturing approach with respect to a conventional fracture



Hydra-jetting (Figure 3-7) represents another notable alternative fracturing process. Tensile failure of the rock occurs at the jetting point without exposing the wellbore to breakdown pressures. This enables precise control of the location of the fracture initiation. Multiple fractures can be created by simply moving the jetting tool.³⁵

Figure 3-7: Hydra-jet perforation and proppant plug diversion to fracture multiple intervals, vertically and horizontally



Best practices in water management

Water used for drilling and making up frac fluids can come from surface water bodies, groundwater, municipal portable water supplies, or flowback water from a previously fractured well.

³⁴ M. Gillard et al., 'A New Approach to Generating Fracture Conductivity', in *SPE Annual Technical Conference and Exhibition* (Florence, Italy: Society of Petroleum Engineers, 2010).

³⁵ Glenda Wylie, Mike Eberhard and Mike Mullen, 'Trends in Unconventional Gas', *Oil & Gas Journal* 105, no 47 (2007).

The water required for drilling a typical shale gas well ranges from 2 300 to 4 000 m³. The volume needed to fracture a well range is from 8 700m³ to 14 500m³.³⁶

Once the frac job is finished, the pressure is released. Then, flowback and produced water (30% to 70% of the fluid injected), which typically contains very high levels of total dissolved solids (TDS) and other constituents (possibly including heavy metals and naturally occurring radioactive materials) returns to the surface.³⁷

Flowback may be directed to tanks or lined pits and centralised impoundments for management. These impoundments should provide structural integrity and have a natural or artificial liner designed to prevent downward flow. They should also be placed at an appropriated distance from surface water to prevent overflows from reaching the surface water.³⁸

Generally, the TDS concentration of flowback and produced water is higher than the desired TDS range for new frac fluids. Thus, thermal distillation can be used, or the flowback and produced water can be blended with fresh water, to reduce TDS concentration and other constituents.³⁹

Operators must manage flowback and produced water in a cost-effective manner that complies with regulatory requirements. The primary options are:

- Injection underground through a disposal well (not possible under EU law);
- Discharge to a nearby surface-water body (permission and treatment are required);
- Haul to a municipal wastewater treatment plant (limitations due to issues with TDS treatment);
- Haul to a commercial industrial wastewater treatment facility (limited to allow TDS discharges without violating surface water quality);
- Reuse for a future frac job, either with or without treatment.⁴⁰

Disposal options are dependent on the availability of suitable zones and the possibility of obtaining permits for injection into these zones; the capacity of commercial and/or municipal water treatment facilities; and the ability of either operators or such plants to successfully obtain surface-water discharge permits.⁴¹

Municipal sewage treatment facilities must have a state-approved pretreatment programme for accepting any industrial waste. Facilities must also notify appropriate regulatory authorities of any new industrial waste they plan to receive, and certify that their facility is capable of treating the pollutants that are expected to be in that industrial waste. They are generally required to perform certain analyses to ensure they can handle the waste without problems to ensure that water quality standards are

³⁶ John A. Veil, 'Water Management Technologies Used by Marcellus Shale Gas Producers', (Washington, DC: Department of Energy, 2010).

³⁷ Ibid.

³⁸ American Petroleum Institute, 'Water Management Associated with Hydraulic Fracturing', in *API Guidance Document* (Washington, DC: American Petroleum Institute, 2010).

³⁹ Veil, 'Water Management Technologies'.

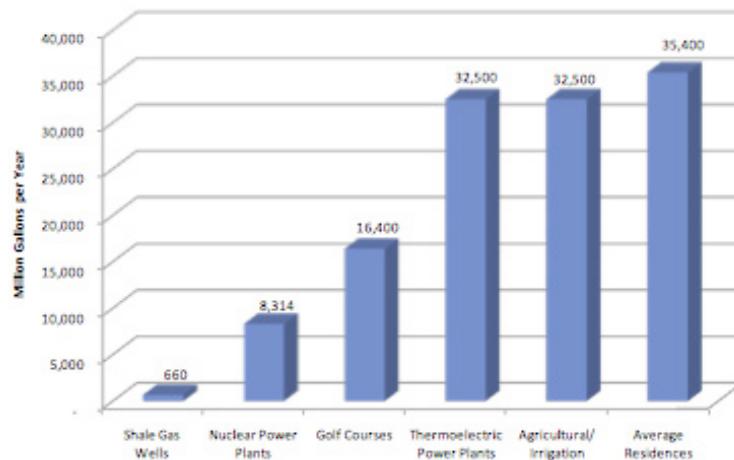
⁴⁰ Ibid.

⁴¹ American Petroleum Institute, 'Water Management'.

maintained at all times. Thus, it may be required that operators provide information pertaining to the composition of the fluid.⁴²

In Figure 3-8, water consumption among different industries is presented. Using an initial drilling rate of 200 wells in a one-year period with an average consumptive water use of 12 500 m³ per well would yield a volume of 250 000 m³ of water, which would be consumptively used for natural gas development on an annual basis.⁴³

Figure 3-8: Consumptive water uses in the Delaware Basin



Although the water required for hydraulic fracturing is only partially recovered (contrary to other industrial uses), such water is typically a small percentage of the water use in any shale basin. While other industries use water on a continuous basis, hydraulic treatment only requires water for short periods.⁴⁴

Table 3-5: Water use by sector in shale gas basins

Shale play	Public supply	Industrial and mining	Power generation	Irrigation	Livestock	Shale gas	Total water use (bl. m ³ /yr)
Barnett	82.70%	4.50%	3.70%	6.30%	2.30%	0.40%	1.77
Fayetteville	2.30%	1.10%	33.30%	62.90%	0.30%	0.10%	5.07
Haynesville	45.90%	27.20%	13.50%	8.50%	4.00%	0.80%	0.34
Marcellus	11.97%	16.13%	71.70%	0.12%	0.01%	0.06%	13.51

Given the constraints on both underground injection and discharge in the USA, serious investments will be needed to advance treatment technologies that enable companies to reuse fluids for subsequent fracturing jobs. Recycling water minimises both the overall amount of water used for fracturing and the amount that must be disposed of. Many water treatment processes are currently being investigated that could potentially be used on a large scale with the ultimate goal of developing a closed-loop system.⁴⁵

⁴² Ibid.

⁴³ J. Daniel Arthur and David J. Bockelmann, 'Analysis Of Delaware River Basin Commission Proposed (Article 7) Natural Gas Development Regulations', (Tulsa, OK: ALL Consulting, 2011).

⁴⁴ J.D. Arthur and B.J. Coughlin, 'Cumulative Impacts of Shale-Gas Water Management: Considerations and Challenges', in *SPE Americas E&P Health, Safety, Security, and Environmental Conference* (Houston, TX: Society of Petroleum Engineers, 2011).

⁴⁵ Zoback, Kitasei and Copithorne, 'Environmental Risks from Shale Gas'.

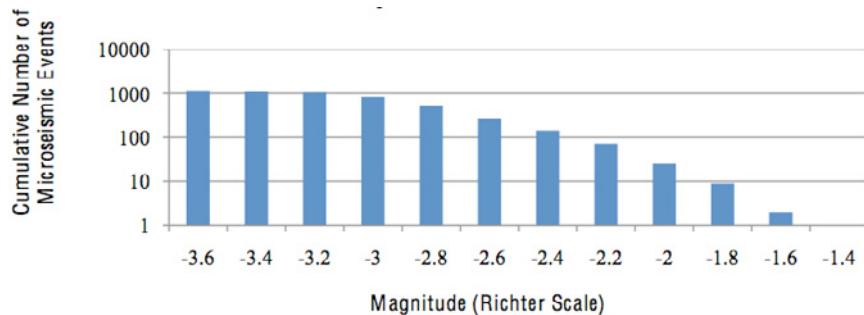
3.2.3 Monitoring

Due to the fluids in each fracturing treatment containing a different subset of chemicals and because some of these chemicals could be hazardous in sufficient concentrations, baseline water testing conducted at each site might play an important role in ensuring that possible exposure is detected. This would help to limit the environmental and health risks posed by fracturing fluids in the case of contamination. Monitoring could also play an important role regarding the surface footprint of drilling activities, the safe transport and disposal of drilling fluids and cuttings, and air and noise pollution.

Microseismic fracture monitoring

Microfractures inducing shear-slip or microseismic events that generally have magnitudes of less than 1.5 on the Richter scale (see Figure 3-9) have about as much energy as that released by a bowl of milk dropped from chest height to the floor. Due to the small magnitudes of these events, which represent micro-earthquakes about one-millionth the size of tremors that might be detected by inhabitants of a populated area, operators must deploy ultrasensitive seismometers in nearby wells in order to detect them.⁴⁶

Figure 3-9: Distribution of magnitudes of microseismic events in Barnett Shale



Microseismic mapping (MSM) provides insight into the development of fracture propagation and the mechanisms by which this is occurring, permitting the real-time analysis of fracture treatments and thereby reducing risks and challenges.

A hydraulic fracture induces an increase in the formation stress proportional to the net fracturing pressure, as well as an increase in pore pressure due to fracture fluid leak-off. Large tensile stresses are generated ahead of the crack's tip, thus generating large amounts of shear stress. Pore pressure and formation stress increases affect the stability of the planes of weakness surrounding the hydraulic fracture, causing these planes of weakness to undergo shear slippage and emit seismic energy, which is detectable as compressional (P) and shear (S) waves by receivers placed in a nearby well.

In recent years, MSM has become a critical technology for imaging, quantifying and evaluating fracture geometry dynamics. It also provides useful information on the fracture azimuth (which is beneficial for well spacing and in-fill drilling programmes) and gives good indications regarding the hydraulic fracture complexity, which helps in the estimation of the volume of the reservoir that has been stimulated. Microseismic mapping has also been vital in observing the interaction or communication of the

⁴⁶ Ibid.

created fractures with other fractures and with geohazards that can be detrimental to the productivity of the wellbore.

MSM has been used in conjunction with wellbore images, resistivity logs and sonic logs to characterise different geological intervals in relation to natural fractures, induced fractures near the wellbore and stress contrast regions. This helps to identify the appropriate perforation location and spacing, as well as the best fracture stimulation staging and technique to deploy (Figure 3-10).⁴⁷

Figure 3-10: Typical hydraulic fracture monitoring configurations for horizontal treatment wells

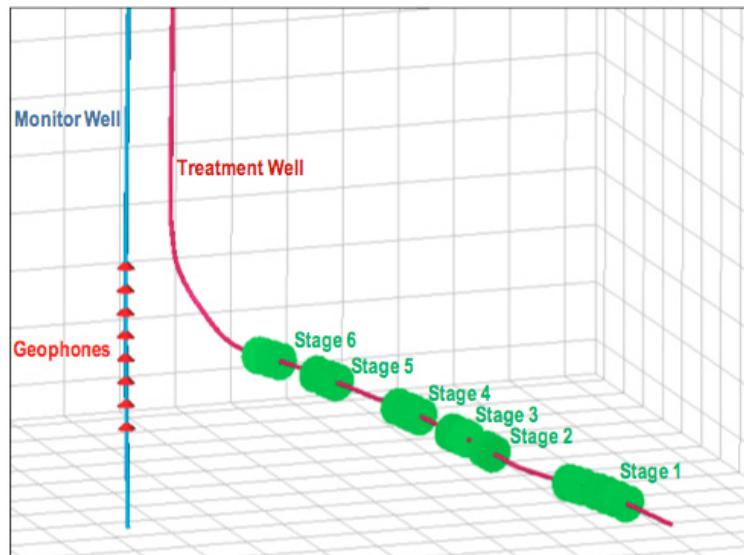


Figure 3-11: Map view of hydraulic fracture intersecting a pre-existing fault⁴⁸

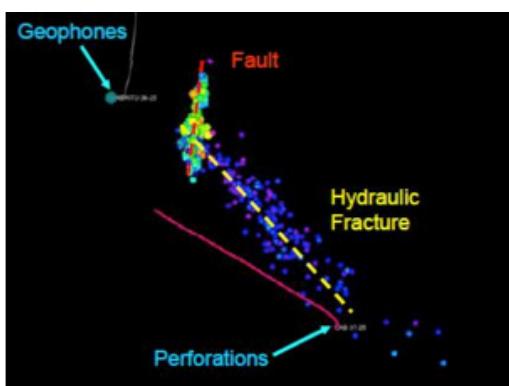
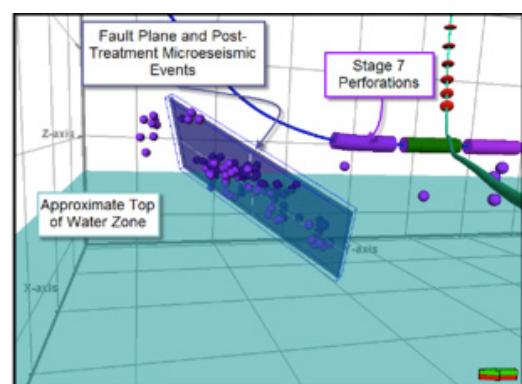


Figure 3-12: Location and orientation of the fault identified by microseismic monitoring⁴⁹



Monitoring of surface leakages

The traditional gas detection systems available today are based on two main concepts, which are called sniffing technologies:

- Point detectors, where the gas has to be in physical contact with the detector;

⁴⁷ Sani and Ejefodomi, 'Horizontal Wells Drilling Activity in South Texas Unconventional Gas Resources and Micro-seismic Hydraulic Fracturing Monitoring Application to Reduce Risk and Increase the Success Rate'.

⁴⁸ Ibid.

⁴⁹ Ibid.

- Open path detectors, where the gas has to be within a predefined path of infrared light to be detected.

Both detection concepts are based on LEL (lower explosive level) measurements. However, in outdoor installations, the gas cloud from a gas leak often either dilutes or drifts away in the wind before it reaches the gas detection point.

Another gas leak detector utilised is an ultrasonic gas leak detector, which is based on airborne ultrasound emitted from the gas leak. It gives an instant alarm as soon as the leak is detected. However, if the hole through which the gas leaks is too large, the pressure drop across the hole will be too small and no ultrasound will be detected.⁵⁰

Hydrocarbon processing facilities are equipped with gas detection system with sensors. There are two types of detectors: 1) flammable gas detectors, which detect leakages of flammable gas exceeding 20% LEL of concentration; and 2) toxic gas detectors, which detect leakages of H₂S exceeding 10 ppm.⁵¹

Underground flow monitoring

Distributed temperature sensing (DTS) is a method for downhole leak detection, where the thermal profile can be instantaneously detected along the entire wellbore in real-time. This allows the precise identification of when and where thermal events occur. An enclosed fibre-optic cable is deployed into the well to allow a continuous, real-time snapshot of the well's temperature profile.⁵²

Other methods are spinners, temperature logs, downhole cameras, thermal-decay logs and noise logs. It is rather difficult to detect small leaks with these tools, because small leaks result in velocity and temperature changes that may be less than the resolution of these logging tools. Noise logs can detect fluid movement but must be used in a stationary mode and more distant noise sources may confuse interpretation. Downhole cameras can be useful in finding a variety of leaks but require the wellbore to be filled with optically clear fluid.

For the detection of small leaks, ultrasonic leak-detection is used. It is known that leaks, regardless of phase, will produce an ultrasonic frequency when active. The sensor is capable of detecting the sound generated by a leak through various media encountered in a downhole environment.⁵³

In August 2009, the EPA released the results of a site investigation near Pavillion, Wyoming, USA: EPA found elevated levels of arsenic, methane, petroleum hydrocarbons and other chemicals in drinking water wells. The presence of 2-butoxyethanol, a known

⁵⁰ Martin T. Olesen, 'Can the Petrochemical Industry Feel Safe with Traditional Gas Leak Detection?', (Ballerup, Denmark: Innova Gassonic).

⁵¹ Fares Al Mansouri and Mohammad Aftab Alam, 'Sources of Hydrocarbon Leaks & Spills in Upstream Oil Industries - Its Potential Reasons & Preventive Measures', in *SPE International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production* (Nice, France: Society of Petroleum Engineers, 2008).

⁵² J.Y. Julian et al., 'Downhole Leak Determination Using Fiber-Optic Distributed-Temperature Surveys at Prudhoe Bay, Alaska', in *SPE Annual Technical Conference and Exhibition* (Anaheim, CA: Society of Petroleum Engineers, 2007).

⁵³ J.E. Johns et al., 'Applied Ultrasonic Technology in Wellbore-Leak Detection and Case Histories in Alaska North Slope Wells', *SPE Production & Operations* 24, no 2 (2009).

constituent in hydraulic fracturing fluids, was confirmed by EPA. EPA will continue the investigation.⁵⁴

In January 2009, there were several reports of methane gas migrating to the surface and at least one report of a drinking water well exploding in Dimock, Pennsylvania, USA.⁵⁵ However, as indicated in the reports, the causes of contamination were poor well integrity, surface spills, etc, rather than fracking.

In order to provide more accurate and continuous underground flow monitoring, sniffing well technology is currently being developed. These are basically slim-hole wells that are drilled to the groundwater level. Sensors are run in, so that they can monitor underground conditions prior to drilling for base-line measurements, during fracking and during production until the end of the well's life. These wells can also be used for running microseismic geophones.

3.3 Evaluation of technical and operational assumptions for shale gas development scenarios in Europe

In the following subsection, we discuss the development of shale gas fields in Europe and the related cost scenarios. These scenarios may be used to show the impact of technological developments on the overall development of shale gas in Europe as part of a technological gap analysis. They are based on the sources cited and the author's own assessment of future developments in Europe. (For a review of how others have attempted to quantify the impact of technological improvements on shale gas extraction, see Section 2.2.3.)

3.3.1 Field development pad sizing and well configuration scenario

In order to evaluate the requirements for the number of wells to be drilled in a given field, assumptions on the geometrical distribution of the well pads from which the wells are drilled have to be made.

The size of the area which can be reached from one pad location depends on the directional reach of the wells being drilled, which in return leads to a certain well density per drilling pad.

Typical drilling densities in shale gas developments lead to one well being drilled per 0.16 to 0.65 km² based on the experience from the USA.⁵⁶

On the basis of this assumption, the development of a field with the size of 1 000 km² would require about 1 540 to 6 250 wells to be drilled. An average scenario of 0.4 km² coverage per well would lead to 2 500 wells. The required equipment capacity (number of drilling rigs and fracturing units) depends on the average length of the wellbore, drilling and fracturing efficiency, and the projected total field development duration.

If a pad is designed to allow 25 to 36 wells to be drilled, such an average scenario would lead to the construction of about 70 to 100 drilling pads in the field.

There are variations to these values for the first complex developments planned in Europe. For example, OMV in Austria is currently planning to drill 25 deep directional

⁵⁴ Riverkeeper Inc., 'Industrial Gas Drilling Reporter - Vol. 4', (Ossining, NY: Riverkeeper Inc., 2009).

⁵⁵ Craig Michaels, James L. Simpson and William Wegner, 'Fractured Communities: Case Studies of the Environmental Impacts of Industrial Gas Drilling', (Ossining, NY: Riverkeeper Inc., 2010).

⁵⁶ Stig-Arne Kristoffersen, *Gas Shale Potential in Ukraine* (lulu.com, 2010).

wells with vertical reservoir sections per pad, with a well density of one well per km². Complex, deep wells may take up to 180 days of drilling time initially.

Future pad sizing developments

The area to be covered from one pad may be extended by drilling longer horizontal well sections for each well. Laterals up to 5 km in length, for example, would extend the theoretical reach from one pad to 100 km². Extended reach wells may be drilled to departures of 10 km and more, but their feasibility is limited by the ability to complete and hydraulically fracture these long wellbores. The required areal density of wells will set the limit of the number of pads required for a field development. In addition, the size of a pad will be limited by the number of wells that can be drilled from a single pad.

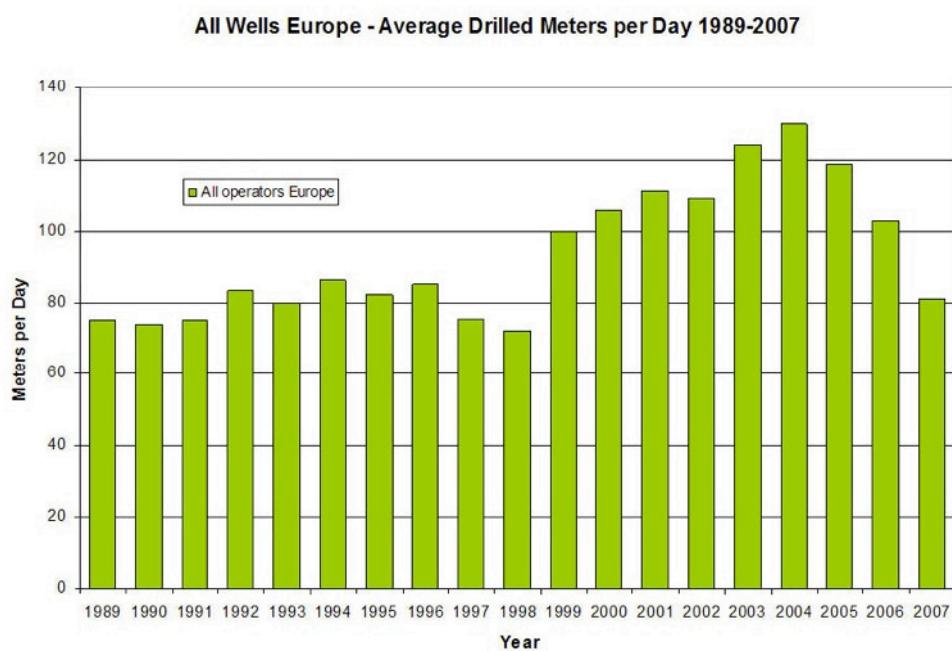
The consequence of drilling longer departure wells is a greater average length per well, thus not directly reducing drilling time. More wells are required per pad to reach the same areal density but the impact on the environment will be reduced by the use of more concentrated surface infrastructure.

3.3.2 Drilling and completion capacity scenario

The scenario outlined here explains the typical well construction time breakdown and defines improvement potential. The capacity to drill is defined by the average number of metres which a rig can drill per day, calculated by dividing the total length of the well by the number of days required to drill, case and cement the well.

The drilling and completion capacity is directly related to the drilling efficiency, which is expressed in the ability to complete as many wells as possible in the shortest possible time.

Figure 3-13: Development of drilling performance in Europe⁵⁷



⁵⁷ Ketil Andersen et al., 'Case History: Automated Drilling Performance Measurement of Crews and Drilling Equipment', in *SPE/IADC Drilling Conference* (Amsterdam, The Netherlands: Society of Petroleum Engineers, 2009).

Drilling and completion operational aspects

One key element in drilling capacity management is the mitigation of drilling problems and the reduction of operational inefficiency. The total potential improvement in this area may be quantified as up to 50% of overall drilling time.

Figure 3-14: Well drilling and completion time breakdown⁵⁸



The time required to drill a well may be broken down into the following categories:

Productive time (PT) is defined as the bit-on-bottom time, where the hole is drilled. PT may be improved by using better bit technology or finding better operating parameters to enhance performance. Generally PT may range from as low as 10% to above 40% of overall well construction time.

Non-productive time (NPT) comprises the time required for solving problems that cause deviations from the plan. NPT may be within a range of 15-25 % of overall well construction time and represents one of the major improvement potentials for drilling performance.

Invisible lost time (ILT) is defined as the difference between actual operation duration and a best practice or benchmark performance. ILT may be within a range of 15-25 % of overall well construction time and represents another major improvement potential for drilling performance.

Flat time (FT) comprises the time required for operations not directly implied in drilling, e.g. running casing, tripping the drill string in and out of hole, etc. FT may be improved by managing the critical path and optimising operating procedures. These keep NPT and ILT as low as possible.

In order to translate drilling performance to useable figures, the drilling performance statistics from Figure 3-13 are used. The average well construction time for a well of about 5 000 m total depth (including an average 1 500 m horizontal section) should be in the range of:

- 62.5 days/well for low performance, assuming an average rate of penetration of about 80 m/day as reached in the years 1989 to 1998;
- 45 days/well as medium performance, a level at about 100 m/day;
- 38 days/well as a high -performance" scenario, where the average performance of the years 2000 to 2006 is attained - approximately 130 m/day.

Future well construction performance targets can be reached by utilising existing savings potential in terms of NPT and ILT. This could be accomplished by means of the industrialisation of the field development process and specialisation, in combination with purpose-built well designs, which are discussed in the next section. The

⁵⁸ Hermann Spoerker, Gerhard Thonhauser and Eric Maidla, 'Rigorous Identification of Unplanned and Invisible Lost Time for Value Added Propositions Aimed at Performance Enhancement', in *SPE/IADC Drilling Conference* (Amsterdam, The Netherlands: Society of Petroleum Engineers, 2011).

development of new drilling technologies, with a focus on compact rig designs, minimal environmental footprint combined with a high degree of automation, will be key enablers to achieve these performance targets in terms of cost, but more importantly, in terms of environmental compliance.

Drilling and completion well design aspects

One key element for the efficient development of shale gas resources is purpose-designed wells, which have the potential to add significant cost savings to a field development campaign.

Exploration or scouting wells can be leaner in diameter and size, and specifically designed to find geological information. If purpose-built equipment is used (for example, using slim-hole drilling technology for exploration) savings potentials of up to 30% of well cost may be realised.

Equipment building capacity

A key element of effective shale gas field development in Europe is the ability to increase the drilling and fracturing equipment building capacity. The current European land rig count is approximately 70 rigs of different specifications.⁵⁹ The majority of these rigs are based on traditional technology.

Table 3-6: Baker Hughes worldwide rig count⁶⁰

	December 2011			Change	November 2011			Last year		
	Land	Offshore	Total		Land	Offshore	Total	Land	Offshore	Total
North America	2 440	43	2 483	-15	2 460	38	2 498	2 084	24	2 108
Europe	70	42	112	-10	74	48	122	56	49	105
Middle East	263	41	304	-4	269	39	308	236	31	267
Africa	48	31	79	-7	55	31	86	53	26	79
Latin America	349	89	438	16	335	87	422	313	72	385
Asia Pacific	151	96	247	0	150	97	247	157	125	282
World Total	3 321	342	3 663	-20	3 343	340	3 683	2 899	327	3 226

⁵⁹ Energy Digger, *European Rig Count Data (Feb. 2012)* (Energy Digger, 2012, cited 27 March 2012); available from <http://www.energydigger.com/rig-counts/european-rig-counts.aspx>; Upstream, *Rig Pulse* (Upstream, 2012, cited 27 March 2012); available from <http://www.upstreamonline.com/marketdata/rigmarket/?view=rigpulse/worldrigcount>

⁶⁰ Baker Hughes Inc., *International Rotary Rig Count* (Baker Hughes Inc., 2012, cited 27 March 2012); available from http://files.shareholder.com/downloads/BHI/1749209798x0x550380/982E1735-B2EB-4DC7-9629-2462B7A6E8B8/International_Rig_Count_February_2012.xlsx

Table 3-7: Baker Hughes rig count Europe

	December 2011			Change	November 2011			Last year		
	Land	Offshore	Total		Land	Offshore	Total	Land	Offshore	Total
Albania	4	0	4	0	4	0	4	1	0	1
Austria	2	0	2	0	2	0	2	3	0	3
Bulgaria	2	0	2	0	2	0	2	0	0	0
Croatia	0	0	0	0	0	0	0	0	0	0
Czech	1	0	1	0	1	0	1	2	0	2
Denmark	0	3	3	1	0	2	2	2	0	2
France	1	0	1	0	1	0	1	0	0	0
Germany	5	0	5	-1	6	0	6	7	0	7
Greece	0	0	0	0	0	0	0	0	0	0
Greenland	0	0	0	-1	0	1	1	0	0	0
Hungary	1	0	1	0	1	0	1	2	0	2
Iceland	0	0	0	0	0	0	0	0	0	0
Italy	2	2	4	-3	5	2	7	3	1	4
Lithuania	1	0	1	0	1	0	1	0	0	0
Netherlands	0	4	4	2	0	2	2	2	5	7
Norway	0	10	10	-9	0	19	19	0	19	19
Poland	11	0	11	1	10	0	10	6	1	7
Portugal	0	0	0	0	0	0	0	0	0	0
Romania	10	0	10	0	10	0	10	13	0	13
Sakhalin (RU)	3	7	10	1	3	6	9	2	2	4
Slovakia	1	0	1	0	1	0	1	1	0	1
Spain (1)	0	1	1	-1	1	1	2	1	0	1
Switzerland	0	0	0	-1	1	0	1	1	0	1
Turkey	24	1	25	0	23	2	25	10	1	11
United Kingdom	2	14	16	1	2	13	15	0	20	20
Europe	70	42	112	-10	74	48	122	56	49	105

Full-scale shale gas field development will require the design and construction of new drilling rigs. Assuming a field development scenario of 2 500 wells, with an average well length of 5 000 metres, it would require drilling 12.5 million metres of hole (average reservoir depth 3 000 metres, with an assumed build section and a horizontal section of about 1 500 metres). With an average performance scenario, as outlined above, 113 600 drilling days will be required, which equates to about 334 rig years (assuming 340 productive drilling days a year). Thirty rigs will work for about 11 years in this particular field. Each pad (25 to 36 wells) would see drilling activities for about 3.5 to 5 years.

If 50 such fields were to be developed in Europe, 500 rigs would work for 33 years, respectively. Two hundred and fifty rigs would work for 66 years. These values only hold if all rigs would be available immediately from the start of the campaign.

In order to build this required rig fleet within a reasonable time, the capacity to manufacture 20 rigs per year would lead to 25 years of fleet building. To achieve a reasonable timeframe, a building capacity of 30 to 40 rigs per year would be required.

Similar numbers apply for fracturing units.

Personnel building capacity

Assuming the above scenarios for a large-scale development of shale gas in Europe, a significant increase of human resources is required. A typical rig crew today consists of five people per shift plus supervisors, rig mechanic and electrician. Assuming three shifts per day, a total of about 30 people is required to run a rig. Using the above number of 500 rigs operating, about 15 000 people would be required to man the rig crews. In addition, a similarly large number of service company personnel will be required for operational tasks. With equipment manufacturing, supplier personnel etc., it can be expected that more than 100 000 jobs would have to be directly or indirectly created and the required training provided.

3.3.3 Drilling technology and cost scenario

Rig technology

Besides the improvement of the drilling process as such, innovative drilling technology utilising manufacturing principles (industrialised drilling) and a high degree of automation will lead to a more efficient technology.

A key aspect of this requirement is the development and utilisation of drilling rigs with the smallest possible environmental footprint combined with the highest possible efficiency.

Figure 3-15: Rig drilling in The Hague (NL)



Figure 3-16: Rig location close to a hospital



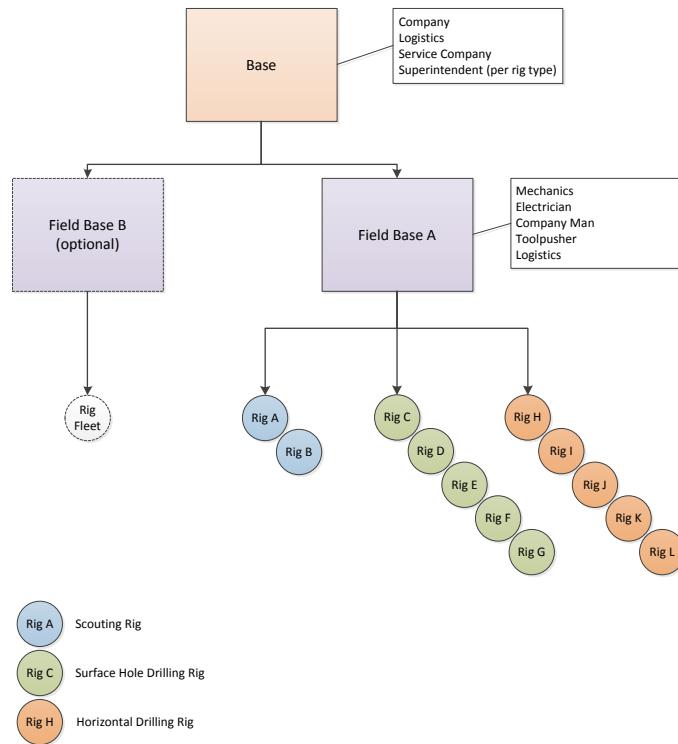
Examples show that such technology is already partly deployed utilising European engineering and manufacturing know-how (see Figure 3-15 and Figure 3-16 above).⁶¹ It is possible today to drill in densely populated areas if state-of-the-art technology is used and the emissions and environmental footprint are minimised.

Concepts of lightweight drilling equipment (for example, aluminum or composite drill pipes as well as casings) have the potential to reduce the required lifting capacity, thus enabling the use of significantly smaller rigs. Hole size requirements have to be reviewed, as smaller hole sizes reduce the consumption of mud, cement and casing, which in return reflects a significant savings potential.

⁶¹ Eric Quinlan et al., 'The Impact of Rig Design and Drilling Methods on the Environmental Impact of Drilling Operations', in *AADE National Technical Conference and Exhibition* (Houston, TX: 2011).

This development should go hand in hand with the specialisation of the drilling machine. Parts of the well construction and field development should be managed by dedicated equipment, e.g. surface section drilling rigs, horizontal well drilling rigs, etc.

Figure 3-17: Field development with centralised functions and rig specialisation



Rig site construction

As rig and fracturing operations will span over multiple years on individual drilling pads, new concepts of constructing rig sites should be adopted. Drilling pads will require a certain size as they are used to drill a large number of wells. The rig site, as well as the rig itself, should be embedded in the environment in the least intrusive way. Wellhead installations and other permanent surface installation should ideally be moved sub-surface. Rigs may be completely housed in order to avoid noise emissions and light emissions during the night.

Well sites should possibly have access to the power grid to avoid the use of diesel-generated power on-site. Noise would thereby be reduced and power could be used from environmentally friendly sources. The rig site may be constructed as a more or less permanent installation and fully housed where drilling activities on a pad are to span over multiple years. This allows for the development of completely new rig sites and rig concepts as a small industrial plant, rather than a conventional rig site.

The means to reduce truck trips to and from the rig site have to be found; for example, through the use of pipelines to supply the rig with fluids. Closed-loop systems should be investigated, which offer the possibility of the reinjecting formation water and cuttings into suitable formations.

Directional drilling technology

Directional and horizontal wells today are drilled with a down-hole motor or a rotary steerable system. Using the rotary steerable system, the drill string and the bit are rotated simultaneously during the drilling process.

For technological reasons, the mud motor can be used either in a 'sliding' or in a 'rotating' mode. In the rotating mode, the drill string and the down-hole motor with the bit are rotated, but to increase or decrease the hole inclination (= angle measured from vertical), the assembly has to be used in a sliding mode, which means that only the down-hole motor and the bit rotate.

In longer, deviated or horizontal sections, the friction borehole, which results from the drill string lying on the bottom of the borehole, creates technical problems with well path control.

In order to overcome these friction problems, alternative or additional systems were developed, namely axial oscillation technology,⁶² friction-reducing oscillation technology⁶³ and directional drilling automation,⁶⁴ all aiming in a 'quasi rotated' drill string, as in the rotating mode of a mud motor.

Downhole communication and measurement systems

In order to enable a high level of rig automation and to mitigate non-productive time, the means to link down-hole measurement systems with surface rig automation system have to be developed and implemented. The early recognition of downhole problems will lead to alarms and allow the rig crew or future rig control systems to take mitigation measures.

Technological developments, which will lead to such improvements, will have to take place in the area of heavy machinery automation, autonomous machines, machine learning, high-temperature and high-pressure electronics and sensor systems.

Such technologies will allow for a significantly reduced NPT and ILT, and lead to the required performance improvements. Converted to a large-scale European shale gas

⁶² Ahmed Al-Zain, Abdulwafi Al-Gamber and Rifat Said, 'Smart Combination of Technology Tools Resulted in Successful Rigless Stimulation on a Tri-Lateral Well, Case Study', in *SPE/DGS Saudi Arabia Section Technical Symposium and Exhibition* (Al-Khobar, Saudi Arabia: Society of Petroleum Engineers, 2011); A. Al Ali, S. Barton and A. Mohanna, 'Unique Axial Oscillation Tool Enhances Performance of Directional Tools in Extended Reach Applications', in *Brasil Offshore Conference and Exhibition* (Macaé, Brazil: Society of Petroleum Engineers, 2011); Franklin Baez and Steve Barton, 'Delivering Performance in Shale Gas Plays: Innovative Technology Solutions', in *SPE/IADC Drilling Conference and Exhibition* (Amsterdam, The Netherlands: Society of Petroleum Engineers, 2011); Franklin Baez, Steve Barton and Aref Alali, 'Drilling Performance Improvement in Shale Gas Plays Using a Novel a Novel Drilling Agitator Device', in *North American Unconventional Gas Conference and Exhibition* (Woodlands, TX: Society of Petroleum Engineers, 2011); John E. McCormick and TzuFang Chiu, 'The Practice and Evolution of Torque and Drag Reduction: Theory and Field Results', in *SPE Annual Technical Conference and Exhibition* (Denver, CO: Society of Petroleum Engineers, 2011).

⁶³ Canrig Drilling Technology Ltd., *ROCKIT™* (Canrig Drilling Technology Ltd., 2012, cited 27 March 2012); available from http://www.canrig.com/default.asp?V_ITEM_ID=205; Colin Gillan et al., 'Applying Precision Drill Pipe Rotation and Oscillation to Slide Drilling Problems', in *SPE/IADC Drilling Conference and Exhibition* (Amsterdam, The Netherlands: Society of Petroleum Engineers, 2009); Colin Gillan et al., 'Applying Computer Based Precision Drill Pipe Rotation and Oscillation to Automate Slide Drilling Steering Control', in *Canadian Unconventional Resources Conference* (Alberta, Canada: Society of Petroleum Engineers, 2011).

⁶⁴ Maidla and Haci, 'Understanding Torque: The Key to Slide Drilling Directional Wells'; Eric Maidla et al., 'Field Proof of the New Sliding Technology for Directional Drilling', in *SPE/IADC Drilling Conference* (Amsterdam, Netherlands: Society of Petroleum Engineers, 2005); Maidla, Haci and Wright, 'Case History Summary: Horizontal Drilling Performance Improvement Due to Torque Rocking on 800 Horizontal Land Wells Drilled for Unconventional Gas Resources'.

development initiative, a 10% increase of efficiency can be equated to 50 rigs operating for 30 years, or €45 billion in potential cost savings (at current drilling spread cost).

Drilling cost

The following cost items form the major elements of drilling-related cost for typical land rig operations in Europe. As a general rule, the total cost can be estimated to range between €75 000 and €126 000 per day as the spread cost (overall well cost divided by number of drilling days). This cost is the sum of a number of key cost items, which are given in greater detail below. Cost items can be split into rig site cost, depth-based cost and day rate-based cost. As can be seen, the drilling cost is driven by day rates, which highlights the importance of improving drilling efficiency in terms of drilling duration.

Rig site cost

The rig site cost per well is a function of pad size and number of wells drilled per pad. Construction costs in Europe can be estimated to be three to five times higher than in the USA due to rigorous regulations concerning surface water protection and waste management. Rigs site costs for shale gas may have to include the cost for building complete housing for the rigs and the equipment for noise and light protection. This may be particularly necessary for rig sites where activities will span over a considerable period of time.

Day rate cost

The rig cost is typically charged as a day rate service with rig rates for relevant size rigs ranging from €15 000 to €28 000 depending on the rig capacity. The rig cost has a strong personnel and maintenance cost component, which has the potential to be reduced by automation and the highest equipment quality standards, as well as rigorous maintenance programmes.

The directional drilling cost is a day rate service, which is available at different levels of complexity, ranging from €10 000 to €15 000. Service includes directional drilling equipment rental as well as service personnel. If vertical drilling is possible in thick reservoirs, the cost may be significantly reduced to basic measurement services. Utilising rotary steerable system technology may more than double typical rates. Alternative directional drilling technologies, as described above, have the potential to significantly lower drilling costs, meaning that the quality levels of rotary steerable systems can be achieved in the 'most likely' scenarios used in this study.

The evaluation cost is the cost to perform formation evaluation and other measurement services during the well construction process. This cost strongly depends on the type of measurements performed and is typically based on service day rates for individual tools, especially when used as a logging-while-drilling service.

Depth based cost

Casing, cementing and wellhead costs constitute a significant cost item, which is hole-size and wellbore-length dependent. This cost is typically dominated by material costs (e.g. for steel or bulk volumes of mud material), where the cost depends on the quantity used per well and the market price. Overall, this cost item contributes to 20-30% of the total well cost.

The **mud cost** may be split into a) bulk material costs, with base fluid; and b) additives and the mud service cost. Mud cost may vary between €400 and €2 000 per m³

depending on the type of mud. Mud service cost is dependent on the number of personnel involved. A decisive factor in predicting mud cost is the ability to reuse mud for multiple wells, which in return depends on the ability to recycle a maximum mud volume.

The **bit cost** has lost its former significance over the years and may only contribute a few per cent to the total well cost.

The **evaluation cost** covers performing formation evaluation and other measurement services during the well construction process. This cost strongly depends on the type of measurements performed.

The **waste and water management cost** is the cost related to managing waste and water, which is dependent on the volume used and the type of waste generated. The waste management cost is related to hole diameter and wellbore (cuttings) volume, and thus linked to the mud volume required.

For the drilling and development costs of shale gas resources in the USA, please refer to the table below.

Table 3-8: Comparison of drill bit finding and development cost per 1 000 cubic feet equivalent (Mcfe) (three-year average) for different US operators⁶⁵

Drill bit F&D cost per Mcfe (3-year average)	
Ultra Petroleum	\$0.75
Quicksilver Resources	\$1.15
XTO Energy	\$1.67
Range Resources	\$1.89
Cabot Oil & Gas	\$1.99
EOG Resources	\$2.10
EnCana	\$2.12
Southwestern Energy Company	\$2.21
Devon Energy	\$2.44
Apache	\$2.53
Denbury Resources	\$2.92
Newfield Exploration	\$3.08
Forest Oil	\$3.66
Noble Energy	\$4.09
St. Mary Land & Exploration	\$4.30
Pioneer Natural Resources	\$4.41
Cimarex Energy	\$4.42
Swift Energy	\$6.08
Anadarko Petroleum	\$6.09
Chesapeake Energy	\$6.18

Future developments in drilling cost

The improvement of drilling efficiency may contribute to a drilling cost reduction of 20 to 40% by mitigating ILT and NPT, which is directly reflected in better overall drilling performance. This will be possible by introducing manufacturing-type principles to large well construction campaigns.

⁶⁵ Southwestern Energy Company, *Form 8-K* (US Securities and Exchanges Commission, 2009, cited 27 March 2012); available from <http://investor.shareholder.com/swn/secfiling.cfm?filingID=7332-09-8>

Additional contributions from rig automation and alternative drilling technologies (for example, directional drilling and evaluation) have the potential to add savings of another 10-20% of the overall drilling cost.

These savings can potentially go hand in hand with a reduction of well construction elements, such as the cost for casing, cementing and the well head, if novel well designs are used and steps towards the specialisation of well designs are taken. For specific cases, additional reductions of drilling costs of up to 30% may be expected.

3.3.4 Fracturing technology and cost scenario

Fracturing technology

The key issues related to hydraulic fracturing are the management of water, the use of chemicals, air pollution, the potential of induced seismic activity as well as surface and groundwater contamination.

Clean fracturing technologies, where potentially harmful chemical additives are not used as part of the fracturing fluid, are being investigated by the author. Such technologies combine closed-loop fluid systems with simple fluid recipes using water, viscosifier and proppant only. Water treatment and recycling is performed by means of technologies used in drinking-water treatment. The cost of such fluids should tentatively be below the cost of current fracturing fluid technology, but at the same time may lead to reduced fracturing efficiency. The investigation of effects of clean fracturing fluids on fracture efficiency and ultimate production is a topic of currently on-going research.

In order to monitor the development of fractures, improved technologies for modelling, monitoring and continuously improving the fracture process should be developed. In terms of research and development it is necessary to combine the mechanical behaviour of the rock with fluid-flow phenomena and chemical reactions that take place when fracturing fluid contacts the formation. Ultimately such an understanding will lead to the definition of the ideal hydraulic fracture to maximise production, thus optimising cost.

New fracking technologies are being applied in the USA that may yield significant time savings. One particular technology claims to reduce fracturing job durations from four to five days to some ten hours for jobs with up to 60 fracture stages, where four stages are pumped simultaneously. In addition, this technology promises to significantly reduce the volume of fracturing fluid used.⁶⁶

Fracturing cost

The fracturing cost is driven by the cost of fracturing units, the volume of water and proppant, as well as the volume of fracturing additives used. The cost is typically expressed in terms of cost per fracturing stage or fracturing job. There is no large-scale experience with shale gas type fracturing in Europe. Cost figures given here are derived from US examples.

The average costs for hydraulic fracturing in the USA is between \$3.3 million and 3.7 million assuming ten fracture stages per well.

⁶⁶ Packers Plus, *QuickFRAC* (Packers Plus, 2012, cited 27 March 2012); available from <http://www.packersplus.com/products/quickfrac.php>

A well with ten fracturing stages produces 25 000 bbl of back flow. Numbers for disposal and treatment costs are in the range of \$7.5 per bbl.

Industry analysts have assumed \$1.56 million for one transverse fracture and \$70 000 per each additional fracture interval for economic analysis.⁶⁷

In Horn River Basin, British Columbia, Canada, fracturing costs were estimated around \$300 000 per stage.⁶⁸

In the cost scenario presented in this report, hydraulic fracturing costs for Europe are divided into a fixed cost element and a stage-based cost. A value of €250 000 to €350 000 has been used per stage. Mobilisation and demobilisation, as well as water supply costs and water disposal costs, with the management of backflow water (€250 000), are estimated to be between €500 000 and €700 000 per well.

The scenario considers large-scale fracture jobs, which have not yet been performed in Europe.

Future developments in fracturing cost

Investigations of fracturing efficiency using production logging in the USA showed that in the cases investigated, 70% of the production came from only 30% of the perforations of a well.⁶⁹ This indicates that there is heterogeneity in the productivity of different formation intervals. As a consequence, technology has to be developed to identify the zones of highest productivity for fracturing. Such technology will depend on a deep geo-mechanical understanding of the reservoir in terms of the physical properties of the rock and the local stress field in the relevant region near the wellbore. The recent developments of multiport fracturing technology allows surface-pumped fracture stages to be reduced from 8 to 15 stages, with a parallel reduction in fluid volumes used.

If such technology could be successfully deployed, a significant reduction in fracturing cost could be achieved by less fracturing stages, ideally with only a small reduction in production. Combining more efficient fracture stage location selection with highly efficient fracture technology (see above) has the potential to significantly reduce the environmental impact of fracturing, as well as the cost.

3.3.5 Field development infrastructure and gas processing and treatment scenario

Technology

The pad-based development of shale gas field infrastructure will lead to such infrastructure being more concentrated. Surface installations should ideally be moved subsurface where it is possible to avoid an impact on the environment in terms of visibility, noise, etc. Gas processing and treatment should be managed in centralised facilities.

⁶⁷ Watson et al., 'One-Trip Multistage Completion Technology for Unconventional Gas Formations'.

⁶⁸ European Energy Exchange AG, *Strom Terminmarkt* (European Energy Exchange AG, cited 27 March 2012); available from <http://www.eex.com/de>

⁶⁹ G. Waters et al., 'Use of Horizontal Well Image Tools to Optimize Barnett Shale Reservoir Exploitation', in *SPE Annual Technical Conference and Exhibition* (San Antonio, TX: Society of Petroleum Engineers, 2006).

Cost

It can be expected that infrastructure costs in Europe will be higher than in the USA. This is based on the higher cost of labour, geographic situation, population density and environmental regulations. For typical conventional field developments, the infrastructure cost may be considered to be equal to the drilling and completion cost, which may also be used as a first initial approach for modelling shale gas field developments.

Due to the investment-intensive nature of shale gas drilling and fracturing, and the highly concentrated infrastructure, it may be considered to assume lower cost figures in relation to drilling and completion. Actual cost values will highly depend on the local situation and the availability of existing infrastructure, e.g. in areas with a hydrocarbon exploration and production history. In this chapter, the cost is estimated to be 30% of the drilling and completion cost.

The numbers in the table below outline lifting costs for a number of shale gas operators in the USA. They can be put in relation to the drilling and development cost in Table 3-8 to calculate a cost ratio.

Table 3-9: Comparison of lifting cost per Mcfe of production (three-year average) for different US operators⁷⁰

Lifting cost per Mcfe of production (3-year average)	
Southwestern Energy Company	\$0.88
Noble Energy	\$1.12
Chesapeake Energy	\$1.16
Ultra Petroleum	\$1.17
EOG Resources	\$1.19
EnCana	\$1.23
Range Resources	\$1.24
Pioneer Natural Resources	\$1.37
Devon Energy	\$1.53
XTO Energy	\$1.54
Newfield Exploration	\$1.60
Forest Oil	\$1.63
Cimarex Energy	\$1.73
Cabot Oil & Gas	\$1.75
Anadarko Petroleum	\$1.77
Apache	\$1.78
Quicksilver Resources	\$1.84
St. Mary Land & Exploration	\$1.87
Swift Energy	\$1.88
Denbury Resources	\$2.56

3.3.6 Gas production scenario from shale developments

On average, production or ultimate recovery is assumed, based on typical US figures (with 1 cubic foot = 0.028 cubic metres).⁷¹ The assumption made in the scenario

⁷⁰ Southwestern Energy Company, *Form 8-K* (cited).

calculation in the next section is based on the values depicted in Table 3-10 and Table 3-11. The most likely scenario used here considers an ultimate recovery of 57 mcm or 0.68 million MWh. The production profile for a typical well is not discussed here. Only commercial development will demonstrate how long the productive life of a well can be sustained in Europe before the well reaches its economic limit. Current examples from the USA indicate an economic limit at a production rate of 100 Mcf per day, but production histories hardly exceed ten years (Barnett Shale). The economic limit is defined as the production rate at well operating cost break-even. However, optimistic projections may reach three to four decades (see Figure 4-5).

Table 3-10: Technically recoverable shale gas resources for the USA⁷²

Play	Technically recoverable resource		Area (sq. miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/well)	Oil (MBO/well)
Marcellus	410.34	...	10 622	84 271	1.18	...
Big Sandy	7.4	...	8 675	1 994	0.33	...
Low Thermal Maturity	13.53	...	45 844		0.3	...
Greater Siltstone	8.46	...	22 914		0.19	...
New Albany	10.95	...	1 600	41 900	1.1	...
Antrim	19.93	...	12 000		0.28	...
Cincinnati Arch	1.44	...	NA		0.12	...
Total Northeast	472.05	...	101 655	128 272	0.74	...
Haynesville	74.71	...	3 574	5 426	3.57	...
Eagle Ford	20.81	...	1 090		5	...
Floyd-Neal & Conasauga	4.37	...	2 429		0.9	...
Total Gulf Coast	99.99	...	7 093	5 426	2.99	...
Fayetteville	31.96	...	9 000		2.07	...
Woodford	22.21	...	4 700		2.98	...
Cana Woodford	5.72	...	688		5.2	...
Total Mid-Continent	59.88	...	14 388		2.45	...
Barnett	43.38	...	4 075	2 383	1.42	...
Barnett Woodford	32.15	...	2 691		3.07	...
Total Southwest	75.52	...	6 766	2 383	1.85	...
Hilliard-Baxter-Mancos	3.77	...	16 416		0.18	...
Lewis	11.63	...	7 506		1.3	...
Williston-Shallow Niobraran	6.61	...	NA		0.45	...
Mancos	21.02	...	6 589		1	...
Total Rocky Mountain	43.03	...	30 511		0.69	...
Total Lower 48 United States	750.38	...	160 413	36 081	1.02	...

⁷¹ Robert B. Kennedy, 'Shale Gas Challenges / Technologies Over the Asset Life Cycle', (Washington, DC: United States Energy Association, 2010).

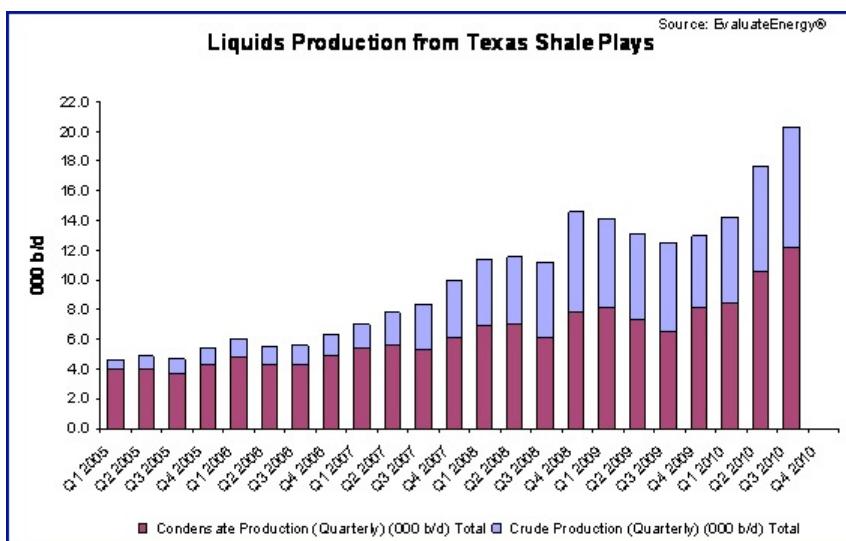
⁷² INTEK, 'Review of emerging resources'. However, see Chapter 2 for the weaknesses in the methodology of this study.

Table 3-11: Technically recoverable shale oil resources for the USA

Play	Technically Recoverable Resource		Area (sq. Miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/well)	Oil (MBO/well)
Eagle Ford	...	3.35	3 323		...	300
Total Gulf Coast	...	3.35	3 323		...	300
Avalon & Bone Springs	...	1.58	1 313		...	300
Total Southwest	...	1.58	1 313		...	300
Bakken	...	3.59	6 522		...	550
Total Rocky Mountain	...	3.59	6 522		...	550
Monterey/Santos	...	15.42	1 752		...	550
Total West Coast	...	15.42	1 752		...	550
Total Lower 48 United States	...	23.94	12 910		...	460

Liquid production from gas shale is steadily increasing and plays a key role in shale gas economics in the USA, as depicted in Figure 3-18 below.⁷³

Figure 3-18: Liquid production from shale gas plays in Texas



3.3.7 Summary and conclusions

In the following pages, a model for the potential development of shale gas in Europe is outlined, covering the minimum, most likely and maximum scenarios of the key variables contributing to the cost of shale gas (including potential liquid production) translated to €/MWh as the bottom line. It is not the objective of this chapter to estimate gas price scenarios. Other sources are used as a reference.⁷⁴

⁷³ Evaluate Energy Ltd., *How Texas Shale Gas Producers are Ramping up Liquids Production* (Evaluate Energy Ltd., 2012, cited 27 March 2012); available from <http://www.oil-blog.com/by-sector/shale-gas-by-sector/texas-shale-gas-producers-ramping-liquids-production/>

⁷⁴ European Energy Exchange AG, *Strom Terminmarkt* (cited).

More information about the individual cost elements can be found in the respective chapter references column in the tables below.

Table 3-12: Typical well configurations

Typical Well Configurations			Unit of measure	Description of model cost component	Chapter ref.	Comments and dependencies
Low	Most likely	High				
3 000	5 000	7 000	m	Average well length	3.3.1	The wellbore length will depend on the local geological situation and reservoir depth. It will also depend on the length of the horizontal hole sections (if required).
385	641	898	m ³	Mud volume per well	3.3.3	Hole size is assumed to be an average 12.25 inch hole over the entire wellbore length. Based on this hole size assumption, the total mud volume is assumed to be 1.5 hole volumes on average (whereas a factor 2 would typically be used with accurate hole size numbers).

The typical well configurations reflect a range of wellbore length scenarios as they may be drilled for different geological situations. For the cost scenarios outlined below the 'most likely' well configuration scenario was considered to establish a number of cost scenarios.

Table 3-13: Typical rig site configurations

Typical rig site configurations						
Low	Most likely	High	Unit of measure	Description of model	Chapter ref.	Comments and dependencies
				cost component		
3 500 000	4 000 000	5 000 000	€	Construction cost per pad	3.3.1	Estimated cost per pad considering a concrete rig site, surface water management system, etc. Pad may have to be maintained for 3 to 15 years for drilling and the following production. Additional cost is considered for housing of the rig and equipment components to minimise noise and light emissions. Roads, etc. are considered in infrastructure cost.
15	25	36	wells	Number of wells per pad	3.3.1	Numbers of wells drilled depends on the local geological and surface location situations.
233 333	160 000	138 889	€/well	Cost per well	3.3.1	The rig site cost per well is calculated based on assuming a certain pad size and the number of wells drilled per pad.

The rig site configuration scenarios, shown in Table 3-13, range for pads from 15 to 36 wells. These numbers are based on wells with longer lateral extensions and the need to minimise the number of rig sites. In the following, only the 'most likely' scenario with 25 wells per pad is considered.

Table 3-14: Depth-based cost scenarios

Drilling depth-based cost						
Optimistic	Most likely	Conservative	Unit of measure	Description of model	Chapter ref.	Comments and dependencies
cost component						
250	275	300	€/m	Casing, cementing and wellhead cost	3.3.3	The cost of well installations in terms of casing, cement and wellhead are assumed to be rather constant as they are dominated by prices of steel, cement and additives. More expensive cement additives may increase the cementing efficiency.
7	5	3	-	Mud re-use factor	3.3.3	Mud may be re-used for multiple wells, so cost is distributed over multiple wells. This number could potentially be increased significantly with investment in mud management and centralised mud supply facilities in the field. Limits are given by mud which is deposited with cuttings and mud losses, which may be encountered.
400	1 000	2 000	€/m ³	Mud material cost	3.3.3	Higher mud cost will typically lead to higher performance due to a reduction in wellbore-related problems. A strong link to drilling performance can be expected.
264	660	1 320	€/m ³	Waste and water management cost	3.3.3	Waste management cost is estimated to be reflected by considering 66% of mud cost required to manage the volume of generating cuttings. The type of mud plays a central role in defining the ability to recycle versus deposition.

Based on the depth and day rate alternatives, we will consider three scenarios, with the 'conservative' scenario reflecting today's costs by utilising current technology and the current average drilling performance in Europe.

In this context it is important to note that the depth and size of the well drives in Depth-based cost (Table 3-14) and the drilling performance is the driver of Day rate-based costs in Table 3-15. The amount of metres a rig is capable of drilling per day on average defines the duration of the drilling project (see Table 3-16 and Table 3-17).

The 'most likely' scenario reflects a cost situation which should be reasonably achievable with cost-effective well designs and an achievable increase in efficiency by drilling process improvements reducing non-productive and invisible lost time. Technology development in this first phase will focus on developing environmentally acceptable ways to drill and perform hydraulic fracturing. Technology development will also have to aim at generating cost-effective technology. It should be realistic to achieve this level of technological improvement, as well as performance and cost levels within a timeframe of five years.

The 'optimistic' scenario assumes a future scenario where field development has undergone industrialisation utilising manufacturing-type processes and technologies with a high degree of specialisation of rigs and equipment. Fields are developed with large-scale drilling campaigns and with a high degree of optimisation. New technologies minimalise drilling risks; for example, downhole sensing, real-time communication between down-hole sensors and the rig, highly automated rigs, which enable early detection of drilling problems. Drilling crews are highly trained specialists, who use highly automated drilling machines. They consistently work in the same field, combining local geological expertise and benefiting from learning curve effects and a high degree of process optimisation. Technologies used are cost-effective as they can also be manufactured in industrial quantities. It seems plausible to assume that building large-scale drilling activities in Europe, combined with the necessary investment, will allow the development of such processes and technology within a timeframe of 10 to 15 years from now and reach widespread deployment.

Table 3-15: Drilling performance scenarios

Drilling performance						
Optimistic	Most likely	Conservative	Unit of measure	Description of model cost component	Chapter ref.	Comments and dependencies
130	110	80	m/day	Drilling performance	3.3.2	Drilling performance is derived from past European experience. There is the potential to increase performance, which will tentatively lead to higher depth-based and day rate-based drilling costs as more technology and higher performance products and services are used.

For the following cost scenarios, different process and technological assumptions are combined. Summarising the above, the results show the following:

- Conservative scenario essentially reflecting today's cost;
- Most likely scenario achievable within a five-year time frame;
- Optimistic scenario assuming 10 to 15 years of technology and process development.

The first row in Table 3-16 below shows the values (in bold) for the total day rate-based cost for wells.

Table 3-16: Drilling operations day-rate-based cost scenarios

Drilling operations day rate cost						
Optimistic	Most likely	Conservative	Unit of measure	Description of model cost component	Chapter ref.	Comments and dependencies
34 800	49 500	78 000	€/day	Drilling operations day rate cost (total)	3.3.3	Total cost as sum of the cost items below.
15 000	20 000	28 000	€/day	Rig cost	3.3.3	Shallower wells require significantly smaller rigs with lower day rates.
6 000	8 000	15 000	€/day	Directional drilling cost	3.3.3	Vertical wells may not need directional drilling costs, whereas highly deviated or horizontal drilling would require directional drilling tools and services.
3 000	5 000	8 000	€/day	Mud service cost	3.3.3	Costs to maintain the mud system and to perform solid control work. The cost depends on the mud system complexity.
800	1 500	2 000	€/day	Bit cost	3.3.3	The bit cost is considered as part of the day rate cost in a range between 1% and 2% of total well cost. Bit cost itself does not reflect a significant cost driver. The drilling performance in the productive time (PT) as a consequence of bit selection has a significant impact.
10 000	15 000	25 000	€/day	Evaluation cost	3.3.3	Evaluation cost may range from standard wire-line logging to using logging while drilling systems. For highly deviated wells, evaluation tools have to be run on the drill string, so using LWD is a viable option.

In the cost model below, the ‘most likely’ rig scenario is combined with the ‘most likely’ cost and performance scenarios.

Table 3-17: Drilling cost scenario per well

Cost scenarios				
Optimistic	Most likely	Conservative	Unit of measure	
160 000	160 000	160 000	€	Site cost per well (25 wells per pad)
5 000	5 000	5 000	m	Depth
301	385	506	€/m	Drilling depth-based cost
34 800	49 500	78 000	€/day	Drilling operations day rate cost
38	45	63	days	Well duration
3 003 000	4 337 000	7 565 000	€	Total well drilling cost (rounded)
78 078	95 414	121 040	€/day	Average cost per day
601	867	1 513	€/m	Average cost per metre

In terms of the fracturing cost, a similar approach is taken where numbers of stages, as well as cost are considered in three scenarios, which show a technological evolution over a timeframe that is similar to the drilling technology above.

Table 3-18: Fracturing cost scenario per well

Typical fracturing configurations						
Optimistic	Most likely	Conservative	Unit of measure	Description of model cost component	Chapter ref.	Comments and dependencies
8	12	15	stages	Number of surface fracture stages pumped per well using multiport fracturing technology	3.3.4	A reduction in number of fracturing stages is based on the assumption that reports show that, in examples, 70% of the production is coming from 30% of the perforations.
Fracturing cost						
Optimistic	Most likely	Conservative	Unit of measure	Description of model cost component	Chapter ref.	Comments and dependencies
500 000	600 000	700 000	€	Fixed cost per fracture job	3.3.4	A fixed cost per shale gas well is assumed to account for infrastructure set-up, mobilisation, etc. and water management cost. Using closed-loop fracture fluid systems and reuse of fluid will have a significant impact on waste management cost.
250 000	300 000	350 000	€/stage	Cost per stage	3.3.4	A variable cost is assumed to account for cost of materials and services per fracture stage. The cost per stage will greatly depend on the type of fracturing fluid that is utilised. No estimate for potential reuse of fluid is made.
'Most likely' well with three cost scenarios						
Optimistic	Most likely	Conservative	Unit of measure			
12	12	12	stages	Number of stages		
3 500 000	4 200 000	4 900 000	€	Fracturing cost		

Field development and infrastructure costs will be highly dependent on the local situation in the individual field. Cost scenarios will vary with complexity and existing infrastructure in terms of pipeline and processing capacity. The possibility of reusing existing pipeline and processing capabilities will allow for cost reductions in certain shale gas regions in Europe. Larger sized pads will allow for more centralised

infrastructure, which in turn leads to reduced costs. In the following study, a simplified approach is taken to the estimation of costs.

Considering the high degree of uncertainty and the potential cost savings from manufacturing-type developments with highly centralised infrastructure, the estimated cost for field development and infrastructure is reflected as 30% of drilling and completion cost in Table 3-19.

Table 3-19: Field development, infrastructure and processing costs by scenario

Field development and infrastructure and processing costs						
Optimistic	Most likely	Conservative	Unit of measure	Description of model cost component	Chapter ref.	Comments and dependencies
3 251 500	4 268 500	6 232 500	€	Field development, infrastructure and processing cost	3.3.5	Lifting cost is assumed to be 30% of drilling and production costs. Cost is estimated on the basis of assuming pad type development with concentrated surface infrastructure.

In the following, a cost summary is provided (with optimistic, most likely and conservative cost estimates), based on the considered scenarios. The cost scenarios are combined with three production scenarios to reflect a range of possible outcomes for a specific well and rig site configuration.

Using liquid production values from Table 3-11, the importance of the impact of condensate production on the overall economics of shale gas plays is shown. The cost per MWh is significantly influenced by the high energy content per barrel of liquid production.

The numbers given below demonstrate the high economic interest in resources with liquid potential in the USA. The production estimates below combine liquid and gas production rates per well using different scenarios.

The amount of liquid potential depends on the maturity of the resource as a consequence of geological situation and deposition history. A realistic assessment of gas-liquid ratios that could possibly be achieved in Europe will have to be proven by intensive exploration.

Table 3-20: Production cost scenario combining optimistic, most likely and conservative cost and production scenarios

Production scenario				Description of model cost component	Chapter ref.	Comments and dependencies
Optimistic	Most likely	Conservative	Unit of measure			
85	57	21	mcm	Estimates of technically recoverable resources from a gas shale	3.3.6	Ultimate gas recovery scenarios based on US references.
1.01	0.68	0.25	Million MWh	Energy produced per well from gas	3.3.6	Conversion of gas production to energy
500 000	300 000	100 000	bbl	Estimates of technically recoverable resources from a shale oil well	3.3.6	Ultimate liquid recovery scenarios based on US references.
0.84	0.50	0.17	Million MWh	Energy produced per well from liquids		Conversion of liquid production to energy
1.85	1.18	0.42	Million MWh	Total energy produced from well	3.3.6	

'Most likely well and rig site scenario versus Three cost and production scenarios' without liquid production

Optimistic	Most likely	Conservative	Unit of measure	
9 754 500	12 805 500	18 697 500	€	Total cost per well
9.64	18.87	74.79	€/MWh	Cost per MWh not considering liquid production

'Most likely well and rig site scenario versus Three cost and production scenarios' with liquid production

Optimistic	Most likely	Conservative	Unit of measure	
9 754 500	12 805 500	18 697 500	€	Total cost per well
5.28	10.86	44.84	€/MWh	Cost per MWh considering liquid production

If the 'most likely' production is combined with the three cost scenarios, it can be seen how the production cost may develop over a timeframe of 5 to 15 years.

Table 3-21: Production cost scenarios based on the ‘most likely’ production and three cost scenarios

‘Most likely well and rig site scenario versus Three cost and “most likely” production scenarios’ with liquid production					
Optimistic	Most likely	Conservative	Unit of measure		
1.18	1.18	1.18	Million MWh	Total energy produced from the well ‘most likely’	
9 754 500	12 805 500	18 697 500	€	Total cost per well	
8.27	10.86	15.85	€/MWh	Cost per considering	MWh liquid production

This comparison can be done in a similar manner for ‘optimistic’ and ‘conservative’ production scenarios, as depicted in the following two figures below.

Table 3-22: Production cost scenarios based on ‘optimistic’ production and three cost scenarios

‘Most likely well and rig site scenario versus Three cost and “optimistic” production scenarios’ with liquid production					
Optimistic	Most likely	Conservative	Unit of measure		
1.85	1.85	1.85	Million MWh	Total energy produced from the well ‘most likely’	
9 754 500	12 805 500	18 697 500	€	Total cost per well	
5.28	6.93	10.12	€/MWh	Cost per considering	MWh liquid production

Table 3-23: Production cost scenarios based on ‘conservative’ production and three cost scenarios

‘Most likely well and rig site scenario versus Three cost and “conservative” production scenarios’ with liquid production

Optimistic	Most likely	Conservative	Unit of measure	
0.42	0.42	0.42	Million MWh	Total energy produced from the well ‘most likely’
9 754 500	12 805 500	18 697 500	€	Total cost per well
23.39	30.71	44.84	€/MWh	Cost per MWh considering liquid production

Global development scenarios

The development of technology and processes to produce shale gas will globally move in a similar direction. The scenarios will be characterised by very cost conscious and performance orientated field developments.

In the current operator/contractor/service company business model, technology in terms of tools and processes will be available on the global market place. Variation will most likely be driven by different personnel costs and local price variations influenced by tax regimes or the like. An additional potentially dominating factor, leading to technology and cost variations, will be variations in environmental standards.

An alternative may develop. Based on US examples, it seems very likely that the business model may undergo changes. Operators will return from an almost exclusive outsourcing policy, which they followed over the past decades, to insourcing again. The drive for that is to combine the highest possible efficiency with competitive advantage. Business success in shale gas plays is not driven by exploration risk but by manufacturing competence at the highest possible environmental standards. Such capability will be key for economic success and potentially the biggest differentiator for companies competing for reserves. Operators, developing unique capabilities in this direction, will have an advantage globally in successfully exploiting shale gas.

3.4 Conclusions

The success of shale gas development in Europe will greatly depend on:

- 1) the ability to increase the efficiency of drilling by industrialising the drilling process, and utilising rig automation technology and equipment by aiming at zero harmful emissions, thus producing the lowest possible environmental footprint;
- 2) the related reduction of drilling and fracturing cost, with could aim at 50% cost reductions for large-scale drilling campaigns;
- 3) the development of clean fracturing technology in combination with a deep understanding of the relationship between geomechanical properties of the rock, fluid flow and chemical interactions, and between formation and stimulation fluid;
- 4) the required investment in research and development to establish and build the required technology in Europe;
- 5) the building of human resource capacity to support large-scale field developments with several hundreds of rigs operating in Europe for many decades, and to develop and build the required infrastructure.

The development of shale gas will only be successful in Europe if the environmental and economic boundary conditions can be fulfilled.

The chapter concludes with developing cost scenarios for future shale development in Europe leading to the following total cost per MWh. These cost estimates are in line with the current break-even costs for shale gas production in Europe proposed by other notable studies, which lie between either €13.5-32/MWh or \$5-12/MBtu given January 2012 market conditions (see Figure 5-12).

Table 3-24: Shale gas cost scenarios for Europe

'Most likely well and rig site scenario versus Three cost and production scenarios' without liquid production				
Optimistic	Most likely	Conservative	Unit of measure	
9 754 500	12 805 500	18 697 500	€	Total cost per well
9.64	18.87	74.79	€/MWh	Cost per MWh not considering liquid production
'Most likely well and rig site scenario versus Three cost and production scenarios' with liquid production				
Optimistic	Most likely	Conservative	Unit of measure	
9 754 500	12 805 500	18 697 500	€	Total cost per well
5.28	10.86	44.84	€/MWh	Cost per MWh considering liquid production

4 Land and market access

I. Pearson and P. Zeniewski (European Commission, JRC F.3)

The rate of production of a resource is influenced by the physical features of that resource, the technology available to exploit the resource and the various economic and political factors that affect the behaviour of the organisations involved. Whilst the first two of the abovementioned factors have already been addressed in this report, this section aims to give a notional overview of some of the remaining 'above ground' issues for one form of unconventional gas – specifically, shale gas – using language that is accessible to readers who do not necessarily have a technical background. In light of the very small amount of research, exploration and production data that are publicly available on European unconventional gas, it is necessary to study cases from North America and elsewhere as a starting point to identifying the likely scale, timeframe and necessary conditions for unconventional gas production in Europe.

As the following pages illustrate, a very wide range of factors may potentially affect land and market access for unconventional gas developments. Because of the difficulty of defining a scope for the review of the evidence on these topics that would be both rigorous and comprehensive at the same time, this chapter does not attempt to provide a systematic review, as Chapter 2 does for reserve estimates. In particular, although steps have been taken to locate the most relevant studies, to limit selection bias and to assess the methodological quality of sources used, the application of protocols and explicit criteria to these ends is unviable. Readers should therefore regard the chapter as an exploratory survey of the econometric, modelling and qualitative evidence around land or market access issues for the purpose of identifying areas of further research or contextually informing the interpretation of future developments on these key topics.

4.1 Land access

The purpose of this section is to discuss land access issues and the regulatory framework governing unconventional gas. It corresponds with the third and fourth factors determining the viability of natural gas production presented in Figure 1-3. The ability to access deposits of shale gas starts on the surface and is crucially determined by a number of physical, social and environmental constraints. Should the size and commercial viability of technically recoverable resources in Europe translate into large scale production, there will be a wide range of issues in need of attention. The aim of this section, therefore, is to answer two key questions. First, what is the surface-level impact of shale gas operations compared with that of conventional gas? Second, what are the primary regulatory factors that can or will affect shale gas operations, particularly in Europe?

The first question requires an analysis of land access issues at the level of the well-head. Accordingly, the first section will begin by comparing the surface requirements of three different types of onshore gas wells – single vertical gas wells, on the one hand, and single horizontal wells and multi-well pads (in which several horizontal wellbores stem from a single pad) on the other. The analysis will then focus on well densities, highlighting the distinction drawn in much of the literature between conventional and unconventional well spacing requirements. Having provided a general picture of the

extent of land use required by unconventional gas development, the second section will discuss the wide range of regulatory issues in Europe that may constrain or enable these surface-level operations. Of primary interest is the extent to which surface-level issues, whether technical, legal or socioeconomic in nature, can be effectively managed by a robust regulatory framework. The key question in this context is whether the interests of three broader sets of actors (market, state and societal) can be effectively balanced by such a framework, and what major issues have been identified in the literature as being critical to successful shale gas exploitation activities.

Many of the references used for this section have been drawn from detailed impact assessments of shale gas development in different US states. These reports are based on the cumulative knowledge and feedback of industrial players, community stakeholders, independent consultancies, scientific experts and public policymakers; therefore, they serve as a relatively authoritative source of information. By drawing on such reports as well as their supporting documentation/annexes, it has been possible to extract a relatively clear picture of the surface-level impact of shale gas development. This picture has been further refined by an extensive review of other literature specific to Europe.

4.1.1 Resource access

Surface requirements and well densities

Surface disturbances are part and parcel of natural gas development. Land is required to find, develop, produce and transport gas. In addition to the immediate infrastructure forming what is known as the 'well pad', the most common surface level requirements include access roads, utility corridors (e.g. water and electricity lines), transportation and processing units (e.g. gas gathering lines, field compressor stations) and water management facilities. The amount of land necessary for such infrastructure varies principally according to the type of well drilled (shallow or deep; vertical or horizontal; single or multi-pad) and the phase of operation (e.g. exploration, development or completion of the well). The example of Poland is instructive. The total area occupied by existing conventional natural gas fields in Poland amounts to approximately 1 600 square kilometres, comprising 260 deposits ranging in size from 4.6 – 7.6 square kilometres.¹ The current area covered by shale gas exploration licences is much larger, constituting roughly 57 000 square kilometres, or about 20% of Polish territory.² The eventual area that will be submitted to industrial activity will, of course, be much smaller. Thus, there is clearly a distinction to be drawn between land access for exploration, and land access for development and exploitation of natural gas deposits. At the level of an individual well, this is illustrated by figures provided by a US Department of Interior study of gas and oil development in Arkansas.

¹ Source: Deloitte, Arcmap GIS.

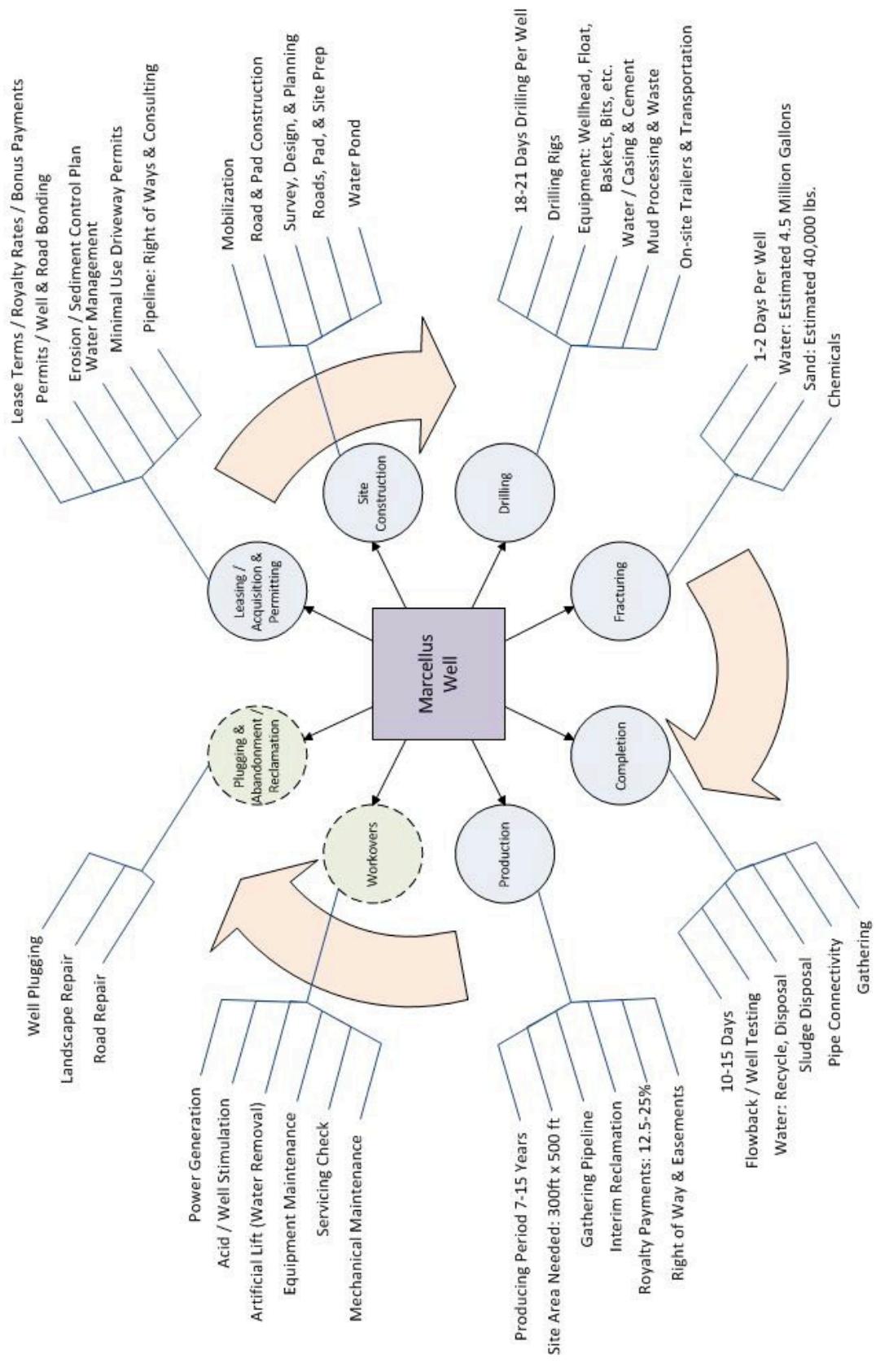
² Advanced Resources International, 'World shale gas resources', V-2, Cleantech, 'Shale Gas Investment Guide', (Warsaw: Cleantech Poland Sp., 2011), 41.

Table 4-1: Surface usage for natural gas well pads and associated facilities, hectares (ha) per well³

	Exploration	Development	Production
Single vertical (<2 000 ft)	0.98	1.93	0.73
Single vertical (5 000-12 000 ft)	1.60	2.72	0.91
Single horizontal	1.39	2.79	0.89
Multi-horizontal (4 wells per pad)	2.69 (0.67 per well)	4.64 (1.16 per well)	1.39 (0.35 per well)

³ Includes size of well pads, access roads, utility and transportation lines and processing units. Bureau of Land Management, 'Arkansas: Reasonably foreseeable development scenario for fluid minerals', (Jackson, MS: Dept of Interior, 2008), 50-55.

Figure 4-1: Phases and key steps in developing a Marcellus shale well⁴

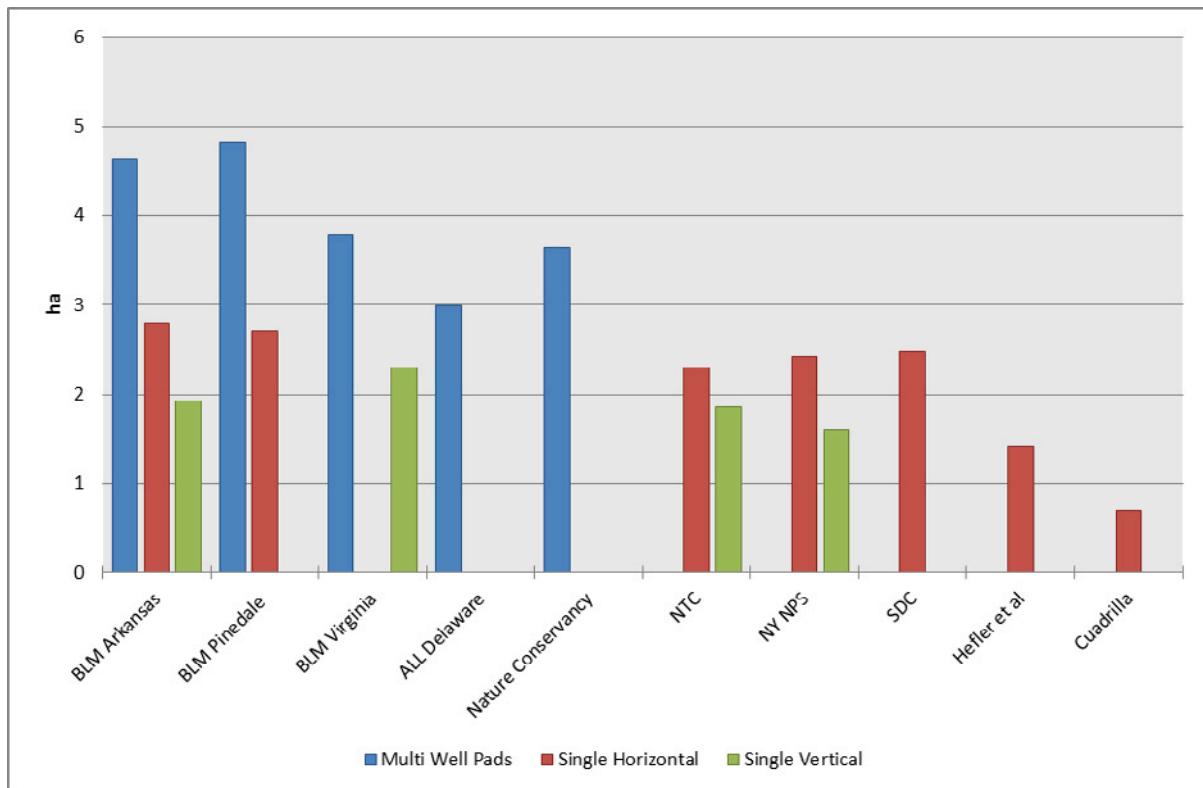


⁴ William E. Hefley et al., 'The Economic Impact of the value chain of a Marcellus shale well', in *Pitt Business Working Papers*, ed. Katz Graduate School of Business (Pittsburgh, PA: University of Pittsburgh, 2011).

The development cycle of a typical horizontal well, together with its economic implications, has been explored by a team of researchers at Pittsburgh University (US). As depicted in Figure 4-1 above, a considerable amount of inputs are necessary to prepare, construct and develop a single drill site. Once all the necessary permitting procedures have been completed, site preparation commences in the form of levelling and access road construction to make way for multiple trucks carrying diverse drilling equipment. Power generators, living quarters with sanitary facilities and security gates must be constructed, in addition to the construction of water pipes and other utility lines. Drilling 'mud' – principally water but also chemicals and additives – must be purchased and transported in order for drilling to commence. Flowback water must be processed, treated and recycled, while casing operations are applied to the wellbore. The fracturing process, once begun in earnest, requires significant and continuous activities in the form of water and wastewater hauling, the construction of water ponds to hold frac fluids and the eventual installation of a gathering system of pipes and compressors to accommodate gas flows from the permanent wellhead. The production life cycle is subject to continuous monitoring and maintenance whilst partial site reclamation operations are initiated. Workover and well stimulation efforts may include additional fracturing operations, which require roughly the same level of initial development activity as the original fracturing process.

As shown in Figure 4-2 below, horizontal well pads require a greater surface area than single vertical wells. This is due to the need for a larger pad to accommodate horizontal drilling equipment, as well as more water management facilities given the necessity to use water-intensive well fracturing technologies during development. Other studies providing estimates of total surface area requirements tend to corroborate the finding that pads containing multiple wellbores occupy the greatest total surface area on a per well-pad basis.

Figure 4-2: Total surface area requirements for developing natural gas wells⁵



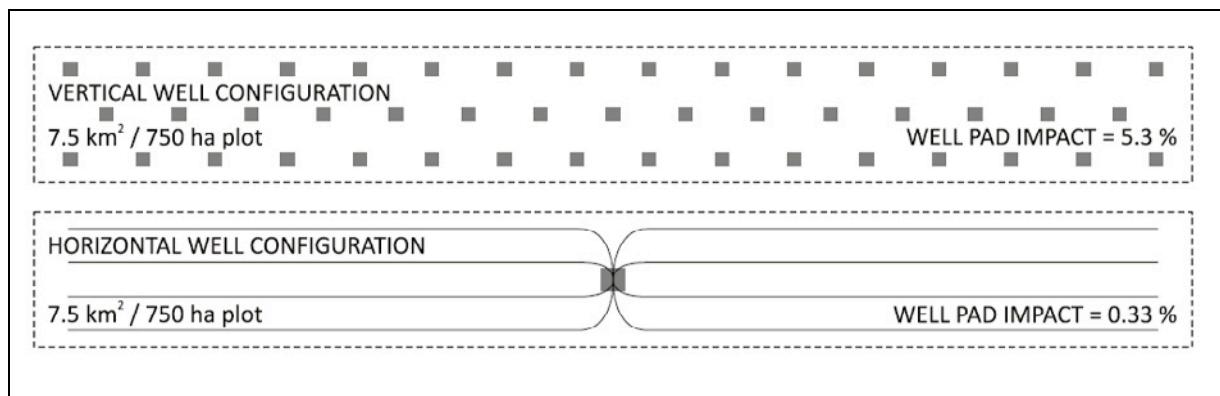
However, a point is often raised that *overall* surface disturbance of multi-well pads is in fact much smaller than for single vertical wells. Indeed, much of the literature on land access for unconventional gas production has highlighted the importance of well spacing, e.g. the maximum area that one well would efficiently and economically extract gas from based on geologic and engineering characteristics.⁶ It is often pointed out that there are different well spacing requirements for horizontal drilling operations that target continuous rock formations rather than conventional reservoirs. Whereas single vertical well pads are said to be spaced at 16 sites per square mile, single horizontal pads, by virtue of accessing longer subsurface laterals, can reduce this figure to approximately nine pads per square mile. Further reduction can be attained by

⁵ Robert M. Anderson, 'Environmental Assessment of Southwestern Production Corp's proposed 8 well horizontal drilling programme in the Hornbuckle Field, Wyoming', (Casper, WY: Anderson Environmental Consulting, 2009); Arthur and Bockelmann, 'Analysis of Proposed Article 7', Bureau of Land Management, 'Arkansas'; Bureau of Land Management, 'Reasonably Foreseeable Development Scenario for Oil and Gas for the George Washington National Forest Virginia and West Virginia', (Jackson, MS: Dept of Interior, 2011); Bureau of Land Management, 'Surface Disturbance associated with Oil and Gas Activities', in *Draft Resource Management Plan for Pinedale, Wyoming* (Jackson, MS: Dept of Interior, 2007); Cuadrilla Resources, 'Economic Impact of Shale Gas Exploration & Production in Lancashire & the UK', (Altrincham, Cheshire: Regeneris Consulting, 2011); Hefley et al., 'Economic Impact', Nels Johnson et al., 'Marcellus Shale Natural Gas and Wind', in *Pennsylvania Energy Impacts Assessment* (Arlington, VA: The Nature Conservancy, 2010); National Park Service, 'Potential Development of the Natural Gas Resources in the Marcellus Shale New York, Pennsylvania, West Virginia, and Ohio', (Denver, CO: Department of the Interior, 2008); NTC Consultants, 'Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in Marcellus Shale and Other Low-Permeability Gas Reservoirs, Final Report Prepared for NYSERDA', (Saratoga Springs, NY 2009).

⁶ In the United States, minimum well spacing requirements are determined by state and local authorities; in some cases, however, these regulations have not adapted to the characteristics of horizontal wellbores, whose lateral length can reach up to 3 000 metres.

constructing a multi-well configuration in which six to eight (or possibly more) wells are drilled from a single pad.⁷ This can yield well densities as low as one per square mile. Based on these assumptions, a Supplemental Generic Environmental Impact Assessment (SGEIS) for the Marcellus shale play by the New York State Department of Environmental Conservation (NYSDEC) concludes that 'there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical well'.⁸ This difference is largely explained by the reduced need for individual well pads and associated access roads, gathering lines and other utility corridors (as illustrated in Figure 4-3 below).

Figure 4-3: Theoretical well densities of vertical and multi-well horizontal pads⁹



However, there is a point of contention in the literature concerning the extent to which multi-well pad drilling actually reduces overall surface disturbance associated with gas development and production. Indeed, most of the above figures on shale gas well spacing are ultimately derived from a single consulting firm, which has published several reports presenting essentially the same data.¹⁰ A caveat is therefore in order about the assumptions made regarding reduced well density and surface disturbance brought about by multi-well horizontal drilling. Indeed, another set of literature has argued that, though it may be the case that multi-well pad spacing begins at one site per square mile, this does not preclude vertical infill drilling between such areas.¹¹ The US case demonstrates that once an area proves to be commercially viable, there is a tendency for firms to perform infill drilling, creating what is known as 'downspacing'. As one report points out, "spacing histories of the Barnett, Fayetteville, Antrim, New Albany, Ohio and Woodford shales all trend from larger to smaller spacing units. For the Marcellus Shale, it is reasonable to expect 320-acre [130 ha] or 160-acre [65 ha] spacing initially and eventually some areas experiencing infill drilling to 80-acre [32 ha] or even

⁷ J. Daniel Arthur et al., 'Hydraulic Fracturing Considerations for Natural Gas Wells of the Fayetteville Shale', (Tulsa, OK: ALL Consulting, 2008).

⁸ New York State Department of Environmental Conservation, 'Draft SGEIS'.

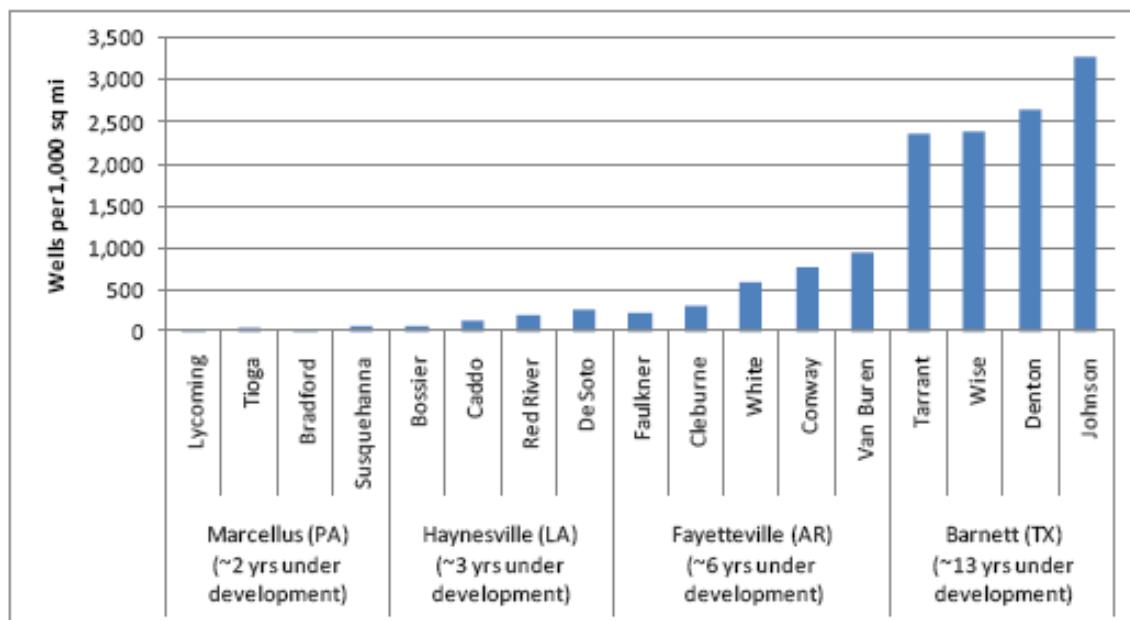
⁹ Matthew D. Alexander et al., 'Considerations for Responsible Gas Development of the Frederick Brook Shale in New Brunswick', (Saint John, NB: Fundy Engineering and Atlantica Centre for Energy, 2011).

¹⁰ ALL Consulting, 'Modern Shale Gas development'; Arthur and Bockelmann, 'Analysis of Proposed Article 7'; Arthur et al., 'Hydraulic Fracturing Considerations'; J. Daniel Arthur and Dave Cornue, 'Technologies Reduce Pad Size Waste', *American Oil and Gas Reporter* 2010, August edition (2010). Reports that draw heavily on this literature include Alexander et al., 'Considerations for Responsible Gas Development', New York State Department of Environmental Conservation, 'Draft SGEIS'; Wood et al., 'Shale gas provisional assessment'.

¹¹ NTC Consultants, 'Impacts on Community Character', 7.

40-acre spacing [16 ha] should infill drilling be economic.”¹² This is corroborated by other reports citing common spacing of one well every 40-160 acres (16-65 ha).¹³ Figures from a recent EIA Report on emerging shale plays in the USA show a range of 2-11 wells per square mile, with a mean of 6.5.¹⁴ The figure below indicates that well densities in shale plays do indeed *increase* over the course of development. Moreover, due to more dispersed ‘gas in place’ for shale plays, one report notes that, “with shale gas plays covering large areas and requiring a greater number of wells drilled more closely together compared with conventional fields, this implies a greater surface footprint over a wider area for shale gas.”¹⁵

Figure 4-4: Current well density in US counties of comparable shale gas plays, 2009¹⁶



Duration and intensity of well drilling

The argument that multi-well pad horizontal drilling reduces surface disturbance is based on a calculation of total surface area and average well spacing which, by themselves, do not necessarily serve as sufficient indicators for overall land use requirements. A more comprehensive method would consider both the duration and intensity of drilling and completion activities. Due account must be taken of factors such as water consumption, truck trips, noise levels and visual impacts, all of which may significantly affect the land access issue, particularly in Europe.

The duration of development for a multi-well pad differs significantly according to the number of wells drilled. Many drilling activities, such as fracking or clean-up operations,

¹² National Park Service, ‘Potential Development of Marcellus Shale’; Joel Parshall, ‘Barnett Shale Showcases Tight-Gas Development’, *Journal of Petroleum Technology* September (2008): 55; Lisa Sumi, ‘Shale Gas: Focus on the Marcellus Shale’, (Washington, DC: Earthworks, 2008), 18.

¹³ Of course, there are spacing arrangements as high as one per square mile; ALL Consulting, ‘Modern Shale Gas development’; National Park Service, ‘Potential Development of Marcellus Shale’; Sumi, ‘Shale Gas’.

¹⁴ See INTEK, ‘Review of emerging resources’, Appendix B.

¹⁵ Howard Rogers, ‘Shale Gas - the unfolding story’, *Oxford Review of Economic Policy* 27, no 1 (2011): 128.

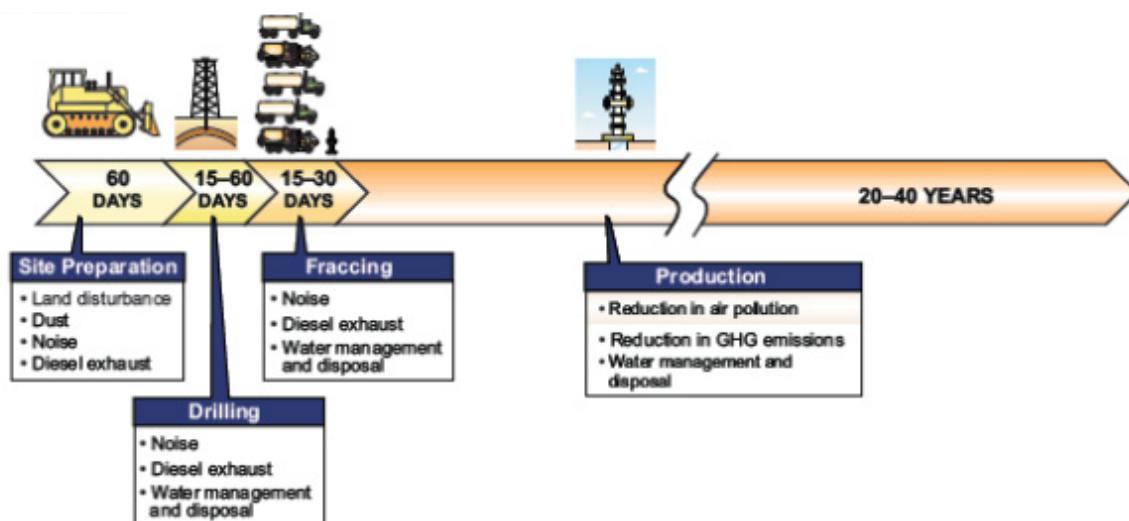
¹⁶ Hazen and Sawyer, ‘Final Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed’, (New York, NY: New York City Department of Environmental Protection, 2009), 23.

can only be carried out for one well at a time; thus, the greater number of wells, the longer pre-production operations are liable to take. Since drilling and completion activities are also contingent on a number of geological, logistical and regulatory factors, estimates of their duration tend to vary. Moreover, whereas some studies provide figures for the total amount of time necessary to develop an entire well-pad (e.g. including the construction of access roads and utility lines), others focus on the duration of drilling and fracking activities. Table 4-2 below summarises the figures provided by these various reports. Despite these differences, a point of agreement in the literature rests on the fact that drilling horizontally generally takes around double the amount of time as for a vertical well.¹⁷

Table 4-2: Duration of drilling and completion activities

Source	Duration	Type
Wood et al. (2011)	500-1 500 days	6-well pad
Downey (2010)	Up to 18 months	Multi-well + pad
Energy Resources Conservation Board (2011)	12-36 months	Multi-well + pad
New York State Department of Environmental Conservation (2009)	6-13 months	Single horizontal well + pad
Cuadrilla Resources (2011a)	6-8 months	Single horizontal well + pad
Hazen and Sawyer (2009)	4-10 months	Single horizontal well + pad
ICF International (2009)	2-4 months	Single horizontal well
Anderson (2009)	2 ½ months	Single horizontal well
NTC Consultants (2009)	1-2 months	Single horizontal well

Figure 4-5: Timeline for shale gas development and production (single well)¹⁸



The duration of drilling for each horizontal well is particularly important in the case of Europe, which has far fewer active land-based gas drilling rigs than the USA. This means that should several shale gas plays in different countries be deemed commercially viable, competition over bookings for well drilling can become a crucial developmental bottleneck. In addition, one overlooked point in determining well drilling times is the

¹⁷ NTC Consultants, 'Impacts on Community Character', 18.

¹⁸ Downey, 'Fueling North America's future'. It must be borne in mind that the life-span of a shale gas well is yet unknown, and that various estimates have been presented in the literature study.

delay caused by force majeure, both in terms of surface level disturbances (e.g. weather-related delays) or unforeseen sub-surface difficulties. Indeed, Cuadrilla Resources experienced all of these developmental bottlenecks whilst attempting to build a test well in Lancashire.¹⁹

In New York state, the regulatory limit on well drilling activity per site is three years, which is indicative of the maximum time it may take for a single site to experience drilling and completion activities.²⁰ It is also important to consider that within this span some pads may not be fully developed in one consecutive period of time. According to a consultancy report for the New York State Energy Research and Development Authority (NYSERDA), operators may drill one or two wells on a pad to determine its productivity before deciding to drill the remaining wells; the decision to further develop a site may also be contingent on favourable market conditions.²¹ Finally, if re-fracking or other stimulation and workover efforts are deemed necessary to prolong the life-span of a well, a renewed period of intense development activity may occur several months after the production phase has started. Thus, given that six to ten wells are expected to be required to fully exploit the natural gas resources in a 640-acre spacing unit, it is reasonable to expect that a given well site will be undergoing a relatively high and constant level of industrial activity for at least one and up to three years.²² Thereafter, one study maintains that drilling operations 'continue for the whole field life and they are required to maintain the production plateau'.²³

Shale gas development requires heavy truck traffic to and from the site for this period of time. Few figures on the intensity of road traffic during well construction are available. One of the few original estimates available stems from NYSDEC, which estimates approximately 4 300-6 600 truck visits for a multiple horizontal well-pad in the development phase of a shale gas project.²⁴ For single horizontal well pads, a related analysis carried out for NYSERDA estimates two scenarios of 1 420 and 2 000 truck trips.²⁵ The majority of this transportation activity is for water and wastewater hauling during the development and fracking phase, which is relatively unique to shale gas development. The report concludes that because of this "the truck traffic associated with drilling a horizontal well with high-volume hydraulic fracturing is 2 to 3 times higher than the truck traffic associated with drilling a vertical well."²⁶ In terms of the timeframe of trucking activities, the table below shows the daily distribution of traffic over a 50-day period during initial well pad development of horizontal/vertical wells. However, it has been argued that the marked increase in truck traffic for horizontal

¹⁹ Cuadrilla Resources, 'Planning Application for Preese Hall Exploration Site: Temporary Planning Permission for a Hydrocarbon Exploration Borehole', (Lichfield, West Sussex: 2011).

²⁰ New York State Department of Environmental Conservation, 'Draft SGEIS', 3-4, 5-30. The Tyndall Centre's report uses NYSDEC figures to arrive at a duration of 500-1 500 days for all operations prior to production of a six-well pad. It is unclear how these figures were calculated. Wood et al., 'Shale gas provisional assessment'.

²¹ ICF International, 'Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs', (Albany, NY: New York State Energy Research and Development Authority, 2009), 9.

²² New York State Department of Environmental Conservation, 'Draft SGEIS', Section 4.

²³ M. Guarino et al., 'An unconventional mindset for shale gas surface facilities', *Journal of Natural Gas Science and Engineering* 6 (2012).

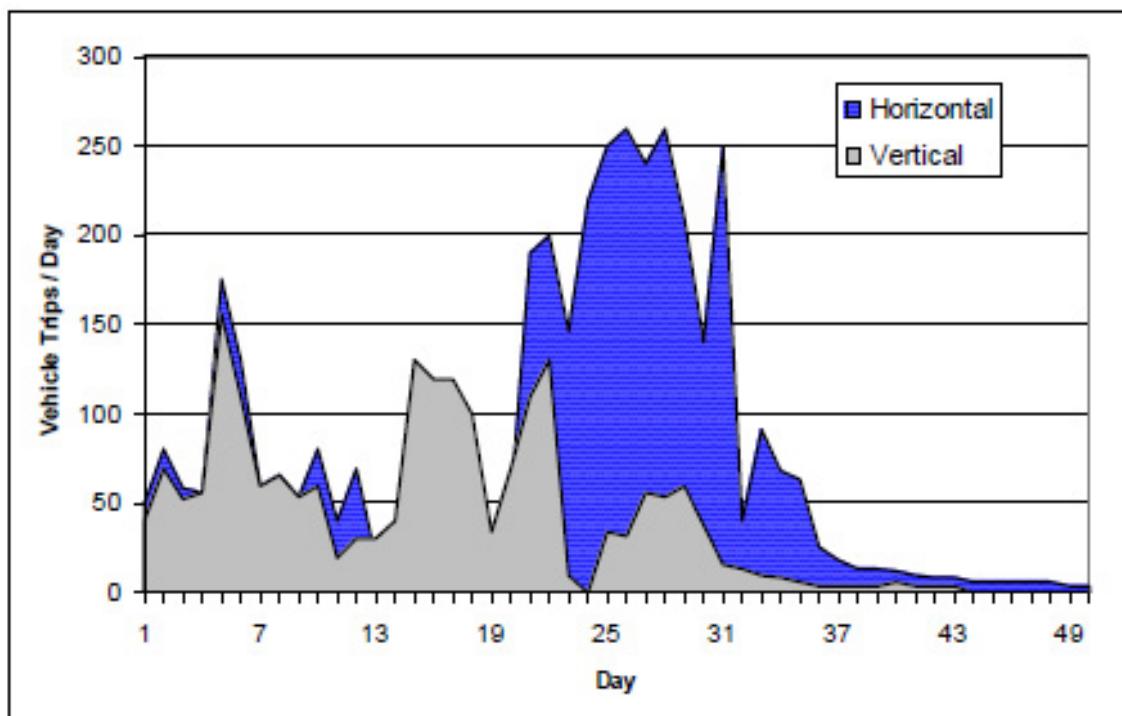
²⁴ Wood et al., 'Shale gas provisional assessment', 24.

²⁵ NTC Consultants, 'Impacts on Community Character', 13.

²⁶ New York State Department of Environmental Conservation, 'Draft SGEIS', 6-301.

wells would be offset by the fewer number of pads necessary to develop a given shale play, given that rigs and equipment would only need to be delivered and removed one time for the drilling and stimulation of all the wells on a given pad.²⁷ This argument, however, can be contested by the earlier reference made to the practice of drilling one or two wells to determine productivity before further developing a well site.

Figure 4-6: Estimated daily heavy and light truck round-trip traffic by well type²⁸



Two additional issues associated with land use intensity and lengthier construction periods are noise and visual impacts. Noise sources, which are most prominent during the drilling phase, include various rigging operations, pipe handling, compressors and operations of trucks, backhoes, tractors and cement mixing. In most cases, moderate to significant noise impacts may be felt within 300 metres of a well site.²⁹ In more highly developed or more densely populated areas, these noise impacts may serve as constraints to the 24-hour drilling activity that is typical for several weeks during the drilling phase of a single horizontal well. In any case, noise impacts are best mitigated through well site location and design. As for visual impacts, it is common for horizontal drilling rigs to reach over 40 metres, compared with 10-30 metres for conventional vertical well-drilling equipment and for their substructure to occupy a larger surface area.³⁰ Thus, although the noise and visual impact stemming from horizontal drilling are both larger and lengthier than those arising from vertical well construction, the theoretically reduced number of well-pads for a given spacing unit may offset the discrepancy. There are other technological developments that have been identified as potential mitigating factors on future levels of surface disturbance; for example, reuse of

²⁷ Ibid., 6-304.

²⁸ Ibid.

²⁹ NTC Consultants, 'Impacts on Community Character', 15.

³⁰ Ibid., 18.

water that can reduce the requisite trucking or horizontal drilling technology that allows a certain level of flexibility in pad placement.³¹

Associated infrastructure

Beyond the immediate surface-level requirements for constructing and operating a shale gas well pad, it is also necessary to consider the surrounding infrastructure necessary to support potentially large-scale development of a much wider area. As one report notes, large scale development of shale gas resources in a continuous play requires facilities to support high-volume hydraulic fracturing (e.g. water withdrawal, storage and treatment facilities). Besides the access roads and utility lines required for individual well pads, it is necessary to develop gas gathering systems, offsite production and processing facilities, and transmission lines, as well as 'other activities to bring the gas resource into production...on a more consolidated and centralized basis because of the overall vision for development and the potential for achieving economies of scale'.³² Depending on the proximity to areas of gas demand, drilling companies may opt either to construct additional pipelines to connect into the main gas pipeline network or create on-site electricity generation which is then connected to the grid. According to a report commissioned by Cuadrilla Resources UK, "under either approach a substantial body of additional labour and equipment is required to put in place the necessary infrastructure, which will grow in scale as the number of wells in any one location increases."³³

In comparative terms, the dearth of upstream onshore gas production infrastructure in Europe is commonly identified as an impediment to large-scale shale gas production.³⁴ In the USA, by contrast, two of the larger shale plays are overlaid by extensive gas transport and processing infrastructure (e.g. in New York and Texas, respectively) owing to these states' previous historical development of conventional gas resources. Even in these well-developed markets, necessary investments in mid-stream infrastructure to support additional gas production have incurred significant additional costs. For example, construction of gas gathering systems and processing facilities constituted 15% of industry spending by Marcellus gas producers in Pennsylvania in 2009.³⁵

A recent study on the surface facilities needed to accommodate shale gas production in Europe makes the valid point that the identification of sweet spots on the basis of geological and reservoir parameters alone may not sufficiently reflect the optimal location for shale gas extraction.³⁶ Rather, a 'multi-disciplinary' mindset is required for anticipating the need for transport and processing infrastructure, as well as the surface-level restrictions brought about by environmental or other land use regulations. These issues of surface-level downstream transport capacity will be taken up in Section 4.2 through a discussion of pipeline transmission and distribution grid density.

³¹ Ibid., 26.

³² Ibid., 4. This type of centralised infrastructure roll-out also importantly affects the commercial viability of a given play.

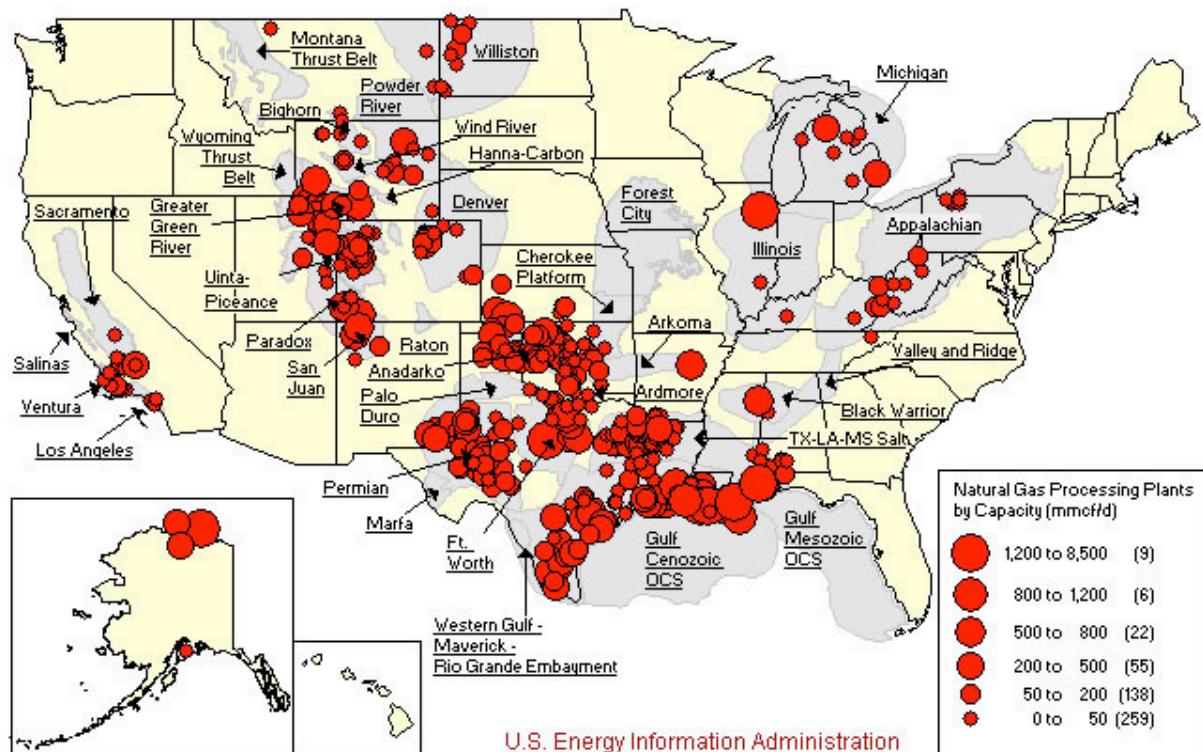
³³ Cuadrilla Resources, 'Economic Impact in Lancashire'.

³⁴ 'Memorandum submitted by Shell' in House of Commons, 'Shale Gas: Fifth Report of Session 2010-12', ed. Energy and Climate Change Committee (London: House of Commons, 2011), points 17, 19 and 21.

³⁵ Timothy J. Considine, Robert Watson and Seth Blumsack, 'The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update', (Altoona, PA: Pennsylvania State University, 2010), 5.

³⁶ Guarnone et al., 'Unconventional mindset'.

Figure 4-7: Natural gas processing plants and production basins in the USA, 2009³⁷



Cumulative impacts

This section has presented the land access requirements for shale gas development in a bottom-up manner by employing a per well approach. However, in order to adequately consider shale gas surface requirements and associated land access issues, it is necessary to consider the *cumulative impact* of several horizontal wells being drilled annually over a longer period of development. Cumulative impacts are the effects of two or more single projects considered together. Since some countries may have considerable quantities of the resource, some studies have speculated on the cumulative effects of large-scale build-outs. For example, a recent study of potential shale gas development in the UK has provided an estimate of the resources required to produce 10% of UK gas consumption from shale; it argues that, "to sustain this level of production for 20 years in the UK would require around 2,500-3,000 horizontal wells spread over some 140-400km² and some 27 to 113 million tonnes of water."³⁸ Such a large-scale activity, with multiple rigs operating at the same time in a continuous area, may lead to a number of potentially negative impacts on water quality, land use, wildlife and natural resources, agriculture, tourism and the overall quality of life in a community. These impacts, of course, may differ depending on the scale of development which, as Section 4.1.2 will address, can be monitored or potentially restricted by the regulatory regime in place. Whatever rules are in place, it is important to recognise that cumulative impacts could be considered excessive, even when individual operators meet or even exceed regulatory requirements. Indeed, "the *combination* of impacts from

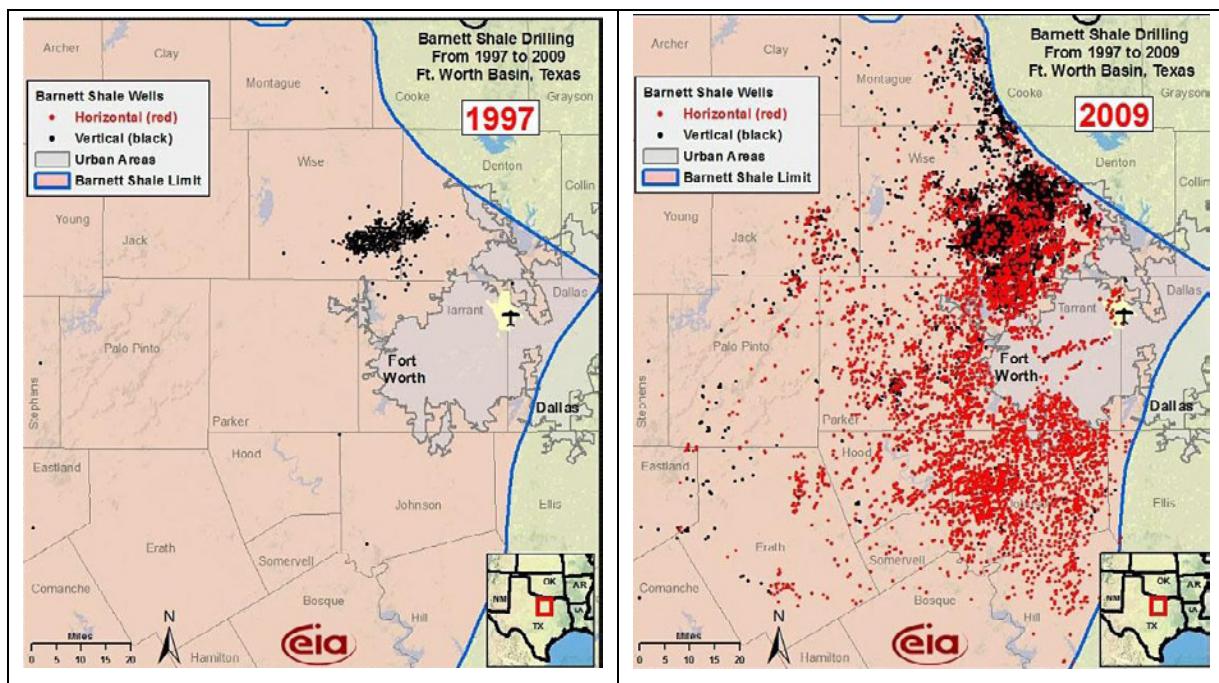
³⁷ EIA, 'Natural Gas Processing Plants in the United States: 2010 Update', (Washington, DC: 2011).

³⁸ Wood et al., 'Shale gas provisional assessment', 53.

multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.”³⁹

For Europe, what would be the cumulative impact of a large-scale roll-out of unconventional gas development and production? A birds-eye view of the most productive shale plays in the USA may be an instructive analogue. Indeed, comparing the two maps below of the Barnett Shale in Texas illustrates the scale of development currently in operation.

Figure 4-8: Barnett Shale drilling in 1997 and 2009, Ft. Worth Basin, Texas, USA⁴⁰



However, several ‘positive’ factors would likely militate against such a large-scale build-out in Europe, principal among which is the improvement in technology that allows for multi-well pad drilling. Other technological developments, such as efficiency gains acquired through refined fracking and water management techniques, as well as improved seismic evaluation methods that avoid the need to drill multiple test wells, may alter the degree of surface-level disturbance as fewer sites with less lengthy well construction activities become the norm.⁴¹ This issue of technological learning and its impact on future development activities is further explored in Chapter 3 and Section C.4 of the Annexes.

4.1.2 Regulatory framework

This section will consider the most common issues identified in the literature regarding the spatial constraints to shale gas development, with a particular focus on Europe. A successful regulatory regime governing the exploitation of any sub-surface mineral must reconcile the objectives of three main sets of actors: governments, with their

³⁹ Subcommittee on Shale Gas Production, ‘The SEAB Shale Gas Production Subcommittee Ninety-Day Report’, (Washington, DC: Secretary of Energy Advisory Board, 2011).

⁴⁰ Richard Newell, ‘Shale Gas and the Outlook for US Natural Gas Markets and Global Gas Resources’ (paper presented at the Organization for Economic Co-operation and Development Paris, 2011).

⁴¹ Gény, ‘Unconventional Gas’, 60.

desire to maximise rents while achieving socioeconomic objectives; market players and their desire for a return on investment that is consistent with the risk associated with the project; and finally, the needs of societal actors to preserve or improve welfare in social, monetary or environmental terms.⁴² The regulatory framework must accommodate these overlapping spheres of interest that often may conflict with one another (see Figure 4-9). This is largely because the three sets of actors tend to use different criteria for evaluating their respective needs. For example, societal actors will judge the desirability of shale gas development from the point of view of welfare effects and related indicators, such as the provision of public goods or the environmental impact of gas drilling, whereas market actors will assess their investments on the basis of the net present value of assets or the internal rate of return for a given project. Regulatory frameworks governing hydrocarbon production must balance these interests so as to encourage investment, prevent environmental degradation and distribute the gains (and losses) of shale gas development fairly.

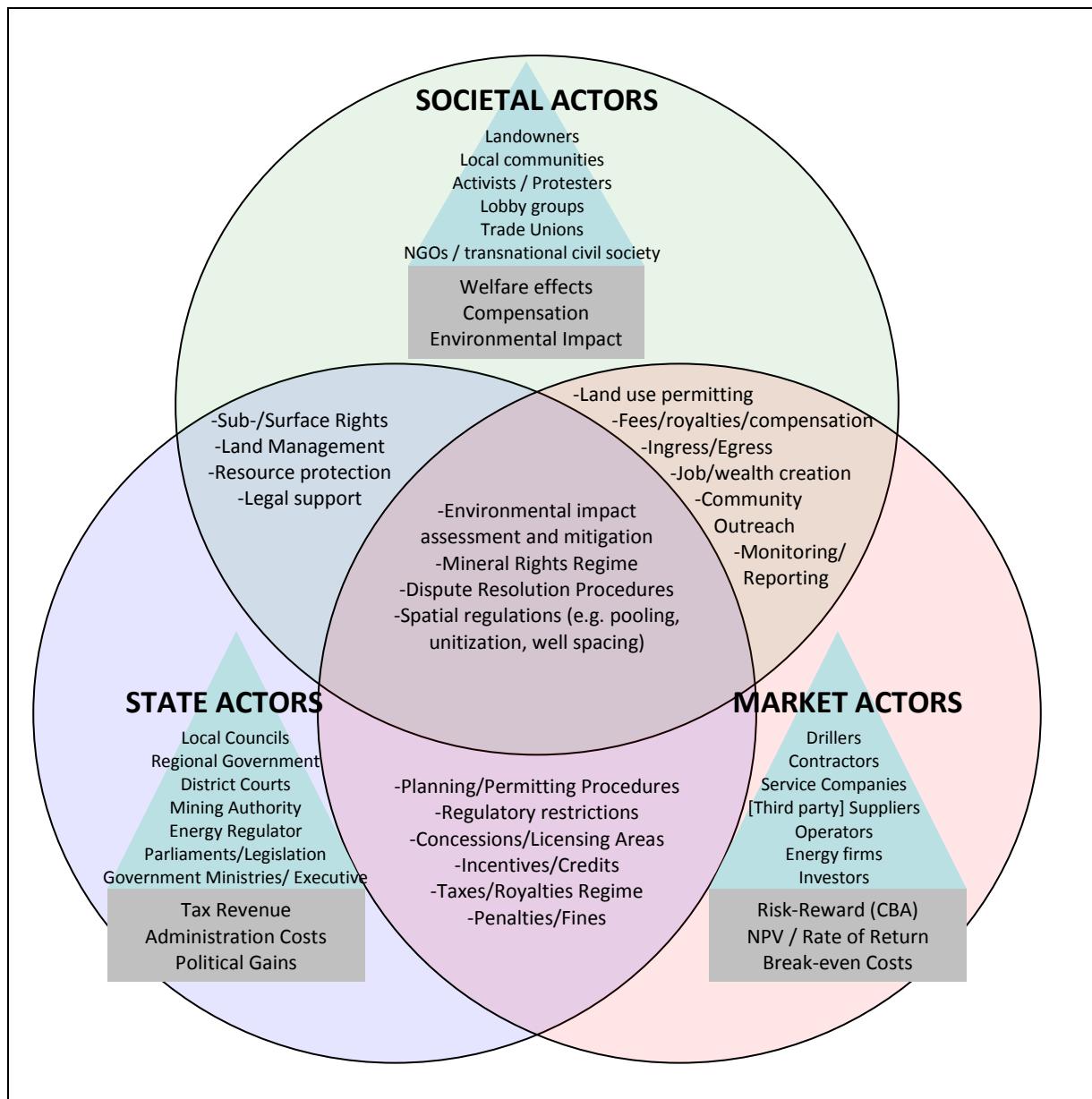
In most European countries – particularly those with indigenous hydrocarbon production – there exists a raft of regulations and procedures governing the various operations associated with sub-surface mining activities. Given the partial degree of overlap between conventional and unconventional gas development, several of the legal regimes in place apply to activities associated with the latter. There are, of course, regulatory challenges unique to unconventional gas. Additional national and EU legislation may apply to activities associated with advanced well stimulation techniques, such as that governing water management and the use of chemicals.⁴³ However, detailing the requisite EU, national and local permits, concessions, licences and potential gaps in legislation for each European country is beyond the scope of this section. A preliminary investigation of these issues has been provided by a legal study commissioned by DG ENER.⁴⁴ However, it is important to note that this study did not assess the applicable EU requirements and covered permitting and licensing requirements in a limited number of Member States (DE, FR, PL and SE); further legal assessment is on-going in the frame of a study commissioned by DG ENV. Drawing on this and other literature, it is useful to highlight the key points that have been raised in relation to surface accessibility for shale gas development. These regulatory issues can be broadly summarised according to their technical/logistical, legal and socioeconomic dimensions.

⁴² Adapted from Silvana Tordo, 'Fiscal Systems for Hydrocarbons, WP 123,' in *World Bank Working Paper* (Washington, DC: World Bank, 2007).

⁴³ See Stefan Lechtenböhmer et al., 'Impacts of shale gas and shale oil extraction on the environment and on human health', (Brussels: European Parliament, 2011).

⁴⁴ Philippe & Partners, 'Unconventional Gas in Europe'.

Figure 4-9: Key elements of an unconventional gas regulatory framework⁴⁵



Technical/logistical issues

Once a prospective drilling area is deemed commercially viable, companies must secure a concession and a right to drill from the owners of the mineral resources (which are usually administered in Europe by state departments – e.g. mining authorities or equivalent). At the same time, drillers must also acquire consent to access the surface area overlaying the shale gas play; this involves negotiations with local authorities as well as private landowners.

According to Florence Gény, there are three methods whereby land can be accessed in Europe, namely through negotiating a fee for renting the land, a compulsory purchase

⁴⁵ Based on analysis by ALL Consulting, 'Modern Shale Gas development'; Sally Kornfeld, 'Socio-Economic Considerations in Shale Gas Development' (paper presented at the Atlantic Council Meeting, 2011); New York State Department of Environmental Conservation, 'Draft SGEIS'; Tordo, 'Fiscal Systems for Hydrocarbons'.

by government (or, in extreme cases, via eminent domain) or through acquisition of the land by the drilling company.⁴⁶ Gény claims that concessions granted by European governments are small, with one block generally comprising 2.6 km², making it highly difficult to conduct exploration activities.⁴⁷ However, it is unclear how this figure has been calculated and there may in fact be much variation hidden behind such a generalisation. For example, a report on shale gas by the British Geological Survey notes that the UK uses 100km² blocks in its licensing rounds (the most recent 13th Onshore Licence Round awarded 55 new licences covering more than 7 000 km²).⁴⁸ In Poland, too, the rule is that a single concession cannot exceed an area of 1 200 km², but even here there is no limit as to the number of concessions one entity can hold.⁴⁹

Nonetheless, even such larger dimensions for concession holders may not be sufficient to evaluate shale gas plays to the scale witnessed in the US case. A report by IHS CERA contrasts a typical 240 km² concession block in Europe with a single US operator's concession area in the Fayetteville shale covering over 3 500 km².⁵⁰ This has a bearing on the amount of landowners that drilling companies must engage with in order to secure access to land, not only for purposes of drilling but also for play evaluation and thoroughfare (for example, extensive use of access roads). Indeed, since open agricultural areas are the most likely candidates for shale gas drilling, it has been noted that the size of farming plots in Europe are much smaller than in the USA.⁵¹ Returning to the example of Poland, most farms are 10-20 hectares in size, meaning that drillers will 'have to engage several landowners for permission to construct a drilling pad and the type of factory-scale production where well pads are placed at regular intervals is impossible'.⁵² This is compounded by the oft-repeated point that exploration for shale gas requires a much larger initial surface area than for conventional gas. Indeed, it is of crucial importance to locate a shale play's 'sweet spots' from which the gas can be extracted under the most favourable geological conditions.

Moreover, in this context comparisons are often made between the population densities surrounding US shale formations versus those found in Europe. It is commonly argued that the comparatively low population density in the United States is particularly amenable to land-intensive exploration and drilling operations.⁵³ To make this point, many studies are content to overlay national spatial population density data with prospective shale plays or compare the population densities of US states with those of

⁴⁶ Gény, 'Unconventional Gas'.

⁴⁷ Ibid.

⁴⁸ Harvey and Gray, 'Unconventional resources of Britain'.

⁴⁹ Ewa Zalewska, 'The Concession granting policy for prospecting, exploration and production of hydrocarbons in Poland', *Przeglad Geologiczny* 55, no 12/1 (2007).

⁵⁰ IHS CERA, 'Gas from Shale: Potential Outside North America?', (Cambridge, MA: IHS CERA, 2009).

⁵¹ Centrica Energy, 'Unconventional Gas in Europe: Response to DECC Consultation', (Windsor: 2010), House of Commons, 'Shale Gas: Fifth Report of Session 2010-12', ed. Energy and Climate Change Committee (London: House Of Commons, 2011). This document contrasts the average farm size of 12 ha in Poland with 160 ha or 210 ha in Oklahoma and Texas, respectively; see also Gény, 'Unconventional Gas', 74.

⁵² Cleantech, 'Investment Guide', 59.

⁵³ Rick Carr and Chuck Chakravarthy, 'Natural Gas: Revoluton or evolution', (New York, NY: Deloitte Development LLC 2011); Centrica Energy, 'Unconventional Gas in Europe'; Gény, 'Unconventional Gas'; Andreas Korn, 'Prospects for unconventional gas in Europe', (Düsseldorf: E.ON, 2010); Maximilian Kuhn and Frank Umbach, 'Strategic Perspectives of Unconventional Gas: A Game Changer with Implications for the EU's Energy Security', in *EUCERS Strategy Paper*, ed. European Centre for Energy and Resource Security (London: Department of War Studies, King's College London 2011); Stevens, 'Hype and reality'.

several European countries.⁵⁴ This kind of coarse analysis, however, does not provide a rigorous insight into the bottom-up prospects for shale gas development for a given area. Indeed, as one of these studies freely admits, "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."⁵⁵

Given these technical and logistical constraints in Europe, an important consideration reveals itself – namely how to manage multiple landowners and their varying claims to restrict and/or require compensation for accessing their property. This constitutes one of the key factors highlighted by Centrica, an energy firm, in its assessment of the potential for unconventional gas development in Europe.⁵⁶ It is all the more pertinent given the additional need for extensive utility line placement in the context of local opposition to any activities that may potentially spoil landscapes or require extensive excavation activities.

Legal issues

The literature on shale gas development prospects often notes that European and US land ownership rules differ; whereas in the latter, landowners own both surface and mineral rights, in the former, sub-surface rights are generally owned by the state.⁵⁷ The argument runs that mineral rights regimes in European countries pose greater challenges for drilling because surface owners are not entitled to royalties or 'signing bonuses' and hence have little incentive to support shale gas development.⁵⁸ However, this argument may obscure the complexity of mineral rights in the USA, which are governed by myriad state laws and where "the leases, sales, gifts and bequests of the past have produced a landscape where multiple persons or companies have a partial ownership of or rights to many real estate parcels."⁵⁹ Particularly in areas where there has been extensive historical oil and gas development (e.g. the Barnett and Marcellus shales) it is common for the mineral and surface estates to be owned by different people (e.g. a 'split estate').⁶⁰ This phenomenon may be under-reported because "the extent of severed rights is very difficult to estimate empirically because of the lack of easily accessible records."⁶¹

Thus, the real distinction between US and European land access rights is not necessarily ownership but rather the degree to which surface landowners have a say in granting permission to develop an area. In the USA, state and local laws tend to favour the holder of the mineral estate. Indeed, where split estates exist in Texas, surface owners must allow the holder of the mineral estate to "freely use the surface estate to the extent reasonably necessary for the exploration, development and production of the oil and

⁵⁴ Gény, 'Unconventional Gas'; House of Commons, 'Shale Gas: Fifth Report of Session 2010-12'; Roderick Keffeputz, 'Shale Fever: Replicating the US gas revolution in the EU? CEPS Policy Brief no 210', (Brussels: Centre for European Policy Studies, 2010); Stevens, 'Hype and reality', 16.

⁵⁵ Gény, 'Unconventional Gas'.

⁵⁶ Centrica Energy, 'Unconventional Gas in Europe'.

⁵⁷ Gény, 'Unconventional Gas'.

⁵⁸ Harvey and Gray, 'Unconventional resources of Britain', 30, House of Commons, 'Shale Gas: Fifth Report of Session 2010-12', 28.

⁵⁹ geology.com, *Mineral Rights* (cited).

⁶⁰ Anthony Andrews et al., 'Unconventional Gas Shales: Development, Technology, and Policy Issues', (Washington D.C.: Congressional Research Service, 2009), 27.

⁶¹ David Kay, 'The Economic Impact of Marcellus Shale Gas Drilling. What Have We Learned? What are the Limitations?', in *Working Paper Series* (Ithaca, NY: Cornell University, 2011).

gas under the property.⁶² This includes comprehensive access to the land for carrying out seismic tests, drilling wells, building roads and utility lines and so on. Similar laws exist in other US states, under which surface owners must provide reasonable access to the land in exchange for the right to protection from “unreasonable encroachment and damage” and compensation for the use of the surface.⁶³

In Europe, by contrast, there seems to be some confusion as to the extent to which surface landowners can restrict the development of shale gas. A legal study on shale gas development in Europe commissioned by the EU does not provide a clear answer. On the one hand it claims that property owners may not be “willing to permit a company on to its land if he is not being compensated by a financial incentive” yet elsewhere in the same report it is stated that such consent from landowners is unnecessary for the exploration and exploitation of state-owned sub-surface minerals.⁶⁴ Whereas some studies state that land owners can be a significant hindrance to shale gas drilling operations⁶⁵, others argue that “hydrocarbons are mostly nationalized, so there is no need for gas firms to negotiate with many different landowners (though the owner of the site of the actual drilling pad will surely need compensation).”⁶⁶

This confusion may stem from the variable importance assigned to landowner consent in different Member States. Under French law, for example, the Mining Code stipulates that any holder of an exploration licence is entitled to conduct all necessary prospection activities regardless of whether the surface owner lends his consent to such activities.⁶⁷ In the UK, by contrast, it is stated that ‘the rights granted by landward licenses do not include any rights of access, and the onus is upon the licensee to obtain all the relevant planning permissions from the respective authorities and landowners’.⁶⁸ Moreover, a court case has laid a precedent for requiring permission from landowners under whose land a horizontal section of a gas well passes.⁶⁹ In particular the court ruled that ‘the owner of the surface is the owner of the strata beneath it, including the minerals that are to be found there, unless there has been an alienation of them by conveyance, at common law or by statute, to someone else’.⁷⁰ In Poland, the authorisation holder always needs to have approval from the concerned land owners as a *conditio sine qua non* before any authorisation can be granted.⁷¹

Drilling companies and regulators in the USA have addressed the problem of obtaining access from multiple landowners by initiating what is known as unitisation and pooling.⁷² These processes both involve negotiations with multiple landowners for receiving a pro-rated share of royalties based on their respective acreage overlaying the gas reservoir. While pooling refers to the combination of several small tracts of land to

⁶² Texas Railroad Commission, 'Oil & Gas Exploration and Surface Ownership', (Austin, TX).

⁶³ Andrews et al., 'Unconventional Gas Shales'.

⁶⁴ Philippe & Partners, 'Unconventional Gas in Europe', 8 and 26, respectively.

⁶⁵ Gény, 'Unconventional Gas'; Kuhn and Umbach, 'Strategic Perspectives'; Stevens, 'Hype and reality'.

⁶⁶ Ridley, 'Shale Gas Shock', 17.

⁶⁷ Philippe & Partners, 'Unconventional Gas in Europe'.

⁶⁸ Rhian Kendall, Nigel Smith and Andrew Bloodworth, 'Alternative Fossil Fuels: Mineral Planning Factsheet', (Keyworth: British Geological Survey, 2011).

⁶⁹ Antoinette Harvey, 'Inquiry concerning shale gas licensing', correspondence with Peter Zeniewski (2011).

⁷⁰ Ibid.

⁷¹ Philippe & Partners, 'Unconventional Gas in Europe', 26.

⁷² See Krista Weidner, 'Natural Gas Exploration, a landowners guide to leasing land in Pennsylvania', (Altoona, PA: PennState College of Agricultural Sciences, 2008).

meet the spacing requirements for a single well, unitisation refers to field-wide or partial field-wide operation of a producing reservoir involving multiple adjoining land tracts. With farm plots smaller and land ownership more diffuse in Europe than in the USA, both unitisation and pooling may be an option required for managing concession areas fairly and effectively. Moreover, both pooling and unitisation can contribute to a reduced surface footprint by reining in excessive drilling brought about by the 'rule of capture' principle (whereby sub-surface minerals can be extracted from adjacent property tracts).

Since much of the sub-surface in Europe is state-owned, legal uncertainties surrounding the rule of capture in many cases are moot, but the centralised approach to drilling programmes implied by pooling and unitisation can be viewed as a useful practice applicable to the European context. Indeed, lessons from unitisation and pooling can be drawn not necessarily from the fair distribution of royalties but as a model for efficiently extracting gas over a given surface area. Gas fields in the USA that have been pooled or unitised have helped to reduce surface disturbance by avoiding unnecessary wells and infrastructure while maximising a field's ultimate recovery according to shared technical or engineering information among different operators and licence holders. In this way, benefits are accrued by licensing authorities as well as landowners. Some industry experts also endorse this method; indeed, it is synonymous with the recommendation of E&P experts at Italy's ENI that shale gas exploitation be pursued according to a modular facilities approach, whereby development and production from a 'complex' of multiple wellpads is managed centrally in order to avoid duplication of infrastructure, goods and service procurement, and to speed up permitting procedures.⁷³ This top-down low-cost strategy contrasts with the US experience of factory-style drilling and resonates instead with conventional gas field development in continental Europe, which has by and large been driven by environmentally conscious, regulated drilling programmes.

Socioeconomic issues

Public acceptance is regularly acknowledged as a major constraint to shale gas operations in Europe. A key dimension of this issue relates to the greater sensitivity in Europe toward activities affecting the environment, health and safety. Several analysts point out that zoning restrictions and tighter regulations on the use of public lands can hinder onshore prospecting for hydrocarbons in much of Europe. In most cases, drilling activities encounter constraints in areas considered out of bounds, such as environmentally protected areas or those in close proximity to building or residential zones. This is complemented by the European Union's biodiversity policy, known as Natura 2000, which protects over 25 000 nature conservation areas collectively covering around 800 000 km², or roughly 20% of the total land area of the EU.⁷⁴ In the case of Poland, this policy has a particularly important bearing on obtaining rights since land exploitation occurring in proximity to such protected sites are subject to a mandatory environmental impact assessment. More generally, analysts have flagged up what is considered a greater 'environmental awareness' in Europe than in the USA.⁷⁵

⁷³ Guarnone et al., 'Unconventional mindset'.

⁷⁴ European Commission, 'Guidance Document: Non-energy mineral extraction and Natura 2000', ed. Directorate-General for Environment (Luxembourg: Office for Official Publications of the European Communities, 2010).

⁷⁵ Kefferputz, 'Shale Fever'.

Public acceptance, it is said, can be secured in large part by providing adequate financial recompense for populations affected by shale gas drilling. Indeed, it is commonly argued that local communities in the USA are more amenable to fossil fuel exploitation on their land given the financial incentives, and the long history of gas and oil development in areas containing shale gas resources.⁷⁶ A report on North America's gas market by IHS CERA states that gas development provides landowners with royalties, rental payments and bonuses, at the same time as creating jobs from road building, land clearing and local service provisions.⁷⁷ In Europe, however, several analysts have noted the limited benefits accrued by local populations and the concomitant potential for considerable opposition to drilling. As Paul Stevens of Chatham House writes:

*"Large-scale disruptions caused by drilling and hydraulic fracturing are likely to generate huge local opposition, especially given concerns over environmental damage. While some operations are beginning to face increased local opposition in the United States, there is a financial incentive for local communities to suffer the inconveniences because the resource is the property of the private landowner and not the state. In Europe, by contrast, the state will reap the financial rewards of the resource and provide no financial incentive for the local community."*⁷⁸

Another set of literature argues that such claims may amount to over-simplification, since it is not strictly true that landowners in Europe are not entitled to any benefits from hydrocarbon production. According to a study by Phillippe & Partners, France and Sweden grant surface owners part of the royalties acquired from production licences.⁷⁹ Still, this does not preclude cases where opposition generates a political backlash that makes shale gas drilling untenable (such as in the case of France and Bulgaria).

In the absence of European landowners directly reaping the rewards from sub-surface resource extraction, it is all the more necessary to clearly communicate other, more indirect economic benefits that can be potentially accrued by local communities. In this context, studies observing the local economic impact of shale gas activities are an important source for considering the degree of public acceptance of shale gas development. The term economic impact refers to the contribution a given investment, policy or project (in this case, shale gas operations) may make to the existing local economy.⁸⁰ Several studies have explored this impact in different US shales. For example, a three-part study led by Timothy Considine at Pennsylvania State University analysed the economic impact of Marcellus shale gas development by calculating "the sum of the direct, indirect and induced spending, set off from the expenditures by natural gas producers."⁸¹ In other words, the infusion of money from the gas industry to

⁷⁶ Gény, 'Unconventional Gas', Kefferputz, 'Shale Fever', Ridley, 'Shale Gas Shock', Stevens, 'Hype and reality'.

⁷⁷ Downey, 'Fueling North America's future'.

⁷⁸ Stevens, 'Hype and reality', 17.

⁷⁹ Phillippe & Partners, 'Unconventional Gas in Europe', 45.

⁸⁰ Kay, 'Economic Impact of Marcellus Shale'.

⁸¹ Timothy J. Considine et al., 'An Emerging Giant: Prospects and economic impacts of developing the Marcellus shale natural gas play', (Altoona, PA: Pennsylvania State University, 2009), 18. Indirect spending refers to gas and oil companies' purchase of goods and services from other businesses (e.g. supply chain expenditure). Induced spending derives from the resulting increase in household incomes,

the local economy was quantified by observing the provision of goods and services, as well as the payment of taxes and royalties. These were modelled using 'input-output' analysis, a widely-used method for measuring how these factors contribute to other sectors of the economy. The study concluded that, in 2008, the Marcellus shale gas industry "generated \$2.3 billion in total value added, more than 29,000 jobs, and \$240 million in state and local taxes."⁸² Table 4-3 below, summarising the work of Considine and his colleagues, shows the metrics used to quantify the economic impacts of shale gas development.

Table 4-3: Economic impacts of Marcellus Shale development in Pennsylvania, USA, 2009⁸³

	Direct	Indirect	Induced	Total	Total (direct / indirect only)
Gross output (\$million)	3 769	1 557	1 844	7 170	5 326
Gross value added (\$million)	1 982	828	1 066	3 876	2 810
Employment (FTE jobs)	21 778	8 732	13 587	44 098	30 510
Tax impacts (state/fed/local, \$million)				1 446	

However, economic impact assessments of hydrocarbon extraction often generate a high level of controversy, mainly due to the numerous assumptions contained therein. Indeed, such assessments rely first and foremost on the expected expenditures and revenues of oil and gas companies and, as a corollary, on likely natural gas production rates. Assumptions must therefore be made about the number of wells drilled in a given surface area annually over an extended period of time (as shown in the note accompanying Table 4-3 above). These assumptions must be underpinned by a relatively clear idea of the amount of gas extracted by a given well (ideally accompanied by decline rate analysis and the approximate cost of well stimulation techniques).

Moreover, it is also necessary to calculate production costs, which are crucially reliant on projections of future natural gas prices. These costs vary, *inter alia*, according to the type, location and length of the well (in addition to other important variables such as technological 'learning curves', lease payments, royalty/tax rates, price pressures resulting from heightened demand for products and services, and so on). Finally, the extent to which expenditure and revenue is divided between external and locally sourced goods and services has an important bearing on whether positive economic gains are felt by the communities closest to drilling operations. Related to this, the

which stimulates spending on local goods and services. See also Wood Mackenzie, 'U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012-2030)', (Wood Mackenzie, 2011).

⁸² Considine et al., 'An Emerging Giant'. Although not within the scope of the present section, there is an interesting meta-analysis that critically engages with studies analysing the economic impact of shale gas development – see Kay, 'Economic Impact of Marcellus Shale'.

⁸³ Note: based on 710 new wells in a year and an average daily production rate of 327mcf. Considine, Watson and Blumsack, 'Economic Impacts of Marcellus'.

extent to which landowners spend their royalty payments in the local economy (an important input for calculating induced effects) can only be inferred. Only by making such assumptions is it possible to estimate the gross output, value added and employment impacts of natural gas operations in different sectors of the economy (whether in the form of direct, indirect or induced impacts).

With so many variables and an inherent range of uncertainty in each, it is small wonder that the results of such studies are so frequently contested.⁸⁴ On a deeper methodological level, the input-output models processing the data are also criticised for being incapable of evaluating the implications of rapid and substantial changes in the economy.⁸⁵ The neglect of boom/bust cycles associated with resource extraction is an important omission, as are the supply/demand effects that crucially inform assumptions about both the profitability and cumulative impacts of additional wells.⁸⁶ There are also certain overlooked risks to longer-term development that resource extraction may bring to bear on local economies. Indeed, as Kay's meta-analysis notes, although large-scale drilling would "increase the wealth and income of various individuals and communities at least during parts of the Marcellus development cycle... it would also bring new risks and most unavoidably, significant change. Whether natural gas development would lead to economic diversification or overspecialized dependency is an important economic development concern."

Finally, there are additional caveats pertaining to the applicability of US-based economic impact assessments to Europe. As noted by a study probing the possible impact of shale gas in the UK, the scale of reserves, geography, drilling costs and royalty payments are all significantly different between the two sides of the Atlantic.⁸⁷ On the last point in particular, drilling companies' payments to private landowners in the USA make up the bulk of total spending, according to Considine's report.⁸⁸ If these expenditures were re-directed to the national level in the form of state taxes and royalties, then the benefits to the local economy would be far less tangible. Fortunately, a recent study carried out for Cuadrilla Resources in the UK quantifies the expected impact of a single test well drilled in the region of Lancashire, based only on the sunk costs incurred by site preparation and well drilling/fracturing operations (and *not* assuming royalties, taxes, gas production rates or additional wells drilled). The results were presented accordingly:

⁸⁴ See Kay, 'Economic Impact of Marcellus Shale', Thoman Kinnaman, 'The Economic Impact of shale gas extraction; a review of existing studies', in *Other Faculty Research and Publications* (Lewisburg, PA: Bucknell University, 2010).

⁸⁵ European Commission, 'Communication from the Commission to the Council and the European Parliament - Report on progress in creating the internal gas and electricity market', (Luxembourg: Office for Official Publications of the European Communities, 2009).

⁸⁶ Kay, 'Economic Impact of Marcellus Shale', 5-6.

⁸⁷ Cuadrilla Resources, 'Economic Impact in Lancashire', 11.

⁸⁸ Considine et al., 'An Emerging Giant', 22.

Table 4-4: Disaggregation of single test well costs (in thousand pounds sterling)⁸⁹

	Workers & suppliers based in				
	Lancashire	Rest of UK	Total UK	Overseas	TOTAL
Labour	303	1 983	2 285	547	2 833
Subsistence	385	77	462	51	513
Bought in goods & services (incl. depreciation)	801	1 793	2 594	2 102	4 696
Overheads	115	691	806	345	1 151
Profits	125	752	877	376	1 254
Total	1 729	5 296	7 024	3 422	10 446
	17%	50%	33%		

As shown in Table 4-4, a single test well drilled over a 12-month period costs £10.5 million, of which roughly 17% is deployed on local workers and suppliers, with the rest split between the rest of the UK, and goods and services procured overseas.

4.2 Market access

This section touches on the impact that infrastructure, and contractual and political limitations may have on market access for unconventional gas. It corresponds with the last of the factors determining the viability of natural gas production as presented in Figure 1-3.

There are two principle determinants of whether new gas resources are able to reach markets: 1) their physical proximity to suitable gas transportation infrastructure; and 2) the regulatory structure of the natural gas market. Whilst the distance between the wellhead and pipelines drives up the capital and operating costs required to deliver gas to consumers, the structure of the natural gas market has important implications for how easily new supplies are able to compete with established supplies. Most notably, the degree to which the market has been liberalised⁹⁰ plays a critical role in ensuring that, for example, incumbent firms do not use control over existing infrastructure to stymie competition from market entrants.

The fact that shale gas operators in the USA have, by and large, experienced 'easy and low-cost access to the gas transport network' has been singled-out by many experts as having played a key role in the rapid development of that resource across the Atlantic.⁹¹ However, there is uncertainty as to whether the US experience can be replicated in other regions of the world. According to the IEA, one of the obstacles to be overcome will be the proximity of a pipeline system to shale plays.⁹² Royal Dutch Shell has echoed this belief, stating that a lack of transmission infrastructure in areas where there has not traditionally been any gas production could challenge the development of

⁸⁹ Cuadrilla Resources, 'Economic Impact in Lancashire'.

⁹⁰ Or deregulated, following US terminology.

⁹¹ Stevens, 'Hype and reality', 12. See also Kuhn and Umbach, 'Strategic Perspectives', 17.

⁹² IEA, 'Medium-Term Oil and Gas Markets', (Paris: Organisation for Economic Co-operation and Development 2010), 185.

unconventional gas in these areas.⁹³ Regarding the scale of the challenge faced, the World Energy Council drew attention to the fact that only 32 of the 142 basins that contained shale worldwide had any existing infrastructure that could reduce initial capital expenditures related to the exploitation of shale gas.⁹⁴

Moving beyond the mere presence of infrastructure, however, the role played by a liberalised energy market has received even greater attention in the literature. The IEA, for example, has been quick to point out that even in markets where extensive pipeline systems are already built, "regulations about third party access to such infrastructure can be important as a means of minimising transport costs".⁹⁵ Much of the discussion is driven by the fact that, whereas the US natural gas market is liberalised, the market liberalisation process in Europe is still ongoing. A number of notable reports thus contrast the "fully deregulated" US market with the European market – a market that they judge to be still "dominated by few players".⁹⁶ These reports add that certain European countries still maintain restrictions on third-party access,⁹⁷ and that transmission pipelines in Europe "are still not independent but are affiliates of major national producers".⁹⁸ By this view, such factors introduce an added degree of uncertainty to unconventional gas production in Europe.

4.2.1 Market structure

Also known as deregulation, market liberalisation involves the opening up of markets to competition by reducing the statutory barriers to entry and exit that exist. It is predicated, on the assumption that the traditional form of government monopoly or regulated public utility operation of gas is inefficient, that a system that introduces market competition inherently provides lower prices, more desirable service options for consumers and – on balance – greater security of public service operations. Structural and regulatory reform measures are introduced to facilitate 'gas-to-gas competition'.⁹⁹

Since the supply of gas is usually geographically removed from its ultimate consumption, the liberalised model also envisions a competitive market for transportation capacity in a system that is subject to open access. A key element is, therefore, ensuring third-party access to the transmission network. Neoclassical economic theory states that the ownership of physical transmission rights (such would be the case under vertical integration) increases the ability of energy suppliers to exercise market power through withholding transmission capacity. When a vertically integrated company becomes unbundled into different companies handling the production, transmission and distribution stages in the value chain separately, this facilitates market entry for new suppliers such as unconventional gas companies, for

⁹³ 'Memorandum submitted by Shell' in House of Commons, 'Shale Gas: Fifth Report of Session 2010-12', 23.

⁹⁴ WEC, 'Survey of Energy Resources', 3-4.

⁹⁵ IEA, 'Golden age', 47.

⁹⁶ Stevens, 'Hype and reality', 17.

⁹⁷ 'However, this will be required to change as the EU 3rd Package of gas regulations becomes law in early 2011.' Gény, 'Unconventional Gas', 39.

⁹⁸ Kuhn and Umbach, 'Strategic Perspectives', 37. See also Farid Gasmi and Juan Daniel Oviedo, 'Investment in transport infrastructure, regulation, and gas-gas competition', *Energy Economics* 32 (2010).

⁹⁹ James T. Jensen, 'The LNG Revolution', *Energy Journal* 24, no 2 (2003): 4.

example. Competition in the market is encouraged and the greater variety of companies can help the market to react to outside shocks more smoothly and flexibly. Additionally, unbundling results in efficiency gains and consumer savings by removing regulatory haze, excess capacity and central planning.¹⁰⁰

The neoclassical assumptions outlined above are often referred to as the structure-conduct-performance paradigm: The *structure* of markets is considered a crucial driver for the *conduct* of firms and the eventual economic *performance*.¹⁰¹ After the adoption of the Single European Market objective in 1985, this paradigm became the point of departure for the European Commission, which used it as an instrument to tackle the prevailing intra-communal barriers to trade.¹⁰² When applied to the natural gas market, the paradigm implies that the main objectives for the regulator are:

- 1) full unbundling and maximum entry in the potentially competitive segments of the value chain; and
- 2) market liquidity and effective access and performance regulation in the natural monopoly segments of the value chain.¹⁰³

In fact, whilst the structure-conduct-performance paradigm presents a parsimonious blueprint for regulators, theorists influenced by the new institutional economics school of thought¹⁰⁴ have questioned the assumption that integration in the utilities sector should always be prevented or removed. These theorists highlight that vertical integration and contracting structures may lead to greater economic efficiency because they help to offset the uncertainty and risk involved in the large up-front payments necessary in natural gas infrastructure investment. Liberalised markets may increase the cost of capital and reduce investment if the size of firms in the market falls, or if regulatory risk is increased due to increased (and inefficient) regulatory oversight of investment decisions.¹⁰⁵

At the heart of the issue lies the concept of transaction costs, which are not explicitly considered in neoclassical economics. These include the direct costs of writing, monitoring and enforcing contracts, plus the costs associated with the risk of *ex ante* investments having an *ex post* performance that is lower than anticipated as a result of contractual hazards and other uncertainties.¹⁰⁶ When one considers that investments in gas markets along the entire value chain are often very large and predominantly

¹⁰⁰ P. Joskow and J. Tirole, 'Transmission rights and market power on electric power networks', *RAND Journal of Economics* 31, no 3 (2000).

¹⁰¹ J. Bain, *Barriers to New Competition: Their Character and Consequences in Manufacturing Industries* (Cambridge, Massachusetts: Harvard University Press, 1956).

¹⁰² Janne Haaland Matláry, *Energy policy in the European Union* (Basingstoke: Palgrave Macmillan 1997).

¹⁰³ Aad Correlje and John Groenewegen, 'The Gas market, transaction costs and efficient regulation ', in *Conference on Applied Infrastructure Research* (Berlin: Workgroup for Infrastructure Policy at Berlin University of Technology, 2006), 1-2, 6; Dieter Helm, 'The Assessment: The New Energy Paradigm', *Oxford Review of Economic Policy* 21, no 1 (2005).

¹⁰⁴ Or transaction cost economics. See O. E. Williamson, *The Economic Institutions of Capitalism* (New York: The Free Press, 1985).

¹⁰⁵ Correlje and Groenewegen, 'The Gas market, transaction costs and efficient regulation '.

¹⁰⁶ *Ibid.*

irreversible (sunk), then it becomes easy to see how potential transaction costs can play a central role in deciding the economic viability of a gas project.¹⁰⁷

To illustrate, take the following example, sometimes referred to as the 'investment hold-up problem'. Prior to investing in a gas pipeline, the investor has a relatively strong bargaining position because the consumer depends on him for undertaking the investment. Once laid, however, the pipeline has very limited, if any, alternative use. This ties the investor to the market for the foreseeable future, shifting the bargaining power to the consumer. The consumer can now adapt his policy to increase his own (or his society's) rents at the expense of the investor's. This may be done through renegotiation, by determining lower prices, or by freely permitting entry to the infrastructure. Investors therefore demand that future customers commit to paying the sunk costs which they, the investors, provide up-front. Without such assurances against so-called regulatory risk, the decision to build a pipeline could never be made.¹⁰⁸

Viewed in this light, the task for regulators is to establish a 'workable' balance between maintaining the pressure for a dynamically competitive market (neoclassical theory) and providing a sufficient degree of stability and coordination to facilitate investments in the system (new institutional economics).¹⁰⁹ The question for potential unconventional gas in Europe is not just whether the market is sufficiently liberalised, but also whether regulators are able to find a form of governance that allows both traditional suppliers and market entrants to minimise transaction costs and their exposure to *ex post* risks.

4.2.2 Market access in North America

This section looks at the regulation of the North American natural gas industry and the trends in new pipeline construction since the rapid increase in unconventional gas production witnessed in recent years. In doing so, it seeks to tease out some of the market access conditions that may have played a role in the sharp rise in unconventional gas production on that continent.

US regulation of natural gas began in the 1930s with an attempt to curb the abuse of market power in the interstate pipeline business. Between this period and 1978, the structure of the North American natural gas industry was simple, with limited flexibility and few options for natural gas delivery. The Federal Government regulated both the price at which producers sold natural gas to transportation pipelines, as well as the price at which pipeline owners could sell to local distribution companies. State governments then regulated the price at which local distribution companies could sell natural gas to their customers. With wellhead prices of gas regulated too, there was little competition in the marketplace and incentives to improve service and innovate were few. The limited incentive for producers and consumers to adapt their behaviour in this rigid system led to natural gas shortages in the 1970s and surpluses in the 1980s.

During the 1980s and early 1990s, interstate natural gas markets in the USA made the gradual transition away from the regulation that had characterised the three previous

¹⁰⁷ Franz Hubert and Irina Suleymanova, 'Strategic investment in international gas transport systems: A Dynamic Analysis of the Hold-up Problem', in *DIW Berlin Discussion Papers*, ed. European Investment Bank (Berlin: Deutsches Institut für Wirtschaftsforschung, 2008).

¹⁰⁸ Aldo Spanjer, 'Regulatory intervention on the dynamic European gas market - neoclassical economics or transaction cost economics?', *Energy Policy* 37 (2009): 3252.

¹⁰⁹ Correlje and Groenewegen, 'The Gas market, transaction costs and efficient regulation'.

decades. The first steps took place in 1978 with the passage of the Natural Gas Policy Act under the initiative of the US Federal Energy Regulatory Commission (FERC). This removed wellhead ceiling prices, which were later deregulated altogether with the Natural Gas Wellhead Decontrol Act (1989). In 1984, FERC Order 380 released local distribution companies (LDCs) from long-term take-or-pay contracts, marking the beginning of the liberalisation of the gas transportation market. Known as the Open Access Order, FERC Order 436 in the very next year established a voluntary framework for non-discriminatory third-party access to gas transmission pipelines – a scheme that all major pipeline systems eventually participated in. And in 1992, FERC Order 636 made the fundamental vertical unbundling of transportation and sales activities compulsory, additionally obliging pipeline companies to publish information about the availability of services and to expand access to interstate storage capacity.¹¹⁰

Table 4-5: Major legislation for the US gas industry by Congress, FERC and court rulings¹¹¹

Date	Legislation	Principal objective
1954	Court: decision Phillips	Federal Power Commission must enforce wellhead price control and use authority to regulate E&P industry
1978	US Congress Natural Gas Policy Act	Provide for gradual phase-out of producer rate regulation and incremental pricing guidelines for industrial gas sales; led to upscaling of cogeneration of electricity in major industrial heat producers in conjunction with Public Utility Regulatory Policies Act
1985	FERC order 436	Third-party access to gas transmission pipelines encouraged, activate discounts for shippers and producers
1987	FERC order 500	Open access to gas transmission pipelines further regulated and shift cost of long-term obligations to producers and shippers in case of no take-up of gas volumes
1988	FERC order 497	Separate operating employees of interstate natural gas pipelines from their marketing affiliates to function independently of each other
1989	US Congress Natural Gas Wellhead Decontrol Act	Complete deregulation of wellhead gas prices
1992	US Congress Energy Policy Act	Reduce US dependence on foreign oil (federal bodies should use natural gas engines and utilities) and provide funding for research to recover more natural gas from conventional and unconventional resources
	FERC order 636	Mandate full third-party access to gas transmission pipelines
1996	FERC order 889	Enforce employees of the transmission providers engaged in transmission system operations to function independently of marketing employees
2000	FERC order 637	Provide full transparency about tariffs and capacity via Open Access Same-time Online Information Platform; daily auctions
2003	FERC order 2004	Corporate separation of marketing and title transfer services to shippers and gas transmission services, overruled by landmark court ruling in 2006 and CFR 18 revision in 2008
2005	US Congress Energy Policy Act	FERC obtained Penal Authority to penalise companies that do not abide with FERC Code of Conduct and Regulation Orders

¹¹⁰ K.G. Aranoa and B.F. Blair, 'An ex-post welfare analysis of natural gas regulation in the industrial sector', *Energy Economics* 30, no 3 (2008), Christian von Hirschhausen, 'Infrastructure, regulation, investment and security of supply: A case study of the restructured US natural gas market ', *Utilities Policy* 16, no 1 (2008).

¹¹¹ Sources: EIA, *Key FERC Orders, 1984-2008* (2009, cited 03 May 2012); Ruud Weijermars, 'Value chain analysis of the natural gas industry: Lessons from the US regulatory success and opportunities for Europe', *Journal of Natural Gas Science and Engineering* 2, no 2-3 (2010).

Date	Legislation	Principal objective
2006	Court ruling in National Fuel Gas Supply Corporation versus FERC	Court rejects the treatment of Energy Affiliates in FERC order 2004, implying FERC's corporate separation between energy and marketing affiliates is not required so long as functional no-conduit rule is fulfilled
2008	FERC order 712 Revision CFR 18 part 358	More efficient pipeline capacity release standards Revision of Orders 497, 889 and 2004 based on 2006 Court ruling to allow integrated planning and competitive solicitation of and transmission capacity; limited to a strict functional separation of transmission function employees and marketing function employees

The restructuring of the US gas market has had a substantial impact. End users now have a number of options to source their natural gas. They are able to choose the best purchase and transportation arrangements from the wellhead to the pipeline. Alternatively, they may choose to turn to the LDC for a bundled product and leave the arrangements for sourcing and interstate transportation of the gas to the LDC. The number of gas marketers (companies that coordinate the business of bringing natural gas from the wellhead to end-users) jumped from 50 in 1986 to some 260 in the 1990s. The number of market centres, or 'hubs', have also increased, as has the size of the financial market, which helps to ensure supply security through contracts that hedge against price changes.¹¹²

Not all of the effects of the new regime have been positive. For example, price spikes in California over the summer of 2000 brought charges of market abuse and raised broader questions about both the effectiveness of competitive pressures in increasing the economic efficiency of the gas market as well as how successfully the US pipeline system can support arbitrage.¹¹³ In spite of certain localised and transient occurrences however, the general consensus is that the new regime has been successful in facilitating competition in the US gas market and this has been a major improvement on the previous system of vertically integrated utilities. Comparable fuel purchases became much less expensive – halved, in some cases – and artificial inefficiencies were reduced in the gas supply chain.¹¹⁴

A liberalised and competitive market thus formed an important part of the regulatory backdrop to the unconventional gas revolution in the USA. But the brief theoretical review presented earlier in this chapter then raises another question: whether the increased regulatory risk in this liberalised market has prevented infrastructure investment – a question more significant for unconventional gas developments because of their narrower profit margins.

In the USA, most shale gas is either proximal to the intended market, as in the case of the Marcellus, or close to major pipelines, as in the case of the Barnett, Haynesville and Woodford. Nevertheless, significant shale reserves lie outside the existing US pipeline

¹¹² Weijermars, 'Value chain analysis'. Hirschhausen, 'Infrastructure, regulation, investment and security of supply'.

¹¹³ P. Joskow and Edward Kahn, 'A quantitative analysis of pricing behavior in California's wholesale electricity market during summer 2000', *The Energy Journal* 23, no 4 (2002).

¹¹⁴ IEA, 'USA Review', in *Energy Policies of IEA Countries* (Paris: Organisation for Economic Co-operation and Development 2002); Tooraj Jamasb et al., 'International benchmarking and regulation of European gas transmission utilities. Report prepared for the Council of European Energy Regulators (CEER)', (Cambridge: University of Cambridge, Electricity Policy Research Group, 2006).

grid and require capital investment to build the infrastructure necessary to utilise the gas. In 2009, the Interstate Natural Gas Association of America estimated that \$133-210 billion would need to be invested during the following 20 years to process the gas coming from shale and other tight gas formations.¹¹⁵

Figure 4-10: US natural gas pipeline capacity additions versus marketed gas production¹¹⁶

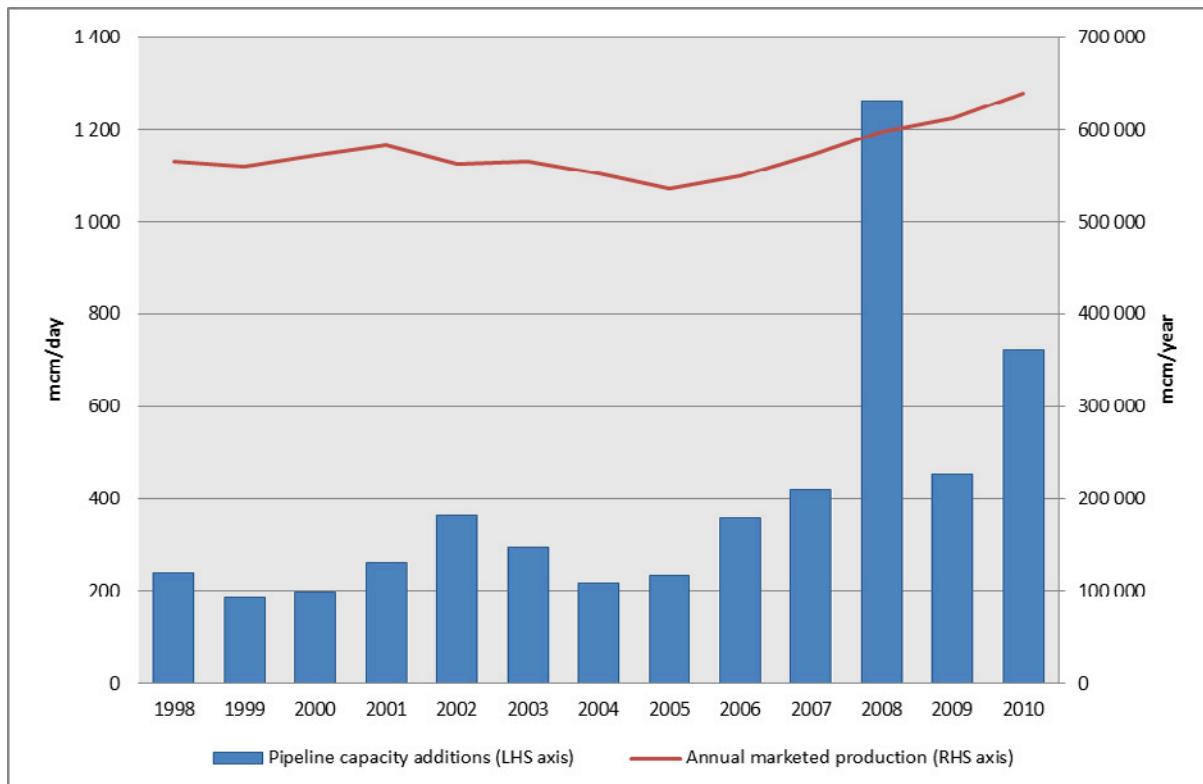


Figure 4-10 above presents new US gas pipeline additions and annual marketed gas production for the period 1999 to 2010. It can be seen that whilst both measures appear either stagnant or in slight decline in the years between 1999 and 2005, the period between 2005 and 2010 is marked by a significant increase in marketed gas production – a trend known to be underpinned by greater unconventional production – and an even more striking jump in additional pipeline capacity. According to the EIA, 2008 was the most active year for US natural gas pipeline construction in more than a decade. Eighty-four projects and close to 6 500 kilometres of pipeline were added. Much of the construction was driven by unconventional supply growth, particularly in northeast Texas, which saw 13 new pipelines related to the development of gas supplies from the Barnett, Woodford or Fayetteville shale formations.¹¹⁷

Pipeline construction activity in 2009 was also considerable, albeit well below the exceptionally high pace of additions in 2008. At least 43 natural gas pipeline projects were completed in 2009 in the lower 48 states, adding close to 4 800 kilometres of pipeline to the natural gas grid and representing an investment of about \$9.9 billion.

¹¹⁵ INGAA Foundation and ICF International, 'Natural Gas Pipeline and Storage Infrastructure Projections Through 2030', (Washington DC: Interstate Natural Gas Association of America Foundation 2009).

¹¹⁶ Source: Energy Information Administration, GasTran Natural Gas Transportation Information System, Natural Gas Pipeline Projects Database. Cited in California Energy Commission, 'Current Trends: Natural Gas Infrastructure', in *Staff Workshop: 2011 Integrated Energy Policy Report* (2011).

¹¹⁷ Andrews et al., 'Unconventional Gas Shales', 6.

Figure 4-11 below shows three projects of particular interest that illustrate how increased unconventional gas production has impacted regional patterns in pipeline utilisation.

Figure 4-11: Significant pipeline expansions in the USA in 2009¹¹⁸



Both the Midcontinent Express and Texas Independence pipelines allow greater deliverability from the Barnett Shale to regional markets.¹¹⁹ However, the longest natural gas pipeline project completed in 2009 was the 1 000-kilometre Rockies Express-East pipeline. This marked the end of the construction of a 2 700-kilometre, \$5 billion pipeline system stretching from Colorado to Ohio. Natural gas resources within the Rockies are found primarily in unconventional formations,¹²⁰ and the pipeline demonstrates that a combination of shale gas, CBM and tight gas development has also driven very significant infrastructure projects in the USA.

For the near future at least, unconventional gas looks set to continue to transform the US transmission network. Table 4-8 below shows a list of pipelines set to come into service between 2011 and 2014 with the express purpose of bringing shale gas to market. Whilst the majority of such pipeline developments in previous years centred on the Barnett Shale in northeast Texas, most of the projects in the immediate time-horizon will service the Marcellus Shale and are located in the states of Pennsylvania, West Virginia and New York.

¹¹⁸ Source: EIA, 'Natural Gas Year-In-Review 2009', (Washington, DC: US Energy Information Administration, 2010).

¹¹⁹ Ibid.

¹²⁰ Tight gas sands are widely distributed in the Green River Basin of south-western Wyoming and the Piceance Basin of north-western Colorado. The Rocky Mountain region is also the location of two of the most prolific coal-bed methane basins in the world: the San Juan Basin in south-western Colorado and north-western New Mexico, and the Powder River Basin in eastern Wyoming. Environmental Protection Agency, 'An Assessment of the Environmental Implications of Oil and Gas Production: A Regional Case Study', (Washington DC: Environmental Protection Agency, 2008), 2-5.

Table 4-6: US shale gas pipeline projects in the near future¹²¹

Name	Status	Expected service date	Value (\$million)	Distance (km)	Add. capacity (Mcm/d)	Route
Iroquois Project	NYMarc Announced	2014	500	106	5.67	NJ to NY
Sunrise Project	Completed	2012	272	80	8.88	PA to WV
Appalachian Gateway Project	Construction	2012	635	177	13.71	WV to PA
Tioga County Extension Project	Construction	2011	46.76	26	9.91	PA to NY
Barnett Gas Pipeline Project	Intrastate Announced	2011	NA	161	28.3	TX to TX

Across the border in Canada, there is also evidence that unconventional gas production is changing gas trade flows and driving new infrastructure investment. The Canadian and US natural gas markets operate as a single integrated market and have a number of similarities. For example, the Canadian natural gas market has a highly liberalised structure as a result of far-reaching regulatory reforms that began in 1985.¹²² Canada has relatively well-developed pre-existing pipeline infrastructure that has been built around historical conventional production. And finally, Canada has experienced a significant increase in unconventional gas production in the last decade.¹²³

Canadian tight and shale gas developments are primarily focused on the Montney and Horn River Basin plays in northeast British Columbia. Whilst the transmission infrastructure in British Columbia as a whole has benefitted from decades of conventional gas production, Canada's National Energy Board forecasts that a slew of modest expansions will be necessary to connect new unconventional supplies to the substantial existing long-haul capacity that brings gas to the major consuming regions of eastern Canada and beyond.¹²⁴ Projects in this vein include the Groundbirch (recently completed) and Horn River Mainline pipelines (planned) that connect supplies in the Horn River Basin to the Alberta system. More significantly, the ambitious Pacific Trail Pipeline project will move gas from northeast British Columbia to the planned Kitimat LNG terminal for export to premium markets in Asia when the two are completed in 2014.

So what does the North American experience tell us about the role that market access plays in unconventional gas development? Due to the fact that large-scale shale gas production has so far not been observed outside of liberalised energy markets, questions remain about whether the phenomenon can be replicated in differently structured markets and, if so, how this might look. What this section does show,

¹²¹ Source: US Energy Information Agency. Information as of December 2011.

¹²² A. Serletis and R. Rangel-Ruiz, 'Testing for common features in North American energy markets', *Energy Economics* 26 (2004), P. I. Wilson, 'Deregulation and natural gas trade relationships: lessons from the Alberta-California experience', *Energy Policy* 25 (1997).

¹²³ Tight and shale gas production accounted for 36% (34% from tight, 2% from shale) of total domestic gas production in 2010, up from 18% in 2000. National Energy Board, 'Canadian Energy Overview 2010', (Ottawa: National Energy Board, 2011).

¹²⁴ National Energy Board, 'Canada's Energy Future: Infrastructure Changes and Challenges to 2020', (Ottawa: National Energy Board, 2009).

however, is that an institutional framework can be found to enable investment in major unconventional gas infrastructure projects in even the most highly liberalised markets. This is in spite of the narrower profit margins and greater uncertainty commonly ascribed to unconventional gas production.¹²⁵ In this regard, tax incentives and loan guarantees, such as those offered under the US Energy Policy Act (2005) and British Columbia's Infrastructure Royalty Credit Program, may play a key role in ensuring an acceptable rate of return for investors in such projects.

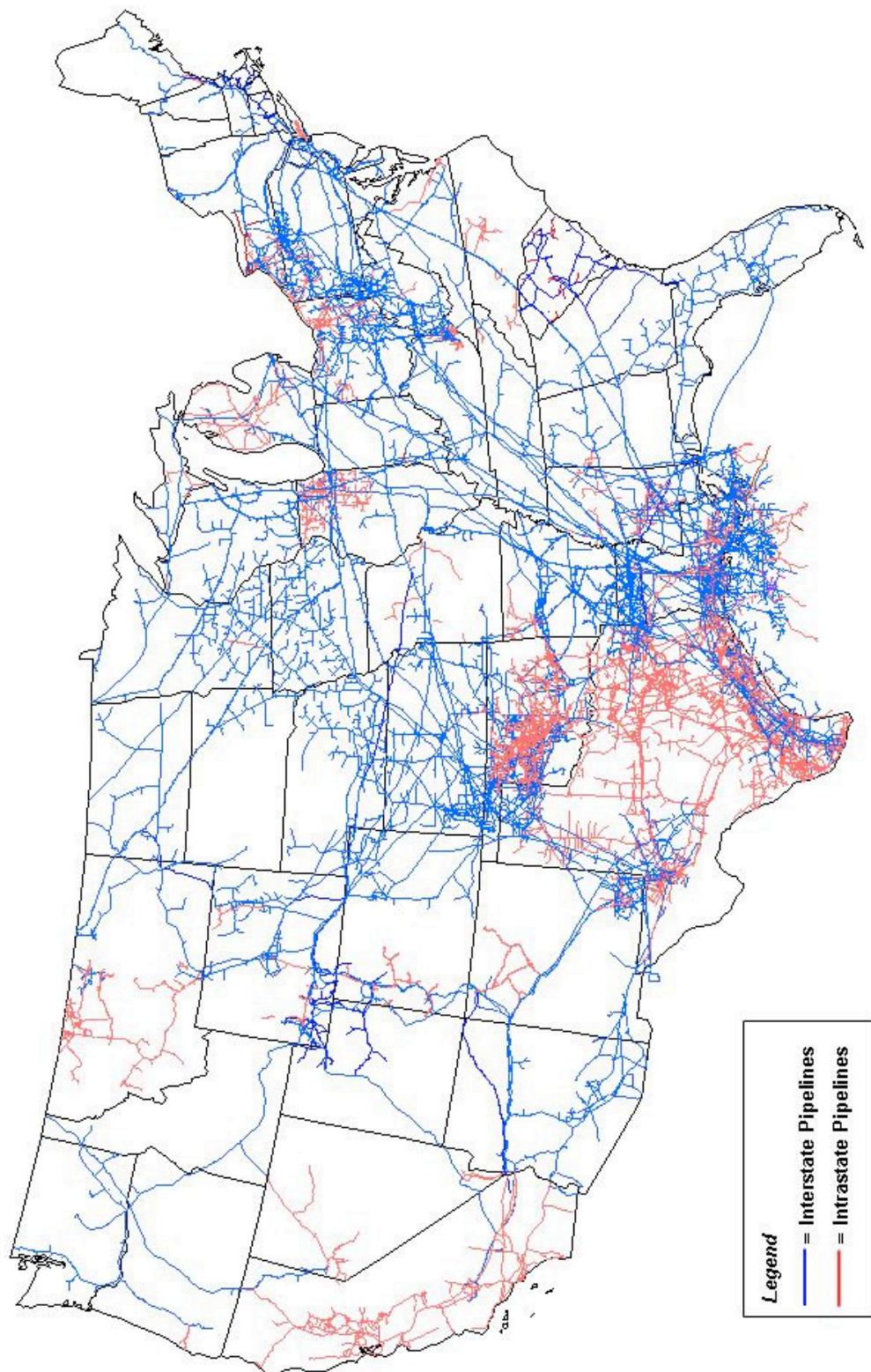
4.2.3 Market access in the EU-27

This section takes a brief look at the existing pipeline system and structure of the natural gas market in Europe to suggest how much the North American experience might be able to inform expectations regarding possible indigenous shale gas production. A note of caution, however: simple infrastructural indicators, such as the combined length of various types of pipelines for example, cannot give a reliable indication of the amount of additional investment necessary to bring new unconventional gas supplies to market due to a host of additional factors that must also be taken into consideration. Similarly, the coincident timing of several market reform steps makes it difficult to find econometric evidence capable of directly testing the effect of liberalisation measures, such as ownership unbundling. There may also be country-to-country differences in the pace at which binding EU legal measures become practically effective.¹²⁶ For the abovementioned reasons, this section cannot offer a methodologically empirical assessment of the factors in question, although it aims to provide a rigorous treatment of some of the most notable and relevant available evidence.

¹²⁵ This echoes the empirical analysis of investment trends in US LNG revealing that infrastructure investment is forthcoming during favourable economic conditions, and that after the 1992 implementation of Order 636, the natural gas pipeline system underwent an investment boom. Hirschhausen, 'Infrastructure, regulation, investment and security of supply'.

¹²⁶ Michael Pollitt, 'The arguments for and against ownership unbundling of energy transmission networks', *Energy Policy* 36, no 2 (2008).

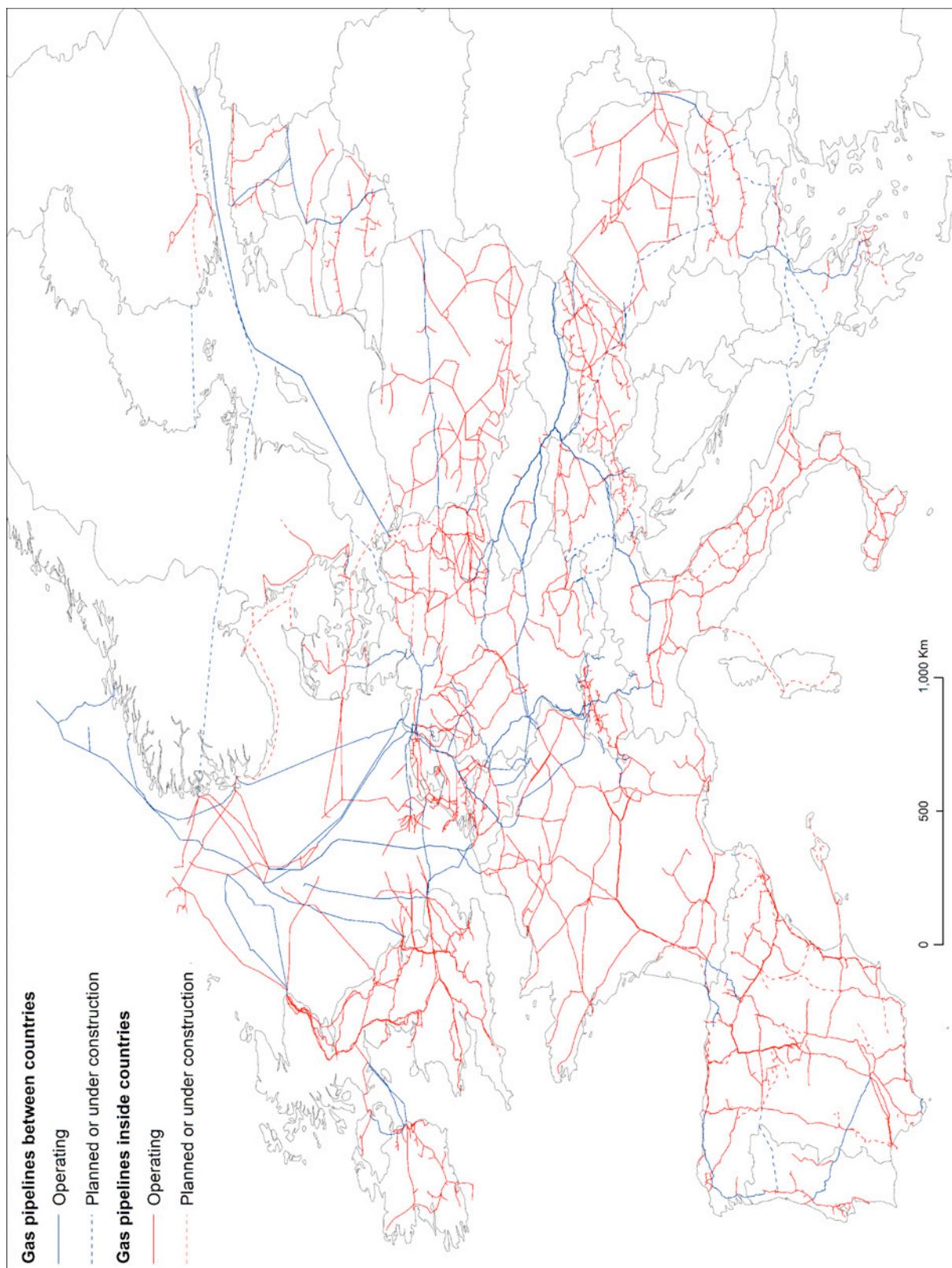
Figure 4-12: The US natural gas transmission network¹²⁷



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

¹²⁷ Source: EIA, Office of Oil and Gas, Natural Gas Division, Gas Transportation Information System.

Figure 4-13: The EU's natural gas transmission network¹²⁸



¹²⁸ Source: European Commission, Platts, IHS.

Figure 4-12 and Figure 4-13 show the transmission pipeline infrastructure in the USA and Europe respectively. The USA was the first country to develop its natural gas resources and has what can be considered a well-developed transmission network. According to the EIA, there were an estimated 490 000 kilometres of interstate and intrastate transmission pipeline in the USA at the close of 2008 – over 53 km of transmission pipeline for every 1 000 km² of land.¹²⁹ Although there are significant differences between individual Member States (see Table 4-7), the equivalent statistic for the EU is comparable – roughly 29 km of transmission pipeline per 1 000km².¹³⁰

Table 4-7: Gas transmission grid density by country¹³¹

United States	Italy	Sweden	United Kingdom	Total EU aggregated
Gas grid (km) /area (1 000km ²)	53	110	1	45

Although these figures suggest that the US and EU gas transportation systems are analogous,¹³² readers should be aware of several factors that complicate the direct comparison of the two markets on simple pipeline density terms. First, whilst pipeline age and efficiency can be considered to be alike, differences in both the geographical distribution of pipelines in relation to unconventional plays and their current levels of utilisation need to be taken into account.¹³³ Secondly, differences in patterns of pipeline development also need to be factored in. For example, the USA is both a major producer and consumer of gas and the dense transmission infrastructure in states such as Texas and offshore in the Gulf of Mexico are a legacy of many years of hydrocarbon development. Being primarily a consumer of natural gas, Europe does not have regions that are as tightly networked and this may have the effect of lowering the aggregated length of pipelines per km².

Finally, the possibility that unconventional gas supplies can be produced close to markets may lessen reliance on transmission pipelines altogether. In government testimony, Shell has stated that successful shale gas development in Europe is likely to first meet local market demand, thus potentially freeing up supply to other parts of Europe.¹³⁴ In the USA, Pennsylvania-based UGI Utilities is investigating the possibility of adding consumer value by selling locally produced Marcellus shale gas directly through their distribution system – a sort of shale gas micro-grid.¹³⁵ Whilst this is an exceptional case, it illustrates how widely distributed unconventional gas resources may challenge traditional assumptions about the role infrastructure plays in resource development.

¹²⁹ EIA, *About U.S. Natural Gas Pipelines - Transporting Natural Gas* (2011, cited 12 December 2011); available from http://205.254.135.7/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html

¹³⁰ Source: European Commission, Platts, IHS.

¹³¹ Sources: EIA, *Natural Gas Pipelines* (cited), IEA, 'Oil and Gas Markets', 187.

¹³² Gény, 'Unconventional Gas', 46.

¹³³ '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.' *Ibid.*, 98.

¹³⁴ Memorandum submitted by Shell, in House of Commons, 'Shale Gas: Fifth Report of Session 2010-12'.

¹³⁵ David Falcheck, 'UGI links shale gas to system: Utility celebrates first Marcellus connection', *Scranton Times-Tribune* 2011.

If the EU shares certain broad similarities with the USA in terms of the development of its energy infrastructure, then energy market structure similarities are less apparent. This is because the USA has a fully liberalised market for natural gas but reforms to the EU's internal gas market are still ongoing.

The liberalisation of gas markets in Europe began in the UK with the 1982 Oil and Gas Act, designed to bring competition to the transmission and distribution of natural gas. In 1986, the UK market was opened for non-domestic customers and British Gas – the largest integrated gas utility company in the world at the time – was privatised. Dramatic changes continued with the 1995 Gas Act, which laid the groundwork for the introduction of full retail competition by creating licensing schemes for companies to engage in the transport and supply of gas. Then in 1996 the Network Code was introduced – a legal document that set the rules for system balancing, capacity acquisition and trading, and gas transportation and trading in the pipeline system.¹³⁶ The UK experience demonstrated that it was possible to move from a monopoly to a competitive environment in natural gas without structural reforms in an EU Member State.¹³⁷

The EU began the liberalisation of the European natural gas sector at the supra-national level in 1998 with the adoption of what has become known as the First Gas Directive.¹³⁸ This sought to break monopolies and create an open and competitive market by requiring that integrated companies unbundle their internal accounts and not abuse commercially sensitive information. It also mandated that network operators provide third-party access to their infrastructure and that Member States gradually introduce market opening. The legislation aspired to bring choice to consumers, accessibility for all suppliers and improvement to security of supply through diversity. Several subsequent legal acts – introduced in Table 4-8 below and covered in more detail in Annex G – have progressively built upon the objectives of the First Gas Directive, albeit with varied success. The most recent Third Internal Market Package took direct effect on 3 March 2011.¹³⁹

¹³⁶ Álvaro Carteaa and Thomas Williams, 'UK Gas Markets: the Market Price of Risk and Applications to Multiple Interruptible Supply Contracts', *Energy Economics* 30, no 3 (2008).

¹³⁷ Andrej Juris, 'Market Development in the United Kingdom's Natural Gas Industry', (Washington DC: World Bank, 1998).

¹³⁸ European Union, 'Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas ', (Luxembourg: Office for Official Publications of the European Communities, 1998).

¹³⁹ European Union, 'Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (Text with EEA relevance)', (Luxembourg: Office for Official Publications of the European Communities, 2009); European Union, 'Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (Text with EEA relevance)', (Luxembourg: Office for Official Publications of the European Communities, 2009); European Union, 'Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (Text with EEA relevance)', (Luxembourg: Office for Official Publications of the European Communities, 2009).

Table 4-8: Major regulations for the EU internal gas market¹⁴⁰

Date	EU Directives and Acts			Principal objective
August 1998	98/30/EC Directive 'Regulation for an internal natural gas market'	First Gas Directive	Gas	Guarantee TPA to improve competitiveness and improve security of supply.
June 2003	2003/55/EC Amended Gas Directive 'acceleration directive'	Second Amended Gas Directive		Encourage legal unbundling of transmission system operators from gas trading companies on a voluntary basis. Deregulate gas markets by July 2004 and have full TPA by July 2007, including TPA for storage systems.
2004	First Strategic Review	Strategic Energy		Directions on security of supply.
March 2005	European Gas Regulatory Forum			Guidelines on services and rules for TPA compiled by the Forum
Oct 2007	EU Commission Report 'An Energy Policy for Europe'			Diverging views within EU; France and Germany favour independent TSOs as in the Netherlands since July 2005.
Nov 2008	Second Strategic Review	Strategic Energy		Securing an energy future.
April 2009	Third Legislative and Gas Package	Legislative Energy and Gas Package		Creation of ACER (Agency for the Cooperation of Energy Regulators) and ENTSO (European Network of Transmission System Operators).

It is too early to tell what the long-term effects of the Third Package will be. On the one hand, there have been encouraging recent developments indicating that liberalisation is gathering pace. A wave of corporate mergers and demergers was occasioned by the reforms, heralding a change in the industrial organisation model in the European utility sector from single product national/regional companies towards a multi-energy pan-European model.¹⁴¹ On the regulatory front, signs of market integration have been observed, along with price decreases in Member States that have diversified supply. Traded volumes on the three most liquid gas spot markets rose by 4.45% to reach 1 455 terawatt hours (TWh) in 2009.¹⁴² And, in combination with the arbitrage possibilities created by the increasingly dense pipeline structure¹⁴³, the market liberalisation process in Europe is being credited by some observers for the growth in pressure from EU consumers to revise long-term oil-indexed gas contracts towards market-based pricing (see Section 5.2.4).¹⁴⁴ With any substantial European unconventional gas production not expected before the end of this decade, some analysts are hopeful that the liberalisation process will have made significant progress by then.¹⁴⁵

On the other hand, market concentration remains high, changes observed in interregional connectivity have only been modest and the switching rate continues to remain low in most Member States. For these reasons, the latest Commission report on

¹⁴⁰ Weijermars, 'Value chain analysis'.

¹⁴¹ Jonathan Stern and Howard Rogers, 'The Transition to Hub-Based Gas Pricing in Continental Europe', (Oxford: Oxford Institute for Energy Studies, 2011), 20.

¹⁴² European Commission, 'Commission Staff Working Document: 2009-2010 Report on progress in creating the internal gas and electricity market', ed. Directorate-General for Energy (2011).

¹⁴³ By 2013, pipeline interconnections will allow LNG arriving in Greece to be delivered to a range of south and central European countries as far north as Austria; or vice-versa for gas to be delivered from the central European Gas Hub to Greece. Stern and Rogers, 'Transition to Hub-Based Pricing', 16.

¹⁴⁴ Miharu Kanai, 'Decoupling the Oil and Gas Prices: Natural Gas Pricing in the Post-Financial Crisis Market', (Paris, Brussels: Institut français des relations internationales 2011).

¹⁴⁵ Gény, 'Unconventional Gas', 84, 98.

market progress concedes: "a truly single energy market is far from complete."¹⁴⁶ Questions thus remain as to whether the EU's internal market rules can be practically applied in the context of possible unconventional gas sources to be clear; non-discriminatory, timely and repeatable across large operations.

Moreover, there is an important factor which may make the European transition more complicated than historical precedents suggest. In the words of one notable commentator: "in both North America and the UK, the vast majority of the parties involved in the market reform process were under the same political and legal jurisdiction (or in the case of the United States and Canada, similar jurisdictions). In the case of Continental Europe, not only are there a large number of importing companies with differing legal systems, but their suppliers – in particular Russia and Algeria, but not forgetting a large number of LNG exporting countries – operate under fundamentally different legal/regulatory frameworks."¹⁴⁷

Turning the question on its head, at least two observers have suggested that indigenous unconventional gas production may facilitate the creation of a genuine single market for gas across the EU by allowing new players to challenge incumbent firms in regions where gas-to-gas competition may not otherwise be observed.¹⁴⁸ The economic theory of contestable markets states that market power, such as monopoly, can be controlled if there is a genuine possibility of entry by new suppliers. Actual entry of competing suppliers is not necessary, simply the threat that the market might be contestable is sufficient to stimulate behaviour associated with a competitive market.¹⁴⁹ In this light, if there are real prospects of significant gas supplies from domestic shale sources, this could have a very powerful influence on the behaviour of Europe's current external gas suppliers forcing them to lower prices in order to maintain market share.¹⁵⁰ For a continuation of this point, see Sections 5.2.3 and 5.2.4.

4.3 Indigenous production and energy security

The energy security benefits of unconventional gas are overwhelmingly portrayed as being associated with increased indigenous production and energy independence. This section will show that while energy independence brings a host of important benefits, directly equating energy independence with energy security is too simplistic. Increasing reliance on energy imports is not necessarily incompatible with increasing energy security, and many of the potential security of supply benefits of unconventional gas to the EU may come by way of more reliable and affordable imports because of the liberalisation of the EU energy markets and growing global energy trade.

Energy plays an essential role in satisfying basic human needs, providing for social welfare and as fuel to power the economic engine. It is what classical economists once called a 'basic good': directly or indirectly, it enters the production of every other

¹⁴⁶ European Commission, 'Commission Staff Working Document: 2009-2010 Report on progress in creating the internal gas and electricity market'.

¹⁴⁷ Stern and Rogers, 'Transition to Hub-Based Pricing', 34-35.

¹⁴⁸ Alan Riley, 'The Importance of 'shale gas' its global implications', in *Presentation at Konrad Adenauer Stiftung* (Berlin: 2010).

¹⁴⁹ In a contestable market, with very low barriers to entry and exit, potential as well as actual competition is a constraint on what the incumbent producers can charge, so that a competitive price is observed even when there is only one seller.

¹⁵⁰ Testimony of Prof. Paul Stevens in House of Commons, 'Shale Gas: Fifth Report of Session 2010-12', Ev w27.

produced commodity or service.¹⁵¹ As such, reliable access to affordable energy is an important national security concern.

In spite of its crucial importance, energy security lacks both a common definition and a methodology for its evaluation. Although its meaning varies between different countries and organisations, in general it may be used to signify some of the following:

- Reliability of supply;
- Self-sufficiency;
- Security of infrastructure;
- Stability and diversity of suppliers;
- Reduced consumption through energy efficiency;
- Diversity of energy carriers; and increasingly...
- Environmental sustainability.¹⁵²

In the UN's *World Energy Assessment*, energy security is described as 'the continuous availability of energy in varied forms, in sufficient quantities, and at reasonable prices'.¹⁵³

In 2003, the UK Department of Trade and Industry (now the Department for Business, Innovation and Skills) reduced the problem of ensuring energy security to one of ensuring reliable supplies of energy at predictable prices delivered through the market.¹⁵⁴

The International Energy Agency described it as "the uninterrupted physical availability at a price which is affordable, while respecting environmental concerns".¹⁵⁵

And, finally, the European Commission refers to 'the uninterrupted physical availability of energy products on the market at an affordable price for all consumers, whilst respecting environmental concerns and looking towards sustainable development'.¹⁵⁶

Each of the aforementioned definitions of energy security carries a good measure of commonsense value. However, energy security is a multi-faceted concept. The following pages will further unpack the concept with specific reference to certain key elements of the European Commission's definition, provided above. In particular, the phrases "for all consumers"; "uninterrupted physical availability"; "on the market at an affordable price"; and "respecting environmental concerns" will be explored in order to clarify a handful of important, but problematic, issues surrounding energy security.

As one notable commentator remarks: "scholarly understanding of the challenges at the intersection of energy and national security, and of the various policy tools available to

¹⁵¹ Christof Rühl, 'Global Energy After the Crisis: Prospects and Priorities', *Foreign Affairs* March/April (2010).

¹⁵² Adapted from Estonian Ministry of Foreign Affairs, *Energy Security* (2011, cited 4 January 2011); available from <http://www.vm.ee/?q=en/node/4116>

¹⁵³ United Nations Development Programme, 'World Energy Assessment', (New York: UNDP, 2000), 113.

¹⁵⁴ UK Department of Trade and Industry, 'Our energy future - creating a low carbon economy', (London: 2003), 73.

¹⁵⁵ IEA, *Energy Security* (2012, cited 4 January 2011).

¹⁵⁶ European Commission, 'Towards a European strategy for the security of energy supply'.

address them, is surprisingly weak.”¹⁵⁷ One of the reasons for this is that the concept of energy security is inherently value-laden. That is to say, energy security means different things to different people. As Daniel Yergin writes:

“Energy-exporting countries focus on maintaining the ‘security of demand’ for their exports, which after all generate the overwhelming share of their government revenues. For Russia, the aim is to reassert state control over ‘strategic resources’ and gain primacy over the main pipelines and market channels through which it ships its hydrocarbons to international markets. The concern for developing countries is how changes in energy prices affect their balance of payments. For China and India, energy security now lies in their ability to rapidly adjust to their new dependence on global markets, which represents a major shift away from their former commitments to self-sufficiency. For Japan, it means offsetting its stark scarcity of domestic resources through diversification, trade, and investment.”¹⁵⁸

The European Commission’s definition of energy security speaks of providing a supply of energy products “for all consumers”. This highlights the fact that energy security in a European context usually refers to the consumer-centric notion of security of supply. But even security of supply is itself context dependent. The level of risk to a country is a function of the flexibility of its energy system and its economy to accommodate supply shocks, as well as the tightness of the energy market concerned.¹⁵⁹

Key analytical factors to consider include:

- 1) The security of the network infrastructure essential to delivering energy supplies to customers (electricity grids, gas and oil pipelines, etc);
- 2) The degree to which a country is dependent on imports;
- 3) Diversity in the types of primary energy an economy relies on (the so-called energy mix), in the sources of this energy and in the means through which this energy is delivered;
- 4) The extent to which various types of energy and fuels can be substituted for each other in the economy;
- 5) Environmental constraints on the type and amount of energy used;
- 6) Fundamental market conditions;
- 7) The political circumstances of countries and regions influencing the supply chain.

Energy independence is, therefore, just one of a series of factors that determine security of supply and not a sufficient condition of security of supply. Countries that are energy

¹⁵⁷ Michael Levi, 'Energy Security: An Agenda for Research', in *Working Papers* (New York: Council on Foreign Relations, 2010), 1.

¹⁵⁸ Daniel Yergin, 'Ensuring Energy Security', *Foreign Affairs* March/April (2006): 71.

¹⁵⁹ Clingendael International Energy Programme for European Commission Directorate-General for Transport and Energy, 'Study on Energy Supply Security and Geopolitics', (Den Haag: Clingendael, 2004), 44.

self-sufficient may also suffer from energy insecurity due to market failures, force majeure or technical stoppages. Equally, increasing reliance on energy imports may not necessarily be incompatible with increasing energy security if suppliers are reliable or if undelivered supplies can be easily substituted in the energy system. In this context, even imported unconventional gas supplies could mitigate the high costs and risks associated with long-distance gas transportation by offering an alternative to supplies sourced from further afield and an additional source of gas in times of shortage. Put simply, unconventional gas could introduce new 'supply shock absorbers' to respond to disruptions and market imbalances.¹⁶⁰

As a result of its conceptual elasticity, energy security has been used to justify a variety of policies. Recently, one major debate in Europe has centred on how to manage declining indigenous natural gas production and increasing import dependence. The terms 'energy security' and 'energy independence' are often used interchangeably; however, they are distinct concepts. Energy imports may exacerbate trade deficits: the development of indigenous energy sources can boost national economies; and tax revenues from energy production can bolster governmental budgets. However, strictly speaking these are not energy security issues *per se*. Moreover, energy independence as a policy goal in and of itself could be considered misleading and costly as most EU Member States do not have the resources to be self-sufficient.¹⁶¹

By referring to the "uninterrupted physical availability of energy", the European Commission Green Paper correctly highlights the most basic aspect of security of supply. Energy resources like natural gas are private commodities that are subject to the same market forces as other commodities, such as steel, wheat, or pork bellies.¹⁶² Large, flexible and well-functioning energy markets are capable of providing a considerable source of physical security by absorbing shocks and allowing supply and demand to reallocate physical supply more quickly and with greater ingenuity than a controlled system could.¹⁶³ Only in extreme circumstances, such as embargoes, strikes or wars, is energy physically unobtainable in developed countries. In the words of one notable economist in the field, "Supply can *almost* always be made equal to demand, *provided* the price is allowed to adjust."¹⁶⁴

This brings us to the issue of the price of energy products – another fundamental component of security of supply. The European Commission's reference to the availability of energy "on the market at an affordable price" raises the tricky question of how to define affordability. It must be recognised that a consumer's point of view on this issue will clash fundamentally with a producer's. In fact, the only way that energy prices can enhance energy security is when they are high enough to guarantee adequate return on investment for producers and low enough to stimulate economic growth in

¹⁶⁰ Downey, 'Fueling North America's future', ES-6.

¹⁶¹ House of Commons, 'UK Energy Supply: Security or Independence? Eighth Report of Session 2010-12', ed. Energy and Climate Change Committee (London: House Of Commons, 2011), 6.

¹⁶² Andreas Goldthau, 'A Public Policy Perspective on Global Energy Security', *International Studies Perspectives* 12, no 4 (2011): 3.

¹⁶³ Yergin, 'Ensuring Energy Security': 80. Pierre Noel, 'Beyond dependence: How to Deal with Russian Gas', (London: European Council on Foreign Relations, 2008).

¹⁶⁴ Emphasis in the original. Dieter Helm, 'Energy policy: security of supply, sustainability and competition', *Energy Policy* 30, no 3 (2002): 175.

the consuming countries.¹⁶⁵ Put simply, low prices are as dangerous to energy security as high prices.¹⁶⁶

In this context, the market plays an essential role in security of supply by deciding the most suitable and sustainable price for energy products based on supply and demand. (This is provided, of course, that the market is functioning well!) Viewed in this light, unconventional gas could play a significant role by reducing the scarcity of natural gas and fundamentally rebalancing supply and demand. As the natural gas supply curve becomes more elastic, as is the case with an increasing abundance of unconventional gas resources, it will become increasingly difficult to price natural gas above marginal cost.¹⁶⁷ This could lower the market price of gas, improve the EU's bargaining position as a gas consumer and make it easier for the EU to meet its future energy needs.

Although the market plays an important role in ensuring energy security, energy is generally considered by policy-makers to be too important to be solely entrusted to the market alone. Moreover, energy markets suffer from multiple market failures. Amongst other things, they are strongly distorted by the 'rent-seeking' behaviour of states and large businesses attempting to capture special monopoly privileges rather than earning profits through competitive trade.

One notable source of market failure is the fact that energy can be considered both an economic and a political good.¹⁶⁸ In recent years, analysts have often commented on the manner in which natural gas is used as a political lever in the Russian-Ukrainian relationship – a practice that has greatly distorted both the price and reliability of the natural gas delivered to Ukraine.¹⁶⁹ However, in the broader historical context, the most noteworthy example of the use of energy for political ends is the deployment of the so-called oil weapon. The switch from international-private to national-public ownership of the international oil market from 1973 onwards paved the way for a number of noteworthy, politically motivated interventions in crude oil reserves and production by OPEC governments.¹⁷⁰ Short-term domestic concerns continue to influence the energy agendas of many producer countries today, a fact that some claim has contributed to the recent volatility of energy markets.¹⁷¹

It is therefore seen that national and international political and strategic issues play a very important role in security of supply. There is a clear economic case for government intervention in markets where some form of market failure is taking place. In light of the indispensable importance of the markets, the goal for policy-makers is "to set a

¹⁶⁵ A.F. Alhajji, 'What is Energy Security? Definitions and Concepts', *Middle East Economic Survey* L, no 45 (2007).

¹⁶⁶ Because of this, some economists have even suggested that energy security can largely be considered 'relatively stable prices over time' rather than dwelling on price levels – producers and consumers may be in tension over how much energy should cost, but the importance of energy to their economies means that they can both agree on the desirability of steady and predictable prices. Helm, 'Energy policy': 176.

¹⁶⁷ Medlock, Jaffe and Hartley, 'Shale Gas and National Security', 31.

¹⁶⁸ Clingendael International Energy Programme for European Commission Directorate-General for Transport and Energy, 'Supply Security and Geopolitics', 31.

¹⁶⁹ Jim Nichol, Steven Woehrel and Bernard A. Gelb, 'Russia's Cutoff of Natural Gas to Ukraine: Context and Implications', (Washington D.C.: Congressional Research Service, 2006), Simon Pirani, 'Ukraine's Gas Sector', (Oxford: Oxford Institute for Energy Studies, 2007).

¹⁷⁰ Clingendael International Energy Programme for European Commission Directorate-General for Transport and Energy, 'Supply Security and Geopolitics', 50.

¹⁷¹ Rühl, 'Global Energy After the Crisis'.

framework which will ensure that the market operates... with a minimum of distortion and energy is produced and consumed efficiently".¹⁷² To this end, factoring in the political dimension of energy is essential to both understanding and mitigating the effects of events such as those mentioned above.

As mentioned earlier, security of supply is not an end in itself. It is one of many means of providing for basic human needs and social welfare. When put into this broader human context, it becomes clear that the production and use of energy should neither endanger the quality of life of current and future generations nor exceed the carrying capacity of ecosystems.¹⁷³ Climate change as a result of rising greenhouse gas emissions represents a threat to international peace, security and development. More than two thirds of the world's carbon dioxide emissions come from the way we produce and use energy, so energy policy has to play a major part in meeting this challenge.¹⁷⁴ It is for this reason that the European Commission makes "respecting environmental concerns" one of the fundamental components of its definition of energy security. By doing so it acknowledges that the short-term benefits of securing energy supplies without due respect for the environment will be outweighed by the long-term costs, both in monetary terms as well as in social welfare.

4.4 Summary

The challenges facing shale gas drilling and development in Europe are not insurmountable. However, should the size and commercial viability of technically recoverable resources translate into large-scale production, there will be a wide range of issues in need of attention.

Clearly there can be no neat separation between the regulatory, environmental, technical, social and economic challenges associated with land access for shale gas development. As the analysis has revealed, these issues are intimately related and affect one another in inextricable ways. Nonetheless, the table below provides an indicative summary of the main obstacles to accessing land for unconventional gas development that have been revealed by the literature review. Surveying these, it becomes clear that land access is, above all, a local issue. Studies that analyse land access issues at the regional or country level will inevitably yield generalisations that abstract from local specificities. While it is important to highlight national regulations governing the exploitation of conventional and unconventional hydrocarbons, in practice the first mover that crucially determines the extent to which development activities will encounter significant obstacles are local authorities. Therefore, a top-down analysis of national regulations and centralised infrastructure planning for large-scale development and production of shale gas should be complemented by a bottom-up analysis of the surface-level constraints and opportunities present in each shale gas play.

¹⁷² Lawson, quoted in Helm, 'Energy policy': 175.

¹⁷³ United Nations Development Programme, 'World Energy Assessment', 31.

¹⁷⁴ UK Department of Trade and Industry, 'Meeting the Energy Challenge: A White Paper on Energy', (London: 2007), 7, 30.

Table 4-9: Summary of the main challenges for accessing land for shale gas development in Europe

	Regulatory	Environmental	Social	Technical/logistic al
Environmenta l	- Water management [Stevens ¹⁷⁵ , Tyndall ¹⁷⁶] - Natural/protected sites [Gény ¹⁷⁷]			
Social	- No sub-surface property rights [Kuhn & Umbach ¹⁷⁸ , Stevens, Gény] - Duration/intensity of drilling [Tyndall] - Proximity to residential areas [Centrica ¹⁷⁹ , Tyndall] - Noise/visual impacts [Tyndall; IHS CERA]	- NIMBYism [Stevens, Kuhn & Umbach] - Community impacts [Kornfeld ¹⁸⁰ , House of Commons ¹⁸¹]		
Technical/ logistical	- Well size, spacing and density - Zoning restrictions (Gény) - Multi-well pad permitting (e.g. adjacent plots) - Smaller land parcels [Kuhn & Umbach, Gény, Centrica]	- Inaccessible terrain - Force majeure [Cuadrilla ¹⁸²] - Obligation to conduct environmental impact assessment	- Population density [E.ON ¹⁸³ , Centrica, Gény, Stevens, Kuhn & Umbach, House of Commons] - Utility line placement	
Economic/ market	- Royalties for the state [CRS, Gény, Stevens, Phillippe and Partners ¹⁸⁴] - Permitting costs - Licensing/con-cessions	- Waste disposal - Site protection (Kornfeld)	- Lack of financial incentives for landowners/loc al communities [Gény, Kuhn & Umbach, Stevens] - Higher labour costs (Kefferputz ¹⁸⁵)	- Equipment/rig transport - Access to distribution/trans mission system [Stevens, Gény] - service availability [House of Commons]

¹⁷⁵ Stevens, 'Hype and reality'.

¹⁷⁶ Wood et al., 'Shale gas provisional assessment'.

¹⁷⁷ Gény, 'Unconventional Gas'.

¹⁷⁸ Kuhn and Umbach, 'Strategic Perspectives'.

¹⁷⁹ Centrica Energy, 'Unconventional Gas in Europe'.

¹⁸⁰ Kornfeld, 'Socio-Economic Considerations'.

¹⁸¹ House of Commons, 'Shale Gas: Fifth Report of Session 2010-12', 48.

¹⁸² Cuadrilla Resources, 'Economic Impact in Lancashire'.

¹⁸³ Korn, 'Prospects in Europe'.

¹⁸⁴ Philippe & Partners, 'Unconventional Gas in Europe'.

¹⁸⁵ Kefferputz, 'Shale Fever'.

5 The impact of unconventional gas on the European energy system

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This chapter provides an overview of the unconventional gas boom in the USA and its knock-on effects globally. As with the previous chapter, the wide range of ways in which unconventional gas may potentially impact the European energy system makes it infeasible to define a strict scope for the review of the evidence on this topic that would be both rigorous and comprehensive. As such, this chapter does not attempt a systematic review, as Chapter 2 does for reserve estimates. Although steps have been taken to locate the most relevant studies, to limit selection bias and to assess the methodological quality of sources used, the application of protocols and explicit criteria to these ends is unviable. Readers should therefore regard the chapter as an exploratory survey of the econometric, modelling and qualitative evidence for the purpose of identifying areas of further research or contextually informing the interpretation of future developments on these key topics.

5.1 The impact of shale gas in the United States of America

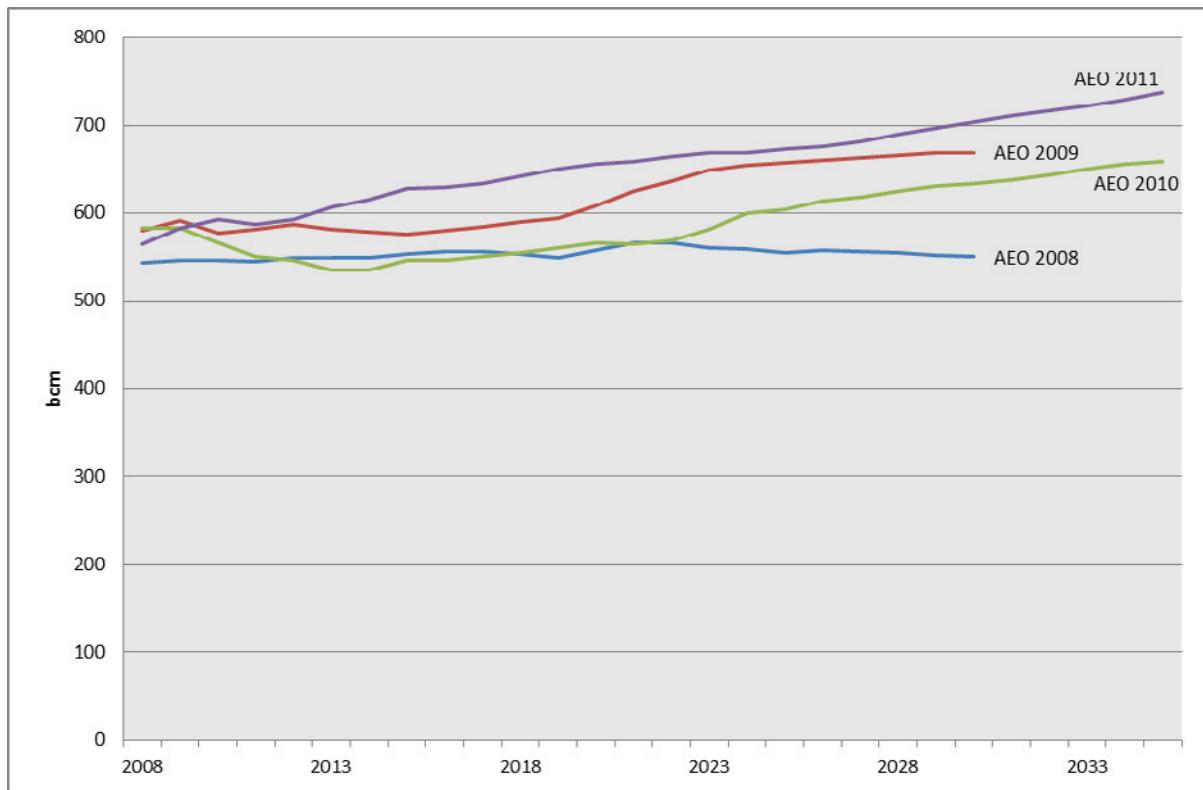
Since unconventional gas production has occurred predominately in the USA, most of the data presented here will refer to the US case. This section highlights how respected industry references have revised their forward-looking energy outlooks in light of the shale gas boom in the USA. A secondary objective is to review shifts and major trends attributable to growing shale gas production which, in turn, will guide the modelling effort in the subsequent chapter.

5.1.1 Projections of supply and production

As late as 2008, the EIA's Annual Energy Outlook (AEO), an authoritative source on US energy industry data, predicted an overall decrease in US natural gas production, from 568 bcm in 2008 to 544 bcm in 2030. These projections were made just as the surge in production from the Barnett Shale in Texas was occurring, causing the USA to surpass Russia as the largest gas producer in the world in 2009. Unconventional gas made up 56% of total US gas production that same year. Since then, estimates of future US gas production have undergone significant revisions as new reserves have been continually added from exploration and development of the Barnett, Marcellus, Haynesville, Fayetteville and Horn River shale plays (among others).

Each AEO has provided diverging production estimates, but there is a visible trend of upward adjustment. The 2011 edition published in the wake of the shale gas boom forecast a steady increase in gas production to 656 bcm in 2020 and 737 bcm in 2035. This represents an annual growth rate of 0.9% over the 2009-2035 period. This significant revision, shown in Figure 5-1, is largely thanks to indigenous shale gas production. Now, predictions envision shale gas production alone, disregarding other unconventional, to reach 230 bcm by 2020 (and 343bcm by 2035). This latter figure would equal roughly half of the total US natural gas production.

Figure 5-1: Projections of US natural gas production¹



Other well-regarded sources for energy data have also significantly revised their estimates of future US gas production. The IEA's 2010 World Energy Outlook (WEO) baseline 'new policies' scenario initially expected production to grow to a moderate 578 bcm in 2020 and 606 bcm by 2035, equivalent to an annual average growth rate of 0.2% over the 2008-2035 period.² By contrast, the more recent 2011 report has predicted US gas production in 2020 to be 685 bcm and 710 bcm in 2035.³

While the EIA's AEO is predominately focused on the USA, the IEA's analysis has also reflected on the impact of US shale gas production on the OECD and wider world. In general, the IEA predicts that natural gas, boosted by the prospects for commercial exploitation of unconventional deposits in different parts of the world, will play an increasingly important role in the global energy mix. In the 2011 WEO, the IEA emphasises the chief attractions of gas: its softer environmental impact relative to other fossil fuels; its ability to act as a backup fuel for intermittent renewable power generation; and, more recently, the growing interregional trade of natural gas brought on by LNG markets (which will be discussed in another section). Key drivers for increased natural gas consumption include the recent turn away from nuclear energy in the wake of the Fukushima plant disaster in 2011, China's announcement of a major push to expand domestic natural gas use and the growing competitiveness of gas-fired power generation vis-à-vis other fuels such as coal. Other research highlighted the potential for gas to serve as an "effective bridge to a lower CO₂ emissions future".⁴ This

¹ EIA, 'Various AEOs'.

² IEA, 'World Energy Outlook 2010', in *World Energy Outlook* (Paris: Organisation for Economic Co-operation and Development 2010).

³ IEA, 'Golden age'.

⁴ Downey, 'Fueling North America's future', E.J. Moniz, H.D. Jacoby and A.J.M. Meggs, 'The future of natural gas: Interim report', (Cambridge, Massachusetts: Massachusetts Institute of Technology, 2010), 36.

portended a debate about whether gas is a competitor to, or facilitator of, renewable energy goals (both in an environmental as well as economic sense). This section will address these issues in terms of their reciprocal impact on the future development of unconventional gas, principally in the USA but also for the rest of the world.

Despite optimistic forecasts for future natural gas production, the wide range of scenarios offered by the IEA's WEO reinforces the degree of uncertainty concerning the future development of the global energy mix. The 'new policies' scenario incorporates the policy commitments and plans that have been announced by countries around the world to address all energy-related policy priorities (e.g. climate change, energy security, efficiency, competitiveness and so on). The 'current policies' scenario, by contrast, presents projections under the assumption that government policies will remain unchanged from what has already been agreed. The '450' scenario assumes a policy agenda of limiting an increase in average global temperature to 2°C. Finally, the 'Gas' scenario considers a positive future outlook for natural gas due to high demand in non-OECD countries, increased production from unconventional sources and competitive prices in relation to other fuels. The variation in assumptions given by each of these scenarios leads to a wide range of possible outcomes in the supply and demand of various forms of energy over the next two decades. However, as repeatedly stressed by these reports, natural gas is the only fossil fuel for which demand rises in all four scenarios.⁵ Therefore, the IEA notes that "there is much less uncertainty over the outlook for natural gas: factors both on the supply and demand sides point to a bright future, even a golden age, for natural gas."⁶

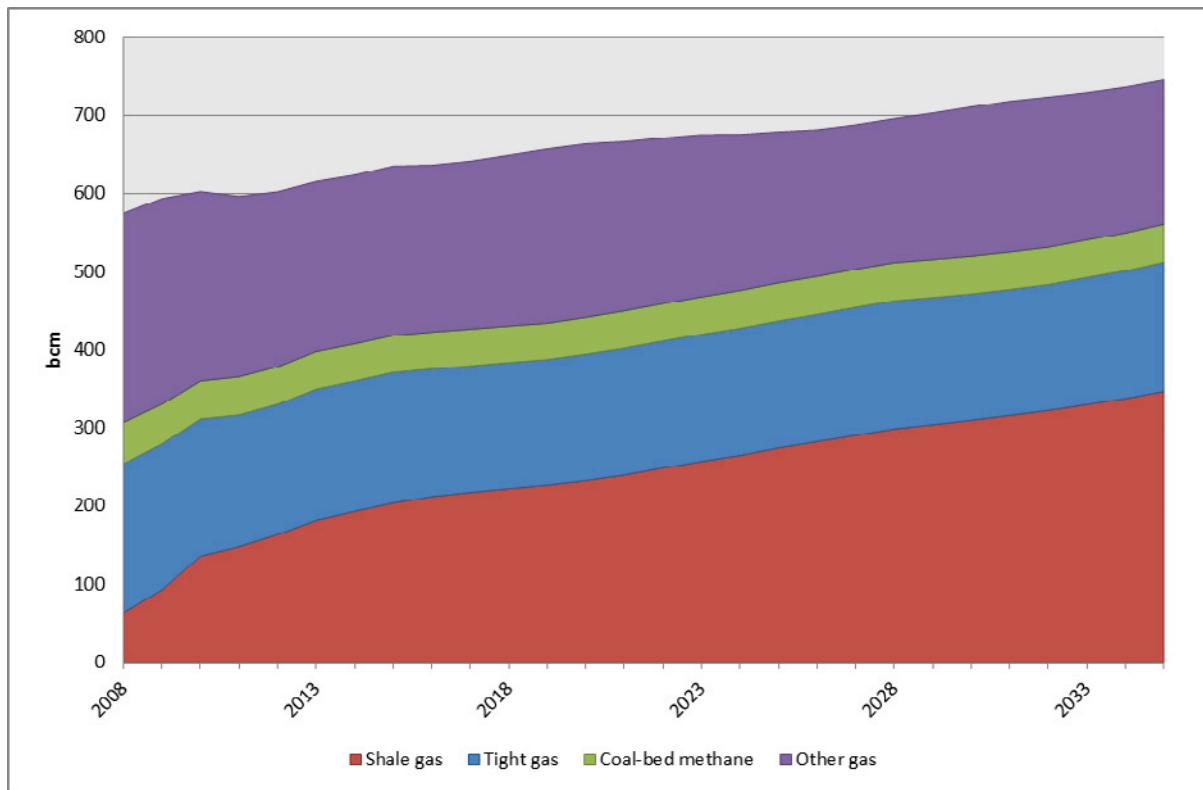
One of the primary drivers of this gas-friendly outlook is the estimates of global unconventional gas reserves and production. Both the IEA and EIA have estimated a significant global presence of shale gas, in the USA in particular but also in Asia Pacific, Latin America, Africa and Europe. Many analyses now ponder whether unconventional gas is an appropriate term for shale gas, when its resource base is estimated at 200 Tcm, or a quarter of total global gas reserves.⁷

⁵ IEA, 'World Energy Outlook 2011', in *World Energy Outlook* (Paris: Organisation for Economic Co-operation and Development 2011), 156.

⁶ Ibid., 42.

⁷ Ibid., 163.

Figure 5-2: Forecasts of US natural gas production by type⁸



Given these impressive figures, it is small wonder that energy analysts, gas firms and political bodies have sought to understand the factors enabling the US shale gas phenomenon and test their application in other regions of the world. The caveat, of course, is that in the early stages of this technological breakthrough the one certainty is that much remains uncertain. Projections of the impact of shale gas development in the USA and elsewhere in the world crucially rely on estimates of technically recoverable resources and assumptions about the economic viability of their extraction. Although this has been taken up in greater depth in Chapter 2, it is useful to note that even reserve estimates for established shale gas plays are subject to contestation and perennial revision. A recent analysis by the EIA helped underscore this phenomenon by making a significant downward adjustment to the technically recoverable resource base for Marcellus shale. This contributed to a wider revision of total US shale gas reserves, from an earlier estimate of 827 tcf in the AEO2010⁹ to 482 tcf one year later (a figure that is 60% less than the one originally put forward).

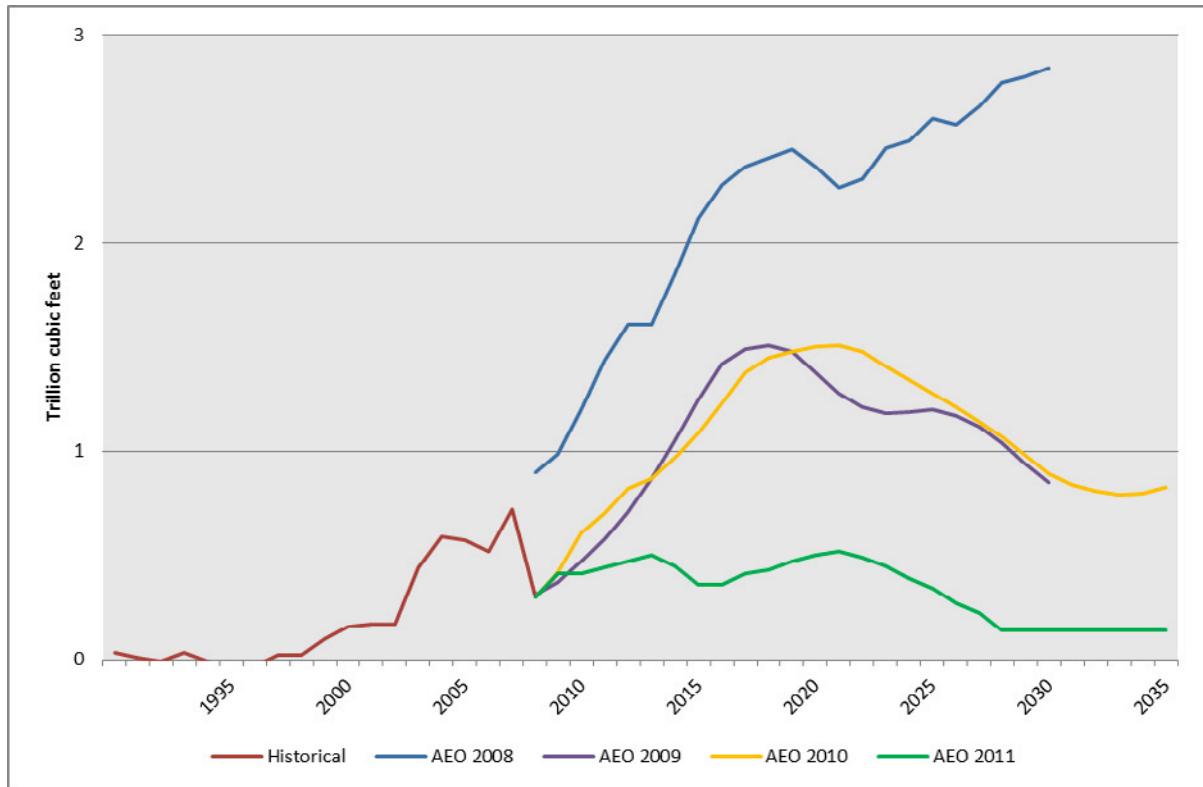
Such stark revisions to the US gas reserve base as a result of shale gas exploration have had knock-on effects on estimates of other gas supply data in the USA. The most obvious change has occurred in predictions concerning US natural gas imports. It was initially expected that the USA would begin importing substantial quantities of LNG. These expectations led to massive investments in the infrastructure needed to import and process liquefied natural gas, while stimulating investments in producer states anticipating a surge in demand for LNG. The reality, however, was that the USA ended up importing only around 13 bcm of LNG in 2009 (out of a re-gasification capacity of nearly 150 bcm). Now there are serious proposals to add export capabilities

⁸ EIA, 'AEO 2011'.

⁹ EIA, 'AEO 2010'.

(liquefaction plants) to underused LNG import terminals. As noted by Howard Rogers, a price differential between US and destination markets of between \$3-4/MBtu would be required to ensure a reasonable return on investment for this export market.¹⁰ Under present circumstances, however, North America will remain largely self-sufficient and therefore will essentially remain isolated from interregional trade.¹¹

Figure 5-3: Historical and projected net US LNG imports¹²



The issues of resource size and LNG development deserve their own treatment and are therefore explored in greater depth in Chapter 2 and Section 5.2. For now, it suffices to draw attention to the great deal of uncertainty surrounding shale gas development and the concomitant divergence in the predictions of its size and impact. These uncertainties aside, there have been tangible impacts on US natural gas infrastructure as a result of unconventional gas production. Substantial investments have been witnessed in mid and down-stream processing, transport and storage capacities. The latter in particular has seen impressive growth as the North American markets have been 'warehousing' gas to accommodate surplus supply, whilst the minimum working gas inventory has been rising to levels considerably above the volumes required for winter demand.¹³

5.1.2 Projections of demand and future energy mix

The impact of shale gas production has been made apparent by the growing role of gas used as a fuel for electricity generation. Indeed, most of the growth in demand for gas in the USA is expected to occur in the power generation sector, since industrial, residential and

¹⁰ Rogers, 'Shale gas': 136.

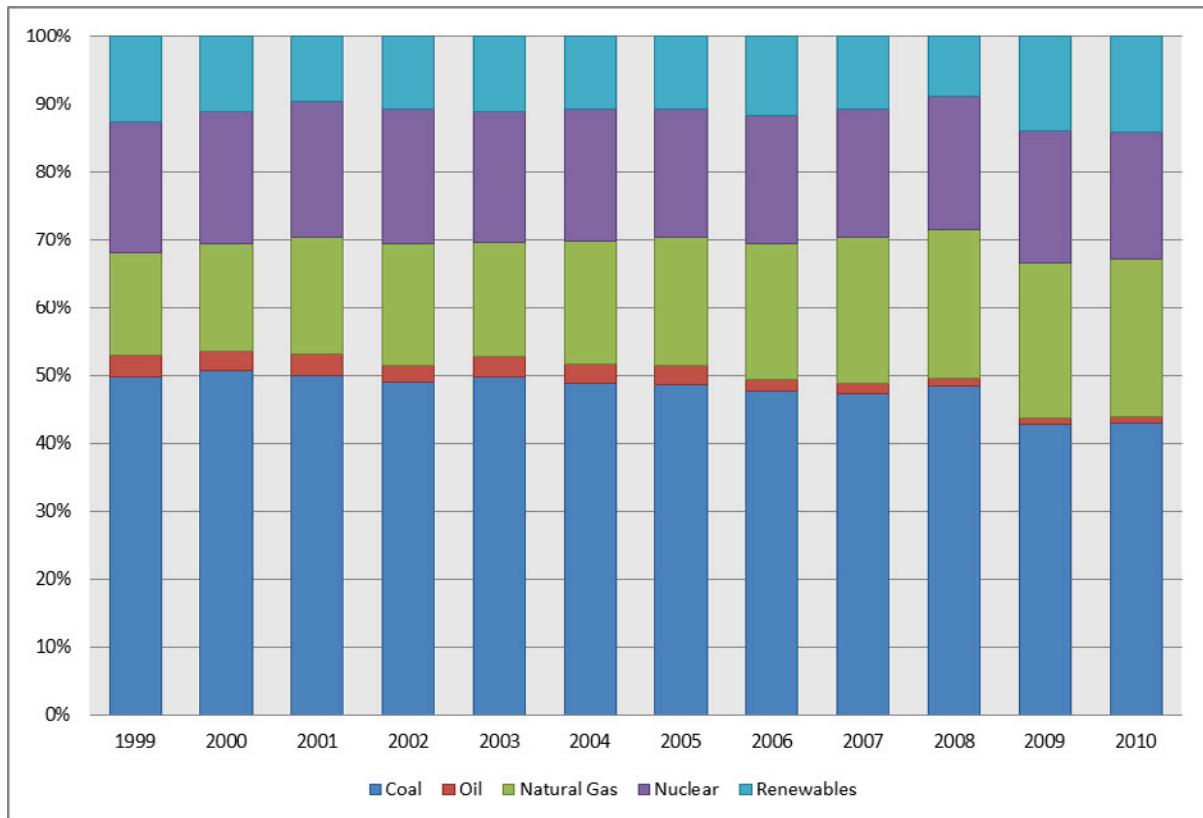
¹¹ IEA, 'Golden age'.

¹² EIA, 'Various AEOs'.

¹³ Howard Rogers, 'The impact of a globalising market on future European gas supply and pricing: the importance of Asian demand and North American supply', (Oxford Institute for Energy Studies, 2012), 27.

commercial sectors are considered mature markets with little growth prospects.¹⁴ Since 2005, incremental increases in gas-fired electricity generation have been observed (as shown in Figure 5-4 below). Although coal retains its position as the fuel of choice for most power-generating units (a legacy of US policy advocating coal as a generating source in the 1970s), this role has recently been challenged by a notable rise in natural gas consumption in the power generation sector. According to IHS CERA, natural gas-fired power plants have cost, timing and emissions advantages compared to coal-fired plants.¹⁵ Whether these advantages are capitalised upon partly depends on the extent to which US producers decide to export natural gas via LNG liquefaction terminals, which would increase the price of natural gas domestically and possibly deter investments in gas-fired electricity generation (at least according to recent EIA analysis¹⁶).

Figure 5-4: US electricity generation by fuel¹⁷



Nonetheless, in the nearer term it is already apparent that gas-fired electricity generation is gaining ground. As shown in Figure 5-5 below, data on generating capacity reveals a sizeable difference in coal and gas-fired investments in the USA over the next four years. Moreover, as large numbers of coal-fired generators are scheduled for retirement, it is likely that investments in combined cycle gas turbines (CCGTs) will gain ground, boosted by the recently narrowed gap between the costs of gas versus coal for electricity generation (Figure 5-6). However, a caveat is that the incremental costs of coal remain lower than for natural gas, even despite the recent surge in shale gas

¹⁴ Downey, 'Fueling North America's future'.

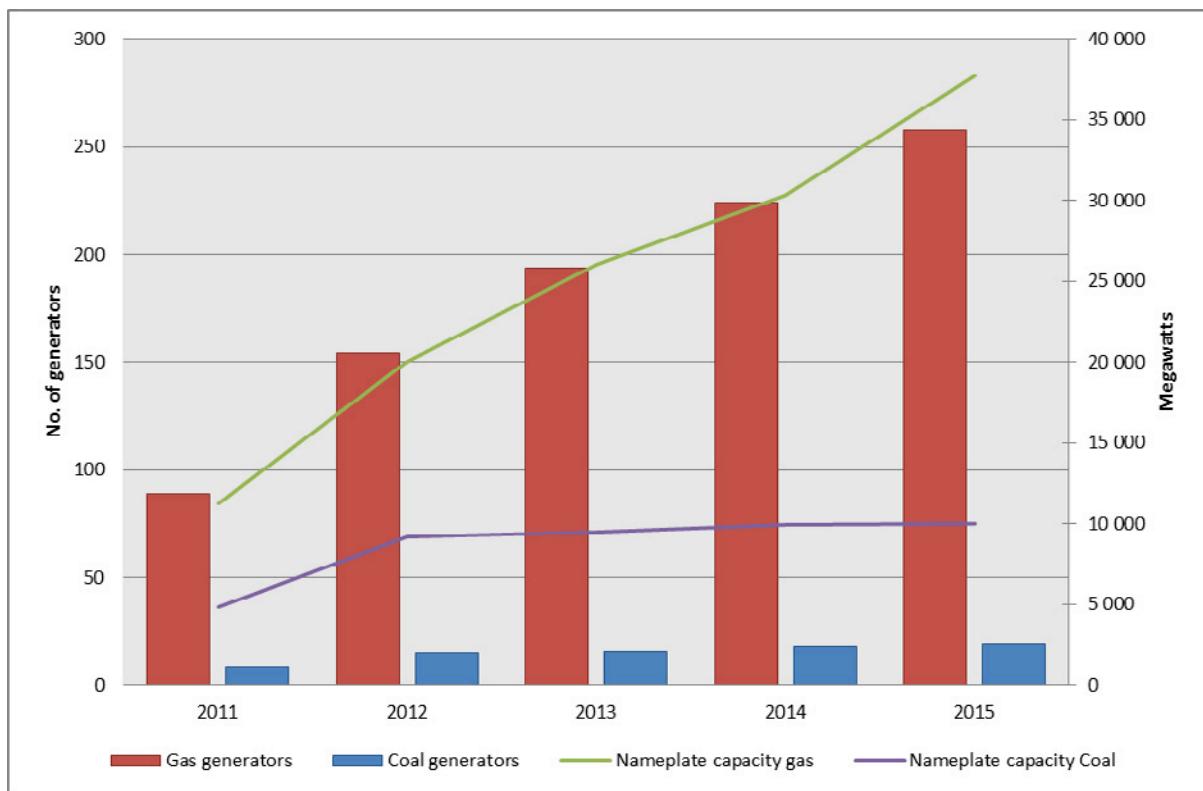
¹⁵ Ibid.

¹⁶ EIA, 'Effect of Increased Natural Gas Exports on Domestic Energy Markets as requested by the Office of Fossil Energy', (Washington, DC: US Energy Information Administration, 2012).

¹⁷ EIA, 'Electric Power Monthly: January 2012', (Washington, DC: US Energy Information Administration, 2012).

production and the corresponding decline in natural gas prices. This means that the capacity utilisation rate for gas-fired plants is, on average, much lower than for coal (although the higher efficiencies of CCGTs relative to coal-fired power plants should be taken into account). Moreover, the fuel costs of combined-cycle plants account for 60-75% of total generation costs (compared with 0-40% for renewables, nuclear or coal), meaning that these gas-fired plants are far more sensitive to changes in fuel prices.¹⁸ Still, according to ConocoPhillips, the full-cycle costs of building new power plants are currently more favourable for combined cycle gas plants than alternatives run on coal (despite lower fuel prices), nuclear, renewables and fossil fuels accompanied by CCS technology. This is largely due to the relatively low capital expenditures of CCGTs in relation to these alternatives.¹⁹

Figure 5-5: Planned additions to coal and gas-fired electricity capacity in the United States of America (aggregate 2011-2015)²⁰

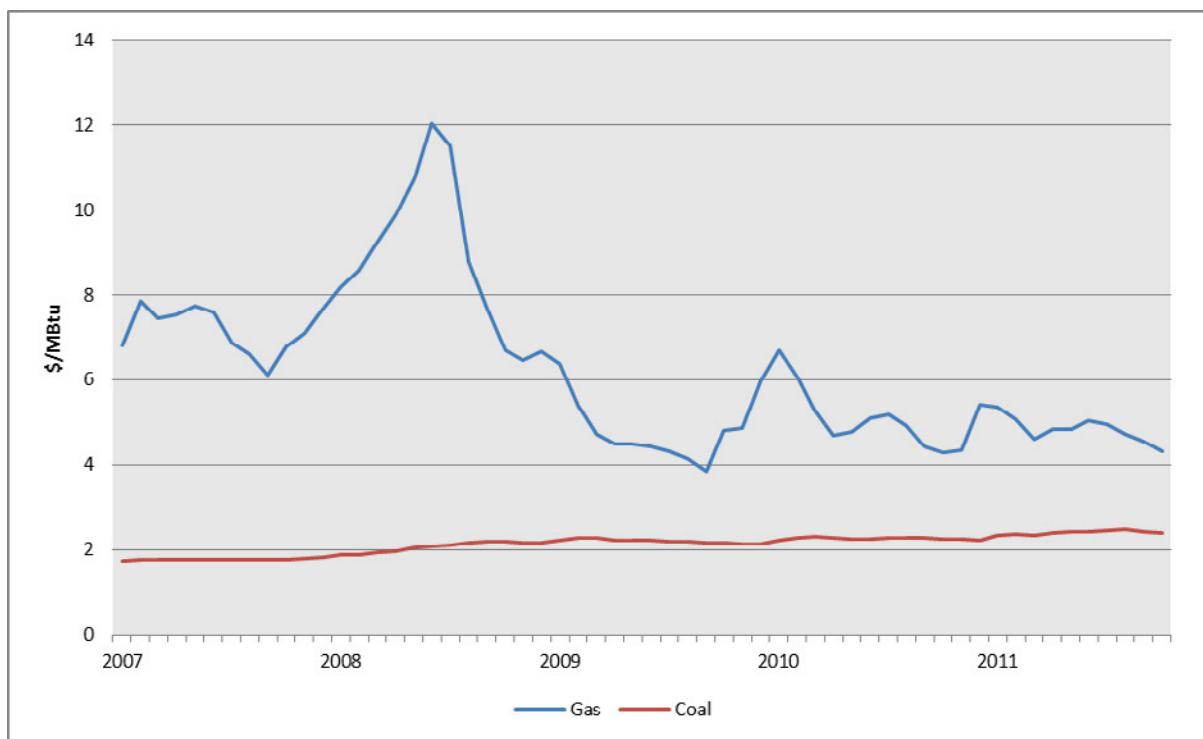


¹⁸ IEA, 'Energy Technology Perspectives: Scenarios & Strategies to 2050', (Paris: Organisation for Economic Co-operation and Development 2006).

¹⁹ This is assuming a price of \$7/mcf. Marianne Kah, 'The future role of natural gas in the US' (paper presented at the UT Energy Symposium, Austin, TX, 2011).

²⁰ EIA, 'Electric Power Monthly: January 2012'.

Figure 5-6: Average cost of coal and gas for electricity generation in the United States of America, January 2007 - October 2011²¹



Besides its growing role in electricity generation, natural gas may very well become an important component of the transportation sector, whether directly in natural gas-powered vehicles (NGVs) or via the generation of electric power to recharge the batteries of an electric vehicle.²² An MIT interdisciplinary study also concludes that the two most significant opportunities for addition market share for natural gas are power generation and transportation.²³ This has been confirmed by IEA analysis, which modelled a significant penetration of NGVs as a result of favourable price differentials between natural gas and oil. The introduction of such vehicles leads to a predicted expansion of gas in the road transportation sector's global energy mix, from 1% to between 3-5% in 2035.²⁴

In addition to fostering investment in gas-fired electricity generation and boosting the prospects for gas-powered transport, the surge in US shale gas production has also had impacts on the transformation sector, particularly the US petrochemicals industry. As a result of this energy-intensive industry requiring a substantial amount of ethane and other natural gas liquids, its competitiveness is heavily dependent on the price of these liquids, as well as the price of competitive feedstocks more generally (such as propane, butane and naphtha). In this context, increases in the ratio of the price of oil to the price of natural gas (from a low of 5.5:1 in 2003 to 15.9:1 in 2009) have been favourable for US exports of petrochemicals, plastics and other derivatives. The American Chemistry Council has therefore been upbeat about its future prospects, noting that 'with the development of new shale gas resources, the US petrochemical industry is announcing

²¹ Ibid.

²² Downey, 'Fueling North America's future'.

²³ Moniz, Jacoby and Meggs, 'Future of natural gas'.

²⁴ IEA, 'WEO 2011', 171.

significant expansions of petrochemical capacity, reversing a decade-long decline'.²⁵ However, it must not be assumed from this trend that shale gas has reinvigorated demand in the US industrial sector as a whole; dramatic efficiency gains, coupled with drops in productivity due to the global recession and anticipated regulation of greenhouse gas (GHG) emissions, have offset increases in demand.²⁶

5.1.3 Natural gas and renewable energy

Natural gas is often promoted as the optimal backup for intermittent renewable electricity generation. Indeed, annual utilisation rates for wind turbines (the renewable energy source with the greatest potential for growth in the USA) stand at around 30%. With load factors (ratio of average/peak demand) in the USA nearing 57%, the integration of wind power into the electricity generation sector requires considerable backup capacity. Gas-fired CCGTs, combustion turbines and steam boilers are well suited to 'cycling' and 'peaking' capacity requirements, in that utilisation rates can be changed in response to load variations, while fuel injection can commence rapidly to meet high but infrequent levels of electricity demand. This makes natural gas an ideal accompaniment to intermittent renewable electricity generation, ensuring grid stability during times of peak demand in a way that coal or nuclear plants cannot.

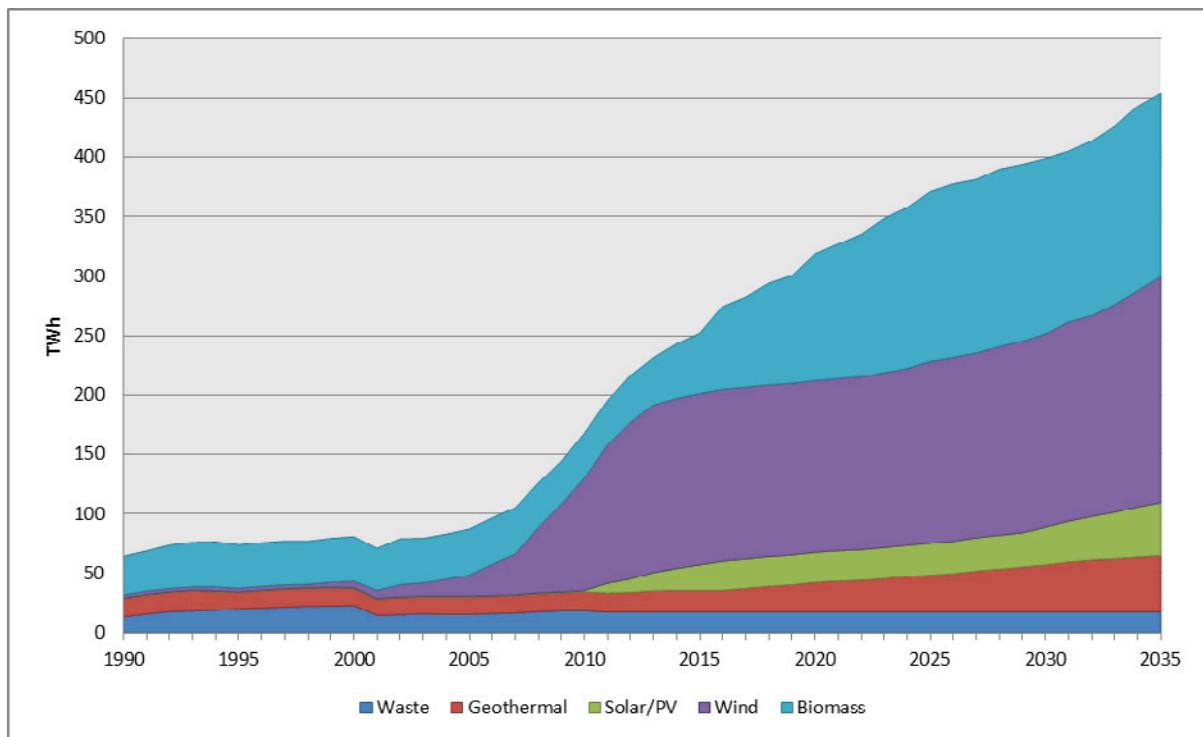
Thus, there are visible prospects of natural gas gaining market share as renewable electricity generation rises. Indeed, a recent analysis carried out by the EIA has predicted strong growth in the renewables sector. Sources that generate variable amounts of electricity (e.g. non-hydro) are set for a growth spurt in the coming decades such that, by 2035, the share of these energy sources in the total generation of the USA is predicted to increase to 9% (up from 4% in 2010).²⁷ The expansion of renewable energy in the USA is contingent on a number of factors, but the necessity for ensuring grid stability through backup capabilities is a key consideration for investment in this sector. Natural gas is an attractive option in this context but it is by no means the only one; reservoir hydro or pumped storage could also serve to stabilise solar or wind-powered electricity generation through storage capabilities (although these sources of flexibility are often not available close to centres of demand).

²⁵ American Chemistry Council, 'Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and US Manufacturing', (Washington, DC: American Chemistry Council, 2011).

²⁶ Downey, 'Fueling North America's future'.

²⁷ EIA, 'EIA projects U.S. non-hydro renewable power generation increases, led by wind and biomass', (Washington, DC: US Energy Information Administration, 2012).

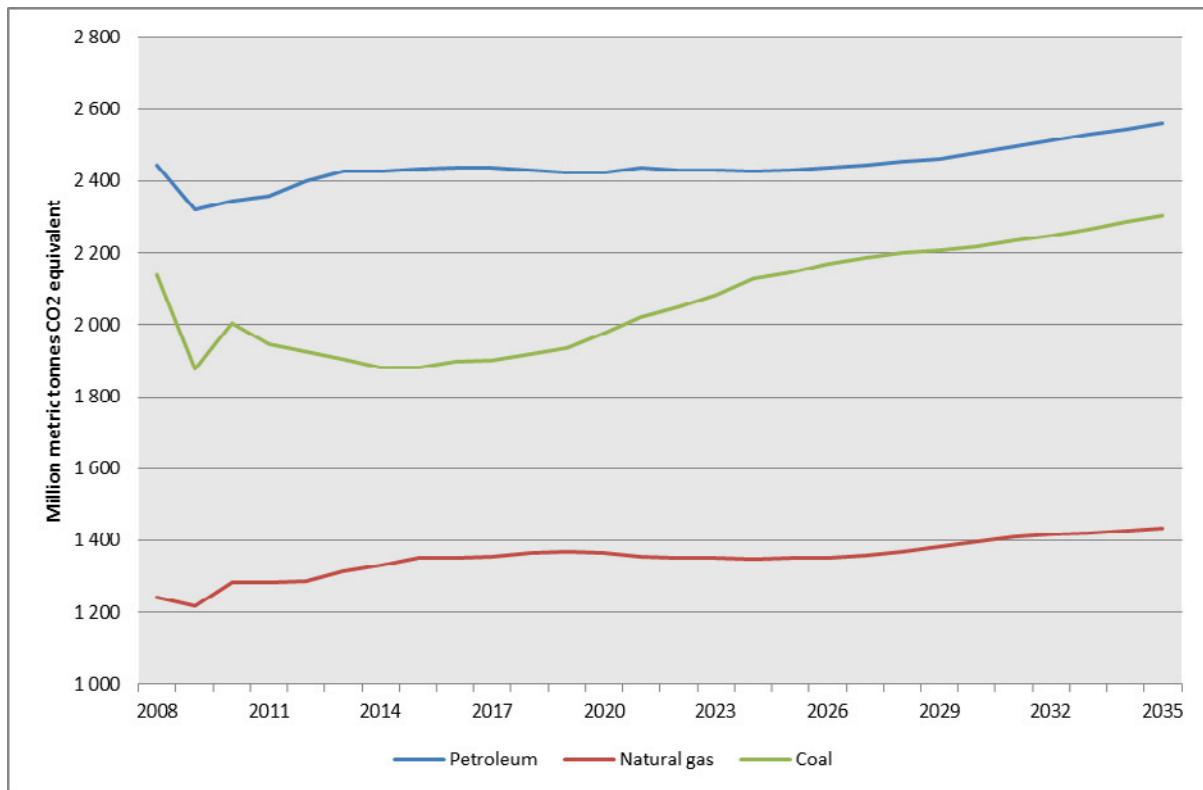
Figure 5-7: Projected non-hydropower renewable electricity generation in the United States of America, 2010-2035²⁸



Much debate has centred around the impact of shale gas development on renewable energy and climate change goals. Whereas proponents invoke the argument that gas is the cleanest fossil fuel and can displace coal while serving as a backup fuel for intermittent renewable power, opponents claim that cheap and reliable gas-fired power generation will divert investment away from renewable energy projects, and that even the comparatively low carbon footprint of natural gas will nonetheless equal increases in overall GHG emissions as global demand for energy continues to grow. Evidence can be presented in favour of both sides, as there is still much uncertainty over climate change policies and the longer-term incentives for market players to invest in renewable and/or gas-based power generation. After all, the planning horizons for energy infrastructure investments, as well as GHG emission reduction goals, are both measured in decades; should countries such as the USA – where fossil fuels constitute over 80% of total primary energy supply – decide on carbon reduction regulations (such as cap-and-trade or an emissions ceiling), this will affect the operating margins of a substantial portion of the energy industry, particularly those players that have chosen the ‘wrong fuel’. Compounding this longer-term uncertainty is the outlook for natural gas prices, which historically have been far more variable than coal (see Figure 5-6 above), as well as the need to quantify the opportunity cost involved in choosing gas over renewables (and, indeed, vice versa).

²⁸ Ibid.

Figure 5-8: Projected CO₂ emissions in the United States of America²⁹



As an unconventional fossil fuel, shale gas has sparked a related debate on whether additional carbon emissions are emitted from its relatively unique method of extraction. It is not the purpose of this section to unpack in any detail the arguments put forward in this context, but merely to draw attention to the differences in life-cycle emissions analyses related to shale gas.³⁰ Robert Howarth and fellow researchers at Cornell University have put forward a controversial claim that fugitive methane emissions from shale gas development contribute to an overall GHG footprint equal to coal over a 100-year time scale.³¹ However, others have countered that life-cycle analysis of emissions from natural gas need to account for the relative efficiencies of different fossil fuels used for power generation. For example, it has been argued that the numbers in the Cornell study "are based on the high heating values (HHV) of shale gas and coal for CO₂ emissions, without taking into account the higher efficiency of shale gas in power generation, which would result in less CO₂ per unit power output."³² One study has noted a caveat in this respect, highlighting the variability of emissions due to site-specific factors, such as the pressure of the fluids brought to the surface; the effectiveness of on-site gas capturing equipment; the control efficiency of any flaring that is done; the chemical composition of the gas and hydrocarbon liquids at the drill

²⁹ EIA, 'AEO 2011'.

³⁰ See EIA, 'Emissions of Greenhouse Gases in the United States 2008', (Washington, DC: 2009), Jinsheng Wang, David Ryan and Edward J. Anthony, 'Reducing the greenhouse gas footprint of shale gas', *Energy Policy* 39, no 12 (2011).

³¹ Robert W. Howarth, Renee Santoro and Anthony Ingraffea, 'Methane and the greenhouse-gas footprint of natural gas from shale formations', *Climatic Change* 106 (2011): 679–90.

³² Wang, Ryan and Anthony, 'Greenhouse gas footprint of shale gas'.

site; and the duration of drilling and completion work before the start of regular production.³³

More generally, the debate on the role of gas in the transition to renewables has evoked ideological arguments concerning the use of fossil fuels. A provisional assessment of the impact of shale gas on the environment and climate change carried out by UK researchers argues that 'whilst world demand for fossil fuels remains high, any new sources of fossil fuel (even if relatively low carbon per unit of useful energy) will be purchased, combusted and consequently added to the global emissions burden. It will not substitute for other fossil fuels and in this regard claiming shale gas as a viable low carbon option for the UK cannot be reconciled with the spirit of UK commitments on climate change.'³⁴ This statement makes it clear that natural gas may be a burden or boon to the carbon agenda depending on one's criteria and expectations. Given the complexity of the issues and the changing incentives of state, market and societal actors under various political, economic and social conditions, it is likely that the evolution of the gas/renewables relationship will be far more nuanced than the stark positions on either side of the debate. In other words, natural gas will at times constrain and at others enable investments in renewable energy. Possible technological and regulatory breakthroughs may yet alter the supply balance in the USA and elsewhere, contributing to a substantially revised outlook for longer-term investments in both renewable and non-renewable energy infrastructure.

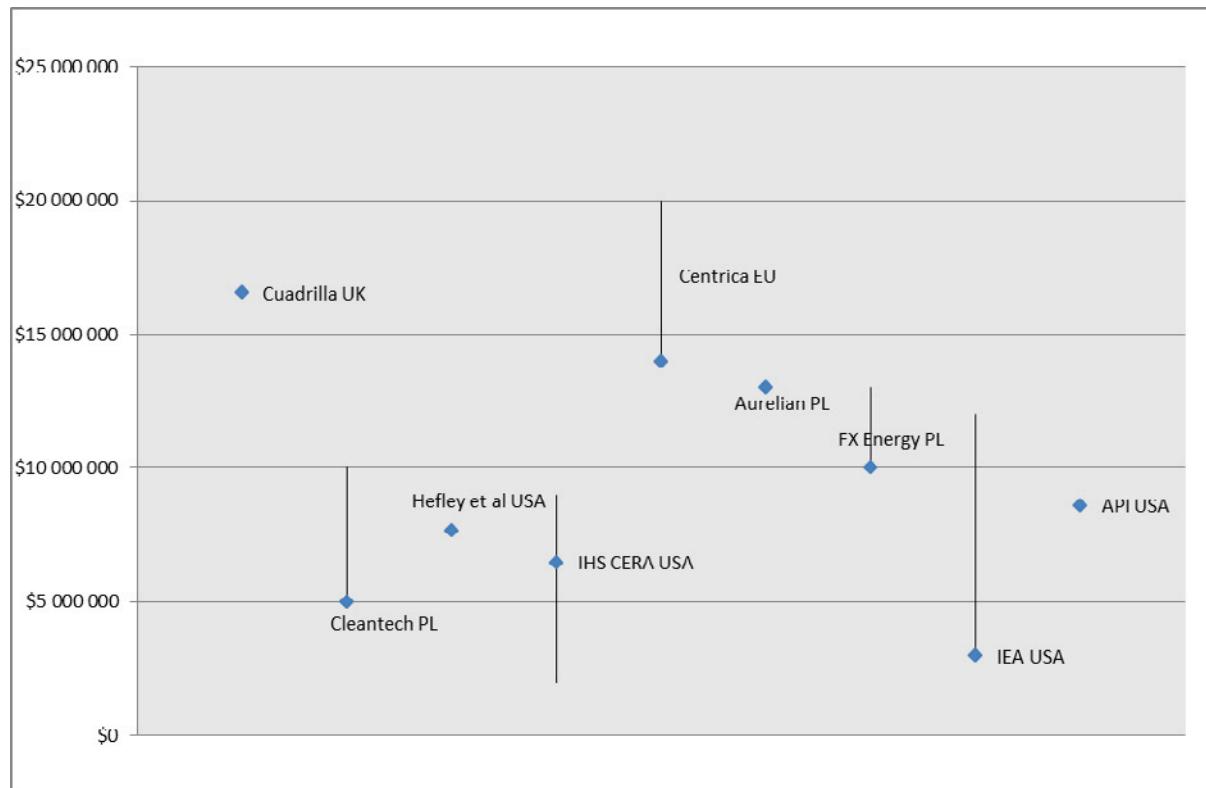
5.1.4 Shale gas production costs and natural gas prices

Production costs of shale wells, particularly their level in relation to general market prices, form a crucial determinant of the degree of future unconventional gas development in the USA and elsewhere. However, there is a notable absence of concrete per-well production costs available in the public domain. From what can be gleaned from various corporate presentations and private consulting firms, per-well production costs for shale gas wells in the USA tend to range from \$2-9 million. Given the early stages at which Europe is assessing its shale gas potential, figures for per-well production costs are even more tentative, with estimates ranging from \$5m up to \$20m (see Figure 5-9).

³³ Al Armendariz, 'Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements', (Dallas, TX: Southern Methodist University, 2009), 33.

³⁴ Wood et al., 'Shale gas provisional assessment', 51.

Figure 5-9: Total per-well production costs for shale gas³⁵



As discussed in Chapter 3, the range of shale gas production costs is influenced by a number of physical and commercial factors. The former includes factors such as the geological characteristics of the play in question (e.g. depth, permeability, total organic carbon content, etc.), the number of frac stages, the length of the horizontal sections of the wellbore and the number of drilling days. Decisions on drilling programmes rely on evaluations of the possible, probable and proved reserves following test drilling and seismic monitoring results (which commonly yield a chance of success expressed in percentage terms). Commercial factors, on the other hand, include taxes, royalty rates and the cost of services and materials for drilling, completion and building the supporting infrastructure for gathering, processing and compressing produced gas. Once in the production stage, well performance indicators such as IP rate, the EUR of gas from the well, the reserves-to-production ratio and the decline curve all affect the net present value of the well (as well as the rate of return for the drilling company). Examples of the way in which shale gas drilling companies evaluate potential wells and quantify finding and developing costs are presented in Annex H.

There are several indirect factors that have been known to significantly affect the cost-competitiveness of shale gas wells in the USA, either positively or negatively. One such factor, for example, is the cost of water. A consulting report notes that an individual shale gas well commonly requires the acquisition and treatment of between 2-6 million gallons of water. Currently, the costs of this water are estimated to range between

³⁵ Mohsen Bonakdarpour et al., 'The economic and employment contributions of shale gas in the United States', in *IHS Global Insight* (Washington DC: IHS Cera, 2011); Centrica Energy, 'Unconventional Gas in Europe'; Cleantech, 'Investment Guide'; Cuadrilla Resources, 'Economic Impact in Lancashire'; FX Energy, 'Poland; A unique play on the strong European gas market', (FX Energy, 2012); Hefley et al., 'Economic Impact'; IEA, 'Oil and Gas Markets'; Mark Kaiser, 'Profitability assessment of Haynesville shale gas wells', *Energy* 38, no 1 (2011).

\$0.25/Mcf to as high as \$1.38/Mcf.³⁶ This range reflects uncertainties concerning water quantities as well as the appropriate treatment strategy (which, in turn, are importantly affected by sub-surface interactions between fracturing fluids and shale rocks). The World Energy Council, moreover, believes that steadily increasing costs related to water reclamation and chemical cleanup have the potential to drive up production costs to \$6-8/Mcf.³⁷ Other such issues bearing on production costs include: changes to tax credits for unconventional fuels; environmental considerations limiting both sub-surface drilling practices and land access for well drilling and completion activities (see Section 4.1 for a more detailed treatment of this issue); and revised fiscal regimes in US states situated atop unexplored shale gas deposits. Analysts often note a number of potential service sector bottlenecks, such as the availability of land-based rigs equipped to horizontal drilling specifications and the sufficiency of skilled human resources. An absence of these may increase the cost base and challenge the commercial viability of well-drilling projects.³⁸

It is, therefore, not surprising that the range of production costs is so great. Nonetheless, analysts have attempted to provide 'rules of thumb' that extrapolate from drilling experience. It is commonly argued, for example, that most of the life-cycle costs of developing a single shale gas well are expended under the categories of finding and development (F&D) and lease operating expenditures (LOE).³⁹ These broader categories can be further sub-divided into constituent cost components. According to IHS CERA, the well capital expenditures that form part of F&D costs can be divided into three main categories – drilling (40%), completions (including fracking, 50%) and facilities (10%).⁴⁰ However, for Europe these cost ratios may not reflect the absence of upstream infrastructure in several countries with shale gas prospects. There is also some scope for debate as to the largest cost components for developing a shale play. Some studies have noted that F&D costs represent the most significant proportion of total well costs and as such are pivotal for determining break-even prices.⁴¹ However, other analysts have pointed out that F&D costs make up a considerable proportion of total expenditure only in the first three years, but subsequently the costs are more evenly dispersed when taking into account the full life cycle of a well.⁴² This bias may be due to the observation that gas drilling firms typically require a pay-out within the first three years of their initial investment.⁴³

³⁶ Black & Veatch, 'Growing shale resources; understanding implications for North American natural gas prices', (prepared for the state of Alaska by Black & Veatch Management Consulting, 2010).

³⁷ WEC, 'Survey of Energy Resources', 14.

³⁸ Rogers, 'Shale gas': 134.

³⁹ Gény, 'Unconventional Gas', 80.

⁴⁰ Bonakdarpour et al., 'Economic and employment contributions', 15. The cost of land acquisition seems to have been considered separately.

⁴¹ Michelle Foss, 'The Outlook for US Gas Prices in 2020: Henry hub at \$3 or \$10?', (Oxford Institute for Energy Studies, 2011).

⁴² Guarne et al., 'Unconventional mindset'.

⁴³ A.E. Berman, 'Shale gas - the eye of the storm' (paper presented at the Middlefield Investment Conference, Calgary, Canada, 14 July 2011, 2011).

Figure 5-10: Indicative cost breakdown of a shale gas project, first three years⁴⁴

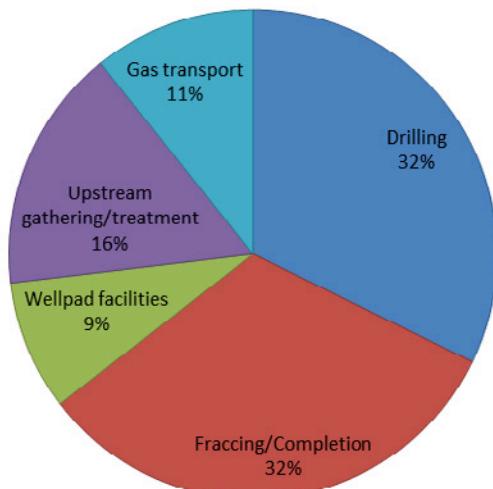
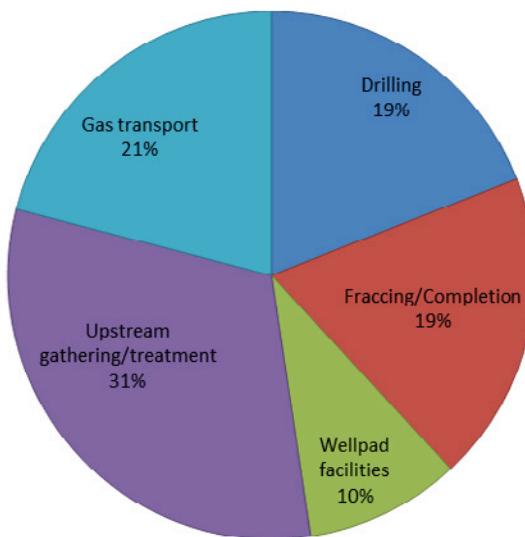


Figure 5-11: Indicative cost breakdown of a shale gas project, full life cycle⁴⁵



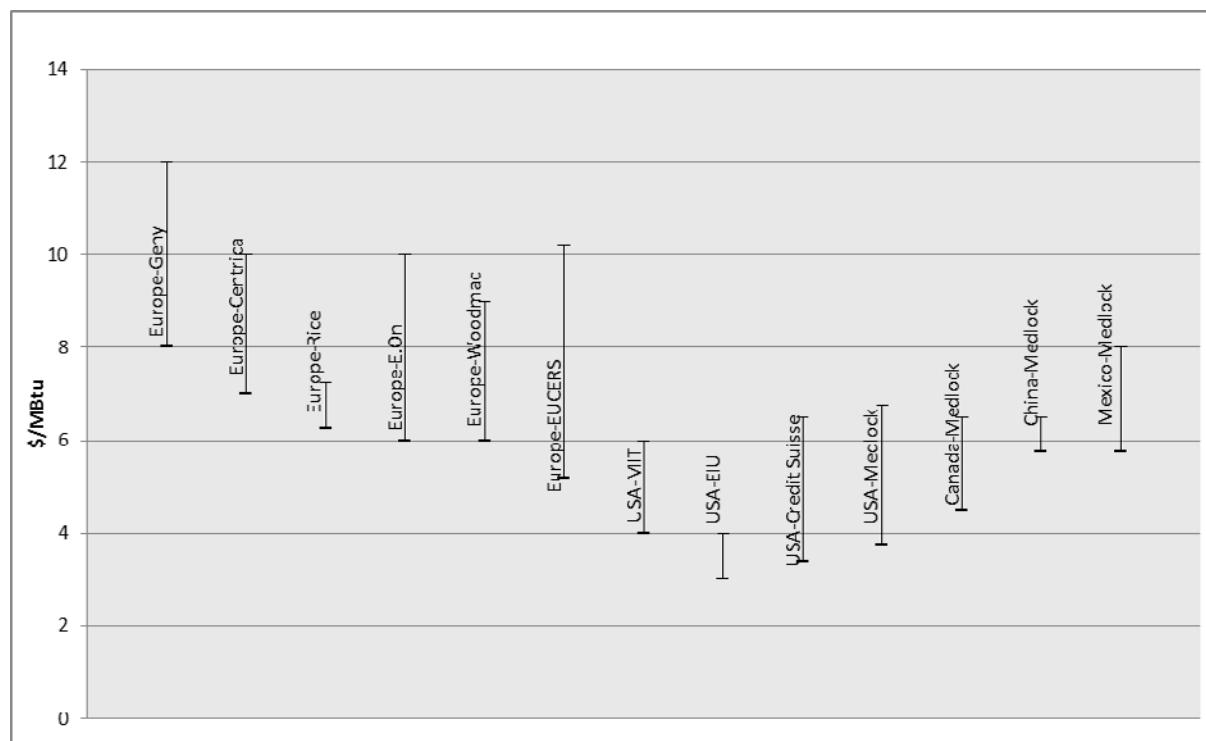
The production costs of natural gas need to be assessed in relation to gas prices in order to determine whether the resource is economically viable. However, estimates of the so-

⁴⁴ Guarnone et al., 'Unconventional mindset'.

⁴⁵ Ibid.

called 'break-even' price of natural gas, which is necessary to recoup per-well expenditures, vary and are subject to much contestation. As noted by the IEA, conventional wisdom in 2008 converged around a price range of \$6-8/MBtu for shale gas to be economic. Since then, this range has been progressively lowered and, writing in 2010, the IEA estimated a price between \$3-6/MBtu for North America.⁴⁶ Early estimates for break-even costs in Europe (specifically Poland and Germany) were provided by an analysis carried out by the Oxford Institute for Energy Studies and range from \$8-12/MBtu.⁴⁷ The IEA's assumptions regarding costs were estimated on a life-cycle production basis only and were hence limited to finding/developing costs, operating expenditures and decommissioning costs (all of which were discounted by the cost of capital).⁴⁸ However, neither transportation costs nor the cost of liquids production were taken into account, despite the latter having been noted as a significant factor positively affecting shale well economics in the USA (see Chapter 3).

Figure 5-12: Break-even prices for unconventional gas production⁴⁹



The effect of shale gas development on prices has already been felt in the USA. As shown in Figure 5-13 and Figure 5-25, US Henry Hub prices began a sharp decline in 2008, which corresponded with, amongst other factors, the steady increase in natural gas production in the USA. Of course, US market conditions are quite variable, as average Henry Hub spot prices have ranged from under \$3 to over \$12 per MBtu in the past five years. Much of this impact has been due to the global recession in 2008, contributing to

⁴⁶ IEA, 'Oil and Gas Markets', 183.

⁴⁷ Gény, 'Unconventional Gas', 87.

⁴⁸ IEA, 'Golden age', 49.

⁴⁹ Centrica Energy, 'Unconventional Gas in Europe'; Economist Intelligence Unit, 'Breaking new ground: A special report on global shale gas developments', (London: Economist Intelligence Unit, 2011); Gény, 'Unconventional Gas'; Korn, 'Prospects in Europe'; Wood Mackenzie, 'Global unconventional gas trends', (Wood Mackenzie, 2009); Medlock, Jaffe and Hartley, 'Shale Gas and National Security'; Moniz, Jacoby and Meggs, 'Future of natural gas'.

a pronounced fall in the US gas price and a corresponding reduction in the number of rigs actively drilling for gas.⁵⁰ It was therefore initially anticipated that depressed prices in the USA would ease indigenous production of gas, as the break-even extraction costs would no longer be covered by wellhead prices. However, contrary to this belief, the margins have improved as the technological learning curve has driven down per-well development costs.⁵¹ Moreover, gas producers 'sold production forward' on gas futures and the expectation of higher prices. This hedging strategy, propped up by a bullish forward price curve, helped to cushion producers from depressed gas prices in the second half of 2008.

However, some research has recently concluded that the production costs claimed by various shale gas-producing companies are optimistically low and that in reality these independent producers have actually been selling their gas at large negative economic margins.⁵² A study undertaken by Weijermars et al. in 2011 compared conventional vs. unconventional gas producers according to earnings, capital, shareholder return, value driver inventory and margin analysis; it was revealed that unconventional producers regularly underperformed in relation to their conventional gas-producing counterparts. A key conclusion of the study was that sustained shale gas production and the avoidance of a liquidity crisis crucially relies on better well-flow rates, lower production costs and significant research and development (R&D) in order to enable a lower F&D cost base.⁵³ Another study that modelled and simulated shale play economics in Haynesville, USA similarly concluded that, given high initial capital expenditures for developing shale gas resources, 'the majority of wells fail to break-even on a full-cycle basis at prevailing gas prices [~\$4/MBtu].'⁵⁴ Compounding these challenging economics is the relatively steep decline curves for shale gas wells, implying that continuous drilling is required to maintain a flat production profile.

One element that must be factored in to any examination of the strong and sustained growth in US shale gas production is NGL production – a topic already touched upon in Chapter 3 (see Table 3-11, Table 3-21 and Table 3-22, for example). For decades, natural gas traded at a relative price to oil of between 6:1 and 10:1. Crude oil prices have since risen and North American gas prices have dropped to yield ratios of almost 20:1 at the time of writing. High oil prices mean that US drilling rigs are migrating from dry shale plays, such as the Marcellus, to liquids-rich plays in the Mid West, such as the Anadarko, Bakken and Permian. As the price of NGLs is determined by the price of oil, such plays are much more commercially attractive, but the significant amounts of dry gas incidentally produced from such plays are sold on the gas market regardless of the already-low market prices. If this trend continues, the US market for natural gas could be in for an extended period of very competitive prices.⁵⁵ See Box 6-2 for additional elaboration of this point.

⁵⁰ Rogers, 'Shale gas': 125.

⁵¹ EIA, 'AEO 2011'.

⁵² Weijermars et al., 'Unconventional gas research initiative'. See also Berman, 'Eye of the storm', Foss, 'US Gas Prices in 2020'.

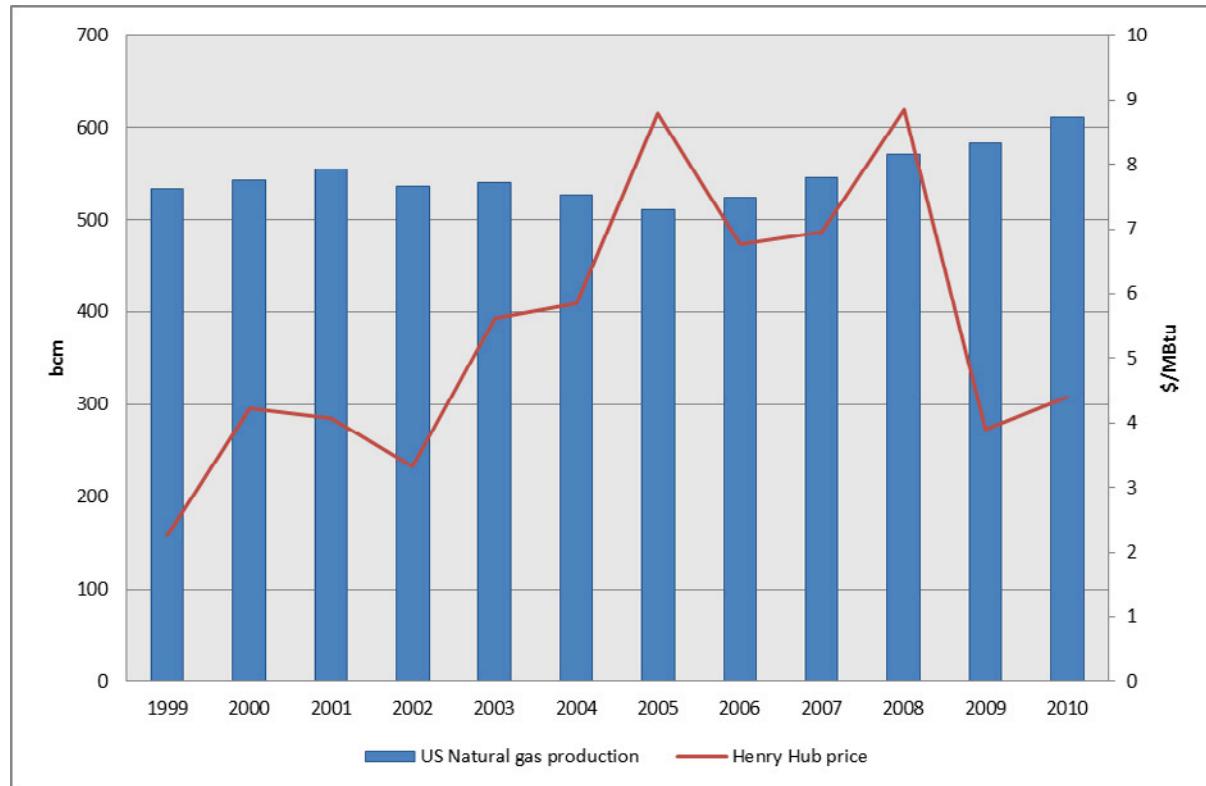
⁵³ Weijermars et al., 'Unconventional gas research initiative'.

⁵⁴ Kaiser, 'Profitability assessment'.

⁵⁵ Bentek Energy LLC, 'US Energy Markets In Transition: Nat Gas, Oil & NGLs Rewrite The Script' (paper presented at the European Commission, Brussels, 2012); Guy Chazan, 'Statoil to switch focus to "liquid-rich shales"', *Financial Times*, 8 February 2012, 2012.

Furthermore, it remains to be seen whether the margins underpinning shale play economics can be improved by the technological learning curve. Analysts at ARI International, a consulting firm, have provided evidence on improved well performance in the form of reduced drilling days, increases in the average IP rates of producing wells and ever-longer lengths of horizontal sections of wellbores.⁵⁶ These factors have contributed to a reduction by half in total drilling and completion costs in the last five years of shale gas drilling, and portend future efficiency gains that may offset the precipitous fall in US wellhead/spot prices.

Figure 5-13: US natural gas production and average annual Henry Hub prices⁵⁷



Disregarding the numerous debates revolving around shale gas well economics and the extent of cost optimisation, it is already apparent that shale gas development in the USA has had a significant effect on the outlook for future gas prices. Indeed, whereas the AEO2011 reference case projects gas prices to reach \$7.07/MBtu in 2035, a scenario of high EUR of shale gas yields a price of \$5.35/MBtu. Conversely, a low shale EUR case predicts prices as high as \$9.26/MBtu.⁵⁸ That the estimated range of prices varies so significantly as a result of different production rates for shale gas bears testament to its importance for the future of the US energy balance. However, it remains to be seen what impact the progressive decline in prices – from an average of \$4.50/Mbtu in 2010, to \$4.00/Mbtu in 2011, to the recent ten-year lows of around \$2/Mbtu – will have on the margins of independent unconventional gas producers over the coming years.

Setting the US case in a wider global context, the IEA's World Energy Outlook has revised its natural gas price assumptions in all three of its scenarios due to what it considers to be improved prospects for the commercial production of unconventional

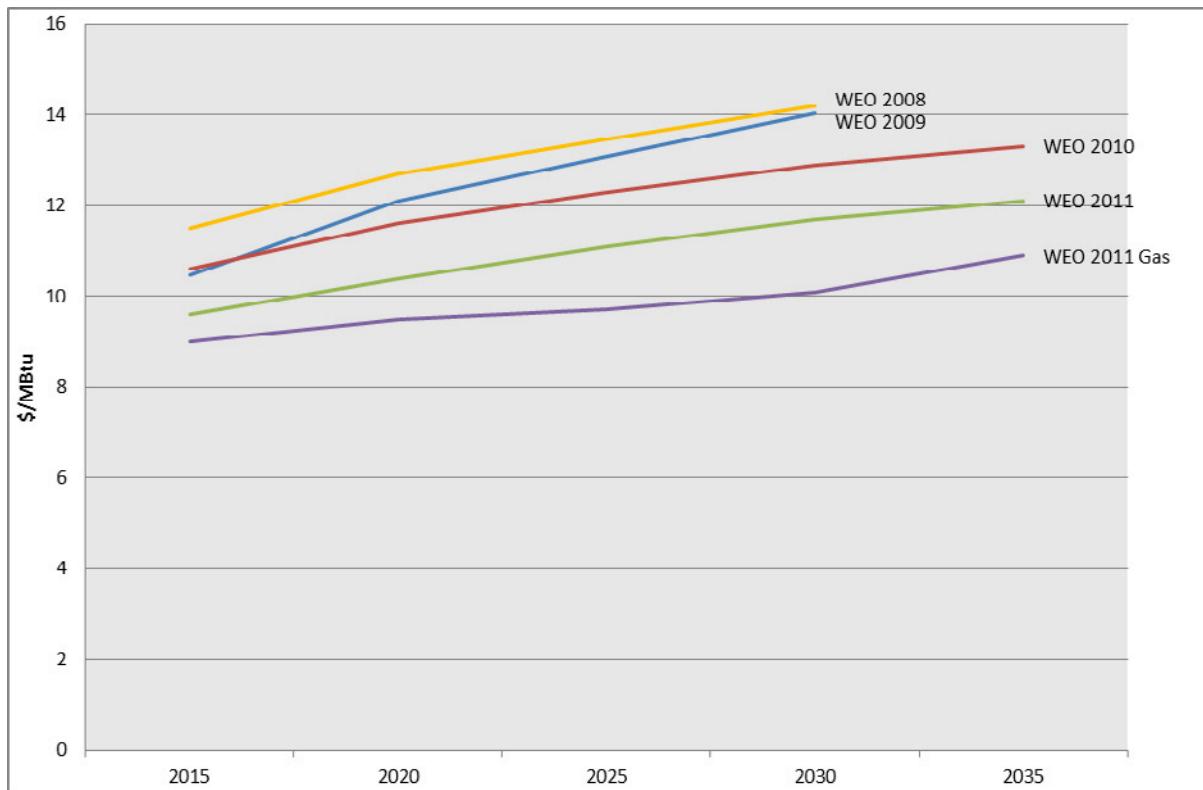
⁵⁶ Kuuskraa, 'Economic and market impacts', 9.

⁵⁷ BP, 'Statistical review 2011'.

⁵⁸ EIA, 'Effect of Increased Natural Gas Exports'.

gas. In particular, the report notes that “higher projected output of unconventional gas acts to keep increases in the price of natural gas below the level envisaged in WEO-2010, increasing its competitiveness against other fuels.” Indeed, although average gas import prices in Europe have since recovered from an earlier five-year low of \$6.34/Mbtu in August 2009 (or €4.51/Mbtu), each IEA WEO since 2008 has nonetheless revised its projections of gas import costs for Europe into the coming decades. As shown in Figure 5-14, the average import prices under the IEA reference and ‘new policies’ scenarios, although steadily rising, have nonetheless been repeatedly revised downwards in recent years (the WEO 2011 ‘Golden Age of Gas’ scenario is added for a reference ‘lower bound’ price estimate).

Figure 5-14: IEA estimates of import price for Europe under reference scenario⁵⁹



5.2 The impact in Europe to date

Unlike the oil market, natural gas markets are currently not globally integrated. At the time of writing, natural gas prices span a range from around \$0.75 per million British thermal units (MBtu) in Saudi Arabia to just over \$2/MBtu in the USA and \$16/MBtu in the LNG-dependent Asian markets. EU prices fall between US and Asian prices, with the price of gas traded at the UK National Balancing Point (NBP) averaging \$9.21/MBtu during November 2011. But even within the EU itself, there can be significant differences between the ‘spot’ prices in North West European Member States like the UK and long-term oil-indexed prices in Central and Eastern European Member States.⁶⁰

In spite of the fragmentation in the global gas system, the last decade has seen gradual, but unmistakable, change that has led to the ripple effects of the unconventional gas

⁵⁹ IEA, ‘Golden age’; IEA, ‘World Energy Outlook’, in *World Energy Outlook* (Paris: Organisation for Economic Co-operation and Development, various).

⁶⁰ EIA, ‘Effect of Increased Natural Gas Exports’, 3.

revolution in the USA being felt worldwide. The natural gas system has gone from being comprised of distinct regional or national markets to one where interregional trade flows have a noticeable impact on physical supply-demand dynamics and in some circumstances even large shifts in prices. Global growth in the trade of LNG has underpinned this transformation. Whereas the concept of a 'world gas market' was almost unthinkable ten years ago, a surge of new global LNG liquefaction capacity, much of which is inherently destination flexible or 'self-contracted', has introduced the first elements of interregional gas price competition.⁶¹

In early 2010, the development of the increasingly globalised LNG market coincided with two other key factors to create a 'perfect storm'⁶² that resulted in a glut of global gas supply: a) the boom in unconventional gas production in the USA; and b) demand levels below those anticipated due to the economic recession.⁶³ This section explains how these issues came together, heralding significant changes in the natural gas system that allowed unconventional gas to significantly impact European markets years before any prospective indigenous production within Europe itself. It also looks at the implications on investment in infrastructure, as well as the implications on the way natural gas is priced in the EU.

⁶¹ Jensen, 'LNG Revolution': 8.

⁶² Howard V. Rogers, 'LNG Trade-flows in the Atlantic Basin: Trends and Discontinuities', (Oxford: Oxford Institute for Energy Studies, 2010), 41.

⁶³ For an overview, see IEA, 'WEO 2010'.

5.2.1 Increasing LNG liquefaction and regasification capacity

Global LNG trade volumes have been steadily growing in the last decade and increasing LNG liquefaction and regasification capacity looks set to continue to drive this trend for the foreseeable future.

Figure 5-15: Global LNG trade volumes and LNG as a percentage of global gas consumption⁶⁴

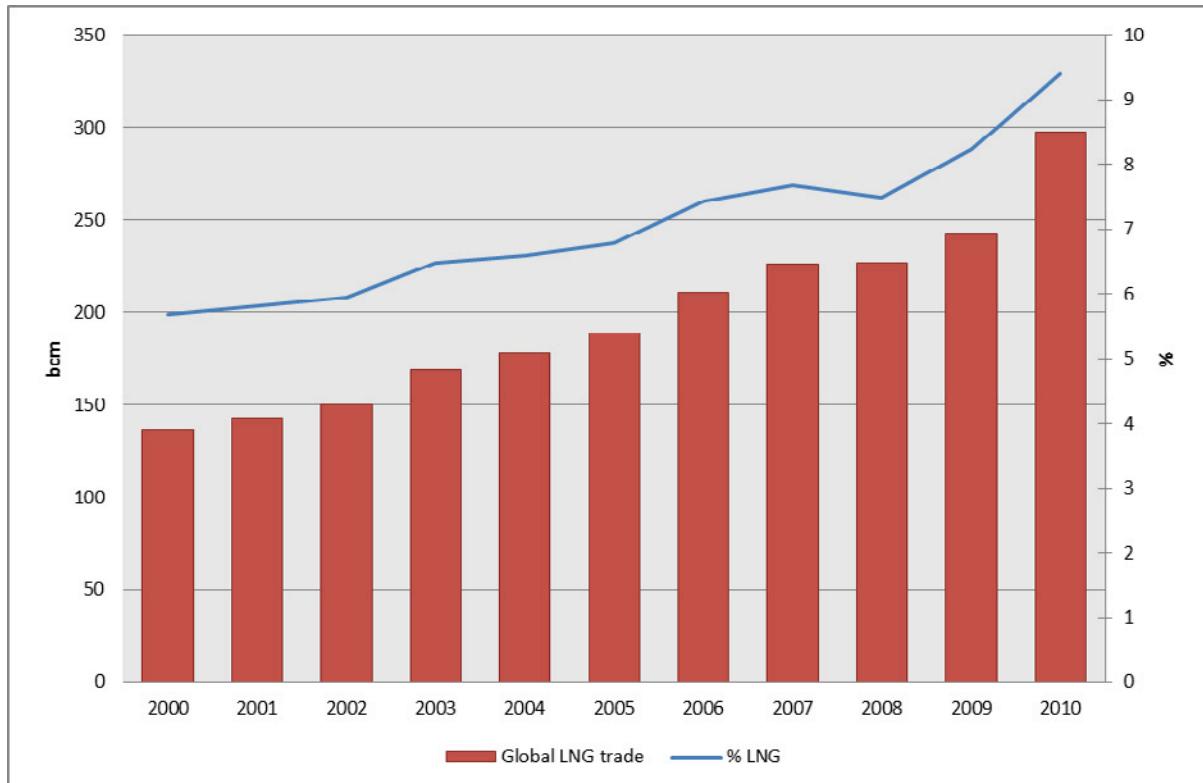
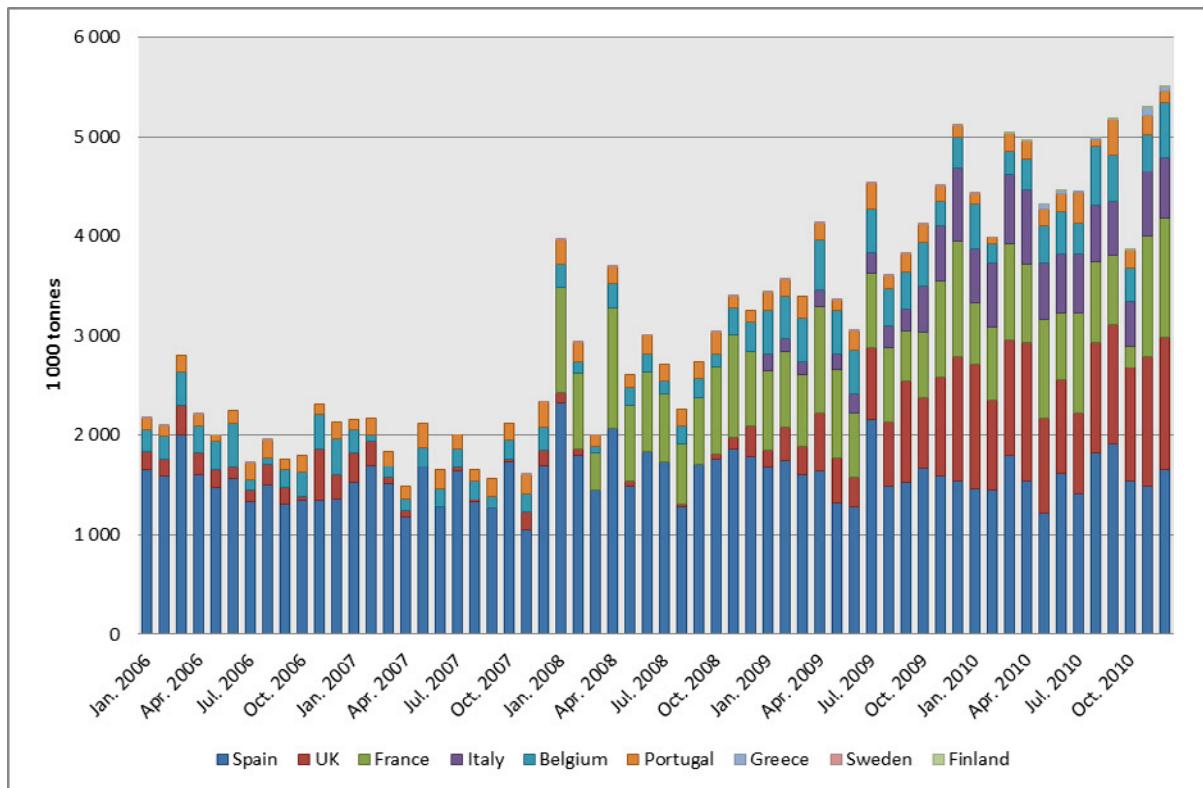


Figure 5-15 above shows a two-fold increase in global LNG trade volumes in the period 2000-2010. In proportional terms, this growth rate far exceeds incremental growth in global gas consumption, resulting in an ever greater percentage of the gas consumed globally – currently around 10% – being transported by LNG. It is expected that interregional gas trading will increase from 590 bcm in 2009 to around 1 150 bcm in 2035. More than half of this growth will come from LNG, increasing the share of LNG in interregionally traded gas from 31% in 2008 to 42% in 2035.⁶⁵

⁶⁴ BP, 'Statistical review 2011'.

⁶⁵ IEA, 'WEO 2011', 93.

Figure 5-16: EU LNG imports by Member State⁶⁶



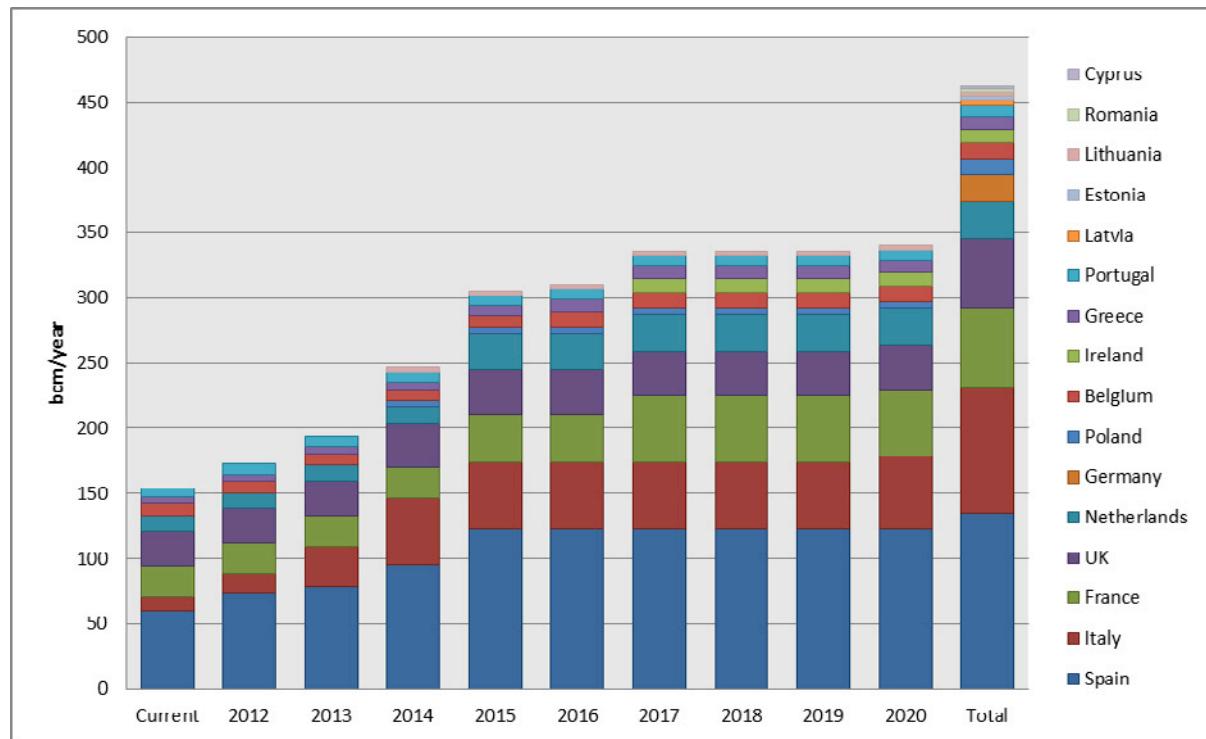
As a major consumer of natural gas, Europe is robustly contributing to this trend. Figure 5-16, above, shows a strong growth in LNG imports into Europe from 2008 to 2010. In this period, North West Europe saw the commissioning and start-up of substantial new LNG terminal import capacity. The Zeebrugge expansion in Belgium, together with three new UK terminals (Isle of Grain Phase II, South Hook LNG and Dragon LNG), added a total LNG import capacity equivalent to 43.5 bcm a year – a volume greater than the total gas demand in the Netherlands alone.⁶⁷ As Figure 5-17 below shows, the EU currently has a regasification capacity of over 150 bcm, which looks set to double in the period to 2020.⁶⁸

⁶⁶ Source: Eurostat. NB: There are differences in the way different Member States have reported LNG import volumes must be taken into account when considering this chart.

⁶⁷ Morten Frisch, 'Current European Gas Pricing Problems: Solutions Based on Price Review and Price Re-Opener Provisions', in *International Energy Law and Policy Research Paper Series* (Dundee: Centre for Energy, Petroleum & Mineral Law & Policy, University of Dundee, 2010), 9.

⁶⁸ Kuhn and Umbach, 'Strategic Perspectives', 44.

Figure 5-17: Current and planned EU-27 LNG regasification capacity (as of September 2011)⁶⁹



In 2010, Europe accounted for 22% of the world's regasification capacity, Korea and Japan 44% and North America 25%.⁷⁰ Given the steep decline in actual and forecast natural gas imports to the USA (examined further later in this section), it is likely that these ratios will change in the coming years. The sharp increase in US gas prices in the winter of 2001/02 had given rise to a rash of regasification terminal proposals,⁷¹ but given that the latest EIA energy outlook sees the USA becoming a net exporter of LNG in 2016 and an overall net exporter of natural gas in 2021,⁷² most of the projects awaiting final investment decisions are unlikely to move forward. With a number of planned LNG regasification projects in the USA on hold, Europe looks set to become the region with the fastest growing regasification capacity globally, soon overtaking the USA to become the second largest regional market for LNG after Asia in terms of regasification potential (see Table 5-1).

Table 5-1: LNG regasification terminals by region (as of June 2010)⁷³

Region	Operation	Construction	Planned
Asia	418	59	131
Europe	173	24	244
Middle East and Africa	3	4	11
North America	165	49	282
Latin America	14	2	8
Total	772	137	674

⁶⁹ Source: Gas Infrastructure Europe, 'GIE LNG Investment Database', (2011).

⁷⁰ IEA, 'Golden age', 71.

⁷¹ As of June 2010, 49 bcm of regasification capacity was under construction in the USA, bringing the forecast for total US capacity to 214 bcm by 2013. Fifteen projects were awaiting final investment decisions. IEA, 'Oil and Gas Markets', 262.

⁷² EIA, 'Annual Energy Outlook 2012: Early Release Overview', (Washington, DC: US Energy Information Administration, 2012).

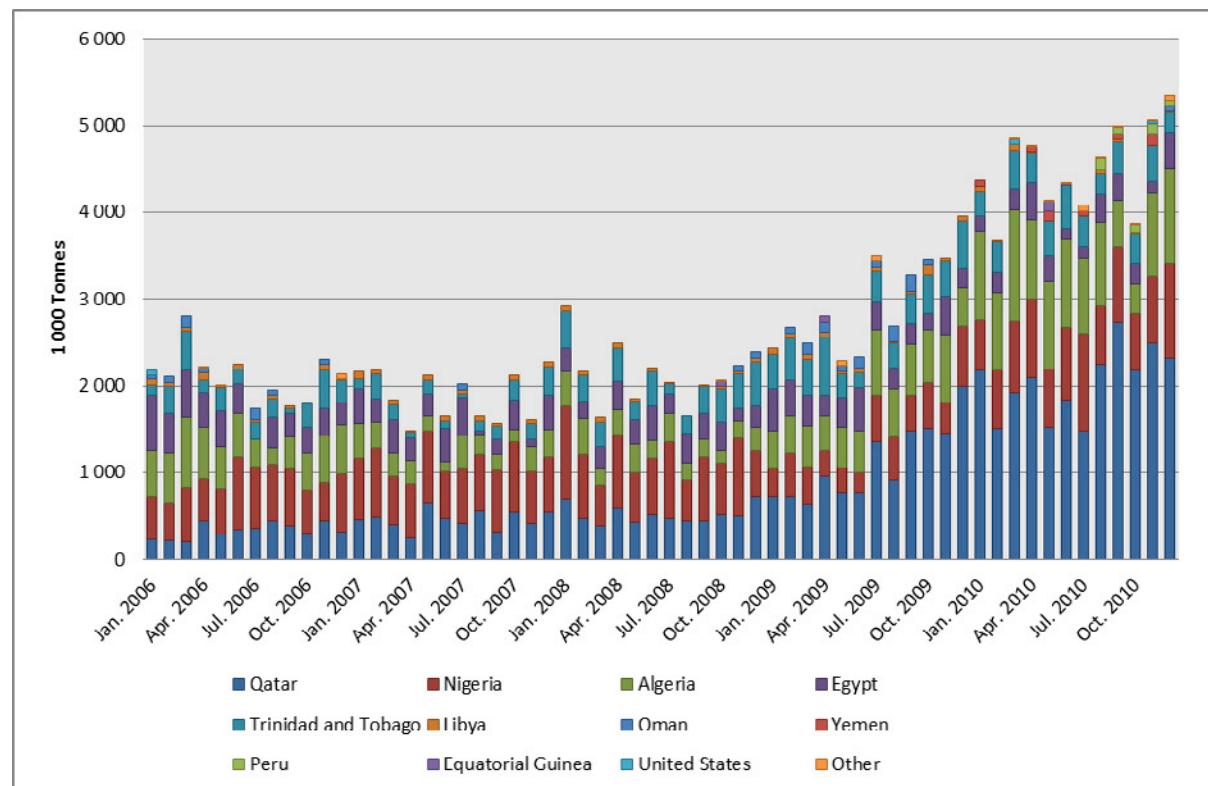
⁷³ IEA, 'Oil and Gas Markets', 254.

The large increase in LNG import capacity in North West Europe has coincided with the start-up of a number of large LNG liquefaction plants around the world. In a much-anticipated development, Qatar launched six 7.8 million-tonne-per annum (mtpa) LNG trains between April 2009 and December 2010, adding 80 bcm to global liquefaction capacity (Table 5-3). The sudden rise in Qatari output is reflected in the profile of EU-27 LNG imports as illustrated in Figure 5-18, below. Along with new LNG developments in Russia, Yemen and Peru, the Qatari projects helped to bring total global liquefaction capacity to around 370 bcm in mid-2011.⁷⁴

Table 5-2: Qatar's new liquefaction trains⁷⁵

Project	Partners	Capacity	No. of trains	Start date
Qatargas 2	Qatar Petroleum, ExxonMobil, Total	7.8 mtpa	2	Apr. 2009
Qatargas 3	Qatar Petroleum, ConocoPhillips, Mitsui	7.8 mtpa	1	Sep. 2010
Qatargas 4	Qatar Petroleum, Shell	7.8 mtpa	1	Dec. 2010
RasGas 3	Qatar Petroleum, ExxonMobil	7.8 mtpa	2	Sep. 2009 Feb. 2010

Figure 5-18: EU LNG imports by origin⁷⁶



At this point, it is worth touching on the apparent mismatch between global liquefaction and regasification capacity. As of June 2010, the world's regasification capacity stood at

⁷⁴ IEA, 'Golden age', 167.

⁷⁵ Kanai, 'Decoupling Oil and Gas Prices', 26.

⁷⁶ Source: Eurostat.

roughly 770 bcm – roughly 2.5 times its liquefaction capacity.⁷⁷ While this means there will be global competition for LNG shipments when world gas supply tightens,⁷⁸ surplus regasification capacity provides a very important flexibility for seasonal load-balancing purposes and may improve security of supply. For example, the value of Japan's excess regasification capacity was clearly demonstrated following the 2011 earthquakes and tsunami, because it allowed extra spot supplies to reach gas-fired power plants in order to bridge the shortfall in electricity generation caused by the loss of the Fukushima reactors.⁷⁹

With the expected completion of projects in Australia, Angola and Algeria, the trend in liquefaction growth looks set to continue into the immediate future, increasing overall capacity by an expected 50% in the five-year period from 2008 to 2013.⁸⁰ Looking further ahead, the Papua New Guinea and Gorgon projects will add significant LNG supplies to Asian markets. Final investment decisions were taken in 2009 and they are scheduled to start by 2014.⁸¹ Also of interest are three projects in Queensland, which are the first in the world to be based on CBM. Based on currently operating and sanctioned projects, Australian LNG export capacity could exceed 70 bcm by 2015, making it the second-largest global LNG exporter after Qatar.⁸²

Table 5-3: LNG liquification plants under construction by country⁸³

	Plant	Capacity		
		(bcm)	(mtpa)	Start date
Algeria	Skikda (rebuild)	6.1	4.5	2013
	Gassi Touil	6.4	4.7	2013
Angola	Angola	7.1	5.2	2012
Australia	Pluto	6.5	4.8	2012
	Gorgon	20.4	15.0	2014
	Gladstone LNG	10.6	7.8	2014
	Queensland Curtis	11.6	8.5	2015
Indonesia	Donggi Senoro	2.7	2.0	2014
Papua New Guinea	PNG LNG	9.0	6.6	2014

Yet further down the line, projects totalling over 500 bcm of additional liquefaction capacity are being evaluated to come online in the period 2015-2020. Liquefaction projects typically take four or more years to permit and build, and are planned to run for at least 20 years. These long lead times mean the maximum amount of supply that can be attained within the next five years is fairly well known, although project delays often result in lower capacity than anticipated.⁸⁴ Forecasts ahead of this five-year window are subject to greater uncertainty and it can be expected that many more LNG projects are reported in the trade press than are ever actually built.

⁷⁷ IEA, 'Oil and Gas Markets', 253.

⁷⁸ Weijermars et al., 'Unconventional gas research initiative': 404.

⁷⁹ IEA, 'Golden age', 71.

⁸⁰ IEA, 'Oil and Gas Markets', 14, 168, 71; IEA, 'WEO 2011', 167.

⁸¹ IEA, 'Oil and Gas Markets', 171.

⁸² IEA, 'WEO 2011', 168.

⁸³ Source: IEA, 'Golden age', 68. European Commission analysis.

⁸⁴ Ibid., 55.

With Henry Hub gas trading below \$3/Mbtu during the mild winter of 2012,⁸⁵ an increasing number of applications for liquefaction projects were submitted in the USA. These would allow applicants to export domestic supplies of natural gas to higher priced overseas markets as LNG. As well as the recent successful request to build the Sabine Pass liquefaction terminal in Louisiana, seven more applications for liquefaction projects have been submitted. If approved by the regulator, these projects would see roughly 18% of current US gas production shipped to markets worldwide.⁸⁶ However, the debate on whether to allow such exports is ongoing. Proponents have emphasised job creation at the LNG plants, while opponents, such as industrial consumers, stress the impact on US business in light of findings that more natural gas exports would lead to higher gas prices.⁸⁷

Notwithstanding this debate, the long-term effectiveness of any effort to resist market forces that naturally incentivise greater US LNG exports may be undermined by the possibility of gas re-exports from Canada. Canada has an existing free trade agreement with the USA and therefore US law requires the Department of Energy to grant gas export applications to Canada without modification or delay.⁸⁸ Without a destination clause, cheap US pipeline imports could either be directly shipped on to Asian markets via Canadian terminals, or be used to meet domestic Canadian demand, thereby freeing greater volumes of Canadian-produced gas for export.

Moreover, any effort to keep natural gas prices in the USA artificially low may prove self-defeating in the long run. As Section 4.3 shows, low gas prices are as dangerous to energy security as high prices because they undermine investment in extraction and production. This means that, should gas exports from the USA be constrained, low gas prices would only be a transitory phenomenon until the price mechanism reduced US gas production to sustainable levels for domestic demand. Prices would then rise again.

The dramatic rise in investment in global regasification and liquefaction capacity outlined so far in this section stands in contrast to seemingly slow progress in other major natural gas infrastructure projects. The period 2010-2013 will see European regasification capacity increase by roughly 25%. Meanwhile, only two major new interregional pipeline projects – Medgaz and the much-awaited Nord Stream pipeline between Russia and Germany – will have come online in the same period. In the words of the IEA: “Across regions, LNG regasification terminals seem to be making more progress than pipelines.”⁸⁹

One explanation for this disparity is the fact that an increasing proportion of undeveloped gas reserves are located further away from major markets. LNG plays a vital role in bringing this gas to the consumer when distance, geographical or political obstacles make pipeline transport impossible. Looking to the future, technological

⁸⁵ Gregory Meyer, 'Mild winter adds to pressure on US gas', *Financial Times*, 10 January 2012, 2012.

⁸⁶ Ed Crooks, 'US industry hits at LNG export plan', *Financial Times*, 10 January 2012, 2012; US Department of Energy, 'Energy Department Approves Gulf Coast Exports of Liquefied Natural Gas: Conditional Authorization for Sabine Pass LNG Terminal Could Bring Thousands of Jobs', (Washington DC: Department of Energy, 2011).

⁸⁷ EIA, 'Effect of Increased Natural Gas Exports'. 'Statement of Christopher Smith, Deputy Assistant Secretary for Oil and Natural Gas, US Department of Energy', in *United States Senate Committee on Energy and Natural Resources United States Senate* (Washington DC: 2011).

⁸⁸ Section 3(c) of the Natural Gas Act. US Congress, 'Exportation or importation of natural gas', in *15 USC 717b* (Washington DC: 1938).

⁸⁹ IEA, 'Oil and Gas Markets', 144, 251.

progress will continue to drive this trend. The world's first floating LNG liquefaction project⁹⁰ was commissioned by Shell in May 2011.⁹¹ Floating LNG provides a way of developing stranded gas reserves far out at sea, which would otherwise be too difficult to pipe to land-based liquefaction plants.

Another explanation for the difference in growth between pipeline and LNG projects lies in their distinct investment risk profiles. Section 4.2.1 describes the 'investment hold-up problem' faced by companies looking to invest large amounts in relatively inflexible energy infrastructure projects, such as pipelines. Such assets are subject to a great deal of locational specificity, meaning that they are dependent on the availability and price of resources from a limited geographical area. They are also usually 'dedicated assets' that are particular to a certain customer. Dedicated assets sink investments into a pre-defined market and create a bilateral relationship between the supplier and buyer that incentivises bargaining over rents *ex post*. The anticipation of this dilemma complicates the decision to invest *ex ante*. Seen in this light, the reduced locational specificity and dedication of an LNG terminal may sometimes make it a less risky investment option, even though operating costs may be marginally higher when compared with a pipeline.⁹²

5.2.2 The LNG trade and global gas markets

LNG markets are difficult to monitor because there is no single supply point whose price fluctuations act as a reference for markets worldwide and no prominent hubs at which physical supplies from a number of sources are commingled and traded.⁹³ Nevertheless the past years have seen ample evidence that LNG is changing the characteristics of global gas markets. Whereas the high cost of transporting gas had previously restricted trade to specific regions, fluctuations in supply, demand and prices are increasingly being transmitted throughout the globe. The words of one analyst capture the essence of this transformation in the simplest terms (although a number of important caveats will be discussed):

*...natural gas is evolving from a local, stationary, non-residential commodity, into a mobile, international, primary product similar to crude oil.*⁹⁴

The vast majority of LNG is still sold via a 'traditional' model: under long-term, oil-indexed, take-or-pay contracts, where the buyers of the gas have the market power to lay off some of the market risk to their end-use customers (i.e. where the buyers are a form of government monopoly or regulated public utility in the retail market). In order to spread exploration risks, project developers are normally joint ventures of companies that operate as if they were shareholders in a corporation, rather than as

⁹⁰ Floating LNG sees liquefaction facilities installed on large ocean-going vessels that are moored above offshore gas fields. LNG and other products are then loaded directly on to carriers for delivery to market, eliminating the need for pipelines to shore or land-based plants.

⁹¹ The Shell floating LNG vessel will be stationed at the Prelude field, off the coast of Western Australia, for an anticipated deployment period of 25 years before potentially being moved to other assets in the region. IEA, 'Golden age', 69, 177.

⁹² Spanjer, 'Regulatory intervention': 3252. Although the mobile nature of floating LNG vessels means that although they are very expensive investments, they cannot be considered an entirely sunken infrastructure cost in the same way that a pipeline or onshore liquefaction plant might be.

⁹³ Jensen, 'LNG Revolution': 21.

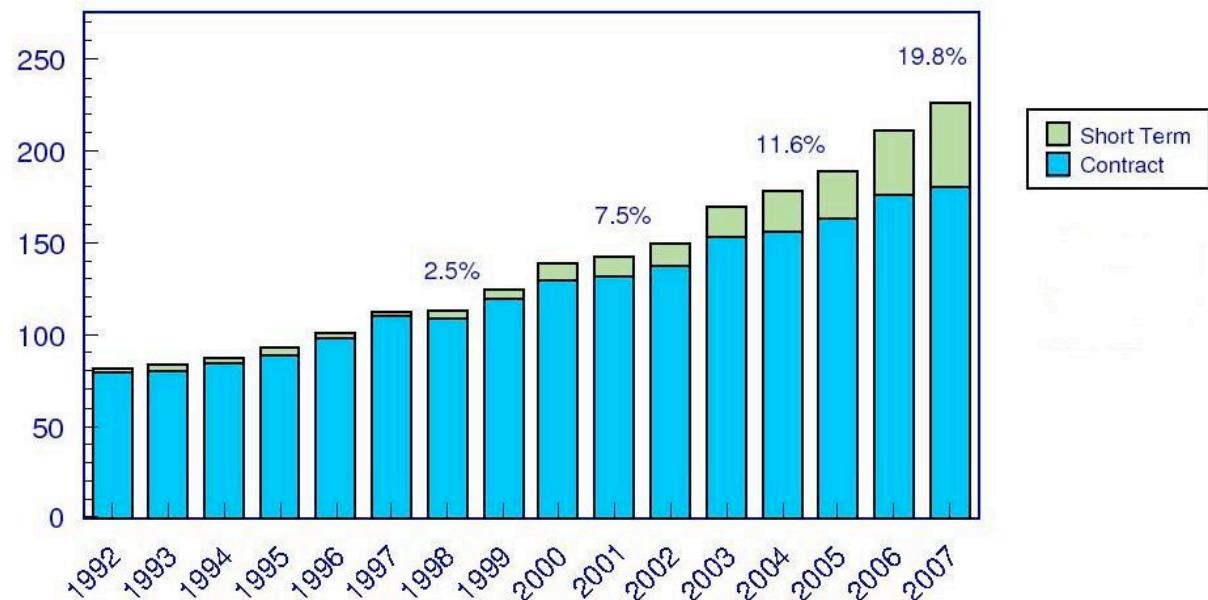
⁹⁴ Kuhn and Umbach, 'Strategic Perspectives', 18.

independent and competitive corporate entities. Competition does exist between projects, but not among the individual participants in the project itself.⁹⁵

This traditional model, however, is being challenged. Contract terms have loosened on both price and volume, and can be negotiated for shorter periods of time (see Figure 5-19).⁹⁶ And increasingly, one or more joint venture partners are contracting for destination-flexible volumes that they can market independently. The development of LNG projects with de-integrated and competitive 'links' in the chain over the last decade has meant that cross shipping – with its inherent inefficiencies – has become increasingly common. This is supported by an increasing number of uncommitted LNG carriers that are free to operate in the short term market. In some respects, the transformation resembles the onshore gas market liberalisation process covered earlier in Sections 4.2.2 and 4.2.3.⁹⁷

Figure 5-19: Short-term trading in LNG⁹⁸

BCM



The Nigerian LNG project at Bonny Island, which began commercial operation in 1999, is a good example of the new model. Although the first three trains of the project were originally contracted under traditional terms, trains 4 and 5 were contracted with Shell and Total to be destination-flexible. The shift towards increased destination flexibility is also reflected in Atlantic's LNG venture in Trinidad and the Egyptian LNG development east of Alexandria. These facilities liquefy volumes of gas for sellers at a fixed fee (so-called LNG tolling) allowing sellers to then market this LNG directly to buyers.⁹⁹

The inherent physical possibility of flexible transport with LNG coupled with the changes within the LNG industry just described have resulted in increased numbers of

⁹⁵ For an excellent overview, see Jensen, 'LNG Revolution': 5.

⁹⁶ EIA, 'The Global Liquefied Natural Gas Market: Status & Outlook', (Washington, DC: US Energy Information Administration, 2003).

⁹⁷ Jensen, 'LNG Revolution': 5, 29.

⁹⁸ Including contracts of three years or less. Source: James T. Jensen, 'Fostering LNG Trade: Developments in LNG Trade and Pricing', (Brussels: Energy Charter Secretariat, 2009).

⁹⁹ Ibid., 23.

varying and more complex LNG trading routes. Underpinning and driving this diversification is the price incentive to move natural gas from low to high-value markets. High prices in Asia and Europe thus represent a potential opportunity for LNG sellers who are able to undercut traditional suppliers in these markets. This process, in turn, contributes towards gas price convergence across the various regions in a global market that is growing less fragmented.¹⁰⁰

LNG cargo 'arbitrage'¹⁰¹ in the Atlantic Basin between the USA and continental Europe can be traced back to the early to mid-2000s following the start-up of the Trinidad and Nigerian projects.¹⁰² The Atlantic Basin currently has the greatest proportion of destination-flexible volumes – a full 41% of capacity in 2008 – meaning that supplies to the basin (i.e. between the North American and European gas markets) can be expected to be the most reactive to demand fluctuations.¹⁰³ As the Middle East is capable of acting as a swing supplier to both the Atlantic and Pacific Basins, Asian LNG markets have become increasingly involved in inter-basin arbitrage following the addition of new capacity in the region from 2005. As liquefaction capacity in the Middle East grows and the industry liberalises, Europe has found itself in an interesting competitive buying position as the closest major LNG market to major Middle Eastern supplies i.e. the market with the lowest transportation costs compared with competing Asian or US destinations.¹⁰⁴

¹⁰⁰ M. J. Oudeman, 'Advisory letter on the emergence of unconventional gas', Letter to Mr M.J.M. Verhagen, The Minister for Economic Affairs, Agriculture and Innovation, 2011.

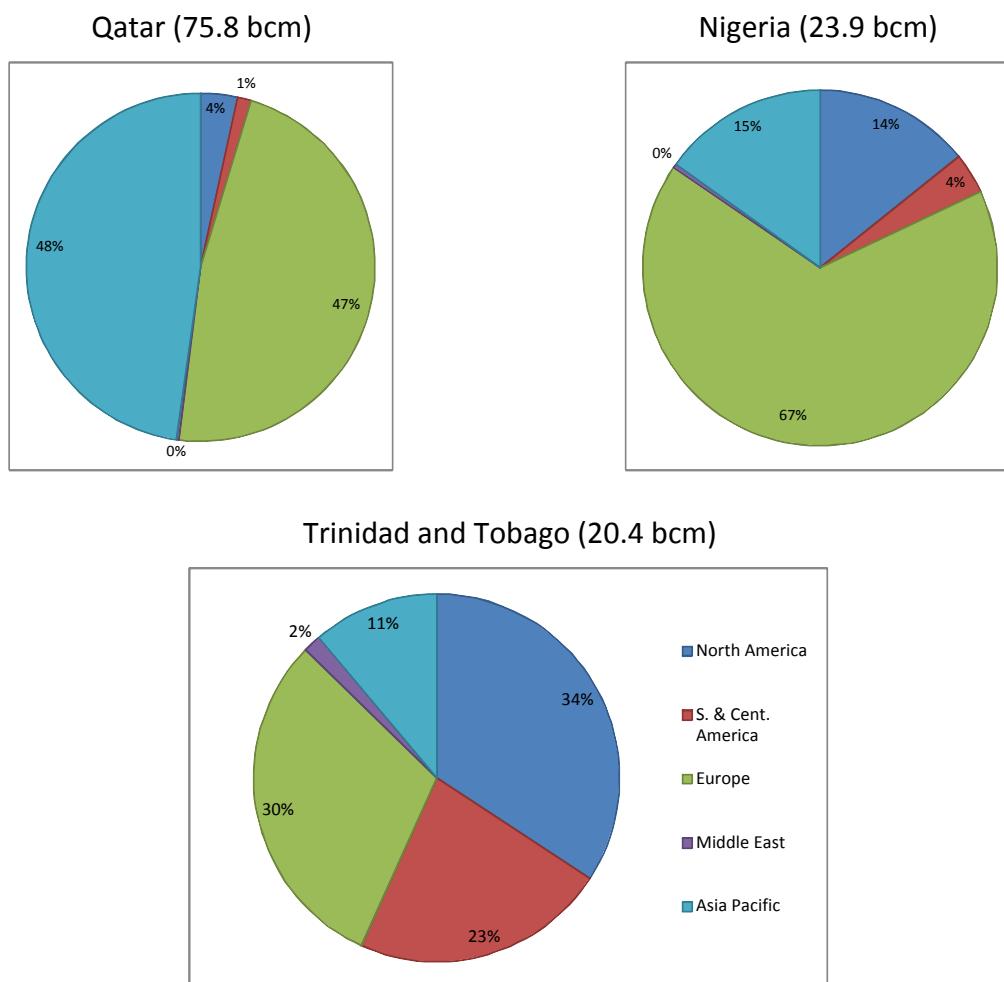
¹⁰¹ The term is in inverted commas because true arbitrage involves the simultaneous buying and selling of the same product in different markets at different prices. In spite of this, the general idea of taking advantage of a price difference between two or more markets to achieve a near risk-free profit at near zero cost holds.

¹⁰² Boriss Silverstovs et al., 'International Market Integration for Natural Gas? A Cointegration Analysis of Gas Prices in Europe, North America and Japan', in *Globalization of Natural Gas Markets Working Papers* (Berlin: Deutsches Institut für Wirtschaftsforschung, 2004), 16.

¹⁰³ Jensen, 'Fostering LNG Trade', 23.

¹⁰⁴ Jensen, 'LNG Revolution': 16-17, 21, 23, 33; Rogers, 'LNG Trade-flows', 1.

Figure 5-20: 2010 export destinations of global LNG swing suppliers¹⁰⁵



In the words of the IEA: “Europe, whether it has noticed it or not, is now effectively competing with China for LNG.”¹⁰⁶ The constant price-driven rebalancing of LNG exports from key interregional swing suppliers, such as those shown in Figure 5-20, means that previously isolated national and regional gas markets are increasingly interacting with each other. Howard Rogers has provided a detailed account of the recent supply, demand and price dynamics of the three major regional gas markets in North America, Europe and Asia that demonstrates how these markets have become connected through LNG.¹⁰⁷ The following subsection will describe how the links between UK and US gas hub prices have enabled many EU Member States to benefit from the unconventional gas revolution in the USA. But before we continue, an important caveat should be addressed.

Although there is a growing consensus that gas markets are globalising, the markets are not fully globalised yet. The IEA highlights that there are still countries that remain largely insulated from broader market developments and that two-thirds of the world’s gas is still consumed in the country where it is produced.¹⁰⁸ Whereas the agency does

¹⁰⁵ BP, 'Statistical review 2011'.

¹⁰⁶ IEA, 'Oil and Gas Markets', 158.

¹⁰⁷ Rogers, 'LNG Trade-flows'.

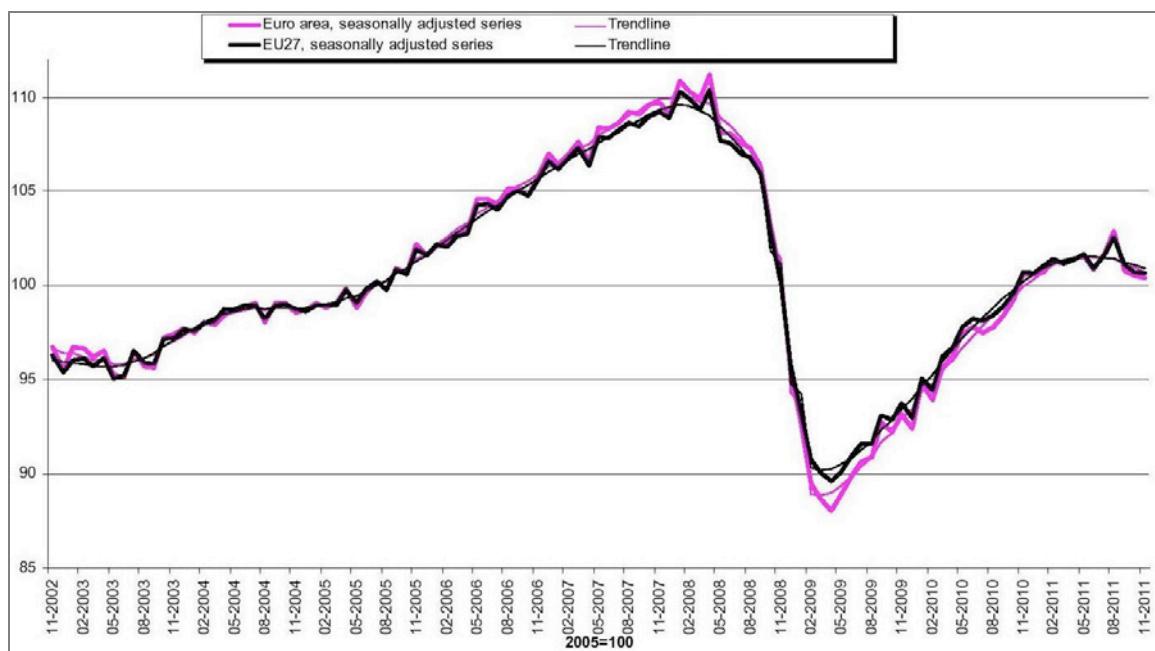
¹⁰⁸ IEA, 'Oil and Gas Markets', 158.

see the interregional trade in gas growing in the years ahead, it believes this growth will only be gradual – from 19% of all gas consumed in 2009 to 25% in 2035. Similarly, it expects considerable price differences between the US, European and Japanese gas markets to persist into 2035, despite a gradual trend towards price convergence.¹⁰⁹ Claims of a global market for natural gas have therefore been downplayed as “over simplistic” and “at best premature” by notable observers who highlight that the inherent physical characteristics of the commodity will always put it at a transportation disadvantage when compared with oil and oil products, dampening momentum towards the realisation of a truly global market.¹¹⁰

5.2.3 EU Member States and the recent ‘gas glut’

Although the three major regional gas markets are increasingly connected, the especially strong connection between North American and European markets in the Atlantic Basin was clearly evident in the coupling of UK and US hub prices between 2009 and 2010.¹¹¹ This connection – a direct product of rapidly increasing LNG-receiving terminal capacity in North West Europe – enabled many EU Member States to benefit from the recent natural gas glut resulting from the financial crisis and the increased unconventional gas production in the USA.

Figure 5-21: Euro area and EU-27 industrial production, total industry excluding construction¹¹²



The general backdrop to the price coupling seen in 2009-2010 was the global economic crisis, which caused both pipeline gas and LNG demand to be reduced in most countries of the world. Seasonally adjusted gas demand data for OECD Europe showed that consumption in winter 2009-10 fell back to 2003-2004 levels before being buoyed by the especially cold winter in the following year.¹¹³ The dramatic fall in EU industrial

¹⁰⁹ IEA, 'WEO 2011', 63, 93.

¹¹⁰ Rogers, 'LNG Trade-flows', 77; Stevens, 'Hype and reality', 6.

¹¹¹ IEA, 'Oil and Gas Markets', 158.

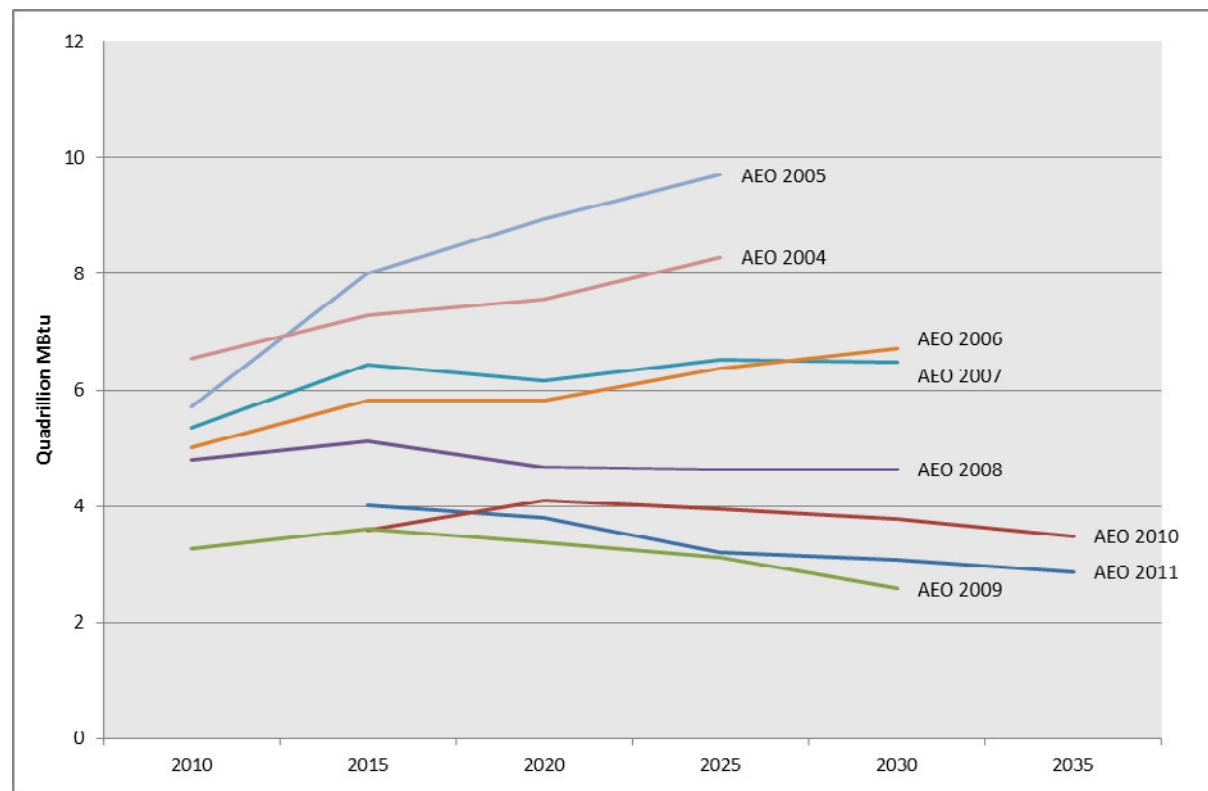
¹¹² Source: Eurostat.

¹¹³ Anouk Honoré, 'Economic recession and natural gas demand in Europe: what happened in 2008-2010?', (Oxford: Oxford Institute for Energy Studies, 2011), 3.

production that was the source of this sharp drop in demand is illustrated in Figure 5-21.

The slump in global gas demand coincided with an increasing and unexpected withdrawal of North America from the LNG market. Figure 5-22 below shows that in 2006 the EIA – like most analysts – was expecting the USA to import increasingly larger volumes of LNG to offset falling local production and increasing consumption. As recently as 2008, the administration was reporting in its Annual Energy Outlook that it expected US gas markets ‘to be tight throughout the projection because of competition for LNG supplies across the world’.¹¹⁴ Significant investments were being made in regasification facilities and major importers of gas were bracing themselves for a seller’s market in the foreseeable future in spite of the imminent large increase in Middle Eastern liquefaction capacity.¹¹⁵

Figure 5-22: Forecast US natural gas imports¹¹⁶



Instead, total year-on-year US gas production increased by 4.5% in 2008, 2.5% in 2009 and then again by 3.5% in 2010 as a result of increased unconventional gas production.¹¹⁷ This reduced LNG import requirements to a meagre ca.10% of total US regasification capacity during that period.¹¹⁸ As a result of a significant proportion of US LNG import volumes being flexibly sold under short-term contracts,¹¹⁹ the USA

¹¹⁴ EIA, 'AEO 2008', 78.

¹¹⁵ Oudeman, 'Advisory letter'.

¹¹⁶ Source: Reference scenario figures from successive US Energy Information Administration Annual Energy Outlook reports, 2004-2011.

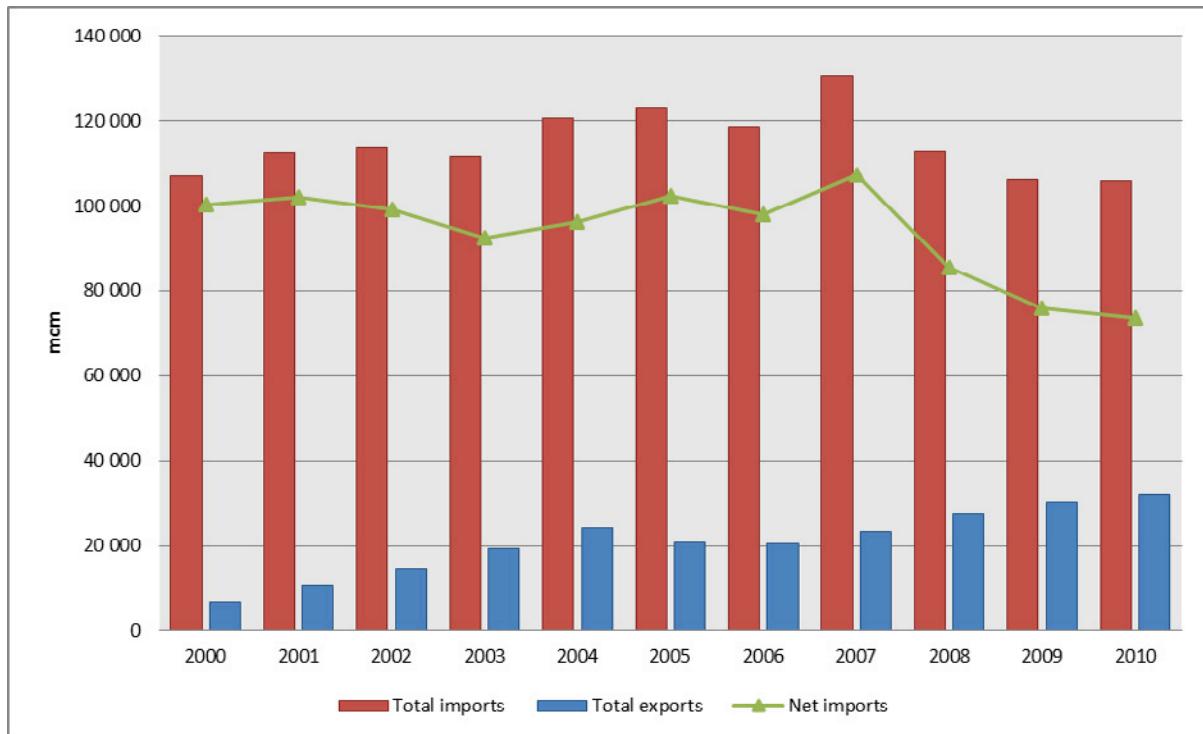
¹¹⁷ Source: EIA.

¹¹⁸ IEA, 'Oil and Gas Markets', 14.

¹¹⁹ They represented 80% of US trade in LNG in 2003 and 70% in 2004. Don Maxwell and Zhen Zhu, 'Natural gas prices, LNG transport costs, and the dynamics of LNG imports', *Energy Economics* 33, no 2 (2011): 220.

effectively became “a large virtual gas exporter”, with LNG cargoes originally destined for US shores diverted to other customers.¹²⁰

Figure 5-23: US natural gas imports and exports¹²¹



In fact, not only was the USA a large *virtual* exporter of natural gas, but its *actual* natural gas exports were also growing (see Figure 5-23 above). The overwhelming majority of these exports were dispatched via trunk pipelines to Canada and Mexico. However, recently released data also reveals a startling two-fold jump in LNG exports in the year 2010 (Figure 5-24). The figures are made even more surprising when considering some of the new export destinations for US LNG. The USA had only one operational LNG liquefaction plant in 2010,¹²² and its location in Alaska made it unsuitable for supplying the UK and Spanish markets. In fact, the growth in LNG exports in 2010 was driven by re-exports: shipments that were previously imported, offloaded into above-ground LNG storage tanks at regasification terminals and then subsequently reloaded on to new tankers for delivery to other countries.¹²³ This highly irregular practice is a testament to the scale of the disruption to the established global supply and demand equilibrium for natural gas during the period.

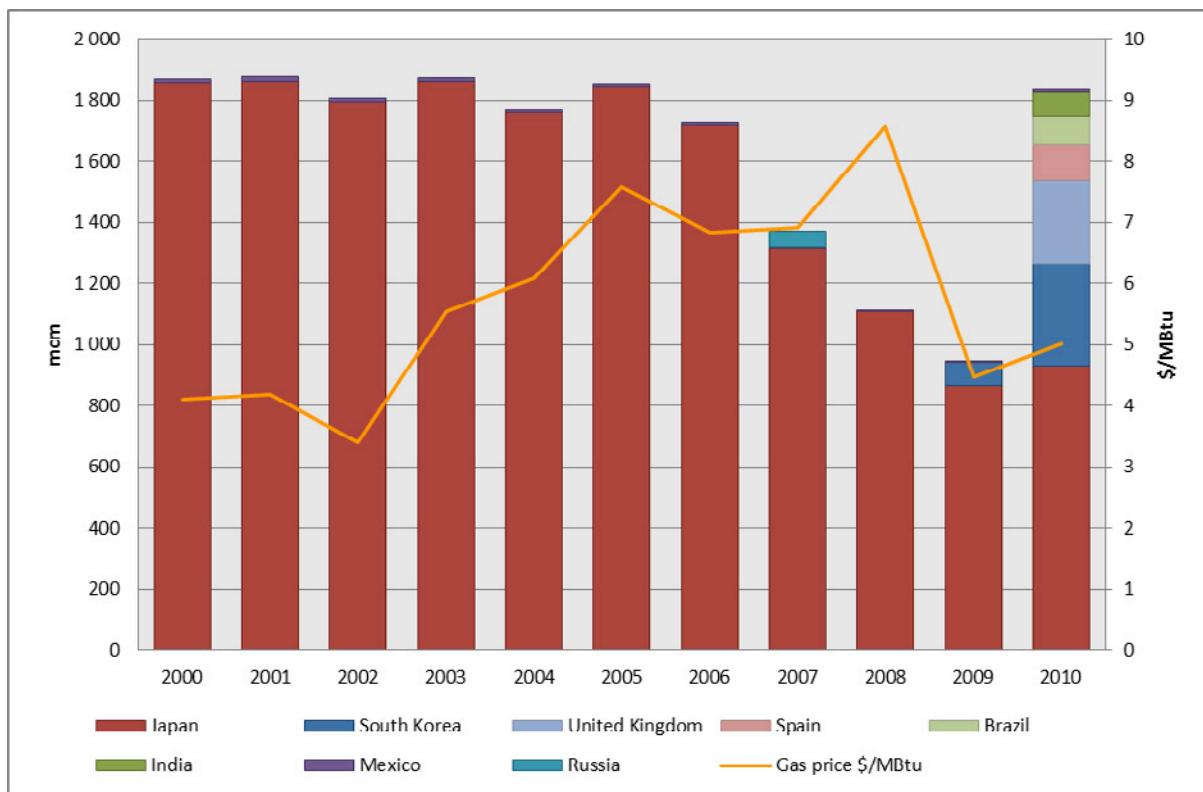
¹²⁰ IEA, 'Oil and Gas Markets', 181.

¹²¹ Source: EIA, 'U.S. Natural Gas Imports & Exports: 2010', (Washington, DC: US Energy Information Administration, 2011).

¹²² ConocoPhilips' Kenai LNG plant.

¹²³ EIA, 'Natural Gas Imports & Exports'.

Figure 5-24: US LNG exports and gas prices¹²⁴



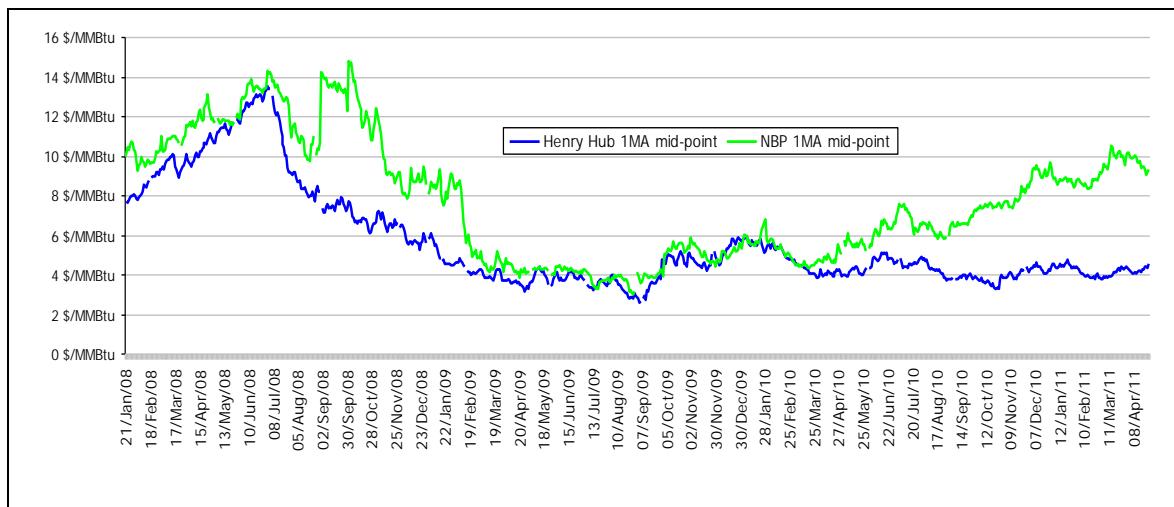
On the other side of the Atlantic, newly completed receiving terminals in Wales, France and Italy enabled a number of EU Member States to absorb some of the LNG originally earmarked for the US market from swing suppliers such as Trinidad and Tobago. However, combined with the large increase in liquefaction capacity from Qatar,¹²⁵ the displaced US supplies still occasioned a fall in European spot prices that started mid 2008 and continued well into 2009. Figure 5-25 below shows that the world's two major spot markets both saw extremely low prices in 2009 (\$4/MBtu at the US Henry Hub and \$5/MBtu at the UK National Balancing Point).¹²⁶ It also reveals a remarkably close correlation between those two markets from early 2009 to early 2010 – a price coupling that was a direct result of both saturated supply and a largely shared pool of LNG suppliers that were able to feed these two markets.

¹²⁴ Source: Ibid.

¹²⁵ 105 bcm of global liquefaction capacity came online over the 2009-2010 timeframe. IEA, 'Oil and Gas Markets', 170-1.

¹²⁶ Ibid., 196.

Figure 5-25: Henry Hub and National Balancing Point gas prices¹²⁷



Writing during this period of Atlantic Basin price convergence, some believed the supply-and-demand fundamentals underpinning this buyers' market for gas would sustain it until the middle, or even the end, of the decade.¹²⁸ In fact, the close correlation between Henry Hub and NBP prices came to an end around April 2010 as a result of unforeseen demand-side events that effectively reduced oversupply. The major factor in Europe was the extremely cold weather in the first three and the last two months of 2010, which broke records established over many decades in several countries. Uncertainty and supply disruptions resulting from the Arab Spring over the course of 2011 were other factors which continued to push European hub gas prices away from low Henry Hub levels and towards the higher German border price – an indicator of oil-linked contract gas prices in North West Europe.

More significantly, Asian LNG demand rose by 18% in 2010, removing perhaps half of the global LNG surplus.¹²⁹ This strong trend would continue into 2011 as natural gas imports to Japan increased sharply in order to offset the shortfall in baseload nuclear power generation resulting from the Fukushima disaster. In 2011, Kansai Electric almost quadrupled its LNG imports from Trinidad and Tobago through the use of short-term contracts, from 58 240 mt the year before to 216 696 mt. The shipments were unusual because of their longer-than-usual voyage compared with other suppliers, but this concretely illustrates how the interregional flexibility of LNG is enabling the global energy system to more easily absorb supply shocks and regional markets to become increasingly interlinked.¹³⁰ The corollary is that spot prices in Europe can be expected to climb should the trend of growing Asian consumption continue without sufficient new gas supplies entering the global market.

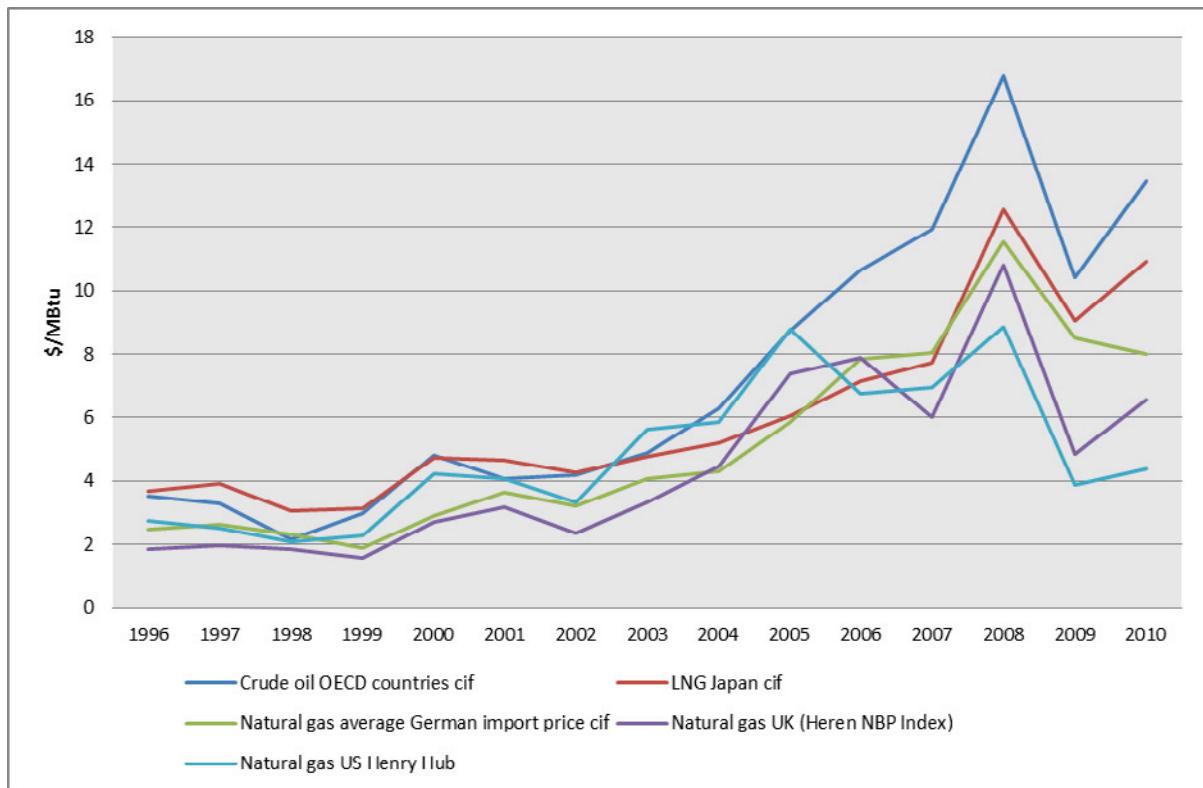
¹²⁷ Source: European Commission, 'Quarterly Report on European Gas Markets, October 2010 - December 2010', in *Market Observatory for Energy* (Brussels: 2011).

¹²⁸ 'In the Atlantic basin, and in Europe in particular, it is hard to see tight supplies before 2015, despite the rapid decline of European domestic production.' IEA, 'Oil and Gas Markets', 142. '...it will be many years before the tide starts to turn the other way (to a seller's market). In the view of the Energy Council, this could take 10 years or more rather than 5 years.' Oudeman 'Advisory letter'.

¹²⁹ Stern and Rogers, 'Transition to Hub-Based Pricing', 8.

¹³⁰ Takeo Kumagai, 'Japan's Kansai Electric hikes Trinidad LNG imports Tokyo', *Platts* 2011.

Figure 5-26: Global natural gas prices¹³¹



Looking at the broader context, Figure 5-26 shows how the relationship between North American, European and Japanese spot prices appears to have changed since 2009. Before that time, they predominantly traded in a narrow band, with temporary price differences reflecting local conditions, such as storage. However, in 2009 and 2010, the differences have grown and appear to be more lasting, with European prices hovering somewhere between the low US prices and higher predominantly oil-indexed Japanese LNG prices. James Jensen calls this the emergence of a bipolar gas-pricing world, where Atlantic basin arbitrage puts downward pressure on European prices.¹³² By this view, regional gas prices reflect relative market exposures to: a) the unit price of oil at the top end; and b) low Henry Hub prices.

As for Europe, a modest but persistent difference between lower NBP prices and higher German border prices reflects both the effects of oil-indexation and deep systemic factors that continue to hinder the liberalisation of the EU gas market.¹³³ It is a reminder that, although many Member States in North West Europe were able to profit from the availability of cheap LNG in 2009 and 2010, the remainder of the continent received only small amounts of that additional supply as the EU gas system remains relatively fragmented. Buyers in Central and Eastern Europe paid on average €0.55/MWh more for their gas than their Western European counterparts in 2008, a figure that sharply

¹³¹ Source: BP, 'Statistical review 2011'. Note: cif = cost + insurance + freight (average prices).

¹³² James T. Jensen, 'LNG - Creating a "World Gas Market"?' (paper presented at the MIT Energy Initiative Fall Research Conference, Cambridge, Massachusetts, 2011).

¹³³ The situation at the time of writing is foretold in Frisch, 'European Gas Pricing Problems', 14.

increased to € 4.86/MWh in 2009.¹³⁴ This “two-tier price system” for natural gas in the EU¹³⁵ is the topic of the next section of this report.

5.2.4 The oil-gas price link

With the physical rationale for oil-indexation diminishing, the increased accessibility of low-priced LNG imports has pressured gas buyers into renegotiating the terms of their existing oil-indexed gas purchase contracts. Progress in liberalising the EU gas market has been a key enabler of this development and the continual removal of barriers to accessing spot-indexed supplies in Europe has prompted a number of experts to question the future of oil-linked gas pricing.

As mentioned, natural gas prices are set via two principal mechanisms in the EU. Oil-product linkage was established in the 1970s on the principle that the price of gas should generally be competitive with the prices of alternative (non-gas) fuels. The economic logic of this ‘market value principle’ or ‘netback’ pricing mechanism was that end-users had a real choice between burning gas and oil products, and would switch to the latter if given a price incentive to do so.¹³⁶

To this day, the majority of the EU’s pipeline-imported gas remains indexed to the price of oil or oil products through long-term take-or-pay contracts whose terms are confidential to the buyers and sellers of that gas.¹³⁷ The continuing rationale of oil-indexation, however, is being increasingly questioned because of the virtual elimination of oil products from modern stationary energy sectors. Whereas oil is still the fuel of choice in the transportation sector, less than 3% of the electricity generated in OECD Europe comes from oil, a figure that has halved over the period 2000 to 2009.¹³⁸

A number of factors are driving this trend, including: 1) rising oil prices; 2) the spread of more efficient turbines that are poorly suited to oil products; 3) the cost of maintaining oil-burning equipment and oil stocks; and 4) tightening environmental standards that penalise the use of oil as a fuel.¹³⁹ Taken together, these factors mean that there is almost “no commercial scenario in which users installing new fuel-burning equipment will choose to use oil products rather than gas in stationary uses.”¹⁴⁰ With gas demand growth in Europe forecast to become increasingly concentrated in the power sector, the logic of oil-indexation seems ever more tenuous (although see Section 6.3.2 for the possibility of oil-gas ‘re-coupling’ in the future).¹⁴¹

¹³⁴ European Commission, 'Non paper: The internal energy market – time to switch into higher gear', ed. Directorate-General for Energy (2011).

¹³⁵ Frisch, 'European Gas Pricing Problems', 1.

¹³⁶ Kanai, 'Decoupling Oil and Gas Prices', 2; Jonathan Stern, 'Continental European Long-Term Gas Contracts: is a transition away from oil product-linked pricing inevitable and imminent?', (Oxford: Oxford Institute for Energy Studies, 2009); Jonathan Stern, 'Is there a rationale for the continuing link to oil product prices in Continental European long-term gas contracts? ', (Oxford: Oxford Institute for Energy Studies, 2007); Stern and Rogers, 'Transition to Hub-Based Pricing', 2.

¹³⁷ In spite of this confidentiality, publicly available border price data has allowed the key variables of these contracts to be inferred over time.

¹³⁸ IEA, 'WEO 2011', 345.

¹³⁹ Kanai, 'Decoupling Oil and Gas Prices', 2; Stern, 'European Long-Term Gas Contracts'; Stern and Rogers, 'Transition to Hub-Based Pricing', 2.

¹⁴⁰ Stern and Rogers, 'Transition to Hub-Based Pricing', 2.

¹⁴¹ See, for example, IEA, 'Golden age', 22.

Alternatively, gas prices may be set freely by the forces of supply and demand for natural gas itself – not oil – in a paradigm known as spot trading or gas-to-gas competition. Spot trading has the theoretical advantage of allocating resources and setting prices more efficiently than oil-indexation. This does not necessarily mean that consumer prices will always be cheaper,¹⁴² but by allowing the price mechanism to more directly incentivise gas production, dampen consumption and reallocate physical supplies when supplies get tighter, spot pricing helps to ensure stable and sustainable prices for both consumers and producers of natural gas (see Section 4.3).

Spot pricing has become prevalent in an increasing number of liberalised markets the world over, including North America, the United Kingdom and Australia. The IEA estimates that one-third of the world's gas may be priced in gas-to-gas competition. In spite of recent efforts to liberalise the EU gas market, however, just one quarter of continental European gas is spot traded. Hold-out advocates of oil-indexation maintain that a continuing lack of liquidity and depth on certain EU gas trading hubs may lead to excessive volatility and the risk of price manipulation. Oil-indexation, by this view, constrains volatility through averaging provisions and by providing a link to the deep, liquid and global market for oil.¹⁴³

Until recently, discussion of the merits and demerits of oil-indexation in Europe was, to some extent, an academic exercise. The market power of many sellers of pipeline-imported gas meant that they were largely able to decide the terms of its sale and these sellers preferred oil-indexation. However, this situation changed as the gradual process of liberalisation impacted on gas market structures in continental Europe. The advent of competition and third-party access means that customers have increasing access to alternatives to the oil-linked supplies once forced upon them by their traditional utility providers. This may explain International Gas Union data showing that the relative share of spot pricing in European wholesale gas price formation increased from 15.5% to more than 28% between 2005 and 2009, whereas oil indexation decreased from 79.1% to 67% in the same period.¹⁴⁴

¹⁴² 'If a general and durable transition to more spot indexed prices were to occur, the result is likely to be lower gas prices on average in Europe in the near to medium term, (at least for some types of consumers) while spare supply capacity exists in the European market. But in the long term, gas prices could actually turn out to be higher at certain times than they would otherwise have been; for example, strong demand during cold winters or through a surge in gas-fired power demand could see prices rise steeply.' *Ibid.*, 76.

¹⁴³ *Ibid.*, 72-75.

¹⁴⁴ Mike Fulwood, 'Trends in Wholesale Gas Price Formation Mechanisms: results on the 2009 IGU Survey', *International Gas Union Magazine* 2011, International Gas Union, 'Wholesale Gas Price Formation: A global review of drivers and regional trends', (Oslo: International Gas Union, 2011).

Table 5-4: European spot gas prices as a percentage of oil-indexed gas prices in €/MWh¹⁴⁵

	TTF average	NWE GCI	TTF/GCI
January 2011	22.24	25.84	86%
December 2010	24.15	26.13	92%
November 2010	19.50	25.98	75%
October 2010	18.56	25.54	73%
September 2010	18.95	25.07	76%
August 2010	18.12	24.21	75%
July 2010	19.52	23.55	83%
June 2010	19.28	22.62	85%
May 2010	16.78	21.80	77%
April 2010	13.53	21.56	63%
March 2010	11.99	21.00	57%
February 2010	13.72	20.74	66%
January 2010	14.48	20.02	72%
Average 2010	17.38	23.19	75%

With legal and technical barriers to growing volumes of spot-traded gas disappearing,¹⁴⁶ the sharp fall in spot prices witnessed in 2009 and 2010 occasioned widespread dissatisfaction amongst the utilities locked into buying gas on oil-indexed terms as they were gradually priced out of the market.¹⁴⁷ Table 5-4 above shows that spot gas prices on the Dutch TTF trading hub were an average of 25% lower than oil-indexed gas prices for North West Europe over 2010 and January 2011.¹⁴⁸ With spot prices so low, midstream gas players sought to replace as much of their oil-indexed wholesale volumes with spot gas as was possible within the limits imposed by infrastructure and their existing take-or-pay contracts. As a result of the abundant supplies on the spot market, even after buyers had reduced their nominations of oil-indexed gas to the minimum off-take limits and replaced the difference with spot volumes, a large disparity between spot and oil-indexed prices still existed. This forced utilities into either selling gas to consumers at a loss or being undercut by competitors able to source cheaper gas from LNG terminals or the UK market.¹⁴⁹ Some estimates put pipeline imports in Contract Year 2008/2009 at 92% of take-or-pay levels, implying that some midstream players may have been compelled to risk contractual penalties because of these testing market conditions.¹⁵⁰

¹⁴⁵ Note: the Table shows TTF day-ahead prices compared with the Platts North West Europe Gas Contract indicator (NWE GCI), which indicates a typical price for long-term oil-indexed supplies. The final column shows TTF as a percentage of NWE GCI. Source: Stern and Rogers, 'Transition to Hub-Based Pricing', 5.

¹⁴⁶ Physically traded volumes on the seven continental spot markets – Zeebrugge (Belgium), TTF (the Netherlands), NCG (Germany), Gaspool (Germany), PEG (France), PSV (Italy) and CEGH (Austria) – increased from just over 100 bcm in 2007 to almost 300 bcm in 2009. IEA, 'WEO 2010', 207.

¹⁴⁷ Rogers, 'LNG Trade-flows', 1; Stern and Rogers, 'Transition to Hub-Based Pricing', 33. 'The advances in gas market liberalisation currently being implemented in Europe at large, but in Germany in particular are playing an important part in creating the changes in the European gas market environment which can now be observed.' Frisch, 'European Gas Pricing Problems'.

¹⁴⁸ For an in-depth overview, see also European Commission, '2009-2010 Report on progress in creating the internal gas and electricity market', ed. Directorate-General for Energy (Luxembourg: Office for Official Publications of the European Communities, 2011).

¹⁴⁹ For a more complete explanation of this process, see Rogers, 'LNG Trade-flows', 24.

¹⁵⁰ Stern and Rogers, 'Transition to Hub-Based Pricing', 23.

Understandably, the situation placed enormous pressure on utilities facing the rapid erosion of their market share. Caught between their long-term contractual obligations and pressure from their (principally industrial) customers to supply cheaper gas, these utilities have in turn pressed their suppliers for contract renegotiations on price and volumes.¹⁵¹ As Howard Rogers writes, Europe's newfound ability to substitute pipeline imports with cheaper LNG had partially undermined the 'national incumbent' gas purchaser in Europe.¹⁵² Exemplifying this point, Dr Bernhard Reutersberg, the chairman of E.ON Ruhrgas, made a strong and public plea to adapt long-term contracts to the changed circumstances in October 2009.¹⁵³

In response, suppliers such as GasTerra, Statoil and, in the end, Gazprom made several concessions to their customers. Sources suggest that several companies were allowed to 'roll over' volumes not taken below minimum take-or-pay levels to future years. GDF Suez, Distrigas and Swissgas were granted a partial decoupling from oil-based pricing by GasTerra during their 2009 contract extension negotiations, and Statoil's customers were allowed to link up to 25% of their volumes to spot prices in early 2010. It was only in February 2010 that Gazprom and E.ON Ruhrgas announced that they had agreed on linking 15% of their volumes to spot prices for the following three years.¹⁵⁴ Rebounding crude prices in 2010 will have buoyed Gazprom's revenues, but figures from the IEA reveal that its hard-line strategy on oil-indexation may have cost it in the longer run: Gazprom's share of EU gas imports declined a substantial 4% in 2010 as it gradually lost market share to competitors more willing to spot-index their pricing formulas.¹⁵⁵

The steady recovery of European hub prices since then has made the benefits of spot-indexation less apparent, blunting the immediate competitive challenge to oil-indexation. In spite of this "near-term illusion of stability", however, the current balance of expert opinion suggests that the EU will move slowly away from oil-indexation because of the persisting risk of future exposure to discount hub prices.¹⁵⁶ Jonathan Stern has been one of the most prominent advocates of this view. In 2007, he questioned the rationale of the continuing linkage of prices in long-term gas contracts to those of oil products.¹⁵⁷ Then, in 2009, he argued that a transition away from oil product-related pricing was inevitable and imminent, and that the endpoint of the transition would be hub-based prices.¹⁵⁸ Commenting on poll results showing that only 16% of respondents at the 2010 European Autumn Gas Conference agreed to the proposition that recent pricing and contractual changes towards spot-indexation were temporary, Stern wrote:

¹⁵¹ IEA, 'Oil and Gas Markets', 195.

¹⁵² Rogers, 'LNG Trade-flows', 1.

¹⁵³ Bernhard Reutersberg, 'Key issues to Address Sustainable Supply and Demand of Natural Gas' (paper presented at the 24th World Gas Conference, Buenos Aires 2009). See also Klaus Schäfer, 'Natural gas markets in Europe - Challenges and developments' (paper presented at the ONS 2010 - Secure Sustainable Supply Stavanger, 2010).

¹⁵⁴ IEA, 'Oil and Gas Markets', 200, Kanai, 'Decoupling Oil and Gas Prices', 3; Stern and Rogers, 'Transition to Hub-Based Pricing', 26.

¹⁵⁵ IEA, 'WEO 2011', 345.

¹⁵⁶ Jensen, 'Creating a "World Gas Market"?'. See also Frisch, 'European Gas Pricing Problems', 1; Kanai, 'Decoupling Oil and Gas Prices', 39; Oudeman, 'Advisory letter'.

¹⁵⁷ Stern, 'Continuing link to oil product prices'.

¹⁵⁸ Stern, 'European Long-Term Gas Contracts'.

*"What we are observing here is a fundamental mindset change on the part of the traditional buyers from one which was appropriate for those in a dominant position with a relatively captive market, to one which increasingly reflects the competitive environment of access to liquid gas hubs and the trading culture of European utilities."*¹⁵⁹

¹⁵⁹ Stern and Rogers, 'Transition to Hub-Based Pricing', 27.

6 The potential impact of shale gas on the global energy system

F. Gracceva and P. Zeniewski (European Commission, JRC F.3)

The relative strengths of natural gas in comparison with other fossil fuels have recently been emphasised by a number of notable studies.¹ In fact, many of the uncertainties facing the energy system as a whole can potentially be considered opportunities for natural gas, i.e. climate change policies, the need for back-up fossil fuel for renewable energy and so on. The aim of this chapter is to use an energy system analysis approach to explore the uncertainties surrounding the future of natural gas, with a particular focus on the role shale gas can play in this wider perspective. It will attempt to answer the following questions:

- How much does the purported golden age of natural gas depend on the development of unconventional gas, and shale gas in particular?
- In what ways will the energy system be affected with or without significant shale gas production?
- What conditions would permit shale gas to gain a significant role in the future energy system, up to the point of becoming a 'game changer'?

To answer these questions, the authors present not a forecast or projection but an *exploration of uncertainty* around the future of shale gas. Indeed, the potential for development and production of this resource cannot be considered in isolation from the existing fuels, trade flows, technologies and infrastructures that make up the global energy system. The extent to which shale gas can meaningfully penetrate this system is contingent on the dynamic interactions of a considerable number of supply- and demand-side drivers and techno-economic developments.

The methodological approach followed in this chapter is a two-step analysis carried out from an energy system perspective. First, we select the key factors affecting future gas supply and demand and, as a corollary, the pace and scale of unconventional gas development. A discussion of these factors will be rendered into a set of workable assumptions on what can be considered the primary determinants of future shale gas development. In particular, we focus on the size and production costs of shale gas resources, as well as global economic growth as a driver of energy demand. A similar analysis was recently carried out by the IEA²; the key similarities and differences are elaborated in Annex I.

A model is then used to construct a set of possible scenarios for future shale gas development. The different trajectories borne out by these scenarios will be analysed and compared, with a particular focus on three main outputs – production, interregional trade and final use. In doing so, it is hoped that light will be shed on the conditions under which shale gas can be integrated into the global energy system.³

¹ For example, see IEA, 'Golden age'.

² IEA, 'Golden Rules for a Golden Age of Gas', in *World Energy Outlook* (Paris: OECD 2012).

³ Despite striving for a systemic treatment of factors affecting shale gas development, it is invariably the case that not all of them can be considered. Aspects such as environmental impacts or legal and regulatory issues are not considered in the present analysis.

As the model used in the analysis divides Europe into Eastern and Western parts (EEU and WEU), any reference to 'Europe' as a whole in the subsequent text will be taken to mean the sum of all of the countries in these two groupings (see Box 6-1 below).

Box 6-1: ETSAP-TIAM and its main characteristics

The ETSAP-TIMES Integrated Assessment (ET SAP-TIAM) model is a multi-region partial equilibrium model of the energy systems of the entire world divided in several regions, linked by trade variables of the main energy forms (coal, oil, gas) and of emission permits. It has been initially developed and is maintained by the Energy Technology Systems Analysis Programme (ET SAP), a consortium of member country teams that maintain and expand the analytical capabilities of the MARKAL/TIMES family of models.³ These models are used by diverse institutions, such as the IEA and EIA, to generate in-depth national and multi-country analyses of energy systems several decades into the future. The ETSAP-TIAM model used in this assessment is the version distributed to the ET SAP partners (such as DG JRC) in April 2011, then further developed by JRC towards a more detailed and updated representation of the global gas market.

The ETSAP-TIAM model used in this assessment contains detailed descriptions of technologies and energy flows used in all the different sectors of the energy system – e.g. residential, industrial, agricultural, etc.. The interaction of these variables, which number in the millions, is driven by an underlying mathematical structure; in a process of *linear optimisation* an intertemporal dynamic partial equilibrium on energy markets is computed. The model chooses energy supply services at minimum global cost by simultaneously making decisions on equipment investment, equipment operation, primary energy supply and energy trade.⁴ By incorporating the whole of the energy supply chain, TIMES is a vertically-integrated model of the entire energy system.

The ETSAP-TIAM model is particularly amenable to exploring possible long-term energy futures based on different sets of assumptions – or scenarios – about the future drivers of the energy system. This makes it particularly amenable to exploring possible long-term energy futures based on different sets of assumptions – or scenarios – about the future drivers of the energy system. Beginning with a base year, in this case 2005, the model is furnished with real data on the processes, commodities and flows making up the energy economy. Countries are grouped into 15 regions. For each region ETSAP-TIAM contains explicit descriptions of more than 1 000 technologies and 100 commodities (energy forms, materials, emissions), logically interrelated in a Reference Energy System covering extraction, processing, conversion, trading and end-uses of all energy forms. Logical inter-relationships exist between:

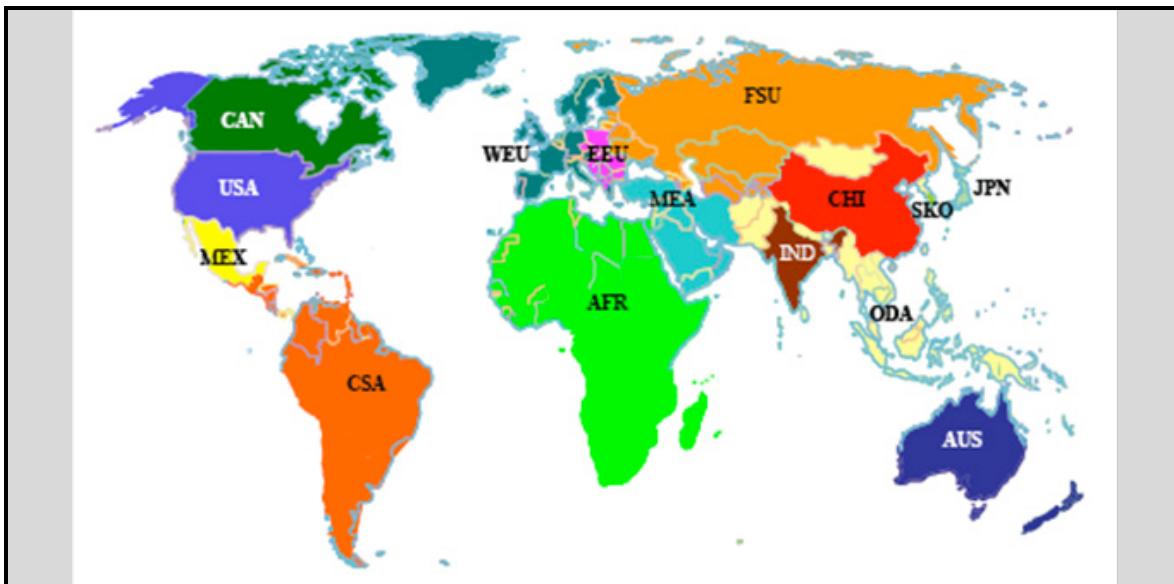
- Technologies (or processes): these represent physical devices that transform commodities into other commodities. There are primary processes that come directly from the source (e.g. upstream or imports of gas) or processes that transform these commodities (e.g. refineries that produce oil products);
- Commodities: these are energy carriers, energy services, materials, monetary flows and emissions. A commodity is generally produced by some process(es) and/or consumed by other process(es);
- Flows: this is the amount of a given commodity produced or consumed by a given process. For example, natural gas is a commodity, whereas natural gas for combined cycle turbine is a commodity flow.⁵

Trade variables of energy commodities (and of emission permits) link the regions, permitting energy forms such as coal, crude oil, petroleum products and gas/LNG to be endogenously traded.

³ www.iea-etsap.org

⁴ Loulou and Labriet, 'ET SAP TIAM'.

⁵ Ibid.: 14.



AFR Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Ivory Coast, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and Other Africa.

AUS Australia, New Zealand, Oceania

CAN Canada

CHI China

CSA Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and Other Latin America

EEU Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Macedonia, Montenegro, Poland, Romania, Serbia (Kosovo), Slovenia, Slovakia

FSU Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Russian Federation

IND India

JPN Japan

MEA Bahrain, Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates, Yemen and Turkey, Cyprus

MEX Mexico

ODA Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, Indonesia, Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Vietnam and Other Asia

SKO South Korea

USA United States of America

WEU Austria, Belgium, Cyprus, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Malta, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, United Kingdom

As a partial equilibrium model, ETSAP-TIAM is vulnerable to the standard criticisms of the simplifying assumptions made in economics. For example, linear optimisation means that the system chooses technologies that are most cost-effective, unencumbered by endogenous political or socioeconomic constraints. However, even if the model assumes competitive energy markets with perfect foresight, its choice of fuels, technologies, investments and trade patterns is, in fact, subject to many constraints, such as supply bounds (in the form of supply curves) for the primary resources;

technical constraints governing the creation, operation and abandonment of each technology; balance constraints for all energy forms and emissions; timing of investment payments and other cash flows; and the satisfaction of a set of demands for energy services in all sectors of the economy. (Energy demand is endogenous, whereas energy *service* demand is exogenous – aspects such as passenger kilometres or residential space heat, which are projected by a set of drivers such as GDP growth and population, number of households and sectoral outputs.)

It is important to remember that no modelling effort can lay claim to a completely accurate or even comprehensive account of the energy system, let alone provide a fully defensible prediction of its future. Thus, the main goal of using the ETSAP-TIAM model is not to forecast the future but to explore the possibilities presented by shale gas in ways that can support decision-making. Used in this way, the ETSAP-TIAM model is an appropriate and powerful tool of analysis for considering the broader trends affecting the future global energy mix.

6.1 Key factors for shale gas development

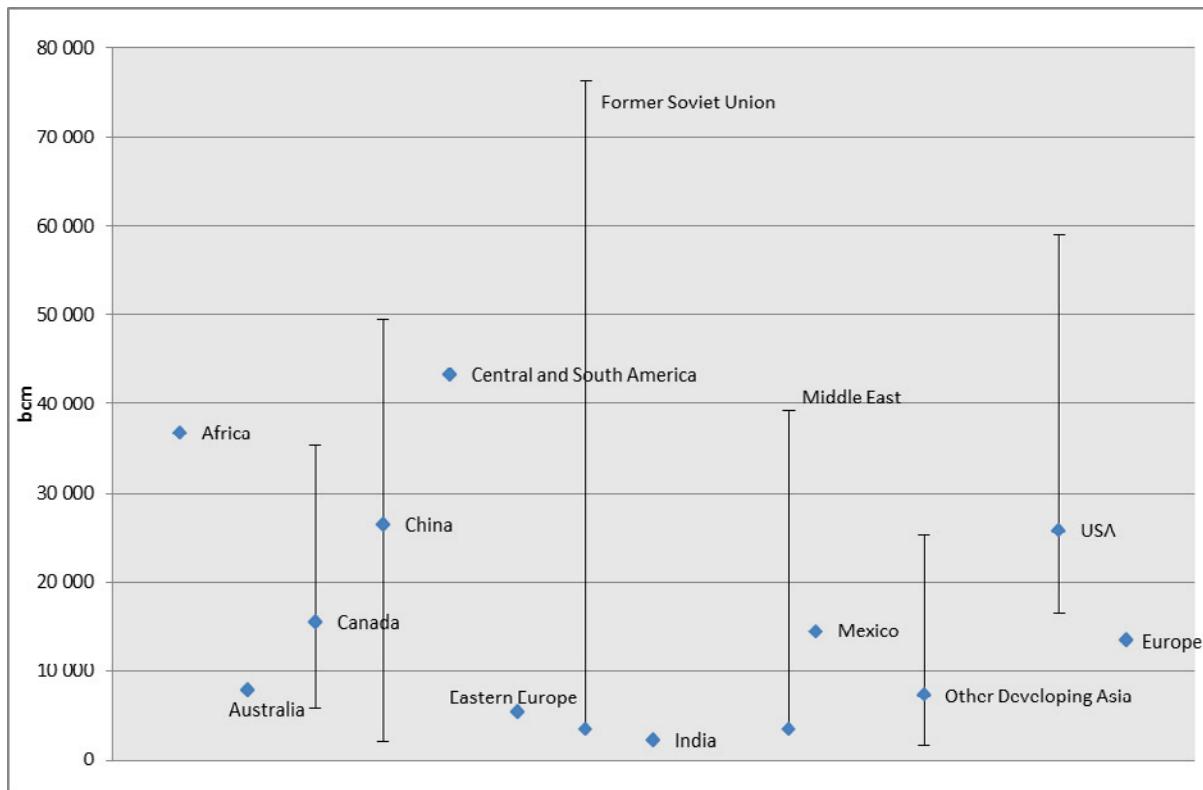
Energy markets are subject to much uncertainty, as many of the events shaping them cannot be anticipated and future developments in technologies and resources cannot be foreseen with certainty. To understand the potential impact of unconventional gas on energy markets it is necessary to take into consideration the key uncertainties that can be considered pivotal for determining upper and lower bounds of future shale gas development. These factors can be categorised in terms of the natural gas supply chain – i.e. upstream exploration and production, mid and downstream processing and transport, and, finally, end use. In the following, a set of key factors are briefly discussed. For each of them a reasonable area of uncertainty is defined in a quantitative manner, by setting in a transparent way reference figures and lower and upper bounds. The ways in which these different figures can impact on the energy system have been explored through the ETSAP-TIAM model.

6.1.1 Upstream natural gas resources and cost

Conventional and unconventional gas resources

Unconventional gas includes tight gas, coal-bed methane and shale gas. The prevailing literature suggests that the latter currently has the most significant growth prospects because new technologies have enabled economically viable extraction of gas from permeable shale reservoirs. This report has provided a range of estimates on the technically recoverable resource base of shale gas. This is one of the key input assumptions used in the scenario analysis. The figure below summarises the data collected in Chapter 2.

Figure 6-1: Assumptions on the global, technically recoverable reserves of shale gas

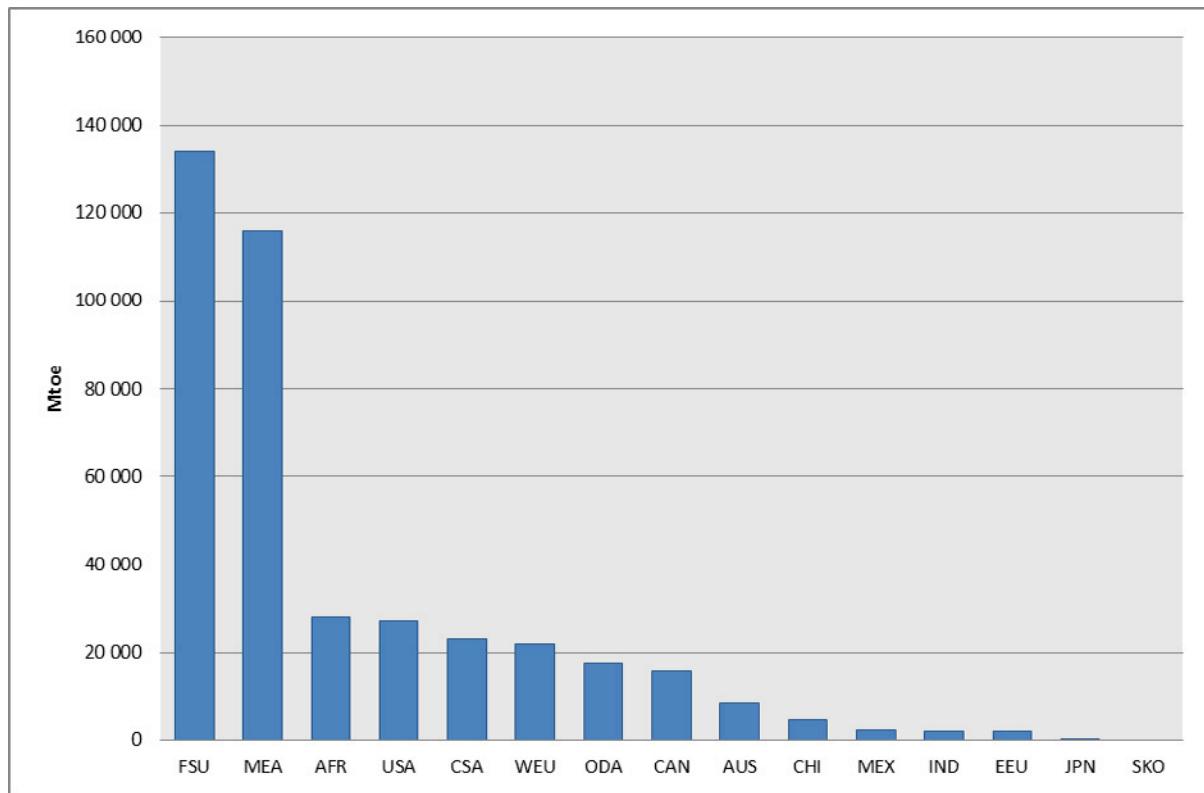


It is useful to consider these unconventional gas resource estimates in the context of the world's existing conventional gas reserves. Figure 6-2 below reveals that the Former Soviet Union (FSU) and the Middle East region retain the largest conventional natural gas reserves. Russia in particular possesses a vast potential for expanding and developing its conventional reserves, which are remotely located and underdeveloped (such as in the Yamal Peninsula or other parts of eastern Siberia). Hence, the projected increase in exports from these two regions is a significant consideration when gauging the future penetration of indigenous unconventional gas, particularly in import-dependent regions such as Europe. The increase in exports from the FSU and the Middle East, in turn, relies on capacity constraints and the price differential between imports and potential indigenous production. In Europe it is down to developments in regional gas pricing, competition from other markets and the corresponding expansion of flexible LNG cargoes, which will crucially affect the quantities of gas bought under long-term piped gas contracts.

Finally, other unconventional fuels may look set to add to the global reserve base; unconventional oil resources, including extra-heavy oil and kerogen oil, have a large potential; however, many technical, commercial and political obstacles need to be overcome before they can be fully developed.⁶ The systemic approach adopted here for the scenario analysis means that, even if the specific uncertainty surrounding unconventional oil is not explored here, any of the following scenarios takes into account the potential competition between unconventional oil and unconventional gas.

⁶ IEA, 'WEO 2011'.

Figure 6-2: Global conventional gas reserves (recoverable, enhanced recovery and new discovery)



Conventional and unconventional gas production costs

The assumptions about the costs of producing conventional gas resources by 2020 are noted in Figure 6-3, taking into account the variable costs of exploiting existing reserves, as well as developing new fields.

Shale gas production costs have been discussed in Section 5.1, as well as in Chapter 3. Clearly there is much variation in the costs of finding, developing and producing unconventional gas, which depend on prevailing market conditions, the characteristics of the well, the regulatory context and the profile of the operating company. For the scenario analysis, the cost estimations have been based partly on the analysis of other sources provided in Section 5.1.4 and partly from the final cost assumptions made in Section 3.3. The caveats and assumptions made for these figures have been discussed in the relevant section and need not be elaborated upon here. The conservative, most likely and optimistic estimates were respectively employed in ten-year intervals (2010-2030) to capture the reduction in costs attributed to technological development.

Figure 6-3: Conventional gas production cost estimates in 2020⁷

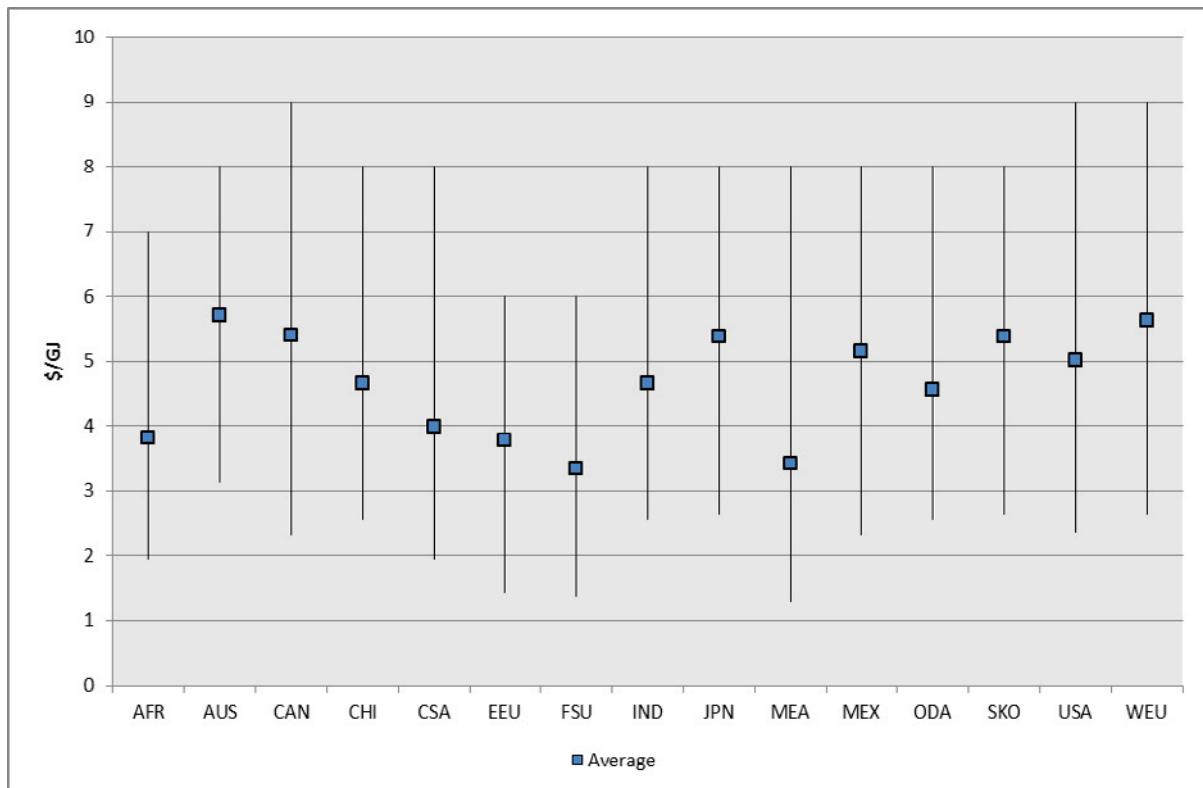


Table 6-1: Total unit production cost per shale gas well in Europe without liquids

€/GJ	Optimistic	Most likely	Conservative
2010	4.56	7.22	20.78
2020	3.23	5.24	15.40
2030	2.68	4.42	13.17

To better capture regional differences in production costs, the authors have constructed a modifying factor based on the EIA's Financial Reporting System (FRS), which is a statistical database on the functional and financial performance of major US energy-producing companies, including their operations abroad.⁸ Data on the upstream cost of finding, developing and producing gas and oil wells were used to derive a total per-unit production cost for the six regions for which data is available (see Table 6-2). These were compared against a European base case to construct multipliers for these respective regions. The rationale for using this dataset is that the expertise of US drilling and service companies is currently a key ingredient for initially exploring shale gas resources in regions of interest. Most of the companies reporting through the FRS have

⁷ The average is the mean value of the minimum and maximum costs of exploiting three categories of reserves: recoverable, enhanced recover, and undiscovered/new discovery. For each category, a three-step supply curve is assumed, where the minimum cost is the cost of the lowest step of the supply curve for recoverable reserves, while maximum costs are for the highest step of enhanced recovery.

⁸ EIA, 'Database: The Financial Reporting System Public Data', (Washington, DC: US Energy Information Administration, 2012). Bear in mind that FRS companies have represented 40-60% of the total US energy-producing industry over the last 30 years; therefore, aggregate production statistics of FRS companies are only a representative sample of the total

portfolios that include shale gas exploration activities in different countries (alongside their conventional oil and gas assets).

Table 6-2: Upstream costs for FRS companies, 2006-2008 and 2007-2009⁹

\$/boe	2006-8	2007-9	Modifying factor
United States of America	41.49	33.76	0.63
Canada	38.75	24.76	0.46
Europe	72.32	53.37	1.00
Former Soviet Union	16.7	20.96	0.39
Africa	42.24	45.32	0.85
Middle East	17.09	16.88	0.32
Other Eastern Hemisphere	21.18	16.56	0.31
Other Western Hemisphere	33.88	26.64	0.50

Resource and data availability issues preclude a more accurate representation of regional differences in shale gas production costs, so the interpretation of this data should be approached with the usual level of caution.¹⁰ Even so, the upstream production costs incurred by major US energy firms represent a proxy, albeit an imperfect one, for the relative level of investment needed in each respective region.

As the upstream costs noted above are for conventional oil and gas wells, extrapolating these to shale gas requires a differentiation of the key cost components of conventional gas versus unconventional shale gas production.¹¹ In technological terms, the key difference between conventional and shale gas extraction lies in the latter's use of horizontal drilling and hydraulic fracturing techniques for targeting gas trapped in continuous rock formations. Compared with conventional gas, this requires lengthier wellbores, a greater amount of land, more water (or drilling mud), more frequent truck trips and expenses unique to fracturing and directional drilling. To provide a conservative representation of these costs, the modifying factor above has only been applied to the proportion of expenses in Chapter 2 that represent additional costs required to drill and develop a horizontal, hydro-fracked shale gas well. These are essentially the day rate costs discussed in Table 3-16, which cover the rig rental, directional drilling cost, mud servicing, and bit and evaluation expenditure. Together, these components are estimated to make up around 25% of total per-well production costs of shale gas in 2015 (followed by 18% and 14% in 2025 and 2030 respectively, reflecting technological learning curves and greater economies of scale). The

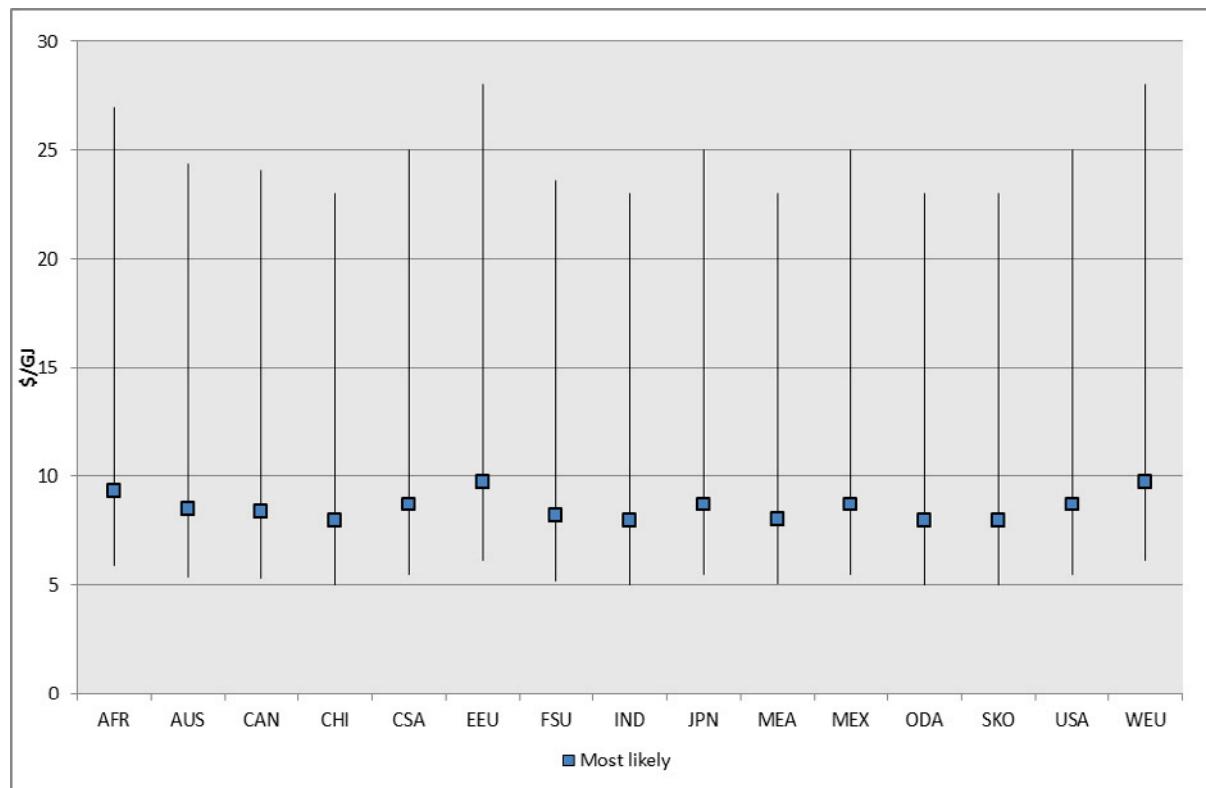
⁹ EIA, 'Performance Profiles of Major Energy Producers', (Washington, DC: 2009). Note: Upstream costs are finding costs plus lifting costs. Natural gas was converted to equivalent barrels of oil at 0.178 barrels per thousand cubic feet. Sum of elements may not add to total due to independent rounding. Source: U.S. Energy Information Administration, Form EIA-28 (Financial Reporting System).

¹⁰ Indeed, upstream costs for US energy firms operating abroad may not reflect average costs for all market players in a given region. Moreover, there is considerable variation in cost components within the different regions that may influence total production expenditure. Notably, operating expenditures and production taxes vary due to different labour, service, regulatory and infrastructural constraints in different countries.

¹¹ One caveat underpinning this approach is that the productivity of shale gas wells in the USA are higher than for conventional wells, meaning a potentially lower per-unit production cost over the entire life of a shale well despite more substantial capital expenditures. Bonakdarpour et al., 'Economic and employment contributions', 8.

calculations have yielded the following costs of shale gas for the 15 world regions in 2020.

Figure 6-4: Shale gas production cost estimates for 2020

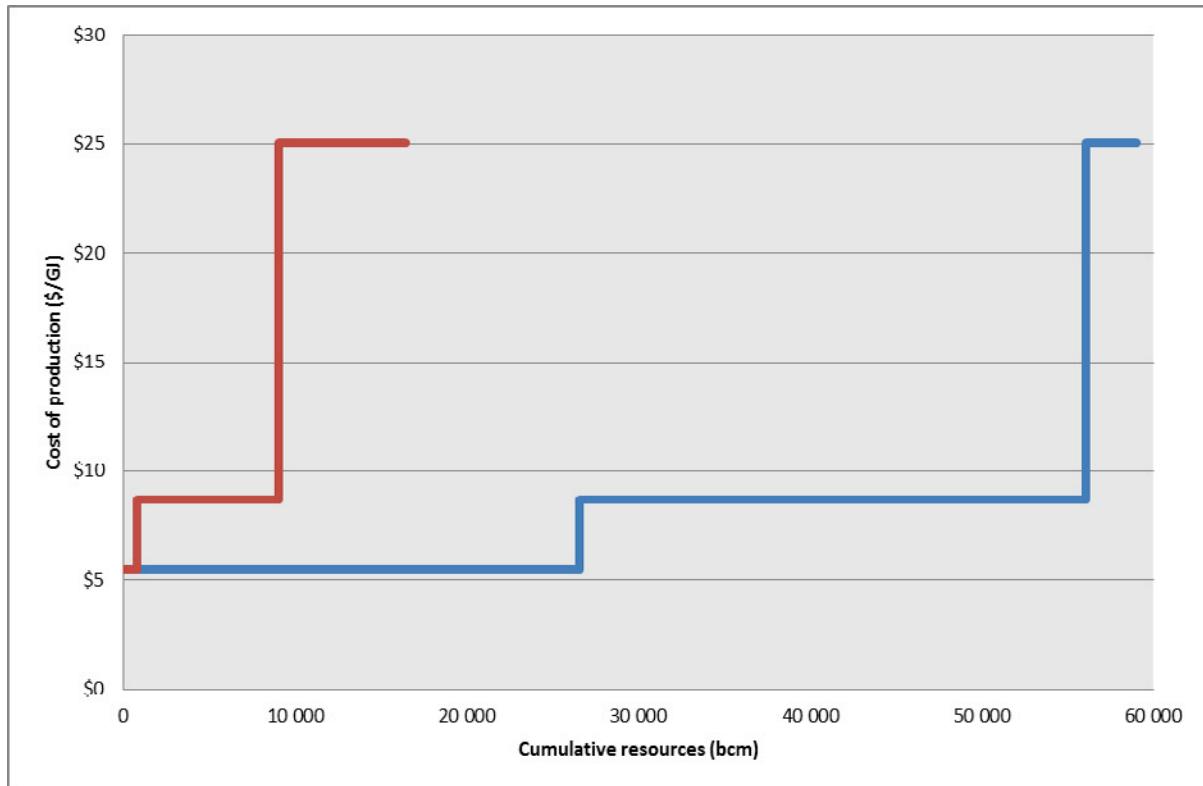


As shown, conservative cost estimates drive up the range of uncertainty. For the energy model used to carry out the scenario analysis, supply curves have been defined by assuming that a proportion of the estimated reserves provided in Chapter 2 can be developed at a certain cost. In an optimistic case of high proven reserves and low production costs for example, 45% of potential shale gas reserves in any region are set to be extractable at the 'optimistic' production cost described in Table 6-1, while 50% are set to be extractable at the 'most likely' production cost and 5% are set to be extractable at the 'conservative' production cost. Conversely, a conservative scenario of low proven reserves and high production cost will make only 5% of reserves extractable at the 'optimistic' cost, with 50% extractable at the 'most likely' cost and 45% at the 'conservative' production cost.¹² Figure 6-5 below shows how, in an optimistic case, the USA can produce around 30 000 bcm of shale gas resources at around \$5.00 per gigajoule (GJ), followed by an additional 30 000 bcm at a production cost of around \$9.00/GJ. On the contrary, in the conservative case, the USA can produce around 1 000 bcm of shale gas resources at around \$5.00/GJ, followed by an additional 9,000 bcm at a production cost of around \$9.00/GJ.

¹² As the ETSAP-TIAM model optimises the balance of fuels and technologies based on cost, just considering scenarios of highest or lowest figures would either preclude commercially viable shale gas production in any region (including the USA and Canada) or on the contrary, assume that shale gas is strongly competitive in any region. The supply curve approach leads to a more realistic assumption, where even a conservative scenario can yield some level of production.

It is informative to compare the two shale gas supply curves below with that used in another notable modelling study by MIT.¹³ The curves used in the aforementioned study lie clearly between the two curves used in the present analysis; that is to say, the curves used here cover a wider range. In particular, the optimistic case used in the present study assumes three times more low-cost shale gas than the MIT study does. The supply curves in the present study therefore represent more extreme cases on both sides, reflecting the great uncertainty in the data that has been identified and addressed by earlier chapters. This is important to bear in mind when considering the results.

Figure 6-5: Shale gas supply curves for the United States of America in 2015



Together with its own production cost, a further factor affecting the competitiveness of shale gas is the production cost of the other types of unconventional gas, i.e. coal-bed methane and tight gas. The supply curves for both types of unconventional gas have been built in line with IEA (2011): the production cost of coal-bed methane ranges between \$3 and \$8/GJ, while the production cost of tight gas ranges between \$4 and \$8/GJ.

The role of natural gas in a carbon-constrained world

At the international level, reliance upon a system of voluntary national pledges of emission reductions by 2020, as set out initially in the Copenhagen Accord, leaves uncertainty concerning the likely structure of any future agreements that may emerge to replace the Kyoto Protocol. The absence of a clear international regime for mitigating GHG emissions in turn raises questions about the likely stringency of national policies in both industrialised countries and major emerging economies over the coming decades. Particularly in the power sector, the relative costs of different technologies may shift

¹³ Moniz, Jacoby and Meggs, 'Future of natural gas', 31.

significantly in response to research, development and demonstration, as well as CO₂ emissions prices.

A carbon tax would increase the absolute cost of energy from fossil fuels. These costs would be passed on to the final consumer in the form of higher prices that, in turn, would lower overall demand. Given the relative efficiencies and carbon emissions of different energy technologies or fuels, the technology mix of the whole energy system would be affected. However, much depends on how substantial the carbon tax or other climate change policies will be. In power generation, gas-fired electricity generation will be less affected by a carbon tax than coal. But there is, after all, a point at which gas-fired power generation loses its competitiveness to non-emission generating sources, such as nuclear or renewables.

As the extent and nature of the GHG mitigation measures that will be adopted is one of the key uncertainties surrounding the future development of the global gas market, the scenario analysis includes a specific sensitivity analysis exploring the impact on the global energy system, particularly on gas, of a future 'carbon constrained' world, i.e. a world committed to halve CO₂ emissions by 2050.

Box 6-2: The impact of liquids on shale gas production costs

An important issue to highlight when discussing shale gas production costs is the presence or absence of associated liquid hydrocarbons, in the form of natural gas liquids (NGLs) that need to be separated in a processing plant, such as butane, propane or ethane. Production and processing of such liquids can serve to lower per-unit production costs and raise the economic profitability of wells. Thus, even if the proportion of total 'dry' gas production dwarfs total liquids production from a given shale well, the energy content and market price of the latter makes for a compelling business case to target liquid-rich shale plays. Moreover, there have been substantial recent additions to proved US 'wet' gas reserves – e.g. gas that includes lease condensates and natural gas plant liquids; the EIA has reported a 9% increase in proved reserves of natural gas plant liquids and a 14% increase in lease condensates from 2008 to 2009.¹⁴

However, despite its growing role in shale gas economics, the figures on unit costs of production per well that are used in the model do not include liquid production. This omission was made to better reflect existing estimates of break-even costs of shale gas wells, such as those found in the IEA's recent *Golden Age of Gas* report, which explicitly do not account for the value or cost of liquid production.¹⁵

6.1.2 Midstream

Gas transportation costs and capacities

Despite the recent surge in interest in Europe's unconventional gas, many analyses nevertheless continue to project significant growth in imports of conventional pipeline gas and LNG for the European gas market.¹⁶ This serves as a reminder that the prospects of unconventional gas gaining market share depends not only on its competitiveness vis-à-vis other fuels such as coal or nuclear, but also on its relationship to conventional gas, as well as the various ways in which gas is transported. In this respect, the cost competitiveness of different modes of gas transport (LNG and pipeline) is a factor of interest for considering future gas-supply market dynamics and the degree of market penetration of unconventional gas reserves.

¹⁴ EIA, 'Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves 2009', (Washington, DC: US Energy Information Administration, 2010).

¹⁵ IEA, 'Golden age', 49.

¹⁶ EIA, 'Various AEOs'; IEA, 'WEO Various'.

Significant growth in LNG infrastructure and trade has the potential to either foster or deter investments in unconventional gas production; just as LNG can encourage gas-producing countries to export their indigenous production, so too can regasification terminals for importing countries – given favourable costs relative to domestic shale gas production – serve as an alternative to the latter. Analysts have already begun to ponder a future scenario in which significant and ongoing US and Canadian shale gas production leads to LNG flows from North America to European and Asian markets.¹⁷ If interregional LNG trade sees such exponential growth, this may reduce the incentive to invest in shale gas production outside of North America (particularly given the regulatory and service-sector bottlenecks that could moderate its degree of development in Europe). Conversely, if high reserves and low production cost stimulate considerable shale gas production in all regions, this may dilute the importance of LNG by challenging the profitability of long-distance interregional trade.

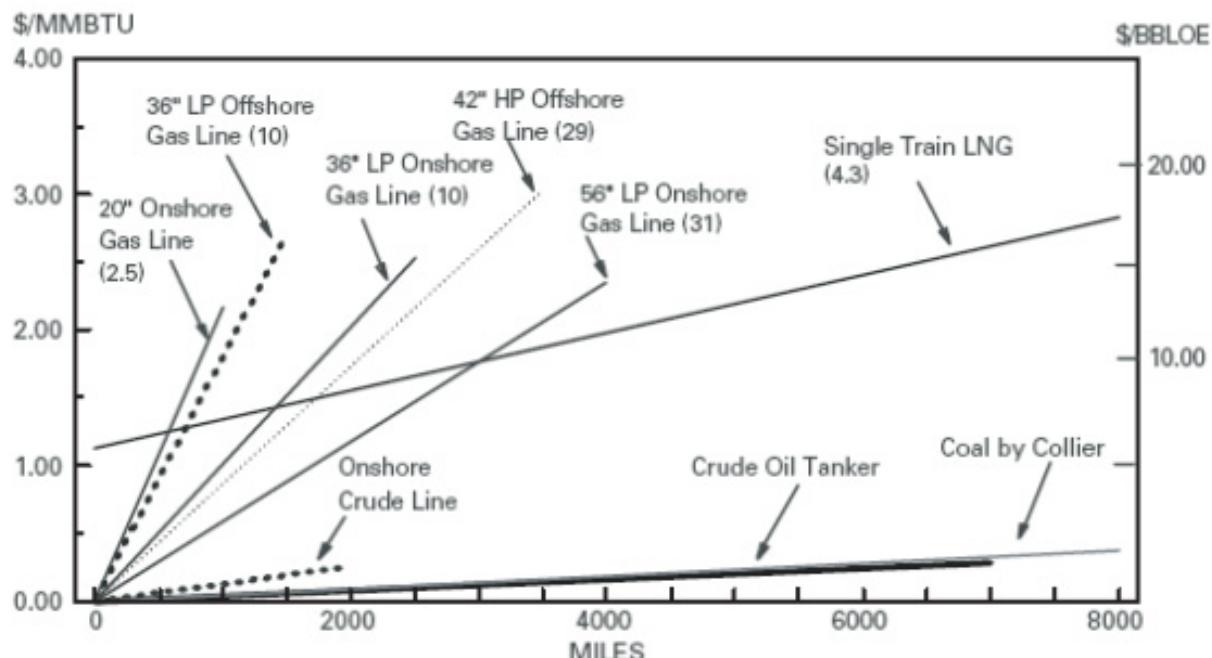
Given these uncertainties, the scenario analysis must take into account the important role played by gas transportation costs, which will crucially inform the price differential between competing sources of natural gas supply as interregional gas trade develops (a differential which must, of course, remain bound by contractual and capacity constraints).

In Figure 6-6 below, James Jensen has provided a rough approximation of the difference in costs of gas (and oil) transport in terms of distance, type, diameter and capacity of supply line. Natural gas must be cooled to minus 162°C in order to condense it into a liquid form. This reduces its volume by approximately 600 times, thereby allowing it to be cost-effectively shipped by tanker. Building and running the liquefaction plants that cool and condense the gas into a liquid is expensive and energy-intensive; however, shipping LNG is less costly than pipeline transport on a per-MBtu basis. As a result of this, LNG usually costs more to ship than pipeline gas over distances less than 1 500 miles. Over distances of more than 2 500 miles, however, LNG is generally cheaper to transport than even the most efficiently piped gas.¹⁸

¹⁷ Rogers, 'Impact of a globalising market'.

¹⁸ James T. Jensen, 'The Future of Gas Transportation in the Middle East: LNG, GTL and Pipelines' (paper presented at the The Annual Conference of the Emirates Center for Strategic Studies & Research, Abu Dhabi, 2004).

Figure 6-6: Illustrative costs of gas, oil and coal transportation¹⁹



Note: Numbers in brackets show gas delivery capability in BCM

The traditional LNG project has been described as a 'chain' with four, or occasionally five, links: 1) field development; 2) in some cases, a pipeline to the coast; 3) the liquefaction facility; 4) tanker transportation; and 5) the regasification terminal.²⁰ For a typical LNG value chain, exploration and production of feedstock supplies represent 15-20% of total capital costs, liquefaction comprises 30-45% of costs, shipping accounts for another 10-30% and gasification and storage account for the remaining 15-25%.²¹ Each link in the chain is capital-intensive, with most LNG projects costing several billion dollars.

There is some debate as to the direction in which LNG production costs are heading. Up until the early 2000s, technological progress had led to a sharp decrease in the large initial capital cost, and hence life-cycle operating cost, of liquefaction plants – the principal cost component in the LNG chain. The average investment for a liquefaction plant dropped from some \$550 a tonne per year of capacity in the 1960s, to approximately \$200 in the early 2000s. Several factors accounted for this trend. Studies highlighted economies of scale in the construction phase that reduced the marginal cost of each additional liquefaction train built at the same greenfield site by 20-30%.²² In a similar vein, larger LNG train sizes resulting from the shift from steam-driven to gas turbine-driven compressors drove down liquefaction costs as well.

¹⁹ James T. Jensen, 'The Development of a Global LNG Market: Is it Likely? If so, when?', (Oxford: Oxford Institute for Energy Studies, 2004), 7.

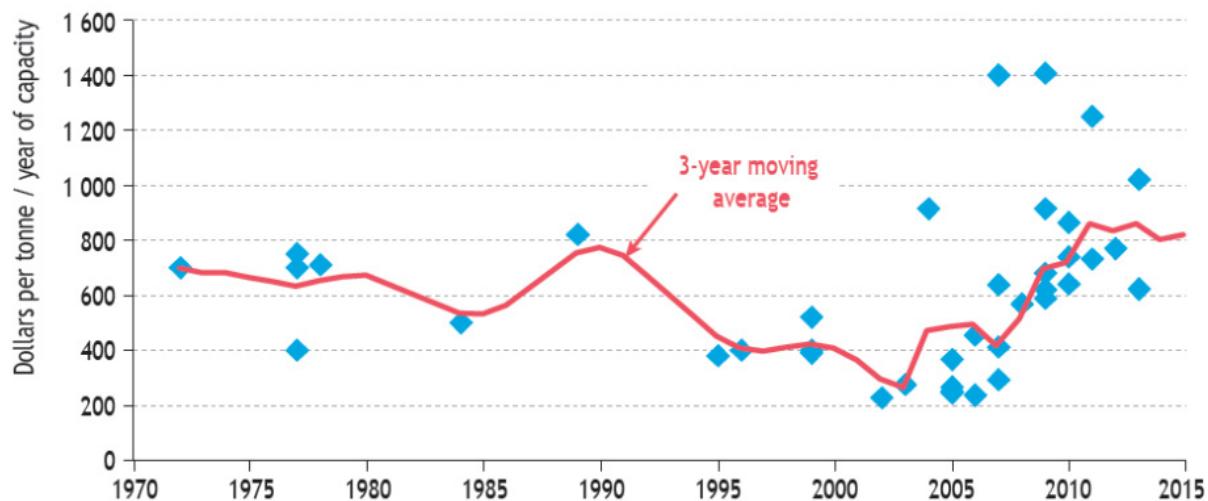
²⁰ Jensen, 'LNG Revolution': 26.

²¹ Maxwell and Zhu, 'Dynamics of LNG imports': 219.

²² Sylvie Cornot-Gandolphe, 'LNG Cost Reductions and Flexibility in LNG Trade add to Security of Gas Supply', in *Energy Prices and Taxes, 1st Quarter 2005*, ed. IEA (Paris: Organisation for Economic Co-operation and Development 2005), xxix.

More recent analyses, however, contend that investment costs for liquefaction terminals have increased by about 20% over the last five years.²³ Writing in 2009, the IEA estimated that LNG liquefaction plants commissioned in the period from 2009-2013 would cost about \$830/tonne compared with \$430/tonne for those commissioned in 2005-2008 (see Figure 6-7 below).²⁴ Another study provided a similar range of liquefaction costs over the decade to 2009, capturing their rise from \$300/tonne to between \$600-1400/tonne per annum.²⁵

Figure 6-7: LNG liquefaction plant capital costs²⁶



As for other links in the LNG chain, shipping costs have fallen markedly, as competition between shipyards reduced the construction cost of LNG tankers from about \$280 million for a 138,000 cu. metre ship in 1995 to \$150-160 million by the mid-2000s.²⁷ Larger tankers, enjoying greater economies of scale also reduced operating costs. Tanker sizes have increased from some 40 000 cubic metres for the first generation to 135 000-140 000 cubic metres.²⁸ In addition, the EIA found in a 2003 report that regasification terminal costs seemed to have fallen, although this trend was more difficult to verify as the costs varied more by location.²⁹

All of the abovementioned cost components of the various stages of the LNG chain hinge on supply-and-demand dynamics, thus implying a considerable degree of uncertainty for the future. Moreover, the extent to which the cost of LNG production witnesses substantial change also depends on the cost of raw materials (steel, nickel and aluminium), labour and services (which come at a premium during periods of significant global investments in capacity), as well as a range of project-specific factors such as plant location and construction times.

²³Stefan Lochner and Jan Richter, 'The impact of recent gas market developments on long-term projections for global gas supply', *Energiewirtschaft* 34 (2010).

²⁴IEA, 'WEO 2009', 451.

²⁵Andrew Morris and Keith Messenger, 'Global gas & LNG markets & GB's Security of Supply; a report to Department of Energy and Climate Change', (Poyry Consulting, 2010).

²⁶IEA, 'WEO 2009', 451.

²⁷ Maxwell and Zhu, 'Dynamics of LNG imports': 221.

²⁸Cornot-Gandolphe, 'LNG Cost Reductions', xxx.

²⁹EIA, 'Global LNG Market', 42.

For the scenario analysis, the costs of regasification and liquefaction terminals are calculated on the basis of initial investment costs, fixed operating and maintenance costs, the plant availability and any losses incurred, which are annualised according to the lifetime of the plant and subjected to a discount rate (in this case 5%). More specifically, the cost of liquefaction plants is in line with the more recent estimates, which, as mentioned, are higher than those given for the first half of the 2000s. The main set of scenarios assume a capex of about \$6 billion for an LNG chain producing 10.6 bcm/a (i.e. 8 mtpa).

For pipelines, the primary determinants of construction costs are the length and diameter of the pipeline, the operating pressure (and the corresponding need for higher grade steel) and the terrain.³⁰ Operating costs, in turn, vary depending on the number of compressor stations and the price of their generating fuel. The total per-unit cost will depend on average capacity utilisation and load factors. According to analysts at the IEA and Cedigaz, the investment required to lay a long distance, large diameter line amounts to \$1-1.5 billion per 1 000km.³¹ Since this figure was presented in 2004, some analysts have found that pipeline costs have increased by 30% for onshore and as high as 70% for offshore projects.³² Recent analysis carried out within the ETSAP community concludes that an onshore pipeline carrying 20bcm per annum over a distance of 1 000km costs between \$0.47-0.80/Mbtu.³³ For sub-sea pipelines, earlier IEA analysis set the capex on a baseline 500km, 12 bcm/pa offshore pipeline at \$2 billion, implying a total gas transportation cost of \$0.70 to \$0.80/MBtu for this distance.³⁴ As with for LNG transport costs, the most recent estimates have been used for pipelines in the scenario analysis.

However, in order to explore the uncertainty surrounding gas transportation costs and its potential impact on the development of indigenous production in the different world regions, a sensitivity analysis has been carried out, by assuming LNG costs decreasing to the levels of the early 2000s.

As for capacity, Table 6-3 and Table 6-4 also show assumptions about medium-term capacity forecasts for both interregional LNG and piped gas, which are derived from recent IEA data. The figures for 2020 are then progressively increased until they are doubled in 2040 to provide a rough approximation of the maximum capacity available in at this time.

³⁰ There are, of course, other factors to consider that vary according to local conditions, such as labour costs, service costs, securing rights of passage, honouring safety regulations, and so on.

³¹ Sylvie Cornot-Gandolphe et al., 'The challenges of further cost reductions for new supply options (pipeline, LNG, GTL)', in *22nd World Gas Conference* (Tokyo, Japan: Cedigaz, 2003).

³² Lochner and Richter, 'Impact of gas market developments'.

³³ Pernille Seljom, 'Oil and Natural Gas Logistics', in *IEA ETSAP Technology Brief P03* (ETSAP, 2011).

³⁴ IEA, 'WEO 2009', 451.

Table 6-3: Major interregional natural gas pipeline projects³⁵

Origin	Destination	Major pipelines	bcm/a
FSU	CHI	Altai	30.0
	SKO	Russia - Asia Pacific	10.0
		Nord Stream	27.5
	WEU	Nord Stream 2	27.5
		South Stream	63.0
		Nabucco	31
MEA	WEU	ITGI (Interc. Turkey Greece Italy)	12
		TAP (Trans Adriatic Pipeline)	20
		IGAT 9 (Iranian Gas Trunkline)	37
FSU	CHI	CAGP	35
		CAGP expansion	25
	ODA	TAPI	30
MEA	IND	IPI	8
	MEA	Arab Gas Pipeline	10
ODA	CHI	Myanmar - China	12
AFR	WEU	GALSI (Gasdotto Algeria Sardegna Italia)	8
Total			386

Table 6-4: Assumed maximum liquefaction capacity 2020

	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
bcm/a	547	138	0	0	195	0	59	0	0	618	0	196	0	57	8

6.1.3 Natural gas in power generation and other end uses

Economic growth and natural gas demand

For any given region, the intensity of unconventional gas exploration and development depends on total gas demand. Historically, this demand has been linked to the level of GDP growth. The scenario analysis will base its GDP assumptions on those found in the EIA's International Energy Outlook 2010, which provides forecasts to 2035 of regional GDP levels.

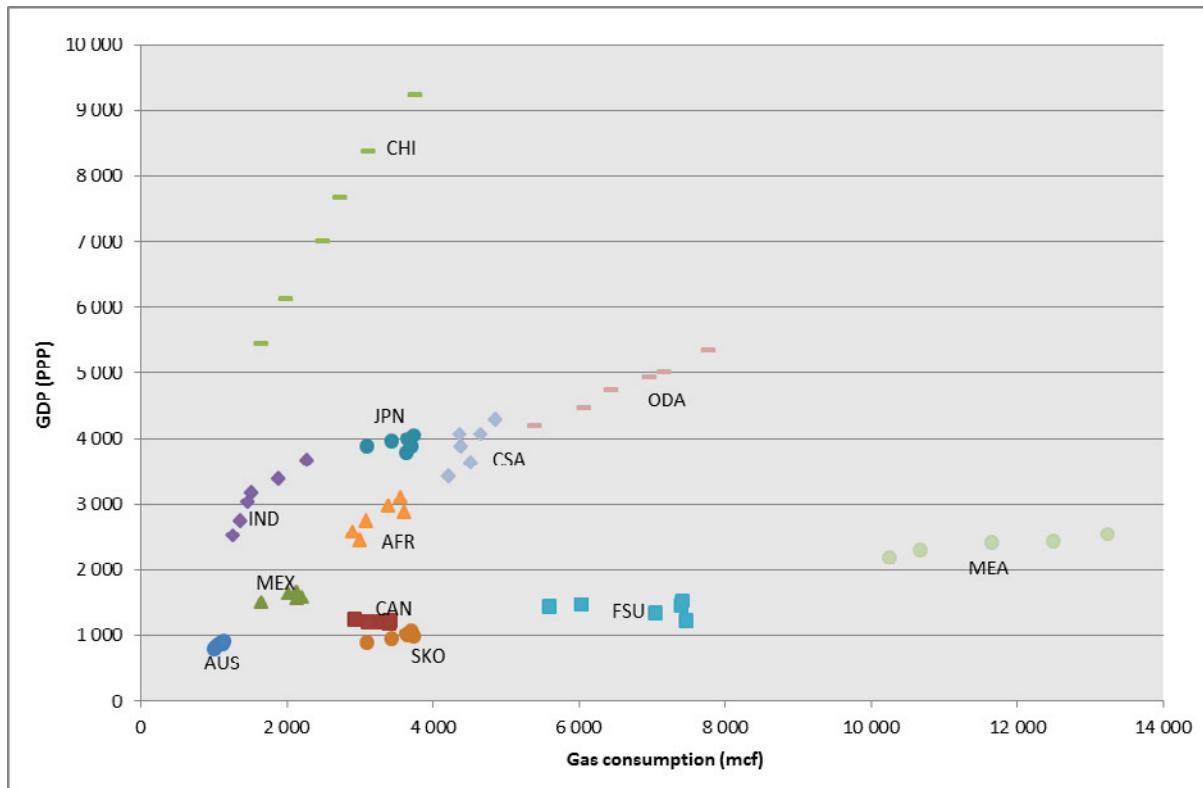
Of course, GDP and total energy demand are not perfectly correlated. As discussed in the IEA's WEO 2011, the degree of increase in energy demand relative to GDP depends on a given country's stage of economic development. For developed countries, increases in energy demand are tempered by efficiency improvements and saturation effects.³⁶ In developing countries, however, there is a higher 'elasticity' of energy consumption relative to GDP, implying more substantial per capita growth in energy demand as these countries' living standards improve. The graph below demonstrates the relationship

³⁵ IEA, 'WEO 2011'.

³⁶ Ibid.

between GDP and natural gas consumption in a set of mainly developing regions by showing their respective values for the regions over the period from 2005-2010.

Figure 6-8: GDP and gas consumption by region, 2005-2010³⁷



At the time of writing, the global economic climate is gloomy, particularly for the world's advanced economies as complex financial and fiscal challenges continue to threaten overall recovery from recession. Current projections of global GDP development, therefore, assign most of the growth to developing countries, implying more substantial increases in global energy demand as these countries 'catch up' with the advanced industrialised economies. In the longer term, as well, most forecasts assume that non-OECD countries – in particular China – will account for most of the economic growth in the coming decades and, as a corollary, the majority of growth in energy demand (see Table 6-5 below). Any output from the model will be highly sensitive to these assumptions about global growth. To capture the consequent uncertainty, the scenario analysis will distinguish between low and high growth cases as shown in Table 6-5. However, both cases do not deviate from the assumption of relative economic convergence, i.e. low income regions growing faster than high income regions.

³⁷ EIA, 'International Energy Outlook 2010', (Washington, DC: US Energy Information Administration, 2010).

Table 6-5: GDP assumptions in the model

Average growth in %, PPP	Low growth		High growth	
	2010-2020	2020-2040	2010-2020	2020-2040
OECD North America	2	2	3.4	3.2
United States of America	2	1.8	3.6	3
Canada	2.1	1.6	3.2	2.6
Mexico	1.4	3.7	2.4	4.7
OECD Europe	1.5	1.4	2.6	2.4
OECD Asia	1.4	0.7	2.5	1.7
Japan	0.8	-0.2	1.9	0.8
South Korea	2.8	2.1	3.9	3.1
Australia/New Zealand	1.9	2	3	3
Total OECD	1.7	1.6	3	2.7
Non-OECD Europe and Eurasia	3	2.3	4.1	3.3
Russia	2.6	2.4	3.7	3.4
Other	3.5	2.1	4.6	3.1
Non-OECD Asia	5.2	3.7	6.3	4.7
China	6	3.8	7.1	4.8
India	5.1	3.5	6.2	4.5
Other non-OECD Asia	3.7	3.6	4.8	4.6
Middle East	3.4	3.1	4.5	4.1
Africa	3	2.7	4.1	3.7
Central and South America	3.5	2.8	4.6	3.8
Brazil	3.7	3.4	4.7	4.4
Other Central and South America	3.3	2.2	4.4	3.2
Total Non-OECD	4.4	3.3	5.5	4.3
Total World	3	2.6	4.2	3.6

Gas-fired, nuclear and renewable power generation

Natural gas has the potential to capture a greater share of the global mix of electricity-generating fuels (largely by muscling in on coal's current dominance). This, of course, depends on the natural gas price, which represents the majority of operating costs for relatively efficient combined cycle plants and the concomitant investment decisions within the industry. The penetration of natural gas in the electricity generation mix also depends on the policies enacted by governments to regulate and tax carbon emissions. Indeed, the IEA's WEO for 2011 has identified carbon pricing and subsidies to renewables as the two government policies that will have the most significant impact on the electricity generation mix over time.³⁸ To explore these issues a specific sensitivity analysis has been carried out in order to assess the robustness of the results (see Figure 6-9).

Gas use in transport and the gas/oil price link

A central question that has arisen in the analysis is whether to assume a coupling or decoupling of oil and gas prices. Much has been written recently about the logic of the price linkage of gas to oil. As discussed in Section 5.2.4, commentators have questioned

³⁸ IEA WEO 2011 p. 178

the long-term viability of oil indexation given the gradual devolution of substitution possibilities between gas and oil products. Analysts have also noted that abundant unconventional gas production in the USA has served to weaken the linkage between oil and gas prices, leading to a NYMEX crude-to-gas futures contract ratio of 43:1 in January 2012, the highest in the last two decades.³⁹ Thus, contemporary wisdom holds that global unconventional gas development will play a key role in enabling a gradual break from gas-oil price linkages as the two fuels and their markets develop their separate ways.

However, uncertainties regarding future technological developments may turn this logic on its head. A persistently high oil-to-gas ratio would create incentives to invest in gas-based transport technologies that are currently deemed uncompetitive against a sector dominated by oil. Indeed, in addition to stimulating growth in natural gas-powered vehicles (NGVs), significant shale gas production could also make gas-to-liquids (GTL) technology attractive. Although Shell's recently completed Pearl GTL plant in Qatar represents a significant step forward for industry, the process that converts dry gas to distillates such as diesel, heating oil and jet fuel had long been regarded as a prohibitively costly investment, justified only in areas where gas reserves are 'stranded' and could not access markets.⁴⁰ However, with a high enough oil-to-gas price ratio and a large enough resource base, GTL plants become increasingly commercially viable, serving as competitors to gasoline and diesel from conventional oil refineries. Paradoxically, then, some of the same forces that are currently driving a wedge between oil and gas prices can, in the longer term, enable their re-coupling, by stimulating investments in technologies such as GTL that once again make gas and oil substitutable fuels. Of course, much hinges on the natural gas and oil price link over a period of decades: in its discussion of the potential of future gas-to-liquids production, the EIA Annual Energy Outlook states that "only with the highest [oil] prices in the Reference case and the low end of GTL plant costs do the break-even economics favour [such] project[s]."⁴¹ Significant shale gas development may very well enable such a scenario.

In the scenario analysis, a basic assumption has been used across all the main scenarios: that natural gas can be priced according to its own specific market economics, i.e. independently from the conditions prevailing in the oil market. However, as this is in fact a strong assumption, in order to explore this factor of uncertainty a specific sensitivity analysis has been carried out, to assess how the results of the analysis change if the assumption of decoupling is removed.

6.1.4 Summary of key assumptions

The table below is by no means an exhaustive account of all the factors that will affect unconventional gas development. Rather, for each broader category some key drivers have been selected that are appropriate for the scenario analysis and in many cases these drivers reflect assumptions about other factors affecting unconventional gas production (e.g. the costs of shale gas are a function of capital and operating

³⁹ Samantha Santa Maria, *Crude oil to gas ratio near all-time highs... who cares?* (Platts, 2012, cited 24 April 2012); available from http://www.platts.com/weblog/oilblog/2012/01/26/crude-gas_ratio.html

⁴⁰ IEA, 'Energy Technology Perspectives', 267. Moreover, in this context the comparatively lower costs of LNG technology, which enhances the mobility of gas, also reduces the incentive to invest in GTL processes.

⁴¹ EIA AEO 2010, p. 40

expenditures as diverse as the cost of water or the price of materials for building gathering systems).

Table 6-6: Summary of modelling assumptions

Category	Variables	Notes/assumptions	Uncertainty	Criticality
Upstream	Unconventional gas resource size	Technically recoverable reserves of shale gas	High	High
	Unconventional gas production costs	Costs per GJ for F&D and producing shale gas, including cost reductions over time	High	High
Downstream	Gas transport costs	Cost-competitiveness of imported LNG and piped gas versus indigenous shale gas production	Medium	Medium
	Oil/gas price link	The difference between oil and gas prices expressed as a ratio (in energy equivalent terms)	High	High
Final use	Total global energy demand	Global GDP growth is the main driver of future demand for energy services	High	High
	Gas-fired power generation	The cost-competitiveness of CCGT in relation to other power generation technologies	Medium	Medium
	Gas use in transportation sector	Depends on competing fuels/technology like biofuels, hybrids, EVs, etc. Also relies on favourable gas/oil price differential	Low	Medium
Regulation	Carbon tax	A carbon tax crucially alters the energy supply mix by incentivising investments in renewable carbon-neutral energy	Medium	High

Three of these factors have been chosen as pivotal, both in terms of their future uncertainty as well as how critical they are for the eventual penetration of unconventional gas in the global energy system. These are the resource size and production cost of shale gas on the one hand and global GDP growth on the other. Therefore, the four main scenarios – ConLG, ConHG, OptLG and OptHG – reflect the combination of assumptions regarding these factors. Accordingly, there are two scenarios with either optimistic or conservative assumptions about shale gas production cost and reserve size (Opt/Con), and another two scenarios with either optimistic or conservative assumptions about global growth (HG/LG). To explore the impact of a lower oil-gas price ratio, an additional differentiation was applied to the conservative-low growth scenario (as shown in Figure 6-9). Combined, these yield five scenarios covering a range of possible outcomes over the period until 2040. A primary advantage of employing this framework is that either set of assumptions about high/low demand and optimistic/conservative supply can be held constant while probing the effects of each. Interpreting the respective results of these scenarios, along with some key sensitivities, will hence reveal the range of uncertainty underpinning future global shale gas development.

Figure 6-9: Schematic of the scenario analysis framework

Main scenarios								
<pre> graph TD EG[Economic growth] -- "-" --> RS1[Reserve Size] RS1 -- "+" --> PC1[Production Cost] RS1 -- "-" --> PC2[Production Cost] PC1 -- "+" --> OptLG[Opt-LG] PC1 -- "-" --> ConLG[Con-LG] PC2 -- "+" --> OptHG[Opt-HG] PC2 -- "-" --> ConHG[Con-HG] </pre>								
Sensitivity analyses								
Carbon constrained global energy system	X							
Social of acceptance of nuclear power	X							
Oil/gas price linkage			X					
LNG transportation costs	X			X		X		

Scenario	Description	Variation for sensitivity analysis
Optimistic-low growth (Opt-LG)	Shale gas resources corresponding to the upper-level estimates, most of which are deployable at low production costs. Low GDP growth at regional level	<ul style="list-style-type: none"> OPT-LG+LCO₂: Optimistic low growth with the additional assumption of CO₂ reduction Opt-LG+HNUC: Optimistic low growth with the additional assumption of possible higher nuclear penetration Opt-LG+LCLNG: Optimistic low growth with the additional assumption of lower LNG transport costs
Conservative-Low Growth (Con-LG)	Shale gas resources corresponding to the lower-level estimates, most of which are deployable at high production costs. Low GDP growth at regional level	<ul style="list-style-type: none"> Con-LG+CP: Conservative low growth with the additional assumption of oil and gas prices still coupled in the long term Con-LG+LCLNG: Conservative high growth with the additional assumption of lower LNG transport costs
Optimistic-High Growth (Opt-HG)	Shale gas resources corresponding to the upper level estimates, most of which are deployable at low production costs. High GDP growth at regional level	<ul style="list-style-type: none"> Opt-HG+CP: Optimistic high growth with the additional assumption of oil and gas prices still coupled in the long term
Conservative-High Growth (Con-HG)	Shale gas resources corresponding to the lower level estimates, most of which deployable at high production cost. High GDP growth at regional level.	

6.2 Scenario analysis results

In the following section, the authors explore the various conditions under which shale gas gains importance in the global energy mix, based on the key factors identified and discussed above. The results of the scenario analysis shed light on some of the primary issues shaping the debate about unconventional gas: for example, the role of gas in the global energy mix; whether shale gas will constrain or enable the globalisation of the gas market (and its impact on traditional buyer-seller relationships); the impact of significant global gas production on energy services such as electricity and transportation; and, as a corollary, the role of natural gas as a bridging fuel to a carbon-free energy future.

Overall, the results convey an impression of uncertainty, which is driven by the different assumptions made about the gas supply curve and overall demand for energy. These two factors are shown to have significant effects on total primary energy supply, transport and trade. The key task is to explore the variability of these impacts and relate them to shale gas development. Thus, it will be shown that the impact of demand growth is particularly important for explaining gas market dynamics, but its impact is less pronounced when probing changes in the role of gas in the wider energy system. Here, different supply curves assume relatively greater importance, yielding different trade and consumption patterns as they adjust to the cost of energy. A crucial area of assessment in this context is, first of all, whether and to what extent the future of the energy system will be carbon-constrained. A second factor of importance is the natural gas pricing environment – i.e. the degree to which prices are determined by gas market dynamics rather than linked to oil prices. The effect of shale gas development on this issue will also be explored.

6.2.1 Context and global trends

At the outset it is useful to note the key differences in the main scenario results. Figure 6-10, Figure 6-11 and Figure 6-12 show some useful parameters to keep in mind when interpreting the trends and patterns revealed in the subsequent analysis. Indeed, the global energy demand and supply balance is subject to considerable variation depending on a countless number of variables. Here, we explore the range of uncertainty around economic growth and shale gas economics. Figure 6-10 shows the impact of different economic growth trajectories on primary energy demand. In the long term, an optimistic growth scenario implies a 17% higher level of total energy demand in 2030 (rising to 30% in 2040). As for gas economics, optimistic assumptions about the shale gas supply curve reveal, as can be expected, a more substantial role for this fuel in the global primary energy supply, as shown in Figure 6-11. But what is interesting is that gas increases in importance, even in the most conservative case of low growth and unfavourable conditions for shale gas development; indeed, from 2010 to 2040 the share of gas in the global energy supply increases from 20% to just over 30% of the total.

The picture is somewhat different when considering the impact of shale gas on the global distribution of energy demand. Indeed, even under different growth trajectories, the presence or absence of shale gas development does not significantly change the relative shares of different sources of primary energy – oil, gas, nuclear and so on – among the different regions. In both cases, China remains the primary engine of growth as it increases its share of global energy demand from 18% to 25%.

Figure 6-10: Total energy demand under different scenario assumptions

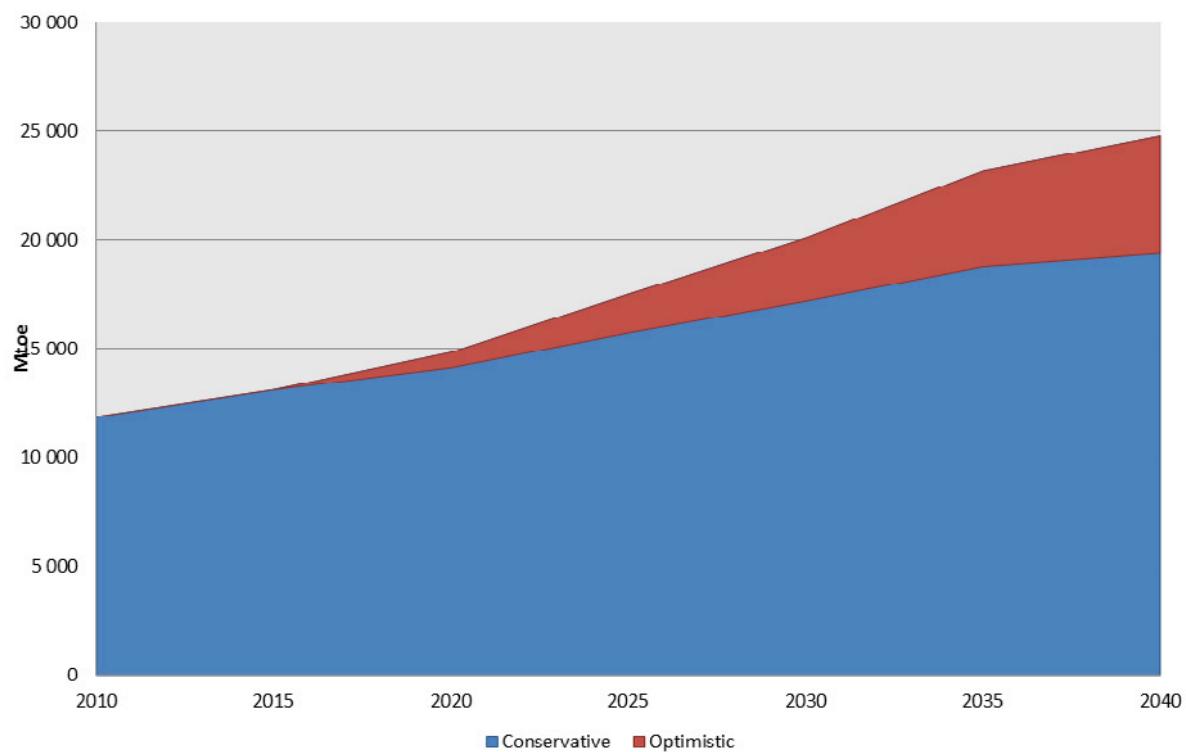


Figure 6-11: Global primary energy supply by fuel (conservative low growth and optimistic high growth)

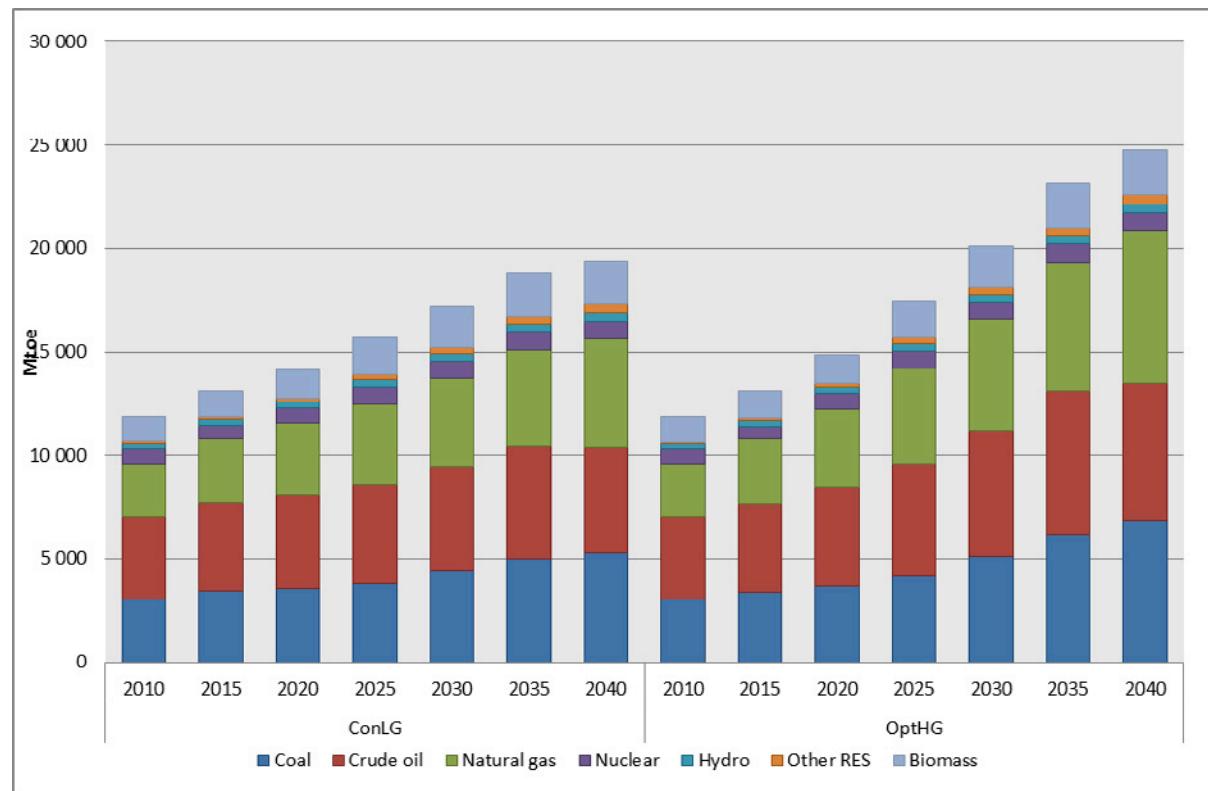
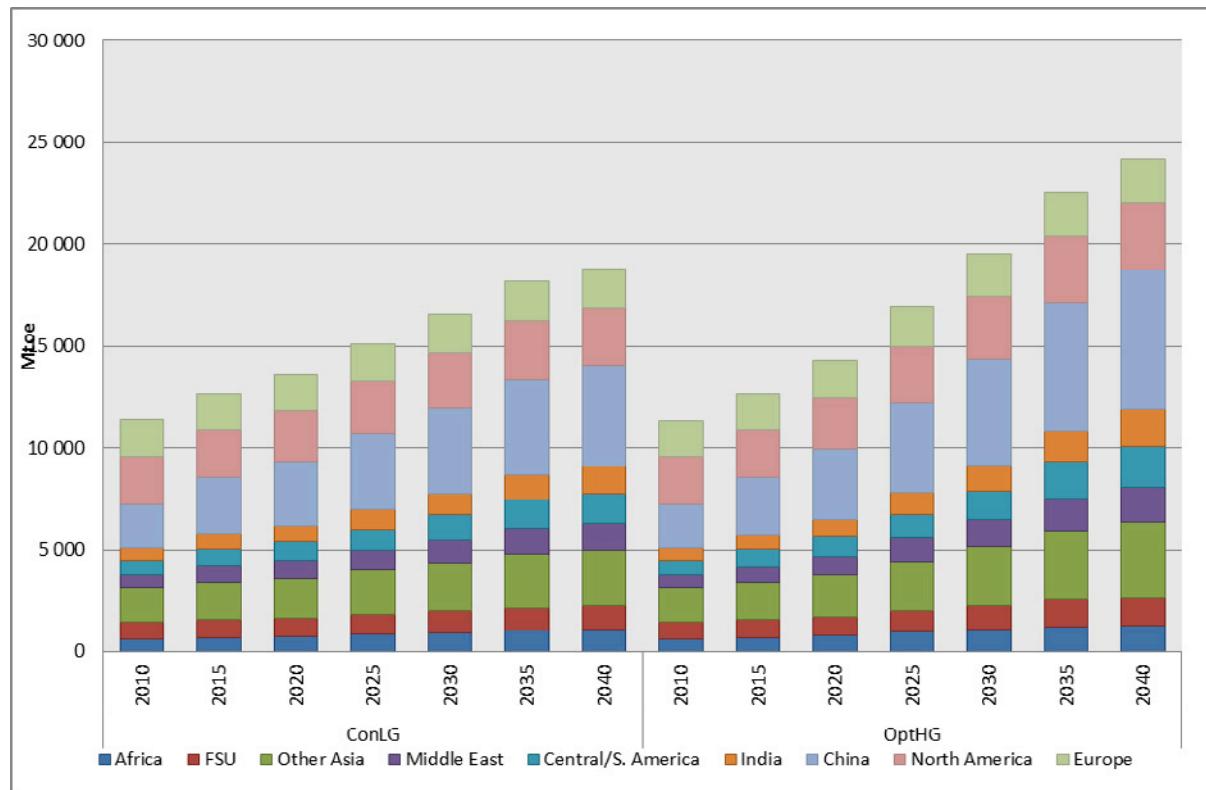


Figure 6-12: Total energy demand by region



6.2.2 Upstream gas production

Observing changes in the upstream sector, two key questions come to the fore. Firstly, what role can unconventional gas play in the future primary energy mix? In particular, how does an optimistic perspective for shale gas development affect global and regional gas production?

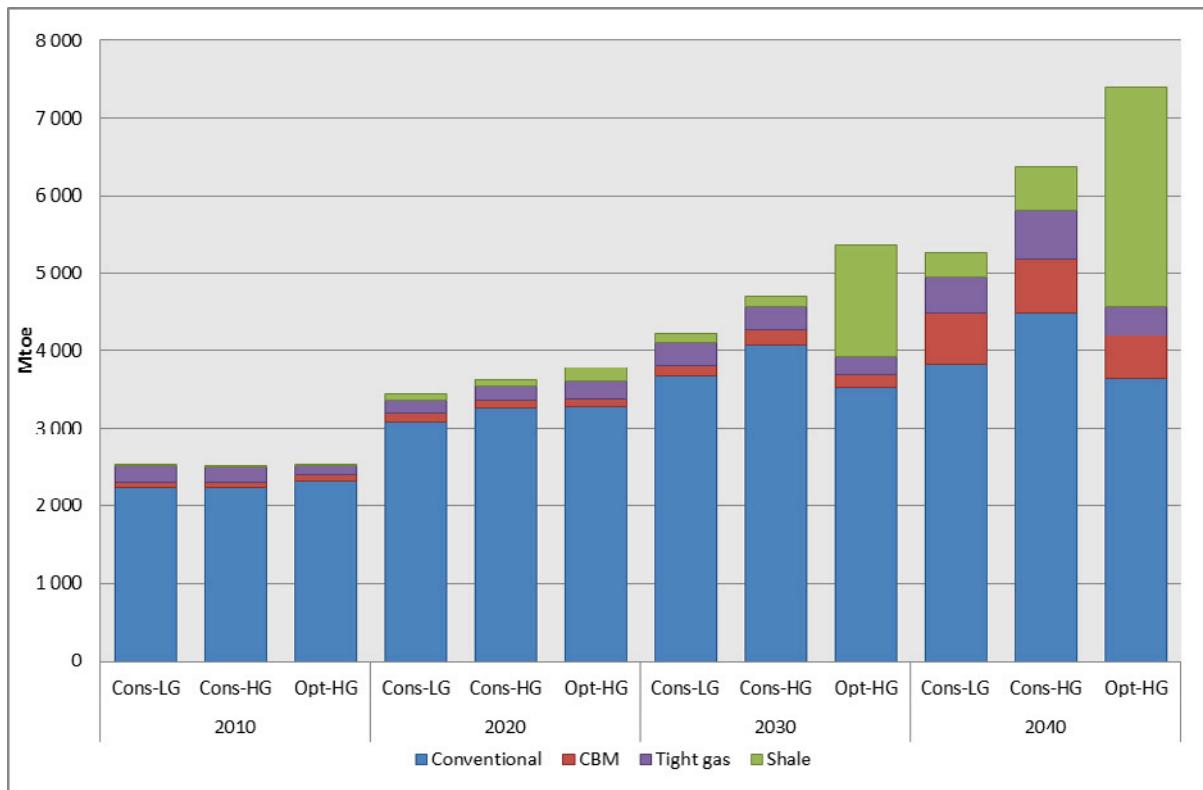
Under conditions of slow growth and conservative assumptions about the resource base, shale gas production is projected to rise at a slow but steady pace to reach a rate of just over 100 Mtoe/year in 2030 and 300 Mtoe/year, or 10% of total global gas demand, by 2040. The optimistic and high-growth scenario, on the other hand, shows how, under assumptions of extremely competitive extraction costs, plentiful resources and high GDP growth, shale gas has the potential to make up a quarter of total global gas production by 2030 and be close to 40% by 2040.

Figure 6-13 also shows how total gas production becomes higher in the high-growth scenario. But the impact of higher growth on shale gas production only becomes apparent at the very end of the time horizon

Other unconventional sources of gas remain relatively unaffected by different growth trajectories. In all cases, both coal-bed methane and tight gas progressively lose their market shares such that, even in the conservative scenario, shale is globally competitive after 2020 and, by 2025, becomes the dominant source of unconventional natural gas.⁴²

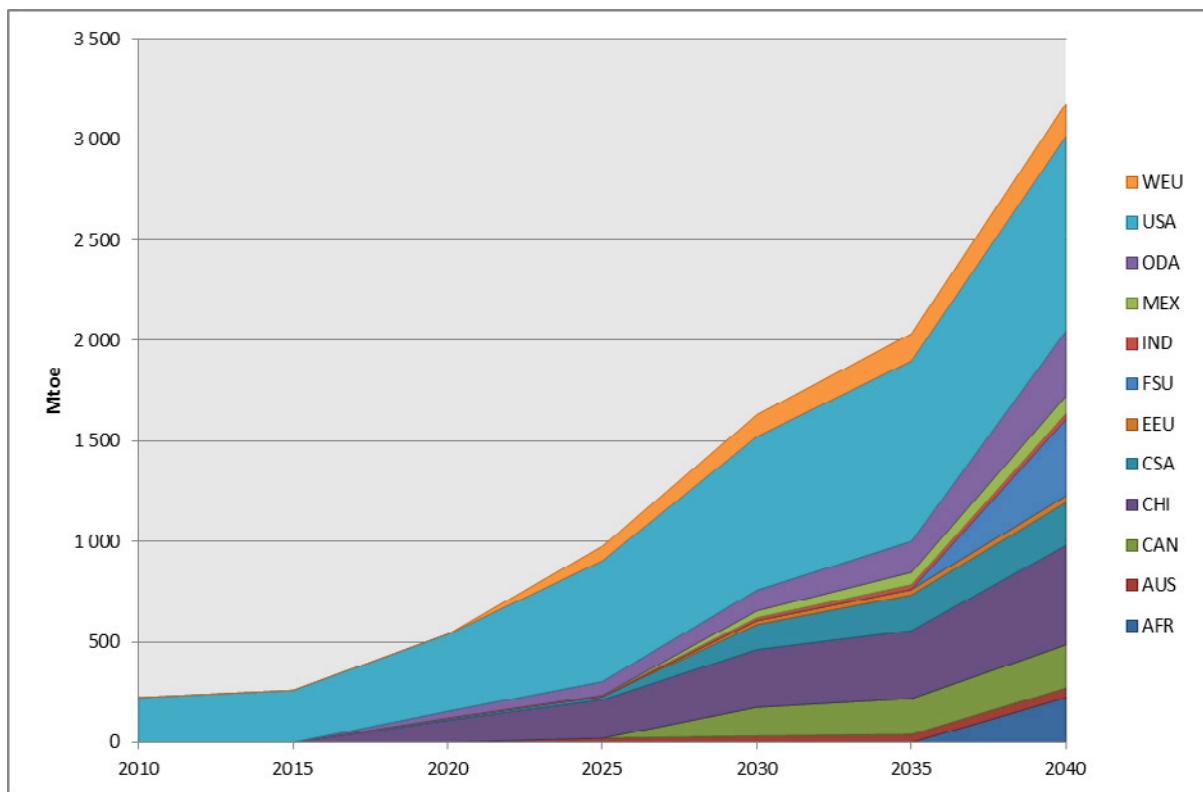
⁴² This result is, of course, related to the assumptions made for the economics of CBM and tight gas, as referred in the previous section's discussion on gas production costs. No exploration of the potential impact of different assumptions around CBM and tight gas has been carried out here.

Figure 6-13: Global gas production



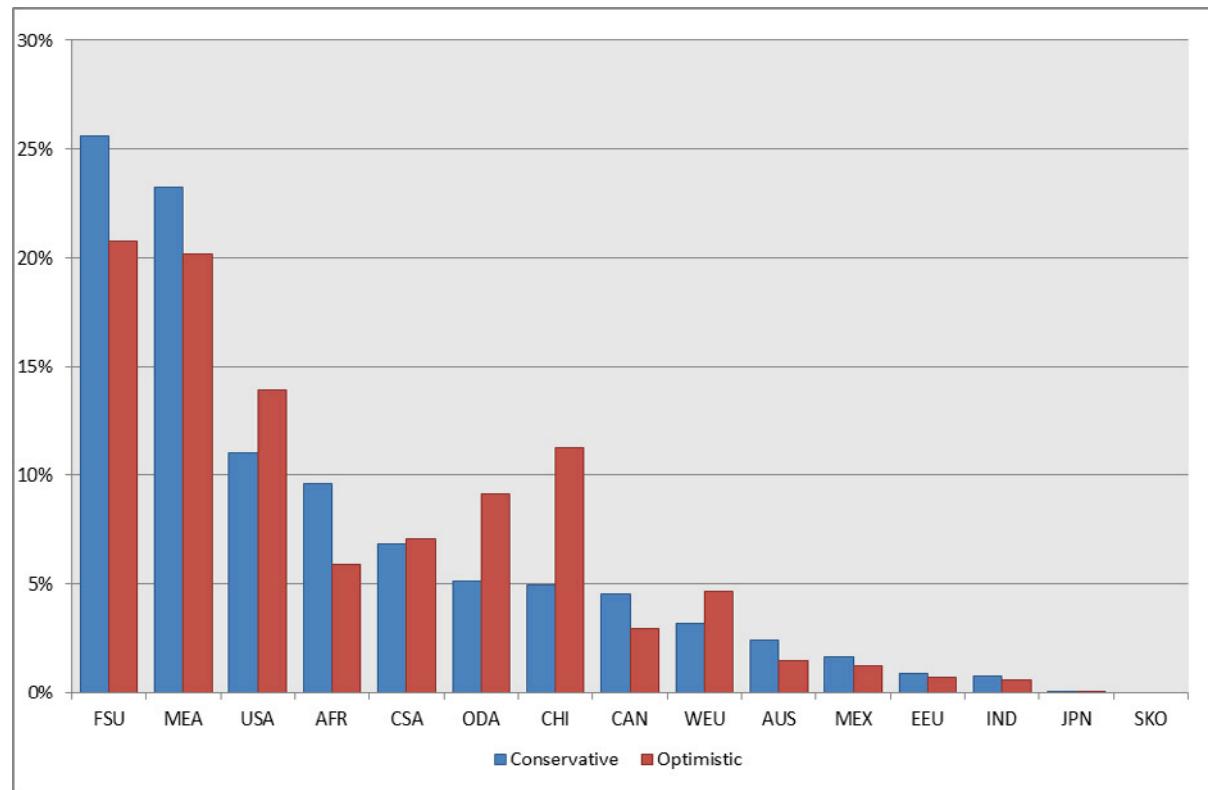
In the scenario most favourable to shale gas development, there are a number of regional trends worth highlighting. As shown in Figure 6-14, the USA captures the lion's share of unconventional gas production in 2020 by producing 70% of the world's total. However, over time the US share declines to 30% as new entrants slowly enter the unconventional gas-producing market. In particular, East Asian markets see a surge in shale gas production after 2020 such that within 20 years these countries provide 28% of the global unconventional gas supply (with China alone producing three quarters of this figure). Other regions witness more moderate but steady growth; significant production takes place in Central/South America (9%), in Europe (8%), in Africa (7%) and in Canada (6%) in 2040.

Figure 6-14: Unconventional gas production in the optimistic high-growth scenario



Traditional conventional gas suppliers, on the other hand, do not exploit their potential for shale gas development. Thus, even in the optimistic case, neither the Former Soviet Union (which includes the Russian Federation and Caspian region) nor the Middle East significantly produces reserves during the period under scrutiny. Some significant shale gas production starts in FSU at the very end of the time horizon, but a more careful analysis of the results shows how, despite having potentially vast shale gas reserves, the margins between conventional and unconventional gas remain tilted in favour of the former. This trend is more strongly visible in the Middle East. This means that both regions' relative share in total global gas production declines proportionately to the increase in shale gas production in other regions (yielding an average of 3-4% less gas over the period from 2010-2040 in a case of significant shale gas production). In the case of the Middle East, shale gas production checks the rise in this region's share of total global gas production, such that a peak share of 17% reached in 2025 begins to decline despite increases in production from 1 000bcm to over 1 500 bcm in 2040. Much of this lost market share is picked up by production in the USA and to a lesser extent by Asia and Europe.

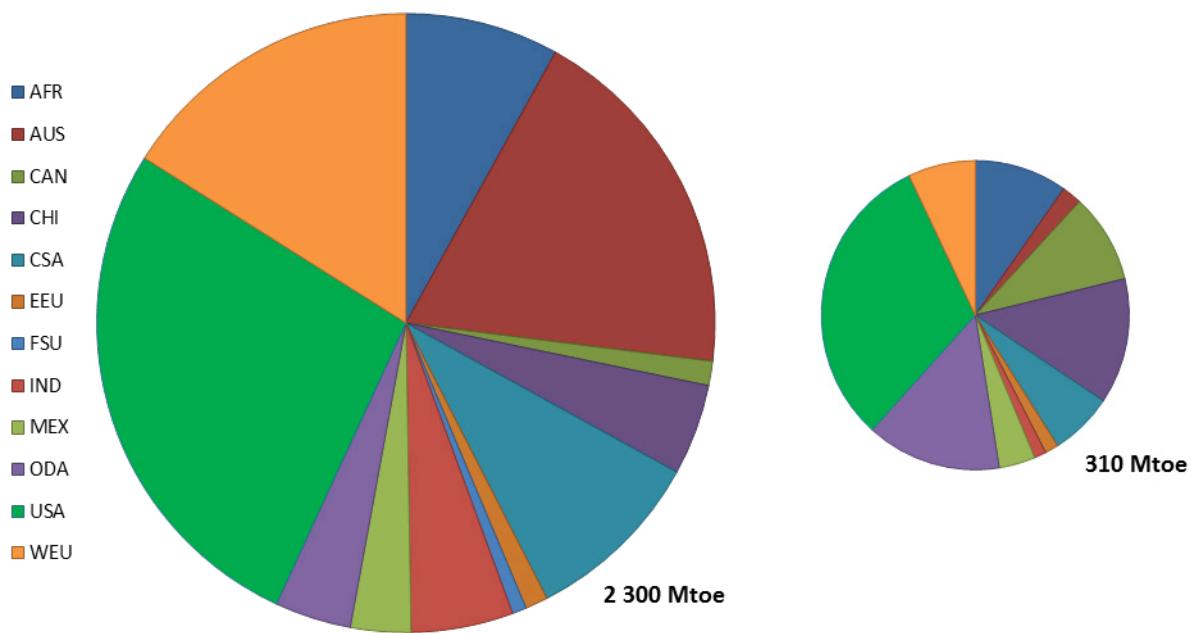
Figure 6-15: Changes in relative share of total gas production in 2040 (conservative/optimistic)



In terms of cumulative production, traditional gas-producing regions also see a slight reduction in their output volumes compared with a situation of cheap and plentiful shale gas. Indeed, a look at the optimistic and conservative scenarios reveals that the Former Soviet Union (FSU) produces an average of 20% less conventional gas than would be the case in a situation where shale gas reserves are less abundant and more expensive to develop. The difference is greater for the Middle East, where there is an average reduction of 15% in total conventional gas production between the two scenarios over the period 2010-2040. These figures imply that in an optimistic case there is enough room for new sources of unconventional gas to be developed alongside conventional production, but there is also some level of competitive substitution.

Overall, it seems that shale gas will be developed under any combination of scenarios. However, this statement belies the vast differences in total volume produced. As shown in Figure 6-16, shale gas production is subject to high levels of variation depending on which assumptions eventually bear fruit.

Figure 6-16: Shale gas production by region in 2040: Optimistic-HG and Conservative-LG scenarios



Box 6-3: Number of European shale gas wells

How many wells would need to be drilled to sustain the most optimistic scenario of shale gas development in Europe? There is no easy way of calculating such a figure and any general estimations must either make several simplifying assumptions or 'explain away' crucial factors such as success rates, decline curves, well types (e.g. 'dry', exploratory, development), ramp-up periods and a whole host of project and play-specific circumstances.

Nonetheless, an attempt to provide an indicative estimate is presented here. The cumulative production of shale gas in Europe in an optimistic case of high demand, low costs and plentiful reserves would total close to 3 trillion cubic metres over the period 2025-2040, an average withdrawal rate of 200 bcm per annum. Two independent assessments made within this report have estimated the ultimate recovery of gas from a single well to stand at approximately 57 mcm over an assumed lifetime of 30 years.⁴³ Extrapolating from the US experience over the last ten years, the authors assume the need for ten exploratory wells and the presence of ten dry holes for every 100 shale gas-producing wells drilled.⁴⁴ Cumulatively, in this case 63 000 wells would need to be drilled during the period 2025-2040 to maintain this rate of production, or roughly 4 200 wells drilled on an annual basis.

However, it must be stressed that the range of uncertainty is wide. Indeed, in a conservative case of low growth, costly production and scarce resources, the total number of wells drilled over the same period could be as low as 7 900 (yielding a cumulative production of 374 bcm). Thus, these estimates should be seen as purely indicative, even though they roughly correspond to similar ratios identified in other sources.⁴⁵

6.2.3 The role of gas in a carbon-constrained world

It is normally assumed that in a carbon-constrained economy the relative importance of natural gas is likely to increase, as it is one of the most cost-effective means by which to maintain energy supplies while reducing CO₂ emissions. But what if the carbon-

⁴³ See Sections 2.3 and 3.3.6.

⁴⁴ EIA, *Crude Oil and Natural Gas Exploratory and Development Wells* (2012, cited 27 April 2012); available from http://www.eia.gov/dnav/ng/ng_enr_wellend_s1_a.htm

⁴⁵ Gény, 'Unconventional Gas'; Rogers, 'Shale gas'. Both studies assume the need for 800 wells drilled per annum to sustain a production plateau of around 30 bcm.

constrained scenario is consistent with the objective of halving CO₂ emissions by 2050? Are the most optimistic projections about the future role of natural gas in the global energy mix consistent with a carbon emissions path towards an average global temperature rise of no more than 2°C? Will natural gas be a cost-effective bridge to a low-carbon future?

To assess these key issues, a specific sensitivity analysis was carried out, adding to one of the two optimistic shale gas scenarios described so far (the Opt-LG scenario) to take a path consistent with the target.

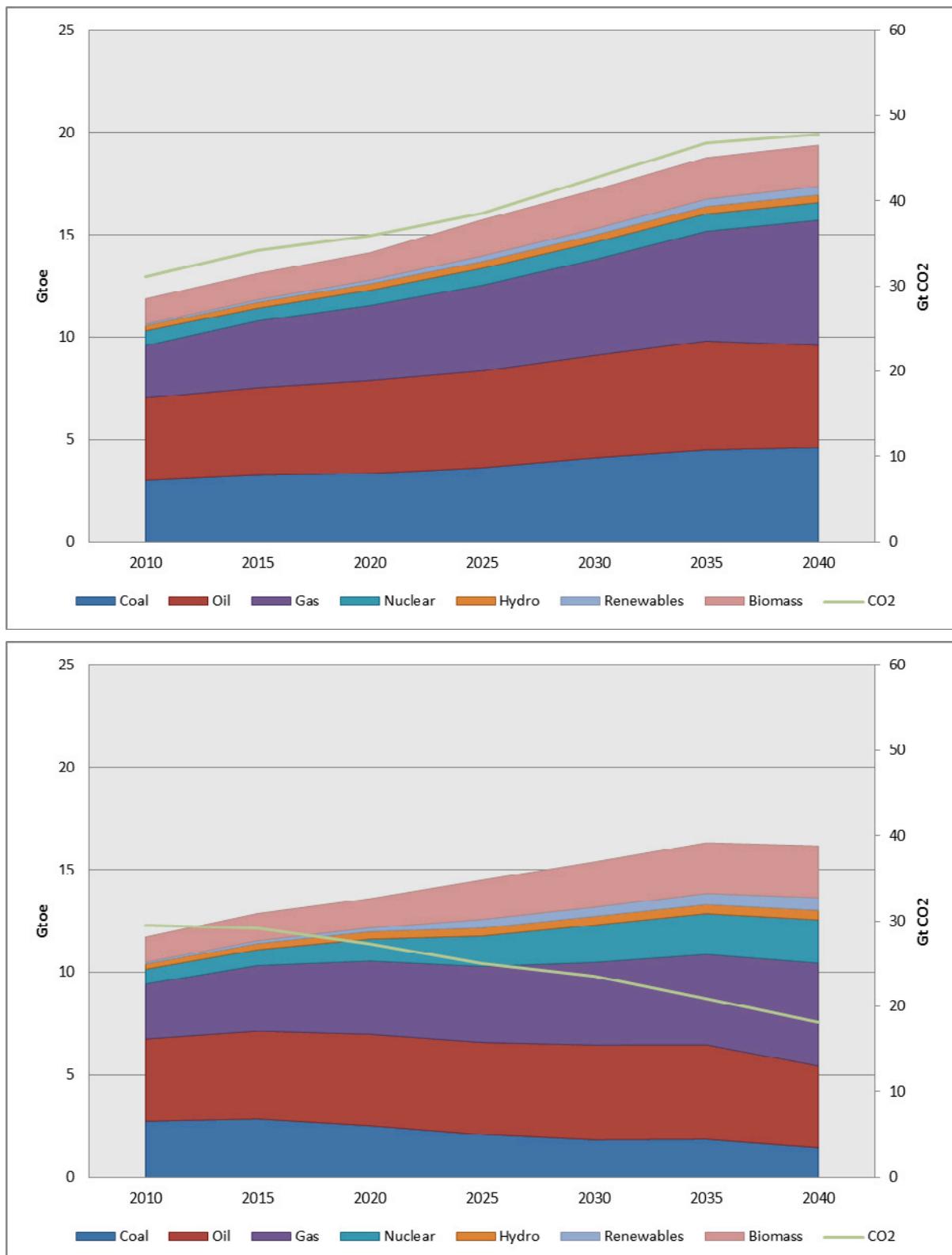
Figure 6-17 shows how the global energy mix can change in a strongly carbon-constrained scenario, with a reduction in overall CO₂ emissions of about 40% in 2040 compared with 2010 emissions levels. What is interesting is that a higher carbon tax does not necessarily prevent natural gas – a subset of which includes shale gas – from being developed in an optimistic scenario.⁴⁶ Rather, the amount of all natural gas produced is lower as the carbon tax progressively rises. The significant change comes in 2040, when the amount of gas produced in a carbon-constrained world is 30% less than one in which a lower carbon tax is in place.

In other words, the strict emission targets modelled do not preclude a significant growth in natural gas use. Therefore the modelling results support the potential role of natural gas as a ‘bridging’ fuel.

However, there is one qualification the reader should bear in mind in interpreting these results. Although the model used here factors in emissions of the different fuels when burned, it does not consider GHG emissions during mining or transportation. Only a complete life-cycle comparison of all the major fuels in the energy system can comprehensively address the controversy surrounding the life-cycle emissions of shale gas.

⁴⁶ The reader should bear in mind that the carbon content of conventional and unconventional gas are the same in the model, and that the analysis does not incorporate life-cycle emissions analysis from their differing methods of extraction.

Figure 6-17: Total primary energy supply and CO₂ emissions in the optimistic low-growth scenario (above) and a carbon-constrained optimistic low-growth scenario (below)



6.2.4 Gas trade

One of the most significant effects of the US shale gas ‘revolution’ so far has been its impact on the current and perspective US gas trade. Therefore, one of the main insights to be analysed through a global energy system approach is the potential for a global shale gas development to change global gas trade. This means answering questions like the followings:

- What kind of correlation, if any, exists between shale gas development and gas trading? Are shale gas and LNG trading complementary or competitive? Would shale gas development reduce or increase gas trading? Would favourable conditions for gas trading help the development of shale gas? Or in other words, to what extent do the answers to the previous question depend on future LNG transportation costs?
- How does shale gas development impact the structure of gas trading? Are there significant changes in the flows between regions, with currently exporting regions penalised from the development of shale gas? Are there regions developing shale gas for export? Also, is there a difference between the impact of shale gas on LNG trading versus its impact on pipeline gas traded between regions?

Global gas trading is likely to increase in any scenario, independent of high or low GDP growth or optimistic/conservative conditions for shale gas. This is true for both liquefied natural gas, which increases two to threefold depending on which scenario is considered and also for pipeline trading, which witnesses around a doubling in total volumes traded between regions during the same period (2010-2040). The main cause behind this increase is the massive growth in demand expected in Asia, primarily in China, a country which is set to import between 570-730 bcm of LNG alone by 2040.

Despite these general trends, a closer look at the scenarios reveals that shale gas does indeed affect the total volume of trade, particularly for LNG. As demonstrated in Figure 6-18 and Figure 6-19, when comparing all scenarios, it appears that conditions of high growth and low shale gas development are most amenable to interregional trade. This implies that shale gas production is predominately reserved for internal use only; there are no cases where significant additions to a region’s gas exports occur as a result of shale production.

Shale gas production and the global LNG trade show a particularly strong interrelationship. With all other factors held constant, the scenario with cheaper and more plentiful shale gas leads to a corresponding reduction in interregionally traded LNG volumes compared with the scenario of more costly and limited shale gas. This is a result of the relatively cheaper cost of indigenous production and transport of gas *within* regions. In China, for example, LNG imports will see a 12% drop in a situation of considerable shale gas production, correspondingly reducing the exports of LNG from other developing Asian countries, as well as the Middle East.

Figure 6-18: LNG exports under optimistic and conservative shale gas development

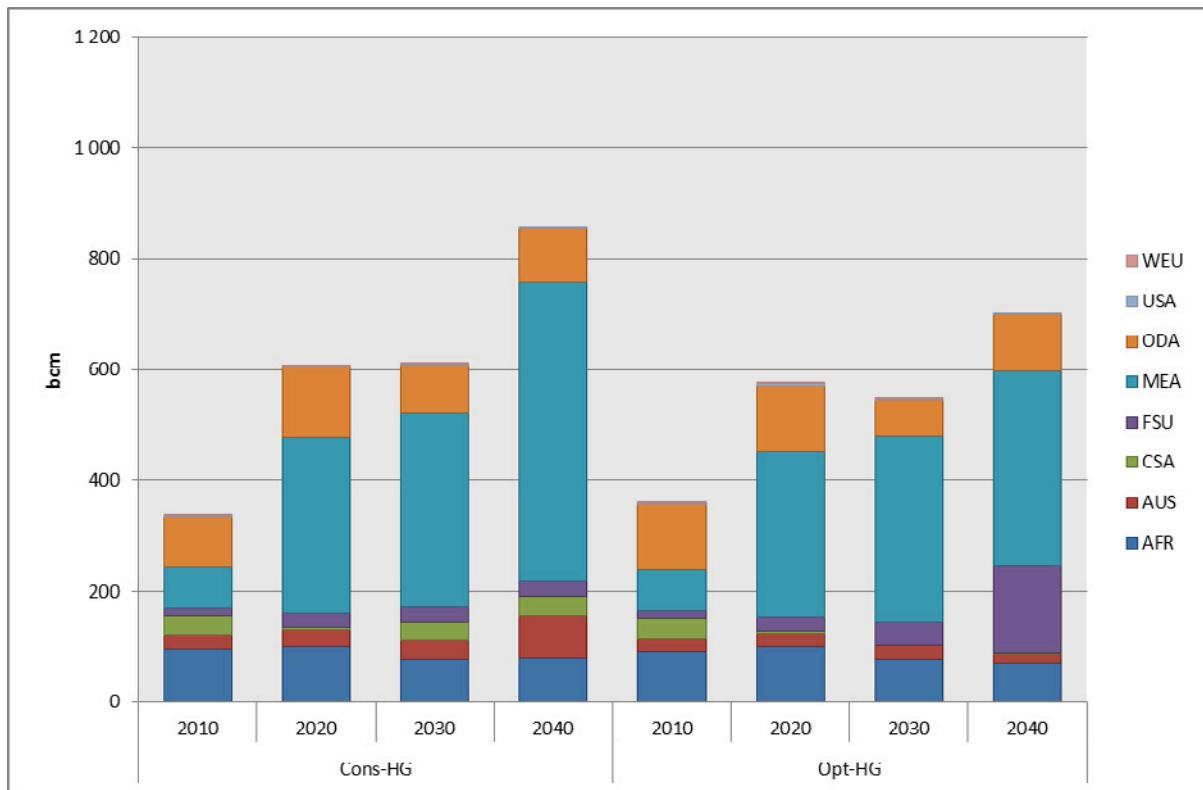
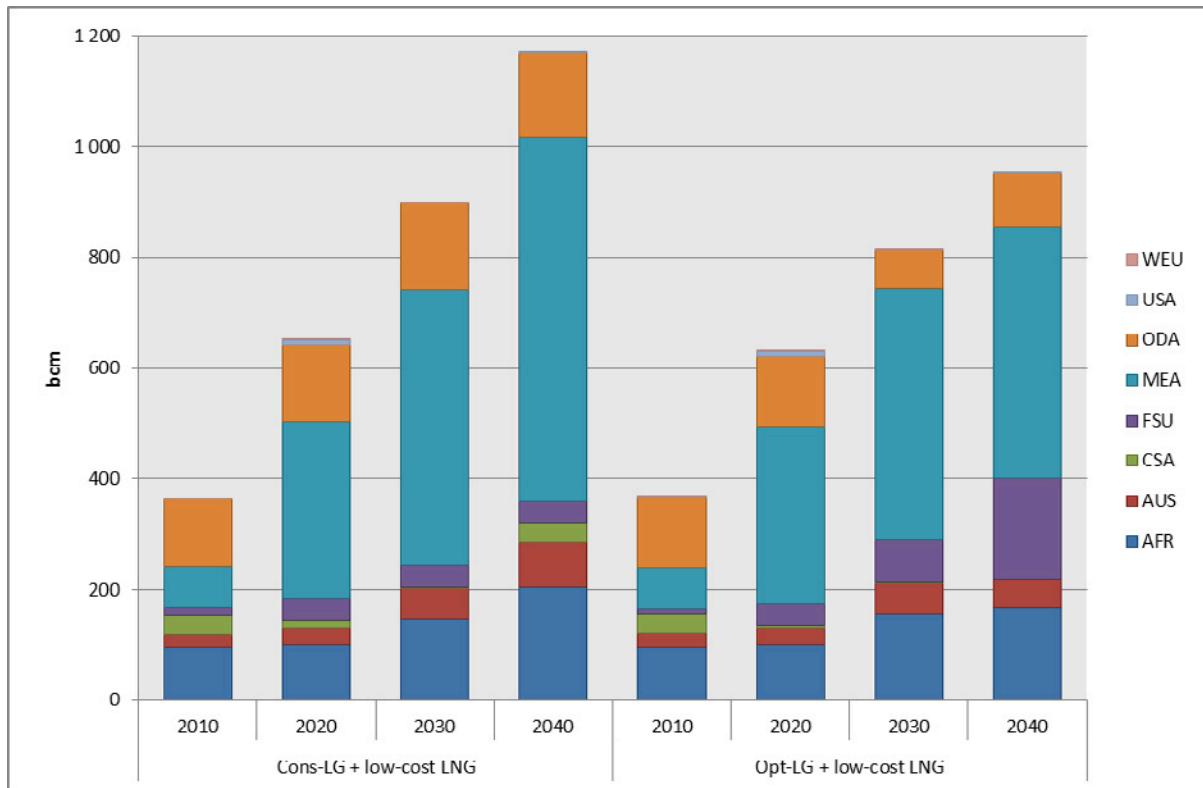


Figure 6-19: LNG exports under conservative and optimistic shale gas development with low LNG cost



But would more favourable conditions for gas trading make a difference to this result? In other words, would a lower transport cost for LNG favour imports over indigenous shale gas production? Figure 6-19 shows that the above holds if a lower LNG cost is

assumed for both scenarios, even if total LNG trade would be much higher in this case: Again the impact of an optimistic shale gas scenario is that it reduces total trade.

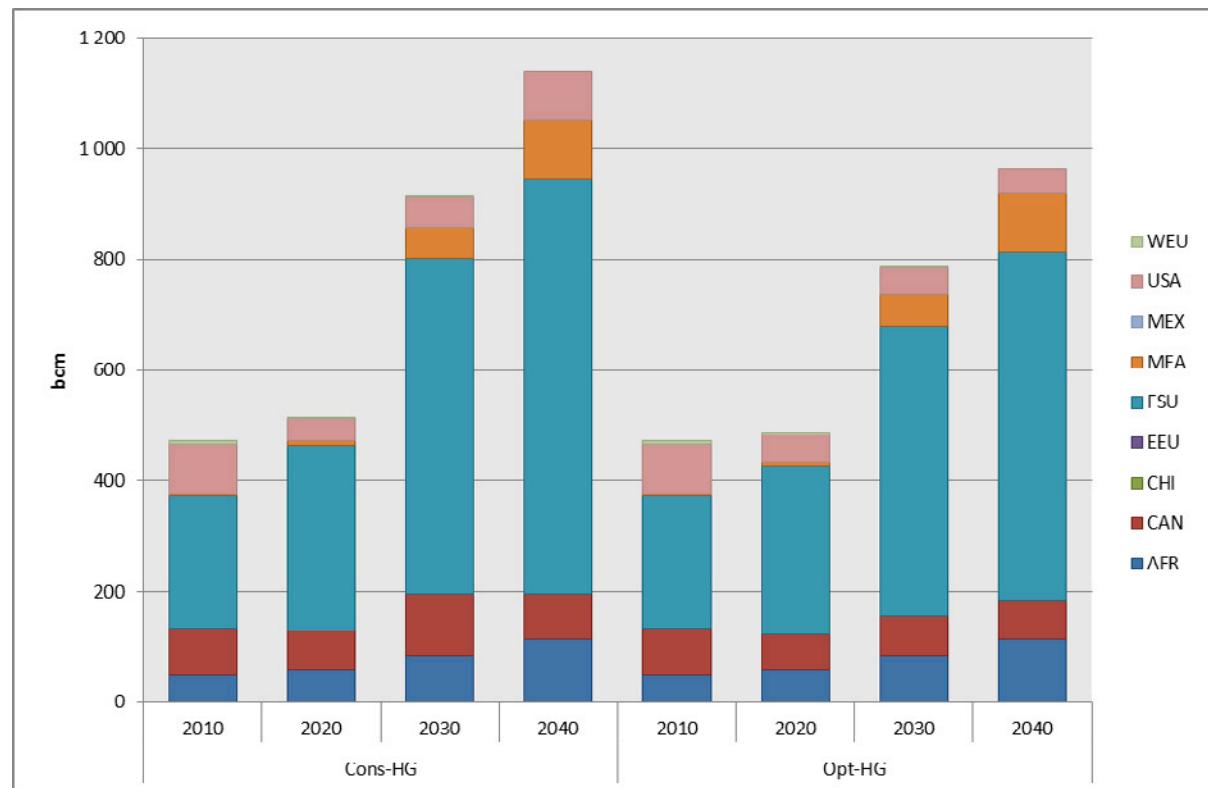
However, a second insight comes from the comparison between total LNG trade in the conservative-HG scenario (Figure 6-18) and the optimistic scenario plus low LNG cost (Figure 6-19). This suggests that a shale gas development would only reduce LNG trade volumes under conditions of the currently high LNG transportation costs.

The MEA region exports the most in any of the scenarios, followed by the Africa, ODA and AUS regions. Low LNG transportation costs increase exports from each of these regions, but particularly from Australia. LNG exports from Australia are also the most reduced in the optimistic shale gas scenario.

For pipeline trading (Figure 6-20), the trend is somewhat different as piped gas records increases in all scenarios, independent of growth or shale gas production assumptions.

Looking east, in the conservative case, the FSU begins to export piped natural gas to non-Chinese eastern markets in 2020 and volumes eventually triple to reach 90bcm by 2040. But in a case of significant shale gas production, this trade link remains undeveloped. Nonetheless, the overall loss in FSU exports is negligible as this market is comparatively small in relation to the link between the FSU and China, which is unaffected by significant shale gas production and grows threefold to 270bcm over the same period. As for North America, similar reductions in interregional pipeline trade occur depending on the amount of shale gas output; comparing the optimistic with conservative cases, the USA reduces the need for pipeline imports from Canada by an average of 27% over the 30-year period.

Figure 6-20: Pipeline exports by region under optimistic and conservative shale gas development



Looking at imports, Figure 6-21 shows the two 'extreme' scenarios for LNG trade, i.e. the conservative shale gas with low LNG cost and the equivalent scenario with optimistic shale gas assumptions. In both cases, the main importing region is China, which is also the region where LNG imports decrease the most, assuming high shale gas development. LNG imports also decrease in the Western Europe and Other Developing Asia regions.

Figure 6-22 shows how the impact of optimistic shale gas assumptions is less significant in pipeline trading than in LNG. In fact, pipeline imports seem more robust to the development of shale gas than LNG, as can be seen by the small difference in pipeline imports to China in the figure below. There are only marginal reductions in all other regions.

Now turning to Europe in more detail (see Figure 6-23 below), piped gas from the FSU and Africa record steady increases in both the conservative and optimistic cases. However, this does not mean that shale gas does not affect interregional pipeline trade. Assuming that high-capacity/long-distance lines such as South Stream, Nabucco and Nord Stream II are constructed, their competitiveness and full capacity use is only assured in a situation where shale gas reserves are costly to develop. Otherwise, shale gas and pipeline imports compete for European market share and, in a scenario of optimistic shale gas resources and low growth, Europe's pipeline imports from the FSU become less competitive over time.

This trend is more pronounced in Western Europe than in Eastern Europe. Indeed, whereas the former reduces total imports by about 30% with significant shale gas production, the latter can only claim a net reduction of 10% in the same scenario. This is likely to be due to the comparatively low transport costs for piped gas relative to new production from shale gas resources. This means that Eastern Europe's imports of pipeline gas from the FSU record steady increases over the period from 2010-2040. Even in an optimistic case of cheap and plentiful shale gas, import dependence in this region remains flat at around 75%. However, this trend also depends on the degree of growth in energy demand. Where there is a relatively high level of GDP growth, shale gas takes a proportionally smaller share of Europe's total gas supply from FSU imports – around 10% – over the period until 2040.

As a final comment, the scenario analysis shows the low robustness of the results with respect to LNG cost. Figure 6-23 shows how the structure of EU gas imports is very sensitive to LNG cost assumptions. If LNG costs remain at the current high levels then an optimistic shale gas scenario mainly decreases LNG imports; in the low LNG cost scenario, it is the pipeline routes that are mainly affected.

Assuming a conservative level of shale gas development under conditions of high growth, Europe's LNG imports until 2025 are set to rise by an average of 3.6 bcm per annum (with most of the volumes sourced from the Middle East region). Only after this period does the slow expansion of shale gas production stop this upward climb. In an optimistic case of shale gas development, on the other hand, LNG imports see a much sharper decrease. In this case, LNG imports fall to zero by 2040 as significant indigenous shale gas reduces the need for relatively costly LNG.

Figure 6-21: LNG imports by region in the conservative shale gas development scenario with low LNG cost versus optimistic low growth

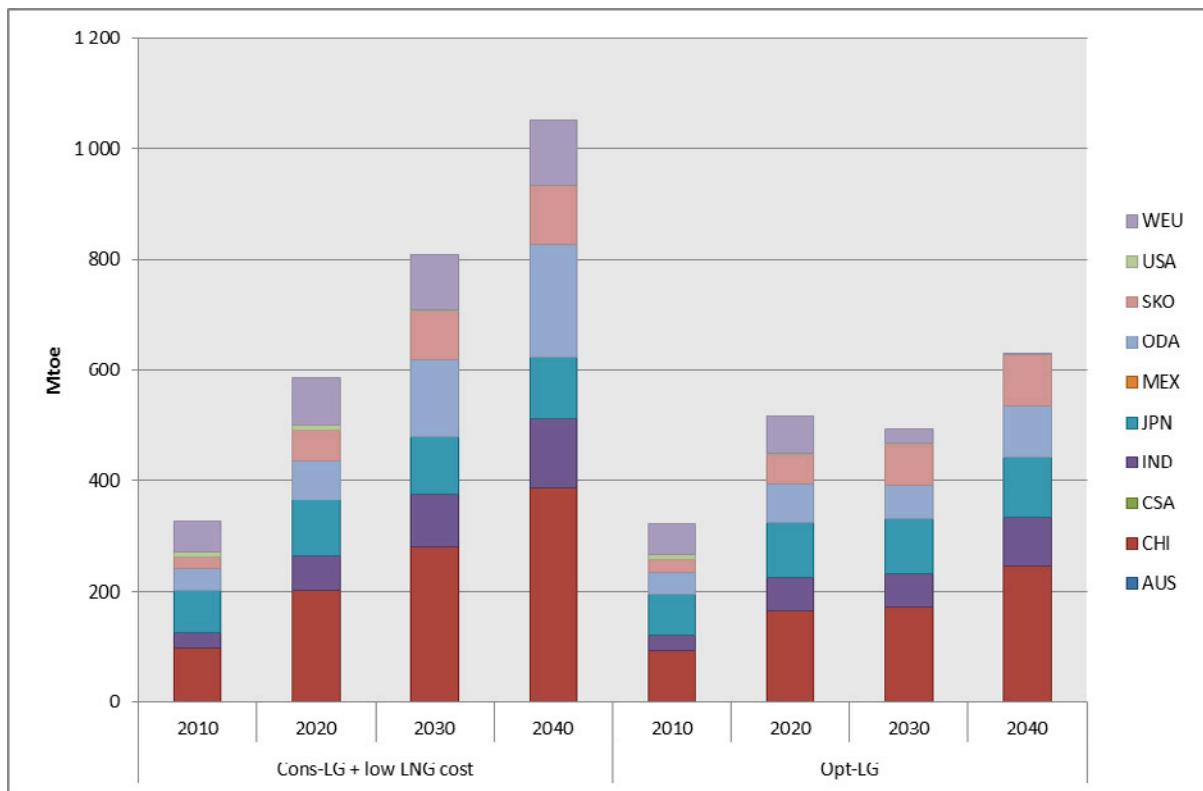


Figure 6-22: Pipeline imports by region in the conservative shale gas development scenario versus optimistic low growth

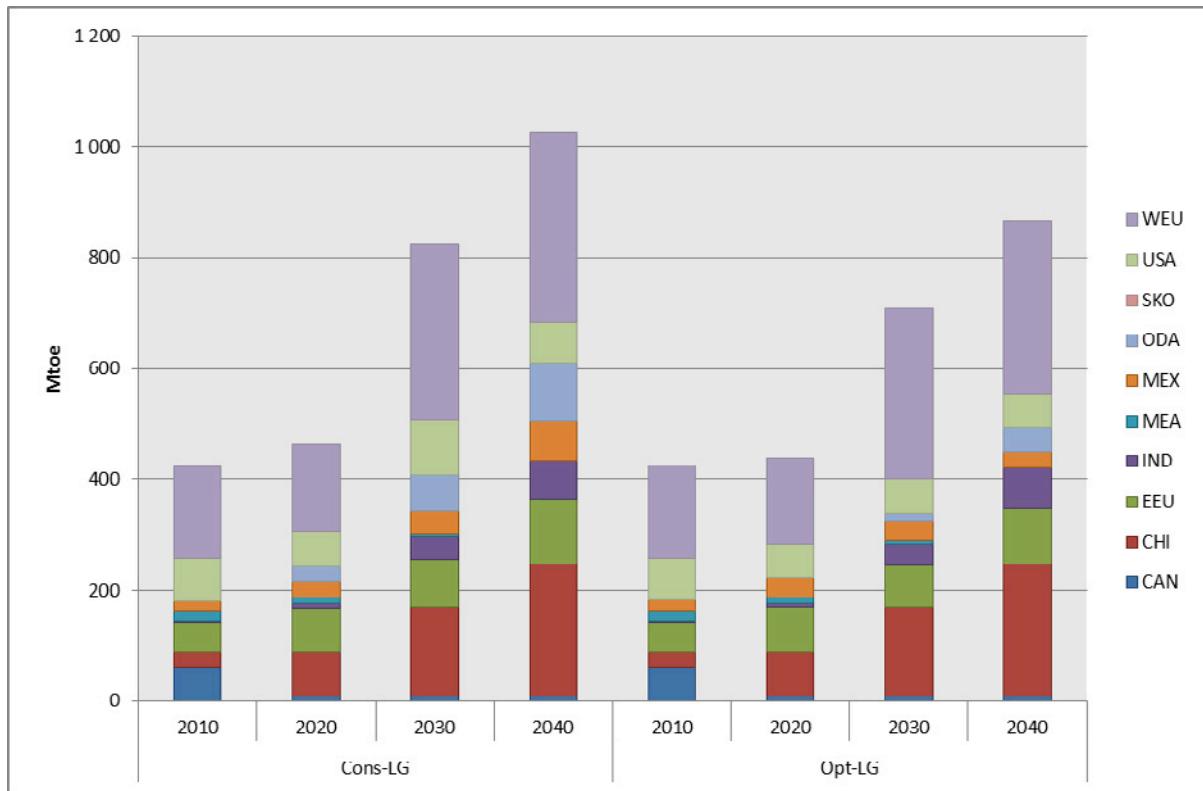
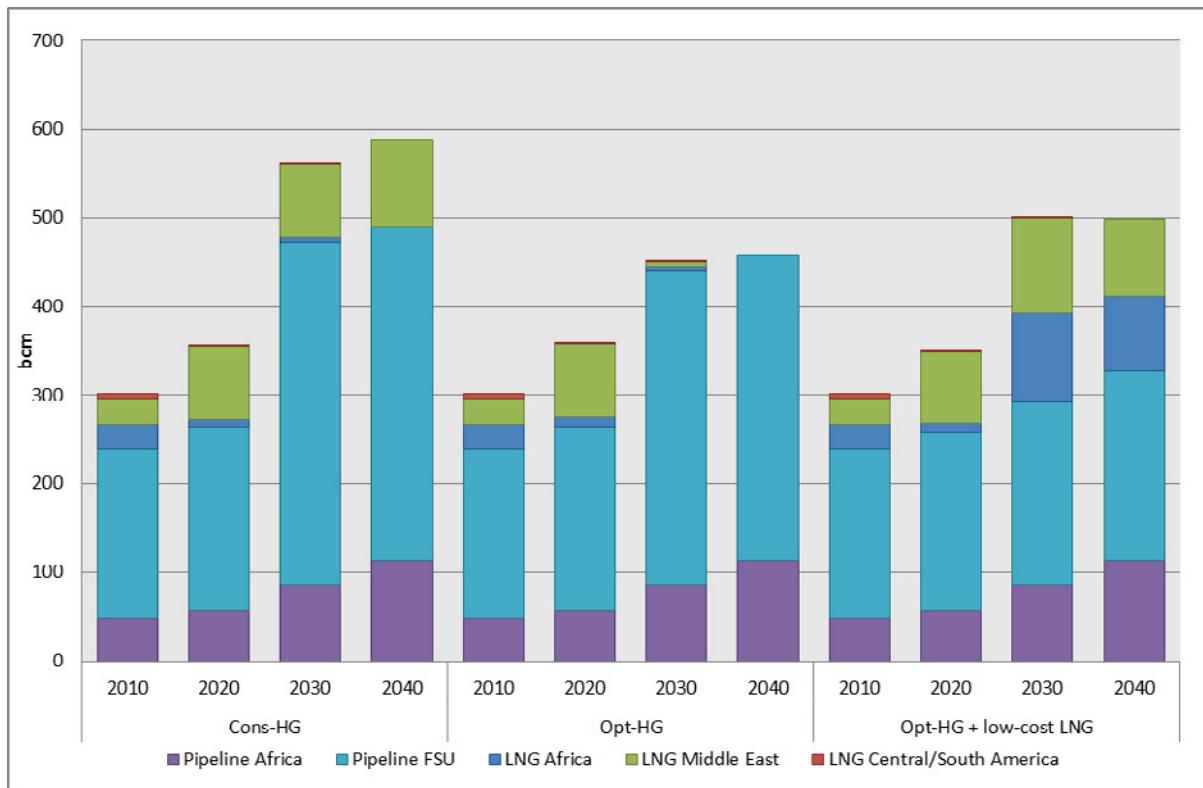


Figure 6-23: European gas imports in conservative/optimistic shale gas scenarios

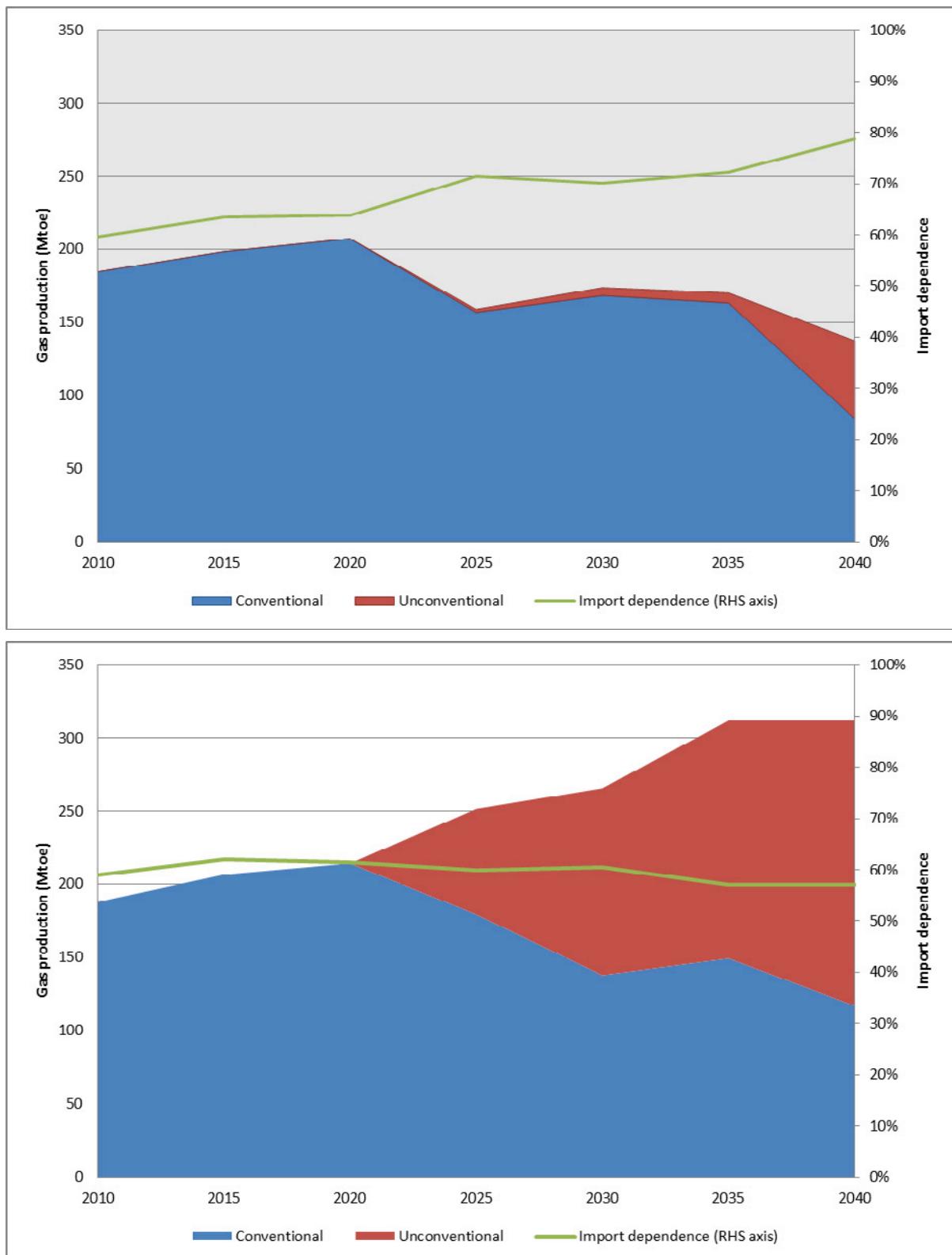


6.2.5 The impact of shale gas production on imports

For the net gas-importing regions, the impact of shale gas on energy dependence largely depends on the degree of production and the increase in gas demand. For Europe, the results suggest that shale gas production will not make the region self-sufficient in natural gas. Even in the most optimistic case of high GDP growth, large reserve size and low production cost, European shale gas development can only compensate for the decline in conventional gas production (as shown in Figure 6-24). Under such circumstances, this implies that Europe's import dependence will remain relatively flat over the period to 2040 as shale gas reserves serve the twin purpose of shoring up indigenous production and keeping pace with rising gas demand. In this way, shale gas manages to reverse what would otherwise be an increase in overall gas demand; in the best case, shale gas development has the potential to reduce Europe's dependence on gas imports by an average of 6% in 2020 to more than 20% in 2040. In other words, by 2040, import dependence decreases from 79% (in the conservative scenario) to 57% in case of significant shale gas production.

In some regions where demand growth is strong, even a surge in shale gas production cannot prevent an increase in imports. This is the case in India where the gas demand increases six-fold, more than offsetting indigenous shale gas production. But in other cases, such as China, significant shale gas production can indeed strengthen a general decrease in import dependence despite rising energy demand. Assuming cheap and abundant shale gas reserves, China will lower its imports from three quarters to half of the total gas demand by 2040. However, if shale gas proves more costly and difficult to find, China's import dependence will reach 60% in the same year.

Figure 6-24: Conservative (above) and optimistic (below) European shale gas production in the low-growth scenario



In the USA, the total volume of net imports is relatively unaffected by unconventional gas development. The higher deployment of shale gas in the optimistic cases is mainly absorbed by the US gas market, as natural gas serves as a substitute for coal in the power generation sector. Indeed, if shale gas is cheap and abundant under lower growth assumptions, coal will generate only 400TWh of electricity in 2040, instead of the 1 800 TWh resulting from a case of limited shale gas production. This substantial gap of 75% is filled by gas-fired power generators, explaining not only the threefold rise in the share of gas used for electricity generation over the period from 2010-2040 but also the lack of significant export of natural gas.

6.3 Natural gas in power generation and end uses

Primarily, shale gas can affect the energy system and its evolution through its impact on the cost of energy and eventually, provided the energy markets are competitive, on energy prices. Significant growth in shale gas production can reduce the gas price, provided that the gas market can decouple from the oil market.

Figure 6-25 and Figure 6-26 show the relationship between demand, production and price in a case of low growth and either high or low shale gas production. As shown, the greater the difference in price between a conservative and optimistic scenario, the more there is an observable effect on gas demand. In Europe, an optimistic case of shale gas production does less to change prices than equivalent scenarios in the USA and China, where the price differential between conservative and optimistic production is around \$2/GJ. The subsequent differences in the effect of shale gas development on demand are shown in Figure 6-26.

Figure 6-25: Gas prices in China, Western Europe and the United States of America in the optimistic and conservative shale gas scenarios

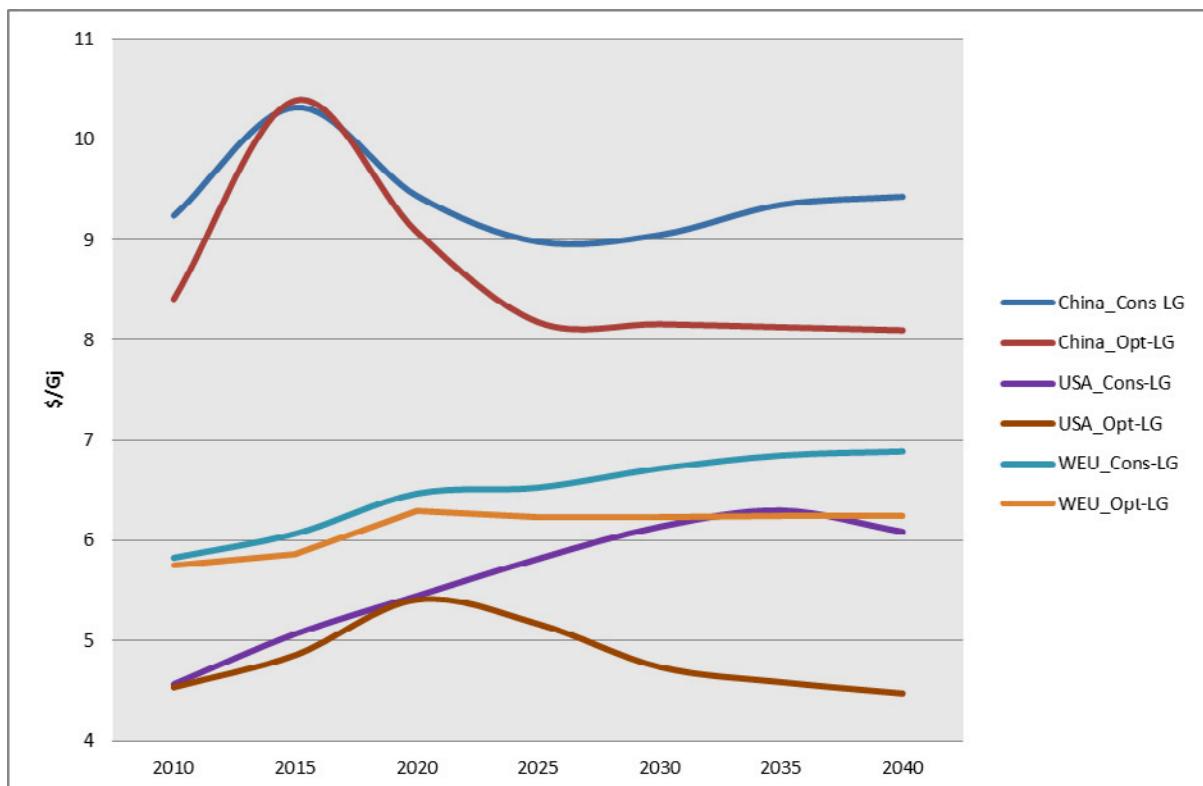
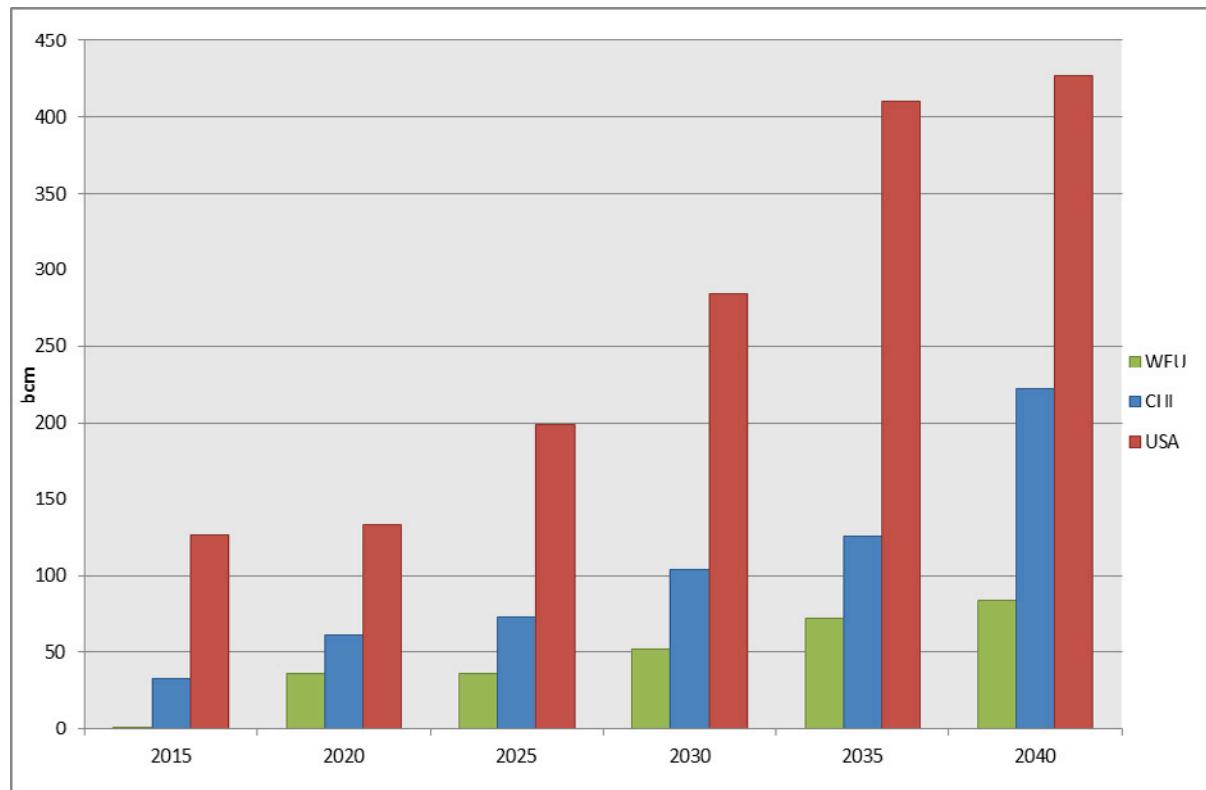


Figure 6-26: Increase in gas demand between conservative and optimistic shale gas scenarios



As discussed on the following pages, in terms of final energy use, the main impact of favourable shale gas development can be expected in the power generation and transportation sectors. As a matter of fact, the scenario analysis shows how unconventional sources help natural gas to challenge the dominance of coal in electricity generation and of oil in the transport sector.

6.3.1 Power generation

With regard to the power sector, the first and most immediate effect of cheap and plentiful shale gas is a strong effect of substitution between fuels. This is apparent first of all when comparing the ratio of gas versus coal in the electricity generation mix, as there is a clear difference between the conservative and optimistic shale gas scenarios. As shown in Figure 6-28, electricity generation from natural gas in the optimistic scenario is about a third higher than in the conservative scenario.

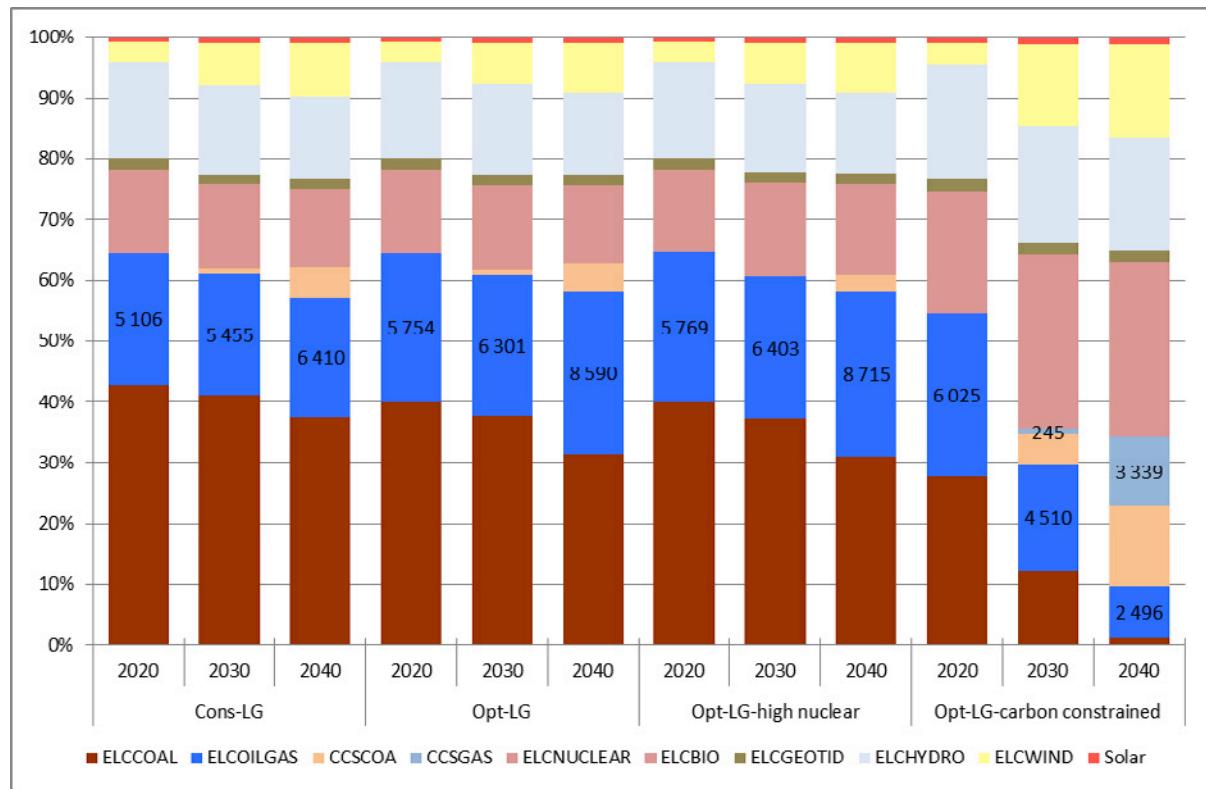
While shale gas appears not to challenge the dominance of coal, it does not seem to deter investments in renewable energy. This is apparent when considering the difference between the conservative and optimistic cases of shale gas development. While in the latter gas grows proportionately to the decline in the use of coal (and to a lesser extent nuclear power), the difference in the amount of electricity generated by renewables is barely noticeable.

Figure 6-28 also shows how this result does not change if a more positive assumption about nuclear power (Opt-LG high nuclear) is used, i.e. if the growth of nuclear power is not significantly constrained by social acceptance. In this case, nuclear would gain some weight in the electricity mix, but basically at the expense of coal with CCS.

Finally, the last scenario depicted in Figure 6-28 demonstrates how the above picture changes dramatically in a strongly carbon-constrained energy system (Opt-LG carbon-

constrained), where the CO₂ emission trajectory is consistent with the target of limiting the global temperature rise to 2°C. Assuming that electricity generation with CCS will be available, this scenario projects an electricity mix which is progressively decarbonised. The share of 'carbon-free' electricity is already above 50% in 2030 and reaches 90% in 2040 (if generation with CCS is included in the figure). With respect to the role of gas in the electricity mix: while in the long term its use without CCS is less than a third compared to the other optimistic shale gas scenarios, this reduction is partially compensated by an increase in its use in plants with CCS. As already seen in Figure 6-17, the strict emissions target modelled does not preclude a stronger role for gas in the energy system, even if the results of this section highlight how this conclusion relies on the future availability of CCS.

Figure 6-27: Electricity production by fuel in four scenarios: conservative vs. optimistic; optimistic with high nuclear; optimistic in a carbon constrained energy system



However, this broader trend of substitution is not uniform across regions. Much depends on regional specificities, in particular the relative competitiveness of the various fuels and technologies used in the electricity generation sector. A look at three key regions illustrates the different types of impacts that optimistic or conservative shale gas production can have in this respect. In China, for example (see Figure 6-28 below), the difference between a conservative and optimistic case for shale gas does little to change the underlying evolution of the electricity generation sector. Demand for electricity in China will grow significantly even when using more conservative figures for GDP growth, while the share of gas used for electricity generation records steadily increases in both scenarios. But overall there is only a minor difference between conservative and optimistic shale gas development trajectories. This implies that coal's dominance is not seriously threatened by an increase in *shale* gas production; instead, forces outside the unconventional gas market are driving the increase in gas-fired power generation.

Figure 6-28: China's electricity generation by fuel

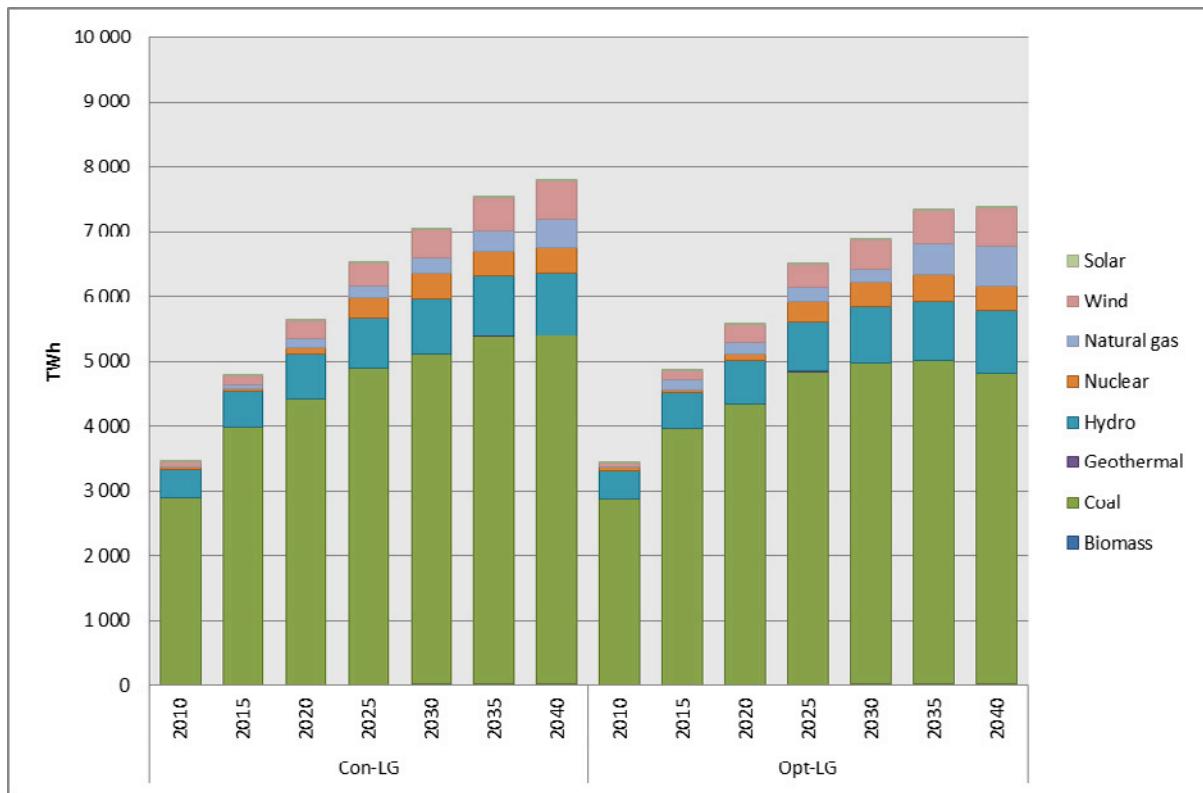
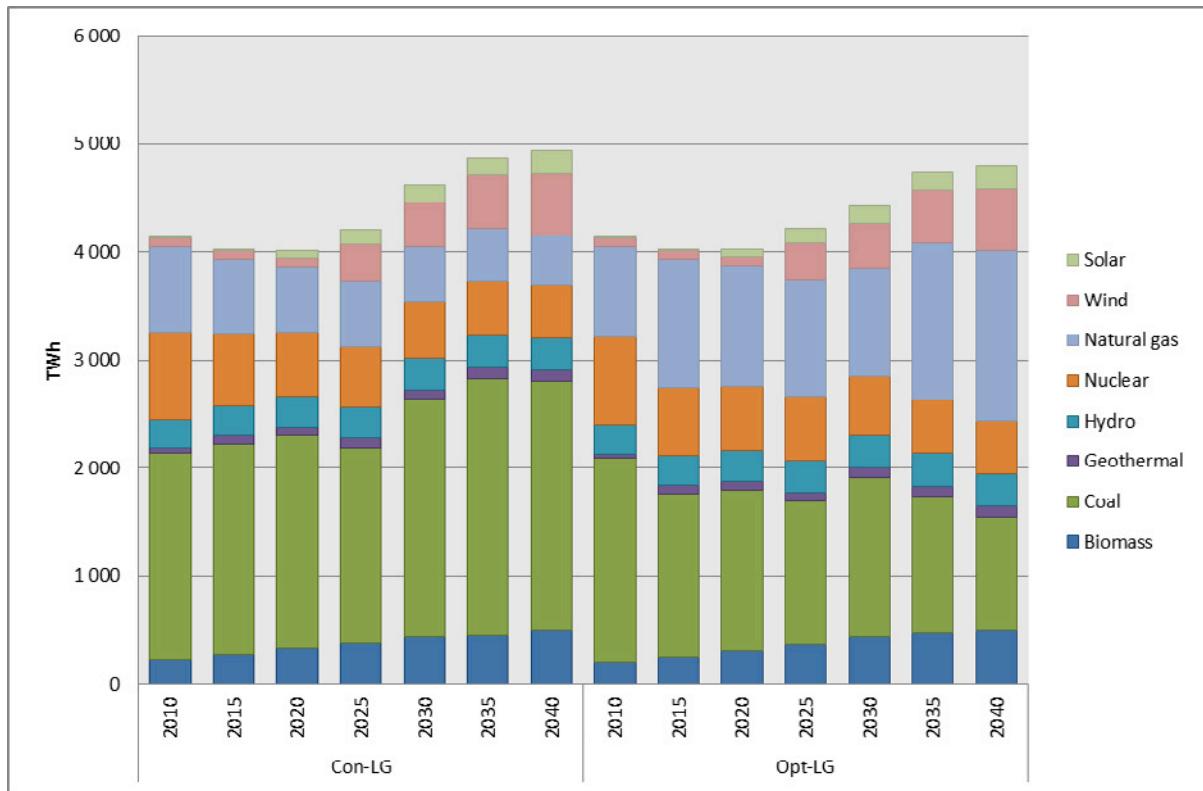


Figure 6-29: US electricity generation by fuel

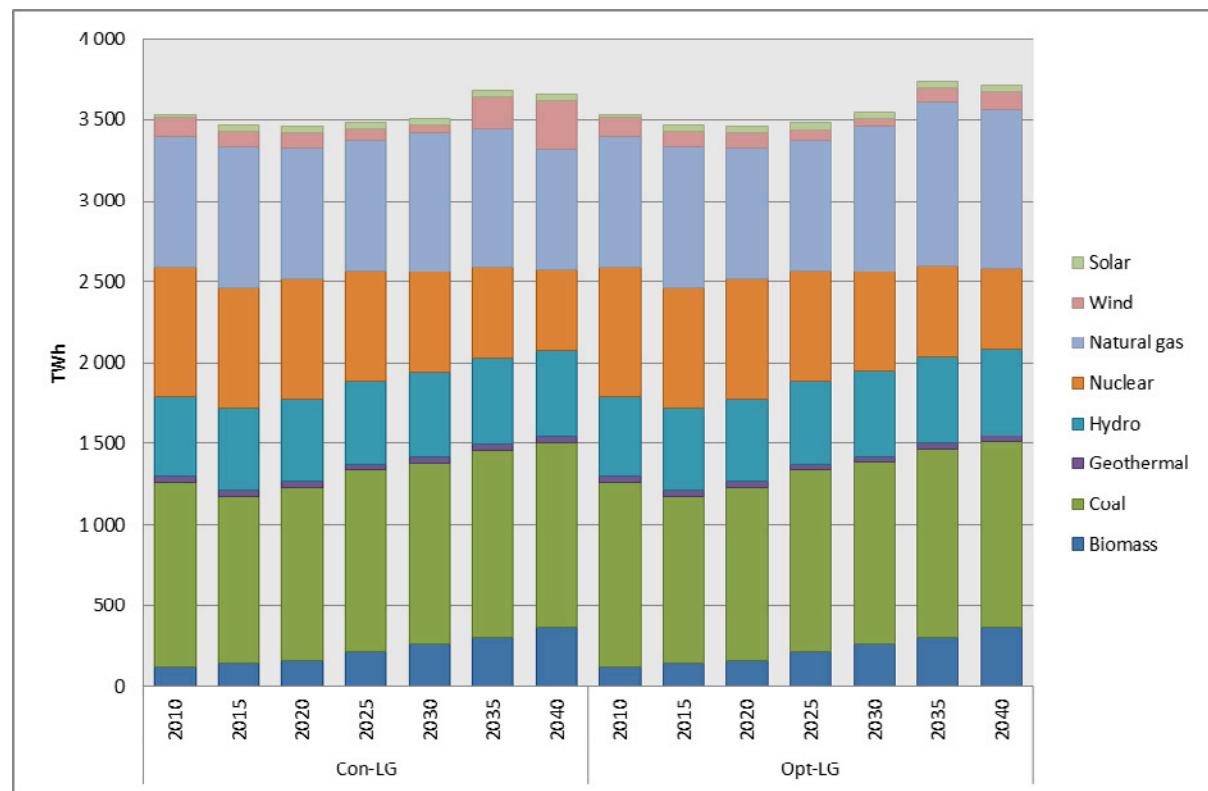


The same cannot be said for the USA, where changes in the electricity generation mix are much more dependent on production of shale gas. Indeed, Figure 6-29 shows a stark difference between the conservative and optimistic cases; in the latter, the percentage share of natural gas in electricity generation doubles, from 21% to 44% by 2040 (an

average annual growth rate of 3.4%). This increase, in turn, causes a correspondingly massive reduction in the use of coal-fired power generation, such that, by the end of the period under scrutiny, coal generates just 400 TWh of electricity compared with 2 200 TWh generated from natural gas. In a scenario where there is less US shale gas production however, gas use in power generation actually witnesses a decrease by 20% over the same period (an average decline of 1.3%), while the share of coal stays relatively buoyant. This means that much of the future development of the US electricity generating sector hinges on the shale gas supply curve.

As regards Europe (see Figure 6-30), coal is set to lose relative market share over time. But unlike the US case, the difference between a conservative and optimistic case of shale gas production is far less dramatic. In the former, coal loses slightly less of its share of overall generation, dropping an average of 0.3% per annum compared with 0.6% in a more optimistic case. Given this slow evolution, the increase in the relative share of gas used for power generation is only visible after 2030, when gas takes a 2% share from coal and a 1% share from renewable energy. This modest development suggests that shale gas will not significantly boost the competitiveness of gas-fired power generation or alter pre-existing patterns of development in electricity generation. Since none of the two scenarios depicted in Figure 6-30 take into account a significant carbon tax regime, renewables lose their relative share in the electricity generation mix as overall demand rises, independent of whether shale gas is produced or not.

Figure 6-30: Europe's electricity generation by fuel

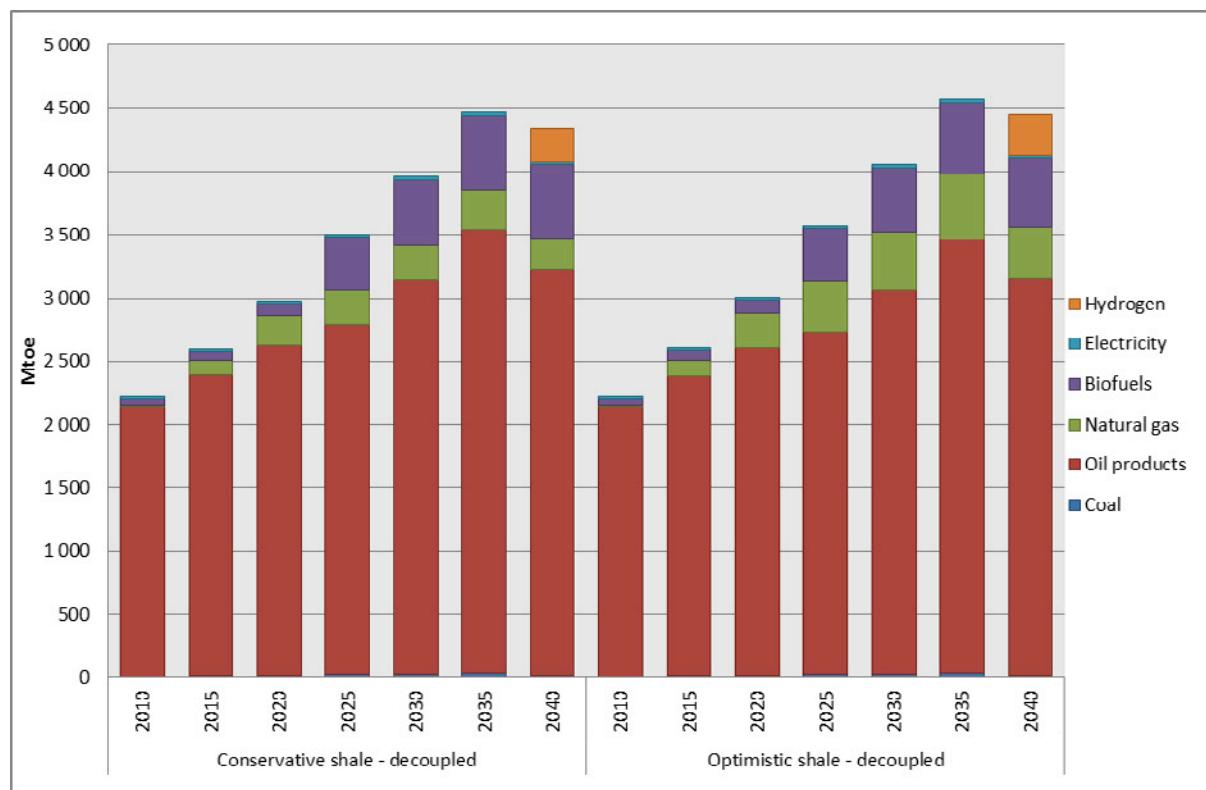


6.3.2 Gas in transport

The penetration of gas into the transportation sector does not depend entirely on shale gas production. Rather, as discussed in the previous section, it is the extent to which oil and gas prices are coupled that will be a key determinant of the future evolution of prices for both sets of commodities, as well as their respective final uses. This is particularly true for transport, where the relationship between oil and gas prices strongly affect the future evolution of this sector.

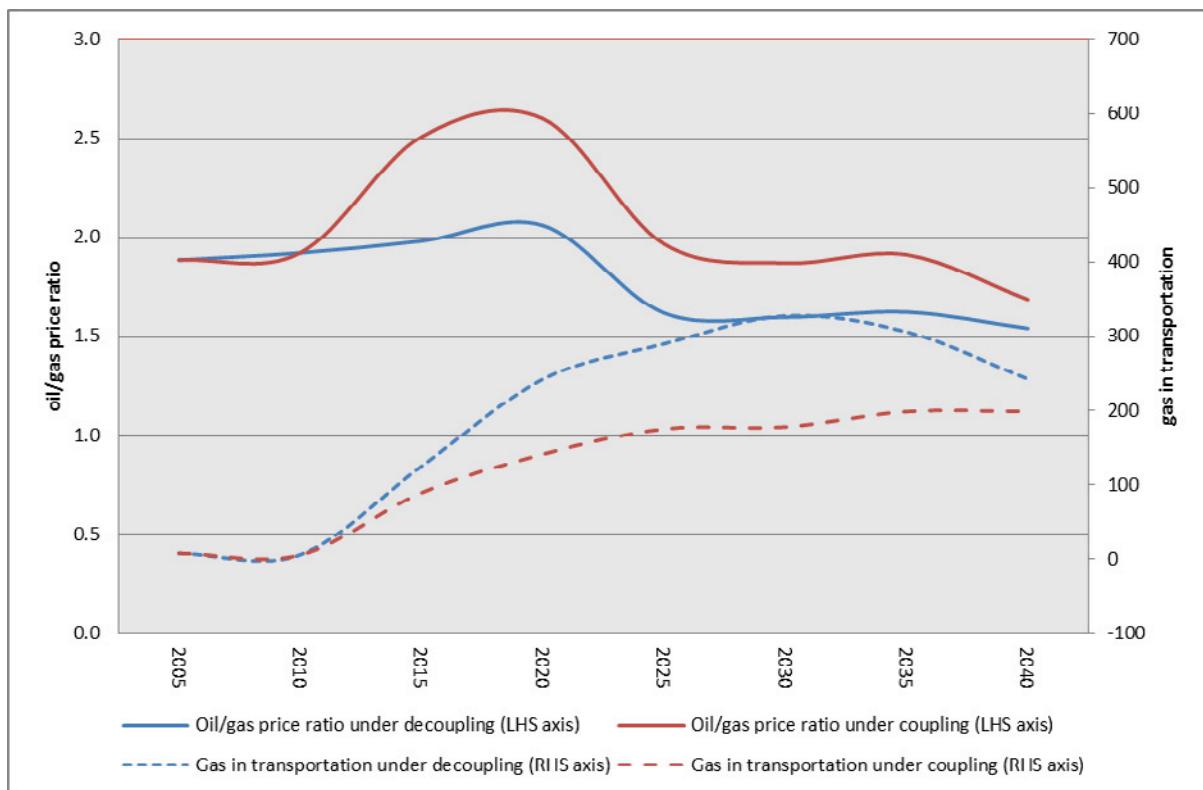
Figure 6-31 shows the degree of penetration of natural gas in the transportation sector, comparing the values between conservative and optimistic shale gas development. Crucially, both scenarios assume a decoupled oil and gas price, which essentially favours natural gas as it can be priced according to its own internal market dynamics. Thus, in both scenarios natural gas grows at a steady rate and, under favourable conditions, the share of gas in transport peaks at close to 13% by 2030. Thereafter, once the cost-competitive gas (vis-à-vis oil) is absorbed by the energy system, the increase in the share of natural gas becomes less pronounced as price 're-coupling' begins to occur.

Figure 6-31: Global gas use in transport in the low growth scenarios



The results set out above seem particularly optimistic. Hence, a contrast must be made with a case in which no significant oil-gas price de-linkage occurs. This is done by comparing two variants of the conservative low-growth scenario, revealing a significant role played by the gas-to-oil price ratio in determining the use of natural gas in the transportation sector. With coupling, there is a lower oil-gas ratio and hence investments in new technologies like gas-to-liquids are more constrained. This causes the share of gas in transportation to be at a significantly lower level than a case where gas and oil prices are more strongly linked. Figure 6-32 below shows this relationship.

Figure 6-32: The oil-gas price ratio compared with the use of gas in transport



6.4 Conclusion

This section presented an exploration of uncertainty rather than a prediction of the future impact of unconventional gas. The latter is only justified in cases where there is greater certainty surrounding the reserve size and production cost of shale gas. As these factors become increasingly known, it will be possible to narrow the range of possible outcomes. In the interim, highlighting the complex and interrelated outcomes of future gas supply and demand developments constitutes a necessary first step toward understanding the potential impact that shale gas can make on the global energy system.

Each scenario presented here must be seen primarily as 'an internally consistent and reproducible set of assumptions about the key relationships and driving forces of change'.⁴⁷ This set of assumptions has been derived from the authors' understanding of the current situation of the global energy system, in particular the gas system, and have been discussed as extensively as possible.

The following summarises some preliminary conclusions as to what can be expected – for Europe and the rest of the world – from shale gas development, and the key factors that can affect this development:

- Overall, the scenario analysis highlights that shale gas does have the potential to extensively impact global gas markets, but only under optimistic assumptions about its production costs and reserves.

⁴⁷ Nebojsa Nakicenovic et al., 'Special Report on Emissions Scenarios', (Geneva: Intergovernmental Panel on Climate Change, 2000).

- In a scenario favourable to shale gas development, natural gas as a whole has the potential to capture 30% of the world's total primary energy supply by 2025, further rising to 35% by 2040. This would make it surpass oil as the world's foremost source of energy.
- Although the strict CO₂ emission targets were modelled to reduce natural gas production – including shale gas – these targets do not preclude a significant growth in natural gas use. The modelling results therefore support the potential role of natural gas as a bridging fuel.
- Shale gas is relatively evenly dispersed around the world and the majority of regions will likely witness at least some level of production in the future. The USA and China are well placed to become the top producers of shale gas, although significant production also takes place in most other regions. The scenario analysis suggests that shale gas will tend to be used within the regions where it is produced; however, no single region will produce enough shale gas so as to move from being a net importer to a net exporter.
- The global trade in natural gas, driven by conventional gas, will increase in any scenario. Shale gas development, however, has the potential to moderate the degree of growth, particularly for interregional LNG flows. Low LNG costs would mitigate the reduction in trade resulting from widespread shale gas development.
- Significant shale gas production has the potential to lower natural gas prices, although to what extent strongly depends on the way natural gas will be priced in the future. In particular, oil indexation has the potential to reduce the fall in gas prices resulting from shale gas development.
- The degree of penetration of gas in transport strongly depends on the oil-gas price link. A weaker link implies greater potential for shale gas to induce a significant growth of gas use in transportation.
- The impact on demand in an optimistic shale gas scenario is not equal across all regions. Much depends on the relative competitiveness of fuels and technologies in each region. This is particularly apparent for electricity generation. While shale gas can induce a dramatic change in the US electricity generation mix, its impact on China's mix is more limited.
- Shale gas production will not make Europe self-sufficient in natural gas. The best case scenario for shale gas development in Europe is one in which declining conventional production can be replaced and import dependence maintained at a level of around 60%. With regard to trade flows, the structure of EU gas imports is very sensitive to the LNG cost assumptions.

ANNEXES

A Systematic review methodology

There are several reasons why the systematic review approach has become so central to the 'evidence based' movement. First, experience in the medical field and elsewhere suggests that policy and practice are often based on inadequate evidence. Second, the increasing volume of research findings makes it difficult for policymakers and practitioners to keep abreast of current understanding, creating a need for more effective synthesis of research results. Third, a combination of the complexity of the relevant issues, the variable quality of research evidence and the methodological and other biases of individual researchers, leads to conflicting recommendations by different authors and corresponding uncertainty over whom to trust. This problem can be exacerbated by the selective use of evidence by powerful interest groups and by the partial and unbalanced treatment of research results by the media (a problem that is particularly relevant to energy policy).

Whilst the use of systematic reviews thus offers a number of benefits for addressing the topic of this study, the methodology does have its weaknesses. In particular, systematic reviews commonly address narrowly-defined, 'micro-level' research on which questions may be more answerable but of less interest to policy-makers and practitioners. Systematic reviews have also proved most successful in natural sciences where there is a tradition of either experimental or quasi-experimental research. This raises questions as to whether the 'gold standard' of methodological rigour normally required can be adapted to the field of energy, where evidence may be econometric or even qualitative and where so-called 'grey literature' may play an important role as a source alongside peer-reviewed studies.

In light of the above, a 'realist' application of the methodology will be employed by this report (see Table A-1).¹ Such an adaptation has informed work by the UKERC to address interesting and relevant energy policy debates such as the costs and impacts of renewable energy intermittency² and global oil depletion.³

¹ R. Pawson et al., 'Realistic synthesis: an introduction', in *ESRC Research Methods Programme* (Manchester: 2004).

² Robert Gross et al., 'The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network', (London: UK Energy Research Centre, 2006).

³ Sorrell et al., 'Oil depletion'.

Table A-1: Stages of a traditional systematic review compared to those of a 'realist' review⁴

Traditional systematic review	Realist review
Identify and refine a specific review question	Clarify scope and purpose of review with client and articulate the key theories to be explored
Search for primary studies, using clear predefined inclusion and exclusion criteria	Search for relevant evidence, refine inclusion criteria in the light of emerging data
Appraise quality of studies using a predefined appraisal checklist, emphasising relevance to the research question and methodological rigour	Appraise quality of studies using judgement to supplement formal checklist and considering relevance and rigour from a 'fit for purpose' perspective
Extract standard items of data from all primary studies using a template	Extract different data from various studies using an eclectic and iterative approach
Synthesise data to obtain effective size and confidence interval and/or transferable themes from qualitative studies	Synthesise data to achieve refinement of relevant theory – i.e., to determine what works for whom, how and under what circumstances
Make recommendations, especially with reference to whether findings are definitive or whether further research is needed	Make recommendations, especially with reference to contextual issues for particular policy-makers at particular times

⁴ Source: Sorrel, 'Improving the evidence base for energy policy'.

B Definitions

The industry-standard term for discussing the ultimate recovery from an individual well is the 'estimated ultimate recovery' (EUR), usually denoted EUR/well and also sometimes referred to as the 'productivity'. EUR is essentially identical to URR, although URR is usually preferred when referring to areas or regions larger than a well. As described in detail in Chapters 3 and 4, a common procedure for estimating the recoverable resources from a country or region is through extrapolating values of EUR/well across an area. Confusion can occur over whether these recoverable resources should be interpreted as the ultimately recoverable or the technically recoverable.

It is important to remember that the estimates of recoverable resources derived in this way rely upon the extrapolation of existing estimates of EUR/well, not just to areas currently being produced but often into new areas which have experienced little or no previous production. The estimates of EUR/well are based upon the use of current technology and so extrapolating them into new areas would be expected to give the recoverable resources in those areas using current technology. Our interpretation is therefore that estimates derived using EUR/well should be seen as the technically recoverable resources (which assume current technology only), unless it is explicitly stated that future technological advances have been incorporated into the analysis. If, by whatever means, economic factors are taken into account – for example if an author estimates that some areas will have very low rates of production or will require excessively complex drilling procedures and hence discounts resources in these areas – the remaining resources are the economically recoverable resources.

Since EUR and URR are identical terms, throughout the report the notation of URR/well instead of EUR/well is used to avoid confusion.

In addition to the competing definitions of resources and reserves, some other definitions are relevant to the interpretation of published estimates. These are summarised and explained in Box B-1.

Box B-1: Measurement of natural gas volumes and energy content

Natural gas is generally reported on a volumetric basis either in imperial (cubic feet) or metric (cubic metres) units. In the imperial system, a prefix of 'M' usually denotes a thousand (so MMcf is a million cubic feet), while in the metric system 'm' corresponds to a million (so mcm is a million cubic metres). For resource estimates, the most common prefixes are 'B' for a billion and 'T' for a trillion, both of which are commonly used with cubic metres and feet.

It is also important to know the temperature and pressure at which natural gas volumes are reported. The EIA and API (the American Petroleum Institute) indicate that volumes of gas in the USA are measured at 60°F (15.56°C) and 14.73 psi (1 atmosphere or 101.325kPa).¹ The UK's Department of Energy and Climate Change (DECC) on the other hand indicates that European natural gas data is generally reported again at atmospheric pressure but at a slightly lower temperature of 15°C.² These different definitions correspond to a volumetric difference of around 4%. The majority of the evidence base presented below has been produced by North American institutions or by organisations relying upon North American data and so the volumes presented are most likely to correspond to the EIA and API definitions. At these conditions, cubic feet can be derived by multiplying cubic metres by 35.3 i.e. 1 Tcm = 35.3 Tcf.

¹ C. Augustine, B. Broxon and S. Peterson, *Understanding Natural Gas Markets* (Boston, MA: Lexecon, 2006), DECC, 'EMS: Atmospheric emissions Calculations', (London: Department for Energy and Climate Change, 2008).

² DECC, 'EMS'.

Gas can also be reported in terms of 'dry' or 'wet' volumes: dry gas is the volume of gas that remains after any liquefiable or non-hydrocarbon portions of the gas stream has been removed, while wet gas includes both dry gas and these liquefiable or non-hydrocarbon components.³ Very little of the evidence base states whether dry or wet volumes of the unconventional gases have been reported. SPE/PRMS indicates however that when the gas is used in the end sector separately from any liquefiable fractions contained within it, reported resource figures should be of dry gas.⁴ For this reason, it is likely that most of the evidence base reports dry natural gas figures, which will be assumed throughout this report.

Gas can also be measured in terms of energy content. The most common unit as used on the New York Mercantile Exchange (the Henry Hub pricing point) is the British Thermal Unit (BTU), usually reported in MBtu (convention used here) or MMBTU (both 1 million British Thermal Units). An alternative unit used to price gas in the UK on the Intercontinental Exchange (ICE) at the National Balancing Point (NBP) is the 'therm', equivalent to 100 000 BTU. One BTU of dry natural gas at 60°F corresponds to around 1 055J.

Conversion between volumes and energy depends on the calorific value of the natural gas, which varies over time and with the 'wetness' of the gas. Yearly data from the USA since 1949 indicates that there are around 1 029 BTU in a cubic foot of dry natural gas with a standard deviation of 4 BTU, while wet gas has an energy content around 7.5% higher than dry gas.⁵ One cubic foot of dry natural gas at 60°F is therefore equivalent to around 1.08MJ.

B.1 Resources, reserves and the USGS definitions

Although the majority of existing literature uses one or more of the categories of resources described in Chapter 2, there is one important exception: the USA Geological Service. The USGS states that it provides estimates of "undiscovered" volumes of unconventional gases in different geological areas of the USA. Two of its most recent studies for example provided the 'undiscovered' resources in areas of the Marcellus, Haynesville and Eagle Ford shales.⁶ These reports do not have a clear definition of the term 'undiscovered'.

One interpretation of the resource figures given by the USGS is given in a paper on its methods for estimating unconventional gas resources.⁷ The USGS states that 'essentially all of the moveable oil or gas in almost any [unconventional] accumulation that can be envisioned has become recoverable from a purely technical standpoint... more restrictive conditions are imposed, to the extent that assessed petroleum volumes must not only be technically recoverable but must also have the potential to be added to reserves'. This indicates that the criteria required for gas to be included in the resource figures are more stringent than simply requiring the gas to be technically recoverable. Although an updated methodological paper issued in 2010 appears to contradict this by stating "USGS oil and gas estimates are of technically recoverable resources", it later refers to figures being "potential additions to reserves" on the required data forms.⁸

³ Society of Petroleum Engineers et al., 'Petroleum resources management system', (Allen, TX: Society of Petroleum Engineers, 2008).

⁴ Ibid.

⁵ EIA, 'Annual Energy Review 2010', (Washington, DC: US Energy Information Administration, 2011), Appendix A4.

⁶ Coleman et al., 'Assessment of undiscovered oil and gas', R.F. Dubiel et al., 'Assessment of undiscovered oil and gas resources in Jurassic and Cretaceous strata of the Gulf Coast', (Reston, VA: United States Geological Survey, 2011).

⁷ The USGS uses the term 'continuous' for unconventional oil and gas resources to emphasise the geological difference between these and conventional oil and gas deposits. These terms are essentially identical however. Schmoker, 'Assessment concepts for continuous petroleum accumulations'.

⁸ Charpentier and Cook, 'Improved USGS methodology'.

Both of these methodology papers therefore suggest that figures provided by the USGS should be interpreted as 'potential additions to reserves'.

A possible confusion that remains is whether the 'potential additions to reserves' estimates provided by the USGS for shale plays include undiscovered unconventional gas in areas outside known formations. Contacts with the USGS indicate that it does not.

To provide an equal basis for comparing the USGS figures to the estimates provided by other organisations, the USGS figures are hence interpreted as being a subset of remaining technically recoverable resources that exclude both: a) resources that have already been classified as reserves; and b) resources in undiscovered areas. An estimate of reserves and undiscovered resources must therefore be added to the USGS figures in order to determine an estimate of the remaining technically recoverable resources of the USA.

Similar to aggregating reserve figures, it is only statistically correct to arithmetically sum estimates of reserves and resources if these correspond to the mean estimates. As indicated above, an estimate of 2P reserves is closest, although not identical, to the mean estimate of reserves and so these should be added together to mean estimates of 'potential additions to reserves' and resources in undiscovered areas.

1P reserve estimates within the USA are publically available, while INTEK⁹ also provide estimates of US 'inferred reserves'. The definition of the term 'inferred reserves' is unclear as it is used by different organisations to mean different things. The USGS in 1995 for example used it to refer to reserve growth in conventional fields,¹⁰ while the EIA indicated that it most likely corresponds to 'probable reserves'.¹¹ This later definition is preferred since it is more recent and more applicable to unconventional gas resources. 'Probable reserves' are different from the description of 'proved and probable' 2P reserves given above in that those reserves classified as proved reserves have been subtracted. 'Probable reserves' would appear, therefore, to be equivalent to 2P minus 1P reserves.

It is therefore concluded that an estimate of the remaining technically recoverable resources for the USA may be derived from the sum of:

- 1) US proved reserves;
- 2) US inferred reserves;
- 3) the USGS mean estimates of potential additions to reserves in known formations; and
- 4) mean estimates of undiscovered technically recoverable resources.

The addition of contemporaneous estimates of total cumulative production gives an estimate of the total technically recoverable resource of the USA.

⁹ INTEK, 'Review of emerging resources'.

¹⁰ Reserve growth is indicated by the USGS to be "resources expected to be added to reserves as a consequence of extension of known fields, through revisions of reserve estimates, and by additions of new pools in discovered fields. Also included in this category are resources expected to be added to reserves through application of improved recovery techniques." Gautier and Survey, 'Assessment of US resources'.

¹¹ EIA, 'Estimation of reserves and resources'.

B.2 Estimates of shale gas resource

A total of 50 sources provide original country or regional-level estimates of shale gas resources and these are listed in Table B-1. No distinction is made between whether total or remaining technically recoverable resources have been reported, as the difference is relatively minor and can be easily transformed from one to the other.

As indicated previously, a number of sources do not indicate whether they have included estimates of undiscovered volumes of shale gas in their estimates of TRR. The likelihood of this can be deduced by examining whether they only consider individual, discovered shale plays and/or make any reference to the potential for shale gas to be found outside these plays. INTEK¹² estimates that there are 1.6 Tcm of undiscovered shale gas resources in the USA. Hence, it is possible to convert estimates of 'discovered TRR' in the USA to estimates of 'full TRR' by adding in the INTEK figure. There are no estimates of undiscovered shale gas outside the USA since the focus to date has been on those shale plays that are known to exist.

¹² INTEK, 'Review of emerging resources'.

Table B-1: Shale gas reports providing original country level estimates by date, countries or regions covered and type of resource estimate

Author/organisation	Date of report	Countries/regions covered	Resource estimate
Mohr and Evans	Sep-11	Continental regions	URR
USGS ^a	Aug-11	USA	'Potential additions to reserves'
Medlock, Jaffe and Hartley	Jul-11	9 North American, European and Pacific countries	TRR ^b
INTEK (for EIA)	Jul-11	USA	'Unproved, discovered TRR' ^c
Petak	May-11	USA, Canada	ERR ^d
Kuuskraa	May-11	USA	TRR
EIA (AEO)	Various ^e	USA	TRR (1999-2010) ERR (1997 and 1998)
Potential Gas Committee	Apr-11	USA	TRR
Advanced Resources International (for EIA)	Apr-11	32 individual countries	OGIP and TRR
Henning	Mar-11	USA, Canada	ERR ⁴
Kuuskraa and T. Van Leeuwen	Jan-11	USA	TRR
Zou et al.	Dec-10	China	OGIP
Medlock and Hartley	Oct-10	USA, Canada	TRR
Kuuskraa (a)	Oct-10	USA	TRR
WEC	Sep-10	Nine continental regions	OGIP
Mohr and Evans	Jul-10	USA, Canada	URR
Moniz, Jacoby and Meggs	Jun-10	USA	TRR
Dawson	May-10	Canada	ERR
Skipper	Mar-10	USA, Canada	TRR
Hennings	Mar-10	USA	OGIP and TRR
Kuuskraa (b)	Mar-10	USA, Canada	TRR
Petrel Robertson Consulting Ltd	Mar-10	Canada	OGIP
Downey	Jan-10	USA, Canada	TRR
Harvey and Gray	Jan-10	UK	TRR
Kuuskraa	Dec-09	USA, Canada, Poland, Sweden, Austria, South Africa	'Recoverable resources'
Potential Gas Committee	Jun-09	USA	TRR
Theal	May-09	USA, Canada	OGIP and TRR
ICF (reported by Ejaz)	Mar-09	USA	ERR ⁴
IHS CERA	Feb-09	Europe	TRR
Mackenzie	Jan-09	Europe	TRR
ICF (Vidas and Hugman)	Nov-08	USA, Canada	OGIP and TRR
Smead and Pickering	Jul-08	USA	TRR
Kuuskraa	Jul-07	USA	URR
Sandrea	Dec-05	USA, Global	'Recoverable reserves'
Laherrère	Jun-04	Global	URR
Kuuskraa	Jan-04	USA	TRR and URR
Rogner	Jan-97	Continental regions	OGIP
Kuuskraa and Meyers	Jan-83	USA, Canada, ROW	TRR

- a) USGS estimate based on several studies.¹³
- b) Medlock indicates that resource should be commercially viable so his definition, although described as technically recoverable resources, could be closer to ERR. This is discussed in further detail in Section 3.2.
- c) TRR can be derived by adding the EIA and INTEK figures for contemporaneous proved and inferred reserves, undiscovered resources and 'unproved discovered technically recoverable resources', all of which are reported separately.
- d) ICF's 2011 report¹⁴ indicates that there is a total of 61.5 Tcm of economically recoverable resources in the USA and Canada. It provides a supply cost curve indicating that this volume is only recoverable at gas prices greater than \$14/Mcf. Since this price is four times higher than current gas prices (around \$3.5/Mcf on 15 December 2011), the authors consider that all of ICF's estimates are better interpreted as TRR.
- e) There have been a total of 15 Annual Energy Outlooks between 1997 and 2011. The AEO in 2003 used the same unconventional gas figures as 2002, while the 2011 estimate was based entirely on INTEK (2011) and so is reported separately. There are therefore a total of 13 AEOs included in this row.

¹³ Coleman et al., 'Assessment of undiscovered oil and gas'; D.K. Higley et al., 'Assessment of undiscovered oil and gas resources of the Anadarko Basin Province of Oklahoma, Kansas, Texas, and Colorado, 2010', (Reston, VA: United States Geological Survey, 2011); Debra Higley et al., '2002 USGS assessment of oil and gas resource potential of the Denver Basin Province of Colorado, Kansas, Nebraska, South Dakota, and Wyoming', (Reston, VA: United States Geological Survey, 2003); David W. Houseknecht et al., 'Assessment of undiscovered natural gas resources of the Arkoma Basin Province and geologically related areas, 2010', (Reston, VA: United States Geological Survey, 2010); Robert C. Milici et al., 'Assessment of undiscovered oil and gas resources of the Appalachian Basin Province, 2002', (Reston, VA: United States Geological Survey, 2003); Richard M. Pollastro et al., 'Assessment of undiscovered oil and gas resources of the Bend Arch-Fort Worth Basin Province of North-Central Texas and Southwestern Oklahoma, 2003', (Reston, VA: United States Geological Survey, 2004); C.J. Schenk et al., 'Assessment of undiscovered oil and gas resources of the Permian Basin Province of West Texas and Southeast New Mexico, 2007', (Reston, VA: United States Geological Survey, 2008); Christopher S. Swezey et al., 'Assessment of undiscovered oil and gas resources of the Illinois Basin, 2007', (Reston, VA: United States Geological Survey, 2007); Christopher S. Swezey et al., 'Assessment of undiscovered oil and gas resources of the US portion of the Michigan Basin, 2004', (Reston, VA: United States Geological Survey, 2005); United States Geological Survey, 'National assessment of oil and gas resources update', (Reston, VA: United States Geological Survey, 2010).

¹⁴ Petak, 'Impact of natural gas on CHP'.

C Methods for estimating the recoverable resources of shale gas

C.1 Description of approaches

A detailed description of the various methods for estimating the technically or ultimately recoverable resources for conventional resources, accompanied by a comparison of results, is given in Sorrell et al.¹ Several of these methods use non-linear regression to fit curves to historic data on production or discoveries for aggregate regions. Such curves typically trend to an asymptote, which is interpreted as the ultimately recoverable resources for that region. More sophisticated methods rely upon data from individual fields.

Such methods are not currently used for unconventional deposits and appear unlikely to be appropriate for a number of reasons. First, the conventional approaches are based upon implicit or explicit assumptions regarding the size distribution of conventional gas fields and the sequence in which these fields are discovered and produced (i.e. with the largest being found first). These assumptions are not applicable to unconventional deposits since these are not located in discrete fields. Second, sufficiently long-time series data on regional production and discoveries is currently unavailable for unconventional resources, even within the USA. Third, continuous drilling is necessary to maintain production levels within a shale play², so the regional production history is more dependent upon the economic and political factors affecting drilling activity than on any geological features of the resource. Hence, procedures relying on plotting cumulative production against time are unlikely to provide any useful information. Finally, shale geology is so variable that aggregating individual shale play production or exploration data that could be used to estimate the recoverable resources to a regional level is, at least at this stage in the development of the resource, neither informative nor useful.

C.2 Methods used by INTEK for the US Energy Information Administration

INTEK³ undertook a review of all shales within the USA for the latest edition of the EIA's Annual Energy Outlook as shown in Figure C-1. INTEK sought to estimate the 'unproved discovered technically recoverable resources'⁴ within 19 individual shale plays in the USA. Aggregate estimates of the proved reserves, inferred reserves⁵ and undiscovered resources for the whole of the USA are provided within INTEK's report. The sum of

¹ Sorrell et al., 'Oil depletion'.

² Petak, Fritsch and Vidas, 'American Midstream Infrastructure'.

³ INTEK, 'Review of emerging resources'.

⁴ Elsewhere in the report these are described as 'undeveloped technically recoverable resources'. Neither of the two definitions provided is particularly satisfactory. The first uses the term 'discovered' in a manner that differs from the SPE/PRMS definition described in Section 2.1.1, which would describe the figures produced by INTEK as 'undiscovered'. The second implies that proved and inferred reserves can only be in developed areas, which is not necessarily the case. United States Securities and Exchange Commission, 'Modernization of the Oil and Gas Reporting Requirements: Conforming version (proposed rule)', in RIN 3235-AK00, ed. United States Securities and Exchange Commission (2008).

⁵ As indicated in Section 2.1.1, inferred reserves are assumed to be equal to 'probable' reserves. The sum of proved and inferred reserves will therefore give an estimate of the 2P reserves.

these, together with INTEK's estimates of the unproved discovered technically recoverable resources from each shale play, gives an estimate for the remaining TRR for the entire USA. The total TRR can then be estimated by adding a contemporaneous estimate of cumulative production. The undiscovered resources are indicated by INTEK to be estimated at 1.2 Tcm in Southern California and 0.4 Tcm in the Rocky Mountain region.

For each shale play, INTEK first split the whole play area into two areas it termed the 'active area' and the 'undeveloped area'.⁶ For a few plays INTEK judged the whole shale play area to be 'active' and so did not differentiate the play, but in general each of the two areas within each shale play was considered separately. Based upon a variety of technical, commercial and industrial reports, INTEK estimated the URR/well and well spacing within each area of each shale play. The product of the URR/well and well spacing with the areal extent of the area under consideration coupled with an assumed 'success factor'⁷ yields an estimate of the 'unproved discovered technically recoverable resources' within that particular area. The sum of the 'active' and 'undeveloped' areas finally gives the 'unproved discovered technically recoverable resources' within the whole shale play.

INTEK's success factor, a percentage that can vary between 0% and 100%, was assumed to depend upon three factors: whether the estimates for URR/well and the well spacing currently used were considered to be representative of what can be expected across the whole ('active' or 'undeveloped') area; how much experience there was of geological factors that can affect production; and how much gas had already been produced or added to reserves. Choice of appropriate values for the success factor appears to be relatively subjective and varies between 10% in the 'active' area of the Fayetteville shale to 100% in the 'active' areas of the Eagle-Ford and Barnett-Woodford Shales. The arithmetic means success factor across all the shale plays is 49%.

Currently producing US shale gas plays are very heterogeneous, with production rates between neighbouring wells varying by a factor of three and across an entire shale play by a factor of ten.⁸ A key issue for this method, therefore, is the validity of taking estimates of well spacing and the URR/well from one area and applying these to a second, potentially very different, area. It is commonly the case that some areas within the shale have significantly higher productivity and ultimate recovery than others. These are commonly referred to as 'sweet spots' and correspond with the area INTEK called the 'active' area. In addition, there also appears to be significant variation in the productivity of wells *within* sweet-spot areas, although this distinction partly depends on how sweet spots are defined.⁹

Given this heterogeneity, it is important not to assume single values for the URR/well and well spacing across the whole area of a shale play. This is particularly relevant

⁶ Again this is not a particularly satisfactory term to use since some parts of the 'active' area have not yet been developed.

⁷ INTEK refers to applying a 'recovery factor' to the product of the URR/well and well spacing. This is easily confused with the recovery factor used to estimate the TRR from the OGIP. INTEK's recovery factor more closely resembles the factor that geologists apply to estimate the risked OGIP from the total OGIP and so the term 'success factor' seems more appropriate to avoid confusion.

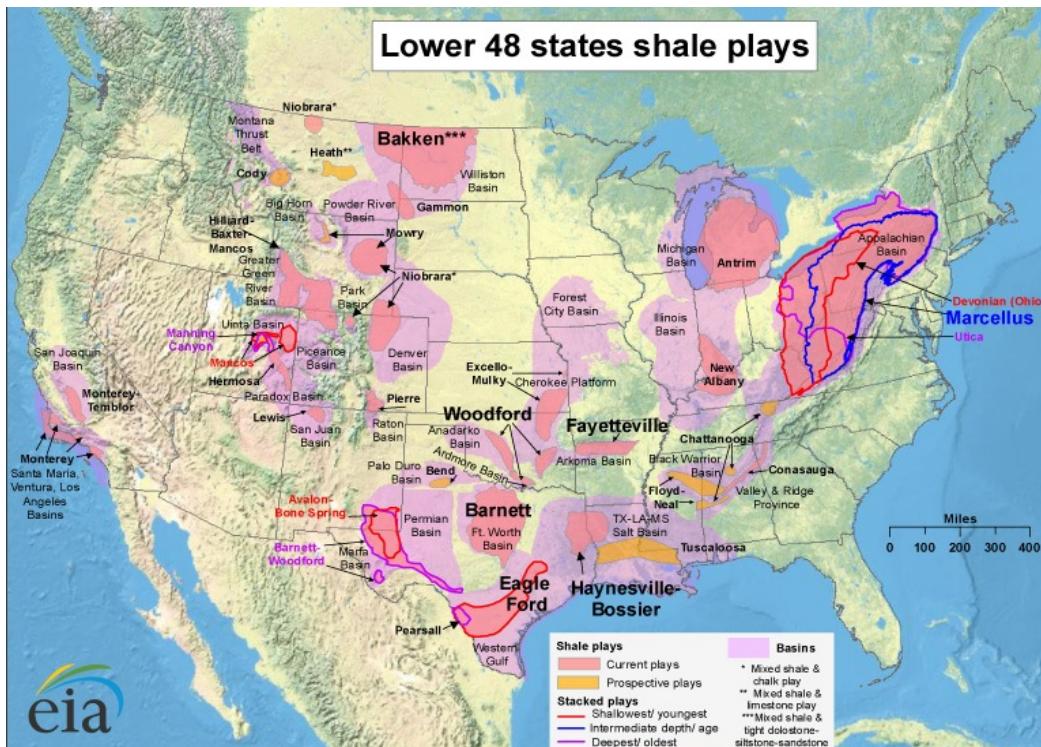
⁸ EIA, 'Estimation of reserves and resources'.

⁹ Kuuskraa, 'Case study #1. Barnett Shale: The start of the gas shale revolution', Strickland, Purvis and Blasingame, 'Reserves Determinations'.

when extrapolating historical URR/well and well-spacing estimates, since these will only be available from the areas of the shale play that have been developed first and which tend to be the most productive. Hence, they are unlikely to be representative of what will be encountered in the remainder of the shale. It was for this reason that INTEK split most shale plays into two areas. INTEK assumed a lower value for at least one of three relevant variables, namely the URR/well, well spacing or success factor in its 'undeveloped' (non-sweet-spot) areas. Which variable was lower, and to what extent it was lower, depended on the shale play under consideration.

Finally, INTEK assumes that the sweet-spot area is the total area leased by shale gas producers.¹⁰ As discussed in Section 2.2.2, this is unlikely to be an appropriate assumption.

Figure C-1: Map of US shale gas plays (lower 48 states)¹¹



C.3 Comparison of USGS and INTEK methods

The INTEK approach differs in a number of important respects to that used by the USGS. First, the USGS acknowledges the considerable uncertainty in all of the above factors and uses Monte Carlo sampling techniques to combine these uncertainties and estimate a probability distribution for the relevant variables. Second, when developing estimates such as the URR/well or the areal extent of the shale (and in estimating the uncertainty in these values), the USGS takes geological factors into account, such as the shale thickness and mineralogy. The USGS indicates that these factors should be plotted as maps and that they can affect the assumed success ratios and/or URR/well. However, little detail is given as to how these factors are actually used. Third, the USGS splits a

¹⁰ S. Nome and P. Johnston, 'From shale to shining shale: a primer on North American natural gas shale plays', (New York, NY: Deutsche Bank, 2008).

¹¹ INTEK, 'Review of emerging resources'.

particular shale play into smaller 'assessment units',¹² and assesses each of these individually. It therefore differentiates between sweet-spot and non-sweet-spot areas on a smaller scale than INTEK. The recent USGS assessment of the Marcellus Shale¹³ for example split the play into three assessment units. Each of these units is divided into sweet and non-sweet spots; the USGS therefore identified six different areas within the Marcellus Shale, each with different sizes and productivities, while INTEK only split it into two.

Fourth, the USGS periodically updates its resource assessments for individual US shale plays or areas of the plays and produces an end-of-year summary combining all of the latest surveys it has carried out.¹⁴ The latest resources assessments were summarised in Table 2-4. It can be seen that some areas have not been examined since 2002. One would expect that those assessments produced after 2010 would have relied upon the updated assessment method described above, but this does not appear to be the case. The USGS recently released the data¹⁵ it used in its most recent assessment for the Marcellus Shale.¹⁶ This data consists of the ranges assumed for the parameters required to estimate potential additions to reserves, for example the mean URR/cell and indicates that the old assessment method was used. While data for the other assessments undertaken since 2010 are not available, it seems likely that the old methodology was used for all of these. As described above, the earlier assessment methodology excluded volumes of gas estimated to exist in non-sweet-spot areas and so is likely to underestimate the total play TRR¹⁷. This represents another important difference between the assessment results of the USGS and INTEK.

Extrapolating a mean URR/well from this area to the whole of the sweet spot could potentially overestimate the resource potential. If these estimates are then extended across the entire shale play, the resource potential of the region could be greatly overestimated. The USGS attempted to mitigate this problem by mapping a range of geological factors and using these to estimate the possible productivities outside the area currently in production, although it has not, in the assessments it has performed so far, attempted to estimate the productivity of non-sweet-spot areas. Nevertheless, its approach is relatively transparent and has the advantage that uncertainties are explicitly accounted for. In contrast, INTEK does not provide any detail on how it estimates either the URR/well or the well spacing in undeveloped or non-sweet-spot areas and there appears to be little empirical basis for the values chosen.

The USGS relies upon geological assessments to classify sweet spots, while INTEK uses the area leased by companies as a proxy. While the latter is a simpler and cheaper approach, it is likely to over-simplify the problem for a number of reasons. Firstly, the acreage details used appear to be significantly out of date. Within the Marcellus Shale, for example, XTO Energy, purchased by ExxonMobil in 2009 when it held around 280 000 acres, is listed as holding 150 000 acres. Similarly, Talisman Energy Inc. is

¹² An 'Assessment Unit' is defined as areas that 'encompasses fields (discovered and undiscovered) which share similar geologic traits and socio-economic factors.' United States Geological Survey, 'Chapter GL Glossary'.

¹³ Coleman et al., 'Assessment of undiscovered oil and gas'.

¹⁴ United States Geological Survey, 'National assessment of oil and gas resources update'.

¹⁵ EIA, *Shale gas: proved reserves* (cited).

¹⁶ Coleman et al., 'Assessment of undiscovered oil and gas'.

¹⁷ Charpentier and Cook, 'Improved USGS methodology'.

reported to hold 640 000 acres yet in a May 2010 investor report indicates that it held around 218 000 acres.¹⁸

A second problem regarding INTEK's choice of sweet-spot areas is its reliance upon a report published in 2008.¹⁹ Since only a limited number of wells had been drilled by that time (e.g. only 234 in Pennsylvania), the productivity of the leased areas was not known with any confidence.²⁰ There is therefore no real justification why the area leased in mid-2008 should correspond to the sweet-spot area. Furthermore, as mentioned above, given the heterogeneity of sweet-spot areas, assuming current productivity will likely provide an overestimate for the remainder of the sweet-spot area.

One final drawback with the INTEK report is its reliance upon highly subjective estimates of the 'success factor' to translate historical production experience into an estimate of recoverable resources for the whole shale. The updated USGS methodology includes a comparable 'success ratio' that reflects the percentage of wells estimated to produce at least the minimum URR. The updated USGS methodology, which requires estimating the success ratio, was not actually used for any of the assessments that were presented in Table 2-4. Nevertheless, the new USGS methodology estimates success ratios at a lower level of spatial aggregation, basing its assumptions to a greater extent on the results from drilling activity and using probability distributions to reflect the associated uncertainties. Hence, it should have a lower degree of subjectivity.

C.4 Impact of technology on resource estimates

The studies reviewed above have focused upon estimating the volume of shale gas that could be recovered using currently available technology. As the USGS comments:

"The USGS oil and gas estimates are of technically recoverable resources as opposed to in-place resources. Technological and economic assumptions are conservative and limited, in that the production data used for calculating well URRs are contemporary to the time of the assessment... large improvements in technology or increasing petroleum prices could possibly increase recovery factor substantially in the future. Because this new methodology is tied to contemporary well-production data, such improved recovery factors are not used as part of this assessment methodology..."

As indicated in Section 2.2, assessment methods that explicitly allow for future technological advances are likely to lead to substantially larger estimates of recoverable resources. Only three reports that attempt to quantify the effects of future technology development have been identified, namely a 2004 report by Kuuskraa,²¹ a paper by the US National Petroleum Council²² and a number of the EIA AEOs²³. In each case,

¹⁸ Talisman Energy, 'Investor open house May 2010: North American operations', (Calgary, AB: Talisman Energy, 2010).

¹⁹ Nome and Johnston, 'From shale to shining shale'.

²⁰ Marcellus Shale Advisory Commission, 'Governor's Marcellus Shale Advisory Commission report', (Canonsburg, PA: 2011).

²¹ Kuuskraa, 'Gas resources, unconventional'.

²² Holditch, 'Unconventional gas'.

technological progress is represented by annual percentage increases in the URR/well.²⁴

This percentage, extrapolated over a given time frame and multiplied by a contemporary estimate of TRR, will yield an estimate of the URR. For example, if TRR in a particular region is estimated at 2.8 Tcm and technological progress is estimated to increase URR/well by 30%, then all else being equal, the URR for that region will be 3.7 Tcm.

Table C-1 illustrates the assumed annual improvement in recovery and the implied overall increase over a 30-year time period. The mean of all 'medium' estimates of the increase in TRR that is estimated to occur from future technological progress is 36% over a 30-year period (this mean has been weighted by the number of reports giving each technological progress and so takes into account that more than one AEO is included in the first and third rows).

The EIA from 2000 to 2009 identified three technologies that it expected would contribute to a greater URR/well for shale gas (and the other unconventional technologies but at different rates).²⁵ These were: "geology technology modelling and matching", "more effective, lower damage well completion and stimulation technology" and "advanced well completion technologies, such as cavitation, horizontal drilling, and multi-lateral wells". The first two of these contribute an annual increase in URR/well and the third an aggregate increase, presumably resulting from switching from vertical to these new drilling technologies, over the timescale of the AEOs, generally around 20-25 years. It can be seen that different AEOs assumed slightly different rates of progress.

These technologies are assumed to be complementary and so the figures indicated in Table C-1 are the sum of the contribution from each, converted into an annual increase and the total increase in the 30-year period.

The latest two AEOs (2010 and 2011) use a slightly different approach and indicate that the "pace at which technology performance improves and the probability that the technology project will meet the program goals" for URR for shale gas was 8% for 'developing' resources and 7% for 'undiscovered' resources.²⁶ It is not clear what these terms mean or how these percentages are actually used and as very little explanation is provided, they are therefore not included in Table C-1.

Two of the three technologies (stimulation²⁷ and horizontal drilling) mentioned above are indeed the technologies that have spurred the recent increase in TRR estimates. The rate at which they would increase URR/well has been vastly underestimated, however. ARI²⁸ indicates that the URR/well within the Barnett Shale averaged around 11.3-14.1

²³ For example, EIA, 'AEO 2010'.

²⁴ Other metrics for measuring the impact of technological progress on recoverable volumes of shale gas can also be used. For example the usual metric for estimating impacts of technology on conventional oil and gas recovery is by increases in the recovery factor IEA, 'World Energy Outlook 2008', in *World Energy Outlook* (Paris: Organisation for Economic Co-operation and Development 2008).

²⁵ For example, EIA, 'AEO 2008'.

²⁶ For example, EIA, 'AEO 2010'.

²⁷ Stimulation, also known as hydraulic fracturing, involves "pumping fluids" consisting primarily of water and sand...injected under high pressure into the producing formation, creating fissures that allow resources to move freely from rock pores where it is trapped'. American Petroleum Institute, 'Hydraulic fracturing'.

²⁸ Kuuskraa, 'Case study #1. Barnett Shale: The start of the gas shale revolution'.

mcm/well between 1985 and 1990 but in 2007-2008 had increased to around 65.2 mcm/well. This corresponds to around a 410% increase in URR/well in about a 20-year period and has occurred primarily through the more widespread and improved use of horizontal drilling and stimulation.

The fastest rate of increase in URR/well anticipated in Table C-1, which includes increases resulting from switching from vertical to horizontal wells and the use of hydraulic fracturing, implies an increase of only 50% over a comparable timeframe. This significant underestimation of the role of technological progress in the past demonstrates the difficulty in estimating future technological progress, even when using a wide range of potential values.

Nevertheless, it is important to note that it was not the introduction of 'new' technologies, i.e. technologies that had not been employed elsewhere and whose potential was unknown, but the adaptation and utilisation of existing technologies that led to the large increases seen in the URR/well. The potential for the utilisation of entirely 'new' technologies for shale gas recovery has not been discussed in any of the EIA AEOs. This suggests that it is the existing technologies of stimulation and horizontal drilling that will continue to be used in the future and that increases in URR/well will be driven by their more widespread usage and improvements in how they are used. New technological breakthroughs can never be ruled out, however.

These two technologies, stimulation and horizontal drilling, are now much more widely used than in 2000, when the estimates of technological progress in URR/well were first given by the EIA. It therefore seems likely that there is less potential for a step increase through switching from vertical wells without stimulation to horizontal wells with stimulation, in addition to there now being a better understanding of the current and future potential of these technologies. There has also been a significant body of work analysing the geology of individual shale plays. One would therefore expect shale geology to be now also much better understood and hence the scope for future improvements in URR/well to be better appreciated. These two factors suggest that such a step change in URR/well as witnessed between 1985 and the present is less likely to occur again in the future.

However, another way to look at the role of technology is by examining the influence of changes in the shale gas recovery factors. Even a very small increase in average recovery factors can have very significant impacts on estimated global recoverable volumes of shale gas. For example, using ARI's global estimate of shale gas OGIP of around 708.2 Tcm,²⁹ a 1% increase in recovery factors globally would lead to an increase in global URR of 7.1 Tcm – over twice the global production of all natural gas in 2010.³⁰

In conclusion, the ranges of technological progress suggested by literature as presented in Table C-1 are likely to represent a better approximation of the role of future technological progress than they have previously. However, the significant impact that even a small improvement in technology can have on the URR and the possibility of major future technological breakthroughs, means that, in principle, estimates of URR will always be more uncertain than estimates of TRR. Estimates of future technological progress must therefore be interpreted with considerable caution.

²⁹ Advanced Resources International, 'World shale gas resources'.

³⁰ BP, 'Statistical review 2011'.

Table C-1: Assumed rates of technological progress in URR/well from various sources³¹

Source	Date	Annual increase			Implied 30-year increase		
		Low	Medium	High	Low	Medium	High
EIA AEO	2004-2009	0.3%	1.3%	2.0%	8%	49%	80%
	2003	0.4%	0.5%	0.6%	13%	16%	19%
	2001-2002	0.6%	0.8%	1.2%	19%	25%	43%
	2000	0.3%	0.5%	1.1%	9%	16%	41%
Kuuskraa	2004		0.8%			27%	
NPC	2003 (updated in 2007)	0.2%	0.9%	1.5%	7%	30%	56%
Mean		0.3%	1.0%	1.5%	9.6%	36.1%	56.3%

³¹ Note: the mean figures have been weighted by the numbers of reports providing each percentage.
Sources: EIA, 'AEO 2010', Holditch, 'Unconventional gas', Kuuskraa, 'Gas resources, unconventional'.

D Decline rate methodologies

Production decline from oil wells was first modelled by Arnold and Anderson¹ and subsequently by Cutler² and Larkey,³ among others. Contemporary decline curve analysis has its roots in Arps,⁴ who synthesised and elaborated a group of techniques now commonly referred to as Decline Curve Analysis (DCA). DCA typically involves fitting a curve to a time series of monthly or annual production from a well or field and extrapolating this curve into the future to forecast production rates and ultimate recovery. Arps identified two main functional forms for these curves: exponential and hyperbolic. More advanced formulations of DCA equations exist,⁵ with some being explicitly developed for the analysis of tight gas and shale gas reservoirs.⁶ However, there is an ongoing debate about the appropriateness of different functional forms for simulating production decline from shale gas wells.

Exponential production decline takes the form

$$q = q_i e^{-Dt}$$

Equation D-1

Where $q(t)$ is the rate of production at time t , q_i is the initial rate of production at $t=0$ and D is a constant reflecting the decline rate ($D \geq 0$). The corresponding equation for hyperbolic decline is:

$$q = q_i \frac{1}{(1 + bD_i t)^{1/b}}$$

Equation D-2

Where D_i is the initial decline rate ($t=0$) and b is a constant, commonly termed the Arps decline constant, which typically (but not always) lies between 0 and 1.0.⁷ The appropriate value of this constant is often the focus of disputes in decline curve analysis.

These two functional forms are illustrated in Figure D-1. For two curves with the same initial production rate and the same initial decline rate, the hyperbolic curve flattens earlier, maintaining a greater production rate for any given time. The area under the

¹ R. Arnold and R. Anderson, 'Preliminary report on Coalinga oil district', in *US Geological Survey Bulletin* (1908).

² W.C. Cutler, 'Estimation of underground oil reserves by oil-well production curves', (Washington, DC: Department of the Interior, 1924).

³ C.S. Larkey, 'Mathematical determination of production decline curves', *Trans AIME* 71 (1925).

⁴ Arps, ed., *Analysis of Decline Curves*.

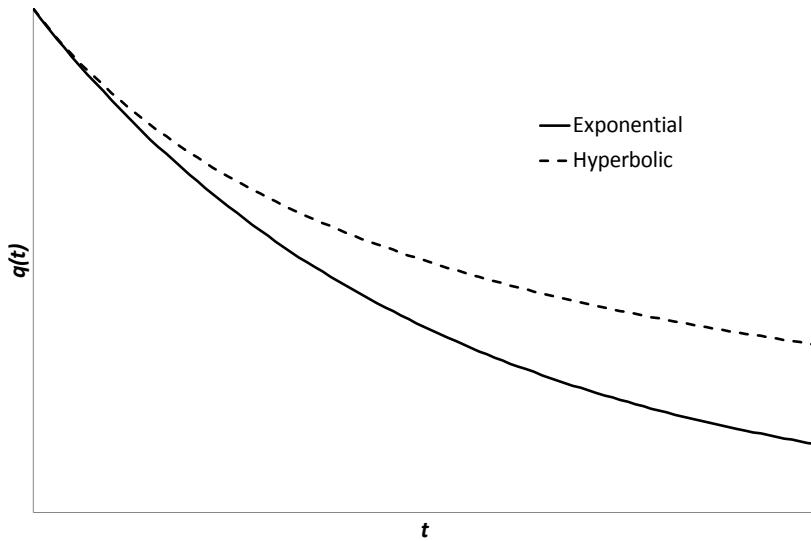
⁵ Ibid, Fetkovich, 'Decline Curve Analysis'.

⁶ Ilk et al., 'Integrating Multiple Production Analysis Techniques To Assess Tight Gas Sand Reserves: Defining a New Paradigm for Industry Best Practices'; P.P. Valko, 'Assigning Value to Stimulation in the Barnett Shale: A Simultaneous Analysis of 7000 Plus Production Histories and Well Completion Records' (paper presented at the SPE Hydraulic Fracturing Technology Conference, Woodlands, TX, 2009).

⁷ D. Ilk et al., 'Exponential vs. Hyperbolic decline in tight gas sands: understanding the origin and implications for reserve estimates using Arps' decline curves' (paper presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, 2008).

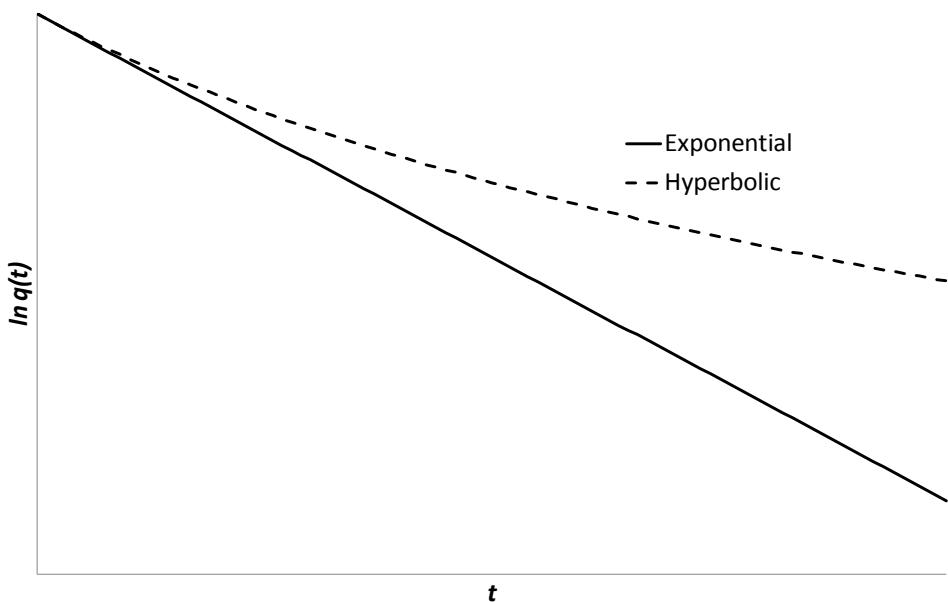
decline curve, from when production begins to when it finally ends represents the ultimately recoverable resource from the well.

Figure D-1: Exponential and hyperbolic decline curves with equal initial production and decline rate



The exponential decline curve exhibits a constant rate of decline, D (i.e. the percentage change in production between time t and time $t+1$ is constant) and a plot of the natural log of production against time takes the form of a straight line (Figure D-2). In contrast, the hyperbolic decline curve exhibits a reducing decline rate over time, so a plot of the natural log of production against time takes the form of a curve (Figure D-2). The constant b represents the rate with which that decline rate reduces.

Figure D-2: Semi-log plot of exponential and hyperbolic decline curves



While originally applied to oil production, decline curves are now commonly applied to gas fields, including shale gas. However, given the relatively recent nature of most shale gas plays, the historical evidence with which to estimate decline curves is relatively limited. The level of uncertainty may be expected to increase with the time period over

which curves are extrapolated, but to estimate the URR/well, extrapolation over long time periods is required. In addition, the rapid technical developments over the past few years are likely to have affected the pattern and rate of production decline – so newer wells may not necessarily behave in the same fashion as older wells, even when the geology is similar. These factors have fuelled the debate regarding the appropriate choice and use of decline curves in shale gas areas.⁸

Whilst the exponential decline curve is simpler, the hyperbolic curve is often found to provide a more accurate model of conventional oil and gas fields, since the rate of production decline typically slows rather than remaining constant. Production from conventional gas wells typically declines by 25-40% per year in the early stages,⁹ but production from shale gas wells declines even faster – for example, by as much as 63-85% per year.¹⁰ But rather than focusing on the initial rate of decline, which is apparent after only a few months of production, the contentious question is how quickly and by how much will these decline rates reduce?

The debate has sometimes been characterised as an argument between hyperbolic and exponential decline.¹¹ However, exponential decline can be viewed as a special case of hyperbolic decline where $b=0$. The debate may therefore be recast as ‘what is the appropriate value of b ?’ Figure D-4 illustrates the change in hyperbolic decline as b varies between 0.01 and 0.99.

The theoretical basis for a hyperbolic decline curve assumes ‘boundary-dominated flow’ – where the influence of the reservoir boundaries affects the flow-rate behaviour. In these circumstances, b is normally found to be between 0 and 1. However, shale gas and other unconventional gas resources exhibit more ‘transient’ or heterogeneous flow rates¹² and it is possible to fit curves with b constants greater than 1. To correct for the anomaly that hyperbolic decline suggests infinite production, a point of economic truncation must be assumed, where the value of produced gas drops below some assumed cost of operation. The well is then assumed to be no longer profitable and is ‘shut-in’. Such calculations require assumptions about the capital and operating cost of the well, the expected price of gas over the well lifetime and the period of time over which these costs should be amortised. Some estimates, based on a gas price of \$5/thousand cubic feet, suggest that wells in the Barnett Shale are no longer profitable when producing below 1 million cubic feet per month.¹³

While estimates of b constants greater than 1 are possible, URR estimates appear to be more sensitive to variation in these higher values of b . Figure D-3 presents the outcome of an analysis of 44 fields in the Haynesville play.¹⁴ In this figure URR estimates are presented on the y axis while b constant values are presented on the x axis. Both initial production and initial decline are fixed. Based on this analysis, the change in URR

⁸ Ibid, J.P. Spivey et al., ‘Applications of the Transient Hyperbolic Exponent’ (paper presented at the SPE Rocky Mountain Petroleum Technology Conference, Keystone, CO, 2001).

⁹ J.D. Hughes, ‘Will Natural Gas Fuel America in the 21st Century?’, (Post Carbon Institute, 2011).

¹⁰ Chesapeake Energy, ‘Investor and analyst meeting’.

¹¹ Dizard, ‘Debate’.

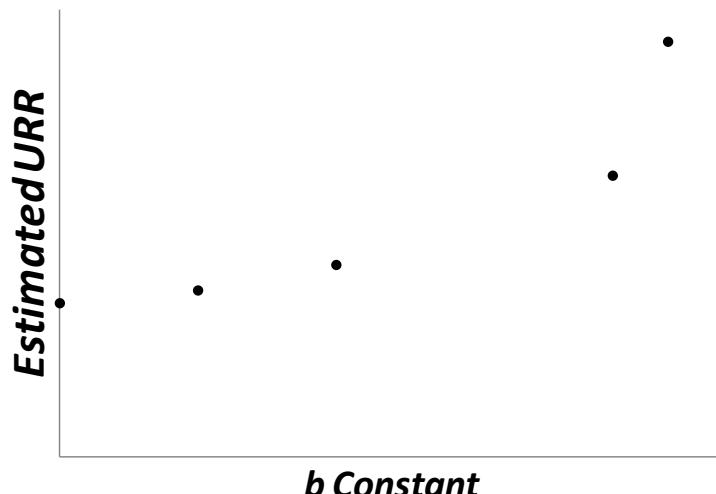
¹² Transient or heterogeneous flow is defined as a changing flow rate over time. In the context of shale gas this means that the flow rate is more volatile than boundary-dominated flow rates, with the potential rate of change being more dramatic.

¹³ The method of calculation of this figure and assumptions are not given. Berman, ‘Shale Gas-Abundance or Mirage? Why The Marcellus Shale Will Disappoint Expectations’.

¹⁴ Ibid.

estimates over a change in b constant appears to increase as b increases. This implies that even small errors in the assumed b constant will have large impacts on the estimated URR. It is also suggested in this analysis that different b constants create hyperbolic curves that fit the data equally well. This underlines the possibility of making a small error in assumed b constant potentially leading to a significant error in estimated URR if b is assumed to be greater than 1.

Figure D-3: Implications of varying b for estimates of URR for 44 wells in the Haynesville Shale¹⁵



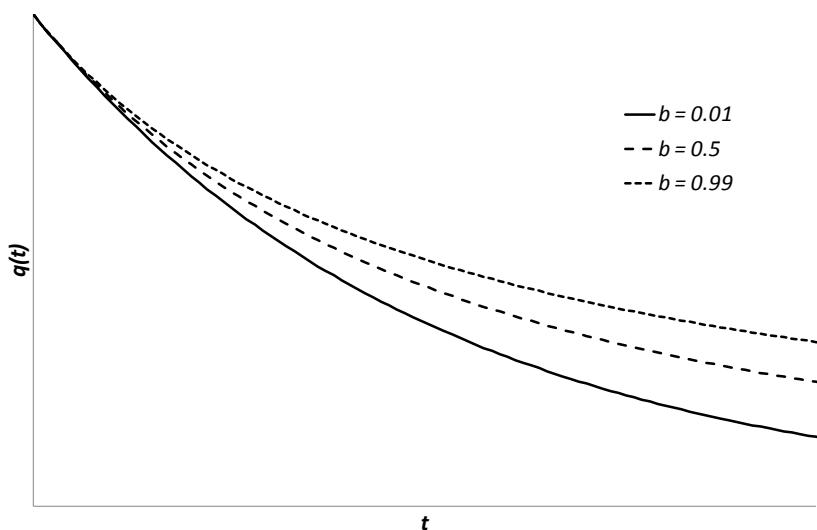
Evidence suggests that shale gas wells are likely to be closed down after relatively short periods of production. In an analysis of well data from the Barnett Shale between 2001 and 2008, Sutton et al.¹⁶ found that 10% of the horizontal wells used to produce shale gas were shut-in within 40 months of initial production. This compares to vertical wells in the same region which took over 70 months to lose the same percentage of producing wells. The difference in expected longevity between horizontal and vertical wells is a function, amongst other things, of the decline rate and the cost of well construction and operation. The implications, therefore, are that using vertical well decline rates to estimate horizontal well behaviour will likely overestimate future well longevity. However, some authors have suggested that shale gas wells have been maintained past this economically rational point in order to avoid downgrading company reserve estimates.¹⁷

¹⁵ Source: Arps, ed., *Analysis of Decline Curves*.

¹⁶ R.P. Sutton, S.A. Cox and R.D. Barree, 'Shale Gas Plays: A Performance Perspective', in *Tight Gas Completions Conference*, ed. Society of Petroleum Engineers (San Antonio, TX: 2010).

¹⁷ Berman, 'Shale Gas-Abundance or Mirage? Why The Marcellus Shale Will Disappoint Expectations'; Berman, 'Abundance or Mirage?'.

Figure D-4: Variation of hyperbolic decline with the value of b



Geologists typically estimate decline curves for wells or groups of wells with the help of non-linear regression techniques.¹⁸ However, this form of curve fitting may have limited accuracy if only short periods of historical data are available. A key difficulty is that curves with different functional forms and/or parameter values can fit short periods of data comparably well but lead to substantially different estimates of the URR (see Figure D-3 and surrounding discussion). In these circumstances, an alternative is to base the choice of curve and parameters on data from 'analogues' – that is, wells with a longer production history that are in areas with similar geological characteristics. The guidelines on what may be considered an appropriate analogue are now well defined.¹⁹ Nevertheless, some commentators argue that resource estimates are frequently based upon inappropriate analogues.²⁰ The considerable variability in decline rates between different shale gas areas highlights the potential error associated with using inappropriate analogues.²¹ This variability also affects the minimum gas price needed to support gas production in different shale gas areas. For example, between 2008 and 2009, a shale gas price of \$4/Mcf would support production in the Barnett and Fayetteville Shales, while a price of \$6/Mcf feet would be required in the other areas.²²

Due to the difficulties associated with hyperbolic decline curves, several authors have suggested using a new decline curve formulation known as the 'power-law exponential' rate relation for shale gas wells instead.²³ But while this new formulation could potentially succeed the hyperbolic decline curve as best practice, it seems unlikely to have a significant impact on the estimation of URR in shale gas wells for some time. The continuing concern over the accuracy of hyperbolic decline curves has also prompted

¹⁸ Jikich and Popa, 'Hyperbolic Decline Parameter Identification'.

¹⁹ J.E. Hodgin and D.R. Harrell, 'The Selection, Application, and Misapplication of Reservoir Analogs for the Estimation of Petroleum Reserves' (paper presented at the SPE Annual Technical Conference and Exhibition, San Antonio, TX, 2006); R. Sidle and W.J. Lee, 'An Update on the Use of Reservoir Analogs for the Estimation of Oil and Gas Reserves', *SPE Econ & Mgmt* 2 no 2 (2010).

²⁰ Hodgin and Harrell, 'Reservoir Analogs'.

²¹ Chesapeake Energy, 'Investor and analyst meeting'.

²² Baihly et al., 'Shale Gas Production Decline Trend Comparison'.

²³ Ilk et al., 'Integrating Multiple Production Analysis Techniques To Assess Tight Gas Sand Reserves: Defining a New Paradigm for Industry Best Practices'; Ilk et al., 'Exponential vs. Hyperbolic decline'; Strickland, Purvis and Blasingame, 'Reserves Determinations'.

some authors to suggest that their use may not qualify under the US Securities and Exchange Commission's (SEC) guidance on the reporting of reserves.²⁴

Finally, analytical models, or their combination in 'hybrid' methodologies, provide an alternative route to derive the b constant.²⁵ Decline curves have traditionally been an empirical technique in which future estimates are derived by extrapolating historical data. These curves may better reflect the later stages of shale gas well production, the so called boundary-dominated flow.²⁶ Newer analytical models seek to derive flow characteristics from horizontal, fractured wells through computer simulations, which model the shape, pressure and characteristics of these wells.²⁷ These analytical techniques may represent the initial transient flow more accurately.²⁸ By applying a combination of these techniques, geologists have created hybrid methodologies that help to balance the potential bias of each technique as the well transitions from transient flow to boundary-dominated flow. These hybrid methods are new and it is unclear whether they will prove valuable given the effort associated.

²⁴ Lee and Sidle, 'Reserves Estimation'.

²⁵ Ray J. Ambrose et al., 'Life-Cycle Decline Curve Estimation for Tight/Shale Reservoirs' (paper presented at the SPE Hydraulic Fracturing Technology Conference, Woodlands: TX, 2011); J.M. Thompson, V.O. Mangha and D.M. Anderson, 'Improved Shale Gas Production Forecasting Using a Simplified Analytical Method-A Marcellus Case Study', in *North American Unconventional Gas Conference and Exhibition*, ed. Society of Petroleum Engineers (The Woodlands, TX: 2011).

²⁶ Ambrose et al., 'Life-Cycle Decline Curve Estimation'.

²⁷ L. Larsen and T.M. Hegre, 'Pressure-Transient Behavior of Horizontal Wells With Finite-Conductivity Vertical Fractures, (paper presented at the International Arctic Technology Conference, Anchorage, AK, 1991).

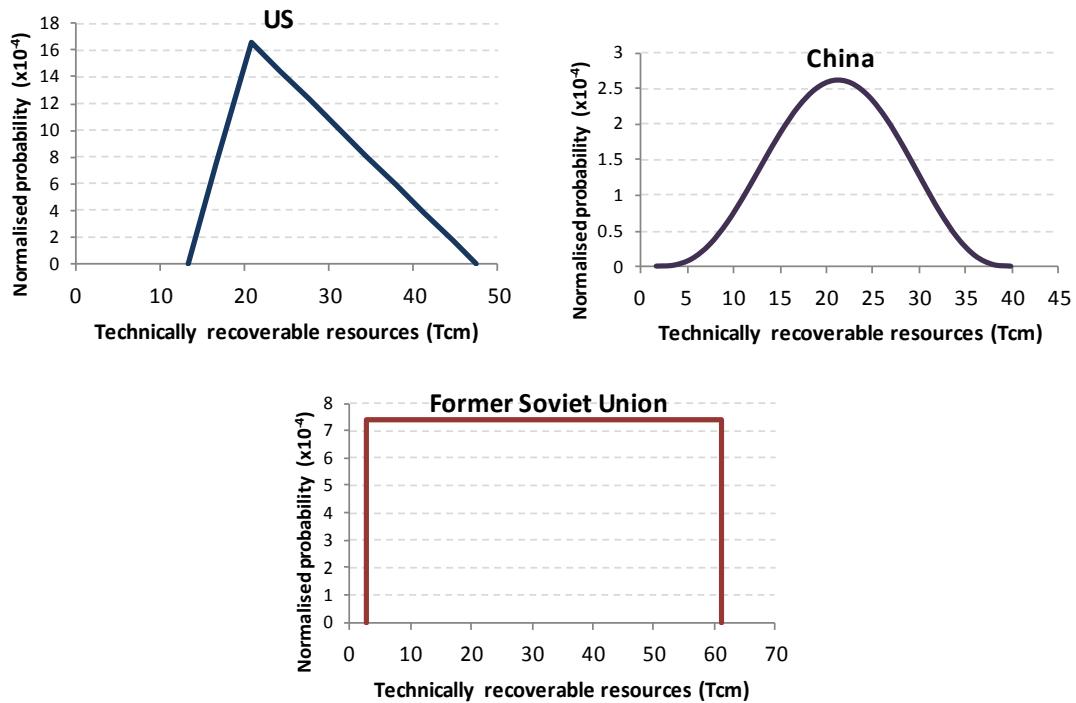
²⁸ Ambrose et al., 'Life-Cycle Decline Curve Estimation'; Thompson, Mangha and Anderson, 'Improved Shale Gas Production Forecasting Using a Simplified Analytical Method-A Marcellus Case Study'.

E Best estimates: characterising the uncertainty

Four regions were given in Table 2-6 where high, best and low estimates have been identified. There is no evidence for the shape of the probability distributions that will be found between these points, however. There is also no evidence of whether the high and low points should be interpreted as absolute maxima and minima or whether they should be seen more as extreme, but not maximum values such as the 95th and 5th percentiles. Given this lack of evidence, a possible approach is to choose as many distributions that are judged to be appropriate, assume that all of these have equal weighting and combine them using statistical procedures. Given that the high and low points are, in general, not equally spread about the central value, the distributions must be capable of being asymmetric.

Various distributions have been used for such purposes previously¹ and would include triangular or beta distributions, with the high and low values at both the maxima and minima and the 95th and 5th percentiles. A selection of possible distributions is shown in Figure E-1. An aggregate distribution for each region with more than one possible distribution could be derived, for example, by randomly sampling from each.

Figure E-1: Examples of possible probability distributions between estimates in a selection of regions



¹ V. Voudouris, 'The ACEGES Project: An ACE Model for the Availability of Global Conventional Oil Supply', in *16th International Conference on Computing in Economics and Finance*, ed. Society for Computational Economics (2010).

F Evidence base

Table F-1: Documentation and classification of the evidence base

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Aluko	Aug-01	No	11 countries	CBM	TRR	Literature review	
ARI (Kuuskraa)	May-11	No	USA	Shale	TRR	Method not stated	It is likely that Kuuskraa adopts a bottom-up analysis of geological features approach as used in ARI Apr 2011 report, but this is not stated
ARI (Kuuskraa, Stevens et al.)	Apr-11	Yes	32 individual countries worldwide	Shale	OGIP and TRR	Bottom-up analysis of geological parameters	
ARI (Kuuskraa)	Jan-11	No	USA	Shale	TRR	Method not stated	
				CBM	TRR	Method not stated	
				Tight	TRR	Method not stated	
ARI (Kuuskraa)	Oct-10	No	USA	Shale	TRR	Method not stated	
ARI (Kuuskraa)	Mar-10	No	USA, Canada	Shale	TRR	Method not stated	
ARI (Kuuskraa)	Dec-09	No	Rest of World	Shale	TRR	Not independently assessed: based on Rogner (1997) and IEA WEO 2009	Recovery factor of 40% suggested
			USA, Poland, Austria, Africa	Canada, Sweden, South	'Recoverable resources'	Method not stated	
			Global	Tight	TRR	Not independently assessed: based on Rogner (1997) and IEA WEO 2009	Recovery factor of 50% suggested
			Individual countries worldwide	CBM	OGIP and TRR	Method not stated	
ARI (Kuuskraa)	Jul-07	No	USA	Shale	URR	Bottom-up analysis of geological parameters	

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
BGR (Kümpel)	Nov-09	No	Individual countries worldwide Continental regions	CBM	URR	Bottom-up analysis of geological parameters	
				Tight	URR	Bottom-up analysis of geological parameters	
				CBM	TRR	Method not stated	
				Shale	OGIP	Not independently assessed: based on Holditch and Chianelli, Kawata and Fujita, and Rognner	No recovery factor suggested
Caineng et al.	Dec-10	Yes	China	Shale	OGIP	Bottom-up analysis of geological parameters	
Chatham (Stevens) House	Sep-10	No	Continental regions	Shale	OGIP	Not independently assessed: based on Holditch (2007)	
Dawson	May-10	No	Canada	Shale	ERR	Method not stated	Indications based on Petrel Robertson Consulting (2010) report; however, the report does not include any ERR figures.
DECC (Harvey and Gray)	Jan-10	No	UK	CBM	ERR	Method not stated	
				Tight	ERR	Method not stated	
				Shale	TRR	Extrapolation of production experience	

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
EIA (AEO)	Various	No	USA	Shale	TRR	Bottom-up analysis of geological parameters	There have been a total of 15 Annual Energy Outlooks between 1997 and 2011. The AEO in 2003 used the same unconventional gas figures as 2002, while the 2011 estimate was based entirely on INTEK (2011) and so is reported separately.
FERC	May-10	No	USA	Shale	TRR	Not independently assessed: based on 'American Clean Skies Foundation'	
Gény	Dec-10	No	Europe	CBM	TRR	Not independently assessed: based on Wood Mackenzie 'Unconventional Hydrocarbons' Multi-client Study	
				Tight	TRR	Not independently assessed: based on Wood Mackenzie 'Unconventional Hydrocarbons' Multi-client Study	
				Shale	TRR	Not independently assessed: based on 'IHS CERA Gas from Shale: Potential Outside North America?'	
Global Warming Policy Foundation (Ridley)	Apr-11	No	Global	Shale	OGIP and TRR	Not independently assessed: based on ARI report	
				CBM	OGIP and TRR	Not independently assessed: based on ARI report	

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Hennings	Mar-10	No	USA	Shale	OGIP and TRR	Bottom-up analysis of geological parameters	
Holditch Chianelli	Apr-08	Yes	Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997) (although not stated)	No recovery factor suggested
				CBM	OGIP	Not independently assessed: based on Rogner (1997) (although not stated)	No recovery factor suggested
				Tight	OGIP	Not independently assessed: based on Rogner (1997) (although not stated)	No recovery factor suggested
Holditch	Jul-07	No	Continental regions	Shale	OGIP	Not independently assessed: based on 'Tight Gas Sands' Holditch (2006)	
				CBM	OGIP	Not independently assessed: based on 'Tight Gas Sands' Holditch (2006)	
				Tight	OGIP	Not independently assessed: based on 'Tight Gas Sands' Holditch (2006)	
Holditch	Jun-06	Yes	Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997) taken from Kawata and Fujita (2001). No recovery factor stated	No recovery factor suggested

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				CBM	OGIP	Not independently assessed: based on Rogner (1997) taken from Kawata and Fujita (2001). No recovery factor stated	No recovery factor suggested
				Tight	OGIP	Not independently assessed: based on Rogner (1997) taken from Kawata and Fujita (2001). No recovery factor stated	No recovery factor suggested
ICF	Mar-09	No	USA	Shale	TRR	Bottom-up analysis of geological parameters	Reported by MIT supplementary pap (Ejaz (2010) SP2.2) The authors consider that all of ICF's estimates are better interpreted as T
				CBM	TRR	Bottom-up analysis of geological parameters	The authors consider that all of ICF's estimates are better interpreted as T
				Tight	TRR	Bottom-up analysis of geological parameters	The authors consider that all of ICF's estimates are better interpreted as T
ICF (Petak)	Jun-11	No	USA. Canada	Shale	ERR	Bottom-up analysis of geological parameters	This report indicates that there is a total of 61.5 Tcm of economically recoverable resource in the USA and Canada. It provides a supply cost curve indicating that this volume is only recoverable at gas prices greater than \$14/Mcf. Since this price is four times higher than current gas prices (around \$3.5/Mcf on 15 December 2011), the authors consider that all of ICF's estimates are better interpreted as TRR.

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
ICF (Henning)	Mar-11	No	USA, Canada	Shale	ERR	Bottom-up analysis of geological parameters	The authors consider that all of ICF's estimates are better interpreted as TRR.
ICF (Vidas and Hugman)	Nov-08	No	USA, Canada	Shale	OGIP and TRR	Bottom-up analysis of geological parameters	
				CBM	TRR	Method not stated	
				Tight	TRR	Method not stated	
IEA (Priddle)	Jan-11	Yes	Continental regions	Shale	TRR	Not independently assessed: based on ARI report (Kuuskraa, Stevens et al. 2011)	Recovery factor of around 25% suggested
				CBM	TRR	Not independently assessed: based on Rogner (1997)	
				Tight	TRR	Not independently assessed: based on Rogner (1997)	
IHS CERA (Downey)	Jan-10	No	USA, Canada	Shale	TRR	Method not stated	Reported by R. Weijermars et al., 'Unconventional gas research initiative for clean energy transition in Europe <i>Journal of Natural Gas Science and Engineering</i> , 2011. 3(2): p. 402-412.
IHS CERA	Feb-09	No	Europe	Shale	TRR	Unknown	
INTEK (for EIA)	Jul-11	No	USA	Shale	'Unproved, undiscovered TRR'	Extrapolation of production experience	TRR can be derived from this figure by adding proved and inferred reserves. undiscovered resources are reported separately
Kawata and Fujita	Apr-01	No	Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
				CBM	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Kuhn and Umbach	May-11	Yes	Continental regions	Tight	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
				Shale	OGIP and TRR	Not independently assessed: based on BGR ¹	
				CBM	TRR	Not independently assessed: based on BGR	
Kuuskraa	Jan-04	No	USA	Tight	TRR	Not independently assessed: based on BGR	
				Shale	URR and TRR	Method not stated	
				CBM	OGIP and TRR	Method not stated	Reported in Kuuskraa, V.A., Natural gas resources, unconventional, in <i>Encyclopedia of Energy</i> , C.J. Cleveland (ed.). 2004, Elsevier Inc. p. 257-272.
Kuuskraa	Oct-92	No	12 countries	CBM	OGIP and TRR	Extrapolation from coal resources	
				CBM	URR and TRR	Method not stated	
				Tight	URR and TRR	Method not stated	
Kuuskraa and Meyers	Jan-83	No	USA, Canada, ROW	Shale	OGIP and TRR	Literature review	Could equally be an expert opinion
				Tight	OGIP and TRR	Literature review	Could equally be an expert opinion
				CBM	OGIP and TRR	Bottom-up analysis of geological factors	
Laherrere	Jun-04	No	Global	Shale	URR	Expert judgment	
Medlock and Hartley	Oct-10	No	USA, Canada	Shale	TRR	Literature review	

¹ BGR, 'Reserves, resources and availability'.

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Medlock et al.	Jul-11	Yes	9 North American, European and Pacific countries	Shale	TRR	Literature review	Medlock indicates that resource should be commercially viable so his definition, although described as technically recoverable resources, could be closer to ERR.
MIT (Moniz)	Jun-10	Yes	USA	Shale	TRR	Literature review	Figures are reported without proved reserves so 1.7 Tcm gas have been added
				CBM	TRR	Literature review	Figures are reported without proved reserves so 0.54 Tcm gas have been added
				Tight	TRR	Literature review	Figures are reported without proved reserves so 2.3 Tcm gas have been added
			Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997)	Reported in Appendix 2A. Recovery factor between 10-35% suggested
				CBM	OGIP	Not independently assessed: based on Rogner (1997)	Reported in Appendix 2A. Recovery factor between 10-35% suggested
				Tight	OGIP	Not independently assessed: based on Rogner (1997)	Reported in Appendix 2A. Recovery factor between 10-35% suggested
Mohr and Evans	Sep-11	Yes	Continental regions	Shale	URR	Literature review	
				CBM	URR	Literature review	
				Tight	URR	Literature review	
Mohr and Evans	Jul-10	Yes	USA, Canada	Shale	URR	Literature review	
				CBM	URR	Literature review	
				Tight	URR	Literature review	
Murray	Jan-96	Yes	12 countries	CBM	OGIP	Adaptation of existing review (Kuuskraa et al 1992)	

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Navigant Consulting (Smead & Pickering)	Jul-08	No	USA	Shale	TRR	Literature review	
				CBM	TRR	Literature review	
				Tight	TRR	Literature review	
Palmer	Mar-08	No	12 regions/countries	CBM	OGIP	Not independently assessed: based on Kuuskraa (1992)	
Petrel Robertson Consulting	Mar-10	No	Canada	Shale	OGIP	Literature review	
				CBM	OGIP	Literature review	
				Tight	OGIP	Literature review	
Potential Committee	Gas Apr-11	No	USA	Shale	TRR	Bottom-up analysis of geological parameters	
				CBM	TRR	Bottom-up analysis of geological parameters	
Potential Committee	Gas Jun-09	No	USA	Shale	TRR	Bottom-up analysis of geological parameters	
				CBM	TRR	Bottom-up analysis of geological parameters	
Rogner	Jan-97	Yes	Continental regions	Shale	OGIP	Extrapolation of production experience	The global figure was modified to regional estimates based on the distribution of conventional gas
				CBM	OGIP	Literature review	
				Tight	OGIP	Literature review	
Ryan	Dec-08	No	12 regions/countries	CBM	OGIP	Not independently assessed: based on Wood Mackenzie 'Unconventional Hydrocarbons' Multi-client Study	

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				Tight	OGIP	Not independently assessed: based on Wood Mackenzie 'Unconventional Hydrocarbons' Multi-client Study	
Sandrea	Dec-05	No	USA	Tight	TRR	Extrapolation of production experience	
				Shale	'Recoverable reserves'	Expert judgment	
				CBM	'Recoverable reserves'	Expert judgment	
Schulz	Jan-10	Yes	Europe	Shale	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
Skipper	Mar-10	No	USA, Canada	Shale	TRR	Method not stated	
Theal	May-09	No	USA, Canada	Shale	OGIP and TRR	Bottom-up analysis of geological parameters	
Total	Jan-06	No	5 regions	Tight	TRR	Method not stated	
			Global	Tight	OGIP and TRR	Method not stated	
USGS	Aug-11	No	USA	Shale	'Potential to be added to reserves'	Extrapolation of production experience	USGS resource estimate based on Coleman et al. (2011); Dubiel et al. (2011); Higley et al (2011); Houseknecht et al. (2010); Schenck et (2008); Swezey et al. (2007); Swezey al. (2005); Pollastro et al. (2004); Higley et al.(2003); Milici et al (2003 and USGS (2010).
				CBM	'Potential to be added to reserves'	Extrapolation of production experience	
				Tight	'Potential to be added to reserves'	Extrapolation of production experience	

Author	Date	Peer review	Countries/regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Wood Mackenzie	Jan-09	No	Europe	Shale	TRR	Method not stated	Reported by R. Weijermars et al., 'Unconventional gas research initiative for clean energy transition in Europe <i>Journal of Natural Gas Science and Engineering</i> , 2011. 3(2): p. 402-412.
Wood Mackenzie	Nov-06	No	12 regions/countries	CBM	OGIP	Unknown	Reported by Ryan (2008) and Gény (2010). Figures appear to be similar to Rogner's
				Tight	OGIP	Unknown	Reported by Ryan (2008) and Gény (2010). Figures appear to be similar to Rogner's
World Energy Council	Sep-10	No	9 regions	Shale	OGIP	Literature review	Recovery factor of 40% suggested to convert to ERR

G Major regulations for the EU internal gas market

The Second Gas Directive of 2003¹ committed Member States to the establishment of a single market throughout Europe by July 2007. Covering much the same ground as its 1998 predecessor – albeit more forcibly – the Directive ruled that each Member State had to appoint system operators for the transmission, storage, LNG and distribution systems who would guarantee non-discriminatory and transparent access for all users. Member States also had to appoint independent regulators who would be responsible for monitoring respect of the non-discrimination principle, the level of transparency and competition, and the tariffs and methods for calculating them. The choice to have regulated or negotiated third-party access was removed. And finally the Directive codified common minimum consumer protection standards, including the rights to change supplier, transparent contract conditions, general information and dispute settlement mechanisms.

In spite of these more robust measures, a series of Commission reports monitoring the Directive's implementation documented disappointing progress in the liberalisation process.² These reports noted that although 'the basic concepts of the internal energy market have become embedded in terms of the legal framework, institutional arrangements and the physical infrastructure... meaningful competition does not exist in many Member States'. Citing 'widespread shortcomings', it was deemed that gas prices in many Member States were more likely 'the direct result of decision of companies with market power' than meaningful competition.³

Complaints about the barriers to market entry and the lack of meaningful consumer choice led the Commission to open an inquiry into the operation of the gas and electricity markets. This found: 1) a continuing high degree of market concentration; 2) inadequate unbundling of network and supply, and suspicions that infrastructure operators were favouring their own affiliates; 3) a lack of market integration, including lack of regulatory oversight for cross-border issues; 4) a lack of market transparency; 5) price formation deficiencies stemming from oil indexation and regulated supply tariffs; 6) limited competition at the retail level; 7) balancing markets that favour incumbents and create obstacles for newcomers; and 8) various other deficiencies in the LNG market.⁴

In response, the Commission launched dozens of infringement procedures against Member States for violation and non transposition in the five years following the Second Directive's transposition deadline on 1 July 2004.⁵ Despite these efforts, however, a

¹ European Union, 'Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC', (Luxembourg: Office for Official Publications of the European Communities, 2003).

² See, for example, European Commission, 'Third benchmarking report on the implementation of the internal electricity and gas market', ed. Directorate-General for Transport and Energy (Luxembourg: Office for Official Publications of the European Communities, 2007).

³ European Commission, 'Communication from the Commission to the Council and the European Parliament - Prospects for the internal gas and electricity market', (Luxembourg: Office for Official Publications of the European Communities, 2007).

⁴ European Commission, 'Communication from the Commission Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report)', (Luxembourg: Office for Official Publications of the European Communities, 2007).

⁵ See, for example, European Commission, 'Commission acts to ensure effective and competitive energy market across Europe', (Brussels: 2009); European Commission, 'Commission brings actions before Court

2009 Commission report noted that the implementation of the second Electricity and Gas Directive was still incomplete. With respect to market concentration, the Commission found that the three largest wholesalers had a market share of 90% or more in 12 Member States. Ownership unbundling was implemented by only 12 of the EU's gas transmission system operators (TSO).⁶

Considering that the internal energy market could not be realised under the prevailing rules, the Commission initiated work on its Third Internal Market Package in 2007 – a collection of regulations and directives that took direct effect on 3 March 2011.⁷ The package set more stringent conditions for pipeline access and gave stronger powers and independence to national energy regulators. It introduced new measures to harmonise pan-European market and network operation to facilitate cross-border trade and reduce transaction costs. It also created new institutions to promote the completion and functioning of the internal market, including an Agency for the Cooperation of Energy Regulators and an association of gas transmission system operators.⁸ The inception of the Third Package coincided with a big legal push against abuse of dominance in the natural gas sector, with the Directorate-General for Competition bringing cases against Distrigaz, E.ON, ENI, GDF and RWE in the period 2007-2011.⁹

of Justice against several Member States for incorrect transposal of Electricity and Gas Directives', (Brussels: 2008); European Commission, 'The Commission takes action against Member States which have still not properly opened up their energy markets', (Brussels: 2006); European Commission, 'Energy markets: five Member States to be taken before the Court of Justice', (Brussels: 2005); European Commission, 'Opening up of energy markets: ten Member States have still not transposed the new EU rules ', (Brussels: 2005).

⁶ European Commission, 'Communication from the Commission to the Council and the European Parliament - Report on progress in creating the internal gas and electricity market '.

⁷ European Union, 'Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (Text with EEA relevance)'; European Union, 'Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (Text with EEA relevance)'; European Union, 'Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (Text with EEA relevance)'.

⁸ In order to properly facilitate investments, both the second Gas Directive and a third package contain provisions for alternative coordination mechanisms, such as derogations from the third-party access provisions and long-term supply contracts.

⁹ European Commission, 'Antitrust / ENI case: Commission opens up access to Italy's natural gas market ', (Brussels: 2010); European Commission, 'Antitrust: Commission accepts commitments by GDF Suez to boost competition in French gas market ', (Brussels: 2009); European Commission, 'Antitrust: Commission fines E.ON and GDF Suez €553 million each for market-sharing in French and German gas markets', (Brussels: 2009); European Commission, 'Antitrust: Commission opens Belgian gas market to competition', (Brussels: 2007); European Commission, 'Antitrust: Commission opens German gas market to competition by accepting commitments from RWE to divest transmission network', (Brussels: 2009).

H Evaluating potential shale gas wells and quantifying finding and developing costs

Table H-1: FX Energy's drilling programme in Poland and net asset value analysis¹

Net Asset Value (NAV) Analysis (\$ in millions, except per share amounts)								Total	per share	per share
Undrilled Potential Prospect	Potential Recoverable		FX Net Interest after 1st well	Net Potential Recoverable		Chance of Success	Est. Net Value (mm) *	Risked Value per share	Unrisked Value per share	Cost (mm) to Drill Discovery
	(Bcfe)	(Bcme)		(Bcfe)	(Bcme)					
Fences - Lisewo satellites (5)	60	1.6	49%	29	0.8	75%	\$ 67	\$ 1.27	\$1.69	\$25
Fences - Lisewo SE	350	9.4	49%	172	4.6	40%	\$ 209	\$ 3.95	\$9.88	\$5
Fences - Plawce (tight gas)	250	6.7	49%	123	3.3	50%	\$ 186	\$ 3.53	\$7.06	\$6
Fences - Plawce East	875	23.5	49%	429	11.5	20%	\$ 261	\$ 4.94	\$24.70	\$5
Fences - Mieczewo	30	0.8	49%	15	0.4	40%	\$ 18	\$ 0.34	\$0.85	\$5
Fences - Miloslaw	50	1.3	49%	25	0.7	25%	\$ 19	\$ 0.35	\$1.41	\$5
WS - Michrow	230	6.2	51%	117	3.1	15%	\$ 53	\$ 1.01	\$6.76	\$4
WS - Grojec	700	18.8	51%	357	9.6	15%	\$ 163	\$ 3.08	\$20.56	\$4
NW - Plonsko	180	4.8	51%	92	2.5	15%	\$ 42	\$ 0.79	\$5.29	\$0
Kutno	9500	254.7	50%	4750	127.3	10%	\$ 1,444	\$ 27.36	\$273.60	\$10
Bakken	675	18.1	33%	225	6.0	40%	\$ 273	\$ 5.18	\$12.95	\$3
Total Risked Potential	12,900	345.8		6,332	169.8	16%	\$ 2,734	\$51.81	\$364.74	\$71
Shares Outstanding (millions)								52.8	52.8	
Risked Discovery Potential and Net Asset Value Per Share								\$57.50	\$370.43	

¹ FX Energy, 'Poland'.

Figure H-1: Example of finding and development costs for range resources²

RANGE RESOURCES CORPORATION
FINDING AND DEVELOPMENT COST CALCULATIONS

During the past three years, we have increased our proved reserves 199% at an average finding and development cost of \$1.23 per mcfc (before future development costs). Our finding and development cost ratio is derived directly from our Costs Incurred schedule, excluding non-cash costs and costs incurred for gathering facilities, (see Note 19 Supplemental Information on "Natural Gas and Oil Exploration, Development and Production Activities") and our reconciliation of beginning and ending proved reserves. The following table details our calculation of finding and development costs which is typically done by financial analysts and a calculation of finding and development described in SEC Oil and Gas Alert 05-1:

	2010	2009	2008	Combined
				Three years
Costs incurred:				
Acquisitions:				
Acreage purchases	\$ 166,677	\$ 176,867	\$ 494,341	\$ 837,885
Unproved leasehold acquired	3,697		99,446	103,143
Proved oil and gas properties	130,767	-	251,471	382,238
Asset retirement obligations	556	-	251	807
Development expenditures	834,890	554,823	862,384	2,252,097
Exploration expenditures	56,879	42,082	63,560	162,521
Exploration expenditures -- non-cash	4,209	4,817	4,130	13,156
Asset retirement obligations changes	(6,523)	6,131	4,647	4,255
Gas gathering facilities:				
Acquisitions				
Development	20,726	29,524	47,056	97,306
Total costs incurred per 10-K	<u><u>\$ 1,211,878</u></u>	<u><u>\$ 814,244</u></u>	<u><u>\$ 1,827,286</u></u>	<u><u>\$ 3,853,408</u></u>
Changes in future development costs	<u><u>\$ 474,058</u></u>	<u><u>\$ 375,344</u></u>	<u><u>\$ 688,259</u></u>	<u><u>\$ 1,537,661</u></u>
Reserve adds (Mmcfe):				
Extension, discoveries, and additions	1,410,358	769,939	518,404	2,698,701
Purchases	124,981	-	95,578	220,559
Revisions	148,559	3,890	(42,334)	110,115
	<u><u>1,683,898</u></u>	<u><u>773,829</u></u>	<u><u>571,648</u></u>	<u><u>3,029,375</u></u>
Finding and development costs as described in SEC Oil & Gas Alert 05-1				
Total costs incurred	\$ 1,211,878	\$ 814,244	\$ 1,827,286	\$ 3,853,408
Changes in future development costs	<u><u>474,058</u></u>	<u><u>375,344</u></u>	<u><u>688,259</u></u>	<u><u>568,090</u></u>
	<u><u>\$ 1,685,936</u></u>	<u><u>\$ 1,189,588</u></u>	<u><u>\$ 2,515,545</u></u>	<u><u>\$ 4,421,498</u></u>
Total overall finding & development costs	<u><u>\$ 1.00</u></u>	<u><u>\$ 1.54</u></u>	<u><u>\$ 4.40</u></u>	<u><u>\$ 1.46</u></u>
Finding and development costs as typically calculated by analysts --				
Total costs incurred	\$1,211,878	\$814,244	\$1,827,286	\$3,853,408
Less -				
Gas gathering facilities	(20,726)	(29,524)	(47,056)	(97,306)
Asset retirement obligations	5,967	(6,131)	(4,898)	(5,062)
Non-cash Exploration expenses	(4,209)	(4,817)	(4,130)	(13,156)
Total costs used	<u><u>\$1,192,910</u></u>	<u><u>\$773,772</u></u>	<u><u>\$1,771,202</u></u>	<u><u>\$3,737,884</u></u>
Total overall finding & development costs	<u><u>\$ 0.71</u></u>	<u><u>\$ 1.00</u></u>	<u><u>\$ 3.10</u></u>	<u><u>\$ 1.23</u></u>

² Range Resources is an upstream player active in the Marcellus Shale play. Range Resources, *Finding and development cost calculation* (SEC Filings, 2011, cited 12 February 2012); available from <http://phx.corporate-ir.net/phoenix.zhtml?c=101196&p=irol-sec&submit.x=0&submit.y=0>

I A brief comparison of JRC and IEA modelling results on unconventional gas

The following pages compare the modelling methodology and results of this report with those of the recently-released 'Golden Rules for a Golden Age of Gas' report by the IEA.³

Framework

- The JRC-IET builds a framework around four base scenarios for the period to 2040. They result from the combination of either optimistic or conservative assumptions about shale gas production cost and reserve size (Opt/Con) and high or low assumptions about global GDP growth (HG/LG). The four scenarios are subsequently submitted to 6 additional sensitivities, to explore the supply and demand side factors that can constrain or enable unconventional gas development, i.e.: a stronger or weaker oil/gas price link, the social acceptance of nuclear energy, a carbon constrained energy system, a less or more costly LNG transport. Thus, the results are an exploration of uncertainty.
- The model used by JRC is the ETSAP-TIMES Integrated Assessment (ETSAP-TIAM) model, a multi-region partial equilibrium model of the energy systems of the entire world divided in 15 regions, linked by trade variables of the main energy forms (coal, oil, gas). It is based on the MARKAL/TIMES family of models.
- The IEA report sets out projections from two scenarios for the period to 2035, both built on the IEA's New Policies Scenario (2011 World Energy Outlook). The two scenarios compare favourable versus unfavourable conditions for unconventional gas. In the Golden Rules (GR) case, all potential obstacles to unconventional gas development are overcome; supportive policies and a lack of constraints leads to an assumed lower unconventional production cost, greater recoverable reserves, more favourable demand-side policies, lower gas prices, and less gas-oil indexation. The Low Unconventional (LU) case models the opposite case, where there is an absence of supportive policies and a lack of public acceptance.
- The IEA uses the World Energy Model (the same used for the annual World Energy Outlook) to project the potential impact of two different trajectories for unconventional gas development.

Assumptions

- The JRC-IET's variables are the size of the recoverable reserves and their production cost, which are used to build supply curves (the rate of increase in production costs of the resource base). These curves represent the range of uncertainty facing unconventional gas development without explicitly linking them to specific factors (e.g. adherence to 'golden rules'). The third key variable is the rate of GDP growth, a main driver for gas demand. Gas prices are endogenous in TIAM, i.e. they result from the supply/demand equilibrium in any given scenario. All other assumptions remain

³ IEA, 'Golden Rules for a Golden Age of Gas'.

constant from TIAM reference scenario, which can be considered similar to the Current Policies case of WEO-2011 (it does not account for future policies).

- The IEA does not directly model the impact of different degrees of adherence to the Golden Rules. Rather, the report assumes that a lack of supportive policies (e.g. failure to abide by the 'golden rules') translates into less recoverable gas reserves than in the GR case. They also assume that the rate of increase in production costs is higher in the Low Unconventional case than in the GR case. Thus, the two main variables are the size of the recoverable reserves and their production costs, which are varied to reflect hypothetical adoption of these rules. GDP assumptions were updated from the baseline WEO-2011 case and applied to both the LU and GR case. Gas price assumptions are exogenous; the IEA assumes that the gas price in the Low Unconventional case is 15-30% higher than in the Golden Rules case, with a more rapid rate of increase over time. All other assumptions remain constant from the New Policies Scenario of WEO-2011, which takes into account policies and declared future intentions as of mid-2011 (e.g. national pledges to reduce GHG emissions and phase out subsidies⁴).

Key Assumptions	JRC	IEA
Recoverable Reserves (tcm)		
Conventional gas	403	421
Shale gas	149-417	30-208
Production Cost (\$/Mbtu)	low/best/high	
USA (Shale)	4 - 6.5 - 19	3-7
EUROPE (Shale)	4.4 - 7 - 21	5-10
Avg. Annual Global GDP growth, % (2012-35)	2.7-3.7	3.5

Results

Due to the different assumptions used in the two analyses, the results can be compared only broadly. However, the tables below show similarities in terms of some key results.

Key Results (Low/High Unconv. Gas)	JRC (2035)	IEA (2035)
Total Gas Demand	4.9 / 5.6 tcm	4.6 / 5.1 tcm
Unconv. Gas Production	1 / 2.1 tcm	0.6 / 1.6 tcm
UG-USA	500 / 940 bcm	274 / 580 bcm
UG-China	170 / 350 bcm	112 / 391 bcm

Key Results	JRC (2035)	IEA (2035)
Total gas trade - High vs Low UG	-11%	-23%
Europe import dependency - High vs Low UG	57% / 72%	59% / n/a
EU gas import (Low-High UG)	430 / 470 bcm	
Electr. prod. from nat. gas (TWh)	6 144 / 7,966	7 100 / 8,780

⁴ It is important to note that the IEA report does not explicitly or systematically present the way in which the assumptions are used in the model. Therefore, the methods used to model the assumptions can only be inferred.

Further significant results are the following:

- A consistent significant result is the impact on gas prices of more unconventional gas. The JRC model results are similar to the IEA's exogenous assumptions: the optimistic shale gas case assumes a reduction of gas price between 20% (Europe) and 30% (USA) in the IEA report, while the JRC report analysis estimates a reduction between 15% (Europe) and 25% (USA).
- Both studies agree that the best case scenario for shale gas development in Europe is one in which declining conventional production can be replaced by unconventional gas, with import dependence maintained at a level around 60%.
- A result consistent across the two studies is that greater unconventional gas has only a slight impact on renewable energy.
- The specific JRC analysis on the potential impact of a carbon constrained world shows that strict CO₂ targets do not preclude a significant growth in natural gas use.

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